Abstract

This paper looks, rather uniquely, at an HPHT field in the UK Sector of the North Sea which was designed and developed during the mid 1990’s and which, relatively recently, gave problems due to a gas leak from a well which was being worked on. The amount of gas emitted from the well caused full evacuation and the fact that the problem was solved with no injury gives full testimony to the high standard of the Operators Policies and Procedures. The well was “killed” from the top and a relief well was also drilled, designed to kill the well “from the bottom”. Unfortunately, the cost of a) loss of production and b) remedial works ran into £billions and the Operator was fined £1,125 million by the Law Courts for contravening the Health & Safety at work act. Sometimes, during the early design phases of a project company departments make decisions which turn out to be less than optimal simply because certain information wasn’t known. This can be unfortunate and very costly.

The field, Elgin, was named after a relatively nearby Scottish town. The field forms a part of the Central Graben and there were essentially two reservoir columns (the Jurassic overlying the Pentland). The paper tries to portray the excellence of planning, management and operations exhibited by the current world class / first rate Operator.

Background

The Central Graben area of the North Sea is portrayed in the figure below. As can be seen, the area is quite central to the UK’s oil and gas provinces and there is good infrastructure in terms of helicopter support, supply boat logistics (both not far from the regions’ central hub, Aberdeen, with secondary supply boat support from Montrose harbour further south and Jack-Up rig maintenance / servicing in Dundee harbor. (Note: - The field was developed by a harsh environment 15 k Jack Up rig; the first rig, the West Epsilon [a brand new build from Keppel FELS in Singapore] actually moored initially at the quayside at Cromarty Firth harbor to the north of Aberdeen.

The operator’s drilling supervisors and specialist personnel were able to spend time on the rig familiarizing themselves with the equipment and with BOP drills, etc. Also, Partners (of which there were
11 initially) were also able to familiarize themselves with the rig, since it was first of all going to be drilling a capital-intensive appraisal well, 22/30c-13.

Figure 1: The Elgin HPHT Field, UK Centra Graben, located approximately 110 miles to the east of Aberdeen. Significant faulting can be seen, as can the well locations ranging from EW1, EC2, EW3, EC3, EE2, EC5 and EC5.

Figure 2: The last appraisal well to be drilled on Elgin: 22/30C13, and S-shaped 45 Degree Tangential Well by the new-build 15,000 psi West Epsilon built at Keppel Fels in Singapore. The 17½ hole section was the shakedown well. Approved by the HSE as being the “initial well” before entering the Transition Zone / Reservoir.
U.S.A. Data

A written agreement allowed the then early Operator in the early 1990’s to spend time and ask unlimited questions of one of the world’s then premier oil companies (Amoco, which was subsequently taken over by BP) in their operating offices of Houston, New Orleans and at their first-class Research & Development facilities in Oklahoma. The amount of data acquired during this one-month long trip was huge. Reports were readily given (copies) and engineers gave freely of their time and expertise, all subsequently written down each evening thence forwarded to Aberdeen every morning. The reports (all directly relevant) were boxed, sellotaped and air freighted to the Operator’s offices in Aberdeen.

The data comprised information pertaining to the following areas: -

- Reservoir
- Drilling
- Production
- Intervention
- Workover
- Field Life Extension
Various Studies
Lessons Learnt.

Amoco were a hugely experienced HPHT company, with top class engineers and thinkers. The wealth of information given was worth £millions in design work alone and also $£millions in terms of life-of-field production.

It must be remembered that no HPHT fields had been developed in the UK at the time and there was no experience available comparable with what Amoco had acquired and given.

Non Full Use of Relevant Data

At the time of conceptual engineering, the earlier Operator thought that studying the Laq, in Aquitaine, the marginal HPHT Lille-Frigg wells, and other Operator drilled HPHT exploration well data (e.g. the Ultramar HPHT well) as being more important than robust Amoco HPHT exploration, appraisal and development wells.

All these wells (i.e. Laq, Lille Frigg and Ultramar) whilst very relevant, appeared though to be a distraction to the Amoco HPHT exploration, appraisal and development data, which was unfortunate as it was both robust and complete and backed by years of production across the USA. So essentially the robust, first-class Amoco HPHT data wasn’t fully incorporated into the conceptual engineering phase of the project as much as it might have been which was a great loss to the project. It may just be possible that the problem referred to in this paper may have been averted.

Data / Study “Sharing”

As can be seen from Figure 4 the several HPHT Central Graben fields (with different Operators) are relatively close together, an ideal situation with which to collaborate and co-operate. However, “sharing” was limited unfortunately.

It was never really a question of sharing reservoir data per se (very few Operators will typically do this) and there might not have been a great deal of value in this anyway. Dense Jurassic fine grade sandstone named the Fulmar sands are the main producing interval dating back to the Jurassic interval of circa 165 million years ago (see Figure 5); temperatures and pressures are roughly the same as are hydrocarbons (gas and condensate), carbon dioxide and hydrogen sulphide. Rather, great benefit would have been secured through the shared testing of equipment and modelling of tubulars, wellheads, drilling fluids, packer fluids, ways in which to complete the wells, minimize their intervention / workover etc and ways in which the steels were to be tested – either through coupons, full-size testing or at the manufacturing stage.

It seems as though great benefit could have been attained through commonality of design, specification and equipment purchase.
The Elgin / Franklin reservoir and well’s characteristics are typically as follows:

- well depth: 5,500 m (3.4 mi)
- pressure range: 600 – 1100 bar
- operational pressure: 860 bar
- fluid temperature: 193 °C (379 °F)
- sea floor depth: 93 m (305 ft)
- Fulmar porosity circa 20%

The West Franklin reservoir is the world's hottest, highest pressure reservoir, with a temperature of 197 °C (387 °F) and pressure of 1,155 bars (115,500 kPa).

The Middle Jurassic Pentland formation forms a second reservoir with a separate hydrocarbon pool. (Production of this reservoir was always contentious.

The Produced oil (light / condensate) is transported through the Forties Pipeline System to BP’s Kinneil terminal in Grangemouth while produced gas is transported through the SEAL Pipeline to Bacton, Norfolk.
Figure 5: The main producing reservoir is the Fulmar Jurassic Sandstone age circa 165 million years.

Elgin 22/30c-G4 Gas Leak

A gas leak was first detected on Elgin on 25\textsuperscript{th} March 2012, the leak estimated to be approximately 200,000 cubic metres per day of natural gas forming a highly explosive gas cloud. The leak was dissipating from well 22/30c-G4 during operations to plug and decommission the well as it had stopped producing on an economic basis. The leak caused the Process Utilities Quarters Platform to shut down and all wells were shut-in.
Figure 6: The 200,000 gas leak egressed from well 22/30c-G4 whilst the JackUp rig the Rowan Viking was carrying out plugging and decommissioning operations on the well. (The rig is seen working over the Drilling Platform; the Process Utilities Quarters Platform is seen to the right)

The cause of the incident was identified as corrosion in the casing of the 22/30c-G4 well, and a sudden release of gas from the Hod chalk formation at a depth of 4,500 metres or 14,800 ft above the producing reservoir. Total identified the origin of the gas leak to be an unexploited chalk reservoir layer of the Hod formation located at a depth of 4,500 metres (14,800 ft), which is above the main reservoir. (This was supported by analysis showing the absence of significant concentration of hydrogen sulphide in the gas, presented in the reservoir gas The Hod formation had been isolated by steel casing during drilling in 1997.

This pressure ruptured the casing. On 25 February 2012 an increase in pressure was observed in the C annulus within the well and remedial operations started on 4 March 2012. Total believed that the C annulus failed and gas was observed leaking from the 30-inch (760 mm) conductor.

During April 2012 a diverter assembly was installed around the 22/30c-G4 well head to divert the leaking gas (estimated at 200,000 cubic metres per day (7,100,000 cu ft/d)) away from the platform in a controlled manner enabling well control operations to begin.

In May 2012 two drilling rigs were working on “repairing the leak”. The West Phoenix semi submersible rig was working on the "top kill" operation. This involved pumping weighted drilling mud into the well via the wellhead assembly, a method which was ultimately successful in halting the leak. A relief well, G4-K1 was drilled to "bottom kill" the well by the Sedco 714.
The leak was stopped following well intervention work on 16 May 2012. Photographs of how the wellhead was rigged-up can be seen in Figures 13, 14 & 15.

Figure 7: The Process Utilities Quarters (PUQ) Platform was shut-down following the 200,000 cubic metres per day gas leak from well 22/30c-G4 whilst the JackUp rig the Rowan Viking was carrying out plugging and decommissioning operations on well 22/30c-G4. Of concern to many people was that the flare was still flaring whilst the platform voided its contained gas.

Figure 8: View of the West Phoenix in orange, the PUQ (yellow), the Viking over the Drilling Platform and the Sedco 714 used to drill the relief well.
Figure 9: The powerful 6th Generation West Phoenix responsible for the “powerful top kill”.

Characteristics of the West Phoenix

- Maximum Drill Depth: 30,000 ft
- Maximum Water Depth: 9,850 ft
- Gross Tonnage: 35,568
- DWT: 25,325
- Year of build: 2008
- Builder: Samsung, South Korea
- Flag: Panama
- Class Society: Det Norske Veritas
- Hookload: 2,000,000
- Mud Pumps: Wirth TPK 2200
- Top Drive: National Oilwell Varco
- Rig Design
- Dimensions: 389 x 246 x 77
- Draught when underway: 10 metres
- Engine Propulsion: typically 6.7 knots
- Crew: 125
- Harsh Environment Classification (Norwegian PSA)
- Generation: 6th
Characteristics of the Sedco 714

Owner: Transocean  
Type: Semi-submersible  
Water Depth: 1,600 ft  
Drilling Depth: 25,000 ft  
Derrick: Dreco 185 ft  
Capacity: 1,300,000 lbs  
Drawworks: National Oilwell E3000 2,500 HP

Characteristics of the Viking

Owner: Rowan Drilling  
Type: Jack Up  
Water Depth: 400 ft  
Drilling Depth: 35,000 ft  
Derrick: NOV 180’ x 40’ x 40’  
Capacity: 2,000,000 lbs  
Hook & Setback 3,200,000 lbs  
Drawworks NOV M4600 4,600HP  
Dimensions 264 x 289 x 35  
Leg Length 568  
Mud Pumps NOV 14-P-220 Triplex  
Top Drive NOV HPS-1,000  
Hookload Capacity 2,000,000 lbs

Figure 10: The PUQ platform with expelling gas around the leg around the PUQ and the Viking Drilling Rig over the Drilling Platform
The Hod formation had been isolated by steel casing during drilling in 1997. On 25 February 2012 an increase in pressure was observed in the C annulus within the well and remedial operations started on 4 March 2012. Total believed that the C annulus failed and gas was observed leaking from the 30-inch (760 mm) conductor.

During April 2012 a diverter assembly was installed around the G4 well head to divert the leaking gas (estimated then at 200,000 cubic metres per day (7,100,000 cu ft/d)) away from the platform in a controlled manner enabling well control operations to begin. In May 2012, two drilling rigs were working on repairing the leak. The West Phoenix semi submersible rig (orange in the photograph) was working on the "top kill" operation. This involved pumping cement and weighted drilling mud into the well via the wellhead assembly, a method which was ultimately successful in halting the leak. A relief well, G4-K1 was drilled to "bottom kill" the well by the Sedco 714 (photo below).

Figure 11: The cause of the incident was identified as corrosion in the casing of the G4 well, and a sudden release of gas from the Hod formation above the producing reservoir.
Unfortunately the following information was not readily given from the reports published on the Internet regarding:-

- The grade of casing
- The weight of casing
- The thread type
- The dope and torque make-up
- The gas type from the Hod formation (was it corrosive)
- Was the casing in bucking mode
- Was the annulus fully clean of mud;
- Was mud struck to the wall of the casing / the wellbore wall;

It seems as though gas from the Hod formation entered the outside casing of the well (presumed to be a crack as a result of corrosion of the casing) and worked its way to surface. The question is: how did the Hod gas come to enter the corroded crack?

Unfortunately, the Internet literature is vague in this area.
Relief well drilling when there’s an escape of hydrocarbons within UK Continental Waters is mandatory, and in this situation the semi-submersible Sedco 714 was utilized. [A Relief Well is a Well drilled from the surface, usually 1 km away, down to the the blowing well – in this case Well G4. It may or may not have intercepted the blowing well en-route – sometimes half-way down – to reduce the ellipse of uncertainty. However, if the accuracy of the surveys of the the blowing well (G4) is high, and the surveys on the Sedco 714 are high, then it may be possible to drill direct to the reservoir and to dynamically kill the well. This is typically a combination of both wells yielding success. Heavy mud is pumped dynamically (typically increasing the Equivalent Circulating Pressure) down the relief well, killing the blowing well.

Here we can see paraffins and waxes in the vicinity of the G4 wellhead. Gas can be seen spurting from the wellhead; analysed gas showed it to be free of hydrogen sulphide (which is contained within the reservoir gas) therefore suggested Hod gas.

The question is: Knowing Hod gas existed, through the drilling of several exploration and appraisal wells (this would be known by influxes due to the hydrostatic pressure of the mud not being high enough and so an influx taken and by a rise in gas and most likely a drilling break [a speed up in the rate of drilling] why not use the appropriate casing and cement? [The appropriate weight and grade of casing plus a first-class cement job would prevent casing corrosion in the first place and the event from occurring in the second place].

Escaping gas on any offshore installation is potentially lethal, especially whilst the flare is still alight as the production train depressurizes or comes into contact with non-positively purged electrical systems.
Explosions which readily come to mind are Piper Alpha in the North Sea in which 167 men died; the Ocean Odyssey again in the North Sea, the West Vanguard (Norwegian Sector of the North Sea), the Montara Jack-Up rig in Northern Australia, the deepwater Horizon / Macondo in the Gulf of Mexico in which 11 men died, the Hercules offshore to Louisiana and the K S Endeavour Jack-Up Offshore Nigeria where 2 men died.

![Figure 14: The cleaned G4 wellhead, free of paraffin](image14.png)

![Figure 15: Diverter Installed on the cleaned-up G4 wellhead](image15.png)
Conclusions

- Production restarted on 9 March 2013 after a long period of being shut-in.
- The Operator was fined by Her Majesty’s Government an amount of GBP 1,125 million for the gas leak.
- Unfortunately, the production loss and the repair costs to the Operator ran into £billions.
- Given that the Operator is world-class and indeed first-rate, the unfortunate incident was managed and the repair executed without any loss of life or major damage, testimony to the Operator’s excellence with it’s Policies, Procedures, Management and Operational Skills.
- It’s marvellous that the Operator has made so much information available on this incident for the rest of the world to learn from.

Figure 16: How the well was eventually sealed.
Explanatory Details

Elgin Gas Leak Seen Escaping from the Wellhead Platform to the Jack-Up

Options for plugging the Gas Leak
Elgin Process Showing Further Gas Leak into the Sea

BATTLE TO PLUG THE LEAK

There are fears a flare on the rig could ignite the gas cloud.

THE POSSIBLE CAUSE:
- Engineers working on pipes to an old gas reservoir caused it to rupture.

HOW THEY COULD FIX IT:
- Pump mud into the well to suppress the flow of gas.
- Drill a relief well from another platform.

ELGIN PLATFORM:
- Location: 149 miles east of Aberdeen, the oil capital of Europe.
- Depth of water: 305ft.

ON STANDBY:
- Two firefighting vessels.
- Sea Bear and Skandia Saigon.
- Unmanned submarine to scan seabed for signs of leaks.
- Hercules aircraft carrying pollution dispersants.

Flare and Gas: An Extremely Dangerous Combination
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