004 PRODUCTION EXPERIENCE BOOSTS FURTHER OIL DEVELOPMENT ON THE TROLL FIELD

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1 INTRODUCTION

The Troll oil and gas field is located in 340 m water depth offshore Norway, about 80km west of Bergen, and covers an area of 700 km^2. It contains an up to 27m thick oil rim sandwiched between a large gas cap and an active aquifer. The field consists of three easterly tilted fault blocks; the Troll West Oil Province (TWOP) with a 22-27 m thick oil column, the Troll West Gas Province (TWGP) with a 12-14m thick oil column, and Troll East with only 0-4m oil column. The estimated oil-in-place volume of Troll West is 680 MSm^3 of which some 75% is located in TWGP. The major gas accumulation is found in Troll East, but huge gas volumes are also found in TWGP. The field layout and estimated oil and gas volumes initially in place are shown in Fig. 1.

The hydrocarbon bearing interval is approximately 160 m thick and belongs to the Sognefjord formation of Middle to Upper Jurassic age. The sediments consist of alternating layers of so-called C- and M-sands. C-sand is clean, medium to coarse grained with permeabilities in the 1-30 darcy range. M-sand is micaceous, silty and fine grained with permeabilities of tens to hundreds of millidarcy. Approximately 2/3 of the oil initially in place is estimated to be located within C-sands.

The thickness of the highly productive C-sands is variable and up to a few tens of meters at its maximum. In combination with a dipping formation and thin oil column, the oilfilled C-sands are limited to distinct, often elongated sand bodies, whose areal position is very sensitive to geological and seismic uncertainty. Major reservoir and fluid properties are given elsewhere[1].

The development of Troll is divided in three phases. Phase 1 includes gas deliveries from Troll East and commenced in October 1996 (Troll A platform and Kollsnes processing plant). Phase 2 covers development of the oil resources in Troll West. Oil production commenced in September 1995 (Troll B platform) and will be extended in 1999 when the Troll C platform is planned to be on stream. Phase 3 includes large scale gas production from Troll West. The gas production strategy for Troll West will be co-ordinated with the oil production strategy and is currently not decided.

This paper describes how early production experience and advancement of technology have influenced the decision to develop the 12-14 m oil layers in TWGP.

2 CHALLENGES AND UNCERTAINTIES

After the discovery in 1979 the oil resources on Troll were considered non-economic to develop for almost a decade. The horizontal drilling technology, available in the North Sea from the late eighties, was the main reason that an economic viable oil development could be proposed. However, at that time, several major uncertainties existed both with respect to performance of such wells and to whether the geological control was good enough to locate long horizontal sections within high quality sand. It was realised that the permissable margin for error, due to the thin oil columns, was lower on Troll than for other North Sea fields being developed at that time.

Major uncertainties and challenges were considered to be:
- geological control of sand bodies and properties
- feasibility of drilling long horizontal sections with high degree of accuracy
- feasibility of completing such wells with sand control
- inflow profile along a horizontal section
- time to gas breakthrough and development of gas cone after breakthrough
- water coning and inflow of aquifer
- feasibility of manifolding of wells on the seabed and transportation to the processing platform.

3 LONG TERM PRODUCTION TESTING (1990-91)

To qualify new technology and to reduce the dynamic reservoir uncertainty, two long term production tests with horizontal wells were performed [2,3].

The test well 31/2-T1 was drilled and completed in the 22 m thick oil zone in the southern part of TWOP. The length of the horizontal section was 502 m with a vertical location in average 4 m above the oil-water contact. High quality sand was encountered in the entire horizontal section. The well was produced for 11 months during 1990. The well produced at a liquid rate of 5000 Sm³/d for 183 days before gas breakthrough was experienced. The liquid rate was then gradually reduced to avoid gas coning into the well. Water breakthrough occurred almost immediately after start-up, but water cut increased fairly slowly with time and reached a level of 35% at the end of the test.

The test result from 31/2-T1 was better than expected (Fig. 2). To match the observed well performance in the simulation model the permeability close to the well had to be increased by 50% compared to plug measurements. Furthermore, less water coning than expected was explained as an effect of the residual oil zone present below the oil-water contact. However, both these effects could be due to local conditions and there was no guarantee that they would occur fieldwide.

A 4 month production test was carried out in the 13 m oil column in the southern part of TWGP during 1991. The well 31/5-T1 was drilled and completed with an 800 m long horizontal section , located in average 1m above the oil-water contact. However, a part of the well was located below the contact, and initial water cut was 60%. The well was produced at a liquid rate of 3000 Sm³/d for 28 days when gas breakthrough occurred. The results from this well was poorer than expected, mainly due to the high water production and early gas breakthrough (Fig. 2). Later experience has made clear that this well is not located in an optimal geological postion, although good sand is penetrated by most of the horizontal section.

4 INITIAL DEVELOPMENT DECISIONS (1991 AND 1994)

Based on the encouraging information from the long term test in the 22m thick oil column it was decided in 1991 to develop the TWOP by 17 horizontal wells [1]. The horizontal sections were planned to be 802 m and the estimated reserves were 55 MSm³. The wells were to be tied back to four subsea manifolding stations and the fluids transported to a semi-submersible production unit, Troll B, by two 9-10" parallel gathering lines per manifold. The length of the gathering lines were 4-9 km. Production was planned to commence in January 1996.

Planning of the development of the 12-14 m oil column in TWGP was continued during 1992-94. Two appraisal wells were drilled to reduce the geological uncertainty. Further improvement of the geological model was obtained when the results from a 3D seismic survey become available. In March 1994 a development plan was submitted for a subsea cluster (H-cluster) in the southern part of the TWGP consisting of four 1500 m long horizontal wells. Another two wells were considered optional. Utilising the infrastructure decided in 1991 the development had attractive economy based on a reserve estimate of 6,8 MSm³ produced by four 1500 m long horizontal wells. Including two optional wells, the estimated reserves were 9,5 MSm³. Production was planned to commence in October 1996. Although an attractive economy was shown, the primary goal for this development was to gain early production experience to be utilised in the further development planning.

5 PREDRILLING INFORMATION (1994-95)

Predrilling was started in March 1994. In the 1991 PDO 800 m horizontal sections were planned, but recent progress within drilling and completion technology enabled considerably longer wells. Consequently, the 7 wells drilled prior to production start-up had horizontal sections ranging from 1350 m to 2020 m.

Valuable information was derived during the predrilling period:
- Good geological control and ability to geosteer wells while drilling
- Reduced drilling and completion time compared to PDO assumptions
- Ability to locate a horizontal section within ±1m vertically
- Inflow profile and drawdown was measured as part of the cleanup procedure

The high quality seismic data was extensively utilised in the well planning and during drilling. Together with the information gained while drilling a pilot hole prior to the horizontal section (for most wells), good geological control was demonstrated in the TWOP. During drilling, use of MWD tools, located a few meters behind the drilling bit, allowed for both accurate navigation and geosteering.

In the 1991 PDO the estimated time for drilling and completion of an 800 m horizontal well was estimated to 75 days. Except for the first two wells a significant reduction of this estimate was obtained. The typical time to drill and complete a well is currently 40-50 days even though the horizontal section has become up to three times longer than in the original plan.

Production logging as part of the cleanup process was performed for 5 of the 7 predrilled wells. The logging confirmed inflow to the entire horizontal section for all wells except for one which needed additional cleanup. Very high productivity indices were measured, typically 5 000-10 000 $Sm^3/d/bar$. The very low drawdown in the wells causes the friction pressure loss in the horizontal section to become significant and leads to a non-linear inflow. This is illustrated in Fig. 3 for well G-4. Matching of the inflow and drawdown data for this well by the simulator indicated a 50% higher permeability level than derived from core data. This confirmed the results from the long term test in well 31/2-T1.

6 FIRST YEAR OF PRODUCTION (AUTUMN 1995 - AUTUMN 1996)

Oil production on Troll B commenced in September 1995 from 7 wells in TWOP, some three months earlier than planned. Within three weeks after production start the plateau rate of 30 000 Sm^3 was reached. Minor modifications to the platform and better well productivity than anticipated allowed a gradual increase of the plateau level up to 40 000 Sm^3/d by July 1996. The regularity in the period was close to 100%, which was significantly better than the design value of 92%. The actual oil production profile for Troll B up to June 1997 is shown in Fig. 4 and is compared with the prognosis from respectively PDO 1991and September 1995.

History matching of the early production from TWOP was possible only when the permeability level in all C-sands was increased by 30-50% compared to core derived values. When this increase was implemented into the simulation model and some of the previous downside due to water inflow was removed, the expected reserves in the TWOP was raised from 60 to 70 MSm^3 in May 1996.

Even more important for the further development decision was the production experience from the first two wells in TWGP. Well H-6 was brought on stream in late November 1995 and well H-5 in early January 1996. The horizontal length of these wells was 1750 m and 2000 m, respectively, and both wells encountered good sand in the majority of the perforated length.

The production history for H-5 and H-6 is shown in Fig. 5. A comparison with the long term test in well 31/5-T1 is shown in Fig . 6. Although the wells were producing at a high liquid rate gas breakthrough did not occur until after some 500 days and at cumulative oil production volumes of 0,9 and 1,1 MSm^3 respectively. This was much later than predicted prior to production start. Also water cut increased more slowly than expected, and the water mobility in the simulation model had to be reduced to obtain a match.

Based on the production experience up to May 1996, the expected reserves for the H-cluster (6 wells) were upgraded from 9,5 to 13 MSm^3.

7 FURTHER DEVELOPMENT OF TWGP, DECISION NOVEMBER 1996

Evaluations performed in 1994 indicated potential to develop TWGP by 23 wells tied-in to 4 clusters and routed to the Troll B platform. The estimated reserves were 42 MSm^3. In summer 1996, prior to selection of concept for further development, a considerable upgrade of this potential was made.

Several factors contributed to this upgrade. Most important was the positive production experience gained through the first 8 month of operation. All the 14 wells on stream at that time produced either as predicted or better. Only three wells had experienced gas breakthrough, and it was shown by PLT-logging that the early breakthrough in two of the wells was due to insufficient cleanup resulting in production from only parts of the wells.

Other contributing factors to the upgrade was a 20% increase of the oil-in-place estimate, mainly caused by a new water saturation model reducing the size of the transition zone. Better utilisation of the high quality 3D seismic data increased the confidence of the geological model and reduced the effect of the geological downside in the uncertainty weighting of the reserves.

The experience by summer 1996 showed that it was possible to determine the position of the C-sands with a high degree of certainty and to drill long horizontal wells (the longest drilled was 2300 m) with good control in vertical position and with minimal skin. The cost of a well was also less than previously anticipated. Furthermore, the cost of subsea equipment and processing platform had been significantly reduced compared to the development decision in 1991.

Based on the concept selection summer 1996 a plan for development of the remaining oil resources in the TWGP was submitted to the authorities in November 1996. According to this plan the TWGP will be developed by 62 wells divided into 11 well groups, including the 6 wells in the already producing H-cluster. To fully utilise the production potential it was decided to build a second platform Troll C and install in the northern part of the TWGP. Six of the well groups are planned to be routed to the new platform while 4 will be routed to Troll B. Production start-up for Troll C is planned to autumn 1999.

The expected oil production profiles for the two platforms are shown on Fig. 7. Estimated oil reserves are 115 MSm³ for TWGP and 70 MSm³ for TWOP, giving total oil reserves for Troll West of 185 MSm³. The change in estimated oil reserves for Troll West as a function of time is shown in Fig. 8. Note that the estimate from 1986 is for a development based on vertical wells and is not commercial.

8 CURRENT STATUS (JULY 1997)

Per July 1997 22 wells are producing on Troll West, 16 in TWOP and 6 in TWGP. The last well brought to stream is the first dual lateral well on Troll, H-3A/B, which was successfully drilled and completed during spring/summer 1997.

Experience from the second year of production is largely in line with the experience from the first year. The field water cut has slowly risen to 33%, varying between 1 and 60% for individual wells. 9 wells have experienced gas breakthrough. Total well capacity is slightly in excess of 40 000 Sm³/d and matches the current capacity of Troll B.

Two wells are currently not producing due to excessive gas coning (E-6 in TWOP and H-4 in TWGP). The E-6 well is located in the upper half of the oil column and encounters only moderate to low permeability sands. H-4 is drilled dip-parallel and penetrates several geological layers, of which low permeable M-sand is dominating. This experience supports the assumption that the most critical factor to effective drainage of the thin oil rims on Troll is to encounter long sections of high permeable sands in the lower part of the oil column.

9 CONCLUSIONS

Development of the 22-27 m oil layers in TWOP was decided in 1991 based on 800 m horizontal wells. Drainage of the 12-14 m oil layers in the TWGP at that time gave marginal economy and was considered very risky due to uncertainty with respect to the dynamic behaviour of such a thin oil zone. Experience has shown that it is possible to drill and complete up to at least 2300 m horizontal sections with minimal skin and with good control in vertical position. The time to drill and complete an average well has been reduced by almost a factor of two since 1991 although the horizontal section is considerably longer. It has been proven that the entire horizontal section contributes to inflow and that initial predictions by the reservoir simulation model with respect to productivity and dynamic behaviour of the reservoir are on the conservative side.

It is experienced that use of advanced geophysical methods enables sufficently accurate determination of the location of the high permeable sands, so that the probability of drilling a misplaced well is very low.

These experiences are the main reason for the increase in oil reserves on Troll from 55 MSm³ in 1991 to 185 MSm³ in 1996. The number of oil production wells has increased from 17 to 80 and a new platform Troll C has been decided. It is likely that further advances in drilling and well technology will enable even larger amounts of oil on Troll to be recovered. The potential for improved oil recovery is considerable especially in the TWGP where the current reserve estimate corresponds to a recovery factor of only 25%.

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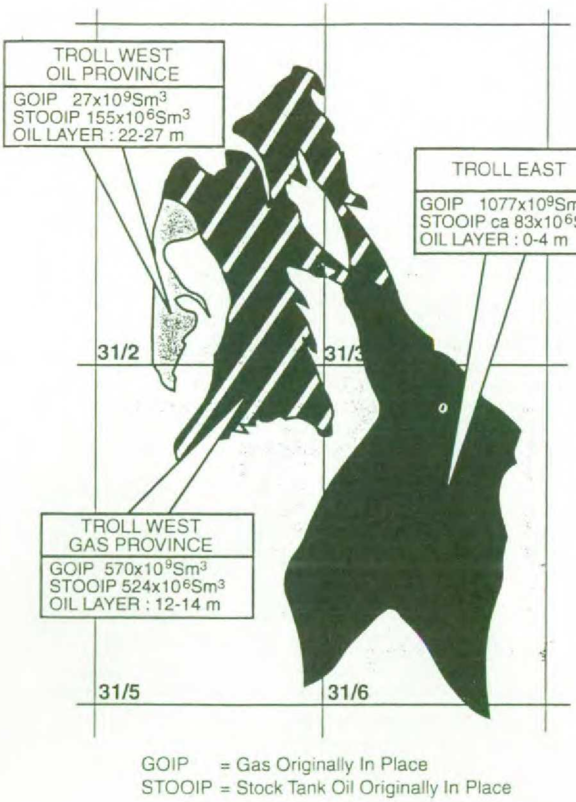

Fig. 1. Location map and distribution of hydrocarbon resources

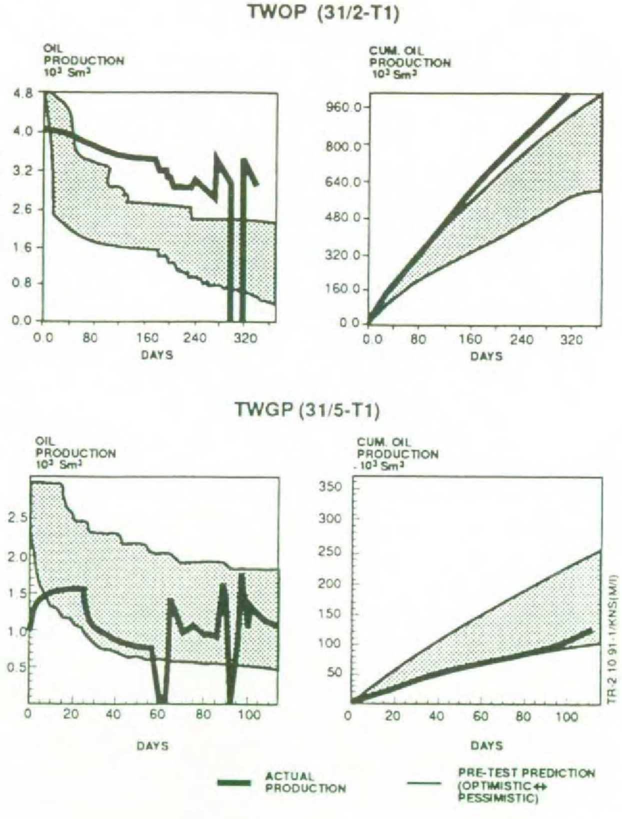

Fig. 2. Long term production testing. Oil production profiles compared against low and high estimates

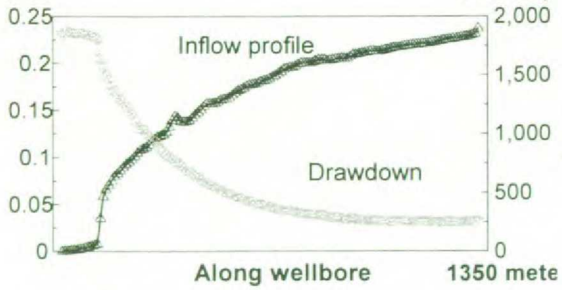

Fig. 3. Initial drawdown and inflow profile for the 1350 m horisontal well G-4

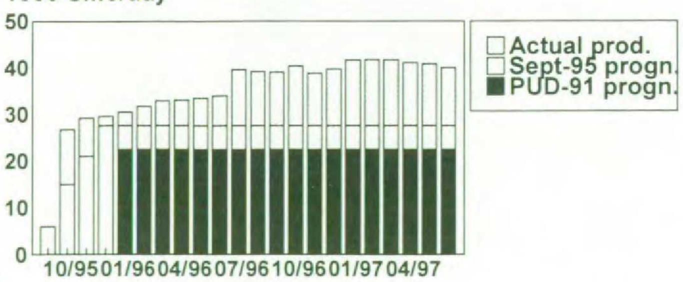

Fig. 4. Actual oil production compared to prognosis

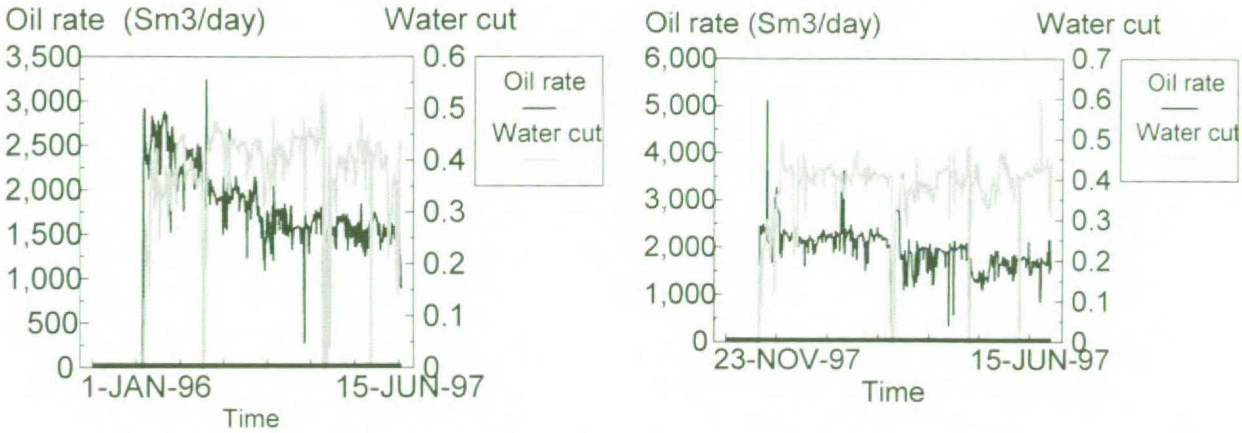

Fig. 5. Oil rate and water cut from wells H-5 (left) and H-6 (right). Gas break through after about 500 days of production for both wells.

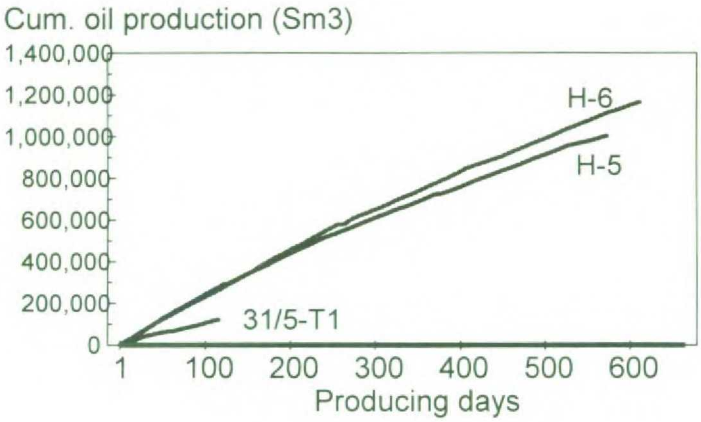

Fig. 6. Cumulative oil production for long term test well 31/5-T1 compared with production from H-5 and H-6.

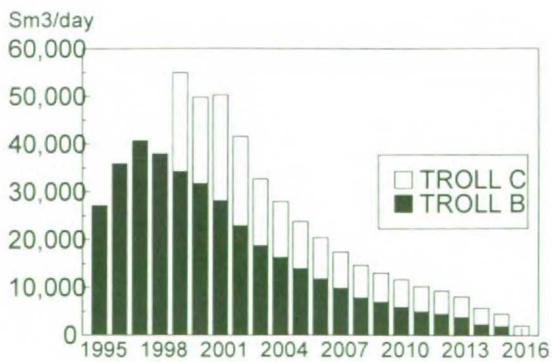

Fig. 7. Expected oil production from Troll B and Troll C

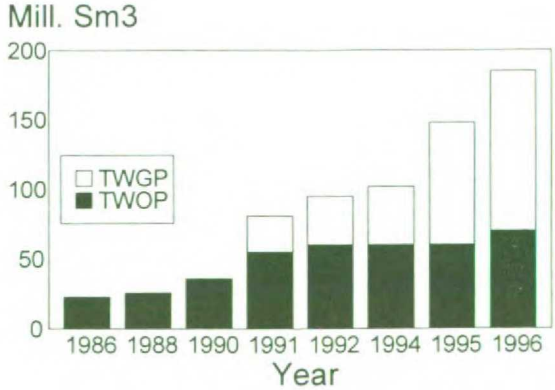

Fig. 8. Historical increase in recoverable oil reserves from Troll