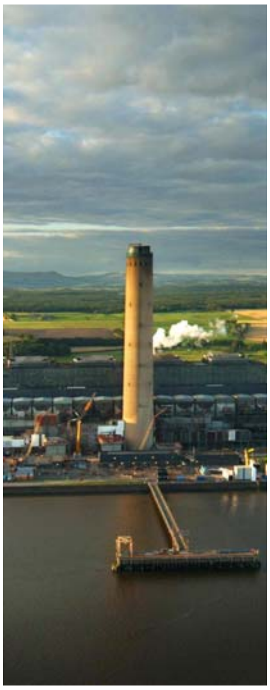  

# UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.21 - Shell - 006

Pore Pressure Prediction

April 2011

ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid

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ScottishPower Generation Limited
Longannet Power Station
Kincardine on Forth
Clackmannanshire
Scotland

# ScottishPower Consortium UKCCS Demonstration Competition:
# Knowledge Transfer

**KEYWORDS**

Goldeneye, $CO_2$, .

**Produced by Shell U.K. Limited**

**ECCN: EAR 99 Deminimus**



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## Table of Contents



## Tables

# Figures

# Executive Summary

The key objectives of this report are two-fold: a) to provide the expected reservoir pressure of the Captain Sandstone for future well activity, be that a work over, sidetrack or new well, and b) to review the expected pore pressure regime in the over- and under-burden which will provide an expected pore pressure in the overall $CO_2$ storage complex. In order to discuss the relevant data and information for each of these objectives, the report is divided into two sections covering the over- and under-burden, and the reservoir.

A thorough review of 17 wells in the area of the Goldeneye Field indicated that the lowest mud weights used to drill the stratigraphic sequence from the seabed to TD in the Permo-Triassic sequence ranged from 0.447-0.520 psi/ft, indicating a relatively low pore pressure regime compared to other parts of the North Sea.

The drilling data did show indications of pore pressure above hydrostatic pressure in the Tertiary mudstones (0.480 psi/ft), which is similar to the range of RFT data from the Area of Interest (AOI) which ranged from 0.475-0.500 psi/ft. Both the Chalk Group and Cromer Knoll Group sequence appear hydrostatically pressured, supported for the latter by the consistency in Goldeneye well RFT data. The deeper Jurassic to Permian sediments encountered in the Goldeneye Field appear normally pressured based on drilling and RFT data, however, the Kimmeridge Clay Formation is undercompacted relative to the general mudstone compaction trend, which indicates possible overpressure. This is supported by the kick that occurred in well 20/4b-4 from a sand unit within the Kimmeridge Clay Formation.

A depth trend of the minimum principal stress (also termed the formation strength) for the Goldeneye Field and surrounding area has been calculated based on the available Leak-Off Test (LOT) and Formation Integrity Test (FIT) data from the well review.

The Goldeneye Captain reservoir has abundant pressure data, from both pre-production logging and testing through to the production wells which all had downhole gauges installed. The virgin pressure at the water contact was 3825 psia at 8592 ft TVDSS, whilst the gas pressure at 8400 ft TVDSS was 3814-3818 psia. Production was paused when the last well cut water in December 2010. The final shut in bottom hole pressures on 8 December 2010 for the five wells GYA01 to GYA05 ranged from 2060 psia to 2117 psia when corrected to a datum depth of 8400 ft. The reservoir subsequently started to re-pressurise due to aquifer support. An extensive dynamic aquifer model for the Captain sand fairway has been constructed which covers adjacent fields including Hannay, Atlantic, Cromarty and Blake, as well as Goldeneye. The model predicts that by 2015 the reservoir pressure in the Captain sand will be in the range 2830-2960 psia. Although the production and well test data indicate that the Goldeneye reservoir is well connected, isolated pockets of high and low pressures can never be ruled out.

# 1. Introduction

**This report is being prepared in the first quarter 2011 at the end of the Front End Engineering design phase of the project. It is NOT VALID for the drilling or work over of wells in 2013 and will require an update in the six months prior to the start of any well work in order to incorporate any new data.**

The aim of this report is to provide data and information on the pore pressure regime in the Goldeneye field. Given the number of wells drilled and data available for the Goldeneye structure and wider area of interest, the focus has been on collating and analysing both the inferred and measured pore pressures rather than using pore pressure prediction routines. However, we do evaluate the compaction trends for the mud-prone sediments to test whether there is evidence of overpressure.

A review of pore pressure requires a wider area of analysis than a specific oil and gas field, hence, this report is divided into two sections; one discussing the non-reservoir pore pressure in the area of interest (over- and underburden) and the other the Goldeneye Captain reservoir which has undergone production since October 2004.

- Chapter 2: The key objective of this chapter is to provide what we can consider background pore pressures for the formations surrounding the Captain reservoir. Establishing a baseline pore pressure in the overburden will allow some assessment of pressure change as part of the monitoring program once $CO_2$ injection commences.
- Chapter 3: The key objective of this chapter is to describe the reservoir pressure and response prior to, during and post production, including the rebound once production is stopped. This data will be key if further reservoir entry is required, either in existing wells or via new wells.

# 2. Overburden and Underburden Pore Pressure

## 2.1. Introduction: Pore Pressure and Overpressure

For the purposes of this report, overpressure is defined as any pore fluid pressure which exceeds the hydrostatic pressure of a column of water or formation brine. For example, the typical density of seawater is 0.444 psi/ft, but if the connate water has higher salt concentrations, then the pore pressure gradient might be greater than 0.444 psi/ft, but still be termed ‘normally pressured’. The connate water analysis of the Captain Formation found total dissolved solids (TDS) of approximately 56 000 mg/L and a density of 0.452 psi/ft at surface. Thus, for this study we will refer to any formation pore pressure gradient greater than 0.452 psi/ft as being overpressured.

Overpressure is principally created by (a) inability of compressible rocks to de-water relative to the imposed in-situ stresses; (b) fluid expansion, such as hydrocarbon generation; and (c) load transfer when thermally driven processes weaken the rock framework[1]. Overpressure in permeable formations, such as reservoirs, is commonly measured via test probes (e.g. RFT, MDT), but in impermeable mudstones the pore pressure is inferred from wireline measurements from sonic and resistivity tools.

[1] O’Connor, S.A. & Swarbrick, R.E. 2008. Pressure regression, fluid drainage and a hydrodynamically controlled fluid contact in the North Sea, Lower Cretaceous, Britannia Sandstone Formation. *Petroleum Geoscience*, 14, 115-126.

The Tertiary section in the North Sea is known to be overpressured from numerous drilling and logging data. The onset is typically taken to be at a depth of about 1000 m [3281 ft][2], increasing within the massive shale-dominated section. The first reservoir sands beneath the shales, usually Eocene or Palaeocene age, show evidence for regional drainage and overpressures lower than the surrounding shales[3]. In the Central Graben area of the North Sea, the Chalk sections can be significantly overpressured, however, no data exists for this to be the case in the Outer Moray Firth area. The Cretaceous section of the Cromer Knoll Group does show signs of overpressure in the mudstones of the Britannia Field, at the very eastern end of the Outer Moray Firth, however, the Lower Cretaceous sands of the Britannia Sandstone show very little evidence of current overpressure[4].

## 2.2. Geological Setting

The pore pressure distribution in a basin is controlled to a large degree by burial history, tectonic activity and lithostratigraphy. To understand the context of the pore pressure regime in the Goldeneye Field and the wider area of interest, a review of the geological setting is required.

Regional geological studies encompassing the Goldeneye Field cover the Outer Moray Firth region of the UKCS Central North Sea. The region is dominated by the Halibut Horst, an area that remained emergent throughout most of the Jurassic and Lower Cretaceous periods. The Goldeneye accumulation is situated on the northern edge of the South Halibut basin adjacent to the southern margin of the South Halibut Shelf. The shelf edge depositional setting of the Lower Cretaceous resulted in the 'ribbon like deposition' of the Captain Sandstones along the southern margins of the Halibut Horst (Blocks 13/23, 13/24, 13/29 and 13/30) and South Halibut Shelf (Blocks 14/26, 14/27, 14/28, 14/29, 14/30, 15/26, 21/1). The deposition of the Captain Sandstones continues along the southern margins of the Renee Ridge through the Glenn Field and towards the Britannia Field area (Blocks 21/2, 21/3, 21/4 and 21/5) (Figure 2-1).

### *2.2.1. Structural History*

The Moray Firth Basin is the name given to the complex series of tilted fault blocks and grabens that extend eastward offshore from the Moray Firth, Scotland. The present day structural fabric is the result of at least five orogenic episodes along with a failed attempt as a spreading centre that span nearly 400 Millenia.

The Outer Moray Firth Basin exhibits several structural compartments, of which the most significant are the Halibut Horst, the Witch Ground Graben, and the Halibut Basin (Figure 2-1). Northwest-trending faults in the Witch Ground Graben and north of the Halibut Horst are likely to be Hercynian age structures which extend from the Central Graben; whereas faults running approximately east to west that fall between the Halibut Horst and Peterhead Ridge result from a complex interaction between Caledonian and Hercynian structures.

---

[2] Leonard, R.C. 1993. Distribution of subsurface pressure in the Norwegian Central Graben and applications for exploration. *In*: Parker, R.J. (ed) *Petroleum Geology of Northwest Europe: Proceedings of the 4th Conference*. Geological Society, London. 1295-1303.

[3] Dennis, H., Bergmo, P. & Holt, T. 2005. Tilted oil-water contacts: modelling the effect of aquifer heterogeneity. *In*: Dore, A.G. & Vinning, B. (eds) *Petroleum Geology: North-West Europe and Global Perspectives – Proceedings of the 6th Petroleum Geology Conference*. Geological Society, London, 145-158.

[4] O'Connor, S.A. & Swarbrick, R.E. 2008. Pressure regression, fluid drainage and a hydrodynamically controlled fluid contact in the North Sea, Lower Cretaceous, Britannia Sandstone Formation. *Petroleum Geoscience*, 14, 115-126.

The Grampian Highlands extend north-eastward to form the Grampian High and Grampian Arch, that subdivide the Moray Firth into the Inner and Outer basins. The Grampian Arch and portions of the Halibut Horst probably owe their existence to the buoyancy of an underlying Caledonian-age granitic pluton that has provided a broad northeast trending high during several phases of the basin's history. The buoyant effect of the granite was evident as early as the Late Devonian, but more significant was uplift during the Middle Jurassic when it separated the Inner Moray Firth from the Halibut Basin, and erosion of the sedimentary cover of the Arch occurred. Basin subsidence together with a eustatic rise in sea level during the Late Jurassic and Cretaceous times resulted in thick sediments being deposited fairly continuously across the basinal areas, which thin or become condensed across the Grampian Arch.

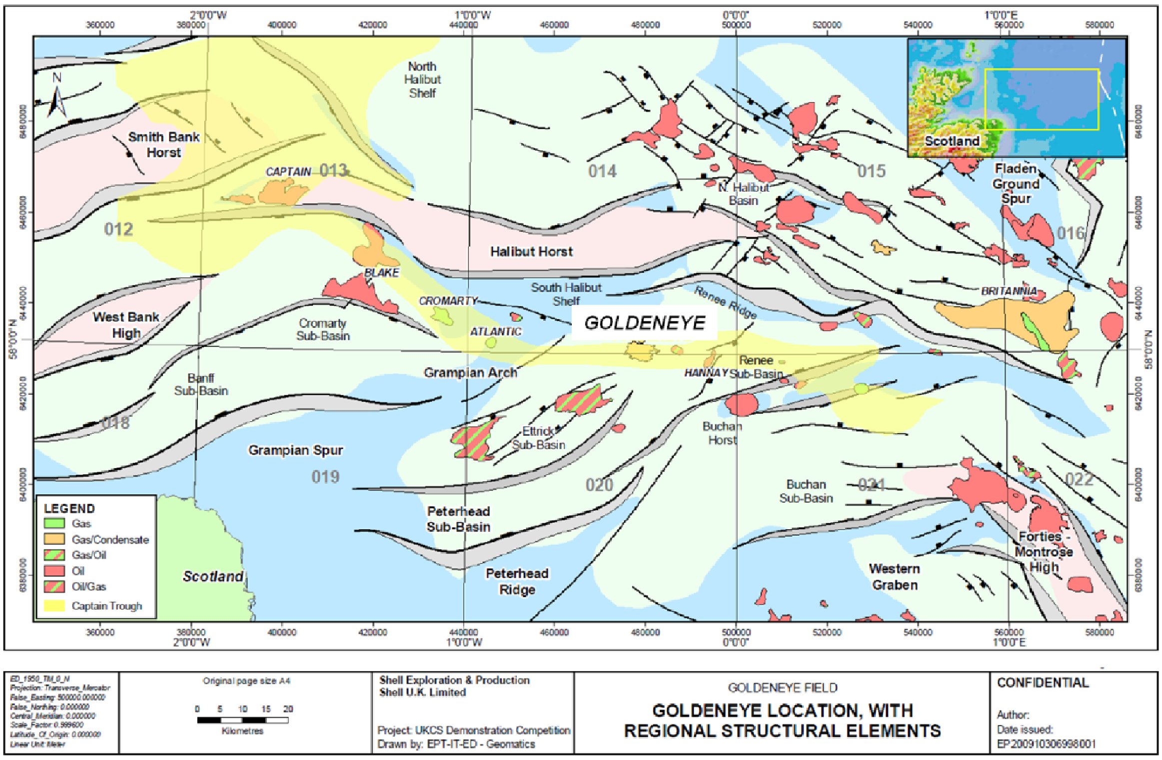


**Figure 2-1: Distribution of Captain Sandstones across the outer Moray Firth: Captain Fairway highlighted in yellow; basinal areas in pale green. The Goldeneye Field straddles Blocks 14 and 20.**

A major change in structural regime and sedimentation occurred in the Palaeogene due to ca. 1km of uplift of the Inner Moray Firth, Scottish Highlands and the East Shetland Platform areas which resulted in a regional eastward tilting of the area. During this period large quantities of clastic sediments were deposited in the Outer Moray Firth and Central Graben areas. There was also a continuation of the mild north-south compressive regime which warped the Top Chalk surface and funnelled the Captain Sandstones west-east through the basin.

### 2.2.2. Regional Stratigraphy

The regional stratigraphic column for the Outer Moray Firth is shown in Figure 2-2. The stratigraphy consists of a thick upper interval of Tertiary age deposits comprising interbedded sands, shales, claystones and lignites. A large variability is seen within the sand/shale ratios in the Tertiary age Montrose Group and appears more abundant towards the east.

Below the Tertiary clastic sediments is a Chalk section of fairly uniform thickness across the area. The Upper Cretaceous Chalk is the oldest formation to have been deposited over the entire Halibut Horst. Prior to this the Halibut Horst is thought to have been emergent. The erosion of the Halibut Horst, and storage of the resultant clastic sediments in both the north and south Halibut shelfal areas, is believed to have contributed significantly to the deposition of turbidites throughout the Lower Cretaceous and Jurassic in the Outer Moray Firth. The periodic deposition of the sand rich turbidites took place within the background deposition of hemipelagic shales, marls and occasional limestones.

The term Kopervik Sandstone has been used to describe the late early Cretaceous mass flows in the Moray Firth, but has never formally been defined. The Kopervik Sandstone can be separated into several members, based on sequence stratigraphy, including the Captain Sandstone Member of the Caarrack Formation. These turbidite sands of Albian–Aptian age are generally massive, blocky, sandy debrite/high density turbidites of the Captain Sandstones.

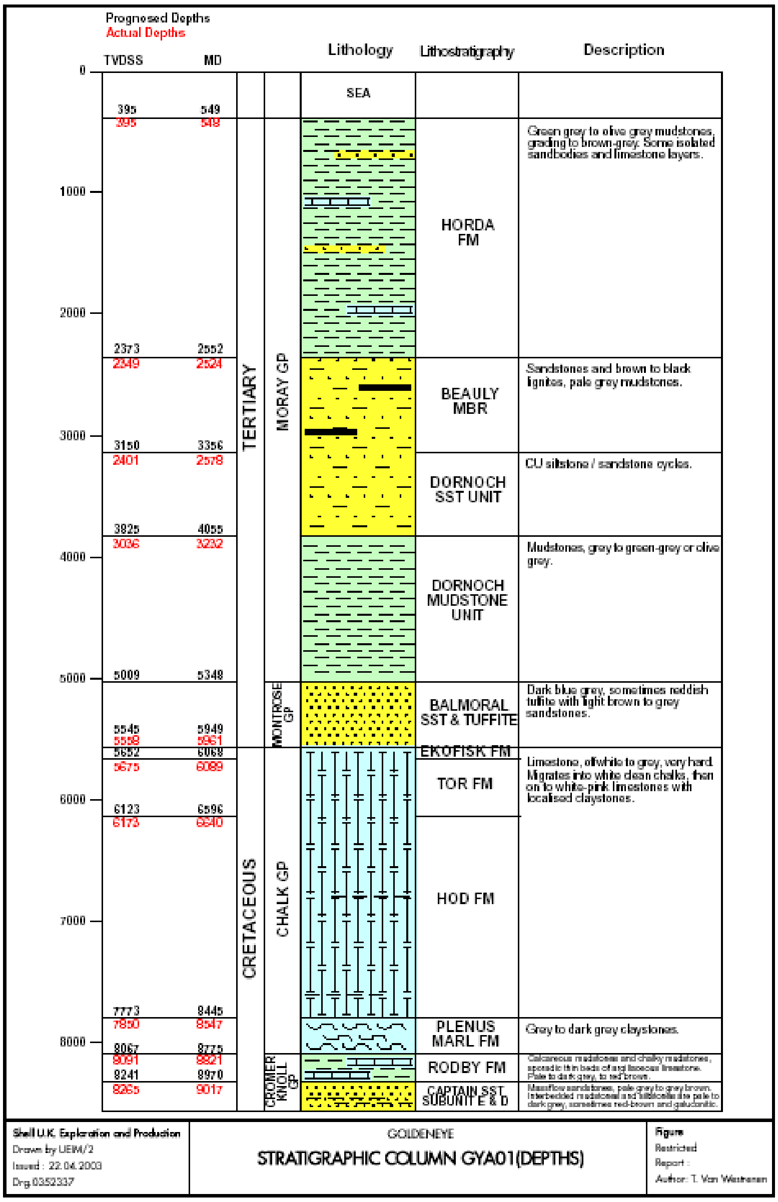


**Figure 2-2: Stratigraphic column for the Outer Moray Firth based on Goldeneye well GYA-01.**

Good reservoir quality turbidite sands are also found within the Upper Jurassic Kimmeridge Clay Formation and underlying the Kimmeridge Formation, Upper/Middle Jurassic paralic sediments were deposited (e.g. Heather/Pentland Formations).

The economic basement consists of Triassic age siltstones and shales of the Smith Bank Formation, Permian Zechstein and Rotliegend Formations and the deeper sand rich clastics of Carboniferous and Devonian age. Below the Devonian sediments basement granites that form the core of the Halibut Horst are present.

## 2.3. Drilling Data Review

All wells which penetrated the Goldeneye structure, as well as many adjacent offset wells, were reviewed in terms of relevant data which would help to define the pore pressure in the overburden. Table 2-1**Error! Reference source not found.** lists the seventeen wells reviewed as part of this study. The locations of the wells are shown in Figure 2-3.

**Table 2-1: Summary of the well data reviewed as part of this study. The minimum and maximum mud weights are summarised at the bottom of the table for the lithostratigraphic column split into four sections: Tertiary sediments, Chalk Group, Cromer Knoll Group and Jurassic-Permian sediments.**

| Well | Tertiary (psi/ft) | Chalk Gp (psi/ft) | Cromer Knoll Gp (psi/ft) | Juras -Perm (psi/ft) | TD TVDSS (ft) | Comments |
|---|---|---|---|---|---|---|
| 14/28a-1 | 0.550 | 0.500 | 0.550 | 550 | 6980 | Kimm/Zech sands noted |
| 14/28a-3A | 0.520 | 0.525 | 0.525 | 540 | 9010 | Pent, Skag, Smith Bk, etc, no CG |
| 14/28b-2 | 0.550 | 0.540 | 0.540 | 557 | 10780 | TD Smth Bk, drill gas only |
| 14/29a-2 | 0.500 | 0.505 | 0.530 | 536 | 10539 | No formation at TD noted |
| 14/29a-3 | 0.525 | 0.525 | 0.520 | 520 | 9941 | TD Smth Bk |
| 14/29a-4 | 0.500 | 0.540 | 0.540 | 540 | 9391 | TD Smth Bk, Kimm sand = water |
| 14/29a-5 | 0.520 | 0.530 | 0.532 | 535 | 9117 | - |
| 20/3-1 | 0.447 | 0.495 | 0.520 | 530 | 12803 | TD in Rotliegendes, Kimm sand, RFT |
| 20/4b-3 | 0.499 | 0.502 | 0.520 | 520 | 13001 | Zech TD, normal Pp |
| 20/4b-4 | 0.520 | 0.510 | 0.520 | 645 | 12053 | Kick at 0.602 psi/ft in Kimm sands |
| 20/4b-6 | 0.540 | 0.540 | 0.540 | 551 | 9821 | TD Pentland, sands no CG |
| 20/4b-7 | 0.520 | 0.520 | 0.520 | 520 | 9415 | TD Kimm, trip gas only |
| 14/28b-4 | 0.447 | 0.499 | 0.499 | 520 | 9880 | - |
| GYA01 | 0.540 | 0.545 | 0.625 | na | 8397 | TD Captain |
| GYA02 | 0.540 | 0.560 | 0.550 | na | 8395 | TD Captain |
| GYA03 | 0.540 | 0.550 | 0.625 | na | 8484 | TD Captain |
| GYA04 | 0.540 | 0.550 | 0.565 | na | 8401 | TD Captain |
| GYA05 | 0.540 | 0.550 | 0.570 | na | 8371 | TD Captain |
| min | 0.447 | 0.495 | 0.499 | 520 | 6980 | |
| max | 0.550 | 0.560 | 0.625 | 645 | 13001 | |
| average | 0.519 | 0.527 | 0.544 | 543 | 9710 | |

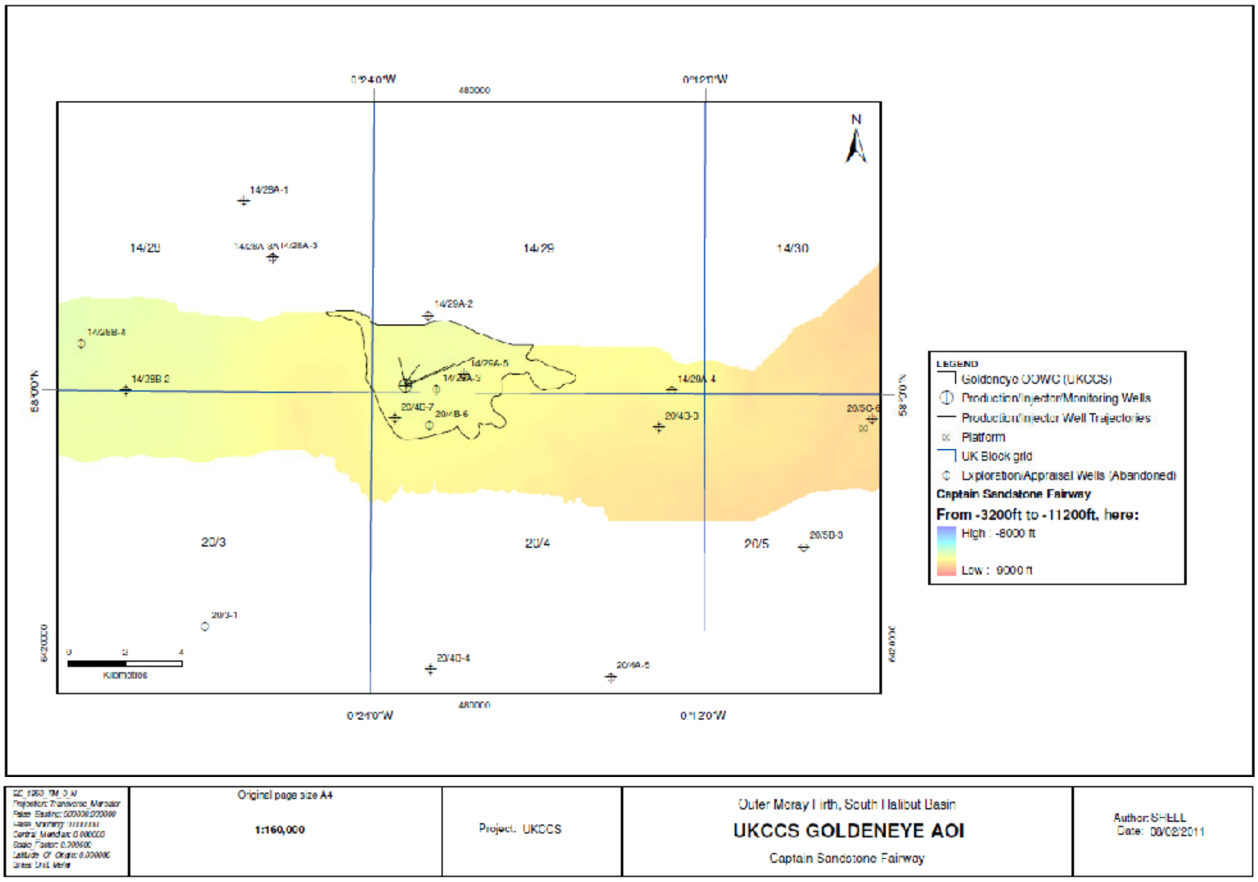


**Figure 2-3: Location of wells referenced in this study.**

In terms of pore pressure signatures, one kick occurred (well 20/5b-4) and limited connection gas was observed in two of the wells reviewed (GYA-04 and -05). After the surface casing was set in the five development wells (GYA-01 to -05), the Mudlog gas readings show significant drilled gas in the mudstones of the Hordaland Formation (Figure 2-4). In terms of pore pressure, the more significant observation is that the first two wells in the sequence (04 and 05) reported connection gas. This provides evidence that the formation pore pressure is slightly greater than the static mud weight at that point. Given that the same rig and mud logging unit was used for all five wells, the fact that all the wells recorded significant drilled gas, but only the first two wells noted connection gas, could imply either that there was minor storage capacity of gas in the Hordaland mudstones and the first two wells circulated out the excess pressure, or, that connection gas also occurred in the latter three wells but wasn't noted or reported by the mud log engineers.

Table 2-2 shows the mud weight and depth, hence, the expected pore pressure in the Hordaland Formation. This corroborates the expected overpressure in the Hordaland mudstones[5] .

[5] Leonard, R.C. 1993. Distribution of subsurface pressure in the Norwegian Central Graben and applications for exploration. *In*: Parker, R.J. (ed) *Petroleum Geology of Northwest Europe: Proceedings of the 4th Conference.* Geological Society, London. 1295-1303.

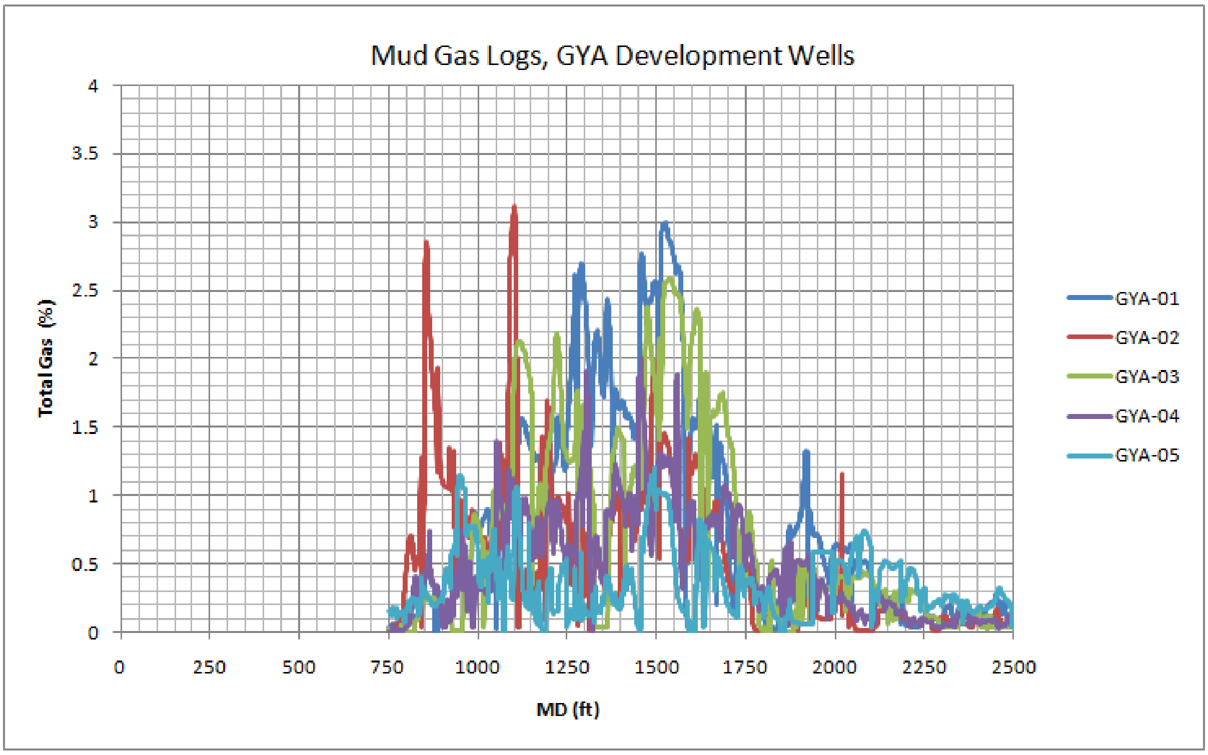


**Figure 2-4: Mud gas logs from GYA-01 to -05. Once 13.375 in casing set and drilled out, then immediately noted drilled gas in the Hordaland Formation**

**Table 2-2: Connection gas data recorded in the development wells. The pore pressure is assumed to be slightly higher than the mud weight at that specific depth.**

| Well | TVDBDF (ft) | Mud Weight (psi/ft) | Pressure (psi) |
|---|---|---|---|
| **GYA-04** | 1050 | 0.475 | 498.8 |
| **GYA-04** | 1700 | 0.475 | 807.5 |
| **GYA-05** | 3050 | 0.48 | 1464 |

Figure 2-5 shows the mud pressure profile for the development wells. Below the Hordaland mudstones there was no more reported connection gas or kicks with mud weights of 0.540 - 0.560 psi/ft. (Some wells used higher mud weights in the Rødby and Captain for borehole stability issues in high inclination wells rather than as a response to high pore pressure.)

## 2.1. Compaction and Pore Pressure Prediction

In largely undrilled areas, where pore pressure prediction methods are used, the compaction trend of mudstone porosity versus depth is often computed, using density and/or velocity log data as an input. For hydrostatically pressured mudstones, the depth trend of the porosity follows a power law type reduction. Where mudstone is overpressured, the porosity of the rock is preserved compared to one which has been dewatered effectively, hence there is a change in the density and sonic log in response to this. See reference[6] for greater detail around this methodology.

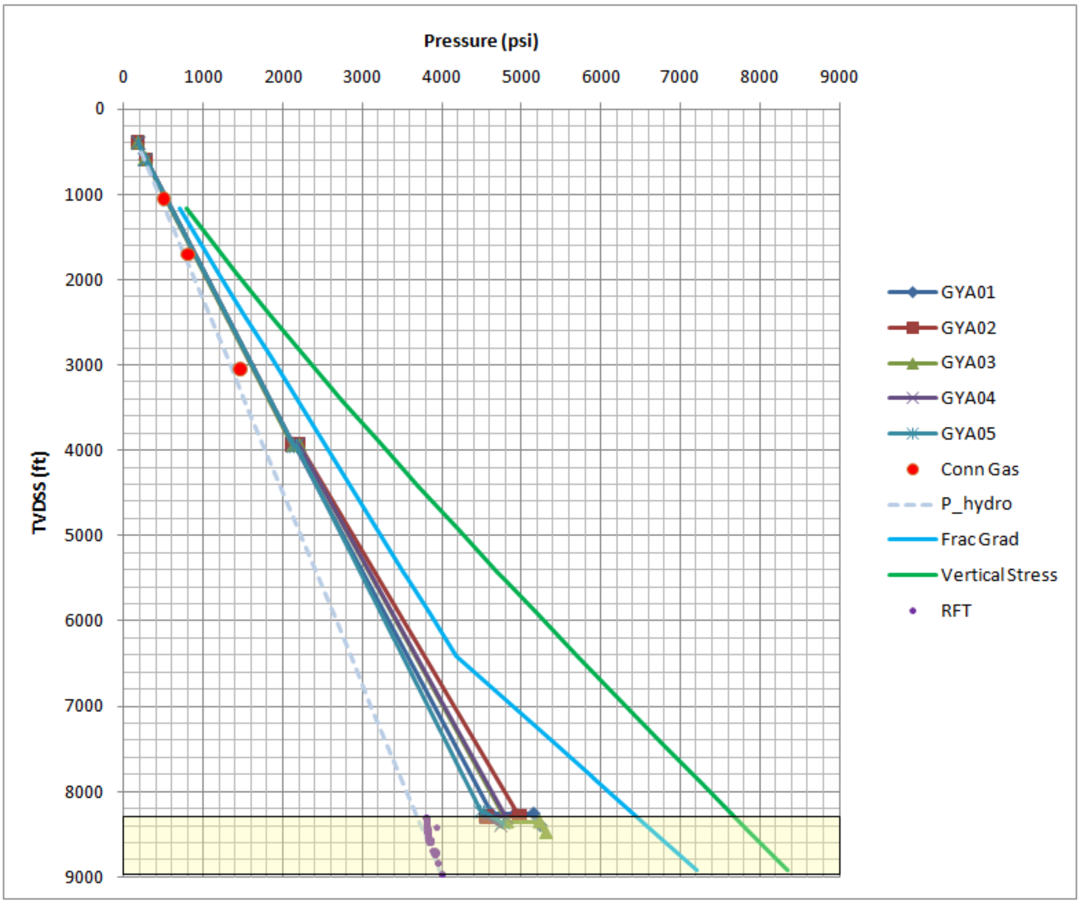


**Figure 2-5: Mud column pressures for wells GYA-01 to -05, including the occurrence of reported connection gas (CG) in wells GYA04 and -05. Yellow bar is the Captain Sandstone reservoir.**

Given the number of wells in the area of the Goldeneye Field, coupled with a wide-ranging RFT database of the area, a full pore pressure analysis is not required. However, it was deemed prudent to review the compaction data for reference purposes and this is shown in Figure 2-6.

There are two separate trends identified in terms of the mudstone compaction in Figure 2-6 (filtered with GR > 70 API), above and below the Chalk Group sediments. Above the Chalk Group, the trend of density change with depth is much lower compared to the sediments below. This is the affect of the loading imposed by the relatively heavy carbonate-based mineralogy of the sediments.

In terms of the trend above the Chalk Group, the log data available from about 3000 ft TVDSS shows a normal compaction trend, with only a little reversal in the Lista Formation. This is a pervasive shale unit around the North Sea and is characterised by the presence of smectite, as well as organic matter. Both these are relatively light compared to other silicate minerals, the former due to

6 Japsen, P. 1999. Overpressured Cenozoic shale mapped from velocity anomalies relative to a baseline for marine shale, North Sea. *Petroleum Geoscience*, 5, 321-336.

a high amount of both surface and interstitial water. Cuttings analysis using dielectric constant measurement (DCM) provides data on the clay mineralogy of the mudstone. DCM data in Figure 2-7 shows the high surface area, identifying significant amounts of smectite present. It is envisaged that the reduction in density is most likely a function of the mineralogy rather than due to undercompaction and overpressure.

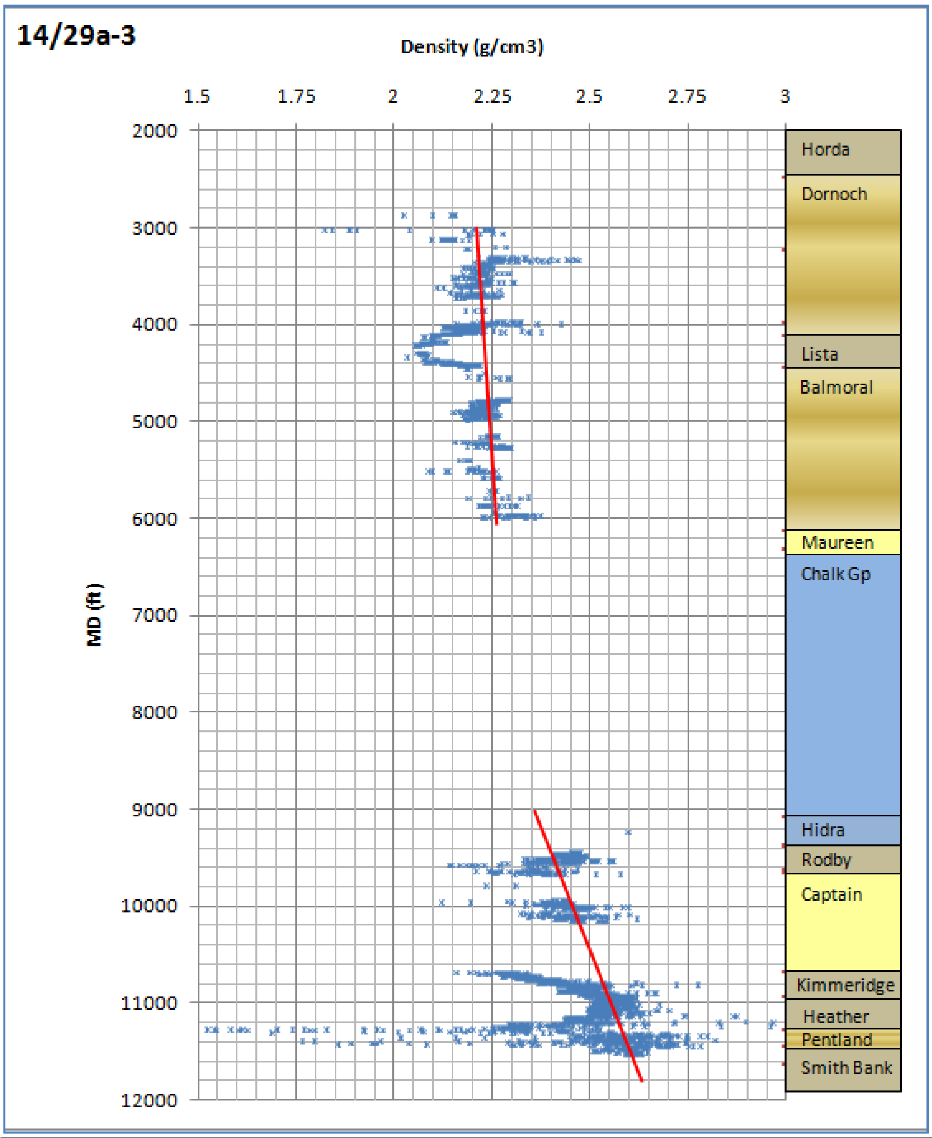


**Figure 2-6: Compaction curve for the mudstones for well 14/29-3. The Lista and Kimmeridge Clay formations appear to be relatively undercompacted compared to the adjacent mudstones.**

As mentioned above, the compaction trend below the Chalk Group is greater, with much reduced porosity in the mudstones. The trend line shows that the majority of the mudstones are on the same trend line, however, there is what appears significant reversal in the Kimmeridge Clay Formation. This is a common occurrence in the North Sea and is a function of the Kimmeridge Clay being the primary Jurassic age source rock. The Kimmeridge ClayFormation has significant organic matter content which has a low density, but also there is sometimes associated high pore pressure too. There is one bit of evidence for this in the well data, where well 20/4b-4 recorded a kick to a pressure gradient of 0.602 psi/ft. Also, as Section 2.3 discusses below, there is wider evidence from Block 20 that higher overpressure can exist in the deeper Jurassic-Triassic sediments underlying the Goldeneye field.

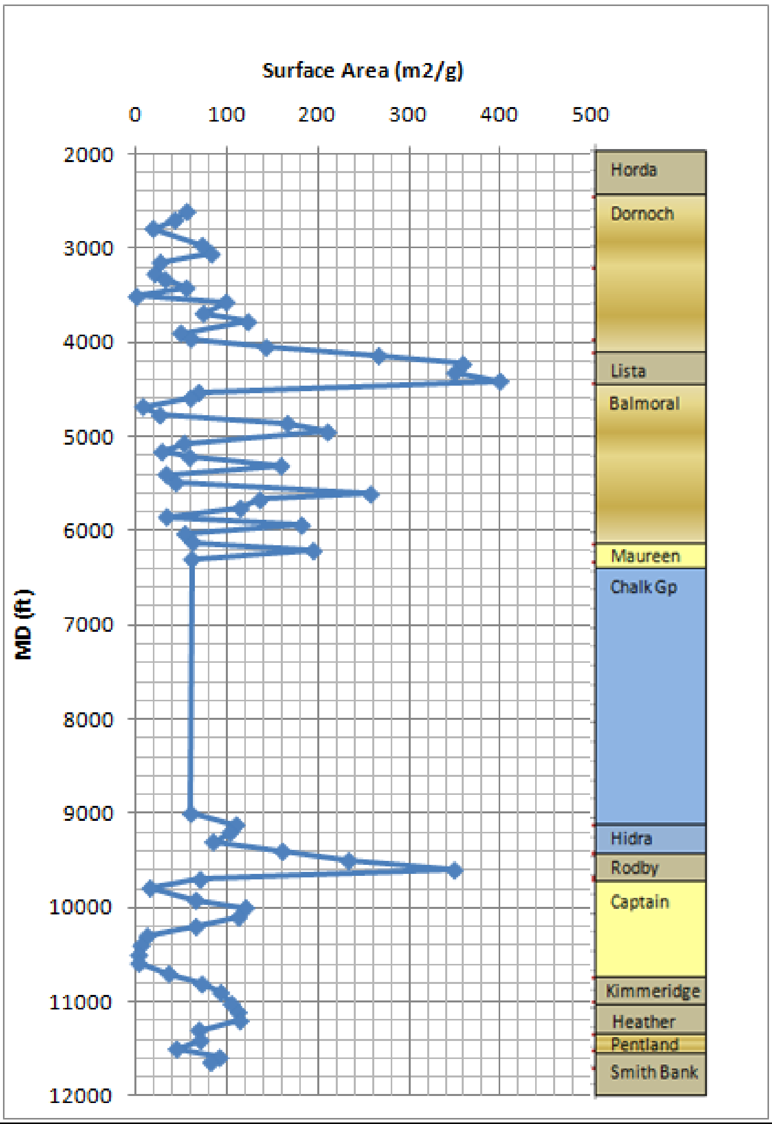


**Figure 2-7: Dielectric constant measurement (DCM) data for cuttings from well 14/29-3. If the surface area value is greater than ~150 m2/g, then significant amounts of smectite are present.**

## 2.2. Formation Minimum Principal Stress

The 'formation strength' or 'fracture gradient' are determined by the minimum principle stress, which in a normal stress setting, such as the Goldeneye Field, is the minimum horizontal stress. This was evaluated by analysis of the available leak-off test (LOT) data for the Goldeneye field and close offset wells. Although the LOT test doesn't measure exactly the minimum horizontal stress (unless it tests past the breakdown pressure), by fitting to the minimum bound of the dataset provides a good estimation.

**Table 2-3: Leak-off test (LOT) data used to determine the minimum horizontal stress, or formation strength, in the Goldeneye Field.**

| Well | Drill Floor Elev. | Water Depth | Casing | TVDBDF | Formation | Equiv. Mud Gradient | Type | Checked? | Leak-Off Pres. |
|---|---|---|---|---|---|---|---|---|---|
| | ft | ft | in | ft | | psi/ft | | | psi |
| GYA-03 | 152 | 395 | 13.375 | 4025 | Dornoch | 0.630 | *LOT* | y | 2536 |
| GYA-04 | 152 | 395 | 13.375 | 4005 | Dornoch | 0.633 | *LOT* | y | 2535 |
| 14/29a-2 | - | - | 20 | 1391 | Nordaland | 0.581 | LOT | y | 808 |
| 14/29a-2 | - | - | 13.375 | 4453 | Andrew | 0.691 | LOT | y | 3078 |
| 14/29a-2 | - | - | 9.625 | 7881 | Hidra | 0.733 | LOT | y | 5777 |
| 14/29a-5 | 80 | 400 | 13.375 | 3960 | Dornoch (L Sst mbr) | 0.630 | LOT | y | 2495 |
| 14/29a-4 | 82 | 397 | 13.375 | 2500 | Hordaland | 0.697 | LOT | y | 1743 |
| 20/4b-3 | 90 | 394 | 20 | 2008 | North Sea | 0.643 | LOT | y | 1291 |
| 20/4b-3 | 90 | 394 | 9.625 | 10095 | Kimm Clay | 0.884 | LOT | y | 8927 |
| 20/4b-7 | 83 | 393 | 13.375 | 3652 | Dornoch (U Sst mbr) | 0.63 | LOT | y | 2301 |
| 14/28b-2 | 82 | 354 | 13.375 | 2011 | Dornoch | 0.64 | LOT | y | 1287 |
| 14/28b-2 | 82 | 354 | 9.625 | 8840 | Valhall | 0.837 | LOT | y | 7399 |
| 14/28a-1 | 85 | 384 | 20 | 1957 | Hordaland | 0.601 | LOT | y | 1176 |
| 14/28a-1 | 85 | 384 | 13.375 | 3008 | Dornoch | 0.839 | LOT | y | 2524 |
| 20/3-1 | 77 | 374 | 13.375 | 5718 | Tor | 0.779 | LOT | y | 4454 |
| 20/3-1 | 77 | 374 | 9.625 | 9713 | Valhall | 0.831 | LOT | y | 8072 |
| 20/4b-4 | 80 | 375 | 20 | 2013 | Nordaland | 0.623 | LOT | y | 1255 |
| 20/4b-4 | 80 | 375 | 7 | 11462 | Heather | 0.894 | LOT | y | 10241 |
| 14/29a-3 | - | - | 13.375 | 2583 | Dornoch | 0.570 | LOT | y | 1473 |
| 20/4b-6 | 83 | 390 | 13.375 | 3084 | Dornoch (U Sst mbr) | 0.58 | LOT | y | 1789 |
| 20/4b-4 | 80 | 375 | 13.375 | 5431 | Lista | 0.613 | LOT | y | 3329 |
| 20/4b-4 | 80 | 375 | 9.625 | 9805 | Valhall | 0.691 | LOT | y | 6774 |
| GYA-01 | 152 | 395 | 13.375 | 4041 | Dornoch | 0.630 | Limit | y | 2546 |
| GYA-02 | 152 | 395 | 13.375 | 4014 | Dornoch | 0.631 | Limit | y | 2533 |
| GYA-05 | 152 | 395 | 13.375 | 4030 | Dornoch | 0.630 | Limit | y | 2539 |
| 14/29a-3 | - | - | 9.625 | 8051 | Hidra | 0.572 | Limit | y | 4607 |
| 14/29a-4 | 82 | 397 | 9.625 | 6502 | Ekofisk | 0.769 | Limit | y | 5000 |
| 20/4b-3 | 90 | 394 | 13.375 | 6496 | Ekofisk | 0.868 | Limit | y | 5640 |
| 14/28b-2 | 82 | 354 | 13.375 | 5524 | Ekofisk | 0.785 | Limit | y | 4336 |
| 14/28a-1 | 85 | 384 | 9.625 | 5189 | Ekofisk | 1.006 | Limit | y | 5220 |

Table 2-3 lists the data that was used in determining the minimum horizontal stress and the data is plotted in Figure 2-8. As is found across the North Sea, there is a lithological effect on the measured LOT value and formation strength, depending on where the casing shoe is set. This is reflected in Figure 2-8 where the Chalk Group sediments elevate the measured leak-off pressure.

Based on the depth trends of the LOT data in the clastic sediments, the expected minimum principal stress ($\sigma_3$) at a given depth is calculated according to the following equations. At depths less than 6000 ft TVDSS:

$$\sigma_3 \text{ (psi)} = 0.4271 * \text{TVDSS (ft)}^{1.049}$$

At depths greater than 6000 ft TVDSS:

$$\sigma_3 \text{ (psi)} = 0.0067 * \text{TVDSS (ft)}^{1.5254}$$

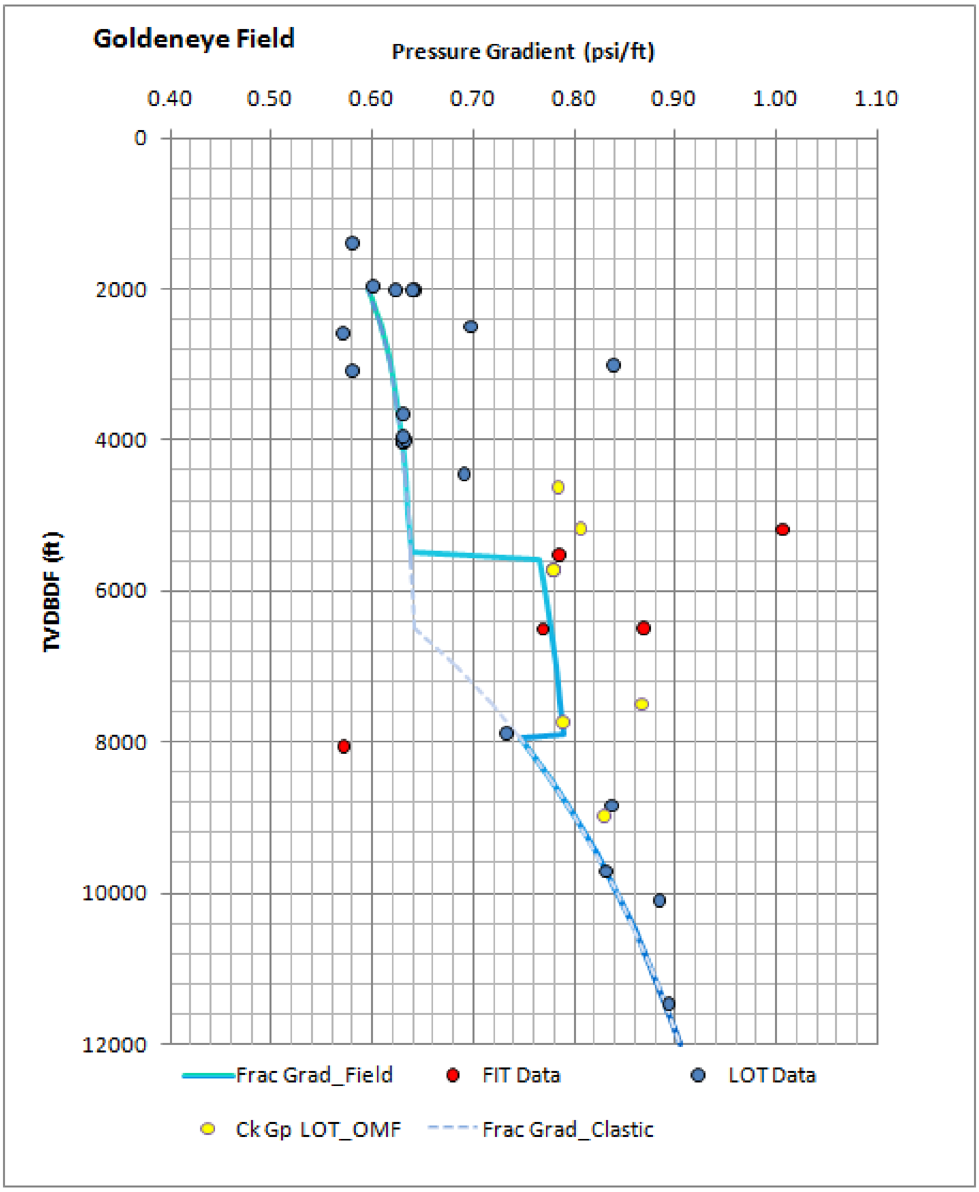


**Figure 2-8: LOT data and determination of the minimum principal stress, or formation strength, for the Goldeneye Field. 'FIT' is a formation integrity test, 'Ck Gp LOT_OMF' refers to Chalk Group LOT data from Outer Moray Firth wells, 'Frac Grad_Clastic' refers to the expected minimum principal stress in clastic sediments which is different to the carbonate sequence.**

## 2.3. RFT Data in Area of Interest

A wide ranging RFT database is available for the area of interest (AOI) around the Goldeneye field and the Moray Firth area. As previously reported[7], in the Britannia Field at the eastern end of the outer Moray Firth, limited overpressure exists in the Kopervik Sandstones and overlying Rødby shale (termed the Britannia and Sola Formations in the study).

[7] O'Connor, S.A. & Swarbrick, R.E. 2008. Pressure regression, fluid drainage and a hydrodynamically controlled fluid contact in the North Sea, Lower Cretaceous, Britannia Sandstone Formation. *Petroleum Geoscience*, 14, 115-126.

To permit a more focussed analysis of the RFT data, a filter was used to select data from Blocks 14 and 20, representing the blocks which the Goldeneye Field straddles. Figure 2-9 shows the data for the overburden and underburden.

The overburden plot illustrates some occurrences of small amounts of overpressure, with all data in the range of 0.445 to 0.500 psi/ft, except for an outlier at 0.60 psi/ft. The connection gas from GYA-04 and -05, discussed earlier in this report, is within the range of the RFT data. The validity of the one data point at 0.60 psi/ft is uncertain; no filtering for supercharging has been done.

The plot for the RFT data deeper than 8000 ft TVDSS in Figure 8b shows that there is a range from 0.445 – 0.730 psi/ft. Within the data range, there are obvious trends for water and hydrocarbon gradients, with a scatter of up to 0.73 psi/ft. Four wells are responsible for the data > 0.60 psi/ft; 20/2-2, 20/5B-2, 20/4B-4, 20/3-2A. These wells show that in deeper Jurassic formations that significant overpressure can exist in the area.

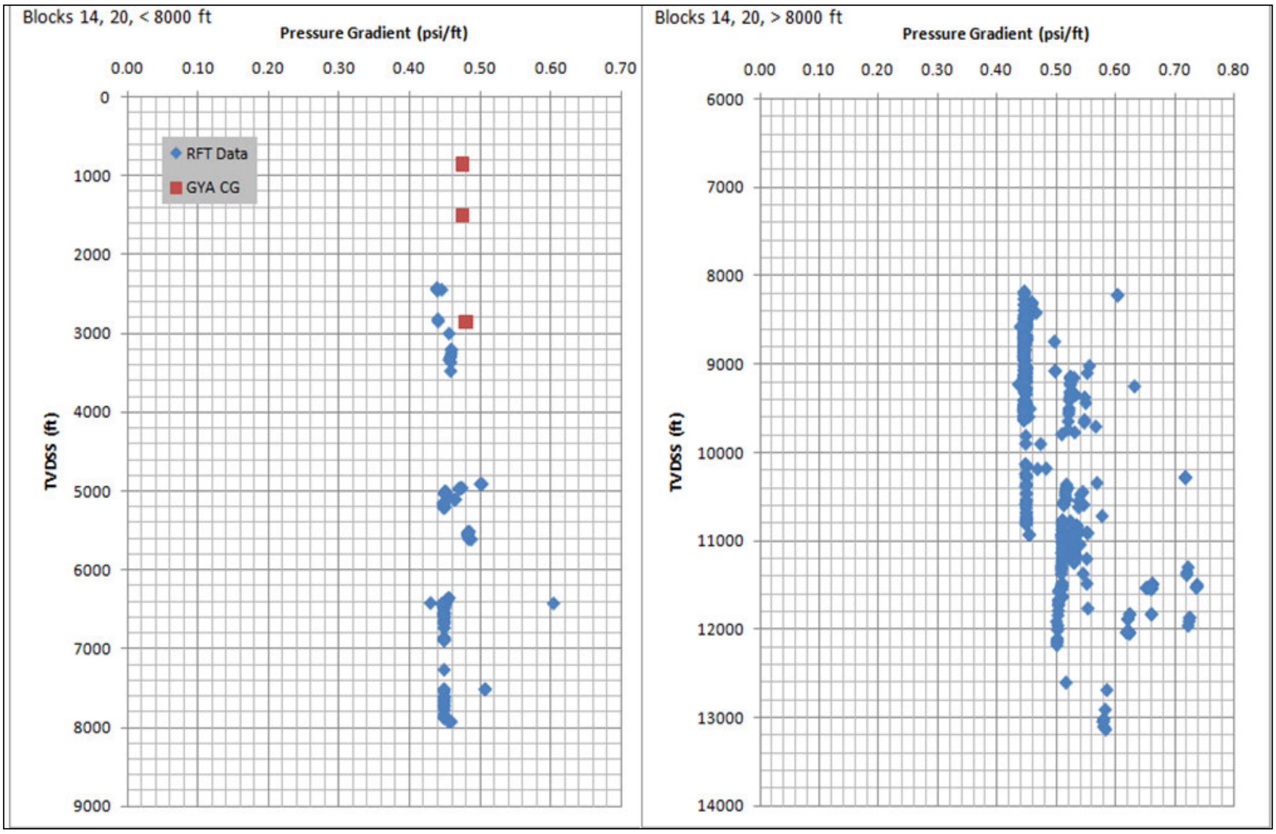


**Figure 2-9: RFT data for blocks 14 and 20, sorted for data in the overburden (8a, left) and data for reservoir and underburden (8b, right).**

## 2.4. Summary

To review the various pore pressure data presented so far, the formations have been grouped into four sections, as shown in Figure 2-10, these are: Tertiary sediments, Chalk Group sediments, Cromer Knoll Group sediments and the Jurassic-Triassic sediments. Table 2-4 below summarises the expected pore pressure in the AOI around the Goldeneye field, and includes the source of the data.

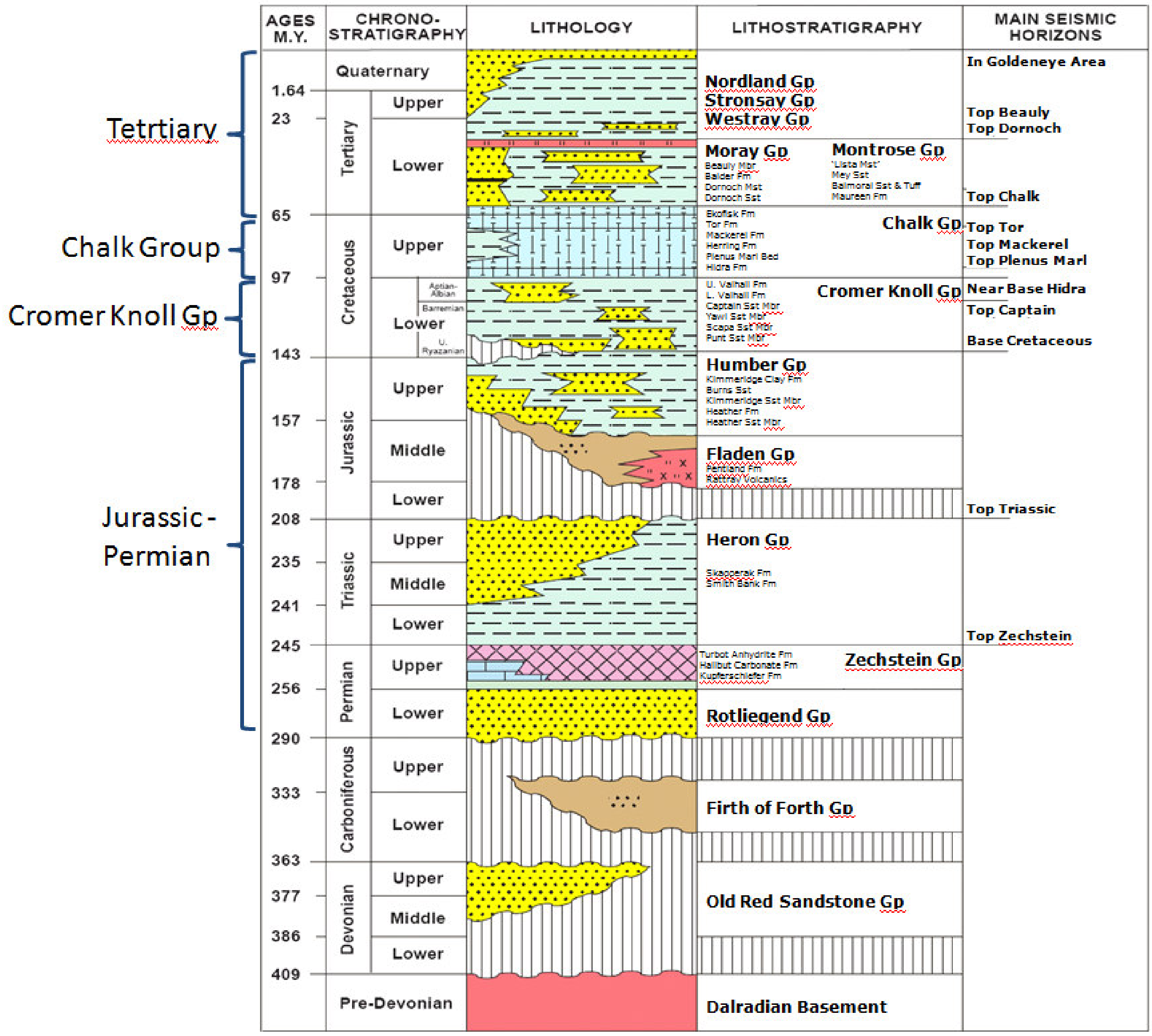


**Figure 2-10: Lithostratigraphic column for the Outer Moray Firth, with the grouping of the formations adopted in this report shown on the left.**

***Tertiary Section*** – The majority of the section appears to be normally pressured. The lowest mud weight through this section was 0.447 psi/ft, just above hydrostatic pressure, with no noted influxes, even though there are several sand-prone intervals. Limited connection gas was noted in the first two development wells, but not the subsequent wells. This suggests limited volume for the pressure cell which was slightly overpressured at 0.48 psi/ft. RFT data for the section from blocks 14 and 20 shows pressure gradients up to 0.50 psi/ft. It is possible the reduction of density for the Lista Formation could be as a result of overpressure to a similar level, however, certain lithological characteristics could also explain the reduced density compared to the adjacent shales.

***Chalk Group*** – The minimum mud weight to drill the Chalk Group was 0.495 psi/ft with no indications of pore pressures above this. All the well data supports a hydrostatically pressured section.

***Cromer Knoll Group*** – The minimum mud weight used to drill the Rødby and Captain Formations was 0.499 spi/ft. There is extensive RFT data of the Captain Sands which indicated that they are hydrostatically pressured and are supported by a large aquifer in the AOI. There is no evidence of the Rødby Formation in the caprock being overpressured, both in terms of the drilling and RFT data, as well as the compaction curve.

**Table 2-4: Summary of the pore pressure regime in the area of the Goldeneye Field. The minimum mud weight is the lowest mud weight used, in the seventeen wells reviewed, to drill the relevant section. The pore pressure inferred from the drilling data is either from connection gas or a kick.**

| Stratigraphic Section | Min. mud weight to drill section (psi/ft) | Pore Press. inferred from drilling data (psi/ft) | Source | Block 14, 20 RFT data (psi/ft) | Exp. pore pressure in AOI (psi/ft) | Comments |
|---|---|---|---|---|---|---|
| **Tertiary** | 0.447 | 0.480 | Conn. Gas | 0.445-0.500 | 0.445-0.500 | Majority of sequence hydrostatically pressured, limited overpressure in Hordaland. |
| **Chalk Group** | 0.495 | na | na | na | 0.445 | Hydrostatically pressured, no evidence for overpressure |
| **Cromer Knoll Group** | 0.499 | na | | 0.445 | 0.445 | Captain sand originally hydrostatically pressured, no evidence for overpressure |
| **Jurassic - Permian** | 0.520 | 0.605 | Kick | 0.445-0.730 | 0.445-0.605 | Well and RFT data suggest some localised overpressure in Block 20. Majority of data shows permeable units hydrostatically pressured, with the Kimmeridge Clay likely to be overpressured. |

***Jurassic-Permian Section*** – This section includes the Kimmeridge Clay Formation down to the Rotliegend Formation in one of the wells. The lowest mud weight through this section was 0.520 psi/ft, however, one of the wells (20/4b-4) experienced a kick which indicated a pore pressure of 0.602 psi/ft. This came from a sand body (Burns Sandstone) in the Kimmeridge Clay section. Although other sand bodies were drilled in adjacent wells, no similar kicks occurred and the maximum mud weight used was 0.550 psi/ft. The data therefore suggests that some sand bodies do exist in the Kimmeridge Formation which are overpressured but these are not extensive based on the well data reviewed in this study. The wider block 14 and 20 RFT corroborates the occurrence of significant overpressure in some of these deeper units in Block 20 specifically, with pressures gradients of up to 0.730 psi/ft measured in wells 20/2-2, 20/5b-2, 20/4b-4, and 20/3-2a.

# 3. Reservoir Pressure Prediction

## 3.1. Pre-production

Pressure data for Goldeneye is available from a number of exploration wells as well as the five production wells. Pressure data from nine exploration wells in Goldeneye and the surrounding area is plotted in Figure 3-1. All the wells were drilled before production started in Goldeneye or any of the neighbouring fields which potentially influence the Goldeneye pressure and so they should represent virgin conditions. There is a good fit to a regional water gradient of 0.4408 psi/ft with a pressure of 3835 psia at the Goldeneye oil water contact of 8592 ft TVDSS. Two of the Goldeneye wells, 14/29a-3 and 14/29a-5 have slightly higher pressures – see Figure 2-3 and Figure 3-2 for all well locations. The gas gradient is slightly less certain as the data is limited to four wells with more variation between them. The gas pressure at a depth of 8400 ft TVDSS is 3814 psia to 3818 psia with a gradient of 0.097 ±0.005 psi/ft.

The pressure differences between the wells are attributed to tool calibration differences. Different runs of the tool in the 14/29a-3 well show different pressure readings.

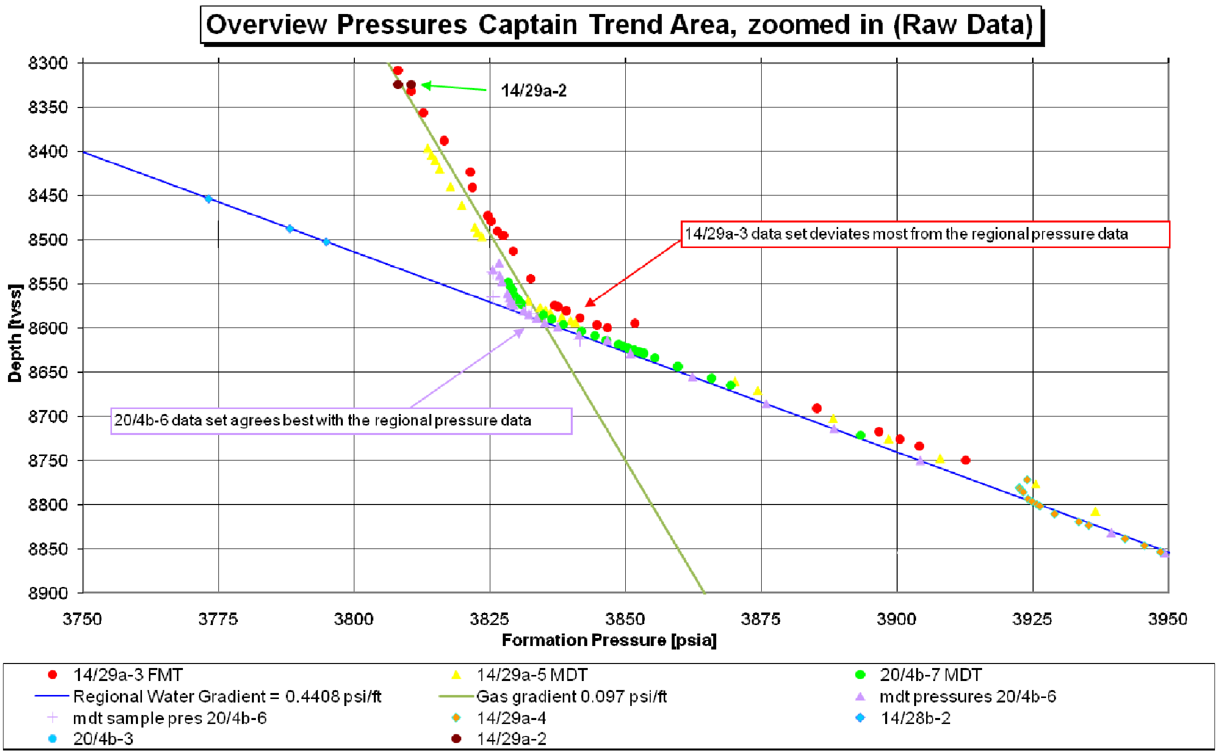


**Figure 3-1: Goldeneye regional pre-production pressure data.**

The Captain sandstone is subdivided into four litho-stratigraphic units[8] , from top to base as shown in Table 3-1 with the 'D' sand being the main productive interval. Units 'C'-'E' can be correlated across Goldeneye, with Unit 'C' representing a field-wide shale-rich horizon. By contrast, Unit 'A' occurs only in wells 14/29a-3 and 14/29a-5 and is only locally present, where it is c. 180-250 m thick. The MDT pressure data for 14/29a-5 show no indication of any barriers between units even though

[8] Static Model (Field). SP-FM020D3(RT063)

significant shales are present between C and A. The results from the dynamic Full Field Model[9] indicate that the 'D' and 'C' sands are in communication but the model cannot clarify whether the 'C' and 'A' sands are in communication.

Geochemical analysis of fluid samples from the exploration wells indicates that the gas in the reservoir is probably fully connected but that the oil in the northern part of the field (14/29a-3) is more mature than in the southern part (20/4b-6).

**Table 3-1: Sub-division of Captain Sandstone Member in the vicinity of the Goldeneye field.**

| Unit | Description |
|---|---|
| **Captain 'E' Unit** | Laterally variable thin heterogeneous unit |
| **Captain 'D' Unit** | Laterally extensive massive sand unit |
| **Captain 'C' Unit** | Laterally extensive, mudstone-rich heterogeneous unit |
| **Captain 'A' Unit** | Laterally restricted sand-rich unit |

The locations of the five Goldeneye production wells are shown in Figure 3-2. All the wells have permanent downhole gauges which were installed at least six months before production started in October 2004. The range in datum corrected initial pressure between the different wells is 4 psi suggesting initial errors are less than ±2 psi. The resolution of the gauges is of the order ± 0.005 psi. The gauges are 356 – 610 ft above the datum depth of 8400 ft TVDSS and the largest errors are likely to be due to uncertainties in hydrostatic correction of the gauge data to datum depth. The uncertainty in initial gas pressure gradient from the RFT/MDTs is ±0.005 psi/ft which gives an uncertainty of ±2 psi to ±4 psi. This will grow with time as the fluid composition in the wellbore changes.

As illustrated in Figure 3-3 these gauges show a slow decline before production of approximately 0.02 psi/day which is ascribed to production from Hannay which started production in March 2002. The decline rates for the five wells range from 0.019 psi/day in GYA02s1 to 0.023 psi/day in GYA04. The larger decline in GYA04 is consistent with the influence of Hannay as it is the closest well to Hannay. The pressure in GYA02s1 deviates from the trend from June 2004 owing to a surface perturbation and the initial pressures from this well cannot be relied upon after that.

9 Dynamic Modelling Report for Goldeneye Project. Doc No. SP-FM150D3

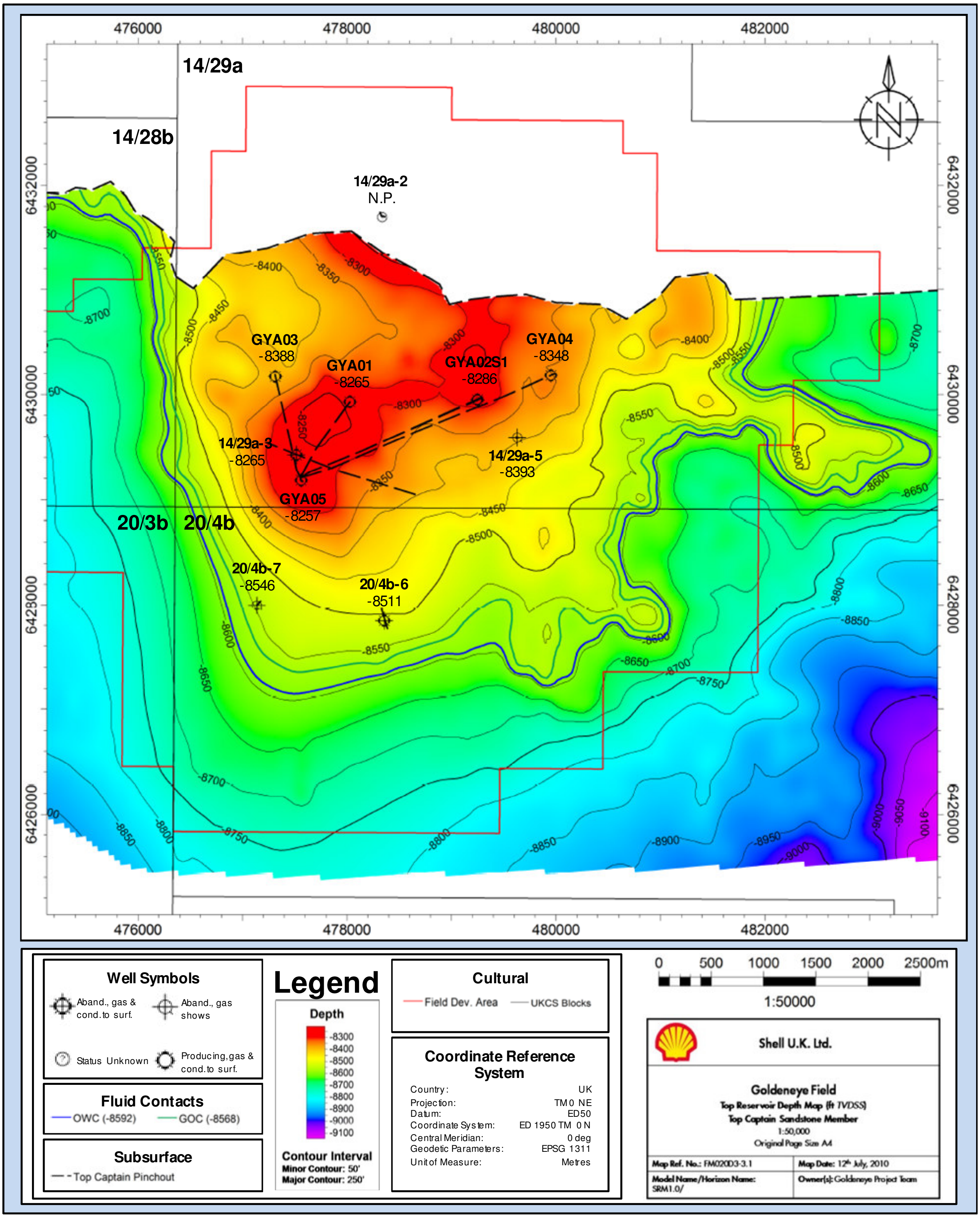


**Figure 3-2:** **Goldeneye field top structure map, True Vertical Depth Subsea (TVDSS), with the location of the five production wells, as well as local exploration and appraisal wells. The notation N.P. for 14/29a-2 indicates the Captain Sandstone was not present in the well.**

Figure 3-4 shows the pressures from two of the initial exploration wells together with the gauge data. The difference in pressure between 14/29a-3 and 14/29a-5 is most likely due to measurement errors. The measurements are taken from the RFT/MDTs and are subject to the calibration errors mentioned above. Extrapolating the gauge data back to 2002 brings it approximately in line with the exploration well pressures. Together with the fact that the largest pressure decline is in GYA04, which is closest to Hannay, this strongly suggests the pressure decline is due to Hannay production

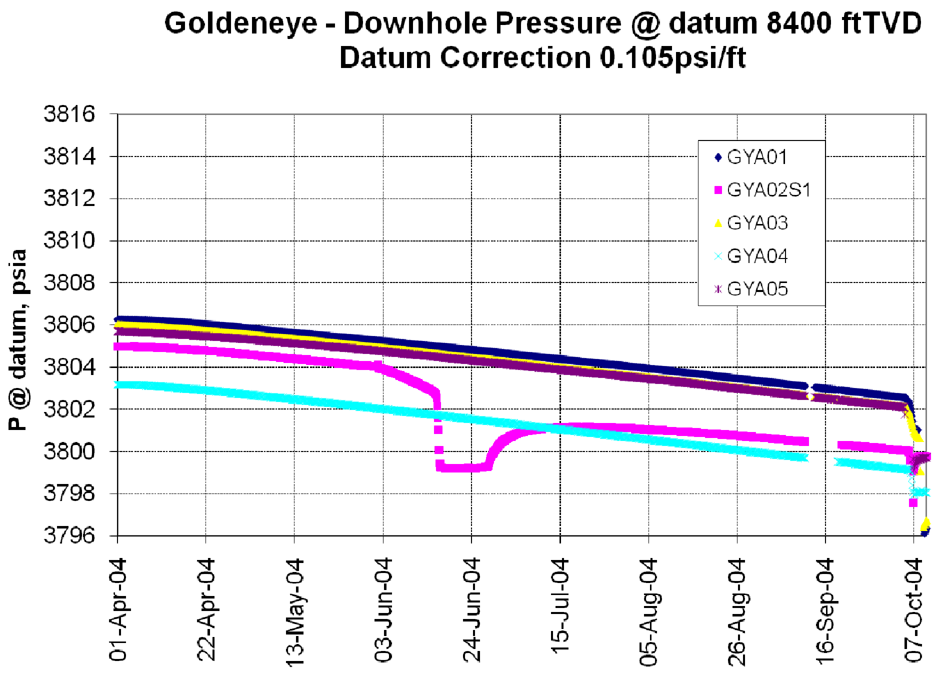


**Figure 3-3:** **Goldeneye pre-production downhole pressure gauge data.**

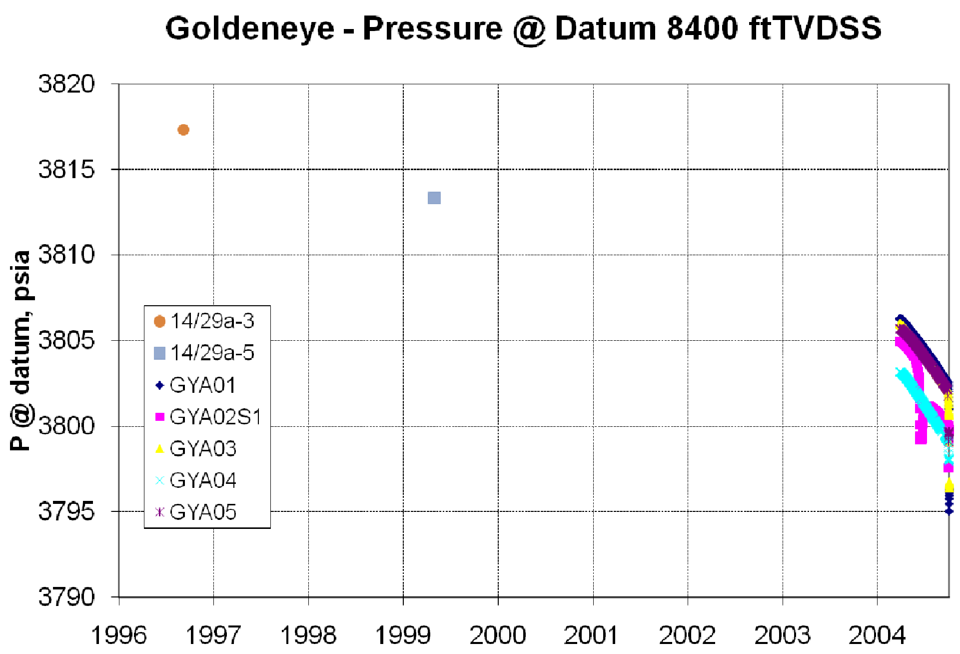


**Figure 3-4:** **Change in Goldeneye pressure from 1996 to 2004.**

## 3.2. During production

The five downhole gauges have recorded the pressure decline of the reservoir since production started in 2004. This is illustrated in Figure 3-5. The initial steep pressure decline has slowed since 2008 due to aquifer influx. The large gap in pressure that develops between GYA01 and GYA02 and the other three wells is due to GYA03, GYA04 and GYA05 being shut in due to water breakthrough. The fluctuations in pressure in GYA03 from late 2008 onwards are attributed to changes in the water level in the shut in well. The similar pressure values in the shut in wells indicates good communication within the reservoir.

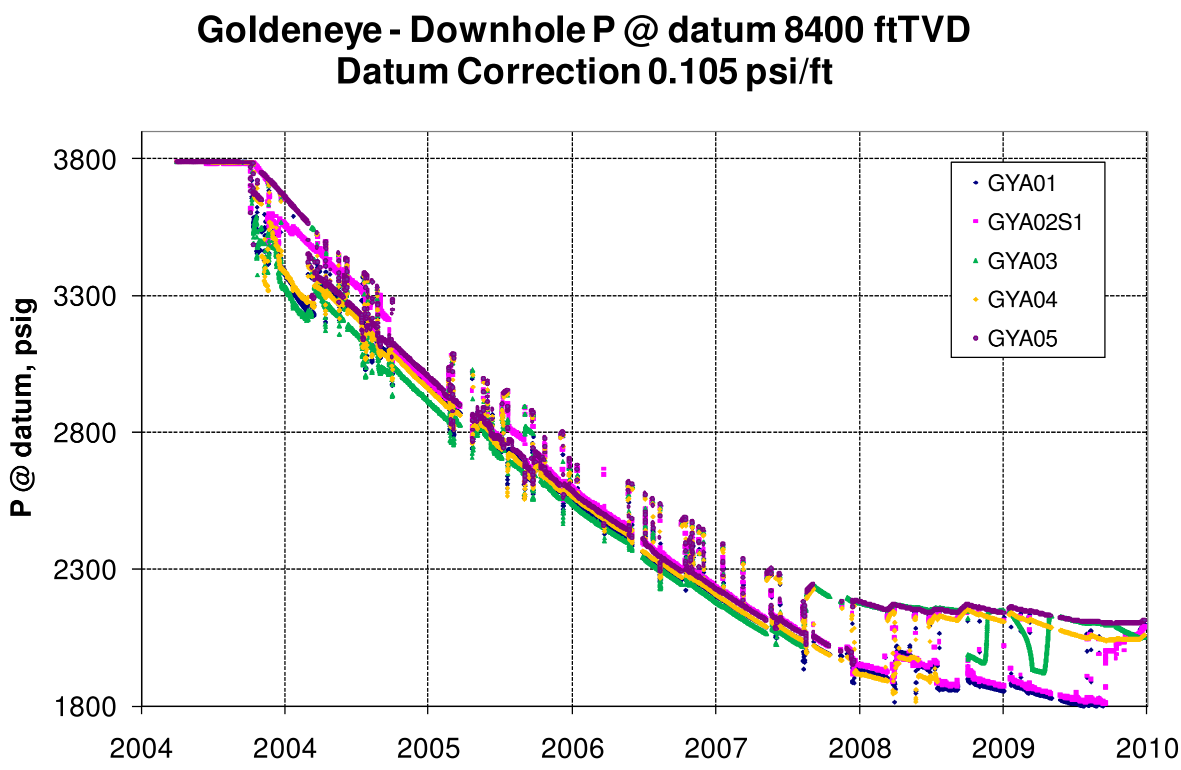


**Figure 3-5: Downhole pressure gauge data for Goldeneye.**

## 3.3. Post-production

Goldeneye production was paused when the last well, GYA01, cut water at the beginning of December 2010 (at the point of writing some wells have been re-started). The subsequent rise in pressure can be seen in Figure 3-6. The pressure drop in GYA03 is ascribed to changes in the water level of this well which is shut in. The changes in pressure in GYA02S1 are due to rate changes during production.

The pressure will continue to rise as the aquifer re-pressurises the reservoir. All the neighbouring fields, with the exception of Blake, have been shut in. Blake is supported by water injection and so will have little influence on the rate at which Goldeneye pressure rises. The Rochelle field, which is approximately 30 km west of Goldeneye, is planned to come on stream at the end of 2011 and could potentially affect Goldeneye pressures.

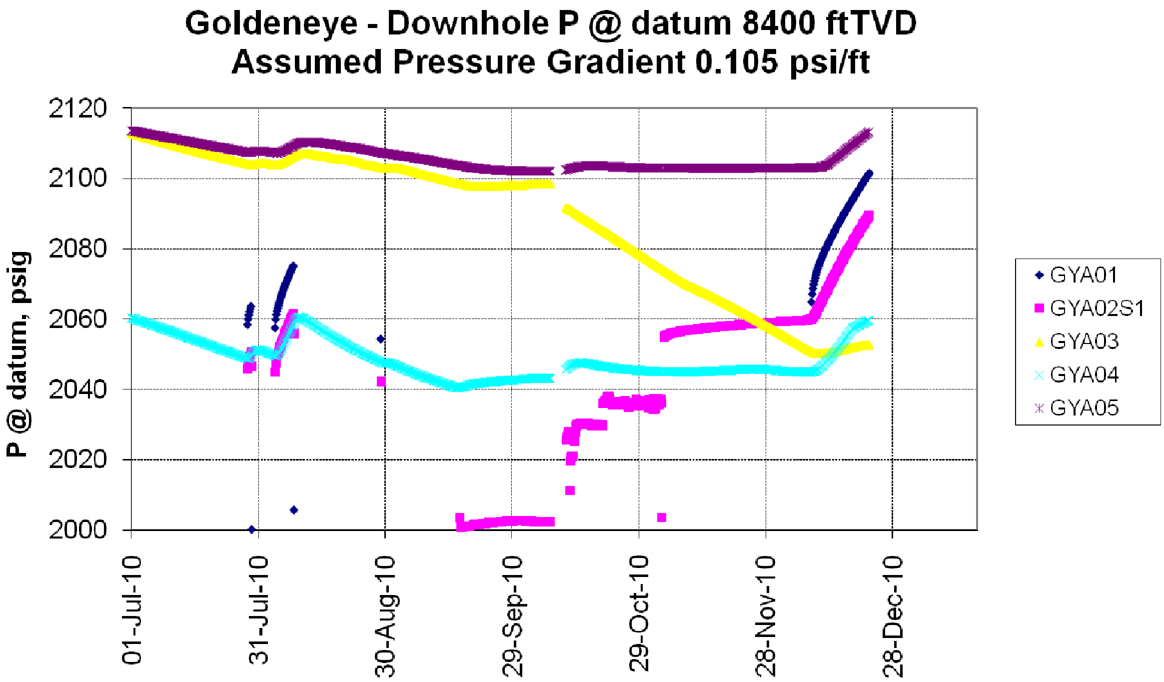


**Figure 3-6:** **Goldeneye downhole pressure gauge data from July to December 2010.**

A dynamic model of the Goldeneye aquifer has been constructed which stretches from Blake in the west to east of Hannay in the east. The model is approximately 100 km from east to west and includes Hannay, Atlantic, Cromarty and Blake as well as Goldeneye (see Figure 2-1 for field locations). The model has been used to investigate the range of possible aquifer strengths and to predict future pressures[10]. The results of these predictions are shown in Figure 3-7 together with the historical pressure data. The lack of firm data from neighbouring fields makes it impossible to distinguish between the various cases represented in the graph. The pressure in 2015 is predicted to be in the range 2830 psia to 2960 psia. The Rochelle field, approximately 30 km east of Goldeneye, is due to start production at the end of 2011. The effect of this field appears to be very minor in the period to 2015 but limited data was available to model this field so the results are subject to some uncertainty.

The model suggests that depletion of the Goldeneye reservoir within the gas cap has been mostly uniform but the poorer quality parts of the reservoir could be at higher pressure. After the end of production these differences decline rapidly. Well tests have also shown some evidence of faults although these are not sealing. Isolated pockets of high or low pressure can never be ruled out. The most likely areas at higher pressure will be in the 'A', 'C' and 'E' sands.

[10] Dynamic Modelling Report for Goldeneye Project. Doc No. SP-FM150D3

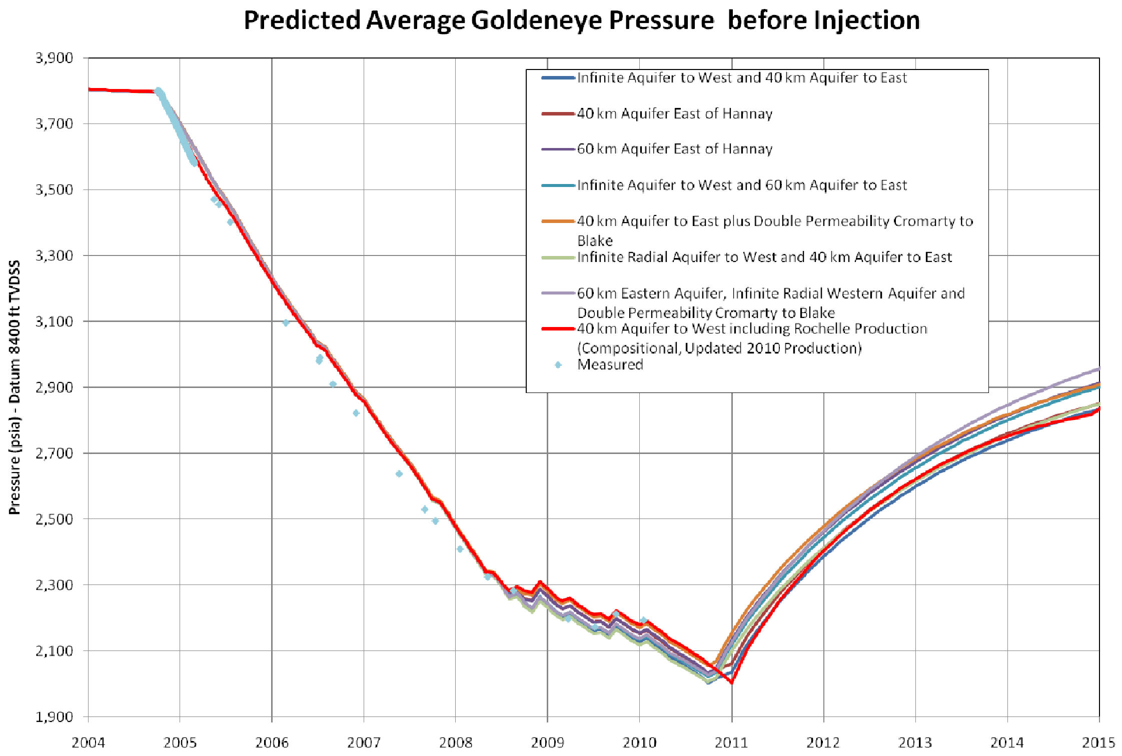


**Figure 3-7: Predicted 'D' sand Goldeneye pressure rise to 2015 (Note model with Rochelle production uses updated production data and uses compositional PVT as opposed to the other models which use black oil PVT hence there are small differences, however, these are minor compared to the forecast prediction).**

### 3.3.1. Predicted Pressures

The predicted pressures for 2012 to 2015 are given in Table 3-2. These pressures are for a datum depth of 8400 ft TVDSS.

**Table 3-2: Predicted Goldeneye pressures at 8400 ft TVDSS.**

| | Absolute Low Pressure (psia) | Realistic Low Pressure (psia) | Expected Pressure (psia) | Realistic High Pressure (psia) | Absolute High Pressure (psia) |
|---|---|---|---|---|---|
| 1 January 2012 | 2060 | 2400 | 2445 | 2490 | 3816 |
| 1 January 2013 | 2060 | 2600 | 2645 | 2690 | 3816 |
| 1 January 2014 | 2060 | 2740 | 2795 | 2850 | 3816 |
| 1 January 2015 | 2060 | 2830 | 2895 | 2960 | 3816 |

The pressure values are calculated as follows:

**Realistic High Pressure**

The realistic high pressure is the highest pressure from the aquifer model cases illustrated in Figure 3-7. *This will require update before future well work to incorporate future data.*

**Expected Pressure**

The expected pressure is the average pressure of the aquifer model cases illustrated in Figure 3-7. *This will require update before future well work to incorporate future data.*

**Realistic Low Pressure**

The realistic low pressure is the highest pressure from the aquifer model cases illustrated in Figure 3-7. *This will require update before future well work to incorporate future data.*

**Absolute Low Pressure**

The absolute low pressure is the lowest pressure given by the downhole gauge data of 2060 psia. The dynamic model predicts a slightly lower pressure of 2000 psia but there is some uncertainty about the match so the gauge data is preferable. Modelling of the impact of Rochelle production is of limited accuracy and so the simulated pressures after Rochelle production starts in 2012 may be too high, hence it is more conservative to use the current pressure.

**Absolute High Pressure**

The absolute high pressure is the initial pressure which is 3816 psia at 8400 ft TVDSS.

*The figures in* Table 3-2 *should be revised closer to the date of drilling so as to incorporate further data from the pressure buildup in the wells.*

# 4. Conclusions

## 4.1. Overburden and Underburden Pore Pressure Prediction

- Of the seventeen wells analysed in terms of mud weights used to drill the stratigraphic sequence in the Goldeneye Field, the lowest mud weights used to drill from seabed to the Permo-Triassic sequence ranges from 0.447-0.520 psi/ft. These pressure gradients indicate that this part of the Moray Firth doesn't contain significantly high pore pressures when compared to other parts of the North Sea (e.g. Central Graben).
- The Tertiary shale section of the overburden contained some indications of connection gas which is in keeping with the RFT data from regional wells indicating that pockets of overpressure exist in the range 0.475-0.500 psi/ft. The sandstones in the Tertiary sequence are not overpressured and indicate drainage and connection to an aquifer.
- The Chalk Group sediments are believed to be normally pressured based on the drilling and log data.
- The Cromer Knoll Group is made up of the Rødby and the Captain Formations. Evidence points to the Rødby caprock being normally pressured, whilst the abundant RFT data for the latter confirms a hydrostatically pressured reservoir.
- The deeper/older Jurassic to Permian sediments encountered in the exploration wells indicates that underlying the Goldeneye Field, these sediments are likely normally pressured, however, some of the offset wells, especially in Block 20, sections 2, 3, 4b, 5b, contain significant overpressure as shown by a kick and RFT data.
- Two compaction curves were found for the mudstones in the over- and under-burden due to the effect of the relatively heavy Chalk Group producing a steeper compaction trend in the underlying sediments. The two units which appear to be relatively undercompacted compared to the adjacent sediments are the Lista and Kimmeridge Clay Formations. Given that a kick was experienced in a sand in the Kimmeridge Clay which indicated a pore pressure of 0.605 psi/ft, it is likely that the Kimmeridge Clay is overpressured.
- The apparent undercompaction in the Lista Formation could be due to overpressure, or a result of mineralogical affects due to high smectite content and/or the presence of organic matter.
- The minimum principal stress in the Goldeneye Field (also termed the formation strength) has been compiled from the available LOT data. Depth-trend equations provide the predicted pressure versus depth subsea.

## 4.2. Reservoir Pressure Prediction

- Based on the abundant available data, the virgin pressure at the water contact in the Captain Reservoir was 3835 psi at 8592 ft TVDSS, whilst the gas pressure at 8400 ft TVDSS was 3814-3818 psi.
- Initial pressure data shows that the 'A', 'C', 'D' and 'E' sands were all on the same pressure gradient. However, there are significant shale layers between the 'A' and 'C' sands and geochemistry analysis shows differences between the oil in the north and south of the field. This means that virgin pressures in the 'A' sand cannot be ruled out. The FFM history match indicates communication between the 'D' and 'C' sands.

- All five production wells have working downhole gauges. These gauges show the effect of other fields in the Captain sand fairway which share a connected aquifer. The last production well cut water in December 2010, with production pausing and the reservoir subsequently starting to re-pressurise due to aquifer support.
- A dynamic model of the Goldeneye aquifer has been constructed, covering approximately 100 km from east to west and including the fields Hannay, Atlantic, Cromarty, Blake as well as Goldeneye. This model predicts that by 2015 the reservoir pressure will be in the range 2830-2960 psi.
- Although the production and test data indicate that the Goldeneye reservoir is well connected, isolated pockets of high or low pressures can never be completely ruled out.
- Pressure predictions should be revised before drilling any wells to take account of the following:
    - The downhole pressure gauges are still active and analysis of the pressure buildup will narrow the uncertainty in pressure.
    - The Rochelle field starts production in 2012 and could potentially affect Goldeneye so the pressure predictions should be revised as more data becomes available about this field.

# 5. Abbreviations

| | |
|---|---|
| AOI | Area of interest |
| API | American Petroleum Institute units |
| $CO_2$ | Carbon Dioxide |
| DCM | Dielectric constant measurement |
| FIT | Formation integrity test |
| GR | Gamma ray |
| LOT | Leak-off test |
| MD | Measured depth |
| MDT | Modular formation dynamics tester |
| RFT | Repeat formation tester |
| TVDBDF | True vertical depth below drill floor |
| TVDSS | True vertical depth subsea |
| UKCS | United Kingdom continental shelf |

In the text well names have been abbreviated to their operational form. The full well names are given in Table 5-1.

| Full well name | Abbreviated well name |
|---|---|
| DTI 14/29a-A3 | GYA01 |
| DTI 14/29a-A4Z | GYA02S1 |
| DTI 14/29a-A4 | GYA02 |
| DTI 14/29a-A5 | GYA03 |
| DTI 14/29a-A1 | GYA04 |
| DTI 14/29a-A2 | GYA05 |

**Table 5-1 Well name abbreviations**