The Morag Field, Block 16/29a, UK North Sea

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Abstract
The Morag Field is a small oilfield underlying the Maureen Field in UK Block 16/29a. Black oil is trapped within Upper Permian, Morag Member, vuggy and fractured dolomite rafts between 9,300 ft and 10,600 ft TVDSS. The dolomite reservoir occurs at the top of a Zechstein salt dome. Morag was discovered in 1979 by well, 16/29a-A1, the first platform well drilled for the overlying Maureen Field with its Palaeocene sandstone reservoir. Morag was produced via a single well (16/29a-A1) between 1991 and 1994. Three more platform wells were drilled into the Permian interval prior to Maureen Field start up but only one penetrated oil-bearing dolomite (16/29a-A2). An additional well (16/29a-A23Z) was drilled into the Morag Field in 1993. The well encountered Morag Member at virgin pressure and tested oil at high flow rate but then the well failed due to mechanical problems. Oil in place was calculated to be about 24 mmbbl in four independent fault blocks. Ultimately 16/29a-A1 delivered 2.6 mmstb from a fault block calculated to have held 6.7 mmbbl STOIIP.

Key Words
Morag Field, Zechstein Morag Member, fractured dolomite reservoir, Block 16/29a

The Morag Field lies 165 km east of Aberdeen and 5 km west of the UK/Norway median line in UKCS Block 16/29a (Figure 1). The water depth in this area is about 100m. Morag and Mary fields are two small oil accumulations in Permian and Jurassic strata respectively that occur beneath the larger Maureen Field (Palaeocene reservoir). The terms 'Morag' and 'Mary' were used to differentiate the three reservoirs in the formally named Maureen Field. All three fields were discovered, developed, produced and abandoned by a Phillips Petroleum led partnership. Production from the Maureen cluster ceased in 1999. Following field abandonment in 2003 but before license relinquishment, the fields were sold to an Acorn Oil and Gas/Apache partnership with a view to field redevelopment. Acorn Oil and Gas was bought-out by Fairfield Energy in 2005 and Apache became the operator. Three wells were drilled by Apache to re-evaluate the Palaeocene reservoir interval but no new wells were drilled into the Zechstein succession. The licences were relinquished in 2010.

This paper describes the Morag Field in detail and builds upon the study by Chandler and Dickinson (2003), adding information from the Acorn/Apache remapping and re-evaluation.

History of Exploration and Appraisal

The first well drilled on Block 16/29 by the Phillips-led consortium was 16/29-1, 1X in 1972. A four-way, dip-closed structure overlying a salt dome had been mapped using just ten seismic lines totalling 135 km acquired over the block. Oil was discovered in the oldest Palaeocene sandstone encountered (Maureen Formation) at 8220 ft true vertical depth sub-sea level (TVDSS). The well was drilled to a terminal depth of 13,000 ft BRT (12, 910 ft TVDSS) of which the lowermost 3228 ft were Upper Permian (Zechstein Group) strata (Figure 2). Although almost entirely halite, the Zechstein Group interval included an uppermost 33 ft of dolomite described from cuttings as white, hard, argillaceous and fractured.

No petroleum shows were recorded from the Zechstein dolomite encountered in the well but it subsequently it must have been recognized as a potential target reservoir. Seven years later the Morag discovery was made.

Development drilling on the Maureen Field began in 1979, ahead of the installation of a steel, gravity-based production and drilling platform in 1983. The first development well was 16/29a-A1, drilled directly beneath the intended platform location. It proved 150 ft of net pay in the Palaeocene Maureen Formation reservoir before being deepened to the Permian section. Below 9571 ft TVDSS the well entered what is now known as the Morag (dolomite) Member of the Turbot Anhydrite Formation. The uppermost 55 ft of dolomite was described as clean and oil bearing and tested at a rate of 6250 BOPD. A second pay interval (221 ft thick) was found beneath a 27 ft thick, tight, dolomitic shale. Two tests on this interval flowed at 537 BOPD and 2383 BOPD (Table 1). Quite when the decision was made to drill into Permian strata is not known but it was certainly after the contemporaneous well forecast was issued by the operator Phillips on 25th June 1979 (three days after the well spudded) for it lists only the Palaeocene Andrew Formation, the Danian Burns Formation and the Chalk Ekofisk Formation as secondary targets. There was no indication that the well would be deepened beyond Upper Cretaceous strata.

Well	DST	Top perforation depth (ft BRT)	Bottom perforation depth (ft BRT)	Oil rate (BOPD)	Gas rate (MMSCF /D)	Gas oil ratio (SCF/ BBL)
16/29a-A1	1F	9900	9950	2383	0.88	369
16/29a-A1	2	9960	9710	5414	2.00	369
16/29a-A1	2A	9960	9710	6250	1.83	293
16/29a-A1	3A	9754	9804	537	0.121	232
16/29a-A2	2A	11250 & 11304	11270 & 11316	2338	1.028	440
16/29a-A2	3	11194 & 11154	11218 & 11184	1432	0.511	357

Table 1 Successful drill stem tests (DSTs) in the Morag Field

Following the Morag discovery the second platform well (16/29a-A2) was also deepened to the Permian interval. It found and tested oil from Morag Member dolomites at a peak rate of 2338 BOPD (Table 1). The 16/29a-A2 well also established an oil-down-to of 10,602 ft TVDSS at the bottom of the DST 2A test perforations. The dolomite interval was cored and from these cores, age dates for the interval and a full description of the reservoir were determined. The success was not to last; two further platform wells, 16/29a-A3 and 16/29a-A6 were drilled to Permian reservoir targets but they found only anhydrite overlying salt.

Regional Context

There are about 60 well penetrations of the Upper Permian (Zechstein) interval in the Central North Sea and adjacent areas, in the Northern Permian Basin (Evans *et al*., 2003). There are four produced fields and four discoveries that have Permian, Zechstein reservoirs (Table 2). The fields and discoveries share a common reservoir but it is not clear that they share a common source rock or charge history.

Block	Field/ Discovery	Comments
UKCS 9/28a-3	Crawford	Untested oil column in Zechstein dolomite (Gluyas and Swarbrick, 2004).
UKCS 14/19	Claymore (Zechstein)	Productive dolomite and limestone of the Halibut Bank Formation, vuggy and fracture porosity, 8.2 litres of 33° API oil recovered from formation test, interval not produced (Harker *et al*., 1991)
UKCS 20/2a	Jarvis	Three wells tested the Zechstein from beneath the Ettrick Field. Well 20/2-2, drilled in 1982, tested 9198 BOPD of 36 °API oil from the Halibut Dolomite. The overlying Turbot Dolomite tested 4414 BOPD of 38 °API oil (Amiri-Garroussi and Taylor, 1987). Two wells (E6 and E7) dual completed in the Zechstein and Jurassic reservoirs of Ettrick and North Ettrick.
UKCS 22/17	Carnoustie	Single well produced field beneath Palaeocene reservoir of Arbroath Field, 1 MMBBL produced at a peak rate of 1800 BOPD (Holloway *et al.,* 2006).
UKCS 30/16	Auk	Production of oil from undifferentiated Zechstein dolomites via fractures (Trewin *et al.,* 2003).
UKCS 30/24 & 30/25	Argyll/ Ardmore/ Alma	Twice redeveloped Argyll Field has produced in excess of 80 MMBBL from Zechstein, Rotliegend and Devonian reservoir intervals with most flow coming from or through wells completed in the Zechstein Halibut and Turbot Bank formations (Gluyas *et al.,* 2018).
UKCS 30/25a-4	30/25a-4 discovery	Oil-bearing Zechstein dolomite, failed to flow on test (Gluyas *et al.,* 2005).
NOCS 16/2, 16/3, 16/5	Johan Sverdrup	Oil has been recorded but not tested from the Zechstein interval, a secondary reservoir the in Johan Sverdrup Field (Gluyas and Swarbrick, 2019).

Table 2 Developed fields and discoveries of oil in Permian, Zechstein dolomite reservoirs in the North Sea's oil provinces.

Devonian strata occur in wells to the northwest of Morag on the Fladen Ground Spur and to the south of Morag in northern Quad 22. The Devonian predominantly comprises thick conglomerates, breccias, sandstones and siltstones of continental derivation. However, the nearest possible oil shale source rocks of Devonian age occur in the lacustrine portion of the Orcadian Basin at least 100 km north of the Morag Field (Duncan and Buxton, 1995). Similarly, the nearest known Carboniferous age oil source rocks occur in the Lothians area of Scotland some 300 km southwest of Morag (Loftus and Greensmith, 1988; Underhill *et al.,* 2008).

Lower Permian Auk and Fraserburgh Formations, comprising terrestrial aeolian and fluvial sandstones likely underlie the Upper Permian (Zechstein) evaporites at Morag. A few wells penetrated the Lower Permian in UKCS Quad 16 and each of the adjacent UK and Norwegian Quads.

The Upper Permian Zechstein Group sequences have been described from onshore NE England and well penetrations in adjacent areas of the North Sea (Tucker, 1991).

The Northern Permian Basin (NPB, Figure 3, Evans et al., 2003) has a different stratigraphy compared with the Southern Permian Basin (SPB). In the NPB the Halibut Carbonate Formation (HCF) is used for the Z1 and part of the Z2 cycle, with the Turbot Anhydrite and Shearwater Salt formations for the evaporites above (Deegan and Scull, 1977). The HCF is subdivided into three members (Figure 3, Cameron, 1994). The overlying strata in the NPB have been divided into: an anhydrite-dominated unit, the Turbot Anhydrite Formation, developed in basin-margin locations, and a halite-dominated unit, the Shearwater Salt Formation, occurring as basin-filling halite. These two formations are equivalent to the upper cycles of the SPB, that is the upper part of Z2 together with Z3, Z4, Z5 and Z6.

Deegan and Scull (1977) defined the stratigraphy of the NPB. Since 1977, new wells have encountered hitherto unknown carbonate and siliciclastic units within the Turbot and Shearwater formations (Taylor, 1990). A carbonate unit that occurs within the thick Turbot Anhydrite Formation, has been referred to as the Turbot Carbonate Member (Cameron, 1994), and this is recorded in well 20/2-2 in the Jarvis-Ettrick field (pers comm M.E. Tucker, January 2019). The carbonates and mudstones in the Morag Field occur above 90 ft (27 m) of anhydrite (referred to as Turbot Anhydrite by Chandler and Dickinson, 2003), itself above more than 150 ft (45 m+) of halite (Shearwater Salt). Cameron (1994) informally named this unit the Morag Member of the Turbot Anhydrite Formation.

Recent work by Słowakiewicz *et al*. (2019) has demonstrated that oil seeps in the Boulby Mine on the coast of NE England were in part sourced from Upper Permian (Zechstein) sapropelic dolomite but there is no evidence to suggest that there is a similar source prone dolomite present close to the Morag Field.

Triassic strata are well-developed regionally but some of the Triassic, all of the Lower Jurassic and some of the Middle Jurassic are missing from the Maureen Field area (Figure 2). Triassic strata have been encountered in wells on the northern and western flank of the overlying Maureen Field. The strata comprise continental mudstones and siltstones of the Smith Bank Formation overlain by sandstones and siltstones of the Skagerrak Formation. In common with the main part of the Central Graben to the south it is likely that the Triassic strata were deposited in lows that flanked the developing salt diapirs.

Uplift associated with the Rattray Volcanic Dome led to erosion of the Lower Jurassic interval. The Middle Jurassic Pentland Formation, although absent from Maureen itself is widespread south and west of the field. It comprises non-marine sandstones, coals and mudstones up to 400 ft thick (Chandler and Dickinson, 2003).

The Upper Jurassic Hugin Formation marks the onset of marine conditions in the area. Hugin Formation sandstones form the reservoir in the Mary Field (Chandler and Dickinson, 2003).

The Upper Jurassic syn-rift Heather Formation and Kimmeridge Clay Formation (KCF) overlie the Middle Jurassic strata and Upper Jurassic Hugin Fomation. The KCF is the proven main source rock in the region. The overlying succession of mudstone, chalk and basin-floor fan deposits in the Cretaceous and Tertiary sections were deposited in a post-rift setting. The Tertiary fan systems in the region are the main petroleum reservoirs (Hempton *et al*., 2005).

Although the Upper Jurassic Kimmeridge Clay Formation is the likely source for the oil in the Morag Field, it remains unclear as to how the field was charged, due to a lack of geochemical analysis of the oil. Oil produced from the 16/29a-A1 well has a density of 31.5° API and that from the overlying Maureen Field 36° API (Chandler and Dickinson, 2003). However, oil with near identical gravity to that in Maureen was measured on the oil tested from Morag in well 16/29a-A2. Morag oil might therefore be a little less mature than that of Maureen although it is slightly less viscous and has a slightly higher gas-oil ratio. The KCF is a proven mature and prolific oil source rock in Quad 16 (Mackenzie et al., 1987). The Morag Field is structurally elevated relative to the mature KCF mudrocks off-structure but it is stratigraphically isolated, beneath Triassic shales with structural compartments separated by salt walls. It is possible that off-structure, faults have allowed transmission of oil from the KCF to the Morag Member dolomite.

Database

The database for the Morag Field is not extensive. Six wells penetrated the pre-Triassic interval beneath the Palaeocene Maureen Field (Table 3). Only three of the wells (16/29a-A1, A2 and A23) found the oil-bearing dolomite reservoir and only in A2 was core cut. Wireline log data comprising gamma, sonic and resistivity logs are available for all six wells.

The seismic data comprise 2D lines acquired in 1971, 1981 and 1984 followed by a 3D survey acquired in 1994. All of these surveys were acquired and owned by the Phillips Petroleum-led consortium that operated the block. In 2004 a non-proprietary 3D regional survey was acquired by PGS (MC3D-LGW2004) and these data formed the basis for the Apache/Fairfield field re-evaluation.

Well	Reservoir	Test rate (bopd)	Fluid contacts
16/29-1	45 ft fractured dolomite	Not tested at Permian level	No petroleum encountered in Permian interval
16/29a-A1	306 ft fractured dolomite	6,250 bopd of 31.3° API oil	No OWC found
16/29a-A2	100 ft fractured dolomite	2,338 bopd	Oil down to 10,602 ft TVDSS
16/29a-A3	Anhydrite, no dolomite	No test	No petroleum
16/29a-A6	No reservoir, well terminated in salt at top Permian	No test	No petroleum
16/29a-A23	20 ft of dolomite base not penetrated	Oil bearing but not tested (mechanical well failure)	No contacts encountered

Table 3 Wells within Block 16/29a that penetrated Permian strata, Morag well database.

Trap

When production from the Palaeocene reservoir of the Maureen Field came off plateau in 1987, the field operator re-examined data from the Morag discovery (Chandler and Dickinson, 2003). The trap was remapped as an upthrown block delineated by faults to the southeast, south and southwest. The crest of the block trends NW-SE. The crest was determined to be at 9,300 ft TVDSS and about 1300 ft above the oil-down-to at 10,602 ft TVDSS. Further structural complexity was revealed on interpretation of two 3D seismic data sets acquired in 1994 and 2004 (Figure 4).

Given that the stratigraphically younger Triassic (Smith Bank and Skaggerak Formations) and Middle Jurassic (Pentland Formation) strata thin onto the crest of the salt structure, there is an element of stratigraphic truncation trapping the Morag Field as well as the more obvious structural trap component (Figure 5).

Reservoir and Petrophysics

The reservoir description for the Morag Field is based on the only cored well, 16/29a-A2. Cores 4 and 5 (20 feet in total) were the only cores cut in the reservoir interval and represent the basal, poorer quality, part of the reservoir (Figure 6). The lowest 2 ft of the core is composed of sub-fissile, silty dolomitic mudstone containing slickenside-covered fracture surfaces.

The dolomite overlying the shale is a complex mixture of dolomitic siltstone, doloarenite and dolomite breccia. It contains bioclastic-rich horizons a few centimetres thickness, with disarticulated bivalves, gastropods, abraded shell fragments and possible ooids. The breccia contains cobble sized and larger clasts that comprise a coarsening upwards sequence. The clasts exhibit a poorly-developed fitted texture with complex rounded shapes. Some pores between clasts and the original porosity within clasts is partially filled by sparry dolomite, calcite and barite.

The breccia is overlain by argillaceous dolomicrite with fine convoluted lamination. In some cases there are numerous white streaks, distorted and broken, as if they are disrupted by veins and/or fracture fills (Fig. 6A). A sinuous sub-vertical fracture filled by dolospar within this layer has been compacted. The dolomicrite is succeeded by further thin units of clast-supported and matrix-supported breccia with some rounded pebble to cobble-sized clasts, but other clasts are extremely angular and appear to have undergone shearing (Figs. 6B, C, D, E, F). Some clasts could consist of microbial laminite (Fig. 7F). The pore system between the clasts and in fractured in-situ dolomite has been partially occluded by dolospar and small quantities of calcite (Fig. 6E). The clast-supported breccia is overlain by a matrix-supported breccia with inverse grading. Towards the top of the core, the coarsely brecciated dolomite shows well-developed but coarsely crystalline laminae and mottled dense patches that be microbial. There are small patches of replacement chalcedonic quartz (Fig. 6F).

In the absence of bioclastic grains and sedimentary structures, the basal shale is interpreted as an evaporite dissolution residue probably formed during exposure of the underlying diapir. Dolomitisation has obscured most of the original sedimentary structures in the overlying dolomite. However, from the structures and allochems that remain the finer grained wackestone are interpreted as low-energy subtidal deposits, probably deposited below normal wave base. The packstone and grainstone intervals may have formed as subtidal facies deposited above normal wave base with the possible development of oolitic and bioclastic carbonate sand bodies. Laminated beds may be microbial, shallow subtidal to intertidal.

The cored interval appears to represent three or more metre-scale shallowing-upward cycles that have been overprinted by collapse brecciation Each cycle comprises an upward transition from very fine-grained argillaceous dolomicrite deposited in a deeper shelf setting that shallows upwards into dolowackestone deposited in a low-energy subtidal environment passing upwards into dolopackstone and dolograinstone, deposited as a series of bioclastic and (possible) oolitic carbonate sand bodies, with local microbial mats.

All of the inferred sedimentary cycles contain evidence of brecciation and deformation with an indication of a progressive upward change from ductile to brittle behaviour through each cycle. The poorly-developed fitted fabric suggests that much of the brecciation is in situ and represents collapse brecciation, the rounded nature of clasts and fractures suggests that these have undergone some dissolution, possibly in a karstic setting. The pervasive presence of collapse brecciation suggests that it is also likely that some evaporites were present at the top of these cycles that have since dissolved. The frequent occurrence of sheared fabrics indicates movement that is likely to have been induced by movement of the salt diapir. This is interpreted as a series of stacked collapse breccias with collapse induced by the dissolution of evaporite minerals underlying the dolomite as a whole and also along former cycle boundaries.

Overall, the dolomite units that form the Morag Field are interpreted as rafts detached from their original stratigraphic position by salt movement (Clark et al., 1998).

There is scant evidence of matrix porosity in the dolomite. The pore system consists of vuggy and fracture-like macroporosity between clasts formed by collapse brecciation and dissolution. Fractures and interclast pores are partly filled by dolomite cement but retain some porosity. The macropore system is restricted to the high-energy dolowackestone to dolograinstone facies that comprise a much harder lithology producing a layered reservoir with permeable layers interbedded with impermeable argillaceous dolomicrite layers. The permeable layers may have been disrupted by deformation.

The porosity in the dolomite reservoir, calculated from wireline log data, is between about 3.5% and 4.2%. This includes both fracture porosity and inter-crystalline porosity. Water saturations are low, ranging between 10-20%. No core-based permeability measurements are available. The productivity index calculated from well test and production data lies in the range of 0-25 bbl/day/psi.

Production History and Reserves

Production from the Morag Field via well 16/29a-A1 began in March 1991 (Figure 7). In April of 1991, with near-zero downtime, the well delivered on average 12,742 bopd with a wellhead pressure of a little over 6000 psig. By July of 1991, production had slipped to below 5000 bopd and although a plateau of sorts was maintained for about a year, production continued to fall.

The operators drilled a second well. The 16/29a-A23 well was side-tracked from a downdip producer that originally targeted the Palaeocene reservoir (16/29a-A6). It was drilled to the south east of the platform into what was expected to be a separate compartment in the Zechstein dolomite reservoir. Spudded in November 1992, the well reached target in June 1993 by which time production from 16/29a-A1 had fallen to 1000 bopd. The new well did find an oil-bearing dolomite reservoir at virgin pressure confirming that this was an area isolated from well 16/29a-A1. However, the coiled tubing became stuck and two subsequent side-tracks failed to penetrate the reservoir objective.

Well 16/29a-A1 continued to produce at an ever-reducing rate until cessation of production in September 1994. By this time the Morag Field had produced 2.6 million barrels of oil. Plotted on Figure 7 alongside the oil production data are those for gas production, water-oil ratio and pressure. The profiles of all four components combine to paint a very clear picture of gas exsolution drive in a system without natural aquifer support. As pressure and hence oil production fell, production of gas trebled in just 18 months after field start-up. It then fell rapidly to the end of field life, effectively robbing the well of any natural lift. Water production was minimal (<300 bwpd) throughout the field life indicating the absence of any natural aquifer beneath the oil leg.

Chandler and Dickinson (2003) published oil-in-place figures for the Morag Field calculated at different stages, both before and after production. To these data more recent oil-in-place figures have been added from the work by Apache and Fairfield in 2007 and based upon the 3D seismic data volume acquired in 2005 (Table 4).

Year	Field segment	Oil in place (MMSTB)	Comments
1989	Morag (all)	5.5 base 9.9 upside	From the Annex B submission 5 wells + 1981 & 1984 2D seismic surveys
1990	Morag 4 compartments A1 area 5.8 A23 area 7.4	16.6	Pseudo 3D seismic based on above surveys
1994	Morag area A1	5.15	Material balance before final well shut-in
2007	Morag 4 compartments A1 area 6.7 A2 area 6.8 NE flank 6.9 S flank 3.5	23.9	Based on 2005 3D seismic volume

Table 4 Progression of oil in place estimates for the Morag Field.

Given that the field production data indicate the Morag Field produced via gas exsolution drive with zero gas-cap or aquifer drive, then the expectation would be to have achieved a low recovery factor of 5% to 30% (Gluyas and Swarbrick, 2004). The field produced 2.6 MMBBL without pressure support and this equates to a recovery factor of 39% if the STOIIP from the 2007 work by Apache and Fairfield is used. It seems likely that all of the STOIIP calculations presented for the volume of oil connected to well 16/29a-A1 presented in Table 4 are too low. Most likely the connected oil volume to well 16/29a-A1 is larger than 8.5 MMBBL (recovery factor 30%). Given the difficulty of imaging the dolomite rafts on 3D seismic data and the low porosity assigned to the dolomite, then a larger volume of connected oil than has previously been calculated for Morag is entirely feasible.

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Captions to figures

Figure 1 Location of the Morag Field in Block 16/29 of the UK North Sea (adapted from the UK Oil and Gas Authority online maps https://ogauthority.maps.arcgis.com/apps/webappviewer/index.html?id=adbe5a796f5c41c68fc762ea137a682e)

Figure 2 Stratigraphic column for the Morag, Mary, Maureen, Moira and Maria fields and Mabel discovery in Block 16/29. Adapted from Chandler and Dickinson, 2003.

Figure 3 Comparison of Zechstein Group stratigraphic nomenclature in the Southern Permian Basin with litho and possible chronostratigraphy of the same interval from the Moray Firth and Morag Field areas (adapted from Johnson et al, 1994).

Figure 4 A. Reference map, top reservoir (top Maureen Formation) depth map for the Maureen Field, B. top reservoir (top Morag Fm.) map for the underlying Morag Field with well penetrations and production/test performance data, C. Inset map showing reservoir compartments in the Morag Field.

Figure 5 A. Seismic two-way time section across the Morag Field (north to left), B. Geoseismic interpretation of the same cross section. Shallowest colour-filled interval is the Jurassic interval.

Figure 6. Core photographs from well 16/29a-A2. A. Argillaceous dolomite with many sheared and deformed white veins/fracture fills. Field of view 10 cm across, core depth 11,205 ft. B. breccia with clay-rich dolomite clasts 5-15 mm across, some appear distorted and shredded. Field of view 8 cm across, core depth 11,198 ft. C. Breccia of dolomicrite matrix with darker clay-rich angular clasts. Field of view 10 cm, core depth 11,197 ft. D. Large rounded clast of dolomite (microbial) in deformed matrix of clay-rich dolomicrite with smaller clasts. Field of view 10 cm, core depth 11,196 ft. E. Coarsely laminated dolomite, possibly with laminoid fenestrae and of microbial origin. Many fractures, filled with coarse dolomite but some porosity remaining. Field of view 10 cm across, core depth 11,200 ft. F. Very hard dolomicrite with thick laminae in upper part and dense colour-mottled areas, all likely microbial; patches of chalcedonic silica (white on left). Field of view 10 cm, core depth 11, 193 ft.

Figure 7 Production profile for oil (barrels of oil per day) and gas (thousand standard cubic feet per day) from the Morag Field with time series data for reservoir pressure (pound-force per square inch gauge, relative to atmospheric pressure) and water oil ratio.

Morag Field	*(Data and suggested Units)*	*(Author's explanatory comments)*
Trap		
Type	Structural (fault blocks) and stratigraphic	
Depth to crest	9300 (ft TVDSS)	
Hydrocarbon contacts	10,602 (ft TVDSS) ODT	Deepest closing contour 10,700 ft TVDSS
Maximum oil column thickness	>1302 (ft)	
Maximum gas column thickness	n/a	
Main Pay Zone		
Formation	Morag Member, Turbot Anhydrite Formation	
Age	Upper Permian (Zechstein)	
Depositional setting	Restricted marine	
Gross/net thickness	310 ft net 110 ft	50 ft upper dolomite, 200 ft dolomitic shale 60 ft lower dolomite
Average porosity (range)	3.8% (0-4.2%)	Includes fracture porosity
Average net:gross ratio	100% (no cutoffs applied)	For both upper and lower dolomite
Cutoff for net reservoir	-	No cut-off used
Average permeability (range)	-	Fracture permeability not measured on core
Average hydrocarbon saturation	85%	
Productivity index range	0.5 to 25 bbl/day/psi	
Hydrocarbons		
Oil gravity	31.5 (°API)	36 and 36.7 °API recorded in well A2
Oil properties	Viscosity 0.566 cp	
Bubble point (oil) Dew point (condensate)	1938 psig	
Gas/Oil Ratio or Condensate/Gas Ratio	232 SCF/bbl	Listed at 700 SCF/bbl in Memoir 20 annex table 232-269 in A1
Formation Volume Factor (oil)	1.614	
Gas gravity	0.836 to 0.879	Recorded from well A2
Gas Expansion Factor	-	
Formation Water		
Salinity	- (ppm NaCl equiv.)	
Resistivity	- ohm-m at - °C	
Pressure gradient - water	- psi ft^{-1}	
Reservoir Conditions		

Temperature	132 (°C)	
Initial pressure	6113 psi	@ 9800 ft TVDSS
Hydrocarbon pressure gradient - oil	0.32 psi ft^{-1}	
Hydrocarbon pressure gradient - gas	19,400 acre ft	
Field Size		
Area	1175 (acres)	
Gross Rock Volume	19,400 (ac-ft)	
STOOIP	16.5 mmstb	1990 value based on 2D seismic, penetrated compartment (1 of 4) 5.8 mmbbl
Associated GIP	Not calculated (bcf)	
Non-associated GIP	-	
Drive mechanism (primary, secondary)	Primary	
Recovery to date - oil	2.6 (mmbbl)	
Recovery to date - gas	Not recorded (bcf)	
Expected ultimate recovery factor/volume - oil	16 (%) / 2.6 (mmbbl)	45% of compartment volume
Expected ultimate recovery factor/volume - gas	- (%) / - (bcf)	
Production		
Start-up date	1991	
Number of Exploration/Appraisal Wells	1 E, 5A	
Number of Production Wells	1	A second production well was drilled to reservoir but was plugged and abandoned due to pressure issues
Number of Injection Wells	0	
Development scheme	Exsolution drive	
Plateau rates – oil/gas	12,000 bopd 0.4 mmcfgd	For 1991 only
Planned abandonment	Shut in 1994, abandoned 2003	

MORAG MEMOIR FIGURES

Fig 1 location map

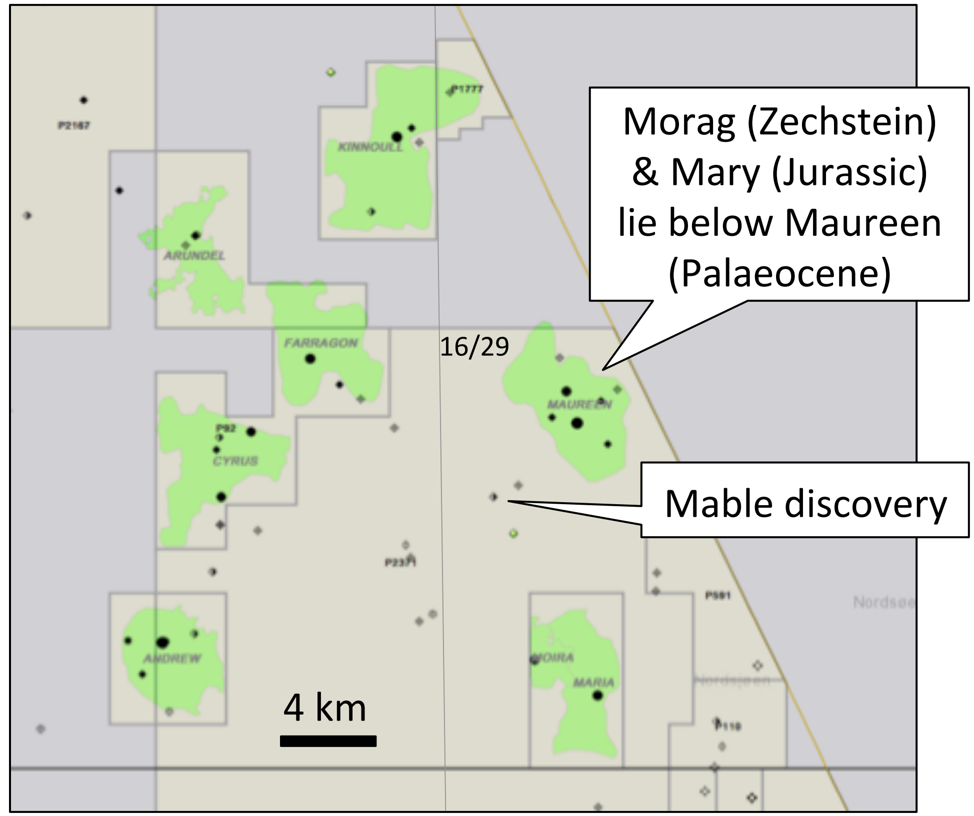


Figure 1 Location of the Morag Field in Block 16/29 of the UK North Sea

Figure 2 stratigraphy

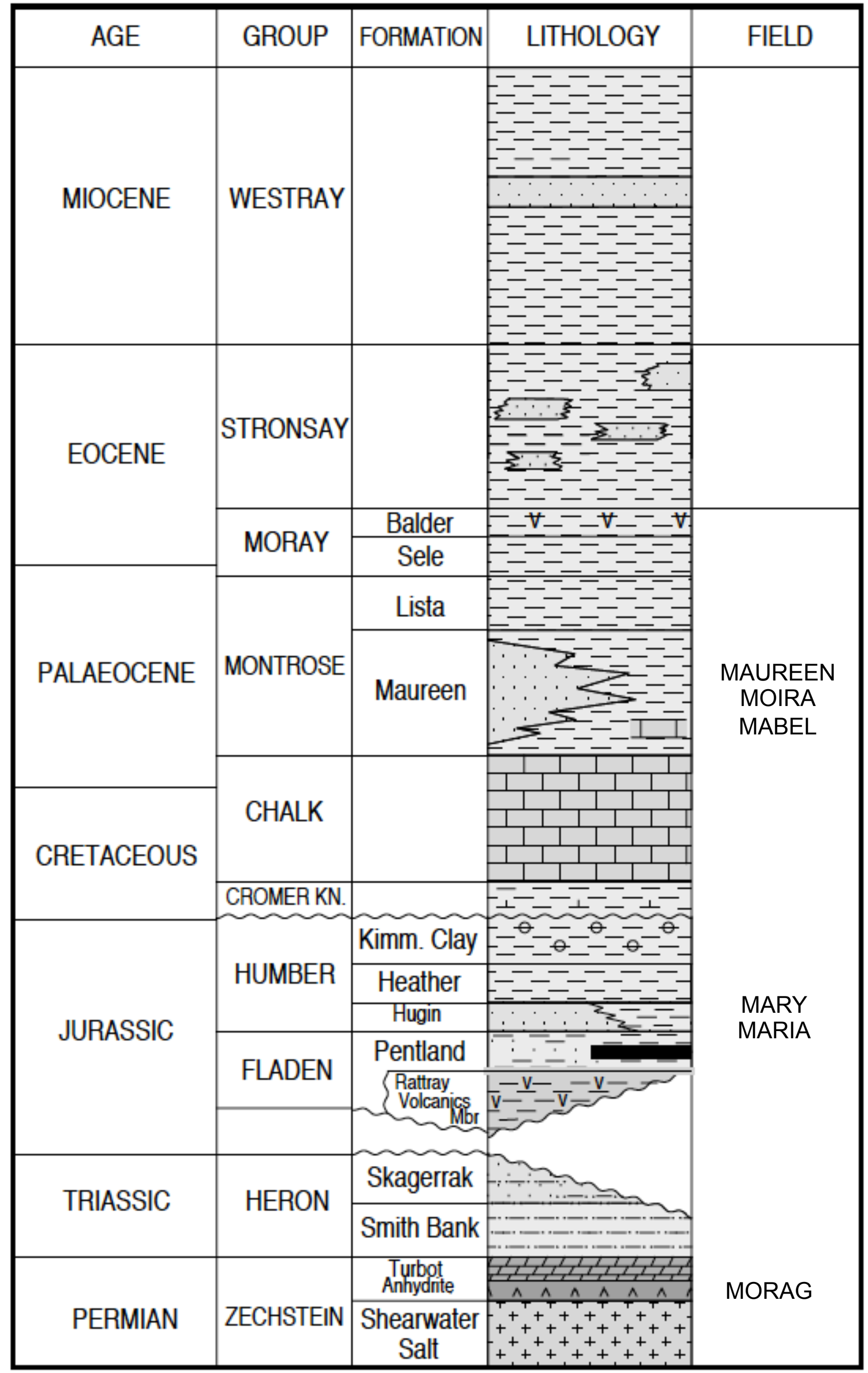
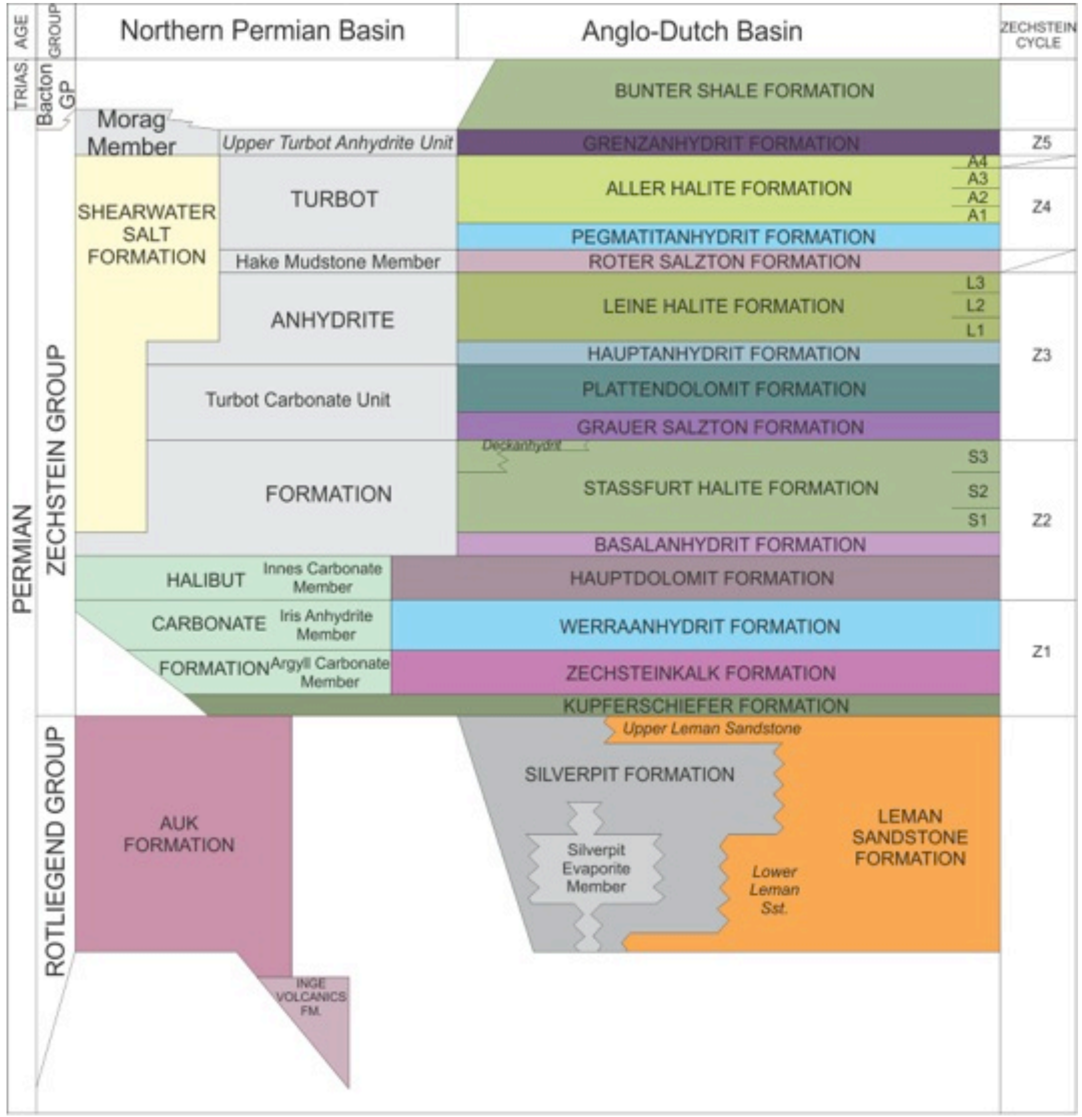


Figure 2 Stratigraphic column for the Morag, Mary, Maureen, Moira and Maria fields and Mabel discovery in Block 16/29. Adapted from Chandler and Dickinson, 2003.

Figure 3



AGE
GROUP
Northern Permian Basin
Anglo-Dutch Basin
ZECHSTEIN CYCLE
TRIAS.
Bacton GP
PERMIAN
ZECHSTEIN GROUP
ROTLIEGEND GROUP
Morag Member
Upper Turbot Anhydrite Unit
SHEARWATER SALT FORMATION
TURBOT
Hake Mudstone Member
ANHYDRITE
Turbot Carbonate Unit
FORMATION
HALIBUT
Innes Carbonate Member
CARBONATE
Iris Anhydrite Member
FORMATION
Argyll Carbonate Member
AUK FORMATION
INGE VOLCANICS FM.
BUNTER SHALE FORMATION
GRENZANHYDRIT FORMATION
ALLER HALITE FORMATION
A4
A3
A2
A1
PEGMATITANHYDRIT FORMATION
ROTER SALZTON FORMATION
LEINE HALITE FORMATION
L3
L2
L1
HAUPTANHYDRIT FORMATION
PLATTENDOLOMIT FORMATION
GRAUER SALZTON FORMATION
Deckanhydrit
STASSFURT HALITE FORMATION
S3
S2
S1
BASALANHYDRIT FORMATION
HAUPTDOLOMIT FORMATION
WERRAANHYDRIT FORMATION
ZECHSTEINKALK FORMATION
KUPFERSCHIEFER FORMATION
Upper Leman Sandstone
SILVERPIT FORMATION
Silverpit Evaporite Member
Lower Leman Sst.
LEMAN SANDSTONE FORMATION
Z5
Z4
Z3
Z2
Z1

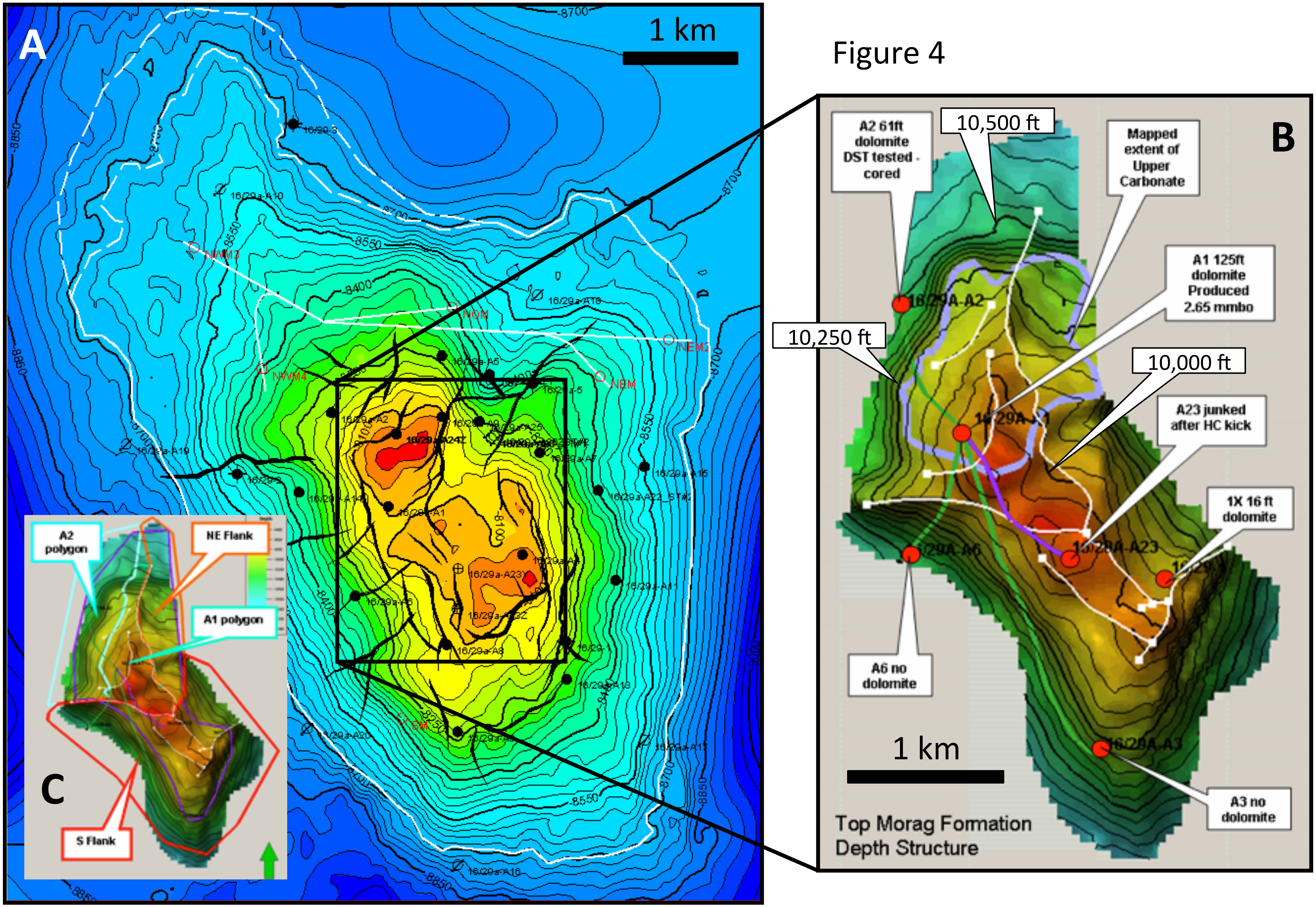


Figure 4
A
1 km
B
A2 61ft dolomite DST tested - cored
10,500 ft
Mapped extent of Upper Carbonate
A1 125ft dolomite Produced 2.65 mmbo
10,250 ft
10,000 ft
A23 junked after HC kick
1X 16 ft dolomite
A6 no dolomite
A3 no dolomite
1 km
Top Morag Formation Depth Structure
C
A2 polygon
NE Flank
A1 polygon
S Flank

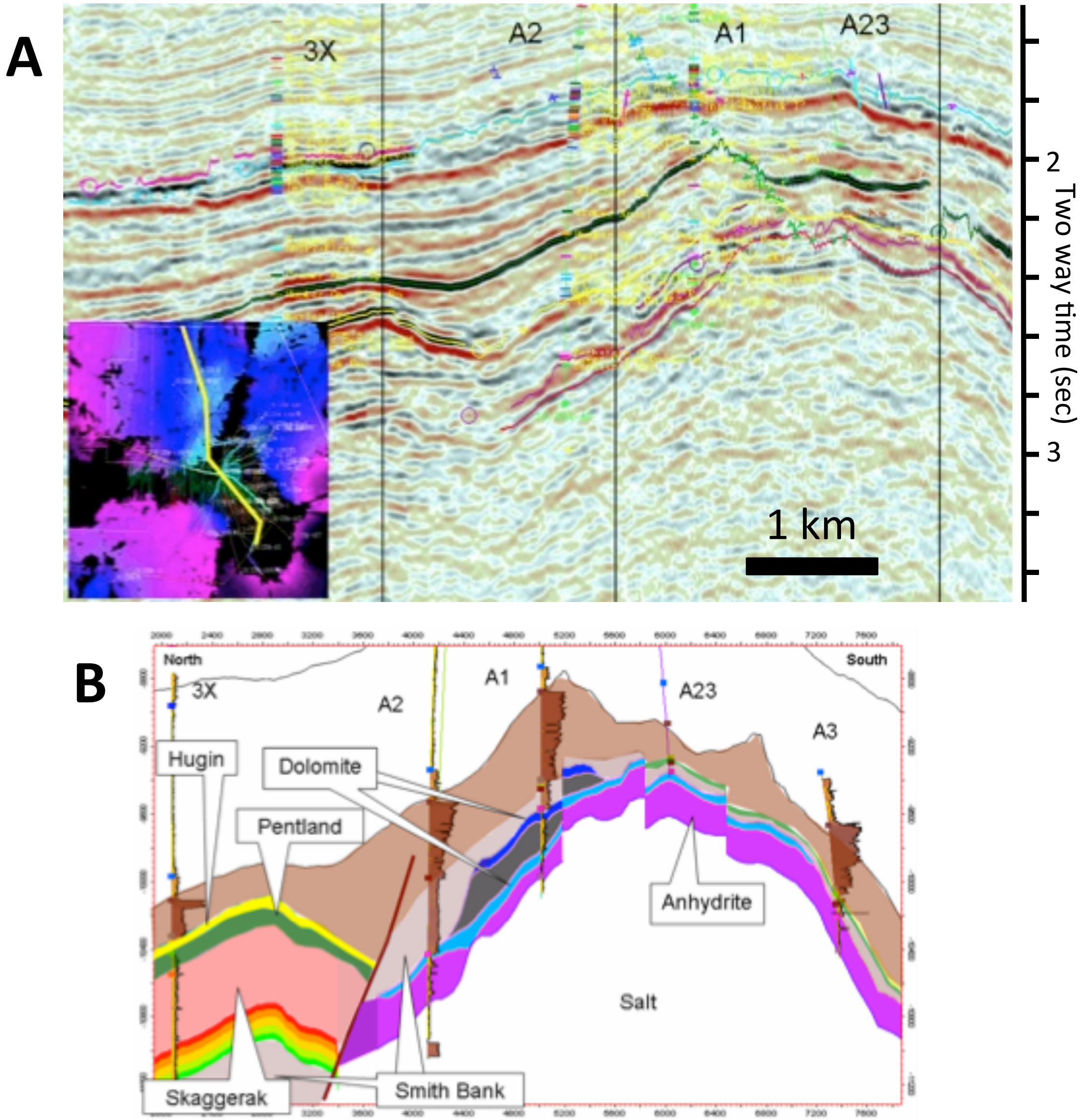

A
3X
A2
A1
A23
2
3
Two way time (sec)
1 km
B
North
South
3X
A2
A1
A23
A3
Hugin
Dolomite
Pentland
Anhydrite
Salt
Skaggerak
Smith Bank

Figure 5

A

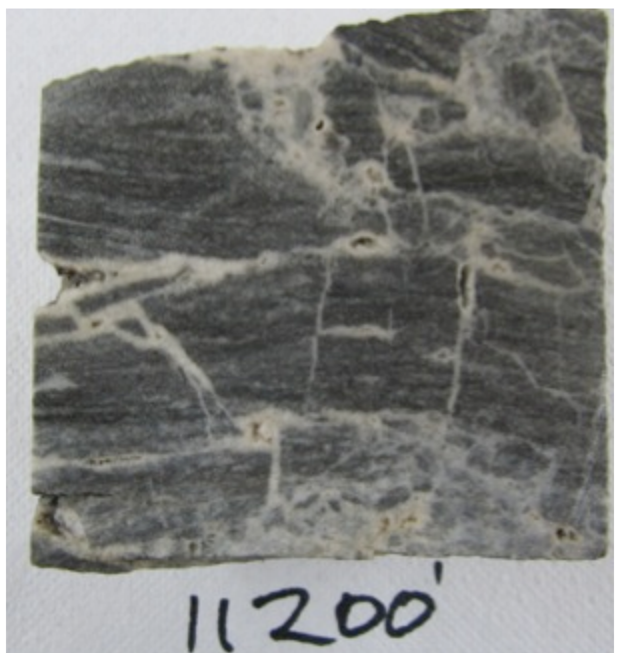
B

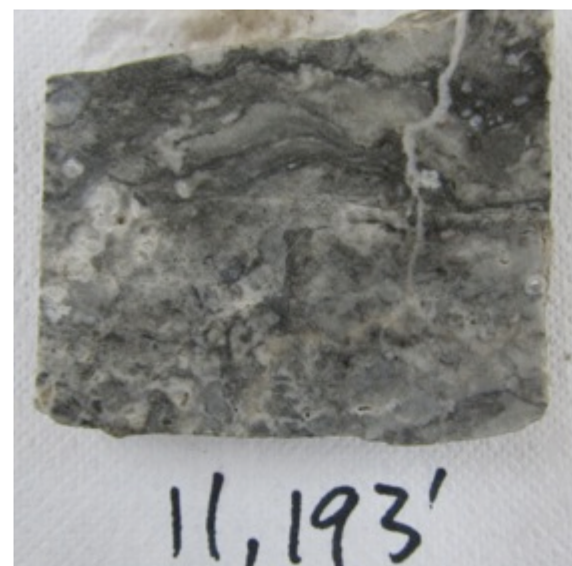
C

Figure 6

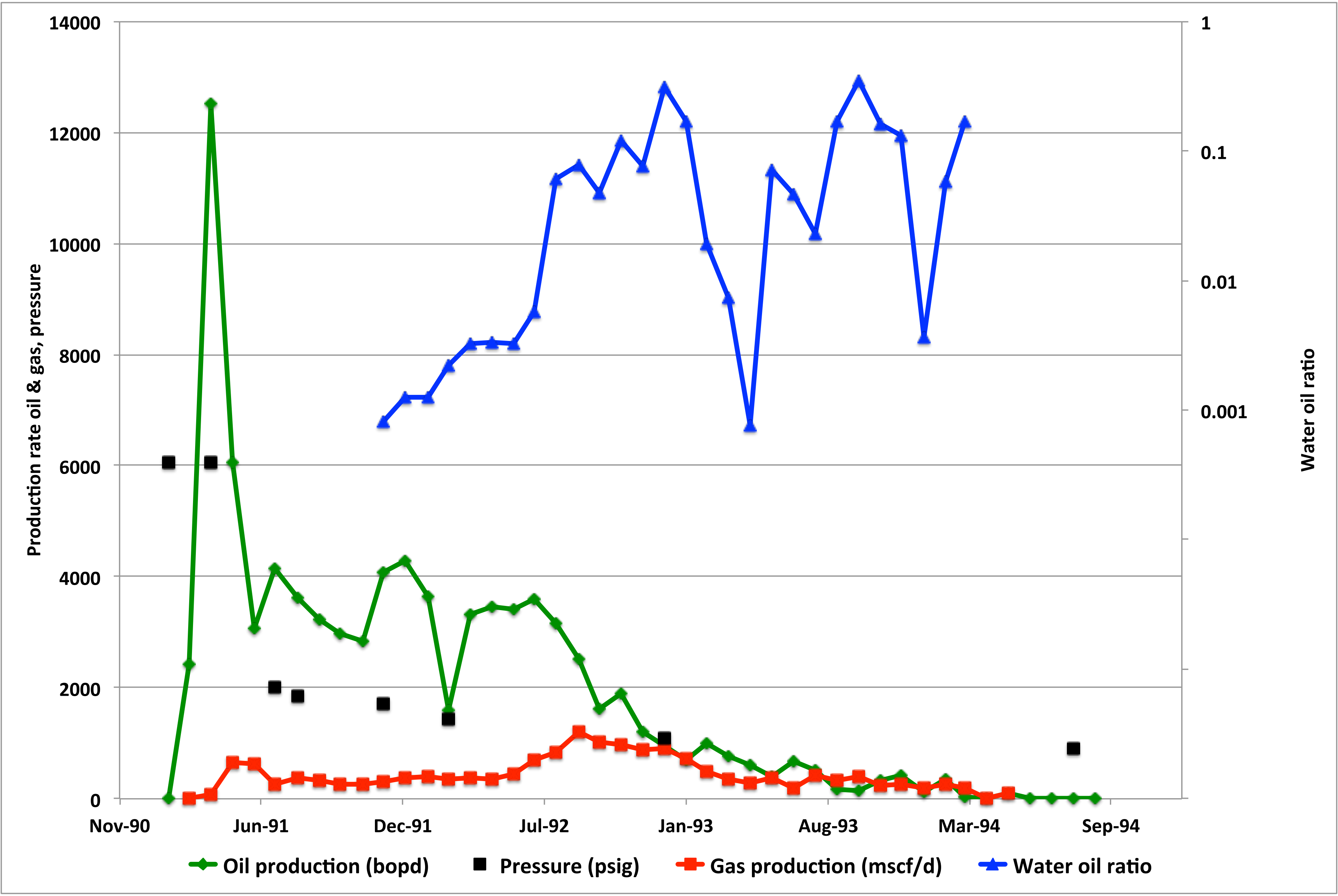
D

E





E



14000
12000
10000
8000
6000
4000
2000
0
Production rate oil & gas, pressure
1
0.1
0.01
0.001
Water oil ratio
Nov-90
Jun-91
Dec-91
Jul-92
Jan-93
Aug-93
Mar-94
Sep-94
Oil production (bopd)
Pressure (psig)
Gas production (mscf/d)
Water oil ratio

Figure 7