CONCLUSIONS

The results of the recent appraisal wells have demonstrated clearly that water encroachment into the Frigg reservoir is not a simple case of bottom water drive. There is now little doubt that parts of the field are being depleted by edge water drive. The water encroachment is being controlled to some extent by the presence of shale barriers within the reservoir sands. The description and prediction of these shale layers is of paramount importance to reservoir performance as it is possible that production will cease due to water encroachment rather than pressure depletion. The presence of isolated gas pockets in the field may be sufficient to warrant future development either from the present installations or from satellite wells. The accurate prediction of such remaining gas calls for an interdisciplinary approach to reservoir simulation.

The models presented here are the first stage in this approach and they will and must be improved to arrive at an optimal depletion policy. The results of our recent appraisal work are adding to the complexity of our geological model. It is apparent now that the reservoir sequence cannot be simplified in terms of either a deep-sea fan or a delta, and a detailed analysis of all the recently acquired data needs to be synthesized into a predictive model to allow us to simulate adequately a fairly complicated reservoir.

ACKNOWLEDGEMENTS

The opinions expressed herein are those of the authors and are not necessarily those of Elf Aquitaine Norge or any of the owners of the Frigg Field. Much of the work presented is that of both the exploration and reservoir divisions of Elf.

REFERENCES


6 The Frigg Field reservoir: characteristics and performance

A. De Leebeeck
Elf Aquitaine Norge A/S, Stavanger, Norway

The Frigg Field is a large gas reservoir straddling the Norwegian–UK frontier which has supplied a significant percentage of British gas requirements since coming on stream in 1977. This chapter follows an examination of the Frigg Field production geology (Chapter 5) and reviews the reservoir factors involved in the determination of Frigg gas-in-place and the uncertainties surrounding their resolution. After a review of the dynamic data leading to a determination of recoverable reserves, there follows a discussion of the various reservoir studies conducted through the phases of the field life (design, development, production and now reappraisal). The study results were a key element in the major decisions. Current studies as outlined will yield the elements required for determining Frigg future performance and related decisions.

INTRODUCTION

The Frigg Field straddles the Norwegian–UK frontier and is located primarily in Block 35/1 on the Norwegian side and Block 10/1 on the British side. The Frigg Field is unitted and is owned jointly by the Frigg–UK Association (Elf UK and Total Oil Marine) and the Frigg-Norwegian Association (Elf Aquitaine Norge (operator), Norsk Hydro, Total Marine Norsk and Statoil). The field was discovered in 1971 and brought on stream in September 1977. This chapter will review the reservoir characteristics of the Frigg Field, the reservoir studies conducted and their impact on field development and exploitation.

The primary function of the reservoir engineer is to determine the recoverable reserves, their quantity and the timing of their recovery (production profile). Throughout the chapter the term “accumulation” will be used to denote hydrocarbon-in-place while “reserves” will denote recoverable reserves. The determination of the reserves begins with the evaluation of the accumulation. The initial data are static data as the values should not change with time. These data consist of the rock volume from seismic analysis, the rock properties and fluid saturations from log and core analyses and their distribution from geological/reservoir studies and fluid properties from the laboratory.

Determination of reserves combines a knowledge of the in situ fluid flow characteristics (permeability, residual saturations) with the expected influence of reservoir barriers, aquifer activity and surface facility limitations (capacity, economics). The derivation of a production profile is an iterative process between reservoir potential, wells available and economics. Handling all the required data from a large field requires extensive reservoir simulation studies. Data which are certain or unavailable during facility design become less certain or change as the field is being produced. This necessitates a review of previous calculations/studies and any downstream decisions.

The Frigg Field is a giant gas reservoir with what was initially an aquifer of unknown activity. It has been on production for eight years. The confirmation of an active aquifer has lead to a complete re-analysis of all available data. An added element in the performance of this reservoir is the adherence to a gas sales contract.

RESERVOIR DESCRIPTION

Field setting

The Frigg Field is a large gas reservoir underlain by an oil disk of some 8–10 m. The reservoir consists of unconsolidated sands of the Lower Eocene. The field is located approximately 100 km off the Norwegian coast and is presently in Block 35/1 on the Norwegian side and in Block 10/1 on the British side (Fig. 1). Gas reservoirs on the same aquifer include Odin (Esso operator) to the north, North-East Frigg and Frigg Alpha and Beta (Elf operator on both). The geological setting is described in the previous chapter (volumes 1 and 2). The reservoir temper North Sea Oil and Gas Reservoirs © The Norwegian Institute of Technology (Graham and Trotman, 1987) pp. 89-100.
minology for the formations differs somewhat from the
bearing sands of the Lower Eocene are the Frigg Forma­
tions, from 2 to 10 m thickness, averaging 8.6 m. Unce­

tain

Balder Formation become the Tuff while all deeper for­
mations become the Cod aquifer (see Fig. 2).

The top of the reservoir is at approximately 1800 m

The sand consistency is much like beach sand and con­

ventional coring techniques such as steel barrel core led
to the recovery of non-representative samples. Later
coring techniques such as rubber sleeve, and now fibre
glass, result in much better recoveries and representa­
tive samples. The first cores arrived in the laboratory
in bags and measurements results from packed columns
are not reliable. Due to the unconsolidated nature of
the sands, laboratory measurements for porosity, per­
meability and density are conducted at reservoir pres­
sure. Measurements available at laboratory conditions
show the same trends, an average 2480 mD from core
measurement.

Porosities from core are comparable to porosities from
logs, corrected for gas effect. The porosity, which ranges
from 26–32%, is considered correct to within 1 pu. Per­
meabilities from core (arithmetic mean) have been com­
pared with well test permeabilities on two wells and
show the same trends, an average 2480 mD from core
and 1800 mD from well test for one and 610 mD and 820
mD respectively for the other well. Permeability in a
depositional model accepted at the time of interpreta­
tion. The net-to-gross pay distribution is also condi­
tioned by the depositional model.

The Frigg oil was tested on Well 25/1-3. An interesting
feature of the oil is the near absence of any C4 to C8
components (Table II). The solution gas-oil ratio was
determined to be about 61 m³/m³. Hydrocarbon prop­
erties are listed in Table III.

Table II Frigg Field fluid compositions (mole fraction)

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<th>Reservoir Condensate</th>
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</thead>
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<tr>
<td>CO₂</td>
<td>0.7</td>
<td>0.3</td>
</tr>
<tr>
<td>C₂</td>
<td>96.5</td>
<td>35.8</td>
</tr>
<tr>
<td>C₃-C₄</td>
<td>3.7</td>
<td>4.3</td>
</tr>
<tr>
<td>C₅</td>
<td>0.1</td>
<td>50.1</td>
</tr>
<tr>
<td>C₆</td>
<td></td>
<td>65.9</td>
</tr>
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Water samples obtained from a water test on Well
25/1-3 were initially accepted as representative. Log
analysis gave an average connate water saturation
of 9.4% in the gas sands and 26% in the oil sands. The
initial water saturation is another parameter sensitive to the
shale content. In clean gas sands the log derived Sₜ_W can
be as low as 2–3% possibly due to dehydration, but direct
measurements become questionable due to tool limits
at low Sₜ_W. The results are summarized in Table IV.

Table III Frigg Field fluid properties

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<tr>
<td>Salinity</td>
<td>0.07 %</td>
<td>0.1 %</td>
</tr>
<tr>
<td>Rₑₑₑ</td>
<td>4.54 x 10⁻³ bar⁻¹</td>
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Table I Frigg Field—rock properties

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Because porosity and permeability are linked to shale
content their distribution is partially controlled by the
depositional model. With the well-sorted nature of the sand it was
presumed that the vertical k equals horizontal k in the clean
sands, k is reduced as a function of the net-to-gross pay ratio.

Fluid properties

The Frigg Field gas is a retrograde gas condensate with
an estimated 4.3 g/m³ of condensate at initial conditions.
To obtain a representative gas sample the production of
one of the production clusters CDP1 was put through
one of the production trains of the treatment platform
TP1. In this way fluid metering could be performed on
the large quantities of gas essential to accurately
measure the small liquid flow rates.

The Frigg oil was tested on Well 25/1-3. An interesting
feature of the oil is the near absence of any C4 to C8
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seismic survey conducted in 1973. Their 1976 report provided the basis for a unit agreement which gave 60.82% to the Norwegian partners and 39.18% to the British partners. Small differences in gas properties give in-house figures of 265 × 10^9 Sm^3 of gas-in-place. An in-house study conducted in 1985 gave an oil-in-place of 135.6 M tonnes. In 1972 a study was undertaken to look into the possibility of commercial oil exploitation. To avoid coring problems it was decided that over 300 wells would be required and such a project was deemed uneconomic (Hamre, 1984).

The Frigg satellites have in excess of 75 × 10^9 Sm^3 of gas-in-place and share a common aquifer with Frigg and must, therefore, be taken into account in Frigg Field exploitation studies.

**Dynamic properties**

To determine the reserves it is necessary to know the recovery mechanism. The recurring question with regard to a gas reservoir is: is there an active aquifer? If not, a P/Z plot is sufficient. If there is an active aquifer, several factors need to be accounted for of which the most important are residual gas saturation (Sg,r) after waterflood and water coning. Because of the oil disk in Frigg the residual oil saturation (S0,rw) and the residual hydrocarbon saturation (Sr,rw) must also be determined.

Recognizing the potential for an active aquifer Elf embarked on a special core analysis programme early in the field appraisal. The first samples were reconstituted from available Frigg sand. The runs were at laboratory condition and gave an Sg,rw of 18% and an Sr,rw of 25%. Later work with more representative samples (cores cut with rubber-sleeves) was done at reservoir conditions. Interpretation of the results gave a correlation of Sg,rw as a function of porosity (Fig. 3). At the field average porosity of 29%, Sg,rw = 25% and Sr,rw = 30%. More recent work has shown that despite interfacial tension and initial water saturation this correlation remains constant. Determination of the influence of depletion and shale content continues to be analysed. Field results will be given later in the chapter.

The 1973 seismic survey ensured that the field structure was well understood when production began. The reservoir, based on nine appraisal wells, was considered a clean homogeneous sand with well-known distributions of porosity and permeability. Laboratory analyses gave the residual hydrocarbon saturations. The most important remaining unknown was the aquifer activity. Given an active aquifer calculation of the reserves requires a determination of the sweep efficiency. As this involves many different factors which are difficult to incorporate in a hand calculation the reservoir engineer resorts to a numerical simulator.

Pertinent Frigg simulation studies will be reviewed after a short section on Reservoir Performance.

---

**TRAPPED GAS SATURATION(%)**

![Graph showing trapped gas saturation vs porosity](image)

**Fig. 3** Frigg cores—correlation of residual gas to water vs porosity.

---

**RESEVOIR PERFORMANCE**

**Development**

The Frigg complex consists of five platforms: two drilling/production platforms (CDP1 and DP2), two treatment platforms (TP1 and TCP2) and a quarters platform (QP). Gas is transported to St Fergus, Scotland, via two 32 in. lines. There is an intermediate compression platform 186 km from Frigg (Plate 12). Each drilling platform has 24 wells grouped into two clusters of 12 wells each. Interconnecting pipelines allow production to either treatment platform. Development drilling started in 1976 on CDP1 and was completed by 1979. Gas sales started in 1977. Compression facilities were added by 1982.

Initially it was uncertain whether Frigg had an active aquifer; it was even more uncertain whether there was communication between the local Frigg aquifer and the regional Cod aquifer. However, recognizing the potential existed, Well 25/1-A22, located on the north-east corner of the DP2 platform (Fig. 4), was drilled through to the Cod sands and completed as an observation well with a permanent downhole pressure gauge. The remaining 47 wells were drilled only 60 m into the gas reservoir, spaced at 250 m at top reservoir level. This shallow penetration was designed to avoid water coning problems.

The decision to implement sand control was taken for two reasons: first, because of the unconsolidated nature of the sand; and, second, because at the time there was no known production from such sands greater than 1 M m^3/d. Many factors were considered and screens were preferred to gravel packs; no sand production problems have been encountered. Initially a through screen velocity of 15 cm/sec was imposed but has since been discarded following further study. A typical completion is shown in Fig. 5.

**Production/monitoring history**

The gas production from Frigg has been trouble-free since production start-up (Fig. 6). The monitoring programme was set up to address three main concerns (Maritvold, 1985):

1. sand production;
2. aquifer activity;
3. gas movement from the satellites.

All wells have been production logged at least once and show that initially sand/mud particles smaller than the screen size caused some sediment fill and screen blockage. All wells have stabilized and more than 70% of the screen length on each well contributes to production. A typical profile is shown in Fig. 7.

Pressures are monitored continuously using downhole recorders with periodic checks with wireline gauges.
Figures 8 and 9 show the pressure decline in the Frigg and Cod sands respectively. Well 25/1-A02 has been logged with a TDT (thermal neutron decay time tool) regularly to monitor the water rise. Figure 10 shows the observed contact rise. Subsequent observation wells (discussed below) are also regularly logged. Biaxial seismic surveys have been performed to monitor any possible gas movements from the satellite fields. Some gas movement has been detected at North-east Frigg and is suspected at East Frigg (Revoy, 1984). More specific comments on the interpretation of the field monitoring results are presented in the next section.

RESERVOIR STUDIES
Design phase (1972–1975)
The first studies conducted were based on the following assumptions:
1. gas-in-place: 270 x 10^9Sm^3
2. well productivity: 4 x 10^6 m^3/d with maximum through screen velocity of 15 cm/s and minimum wellhead pressure of 65 bars;
3. field life: 30 years, later modified according to the sales contract.
The Frigg Field reservoir: characteristics and performance

Development phase (1976–1978)

The development wells only partially penetrated the reservoir and covered a limited area of it (250 m spacing) and so did not provide any information to justify changing the geological model. Shale and limestone stringers were deemed not correlateable.

Frigg came on production in September 1977 and the pressure response confirmed the presence of an active aquifer. Continued studies showed the need for compression (implemented in 1982). Other studies were conducted to determine the development potential of the satellites. An extensive study in 1979 aimed primarily at determining the risk of gas movement from the satellites assumed the following details:

- gas-in-place $265 \times 10^9$ Sm$^3$
- homogeneous reservoir
- active aquifer via increased permeability across the Tuff
- trapped gas saturation $S_{grw} = 19\%$

The increased aquifer support gave an increased recovery pushing reserves to $227 \times 10^9$ Sm$^3$. Field abandonment was still linked to abandonment pressure. Water encroachment/coning at the platform was concurrent with the pressure limitation.

Production phase (1977–1984)

By 1978 it was evident that Frigg Field gas recovery was affected by aquifer support and it became apparent by the Autumn of 1980 that the Cod aquifer was giving a great deal of support. Water coming below the platforms was not a concern because the observations on Well 25/1-A22 showed a limited water rise (Fig. 10). The support from Cod was greater than expected and could not be explained by an increased permeability across the Tuff as laboratory measurements suggested the Tuff was nearly impermeable (0.001 mD). Earlier geological reports suggesting the absence of Tuff in some wells were investigated further. A permeability window was introduced to the west and south-west of the platforms (Fig. 13).


The results of Well 10/1-A25 questioned some of the basic input to the reservoir model but, at the same time, questioned the concept of the Tuff as a permeability barrier.

(1) the absence of any pressure shift across the Tuff confirmed the existence of permeability windows but, at the same time, questioned the concept of the Tuff as a permeability barrier;
(2) the expected water rise was confirmed but the time to possible water breakthrough at the platform was shorter than forecast;
(3) log evaluation of the swept gas zone gave residual saturations in agreement with lab measurements ($S_{grw} = 29\%$).

The location and strength of the model water rise was a direct consequence of the supposed location of the permeability windows through the Tuff and the permeability assigned to them. The observation Well 25/1-A22 continued to show no significant water rise. This could be explained by the presence of shales which block the water locally. In Autumn 1984 Well 10/1-A12 (now A25) was deepened to validate the geological model and confirm the simulation results. The reservoir model gave between 38 m and 42 m of water rise. The measured rise was near 55 m. The consequences of this well were significant:

- the existence of any pressure shift across the Tuff confirmed the existence of permeability windows but, at the same time, questioned the concept of the Tuff as a permeability barrier;
- the expected water rise was confirmed but the time to possible water breakthrough at the platform was shorter than forecast;
- log evaluation of the swept gas zone gave residual saturations in agreement with lab measurements ($S_{grw} = 29\%$).

The Frigg Field schematic cross-section—development phase.

The wells have been extensively cored and logged. VSPs have been conducted on all wells. RPT runs have
The Frigg Field reservoir: characteristics and performance

LOG INTERPRETATION

1. The Frigg reservoir is not homogeneous;
2. Shale events within the Frigg sands control the water rise (schematic Fig. 14).

The hypotheses on the nature and extent of the shale events control the simulation results. Differing hypotheses change the productive lifetime of the platforms and the distribution of the remaining gas. The level of trapped gas saturation is known as a function of porosity in clean sands but needs to be determined in shaly sands. This will aid in determining the quantity of movable gas.

Log interpretation results suggest that laboratory $S_p$ results may be a little pessimistic (Fig. 15).

The uncertainties elaborated in the “Reservoir description” section remain and become more significant when considering remaining reserves. Results to date suggest a range of ±10-15% on the median reserves figure which translates to ±30-35% on the remaining reserves. Studies continue to quantify the uncertainties.

Fig. 13 Location map—Frigg exploration and appraisal wells to December 1985.

Fig. 14 Frigg Field schematic cross-section—water influx model.

Fig. 15 Frigg cores and logs—correlation of residual gas to water vs porosity.

CONCLUSIONS

1. The image of a field based on the initially available static data will necessarily be modified as more dynamic data become available. This reinterpretation often leads to the need for more precise static data and leads inevitably to a more complicated reservoir/ geological model.
2. The determination of the uncertainties linked to a field evaluation becomes more critical as the remaining recoverable reserves decrease and even more so when linked to a gas contract.
3. The Frigg Field geological model and, consequently, the field’s future performance is not yet definitive, but the data acquisition and studies programme currently underway should provide the elements for determining the need for and nature of further field development.

Through time the nature of the certainties and uncertainties have changed. The existence of an aquifer is now confirmed. The level of the trapped gas saturation is known with some confidence (as it was previously) but not at the same level. And what was once accepted as a homogeneous reservoir now has as its prime unknown the distribution of the shale barriers within it.

The interpretation of the newly acquired 3D seismic lines combined with the geological correlations being developed should provide the basis for one or more geological models. All petrophysical (log and core) data are being reanalysed in order to obtain a uniform interpretation and reduce the uncertainties as much as possible. The simulation results combined with continued field monitoring will provide the basis for determining the need for and nature of further field development.

The objective of any future reservoir studies will be to determine the quantity and distribution of remaining reserves and the best means of recovery. The expected production profile must be known to meet contractual obligations. The consequences for management are discussed further in Barril, 1985.
ACKNOWLEDGEMENT

The Author wishes to thank the Management of Elf Aquitaine Norge A/S and the Frigg Unit Partners, Norsk Hydro A/S, Statol, Total Marine Norsk A/S, Total Oil Marine plc and Elf UK plc for permission to present this paper.

REFERENCES


Part II

Reservoir Geophysics