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10 Fields in production

Keys to tables in chapters 10–12

Interests in fields do not necessarily correspond with interests in the individual production licences (unitised fields or ones for which the sliding scale has been exercised have a different composition of interests than the production licence). Because interests are shown up to two decimal places, licensee holdings in a field may add up to less than 100 percent. Interests are shown at 1 January 2005.

"Recoverable reserves originally present" refers to reserves in resource categories 0, 1, 2 and 3 in the NPD's classification system (see the definitions below).

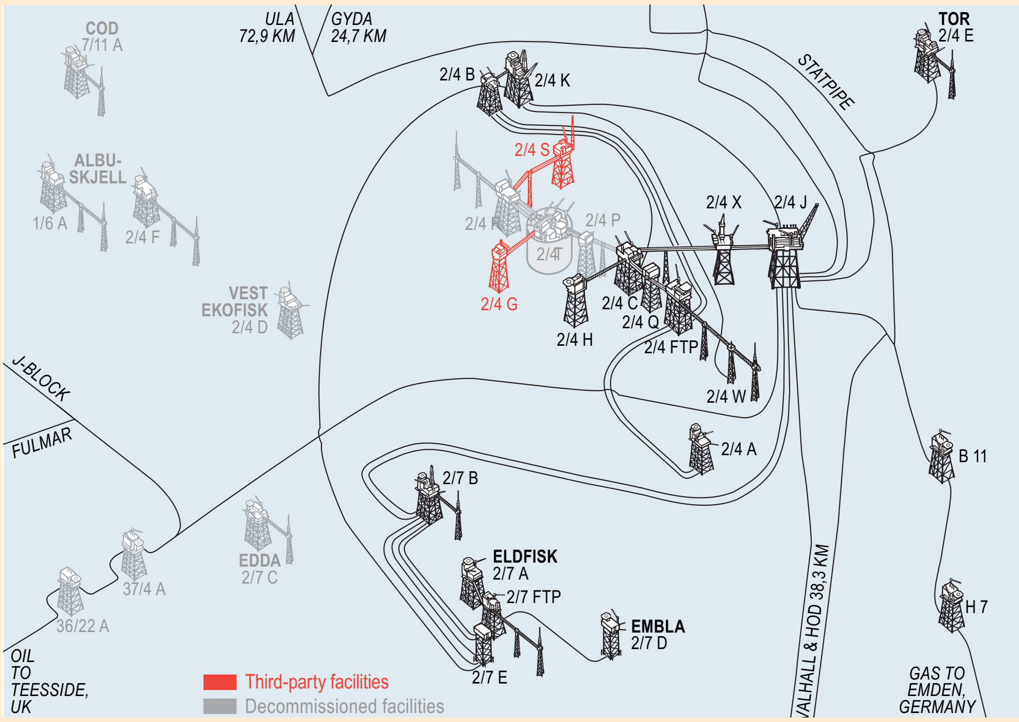
"Recoverable reserves remaining" refers to reserves in resource categories 1, 2 and 3 in the NPD's classification system (see the definitions below).

Resource category 0: Petroleum sold and delivered
Resource category 1: Reserves in production
Resource category 2: Reserves with an approved plan for development and operation
Resource category 3: Reserves which the licensees have decided to develop

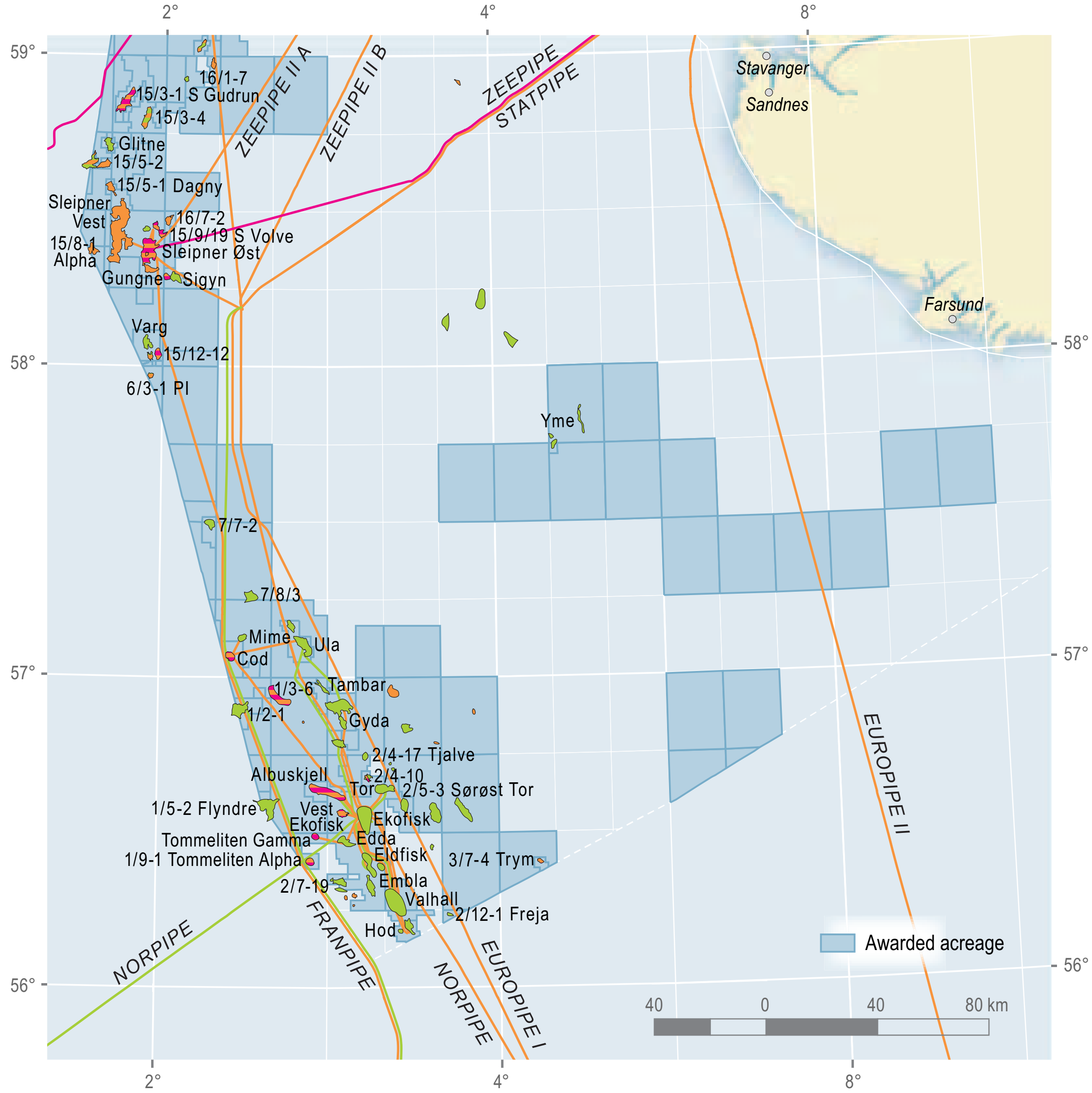
Southern North Sea

The southern part of the North Sea sector became important for the country at an early stage, with Ekofisk as the first Norwegian offshore field to come on stream, more than 30 years ago. Ekofisk serves as a hub for petroleum operations in this area, with surrounding developments utilising the infrastructure which ties it to continental Europe and Britain. Norwegian oil and gas is exported from Ekofisk to Teesside in the UK and Emden in Germany respectively. North of Ekofisk are the Sleipner fields. Sleipner Øst came on stream in 1993, followed by Sleipner Vest in 1996. In addition to producing substantial quantities of gas and condensate, these fields serve as a hub for the gas transport system on the Norwegian Continental Shelf (NCS).

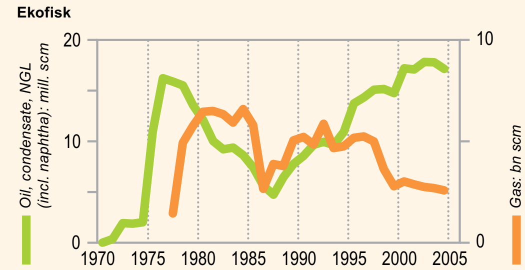
Although there has been production from the Southern North Sea for many years, remaining resources in the region are substantial. Oil and gas output is accordingly expected to continue beyond another three decades.



Facilities in the Ekofisk Area



Southern North Sea



Ekofisk

Block and production licence	Block 2/4 – production licence 018. Awarded 1965.	
Discovery	1969	
Development approval	01.03.1972	
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	12.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5,00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	524.1 million scm oil	178.3 million scm oil
	184.9 billion scm gas	58.7 billion scm gas
	14.3 million tonnes NGL	3.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 281,000 barrels/day Gas: 2.71 billion scm NGL: 0.29 million tonnes	
Investment	Total investment is likely to be NOK 134.2 billion	
	NOK 103.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

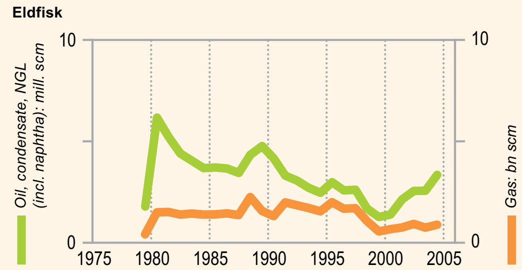
Development:
Production at Ekofisk began in 1971 from the jack-up facility Gulftide. The sea depth in the area is between 70 an 75 metres. During the first years, the field produced to tankers from four wells, until the concrete tank was in place in 1973. Since then, the field has been populated by many facilities, including riser facilities for associated fields and export pipelines. Several of these have been decommissioned and are awaiting disposal. Today, the operative parts of the Ekofisk Centre consist of the accommodation facility 2/4-H, the production facility 2/4-C, drilling and production facility 2/4-X and the processing facility 2/4-J. Other facilities at the centre that are still in use are 2/4-FTP and 2/4-W which are a riser facility for production from the wellhead facility 2/4-A in the south and 2/4-B in the north and a wellhead facility for water injection, respectively. In addition, 2/4-K is in use in the north of the field as main facility for water injection. 2/4-K is tied back to 2/4-B by a bridge. Test production from the Ekofisk field was formally started on 09.06.1971. Approval in principle of the technical system for development of the Ekofisk field was given on 01.03.1972. Water injection was approved on 20.12.1983, Ekofisk II was approved on 09.11.1994, Ekofisk Growth was approved on 06.06.2003.

Reservoir:
The Ekofisk field produces from the Ekofisk and Tor chalk formations.

Recovery strategy:
Ekofisk was originally developed using depletion. Since then, limited gas injection and comprehensive water injection have contributed to a substantial increase in oil recovery. Large scale water injection started in 1987, and in subsequent years the water injection area has been extended in several phases. Experience has proven that water displacement of the oil is more effective than expected, and the estimated reserves have been adjusted upwards to accommodate this. In addition to the water injection, compaction of the soft chalk provides extra force to drainage of the field. This effect is reinforced because the injected water contributes to weakening the chalk.

Transport:
Oil and gas is piped to the export pipelines via the processing facility on 2/4-J at Ekofisk.
Gas from the Ekofisk area is piped to Emden, while the oil, which also contains the NGL fractions, is piped to Teesside.

Status:
Production from Ekofisk is expected to maintain its current high level, and increase to a degree. This is mainly due to increased numbers of wells and increased processing capacity from a new facility coming on stream in 2005. In relation to current plans, there are good chances for further increase in the reserves when water injection is optimised.
High activity is expected to continue at the field over the next years. The base of 2/4-M, has been installed and drilling has commenced. Planned completion of the topside is in 2005. A possible transference of production from 2/4-A and 2/4-B is still being considered, and a decision is expected during 2005. Continual drilling is, under the current strategy, the key to high recovery levels. Work on cleaning and disposal of disused facilities is still continuing.



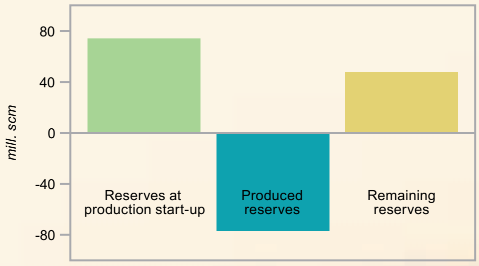
Eldfisk

Block and production licence	Block 2/7 - production licence 018. Awarded 1965.	
Discovered	1970	
Development approval	25.04.1975	
On stream	08.08.1979	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	12.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5.00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	124.7 million scm oil	47.6 million scm oil
	50.6 billion scm gas	15.6 billion scm gas
	4.4 million tonnes NGL	1.0 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 52,000 barrels/day Gas: 1.14 billion scm NGL: 0.09 million tonnes	
Investment	Total investment is likely to be NOK 53.6 billion	
	NOK 42.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
The original Eldfisk development consisted of three facilities. The sea depth in the area is between 70 and 75 metres. Eldfisk B is a combined drilling, wellhead and process facilities on the Bravo structure, while Eldfisk A and FTP are wellhead and process facilities tied back by a bridge at the Alpha structure. Eldfisk A has drilling facilities. Oil and gas is transported in two pipelines to the Ekofisk Centre for onward transport to Teesside and Emden. Modifications have been made to Eldfisk and Ekofisk to enable the oil from Eldfisk to be piped directly to the export pumps on 2/4-J. In 1999, a new water injection facility, 2/7-E, was installed on the Alpha structure. The facility also supplies the Ekofisk field with some injection water through a new pipeline from Eldfisk to Ekofisk 2/4-K. Eldfisk was approved as Phase IV of the Ekofisk development in the Royal Decree of 25.04.1975. Eldfisk water injection was approved on 12.12.1997. Upgrading of the capacity of Eldfisk was approved on 06.06.2003, as part of the plan for Ekofisk Growth.

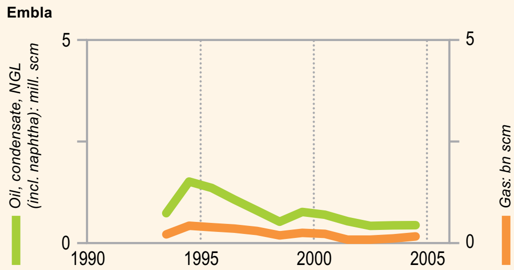
Reservoir:
Production from the Eldfisk field recovers oil from the Ekofisk, Tor and Hod chalk formations. The field consists of three structures: Alpha, Bravo and Øst Eldfisk.

Production strategy:
Eldfisk was originally developed with depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected that, for capacity or marketing reasons, has not been sold.



Transport:
Oil and gas are piped to the export pipelines through the Ekofisk Centre. Gas from the Ekofisk area is piped to Emden, while the oil, which also contains the NGL fractions, is piped to Teesside.

Status:
In lack of special measures, Eldfisk production is expected to remain constant in the years to come. In relation to current plans, there exists a great potential for increase in the reserves by increasing the number of wells and by optimising water injection. A study is in progress to determine measures to increase recovery from Eldfisk. The measures may necessitate new facilities at the field. A conclusion is expected in the autumn of 2005. The figure above shows the development of reserves.



Embla

Block and production licence	Block 2/7 - production licence 018. Awarded 1965.
Discovered	1988
Development approval	14.12.1990
On stream	12.05.1993
Operator	ConocoPhillips Skandinavia AS

Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	12.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5.00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	13.3 million scm oil	4.7 million scm oil
	4.1 billion scm gas	1.3 billion scm gas
	0.5 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 0.19 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is likely to be NOK 3.5 billion	
	NOK 3.5 billion had been invested as at 31.12.05 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

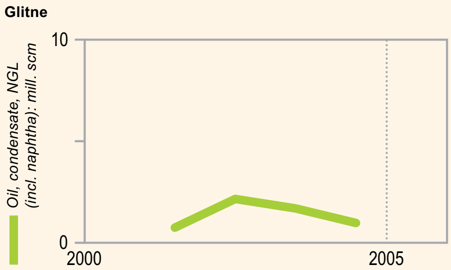
Development:
Embla has been developed with an unmanned wellhead facility that is remotely controlled from Eldfisk. The sea is 70 – 75 metres deep in the area. The PDO for Embla was approved on 14.12.1990. The amended PDO was approved on 25.04.1995.

Reservoir:
The Embla field produces from a segmented sandstone reservoir from the Devonian and Jurassic Ages. The reservoir is over 4,000 m beneath the sea bed.

Recovery strategy:
Embla uses depletion as the drive mechanism.

Transport:
Oil and gas is transported to Eldfisk and on to the Ekofisk Centre for export. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains the NGL fractions, is piped to Teesside.

Status:
Without drilling more wells, or stimulating the existing wells, production from Embla will decrease in the future.



Glitne

Blocks and production licences	Block 15/5 - production licence 048 B. Awarded 2001.	
	Block 15/6 - production licence 029 B. Awarded 2001.	
Discovered	1995	
Development approval	08.09.2000 by the Crown Prince Regent in Council of State	
On stream	29.08.2001	
Operator	Statoil ASA	
Licensees	DONG Norge AS	9.30%
	Det Norske Oljeselskap AS	10.00%
	Statoil ASA	58.90%
	Total E&P Norge AS	21.80%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	7.2 million scm oil	1.7 million scm oil
Production	**Estimated production in 2005:**	
	Oil: 16,000 barrels/day	
Investment	Total investment is likely to be NOK 1.6 billion	
	NOK 1.6 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Glitne is an oilfield that lies 40 km northeast of the Sleipner area in 110 metres of water. The development consists of the floating production, storage and offloading vessel, Petrojarl 1, which is tied back to four production wells and a water injection well.

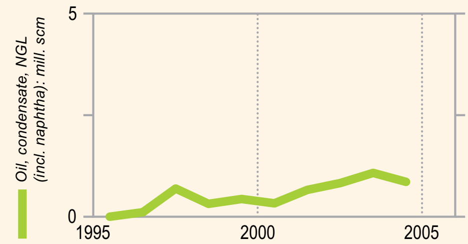
Reservoir:
The reservoir consists of amalgamated structureless sand sheets of deep-marine fandeposits in the upper Heimdal formation.

Recovery strategy:
Associated gas is used for gas lift, while excess gas is re-injected.

Transport:
Oil from Glitne is processed and stored on board the production vessel. The oil is exported using shuttle tankers.

Status:
Production from Glitne was originally planned to last for a little more than two years, but is now estimated as lasting twice as long, i.a. due to effeciert placement of wells and good pressure support. Water production is now around 70 percent of fluid processing capacity and is expected to increase to around 90 percent in 2005.

Gungne



Gungne

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1982	
Development approval	29.08.1995 by the King in Council of State.	
On stream	21.04.1996	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	28.00%
	Norsk Hydro Produksjon AS	9.40%
	Statoil ASA	52.60%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	9.9 billion scm gas	9.9 billion scm gas
	1.3 million tonnes NGL	0.3 million tonnes NGL
	3.1 million scm condensates	
Production	**Estimated production in 2005:**	
	Gas: 1.51 billion scm NGL: 0.22 million tonnes Condensate: 0.49 million scm	
Investment	Total investment is likely to be NOK 1.0 billion	
	NOK 1.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

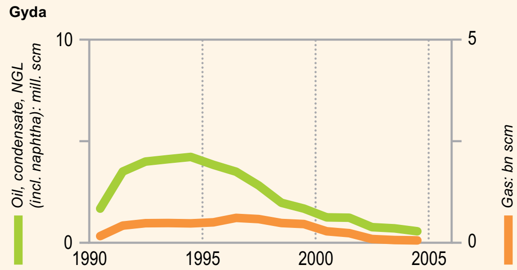
[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst are measured together and therefore the remaining gas reserves are shown equal to the original.

Development:
Gungne is a gas field that lies in 83 metres of water and produces via two wells at Sleipner A.

Reservoir:
Gungne produces gas and condensates mainly from sandstone reservoirs in the Skagerrak formation from the Triassic Age. Reservoir sandstones from the early Jurassic Age overlap the structure in the south, but are not present over the highest parts of the structure in the north. The field has been heavily affected by salt tectonics. The characteristics are generally good, apart from the permeability. The reservoir is faulted and lateral continual slate strata act as barriers.

Recovery strategy:
Gungne produces using depletion.

Transport:
Gas and condensate from Sleipner Øst and Gungne are processed on Sleipner A. Processed gas from Sleipner A is mixed with gas from Troll and exported via Draupner to Zeebrugge.



Gyda

Block and production licence	Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1980	
Development approval	02.06.1987 in Parliament	
On stream	21.06.1990	
Operator	Talisman Energy Norge AS	
Licensees	DONG Norge AS	34.00%
	Norske AEDC A/S	5.00%
	Talisman Energy Norge AS	61.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	36.8 million scm oil	4.6 million scm oil
	5.9 billion scm gas	0.6 billion scm gas
	1.9 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 14,000 barrels/day Gas: 0.16 billion scm NGL: 0.03 million tonnes	
Investment	Total investment is likely to be NOK 14.2 billion	
	NOK 13.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

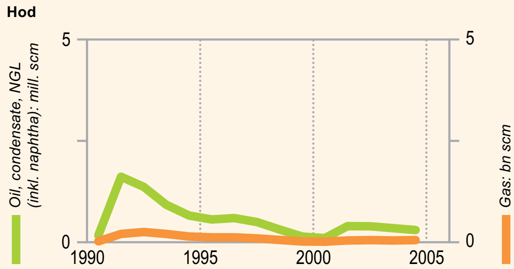
Development:
The Gyda field is in 66 metres of water. The field has been developed with a combined drilling, accommodation and processing facility with a steel jacket.

Reservoir:
The reservoir consists of late Jurassic sandstone.

Recovery strategy:
The field is developed with water injection as drive mechanism.

Transport:
The oil is transported to Ekofisk via the oil pipeline from Ula and on to Teesside. The gas is transported in a dedicated pipeline for onward transport to Emden.

Status:
Water production is increasing and assessment of measures for reduction of water production are ongoing.



Hod

Block and production licence	Block 2/11 - production licence 033. Awarded 1969.	
Discovered	1974	
Development approval	26.06.1988 in Parliament	
On stream	30.09.1990	
Operator	BP Norge AS	
Licensees	Amerada Hess Norge AS	25.00%
	BP Norge AS	25.00%
	Enterprise Oil Norge AS	25.00%
	Total E&P Norge AS	25.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	8.3 million scm oil	0.5 million scm oil
	1.4 billion scm gas	
	0.2 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 4,000 barrels/day Gas: 0.04 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is likely to be NOK 2.1 billion	
	NOK 2.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

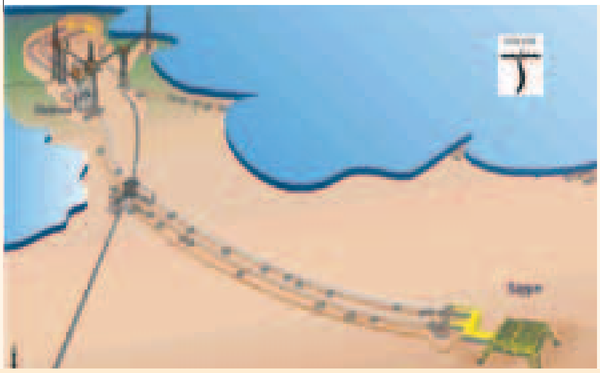
Development:
Hod is an oil field in 72 metres of water. The field is developed with an unmanned production facility, which is controlled remotely from the Valhall field 13 kilometres farther north. The PDO for Hod was approved on 26.06.1988. The PDO for the Hod Sadel area was approved on 20.06.1994.

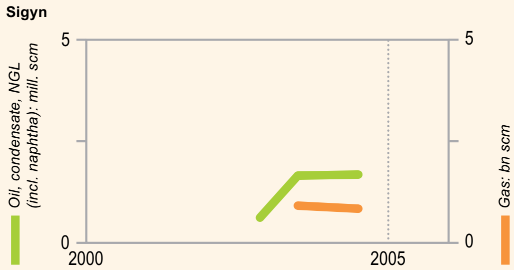
Reservoir:
The field is producing from chalk rocks in the Ekofisk, Tor and Hod formations. The field consists of the three structures Hod Vest, Hod Øst and Hod Sadel.

Recovery strategy:
Recovery takes place through depletion. Since 2001, gas lift has been used in the most important well in the field to increase production.

Transport:
Oil and gas are separated using a separation unit on the production facility before being transported in a shared pipeline to Valhall for further processing. The transport systems to Teesside and Emden are used for onward transport.

Status:
Production from Hod is relatively stable at a low level. The field is in a late phase with the current recovery strategy. At the moment, water injection is being considered to improve the resource exploitation from the Hod Øst structure. A pilot project for water injection in the field may prove appropriate.





Sigyn

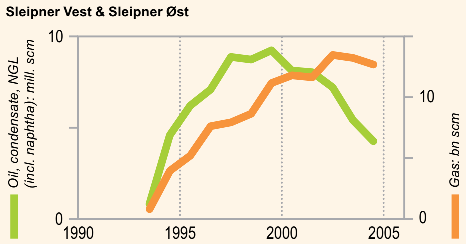
Block and production licence	Block 16/7 - production licence 072. Awarded 1981.	
Discovered	1982	
Development approval	31.08.2001 by the King in Council of State	
On stream	22.12.2002	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	40.00%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	50.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	6.1 billion scm gas	4.4 billion scm gas
	3.0 million tonnes NGL	2.3 million tonnes NGL
	4.6 million scm condensate	2.6 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 0.96 billion scm NGL: 0.29 million tonnes Condensate: 0.80 million scm	
Investment	Total investment is likely to be NOK 2.2 billion	
	NOK 2.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Sigyn is located in the Sleipner area in around 70 metres of water. The field has been developed with a subsea template as a satellite of Sleipner Øst. Production is controlled from Sleipner Øst. The wellstream is sent through two pipelines to the Sleipner A facility. The PDO for Sigyn was approved by Royal Decree on 31.08.2001. Test production from the Sigyn Øst field was carried out in December 1997.

Reservoir:
The field consists of the Sigyn Vest deposits, which contain gas/condensate, and Sigyn Øst, which contains light oil. The main reservoir is located in the Skagerrak formation.

Recovery strategy:
The oil is recovered by depletion.

Transport:
The gas is exported using the dry gas system at Sleipner. Condensate is transported via the Sleipner condensate pipeline to Kårstø.



Sleipner Vest includes total production from Sleipner Øst and Sleipner Vest

Sleipner Vest

Blocks and production licences	Block 15/6 - production licence 029. Awarded 1969.	
	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1974	
Development approval	14.12.1992 in Parliament	
On stream	29.08.1996	
Operator	Statoil ASA	
Licensees in Sleipner Vest	ExxonMobil Exploration and Produksjon Norway AS	32.24%
	Norsk Hydro Produksjon AS	8.85%
	Statoil ASA	49.50%
	Total E&P Norge AS	9.41%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	108.1 billion scm gas	65.7 billion scm gas
	8.1 million tonnes NGL	5.0 million tonnes NGL
	28.1 million scm condensate	6.2 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 9.23 billion scm NGL: 0.45 million tonnes Condensate: 1.70 million scm	
Investment	Total investment is likely to be NOK 23.3 billion	
	NOK 22.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves shows Sleipner Øst and Vest collectively.

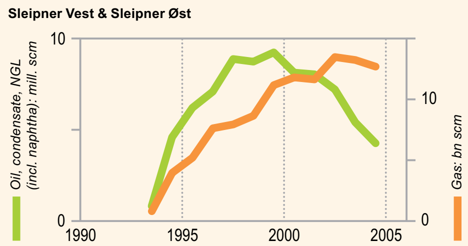
Development:
Sleipner Vest is a gas field in 110 metres of water, which consists of a normally unmanned wellhead facility, Sleipner B and a processing facility, Sleipner T. The Alpha Nord segment has been developed with a subsea template and four production wells. The subsea template is tied back to Sleipner T.

Reservoir:
Sleipner Vest produces from the Mid-Jurassic Sleipner and Hugin formations. Gas and condensate are mainly produced here, but local oil deposits have been observed without being produced. Most of the reserves are found in the Hugin formation, which is divided into an upper and lower section. The Hugin reservoir consists of a series of beach deposits. The Sleipner formation is part of the Hugin formation and consists of a sequence of fluvial deposits. The salt tectonic activity from the Triassic Age further complicates the structure. The faults in the field are generally not sealing, and communication between the geological sand accumulations is generally good.

Recovery strategy:
Sleipner Vest production is driven by depletion.

Transport:
Gas and condensate from Sleipner Vest are processed at Sleipner T, where CO_2 is also removed from the gas. Processed gas from Sleipner Vest is injected into Sleipner Øst. The gas that is not reinjected is piped to Sleipner Øst for export. CO_2 is reinjected from Sleipner A in the Utsira formation via its own injection well. Unstable condensate from Sleipner Vest and Sleipner Øst is combined at Sleipner A and sent to Kårstø for processing to stable condensate and NGL products.

Status:
The field is divided into five segments: Epsilon, Delta, Beta, Alpha Sør and Alpha Nord. Alpha Nord came on stream in October 2004. Gas export capacity amounts to 100 percent of the design basis for both facilities. Sleipner T was modified for low pressure production in 2002, and low pressure production has been implemented on Sleipner B. Well-boring for Delta and Beta Vest at Sleipner Vest will be considered in the light of the new 3D seismic survey.



Sleipner Øst

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1981	
Development approval	15.12.1986 in Parliament	
On stream	24.08.1993	
Operator	Statoil ASA	
Licensees in Sleipner Øst	ExxonMobil Exploration and Production Norway AS	30.40%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	49.60%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	65.8 billion scm gas	65.7 billion scm gas
	12.5 million tonnes NGL	5.0 million tonnes NGL
	27.1 million scm condensate	6.2 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 2.24 billion scm NGL: 0.34 million tonnes Condensate: 0.64 million scm	
Investment	Total investment is likely to be NOK 33.9 billion	
	NOK 32.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

[1] Gas production for Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves shows Sleipner Øst and Vest collectively.

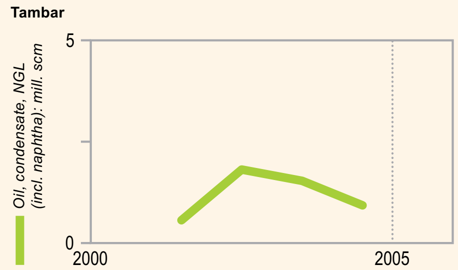
Development:
Sleipner Øst is gas condensate field in 82 metres of water. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete casing, Sleipner A. A separate riser facility has also been built, Sleipner R which is tied back to Sleiner A with a bridge. Sleipner R connects Sleipner A to the pipelines for gas transport, two subsea templates and the flare stack Sleipner F. A subsea template has been installed for production from the northern part of Sleipner Øst and one for production at Loke. Three Sigyn wells are also tied back to Sleipner A.
PDO for Sleipner Øst was approved on 15.12.1986. PDO for Loke was approved in 1991 and production started in 1993. Development of Loke Trias was approved on 29.08.1995 and production started on 19.06.1998.

Reservoir:
The Sleipner Øst and Loke resources are mainly found in sandstone in the Ty formation from the Tertiary Age and sandstones in the Hugin formations from the Mid-Jurassic Age. There is no pressure communication between the two reservoir zones. The Hugin formation consists of shallow marine deposits and coastal, land-deposited sediments. The Ty reservoir consists of shallow marine fan deposits. Below the Hugin formation is the Triassic Skagerrak formation. The Skagerrak formation, which makes up the main reservoir at Loke, consists of alluvial deposits and has moderate to poor reservoir characteristics. The sandy Skagerrak formation is, however, not present in the main Sleipner Øst field. The Late Jurassic Draupne formation occurs over the Hugin formation, and consists mainly of deep marine slate in the Sleipner Øst area, with a sequence of slate and sandstone localised in Loke. Faults segment the Hugin reservoir.

Recovery strategy:
The Hugin reservoir at Sleipner Øst and Loke produces with depletion, while the Ty reservoir receives pressure support from gas injection, in order to accelerate and increase production of condensate. The injectors are positioned on the edges of the reservoirs to avoid breakthrough of dry gas in the producers.
In order to accelerate gas and condensate recovery and extend the individual wells' plateau production, the pressure in the separator B on Sleipner A has been reduced.

Transport:
Gas and unstable condensate from Sleipner Øst, Loke, Sigyn and Gungne is processed on Sleipner A. Processed gas from Sleipner A and Sleipner T (the process facility Sleipner Vest) is mixed with gas from Troll and exported via Draupner to Zeebrugge. Unstable condensate from Sleipner Vest and Sleipner Øst is mixed at Sleipner A and piped to Kårstø for processing into stable condensate and NGL products.

Status:
There are a total of 17 production wells at Sleipner Øst. At the moment, well capacity is greater than processing capacity. Produced gas that is not exported is injected into the Ty reservoir for pressure support, using five injection wells.
Gas injection into the Ty reservoir will continue until 2005-2006. After this, a massive blowdown of the reservoir will begin. In 2007, gas from Ormen Lange will be exported to the UK via Sleipner A. During 2005, wells are planned to be drilled from Sleipner A to the segments My2 and My3 at Sleipner Øst, as well as to an isolated segment of Gungne.



Tambar

Blocks and production licences	Block 1/3 - production licence 065. Awarded 1981.	
	Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1983	
Development approval	03.04.2000 by the King in Council of State	
On stream	15.07.2001	
Operator	BP Norge AS	
Licensees	BP Norge AS	55.00%
	DONG Norge AS	45.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	6.7 million scm oil	2.1 million scm oil
	1.8 billion scm gas	1.8 billion scm gas
	0.2 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 15,000 barrels/day Gas: 0.28 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is likely to be NOK 1.7 billion	
	NOK 1.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

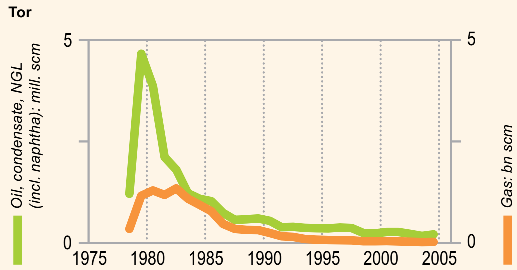
Development:
Tambar is an oilfield that is located around 16 km southeast of the Ula field and around 12 km northwest of the Gyda field. The field has been developed with an unmanned wellhead facility without a processing plant.

Reservoir:
The reservoir consists of Late Jurassic sandstone which was deposited in a shallow marine environment. The hydrocarbon trap is a fault trap with two anticlines that are separated by a structural saddle. The reservoir quality is heterogeneous, and the reservoir is divided into zones according to the quality of the sand.

Recovery strategy:
Three wells have been drilled that produce from the C sand. Oil is recovered from them by depletion. Studies have been carried out to investigate the potential of different ways of increasing oil recovery, but the reservoir's complexity indicates that water or gas injection would not be financially viable.

Transport:
Production is piped to Ula, where the oil is separated and exported in the existing pipeline to Teesside via Ekofisk. The gas is injected into the Ula reservoir to contribute to increased recovery of oil.

Status:
Installation of a multiphase pump for transfer to Ula and drilling supplementary wells are being considered to increase oil recovery. In June 2004, a leak was discovered in the export pipeline to Ula, and Tambar was shut down. Production was resumed in mid-December 2004, using the Ula Gyda Interconnector Pipeline (UGIP) as an export pipeline to Ula. UGIP is a temporary solution until a new pipeline is in place.



Tor

Blocks and production licences	Block 2/4 - production licence 018. Awarded 1965. Block 2/5 - production licence 006. Awarded 1965.	
Discovered	1970	
Development approval	04.05.1973	
On stream	28.06.1978	
Operator	ConocoPhillips Skandinavia AS	
Licensees in Tor	ConocoPhillips Skandinavia AS	30.66%
	Eni Norge AS	10.82%
	Norsk Hydro Produksjon AS	5.81%
	Petoro AS	3.69%
	Statoil ASA	0.83%
	Total E&P Norge AS	48.20%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	26.7 million scm oil	4.7 million scm oil
	11.6 billion scm gas	0.9 billion scm gas
	1.2 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 3,000 barrels/day Gas: 0.03 billion scm	
Investment	Total investment is likely to be NOK 8.1 billion NOK 8.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

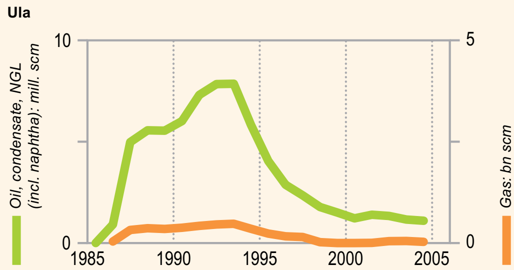
Development:
Tor is an oil field in about 70 metres water that has been developed with a combined wellhead and processing facility with transport by pipelines to the Ekofisk Centre for export. The Tor field won development approval in phase III of the Ekofisk development.

Reservoir:
The main reservoir at Tor is at a depth of around 3,200 metres and consists of fractured chalk rock belonging to the Tor formation. The Ekofisk formation also contains oil, but has poor production characteristics.

Recovery strategy:
Tor was originally produced by depletion. In 1992, limited water injection at Tor commenced. The facility has later been upgraded.

Transport:
Oil and gas are piped to the export pipelines through the 2/4-J processing facility at Ekofisk. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains NGL fractions, is piped to Teesside.

Status:
A study is currently considering future prospects for Tor. Seismic surveys, which form part of this work, will be completed in 2005.



Ula

Blocks and production licences	Block 7/12 - production licence 019. Awarded 1965	
	Block 7/12 - production licence 019 B. Awarded 1977.	
Discovered	1976	
Development approval	30.05.1980 by Parliament	
On stream	06.10.1986	
Operator	BP Norge AS	
Licensees	BP Norge AS	80.00%
	DONG Norge AS	5.00%
	Svenska Petroleum Exploration AS	15.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	78.2 million scm oil	12.5 million scm oil
	3.8 billion scm gas	0.4 million tonnes NGL
	2.9 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 28.000 barrels/day NGL: 0.04 million tonnes	
Investment	Total investment is likely to be NOK 19.9 billion	
	NOK 18.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

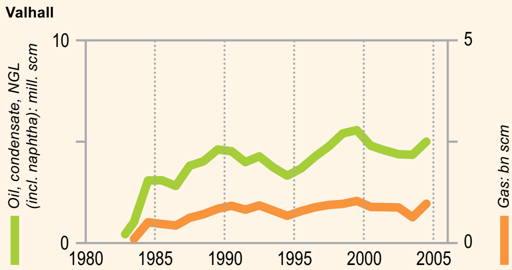
Development:
The Ula oilfield lies in about 70 metres of water. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are tied back to each other by bridges.

Reservoir:
The main reservoir is in Late Jurassic Age sandstone. The sand was deposited in a shallow marine environment and is extremely bioturbated. Permeability varies from good to very good, but deteriorates towards the edges.

Recovery strategy:
To begin with, oil was recovered by depletion, but after some years water injection was used to increase recovery. WAG (water/alternating gas injection) started in 1998. As access to gas increased by processing production from Tambar at Ula, the WAG programme has been extended. The operator considers that WAG has had a very favourable impact on draining the reservoir, and wishes to extend the WAG programme further. At present, there are 15 wells in the field: eight production wells, three water injection wells and four WAG wells. The wells in the WAG programme are positioned so that injection takes place on the edges of the field, while production comes from the top of the reservoir.

Transport:
The oil is piped via Ekofisk to Teesside. All gas is reinjected into the reservoir in order to increase oil recovery.

Status:
Depending on access to injection gas, the extent of the WAG programme will be decided at the end of 2005.



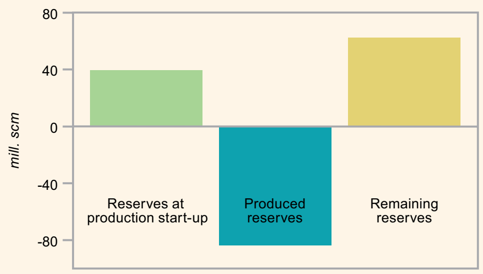
Valhall

Blocks and production licences	Block 2/11 - production licence 033 B. Awarded 2001. Block 2/8 - production licence 006 B. Awarded 2000.	
Discovered	1975	
Development approval	02.06.1977 by Parliament	
On stream	02.10.1982	
Operator	BP Norge AS	
Licensees in Valhall	Amerada Hess Norge AS BP Norge AS Enterprise Oil Norge AS Total E&P Norge AS	28.09% 28.09% 28.09% 15.72%
Recoverable reserves	**Original:** 171.5 million scm oil 29.2 billion scm gas 4.4 million tonnes NGL	**Remaining as at 31.12.2004** 87.6 million scm oil 12.6 billion scm gas 1.6 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 110,000 barrels/day Gas: 1.37 billion scm NGL: 0.14 million tonnes	
Investment	Total investment is likely to be NOK 53.6 billion NOK 41.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Valhall is an oilfield lying in 70 metres of water. The field was originally developed with three facilities, for accommodation, drilling and production. Oil is separated from gas at Valhall using two separation units. The heavier gas fractions, NGL, are separated at Valhall through a fractioning tower and are then mainly transported in the oil stream. In May 1996, a riser facility (WP) with space for 19 wells was installed. The four facilities are tied back to each other with bridges. The water injection facility was installed centrally in the field in the summer of 2003 and tied back with a bridge to WP. The drilling rig on this facility will also be used by WP. The flank development consists of two wellhead facilities positioned in the north and south of the field. The southern facility was installed in October 2002 and came on stream in May 2003. The northern facility was installed in the summer of 2003 and came on stream in January 2004. Valhall processes production from Hod, and delivers gas for gas lift in Hod's wells. The Valhall development was approved by the Norwegian Parliament in 1977. The PDO for Valhall WP was approved on 02.06.1995. The PDO for Valhall water injection was approved on 03.11.2000. The PDO for Valhall flank development was approved on 09.11.2001.

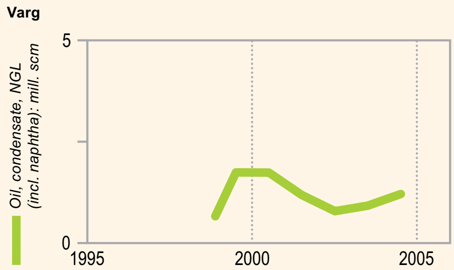
Reservoir:
The Valhall field produces from chalk rock in the Tor and Hod formations.

Recovery strategy:
Recovery originally took place using depletion with compaction. Water injection in the centre of the field was decided on in 2000, and started in January 2004 in a converted production well.



Transport:
Oil and NGL are piped to Ekofisk for onward transport to Teesside. Gas is piped to Norpipe for onward transport to Emden.

Status:
Production from Valhall is expected to increase from current levels. This is mainly due to the increased number of wells and the start of water injection. In relation to current planning, there are significant possibilities for further increases in reserves by using all well slots and optimising water injection. The water injection project has suffered delays, but, as at January 2005, drilling from the injection facility has commenced. As the seabed has subsided at the centre of the field, and the original facilities have aged, new development is planned. This will probably involve a new facility with processing plant and accommodation. The licensees have commenced work and a decision is expected in the course of 2005. Fixed cables on the seabed are also used to monitor the reservoir. The figure above shows the development of reserves.



Varg

Block and production licence	Block 15/12 - production licence 038. Awarded 1975.	
Discovered	1984	
Development approval	03.05.1996 by the King in Council of State	
On stream	22.12.1998	
Operator	Pertra AS	
Licensees	Pertra AS	70.00%
	Petoro AS	30.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	12.1 million scm oil	4.5 million scm oil
Production	**Estimated production in 2005:**	
	Oil: 21,000 barrels/day	
Investment	Total investment is likely to be NOK 5.8 billion	
	NOK 5.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Trondheim	
Main supply base	Tananger	

Development:
Varg is an oilfield to the south of Sleipner Øst in 84 metres of water. The field is being produced from a leased production vessel (Petrojarl Varg) with integrated oil storage that is connected to a wellhead facility called Varg A. In 1999, the production vessel was sold to Petroleum Geo Services (PGS), who also assumed responsibility for the operation of the vessel. The wellhead facility and production vessel are tied back to flexible flowlines for oil production, water and gas injection, as well as power and control cables.

Reservoir:
The field contains oil in Late Jurassic sandstone reservoirs. The structure is faulted and segmented. In 2003, an appraisal well was drilled that showed additional oil in a segment in the western region of the Varg field (Varg Vest segment). Production from this segment started in January 2004, and has increased the chances of extended operations at Varg considerably.

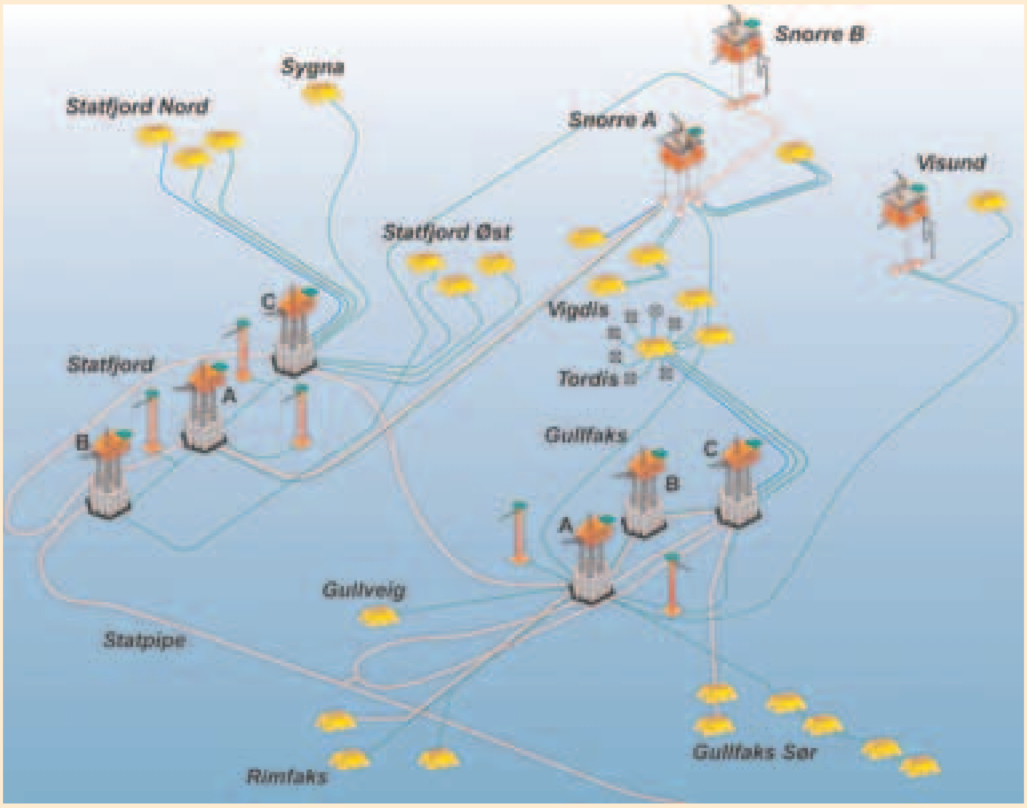
Recovery strategy:
Recovery currently takes place by injection of gas into the reservoir for pressure maintenance, through two injection wells that are located furthest north and south of the field, as well as in the Varg Vest segment.

Transport:
Oil is unloaded from the production vessel into shuttle tankers.

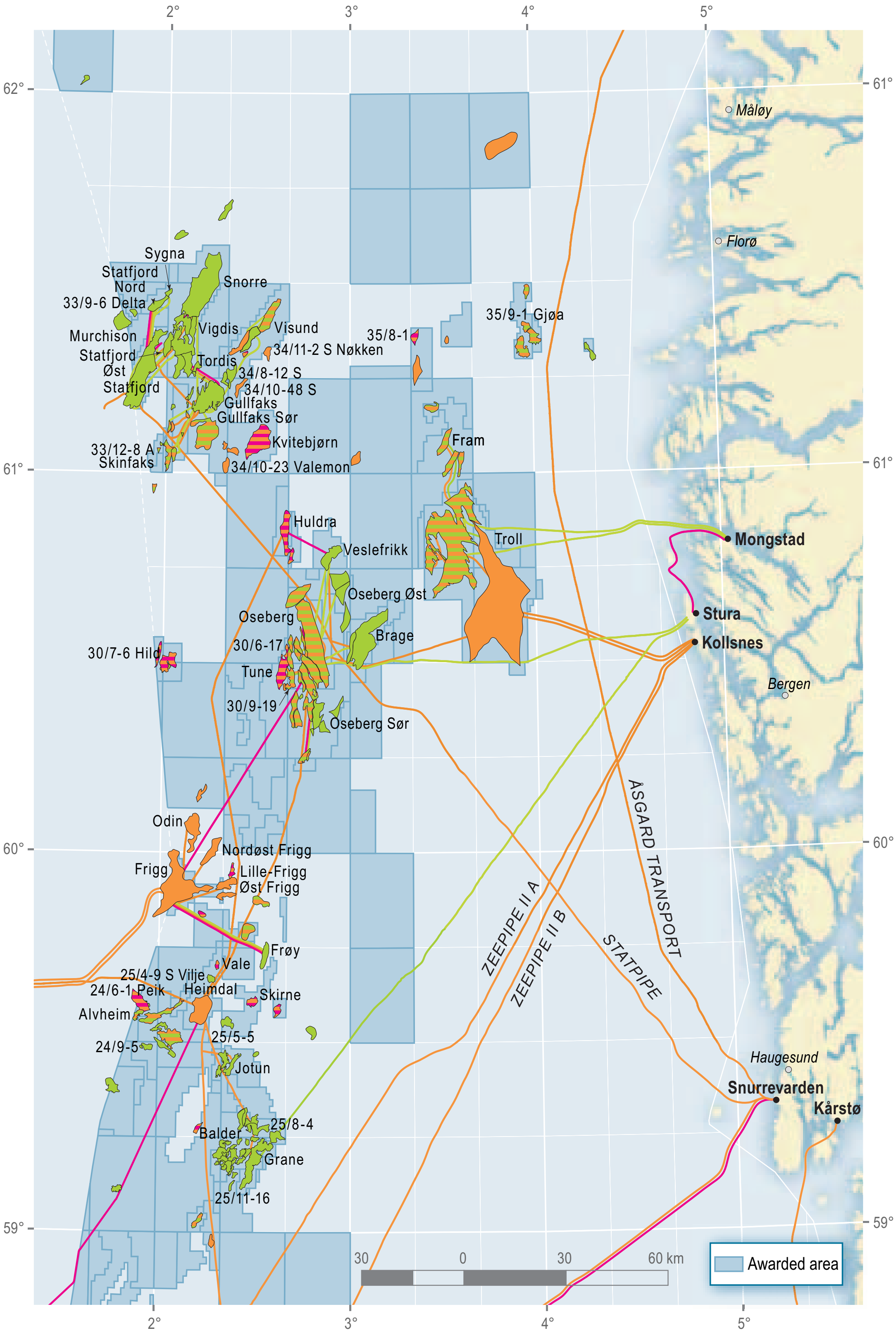
Status:
The decommissioning plan for the field was approved in 2001. The plan was to produce until the summer of 2002. Petra has, however, been successful in its work to increase the reserves in the field, and has also carried out initiatives to prove additional resources. In 2001, oil and gas were proven in the wildcat well 15/12-12 that was drilled into a structure in the south of Varg (Varg Sør). An appraisal well was drilled into the structure in 2003, and this proved gas and small amounts of oil. Plans are being prepared for development of the Varg Sør structure.

Northern North Sea

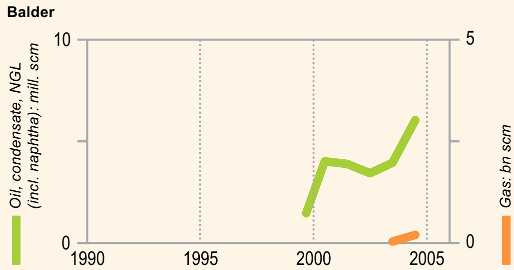
The main areas in the northern part of Norway's North Sea are Tampen, Troll/Oseberg and Frigg/Heimdal. Tampen contains a number of fields, including Statfjord, Snorre, Gullfaks, Visund, Vigdis and Tordis. Several of these rank among Norway's largest oil fields. Although this is a mature petroleum province, its resource potential remains considerable. Troll has a very important function in gas deliveries from the Norwegian vontinental shelf, but has also become a substantial oil producer. The Oseberg area includes Brage and Veslefrikk as well as Oseberg itself. Oil production from this part of the Norwegian vontinental shelf is declining, but will remain substantial for many years to come. Oseberg is set to increase its gas deliveries. Heimdal has developed into a gas centre which provides processing services for surrounding fields. Production from the Frigg field, one of the first and largest gas fields in the North Sea, was shut down in the autumn 2004.



The Tampen area



Northern North Sea



Balder

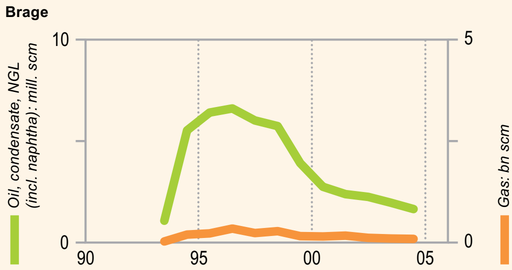
Blocks and production licences	Block 25/10 - production licence 028. Awarded 1969. Block 25/11 - production licence 001. Awarded 1965. Block 25/8 - production licence 027. Awarded 1969. Block 25/8 - production licence 027 C. Awarded 2000. Block 25/8 - production licence 169. Awarded 1991.	
Discovered	1967	
Development approval	02.02.1996 by the King in Council of State	
On stream	02.10.1999	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	100.00%
Recoverable reserves	**Original:** 58.9 million scm oil 1.6 billion scm gas	**Remaining as at 31.12.2004** 36.5 million scm oil 1.4 billion scm gas
Production	**Estimated production in 2005:** Oil: 119,000 barrels/day Gas: 0.30 billion scm	
Investment	Total investment is likely to be NOK 25.2 billion NOK 22.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
The Balder field is an oil field 190 km west of Stavanger in 125 metres of water. The field has been developed with subsea wells that are tied back to the production and storage vessel, Balder FPSO, from which oil and gas are processed. The Ringhorne discovery has been developed with a combined accommodation, drilling and wellhead facility, which is also tied back to Balder FPSO and a subsea template with an oil production well and a water injection well. The PDO for Balder was approved on 02.02.1996. The PDO for Ringhorne was approved on 11.05.2000 and production started on 21.05.2001. Production from the Ringhorne facility started 11.02.2003. Ringhorne is now integrated as part of Balder. The amended PDO for Ringhorne and PIO for transport of oil from the Jurassic reservoir at Ringhorne to Jotun and gas from Balder to Jotun was approved on 14.02.2003. Exemption from PDO for development of the Ringhorne Vest reservoir in the Ty formation was granted on 14.11.2003.

Reservoir:
The Balder development contains several separated structures of Tertiary sandstones. The Ringhorne development includes several reservoirs of the same type as the original Balder and a reservoir from the Jurassic Age.

Recovery strategy:
Balder is recovered by natural water mechanism, water injection and gas injection.

Transport:
Oil and gas from the Jurassic reservoir at Ringhorne are transported to Jotun for final processing. Excess gas from Balder was originally reinjected into the reservoir.



Brage

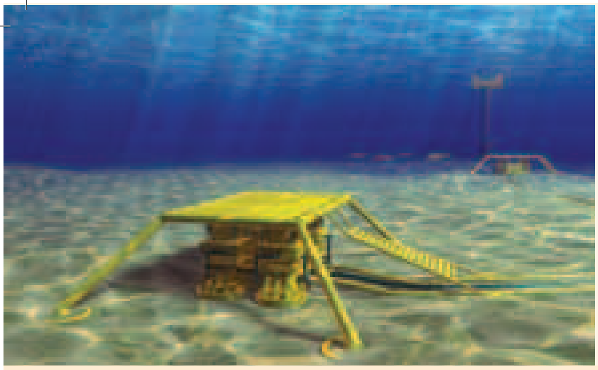
Blocks and production licences	Block 30/6 - production licence 053 B. Awarded 1998.	
	Block 31/4 - production licence 055. Awarded 1979.	
	Block 31/7 - production licence 185. Awarded 1991.	
Discovered	1980	
Development approval	29.03.1990 by Parliament	
On stream	23.09.1993	
Operator	Norsk Hydro Produksjon AS	
Licensees in Brage	Endeavour Energy Norge AS	4.44%
	Eni Norge AS	12.26%
	ExxonMobil Exploration and Production Norway AS	13.84%
	Norsk Hydro Produksjon AS	20.00%
	Paladin Resources Norge AS	20.00%
	Petoro AS	14.26%
	Revus Energy AS	2.50%
	Statoil ASA	12.70%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	48.5 million scm oil	3.8 million scm oil
	2.9 billion scm gas	0.8 billion scm gas
	0.8 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 29,000 barrels/day Gas: 0.08 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is likely to be NOK 16.8 billion	
	NOK 16.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

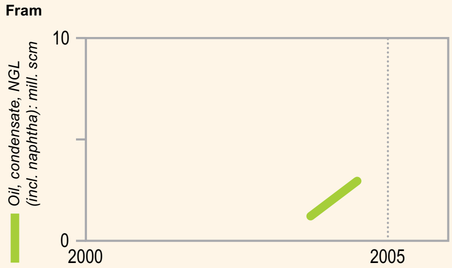
Development:
The Brage field is an oilfield that is in 140 metres of water and has been developed with an integrated production and accommodation facility with a steel casing. The development was approved by Parliament on 29.03.1990 and the field came on stream on 23.09.1993. Trial production from the Sognefjord formation took place in the autumn of 1997, and these deposits were given development approval by the King in Council of State on 20.10.1998.

Reservoir:
The Brage field consists of Jurassic sandstone reservoirs in the Early Jurassic Statfjord formation and the Mid-Jurassic Fensfjord formation. There is also oil and gas in the Late Jurassic Sognefjord formation.

Recovery strategy:
The recovery mechanism in the Statfjord formation is by water injection, in the Fensfjord formation by water and gas injection. The Sognefjord formation is recovered using natural depletion.

Transport:
The oil is piped to Oseberg and on through the pipeline in the Oseberg Transport System (OTS) to the Sture terminal. One gas pipeline is tied back to Statpipe.





Fram

Block and production licence	Block 35/11 - production licence 090. Awarded 1984.	
Discovered	1992	
Development approval	23.03.2001 by the King in Council of State	
On stream	02.10.2003	
Operator	Norsk Hydro Produksjon AS	
Licensees	Gaz de France Norge AS	15.00%
	Idemitsu Petroleum Norge AS	15.00%
	Mobil Development Norway AS	25.00%
	Norsk Hydro Produksjon AS	25.00%
	Statoil ASA	20.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	11.2 million scm oil	7.6 million scm oil
	4.3 billion scm gas	4.3 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 29,000 barrels/day	
Investment	Total investment is likely to be NOK 3.9 billion	
	NOK 3.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

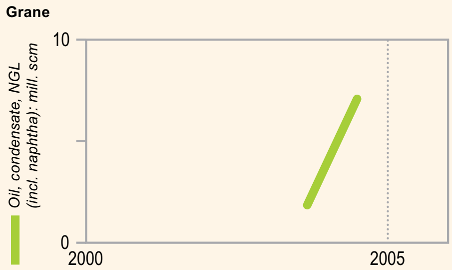
Development:
Fram is an oilfield that is located in the northern part of the North Sea, around 22 km north of Troll. The development so far (Fram Vest) consists of two subsea templates tied back to Troll C. The gas is separated from the fluid on Troll C and reinjected into the Fram Vest reservoir. Development of the Fram Vest deposits was approved by the King in Council of State on 23.03.2001.

Reservoir:
The reservoir consists of Late Jurassic sandstone and is on a rotated and faulted block.

Recovery strategy:
The recovery mechanism is gas injection.

Transport:
The Fram wellstream is piped to Troll C for processing. The oil is then transported to Mongstad through the Troll II pipeline. When gas injection ceases, the gas will be exported via Troll A to Kollsnes.

Status:
Work is in progress on further development of other structures in the area. A PDO for the eastern sections (Fram Øst), has been submitted to the authorities in february 2005 and will most likely be considered during spring.



Grane

Blocks and production licences	Block 25/11 - production licence 001. Awarded 1965. Block 25/11 - production licence 169 B1. Awarded 2000. Block 25/11 - production licence 169 B2. Awarded 2000.	
Discovered	1991	
Development approval	14.06.2000 by Parliament	
On stream	23.09.2003	
Operator	Norsk Hydro Produksjon AS	
Licensees in Grane	ExxonMobil Exploration and Production Norway AS	25.60%
	Norsk Hydro Produksjon AS	38.00%
	Norske ConocoPhillips AS	6.40%
	Petoro AS	30.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	120.3 million scm oil	112.5 million scm oil
Production	**Estimated production in 2005:** Oil: 176,000 barrels/day	
Investment	Total investment is likely to be NOK 18.4 billion NOK 13.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

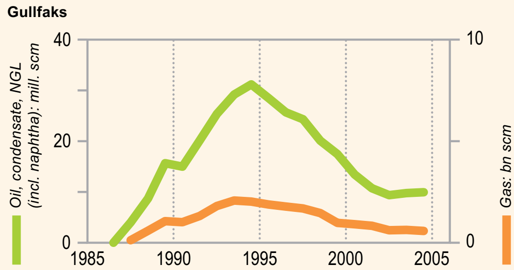
Development:
The Grane oilfield is located to the east of the Balder field in the North Sea, in 127 metres of water, and has been developed with an integrated accommodation, drilling and processing facility with a seabed-standing steel casing. The facility has 40 well slots.

Reservoir:
The field consists of a main structure and some additional structures. The reservoir consists of Tertiary Age sandstones with good reservoir characteristics, containing high viscosity oil.

Recovery strategy:
The recovery mechanism is gas injection at the top of the structure, and long-range horizontal production wells at the bottom of the oil zone.

Transport:
Oil from Grane is piped from the field to the Sture terminal for metering, storage and export. Injection gas will be imported through a pipe from the Heimdal facility.

Status:
Nine oil producers and two gas injection wells were pre-drilled, in addition to a well for injection of cuttings. Drilling of production wells continues.



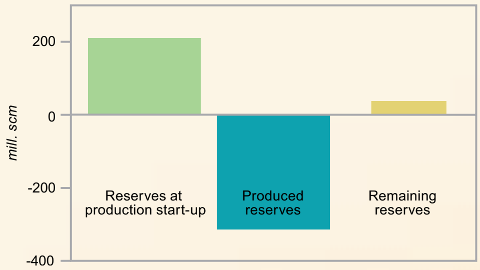
Gullfaks

Blocks and production Licences	Block 34/10 - production licence 050. Awarded 1978.	
	Block 34/10 - production licence 050 B. Awarded 1995.	
Discovered	1978	
Development approval	09.10.1981 by Parliament	
On stream	22.12.1986	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	9.00%
	Petoro AS	30.00%
	Statoil ASA	61.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	351.9 million scm oil	37.5 million scm oil
	22.6 billion scm gas	1.3 billion scm gas
	2.6 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 151,000 barrels/day Gas: 0.53 billion scm NGL: 0.06 million tonnes	
Investment	Total investment is likely to be NOK 107.9 billion	
	NOK 101.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

Development:
Gullfaks is an oilfield in from 130 to 220 metres of water. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides, Gullfaks A, B and C. Gullfaks B has a simplified processing plant with only first-stage separation. Over the last few years, Gullfaks A and C have been developed in order to receive and process oil and gas from Gullfaks Sør. Gas capacity on Gullfaks A was expanded in the spring of 2003. In addition to processing petroleum from Gullfaks and Gullfaks Sør, the facilities are also involved in production and export from Tordis, Vigdis and Visund. The Tordis production is processed in a separate facility on Gullfaks C. The original PDO for the Gullfaks field included the Gullfaks A and Gullfaks B facilities and was approved on 09.10.1981. Production started on 22.12.1986. The PDO for the eastern section (Gullfaks C) was approved on 01.06.1985. The development plan for Gullfaks Vest was approved on 15.01.1993, and recovery from the Lunde formation was approved on 03.11.1995.

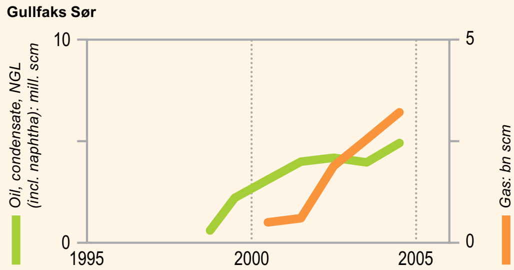
Reservoir:
The Gullfaks reservoirs consist of sandstones in the Brent group from the Mid-Jurassic Age, and Early Jurassic and Late Triassic sandstones in the Cook, Statfjord and Lunde formations. The reservoirs are 2,800 – 3,400 m below the seabed. Gullfaks consists of rotated fault blocks in the west and a structural horst in the east, with an intermediate highly faulted area.

Recovery strategy:
The drive mechanism for recovery from Gullfaks is mainly full pressure support, using water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the various drainage areas in the field. Certain minor fault blocks are recovered using depletion.



Transport:
Oil is exported from Gullfaks A and C via loading buoys to tankers. Processed rich gas is sent into the export pipeline directly to Statpipe for further processing at Kårstø and export through Norpipe/Europipe to the Continent. When needed, parts of the gas may also exported via the Statfjord field.

Status:
Production from Gullfaks is in the decline phase. Potential for increased recovery from Gullfaks has been identified, partly by finding and draining pockets of remaining oil in water-flooded areas, and partly through massive water circulation. Comprehensive analysis has also been carried out to calculate the potential for injecting CO_2 into the reservoir. There are a number of small deposits in the flank areas around Gullfaks that can be drilled and recovered using long-rage wells. Some of these have been granted exemption from PDOs and are already on stream. The figure above shows the development of reserves.



Gullfaks Sør

Blocks and production licences	Block 33/12 - production licence 037 B. Awarded 1998.	
	Block 34/10 - production licence 050. Awarded 1978.	
	Block 34/10 - production licence 050 B. Awarded 1995.	
Discovered	1978	
Development approval	29.03.1996 by the King in Council of State	
On stream	10.10.1998	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	9.00%
	Petoro AS	30.00%
	Statoil ASA	61.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	43.8 million scm oil	23.4 million scm oil
	39.1 billion scm gas	30.4 billion scm gas
	4.5 million tonnes NGL	3.4 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 75,000 barrels/day Gas: 3.34 billion scm NGL: 0.38 million tonnes	
Investment	Total investment is likely to be NOK 22.7 billion	
	NOK 19.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

Development:
Gullfaks Sør has been developed with subsea templates tied to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have been developed with four subsea templates tied to Gullfaks A for phase 1 and two subsea templates tied to Gullfaks C for phase 2. A production well has also been drilled from Gullfaks A to Gullfaks Sør. Rimfaks and Gullveig have been developed with three and one seabed templates, respectively, tied to Gullfaks A. The wellstream from phase 1 is processed on Gullfaks A. The gas from phase 1 is reinjected into Gullfaks Sør and Rimfaks. The wellstream from phase 2 is processed on Gullfaks C.

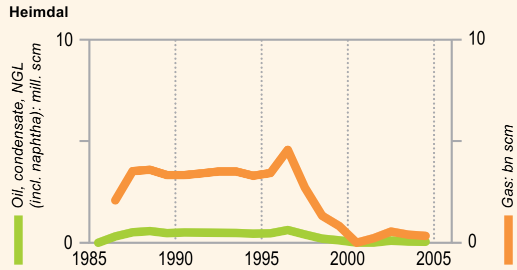
Gulltopp will be developed through an extended reach production well from Gullfaks A. Gullfaks Sør has been developed in two phases. The PDO for phase 1 was approved on 29.03.1996 and includes recovery of oil and condensate from deposits 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig. The PDO for phase 2 was approved on 08.06.1998 and includes recovery of gas from the Brent group in the Gullfaks Sør deposit. In January 2004, PDO exemption was granted for 34/10-47 Gulltopp, and Gulltopp was included in Gullfaks Sør.

Reservoir:
The Gullfaks Sør reservoirs consist of Mid-Jurassic sandstones in the Brent group and the Early Jurassic and Late Triassic Statfjord formations. The reservoirs are around 2,400 – 3,400 m under the seabed in western rotated fault blocks. Gullveig is the shallowest of the three deposits, with the top reservoir at 2,400 metres. The reservoirs in the Gullfaks Sør deposits are heavily segmented, with many internal faults, and the Statfjord formation has poor flow characteristics. Rimfaks, Gullveig and Gulltopp show good reservoir characteristics.

Recovery strategy:
Recovery of oil and condensate from Gullfaks Sør is partly driven by pressure maintenance, using gas reinjection in the Brent group, and by depletion in the Statfjord formation. Recovery of gas is driven by depletion. Rimfaks is produced using full pressure maintenance using gas reinjection. Recovery of oil from Gullveig is driven by depletion, and production is affected by the production at Tordis and Gullfaks. Gulltopp will be recovered using gas lift in the production well from Gullfaks A.

Transport:
The oil is exported from Gullfaks A via loading buoys to tankers. Rich gas from phase 2 is exported through Statpipe to Kårstø for further processing and export to the Continent. A gas export pipeline ties Gullfaks A and Gullfaks C to Statpipe.

Status:
The Gullfaks Sør reservoirs show different productivity and pressure development. The estimated reserves for the Gullfaks Sør deposit have been adjusted down in relation to the original plans, especially in the Statfjord formation, as a result of lower productivity than originally assumed. Gullveig and Rimfaks have proved to have better production characteristics than estimated in the original plans, and existing facilities at Rimfaks have insufficient capacity to recover the Rimfaks resources. In order to increase well capacity at Rimfaks, installation of an extra subsea template in the Gullfaks Sør area is planned. The amended PDO for Rimfaks was approved by the authorities in February 2005.



Heimdal

Block and production licence	Block 25/4 - production licence 036 BS. Awarded 2003.	
Discovered	1972	
Development approval	10.06.1981 by Parliament	
On stream	13.12.1985	
Operator	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	23.80%
	Norsk Hydro Produksjon AS	19.44%
	Petoro AS	20.00%
	Statoil ASA	20.00%
	Total E&P Norge AS	16.76%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	7.1 million scm oil	0.8 million scm oil
	42.1 billion scm gas	
Production	**Estimated production in 2005:**	
	Gas: 0.1 billion scm	
Investment	Total investment is likely to be NOK 18.4 billion	
	NOK 18.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Dusavik	

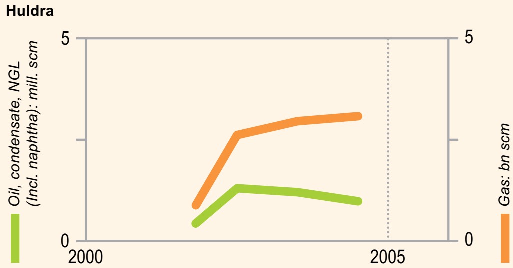
Development:
Heimdal is a gas field in 120 metres of water. The field has been developed with an integrated drilling, production and accommodation facility with a steel base (HMP1). The PDO for Heimdal was approved by the Norwegian Parliament on 10.06.1981. The field came on stream on 13.12.1985. The Heimdal Jura development was approved on 02.10.1992. The PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999 and the centre came on stream in 2000. The plan involves construction of a new riser facility (HRP) and modification and upgrade of HMP1. HRP is a steel-based facility tied back to HMP1 by a bridge.

Reservoir:
The reservoir consists of Tertiary sandstones in the Heimdal formation laid down as deep-marine turbidites.

Recovery strategy:
Heimdal is developed with natural depletion.

Transport:
Originally, gas was piped from Heimdal to Statpipe, but may also now be transported by other pipelines. Condensates are piped to Brae in the British sector. After HGS was constructed, a new gas pipeline (Vesterled) has been laid up to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has been laid from HRP to Grane for gas injection. Huldra, Vale and Skirne are tied to a pipeline to Heimdal for processing.

Status:
The production facilities are mainly used for processing from Huldra, Vale and Skirne. If the facility has spare capacity, gas is also produced from the Heimdal reservoir.



Huldra

Blocks and production licences	Block 30/2 - production licence 051. Awarded 1979. Block 30/3 - production licence 052 B. Awarded 2001.	
Discovered	1982	
Development approval	02.02.1999 by Parliament	
On stream	21.11.2001	
Operator	Statoil ASA	
Licensees in Huldra	Norske ConocoPhillips AS	23.34%
	Paladin Resources Norge AS	0.50%
	Petoro AS	31.96%
	Statoil ASA	19.88%
	Total E&P Norge AS	24.33%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	4.3 million scm oil	0.9 million scm oil
	12.9 billion scm gas	4.2 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2005:** Oil: 8,000 barrels/day Gas: 1.92 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is likely to be NOK 7.1 billion NOK 7.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

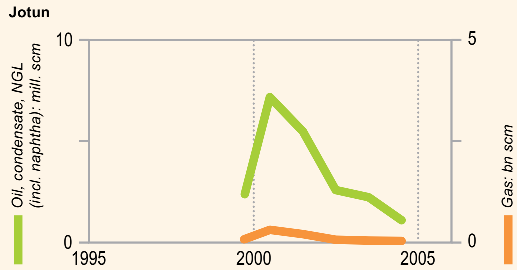
Development:
Huldra is a gas field in 125 metres of water. The field is developed with a wellhead steel facility that separates gas and condensate for transport in separate pipelines. The facility is normally unmanned and is remotely operated from Veslefrikk B, 16 km away.

Reservoir:
The reservoir is in a rotated fault block which inclines to the east, and consists of Jurassic sandstone belonging to the Brent group. The Huldra reservoir has high pressure and high temperature. Communication in the reservoir is uncertain, but the production history indicates two main segments without pressure communication. There are many small faults in the field.

Recovery strategy:
The field's recovery strategy is depletion.

Transport:
Following first stage separation, the wet gas is transported to Heimdal for further processing. Some of the gas is cold ventilated. Condensate is transported to Veslefrikk for processing.

Status:
Drilling has been completed at the field, and it is producing gas and condensate from a total of six production wells. Production at Huldra now exceeds the forecast plateau rate. The field is estimated as remaining at its plateau rate for just less than three years, before the production rate gradually declines.



Jotun

Blocks and production licences	Block 25/7 - production licence 103 B. Awarded 1998. Block 25/8 - production licence 027 B. Awarded 1999.	
Discovered	1994	
Development approval	10.06.1997 by Parliament	
On stream	25.10.1999	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees in Jotun	Enterprise Oil Norge AS	45.00%
	ExxonMobil Exploration and Production Norway AS	45.00%
	Lundin Norway AS	7.00%
	Petoro AS	3.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	25.4 million scm oil	6.0 million scm oil
	0.7 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2005:** Oil: 14,000 barrels/day Gas: 0.01 billion scm	
Investment	Total investment is likely to be NOK 10.7 billion NOK 10.3 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

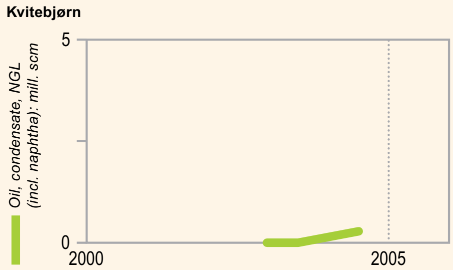
Development:
Jotun is an oil field in 126 m of water located around 25 km north of Balder, 165 km west of Haugesund. It has been developed with a production vessel, Jotun A (FPSO), and a wellhead facility with drilling module and accommodation, Jotun B. Jotun also processes gas from Balder and oil from the Jurassic reservoir in the Ringhorne deposits at Balder.

Reservoir:
The Jotun oilfield consists of three structures. The eastern structure also has a gas cap. The reservoirs are distally located in a submarine fan system. The three structures are relatively flat and only separated by minor depressions. Between the three structures, there is a difference of only a few metres in oil/water contact. To the west the sand is mostly homogenous and has the best reservoir quality, while to the east there is more slate content in the reservoir.

Recovery strategy:
Recovery is driven by reinjection of produced water.

Transport:
The oil is exported via loading buoys to tankers. The processed rich gas is exported via Statpipe to the Kårstø plant. The facility and the ship are tied together by flowlines for oil and gas injection and for water injection, as well as power and control cables.

Status:
Jotun production fell from plateau earlier than estimated, and the drop in production has been larger than previously estimated. Since 2004, Jotun has received oil and gas from Balder for processing and onward transport.



Kvitebjørn

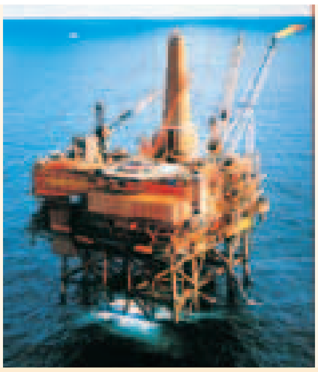
Block and production licence	Block 34/11 - production licence 193. Awarded 1993.	
Discovered	1994	
Development approval	14.06.2000 by Parliament	
On stream	26.09.2004	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	15.00%
	Petoro AS	30.00%
	Statoil ASA	50.00%
	Total E&P Norge AS	5.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004.**
	18.0 million scm oil	17.7 million scm oil
	51.8 billion scm gas	51.3 billion scm gas
	2.2 million tonnes NGL	2.2 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 36,000 barrels/day Gas: 4.48 billion scm NGL: 0.21 million tonnes	
Investment	Total investment is likely to be NOK 10.7 billion	
	NOK 8.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	

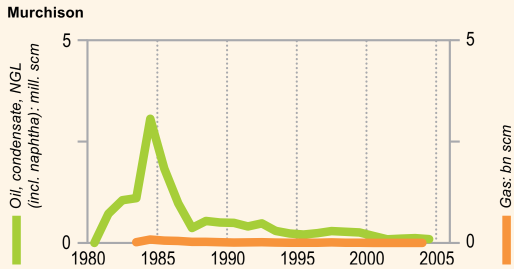
Development:
Kvitebjørn is a gas condensate field that has been developed with an integrated accommodation, drilling and processing facility with a seabed steel jacket. It is in 190 metres of water. 11 production wells are planned to be drilled. The processing plant is dimensioned for a daily production of 20.7 mill. scm rich gas and 10,000 scm condensate. Drill cuttings and polluted water are injected in a dedicated disposal well.

Reservoir:
The reservoir consists of sandstones in the Mid-Jurassic Brent group. The area of the reservoir is around 44 km^2, and it lies at an approx. depth of 4,000 metres, at high temperature and pressure.

Recovery strategy:
Recovery is driven by depletion.

Transport:
Rich gas is transported in a dedicated pipeline to Kollsnes, while condensate is transported in a pipeline tied to the Troll Oil Pipeline II for onward transport to Mongstad.



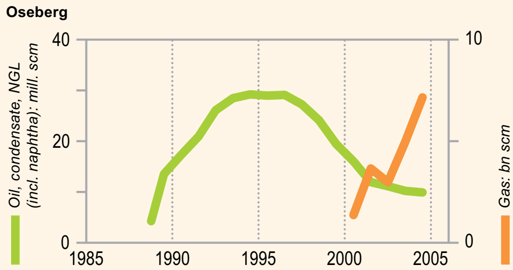


Murchison

Block and production licence	Block 33/9 - production licence 037 C. Awarded 2000. The Norwegian share of the field is 22.2 percent, the British share 77.8 percent.	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees in Murchison	Revus Energy AS	10.68%
	Statoil ASA	11.52%
	CNR International (UK) Limited	68.72%
	Ranger Oil (UK) Ltd	9.08%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
(Norwegian share)	14.0 million scm oil	0.7 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2005:**	
(Norwegian share)	Oil: 2,000 barrels/day	
Investment	Total investment is likely to be NOK 7.1 billion NOK 6.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

Development:
Murchison has been developed with a combined drilling, accommodation and production facility with a steel jacket. The British and Norwegian licensees entered into an agreement in 1979 concerning common exploitation of the resources in the Murchison field. The agreement also involves British and Norwegian authorities. This is established in the agreement between Norway and the United Kingdom relating to exploitation of the Murchison reservoir and offtake of petroleum therefrom, cf. Parliamentary Bill. no. 15 (1980–1981) and Recommendation no. 57 (1980–1981). Supplementary agreement, cf. Parliamentary Bill no. 68 (1981–82) and Recommendation no. 169 (1981–1982).

Transport:
Both the Norwegian and British licensees' share of the oil and NGL is piped through the Brent system to Sullom Voe in the Shetlands. The gas is piped to St. Fergus in Scotland. In 2002, CNR International (UK) took over as operator from Kerr McGee North Sea (UK) Ltd.



Oseberg

Blocks and production licences	Block 30/6 - production licence 053. Awarded 1979. Block 30/9 - production licence 079. Awarded 1982.	
Discovered	1979	
Development approval	05.06.1984 by Parliament	
On stream	01.12.1988	
Operator	Norsk Hydro Produksjon AS	
Licensees in Oseberg	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	353.7 million scm oil	32.7 million scm oil
	102.8 billion scm gas	82.7 billion scm gas
	6.2 million tonnes NGL	3.3 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 126,000 barrels/day Gas: 2.02 billion scm NGL: 0.50 million tonnes	
Investment	Total investment is likely to be NOK 79.3 billion NOK 74.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

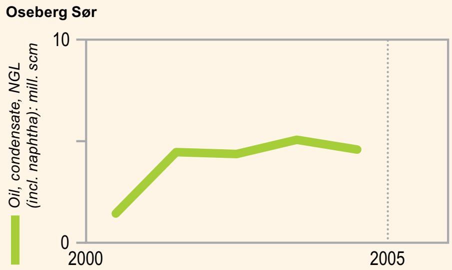
Development:
Oseberg is an oilfield with an overlaying gas cap. Oil recovery from Oseberg was developed in two phases. The first phase of the development included a field centre in the south consisting of two facilities, Oseberg A and B. Oseberg A is a process and accommodation facility with a concrete base structure. Oseberg B is a drilling and water injection facilities with a steel jacket. Phase 2 includes development of the northern part of the field. The Oseberg C facility is an integrated production, drilling and accommodation facility (PDQ). The Oseberg D facility is an facility for gas processing with a steel jacket tied to Oseberg Field Centre. Oseberg Vest flank has been developed with a four-well subsea template that is tied to Oseberg B. The facilities at the field centre will also be used for processing oil and gas from the Oseberg Øst, Oseberg Sør, Oseberg Vest and Tune fields. The PDO for Oseberg Phase 1 was approved on 05.06.1984. The field came on stream on 01.12.1988. Oseberg Phase 2, development of the northern part of the field, was approved on 19.01.1988. Oseberg Phase 3, the gas phase with installation of a facility for gas processing, was approved on 13.12.1996 and began operation in October 1999. The PDO for Oseberg Vestflanke was approved on 19.12.2003.

Reservoir:
The field consists of several reservoirs in the Mid-Jurassic Brent group, and is divided into three main structures. The main reservoir is located in the Oseberg and Tarbert formations, but production also takes place from the Etive and Ness formations. The field has generally good reservoir characteristics, and there is a high recovery factor from the field.

Recovery strategy:
Pressure in the Oseberg field is maintained by gas, water and WAG (Water/Alternating Gas) injection. Massive upflank gas injection has provided extremely good oil displacement, and a large gas cap has now developed that will be recovered in the future. Formerly, injection gas was imported from Troll Øst (TOGI) and Oseberg Vest. TOGI was taken off stream in 2002 in accordance with the gas delivery agreement.

Transport:
The oil is piped through the Oseberg Transport System (OTS) to the Sture terminal. Gas export began in autumn 2000 through a new pipeline, Oseberg Gas Transport (OGT), to the Statpipe system via the Heimdal facility.

Status:
Most production wells are now drilled horizontally. Use of horizontal and advanced wells, in conjunction with gas injection and VAG, has contributed to high oil recovery levels from the Oseberg field. The challenge in the future will be to recover the oil that remains between the gas cap and the water zone, and to balance the gas recovered by taking into account the oil production from the field. Oseberg Vestflanke will come on stream in the autumn of 2005.



Oseberg Sør

Blocks and production licences	Block 30/12 - production licence 171 B. Awarded 2000. Block 30/9 - production licence 079. Awarded 1982 Block 30/9 - production licence 104. Awarded 1985.	
Discovered	1984	
Development approval	10.06.1997 by Parliament	
On stream	05.02.2000	
Operator	Norsk Hydro Produksjon AS	
Licensees in Oseberg Sør	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	57.6 million scm oil	37.7 million scm oil
	8.9 billion scm gas	8.9 billion scm gas
Production	**Estimated production in 2005:** Oil: 81,000 barrels/day Gas: 0.82 billion scm	
Investment	Total investment is likely to be NOK 14.5 billion NOK 12.5 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

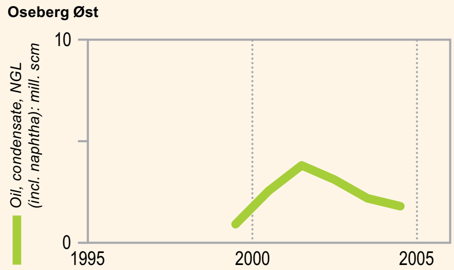
[1] Gas from Oseberg Sør is not reallocated from Oseberg and therefore the remaining gas reserves are equal to the original.

Development:
Oseberg Sør is an oil field and has been developed with an integrated facility with accommodation, drilling module and first stage separation of oil and gas. The jacket and topside are made of steel. There are also several structures in the field that have been produced from subsea templates that are tied back to the Oseberg Sør facility. Final processing of oil and gas takes place on the Oseberg Field Centre. The PDO for Oseberg Sør was approved by the Norwegian Parliament on 10.06.1997. The field came on stream on 05.02.2000. An amended PDO for part of the development, the Oseberg Sør J structure, was approved on 15.05.2003.

Reservoir:
The reservoir consists of Jurassic sandstones and is divided into several separate structures.

Recovery strategy:
Recovery mainly takes place using water injection, but associated gas is also reinjected from the Oseberg Sør facility, so that there is WAG (Water/Alternating Gas) injection in parts of the field.

Transport:
The oil is piped from the Oseberg Sør facility to the Oseberg Field Centre. Following final processing, the oil is piped to the Sture terminal. Gas is transported via Oseberg Gas Transport into Statpipe via the Heimdal facility.



Oseberg Øst

Block and production licence	Block 30/6 - production licence 053. Awarded 1979.	
Discovered	1981	
Development approval	11.10.1996 by the King in Council of State	
On stream	03.05.1999	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	30.2 million scm oil	15.8 million scm oil
	0.7 billion scm gas	0.7 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 24,000 barrels/day Gas: 0.06 billion scm	
Investment	Total investment is likely to be NOK 9.4 billion	
	NOK 6.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

[1] Gas from Oseberg Øst not allocated separately from Oseberg, remaining reserves therefore equal original reserves.

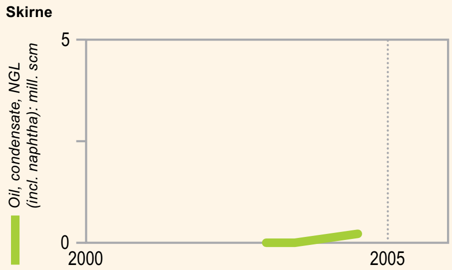
Development:
Oseberg Øst is an oil field and has been developed with a facility with a steel jacket with accommodation, drilling equipment and first stage separation of oil, water and gas. The facility stands in 160 metres of water.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Mid-Jurassic Brent group.

Recovery strategy:
Pressure is maintained in the field using both water injection and WAG (Water/Alternating Gas) injection.

Transport:
The oil is piped to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) pipeline to Sture terminal. The gas is mainly injected into the field, although a minor amount is extracted at Oseberg Field Centre and exported through Oseberg Gas Transport.

Status:
The field has a relatively low rate of recovery, although various measures for increasing oil recovery are being considered in an ongoing process. A new drilling campaign, comprising up to seven new wells, was decided in autumn 2004. The wells will contribute to increasing the oil reserves to the extent of six million scm.



Skirne

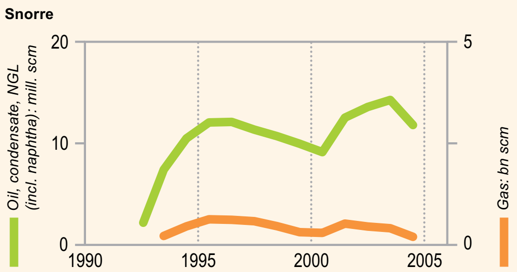
Block and production licence	Block 25/5 - production licence 102. Awarded 1985.	
Discovered	1990	
Development approval	05.07.2002 by the Crown Prince Regent in Council of State	
On stream	03.03.2004	
Operator	Total E&P Norge AS	
Licensees	Marathon Petroleum Norge AS	20.00%
	Norsk Hydro Produksjon AS	10.00%
	Petoro AS	30.00%
	Total E&P Norge AS	40.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	1.6 million scm oil	1.4 million scm oil
	6.7 billion scm gas	6.0 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 1.31 billion scm	
Investment	Total investment is likely to be NOK 2.4 billion	
	NOK 2.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	

Development:
Skirne has been developed in association with Heimdal. The production wells are tied back with a pipeline to Heimdal for processing. The PDO for the Skirne field, including Byggve, was approved on 05.07.2002. Following an application by the operator, Byggve has been regarded as part of the Skirne field from the autumn of 2003.

Reservoir:
The reservoir consists of sandstone in the Mid-Jurassic Brent Group.

Recovery strategy:
The recovery mechanism is natural depletion.

Transport:
Gas condensate is piped to the Heimdal facility.



Snorre

Blocks and production licences	Block 34/4 - production licence 057. Awarded 1979.	
	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1979	
Development approval	27.05.1988 by Parliament	
On stream	03.08.1992	
Operator	Statoil ASA	
Licensees in Snorre	Amerada Hess Norge AS	1.18%
	Enterprise Oil Norge AS	1.18%
	ExxonMobil Exploration and Production Norway AS	11.16%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	17.65%
	Petoro AS	30.00%
	RWE Dea Norge AS	8.88%
	Statoil ASA	14.40%
	Total E&P Norge AS	5.95%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	242.4 million scm oil	113.0 million scm oil
	6.4 billion scm gas	1.3 billion scm gas
	4.7 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 193,000 barrels/day	
Investment	Total investment is likely to be NOK 76.9 billion	
	NOK 58.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

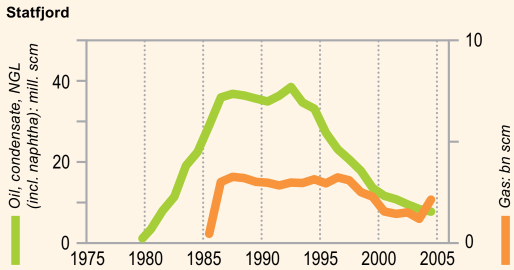
Development:
Snorre is an oil field that has been developed in two phases. Phase 1 includes a floating steel facility for accommodation and processing (Snorre TLP) in the south, and a subsea template with ten well slots (Snorre SPS) centrally in the field, tied back to Snorre TLP. Snorre TLP has also been developed with its own processing facility for production from the Vigdis field. Phase 2 includes a semi-submersible integrated drilling, processing and accommodation facility (Snorre B) in the northern part of the field. The PDO for Snorre phase 1, which covers the southern part of the field with the Snorre A facility, was approved on 27.05.1988. The amended development plan for Snorre, with a new module on Snorre A for production from Vigdis, was approved on 16.12.1994. The PDO for Snorre phase 2, which covers the northern part of Snorre with the Snorre B facility, was approved on 08.06.1998. Snorre B came on stream in June 2001.

Reservoir:
The Snorre field consists of several large fault blocks. The reservoir sandstone belongs to the Early Jurassic and Triassic Statfjord and Lunde formations, and has been deposited on a flood plain. The reservoir has a complex structure with many channels and internal flow barriers.

Recovery strategy:
Pressure in Snorre is maintained fully using water injection, gas injection and water/alternating gas (WAG) injection. Foam assisted injection (FAWAG) has also been used in parts of the reservoir.

Transport:
Oil and gas are separated in two stages on Snorre TLP before transport to Statfjord A for final processing and export. The oil is loaded onto tankers at Statfjord and the gas is sent through Statpipe to Kårstø. Processed oil from Snorre B is piped to Statfjord B for storage and loading to tankers. All gas from Snorre B is reinjected into the reservoir, but can, if required, also be piped to Snorre TLP.

Status:
There are plans to modify the processing plant at Snorre A in order to increase the capacity for production and injection of water and gas.



Statfjord

Blocks and production licences	Block 33/12 - production licence 037. Awarded 1973. Block 33/9 - production licence 037. Awarded 1973. Norwegian share of the field is 85.47%, British share is 14.53%	
Discovered	1974	
Development approval	16.06.1976 by Parliament	
On stream	24.11.1979	
Operator	Statoil ASA	
Licensees in Statfjord	A/S Norske Shell	8.55%
	Enterprise Oil Norge AS	0.89%
	ExxonMobil Exploration and Production Norway AS	21.37%
	Norske ConocoPhillips AS	10.33%
	Statoil ASA	44.34%
	BP Petroleum Development Ltd	4.84%
	Centrica Resources Limited	4.84%
	ConocoPhillips UK Ltd.	4.84%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
(Norwegian share)	565.8 million scm oil	24.2 million scm oil
	54.3 billion scm gas	4.6 billion scm gas
	14.9 million tonnes NGL	1.6 million tonnes NGL
Production	**Estimated production in 2005:**	
(Norwegian share)	Oil: 99,000 barrels/day Gas: 1.52 billion scm NGL: 0.53 million tonnes	
Investment	Total investment is likely to be NOK 112.5 billion NOK 106.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply bases	Sotra and Florø	

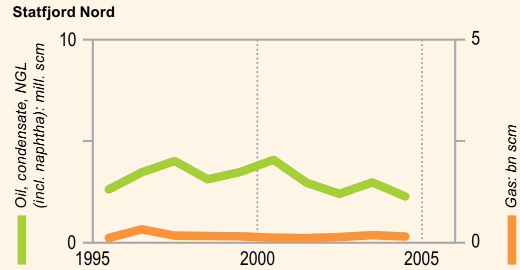
Development:
Statfjord is an oil field that is on the border between the Norwegian and British sectors of the continental shelf, in around 145 metres of water. The field has been developed in three phases with the fully integrated facilities Statfjord A, Statfjord B and Statfjord C. Statfjord A is centrally positioned on the Statfjord field, and came on stream in November 1979. Processing capacity for oil at Statfjord A is approx. 67,000 scm per day, and the facility has a storage capacity of 175,000 scm. Capacity for water injection is approx. 65,000 m^3 per day. Partially processed oil from Snorre TLP has been piped to Statfjord A since August 1992. Statfjord B is located on the southern part of the Statfjord field, and came on stream in November 1982. Production capacity for oil is 16,000 scm per day, and the facility has a storage capacity of 302,000 scm. Water injection capacity is approx.. 65,000 m^3 per day. Statfjord C is positioned on the northern part of the Statfjord field, and came on stream in June 1985. The facility is identically constructed to Statfjord B. Production capacity for oil is 20,000 scm. Capacity for water injection at Statfjord C is approx. 60,000 m^3 per day. Statfjord's satellite fields (Statfjord Øst, Statfjord Nord and Sygna) have a separate inlet separator on Statfjord C with a capacity of approx. 20,000 scm oil. The northern flank of the Statfjord field has been developed with two subsea facilities, one for production and one for injection, tied back to Statfjord C. Production from the northern flank started in the summer of 1999.

Reservoir:
The Statfjord field consists of a large fault block, inclining towards the west, as well as a number of smaller fault blocks along the east flank. The field extends into the British sector. The reservoirs in the Statfjord field consist of sandstones belonging to the Brent group, the Cook formation and the Statfjord formation.

Recovery strategy:
The Brent reservoir was originally developed using pressure support from water injection. In 1998, based on results from a trial with WAG injection in lower Brent, and reservoir studies, it was decided to implement WAG injection as the recovery strategy throughout Brent. Calculations indicate that WAG injection at Brent provides increased oil recovery to the extent of 10.5 million scm by injecting 15 billion scm gas. The Statfjord formation has been developed using pressure support from upflank gas injection. Since 1994, implementation of a new recovery strategy, with upflank water injection and supporting gas injection in the upper part of the Statfjord formation and down flank WAG injection in the lower part of the Statfjord formation, has begun in stages, based on experience from production and reservoir studies. The Cook formation came on stream in 1994. The recovery strategy is based on phasing in wells that already penetrate the reservoir, and possibly deepening existing wells. Pressure in production is supported by water injection. The Northern flank of the field came on stream with its own subsea wells in August 1999.

Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded from one of the three oil loading systems at the field. The gas is piped through Statpipe to Karstø, where NGL is separated before dry gas is transported on to Emden. The UK extracts its share of the oil through the Flags pipeline from Statfjord B to St. Fergus in Scotland.

Status:
There is high activity with reboring and reperforation of the wells in order to maintain production levels. Plan for gas blowdown for the Statfjord field (Statfjord Late Phase) was submitted to the authorities in February 2005. The Plan will extend the lifetime of the field by around 10 years and provide significant extra recovery of approx. 41 billion scm and an increase in oil recovery of around four million scm.



Statfjord Nord

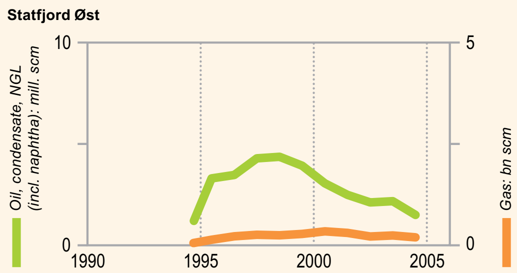
Block and production licence	Block 33/9 - production licence 037. Awarded 1973.	
Discovered	1977	
Development approval	11.12.1990 by Parliament	
On stream	23.01.1995	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	10.00%
	Enterprise Oil Norge AS	1.04%
	ExxonMobil Exploration and Production Norway AS	25.00%
	Norske ConocoPhillips AS	12.08%
	Petoro AS	30.00%
	Statoil ASA	21.88%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	39.3 million scm oil	8.9 million scm oil
	2.6 billion scm gas	0.9 billion scm gas
	0.9 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 35,000 barrels/day Gas: 0.28 billion scm NGL: 0.10 million tonnes	
Investment	Total investment is likely to be NOK 7.4 billion	
	NOK 7.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

Development:
Statfjord Nord is an oil field that is located around 17 km north of Statfjord in 250 – 290 metres of water and has been developed with three subsea templates tied back to Statfjord C. Two of the well templates are for production and one is for water injection. Each of the well templates has four well slots. One well slot on the injection well template at Statfjord Nord has been used for an injection well at the Sygna field. The water injection capacity of Statfjord Nord and Sygna together is 28,000 m^3 per day.

Reservoir:
The Statfjord Nord reservoir consists of Mid-Jurassic sandstones belonging to the Brent group and Late Jurassic sandstones (the Munin formation).

Recovery strategy:
The field is recovered using pressure support from water injection.

Transport:
The wellstream is piped through two pipelines to Statfjord C for processing, storage and export. Statfjord Nord and Statfjord Øst use the same equipment on Statfjord C.



Statfjord Øst

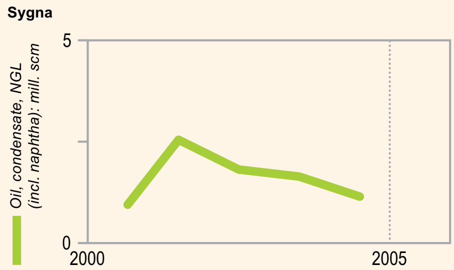
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1976	
Development approval	11.12.1990 by Parliament	
On stream	24.09.1994	
Operator	Statoil ASA	
Licensees in Statfjord Øst	A/S Norske Shell	5.00%
	Enterprise Oil Norge AS	0.52%
	ExxonMobil Exploration and Production Norway AS	17.75%
	Idemitsu Petroleum Norge AS	4.80%
	Norsk Hydro Produksjon AS	6.64%
	Norske ConocoPhillips AS	6.04%
	Petoro AS	30.00%
	RWE Dea Norge AS	1.40%
	Statoil ASA	25.05%
	Total E&P Norge AS	2.80%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	35.7 million scm oil	6.1 million scm oil
	3.9 billion scm gas	1.4 billion scm gas
	1.4 million tonnes NGL	0.5 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 24,000 barrels/day Gas: 0.42 billion scm NGL: 0.15 million tonnes	
Investment	Total investment is likely to be NOK 6.5 billion NOK 6.2 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

Development:
Statfjord Øst is an oil field located around 7 km northeast of the Statfjord field in 150 – 190 metres of water. The field has been developed with three well templates that are tied back to Statfjord C. Two of the templates are for production and one for water injection. Each subsea template has four well slots.

Reservoir:
The Statfjord Øst reservoir consists of Mid-Jurassic sandstones in the upper and lower parts of the Brent group.

Recovery strategy:
The field is recovered using pressure support from water injection.

Transport:
The wellstream is piped through two pipelines to Statfjord C for processing, storage and export. Statfjord Øst and Statfjord Nord use the same processing equipment on Statfjord C.



Sygna

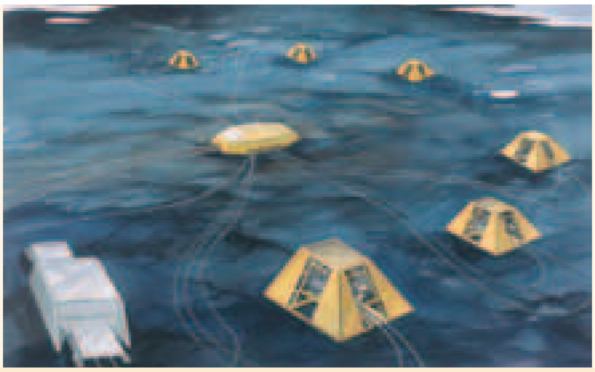
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1996	
Development approval	30.04.1999 by the King in Council of State	
On stream	01.08.2000	
Operator	Statoil ASA	
Licensees in Sygna	A/S Norske Shell	5.50%
	Enterprise Oil Norge AS	0.57%
	ExxonMobil Exploration and Production Norway AS	18.48%
	Idemitsu Petroleum Norge AS	4.32%
	Norsk Hydro Produksjon AS	5.98%
	Norske ConocoPhillips AS	6.65%
	Petoro AS	30.00%
	RWE Dea Norge AS	1.26%
	Statoil ASA	24.73%
	Total E&P Norge AS	2.52%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	10.9 million scm oil	3.2 million scm oil
Production	**Estimated production in 2005:** Oil: 11,000 barrels/day	
Investment	Total investment is likely to be NOK 2.3 billion NOK 2.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

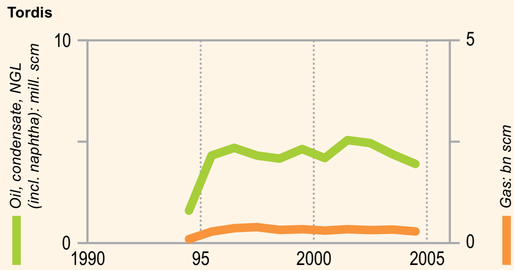
Development:
Sygna is an oil field that straddles the boundary between production licences 037 and 089 between the Snorre and Statfjord fields. The field has been developed with a subsea template, with four well slots, that is tied back to Statfjord C. Three production wells have been drilled at Sygna. An injection well from Statfjord Nord provides water injection.

Reservoir:
The Sygna reservoir consists of Mid-Jurassic sandstones belonging to the Brent group.

Recovery strategy:
The field is recovered using pressure support from water injection.

Transport:
The wellstream is piped to Statfjord C for processing, storage and export. Statfjord Nord, Statfjord Øst and Sygna share processing equipment on Statfjord C.





Tordis

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1987	
Development approval	14.05.1991 by Parliament	
On stream	03.06.1994	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	13.28%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.80%
	Statoil ASA	28.22%
	Total E&P Norge AS	5.60%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	58.1 million scm oil	14.3 million scm oil
	5.2 billion scm gas	1.9 billion scm gas
	1.7 million tonnes NGL	0.4 million tonnes NGL
Production	Estimated production in 2005: Oil: 58,000 barrels/day Gas: 0.28 billion scm NGL: 0.11 million tonnes	
Investment	Total investment is likely to be NOK 8.9 billion NOK 8.6 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development: Tordis is an oil field located between the Snorre and Gullfaks fields in around 200 metres of water, and has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite wells and two subsea templates are tied back to the subsea manifold. The wellstream is piped to Gullfaks C through two pipelines. Injection water is piped from Gullfaks C. Tordis consists of four discoveries: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis was approved on 14.05.1991. The PDO for Tordis Øst was approved on 13.10.1995. Test production were carried out at Borg in 1998 for a period of six months. The PDO for Borg was approved on 29.06.1999. 34/7-25 S was regarded as part of Tordis, and the authorities did not require separate approval for development of this discovery.

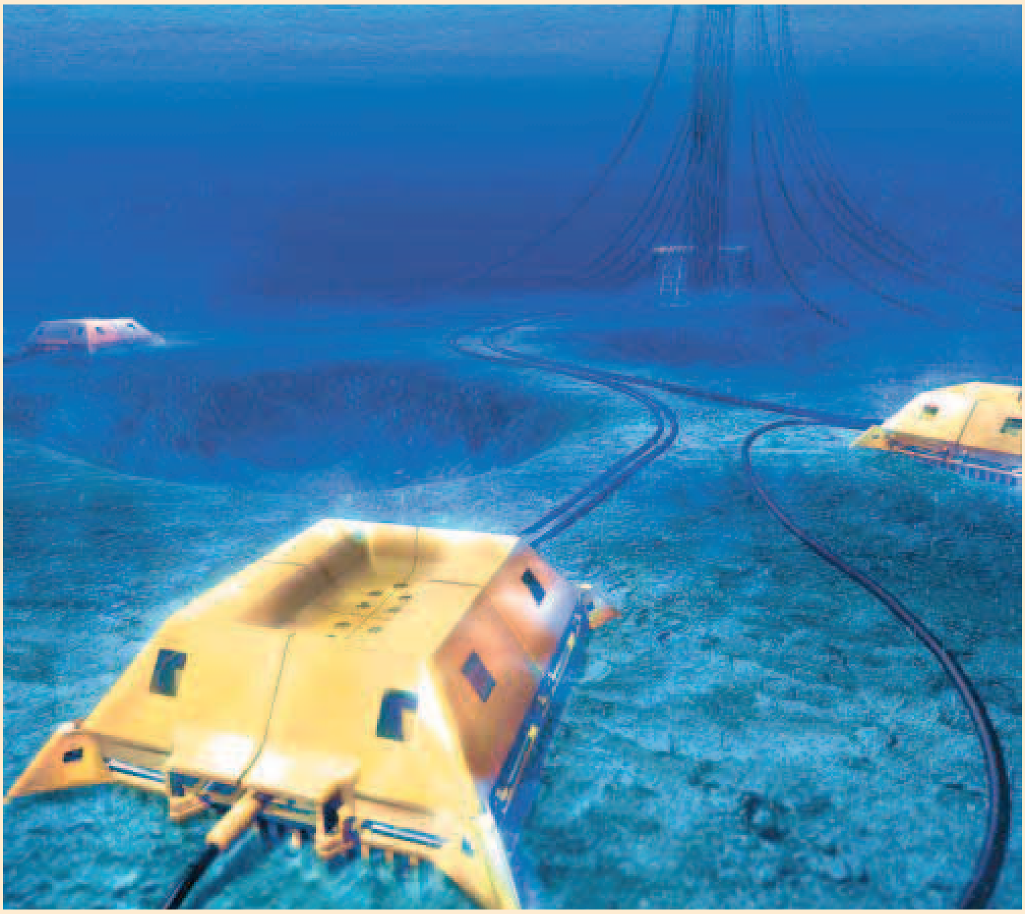
Reservoir: The reservoirs in the Tordis and Tordis Øst discoveries consist of Mid-Jurassic sandstones in the Brent group. The reservoir at Borg consists of sandstones that are equivalent in period with the Late Jurassic Draupne formation. The reservoir in 34/7-25 S consists of fallen sandstones from the Brent group and sandstones that are from the equivalent period to the Draupne formation. The Tordis reservoirs lie at a depth of 2,000 – 2,500 m.

Recovery strategy: Pressure in the Tordis and 34/7-25 S discoveries is partially maintained using water injection and natural water pressure. Pressure at Borg is fully maintained using water injection. Recovery at Tordis Øst takes place with pressure support from natural water pressure.

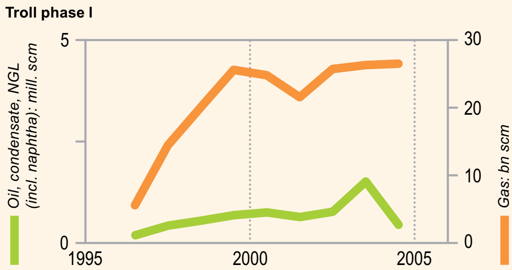
Transport: Oil from Tordis is exported from Gullfaks C. The export gas is piped through Statpipe to Kårstø.

Troll

Troll lies about 65 km off Kollsnes and comprises two main structures: Troll Øst and Troll Vest. The first of these primarily occupies blocks 31/3 and 31/6, while most of Troll Vest is found in block 31/2. Roughly two-thirds of the field's recoverable gas reserves are thought to lie in Troll Øst. A staged development has been pursued, with phase I covering gas reserves in the eastern region and phase II focusing on the oil reserves in Troll Vest. Phase III will cover gas reserves in the latter area. A thin oil layer underlies the whole Troll field, but is only sufficiently thick for commercial recovery in the Troll Vest region. The latter divides into oil and gas provinces, where the thickness of the oil-bearing zones is 22-27 and 11-14 metres respectively. Test production from the two provinces in 1990 and 1991 yielded positive results. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf.



Troll Pilot



Troll Phase I

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979	
	Block 31/3 - production licence 085. Awarded 1983	
	Block 31/3 - production licence 085C Awarded 2002	
	Block 31/5 - production licence 085. Awarded 1983	
	Block 31/6 - production licence 085. Awarded 1983	
	Block 31/6 - production licence 085C Awarded 2002	
Discovered	1983	
Development approval	15.12.1986 by Parliament	
On stream	09.02.1996	
Operator	Statoil ASA	
Licensees in Troll	A/S Norske Shell	8.10%
	Norsk Hydro Produksjon AS	9.78%
	Norske ConocoPhillips AS	1.62%
	Petoro AS	56.00%
	Statoil ASA	20.80%
	Total E&P Norge AS	3.69%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	1318.0 billion scm gas	1128.6 billion scm gas
	30.8 million tonnes NGL	30.8 million tonnes NGL
	1.6 million scm condensate	
Production	**Estimated production in 2005:**	
	Gas: 27.20 billion scm NGL: 0.51 million tonnes	
Investment	Total investment is likely to be NOK 70.0 billion	
	NOK 47.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

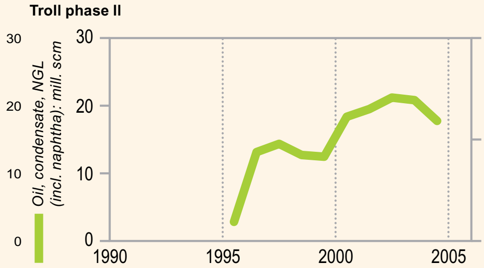
Development:
Troll Phase I has been developed with Troll A, in which the gas from Troll Øst has been recovered by Statoil as operator. Troll A is a fixed wellhead facility with a concrete casing. At Troll Øst there also has been installed the TOGI subsea template which has exported gas to Oseberg for gas injection. The sea in the Troll area is more than 300 metres deep. The PDO for Troll phase I, which included Troll A and the gas reserves at Troll Øst, was approved on 15.12.1986. An updated plan, in which processing was moved to a land-based facility (at Kollsnes), was approved in 1990. The PIO for the NGL facility at Kollsnes was approved in 2002.

Reservoir:
The gas and oil at Troll Øst and Vest are mainly found in the Sognefjord formation that consists of Jurassic sandstone. Some of the reservoir is also in the underlying Fensfjord formation. The field consists of three relatively large rotated fault blocks.

Recovery strategy:
The gas in Troll Øst is recovered using depletion.

Transport:
The gas from Troll Øst and Troll Vest is transported through two multiphase pipelines to the gas processing plant at Kollsnes. The condensate is separated from the gas, and piped partly to the Sture terminal, partly to Mongstad. The dry gas is piped in Zeepipe II A and II B. Small gas quantities are supplied to Kollsnes Industrial Estate.

Status:
In 2002 and 2003 Troll was the field that produced most oil and gas from the Norwegian sector of the continental shelf. Increased compression capacity for gas has been under development at Troll A in 2004.



Troll Phase II

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Block 31/3 - production licence 085. Awarded 1983. Block 31/3 - production licence 085C Awarded 2002. Block 31/5 - production licence 085. Awarded 1983. Block 31/6 - production licence 085. Awarded 1983. Block 31/6 - production licence 085C Awarded 2002.	
Discovered	1979	
Development approval	18.05.1992 by Parliament	
On stream	19.09.1995	
Operator	Norsk Hydro Produksjon AS	
Licensees in Troll	A/S Norske Shell	8.10%
	Norsk Hydro Produksjon AS	9.78%
	Norske ConocoPhillips AS	1.62%
	Petoro AS	56.00%
	Statoil ASA	20.80%
	Total E&P Norge AS	3.69%
Recoverable reserves	**Original:** 233.2 million scm oil	**Remaining as at 31.12.2004** 77.0 million scm oil
Production	**Estimated production in 2005:** Oil: 249,000 barrels/day	
Investment	Total investment is likely to be NOK 66.8 billion NOK 62.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

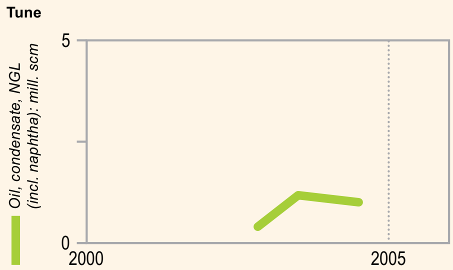
Development:
Troll Phase II has been developed with Troll B and Troll C recovering oil from Troll Vest with Norsk Hydro as operator. Troll B is a floating concrete facility, while Troll C is a semi-submersible steel facility. Oil from Troll Vest is produced from several subsea templates that are tied back to Troll B and C by flowlines. Troll Pilot, which is tied back to one of the subsea templates, is a plant for subsea separation and reinjection of produced water. The sea depth in the Troll area exceeds 300 metres. The Troll C facility is also used for production from the Fram field. The PDO for Troll phase II, which included Troll B and development of the Troll Vest oil province, was approved on 18.05.1992. A further development of Troll Vest, with Troll C, was approved in 1997. There have been several PDO approvals concerning subsea templates at Troll Vest.

Reservoir:
The gas and oil at Troll Øst and Vest is found mainly in the Sognefjord formation, which consists mainly of Jurassic sandstone. Some of the reservoir is also in the underlying Fensfjord formation. The field consists of three relatively large rotated fault blocks. The oil in the Troll Vest province is formed as a 22-26 metre thick column under a small gas cap. In the Troll Vest gas province there is an oil column of around 12-14 metres and a gas column of up to 200 metres.

Recovery strategy:
Oil production at Troll Vest takes place through horizontal wells that are drilled immediately above the oil/water contact in the thin oil zone. There is also depletion here, but there will be simultaneous expansion of the gas cap and the water zone below the oil. There has been reinjection of some of the gas produced to assist in optimising the oil production. One important aspect of the strategy has been to recover the oil quickly. The timing of the recovery has been considered critical because of the risk of reduced oil production when the pressure is reduced in Troll Øst. For this reason, limits have also been placed on gas extraction from Troll Øst.

Transport:
Gas from Troll Øst and Troll Vest is transported through two multiphase pipelines to the gas processing plant at Kollsnes. Condensate is separated from the gas and piped partly to the Sture terminal, partly to Mongstad. The dry gas is piped in Zeepipe II A and II B. Small amounts of the gas are delivered to Kollsnes Industrial Estate. The oil from Troll B and C is piped in the Troll Oil Pipelines I and II, respectively, to the oil terminal at Mongstad.

Status:
Troll Vest has been drilled with horizontal production wells from subsea templates with up to four drilling facilities at the same time. In all, more than 100 oil production wells have been drilled at Troll Vest. Over the last few years, annual decisions have been in favour of drilling new production wells that contribute to increasing oil reserves from Troll, and there are still a number of wells planned to be drilled. A number of multi-branch wells have been drilled and future plans also include five and six branch wells. Several well templates, which may increase recovery, are under evaluation. Kollsnes was split out of the coordinated Troll field in 2004, so that the Kollsnes terminal is now operated by Gassco as a part of Gassled.



Tune

Blocks and production licences	Block 30/5 - production licence 034. Awarded 1969.	
	Block 30/6 - production licence 053. Awarded 1979.	
	Block 30/8 - production licence 190. Awarded 1993.	
Discovered	1996	
Development approval	17.12.1999 by the King in Council of State	
On stream	28.11.2002	
Operator	Norsk Hydro Produksjon AS	
Licensees	Norsk Hydro Produksjon AS	40.00%
	Petoro AS	40.00%
	Statoil ASA	10.00%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**[1]
	3.8 million scm oil	1.6 million scm oil
	15.9 billion scm gas	15.9 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 6,000 barrels/day Gas: 2.16 billion scm	
Investment	Total investment is likely to be NOK 4.7 billion	
	NOK 3.9 billion had been invested as at 31.12.04 (2005 values)	

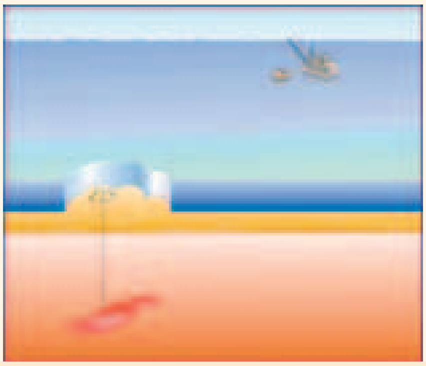
[1] Gas from Tune is not reallocated from Oseberg and therefore the remaining gas reserves are equal to the original

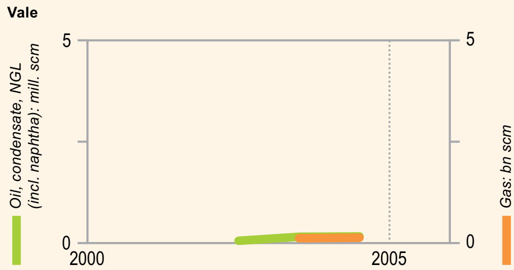
Development:
The Tune field is a gas and gas condensate field that is located around 10 km west of the Oseberg Field Centre. The field has been developed with a subsea facility with four production wells in the centre of the field. A new well template was tied back in 2004 to produce from the Tune Nord area. The PDO for the Tune field was approved on 17.12.1999 and it came on stream in 28.11.2002. In March 2004 PDO exemption for development of the northern part of the field was granted.

Reservoir:
The reservoir consists of Mid-Jurassic sandstones and is divided into several inclined fault blocks.

Recovery strategy:
Recovery is driven by depletion.

Transport:
The Tune subsea facility is tied back to the Oseberg D facility by two flowlines and a service line. A reception module for Tune has been built at Oseberg D. Condensate from Tune is stabilised at the Oseberg Field Centre and is transported to Sture through the Oseberg Transport System (OTS). Gas from Tune is injected into the Oseberg field, while the field's licensees are returned sales gas from the Oseberg field.





Vale

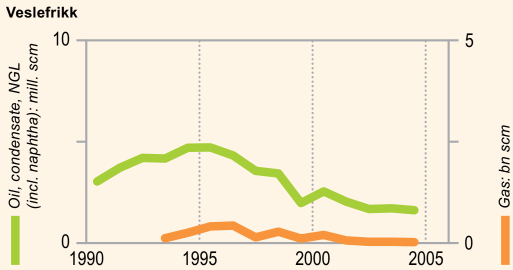
Block and production licence	Block 25/4 - production licence 036. Awarded 1971.	
Discovered	1991	
Development approval	23.03.2001 by the Crown Prince Regent in Council of State	
On stream	31.05.2002	
Operator	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	46.90%
	Norsk Hydro Produksjon AS	28.85%
	Total E&P Norge AS	24.24%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	1.8 million scm oil	1.4 million scm oil
	2.4 billion scm gas	2.2 billion scm gas
Production	**Estimated production in 2005:**	
	Oil: 8,000 barrels/day Gas: 0.53 billion scm	
Investment	Total investment is likely to be NOK 2.0 billion	
	NOK 1.6 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	

Development:
Vale is located 16 km north of Heimdal and has been developed with a subsea facility tied back to Heimdal.

Reservoir:
The reservoir consists of Mid-Jurassic sandstone in the Brent group.

Recovery strategy:
Recovery is driven by depletion.

Transport:
Gas condensate is produced at the Heimdal facility.



Veslefrikk

Blocks and production licences	Block 30/3 - production licence 052. Awarded 1979.	
	Block 30/6 - production licence 053. Awarded 1979.	
Discovered	1981	
Development approval	02.06.1987 by Parliament	
On stream	26.12.1989	
Operator	Statoil ASA	
Licensees	Paladin Resources Norge AS	27.00%
	Petoro AS	37.00%
	RWE Dea Norge AS	13.50%
	Statoil ASA	18.00%
	Svenska Petroleum Exploration AS	4.50%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	56.1 million scm oil	10.9 million scm oil
	2.6 billion scm gas	0.5 billion scm gas
	1.1 million tonnes NGL	
Production	**Estimated production in 2005:**	
	Oil: 30,000 barrels/day	
Investment	Total investment is likely to be NOK 16.8 billion	
	NOK 16.0 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply bases	Sotra and Florø	

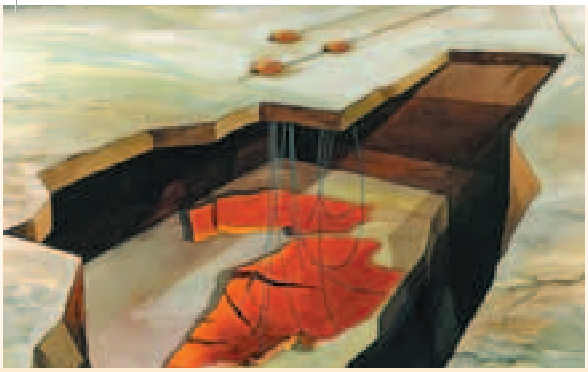
Development:
Veslefrikk is an oil field and is developed with two facilities. Veslefrikk is a steel facility with a drilling plant and bridge connection to Veslefrikk B, which processes the wellstream. Veslefrikk B is a converted drilling facility with processing facility and accommodation. The facility was upgraded in 1999 to receive condensate from the Huldra field. The PDO for the Veslefrikk field was approved on by Parliament on 02.06.1987. Production started 26.12.1989. The PDO for the Statfjord formation was approved on 11.06.1994. The PDO for the reservoir in Upper Brent and I areas was approved on 16.12.1994.

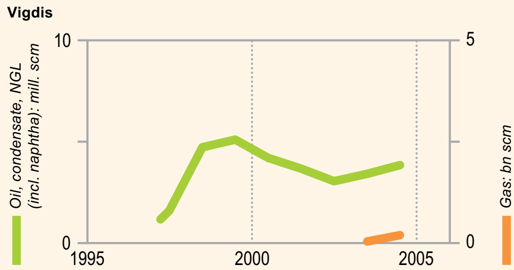
Reservoir:
The main reservoir consists of Jurassic sandstone in the Brent group, and is a raised fault block (horst). There are also reservoirs in the Intra Dunlin Sand and in the Statfjord formation.

Recovery strategy:
Pressure in the reservoir is supported by injection of water and gas.

Transport:
An oil pipeline is tied back to the Oseberg Transport System (OTS) for transport to the Sture terminal. Gas is transported through the Statpipe system.

Status:
Production from Veslefrikk is in the decline phase. Continual work is taking place to increase recovery for the field, including by drilling new wells and by distributing the gas injection optimally in the field. A pilot project to inject polymer gel into the reservoir, in order to reduce water flow into a production well, was carried out at the end of 2004.





Vigdis

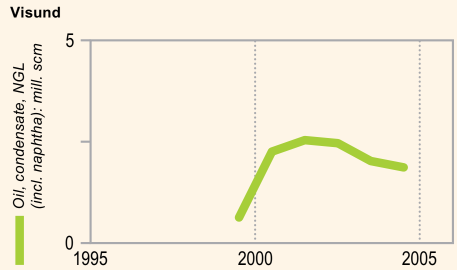
Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1986	
Development approval	16.12.1994 by the King in Council of State	
On stream	28.01.1997	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	13.28%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.80%
	Statoil ASA	28.22%
	Total E&P Norge AS	5.60%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	47.9 million scm oil	18.6 million scm oil
	1.2 billion scm gas	1.0 billion scm gas
	0.8 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 71,000 barrels/day Gas: 0.21 billion scm NGL: 0.13 million tonnes	
Investment	Total investment is likely to be NOK 10.8 billion	
	NOK 10.1 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Vigdis is an oil field that is located between the Snorre and Gullfaks fields in 280 metres of water. The field has been developed with subsea templates tied back to Snorre TLP. The wellstream is piped to Snorre TLP through two flowlines. Injection water is piped from Snorre TLP. Oil from Vigdis is processed in a dedicated processing module on Snorre TLP. The PDO for parts of Vigdis was approved on 16.12.1994. It came on stream on 28.01.1997. The PDO for the remaining parts of Vigdis, including discoveries 34/7-23 S, 34/7-29 S and 34/7-31, and the adjoining deposits (Vigdis Extension) was approved on 20.12.2002.

Reservoir:
The reservoirs consist of Mid-Jurassic sandstones in the Brent group. The field also contains reservoirs that consist of Early Jurassic and Late Triassic sandstones in the Statfjord formation, and sandstone reservoirs that are equivalent in time to the Late Jurassic Draupne formation. The reservoir in discoveries 34/7-23 S, 34/7-29 S and 34/7-31 consists of sandstones that are equivalent in time to the Draupne formation. The reservoirs are at a depth of 2200 - 2600 metres.

Recovery strategy:
Pressure is partially maintained using water injection.

Transport:
Stabilised oil from Vigdis is sent to Gullfaks A for storage and export. Gas from Vigdis is used for injection at Snorre.



Visund

Block and production licence	Block 34/8 - production licence 120. Awarded 1985.	
Discovered	1986	
Development approval	29.03.1996 by Parliament	
On stream	21.04.1999	
Operator	Statoil ASA	
Licensees at Visund	Norsk Hydro Produksjon AS	20.30%
	Norske ConocoPhillips AS	9.10%
	Petoro AS	30.00%
	Statoil ASA	32.90%
	Total E&P Norge AS	7.70%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	27.6 million scm oil	15.8 million scm oil
	52.2 billion scm gas	52.2 billion scm gas
	6.7 million tonnes NGL	6.7 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 33,000 barrels/day Gas: 0.43 billion scm NGL: 0.07 million tonnes	
Investment	Total investment is likely to be NOK 20.1 billion	
	NOK 16.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Bergen	
Main supply base	Florø	

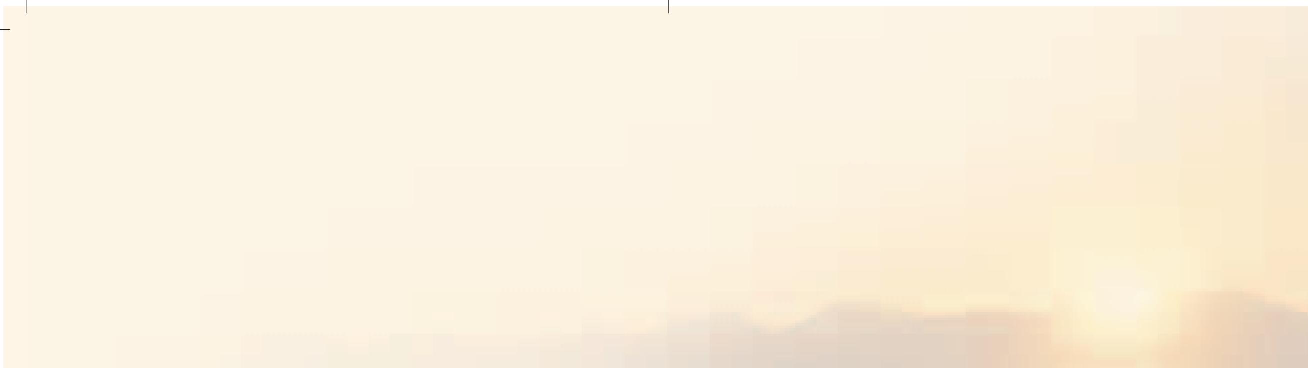
Development:
Visund is an oil field to the east of the Snorre field. The development includes a semi-submersible integrated steel accommodation, drilling and processing facility (Visund A). Visund A is in 335 metres of water. The northern section of Visund has also been developed with a subsea facility around 10 km to the north of Visund A. The PDO for the oil deposits at Visund was approved on 29.03.1996. The PDO for the gas deposits and the PIO for gas export were approved on 04.10.2002.

Reservoir:
Visund contains oil and gas in several inclined fault blocks with several separate pressure and fluid systems. Oil and gas are found in Jurassic and Triassic sandstones.

Recovery strategy:
Recovery is driven by gas injection, water is also injected into one of the reservoirs. From the autumn of 2005, some of the gas produced will be exported.

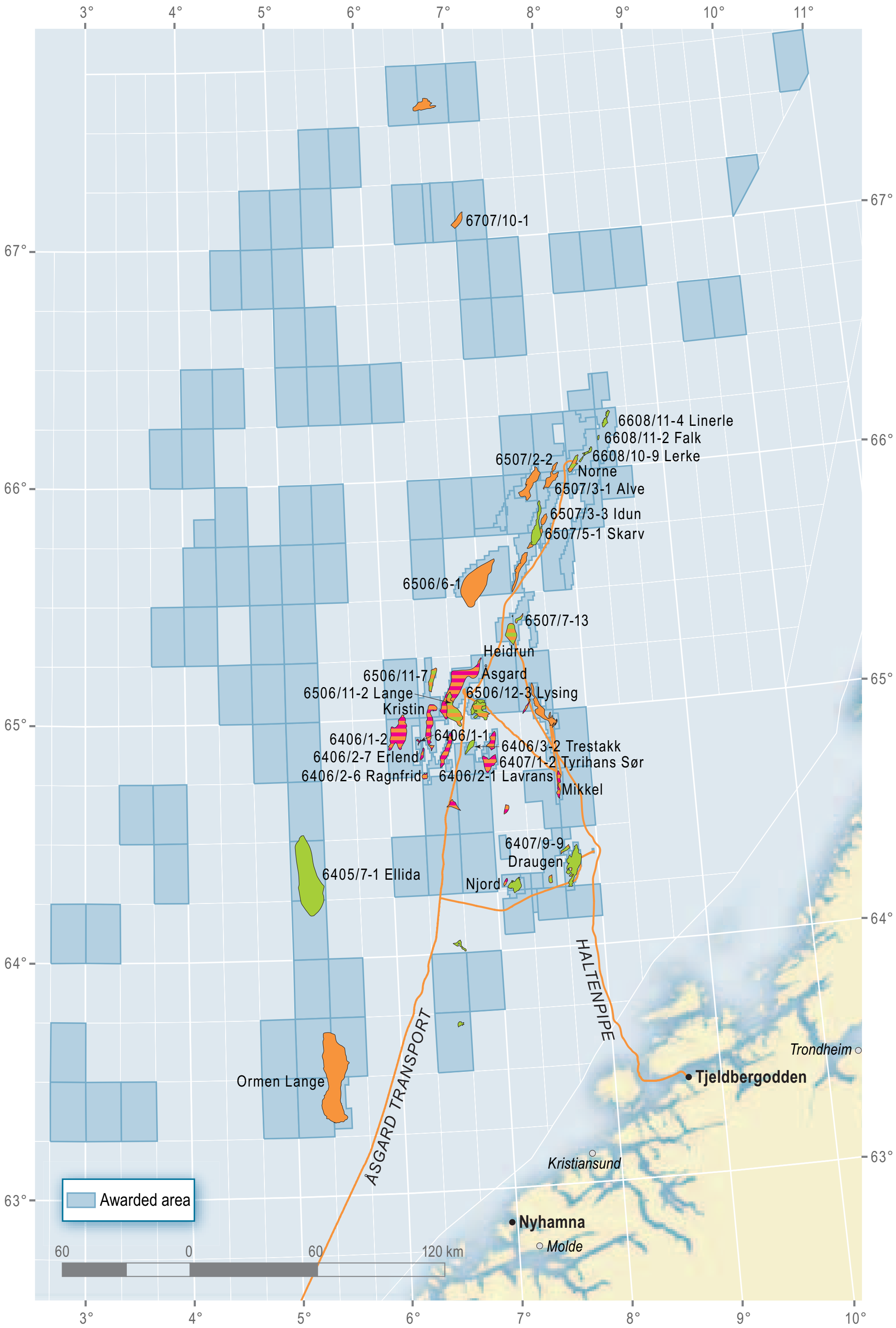
Transport:
The oil is piped to Gullfaks A, for storage and export with the oil from Gullfaks. The gas will be exported in a new pipeline to the Kvitebjørn gas pipeline and transport to Kollsnes. At Kollsnes, NGL is separated for onward transport of gas to the market.

Status:
According to the plans, gas export will commence on 1.10.2005.

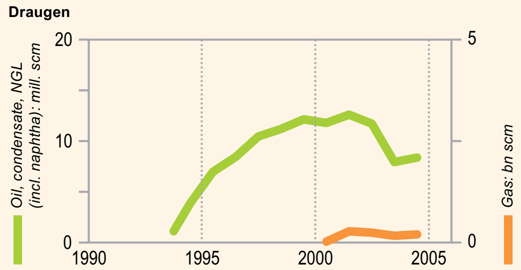


Norwegian Sea

The Norwegian Sea was opened for exploration in connection with the fifth licensing round in 1979. In the autumn of 1988, it was decided that the Draugen oil field would be the first Norwegian Sea discovery to be developed, and it came on stream in October 1993. Heidrun, Njord, Norne, Åsgard and Mikkel have since started production, while a plan for development and operation (PDO) for Kristin was approved in 2001. This region also contains substantial gas resources, including the Ormen Lange field, for which development approval was given in 2004.



The Norwegian Sea



Draugen

Block and production licence	Block 6407/9 - production licence 093. Awarded 1984.	
Discovered	1984	
Development approval	19.12.1988 by Parliament	
On stream	19.10.1993	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	26.20%
	BP Norge AS	18.36%
	ChevronTexaco Norge AS	7.56%
	Petoro AS	47.88%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	131.4 million scm oil	28.2 million scm oil
	1.5 billion scm gas	0.6 billion scm gas
	2.3 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 110,000 barrels/day Gas: 0.19 billion scm NGL: 0.24 million tonnes	
Investment	Total investment is likely to be NOK 25.5 billion	
	NOK 24.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

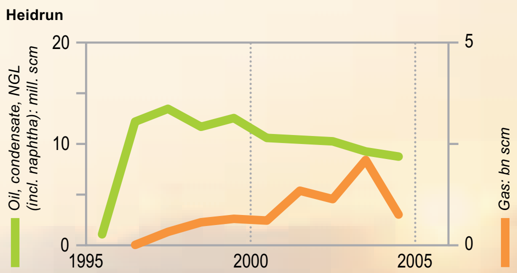
Development:
Draugen is an oil field in 250 metres of water. The field has been developed with a concrete fixed facility (monotower) supporting an integrated topside. The oil is processed at the facility and stabilised oil is stored in tanks in the base of the facility. Two flowlines link the facility to a floating loading buoy. The Garn Vest and Rogn Sør deposits have been developed with a total of five subsea wells and tied back to the main facility at Draugen. The field has six subsea water injection wellheads. The PDO for Draugen was approved on 19.12.1988. The field came on stream on 19.10.1993. Additional resources in the Garn Vest structure came on stream in December 2001, while development of additional resources at the Rogn Sør structure were approved in the spring of 2001, coming on stream in January 2003.

Reservoir:
The main reservoir consists of Late Jurassic sandstones in the Rogn formation. The Garn formation in the west of the field is also on stream. The reservoir is relatively homogenous, with good reservoir characteristics.

Recovery strategy:
Pressure in the field is maintained using water injection.

Transport:
The oil is exported via a floating loading buoy to tankers. Since November 2000, associated gas has been delivered through the Åsgard Transport pipeline for onward transport to Kårstø.

Status:
It is expected that production will fall from plateau in 2005, and that the quantity of produced water will increase significantly. Various measures to increase recovery are being considered. A pilot project for reinjection of the produced water is underway, and permanent full-scale reinjection will be considered when results are available. 4D-seismics to survey remaining resources and relevant drilling targets are being acquired.



Heidrun

Blocks and production licences	Block 6507/8 - production licence 124. Awarded 1986. Block 6707/7 - production licence 095. Awarded 1984.	
Discovered	1985	
Development approval	14.05.1991 by Parliament	
On stream	18.10.1995	
Operator	Statoil ASA	
Licensees in Heidrun	Eni Norge AS Norske ConocoPhillips AS Petoro AS Statoil ASA	5.12% 24.31% 58.16% 12.41%
Recoverable reserves	**Original:** 175.0 million scm oil 40.7 billion scm gas 2.9 million tonnes NGL	**Remaining as at 31.12.2004** 75.5 million scm oil 33.2 billion scm gas 2.6 million tonnes NGL
Production	**Estimated production in 2005:** Oil: 142,000 barrels/day Gas: 0.46 billion scm NGL: 0.08 million tonnes	
Investment	Total investment is likely to be NOK 61.5 billion NOK 52.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
The Heidrun field is located on the Halten bank off mid-Norway in 350 metres of water, and has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with seabed facilities. The PDO for Heidrun was approved on 14.05.1991. The field came on stream on 18.10.1995. The PDO for the Heidrun northern flank was approved on 12.05.2000.

Reservoir:
The reservoir consists of Early and Mid-Jurassic sandstones. The structure is heavily faulted.

Recovery strategy:
Pressure in the field is maintained using water injection, as well as injection of excess gas.

Transport:
Heidrun oil is transferred to tankers at the field. The oil is shipped to Mongstad and Tetney (UK). The gas is piped to Tjeldbergodden and Kårstø.

Status:
The plant for reinjection of produced water has shown good regularity since upstart in 2003.
There is great potential for increased oil recovery and huge prospect possibilities. Active efforts are been made to find methods that can contribute to increasing the degree of recovery, as well as discover new deposits.

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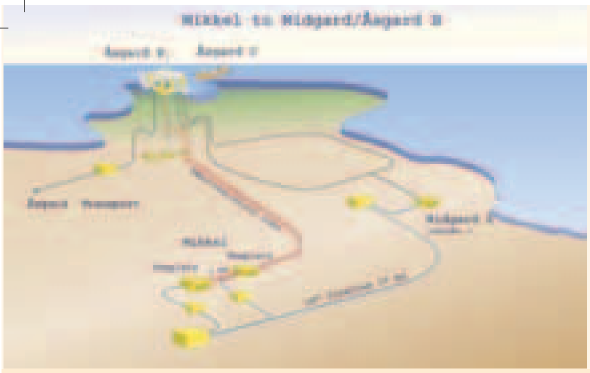
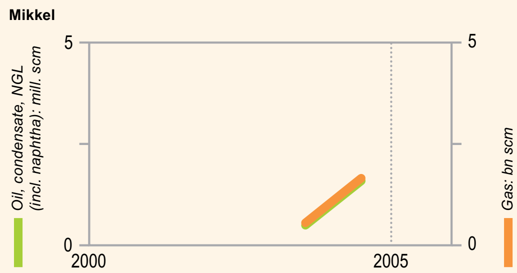




Mikkel

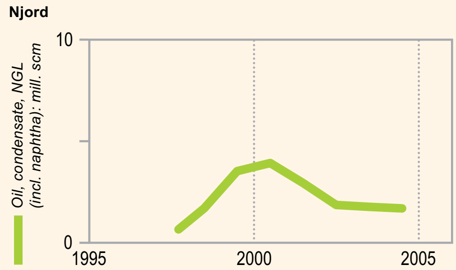
Blocks and production licences	Block 6407/5 - production licence 121. Awarded 1986.	
	Block 6407/6 - production licence 092. Awarded 1984.	
Discovered	1987	
Development approval	14.09.2001 by the King in Council of State	
On stream	01.08.2003	
Operator	Statoil ASA	
Licensees in Mikkel	Eni Norge AS	14.90%
	Mobil Development Norway AS	33.48%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	33.97%
	Total E&P Norge AS	7.65%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	24.1 billion scm gas	22.0 billion scm gas
	6.0 million tonnes NGL	5.4 million tonnes NGL
	6.6 million scm condensate	5.7 million scm condensate
Production	**Estimated production in 2005:**	
	Gas: 1.74 billion scm NGL: 0.44 million tonnes Condensate: 0.69 million scm	
Investment	Total investment is likely to be NOK 2.1 billion	
	NOK 1.9 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Mikkel is a gas field that lies to the east of the Halten bank around 40 km south of Åsgard and 40 km north of Draugen in 220 metres of water. The field consists of a subsea facility with two well templates. The wellstream from the Mikkel field is led through a well template at 6507/11-1 Midgard to Åsgard B, where it is separated and processed.

Reservoir:
The reservoir consists of Mid-Jurassic sandstone in six structures, separated by faults.

Recovery strategy:
Depletion is used for recovery.

Transport:
From Mikkel, the wellstream flows to the Åsgard B facility for processing. Condensate is separated from the gas on Åsgard B. The separated condensate is stabilised on Åsgard B before it is exported from the field together with Åsgard's own condensate. The rich gas is piped through the Åsgard Transport pipeline to Kårstø for separation of the wet gas components. The dry gas is transported on from Kårstø to the Continent through the Europipe II pipeline.



Njord

Blocks and production licences	Block 6407/10 - production licence 132. Awarded 1987.	
	Block 6407/7 - production licence 107. Awarded 1985.	
Discovered	1986	
Development approval	12.06.1995 by Parliament	
On stream	30.09.1997	
Operator	Norsk Hydro Produksjon AS	
Licensees in Njord	E.ON Ruhrgas Norge AS	15.00%
	Endeavour Energy Norge AS	2.50%
	Gaz de France Norge AS	20.00%
	Mobil Development Norway AS	20.00%
	Norsk Hydro Produksjon AS	20.00%
	Paladin Resources Norge AS	15.00%
	Petoro AS	7.50%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	25.6 million scm oil	7.8 million scm oil
	8.7 billion scm gas	8.7 billion scm gas
	1.4 million tonnes NGL	1.4 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 31,000 barrels/day	
Investment	Total investment is likely to be NOK 12.5 billion	
	NOK 10.8 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

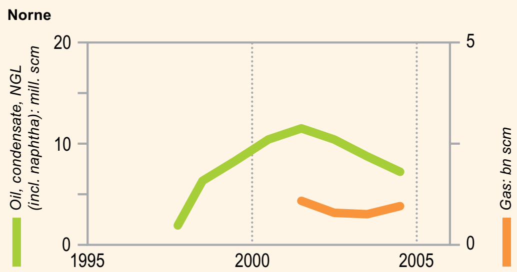
Development:
Njord is an oil field that is located around 30 km west of Draugen in 330 metres of water, which has been developed with a steel semi-submersible drilling, accommodation and production facility. The facility is located over the field's subsea completed wells, which are tied back to the facility through flexible risers. The Plan for Development and Operation (PDO) for the Njord field was approved on 12.06.1995. The PDO and Plan for Installation and Operation (PIO) for Njord gas export were submitted to the authorities on 15.11.2004.

Reservoir:
The reservoir consists of Jurassic sandstones in the Tilje and Ile formations. The field has a complicated fault pattern with only partial communication between the segments.

Recovery strategy:
Most of the gas that is produced at Nord is reinjected on the east flank for pressure support and increased oil recovery from this part of the field. The western and northern segments produce using depletion.

Transport:
The oil is offloaded from the storage vessel, Njord B, to tankers for transport to the market.

Status:
Production from Njord is in the decline phase. At the end of 2004, a new drilling and intervention campaign to increase oil recovery was initiated. Gas export is planned to begin on 01.10.2007.



Norne

Blocks and production licences	Block 6508/1 - production licence 128 B. Awarded 1998.	
	Block 6608/10 - production licence 128. Awarded 1986.	
Discovered	1992	
Development approval	09.03.1995 by Parliament	
On stream	06.11.1997	
Operator	Statoil ASA	
Licensees in Norne	Eni Norge AS	6.90%
	Enterprise Oil Norge AS	6.00%
	Norsk Hydro Produksjon AS	8.10%
	Petoro AS	54.00%
	Statoil ASA	25.00%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	88.5 million scm oil	25.9 million scm oil
	13.8 billion scm gas	10.2 billion scm gas
	2.5 million tonnes NGL	2.1 million tonnes NGL
Production	**Estimated production in 2005:**	
	Oil: 100,000 barrels/day Gas: 1.21 billion scm NGL: 0.15 million tonnes	
Investment	Total investment is likely to be NOK 19.5 billion	
	NOK 16.4 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

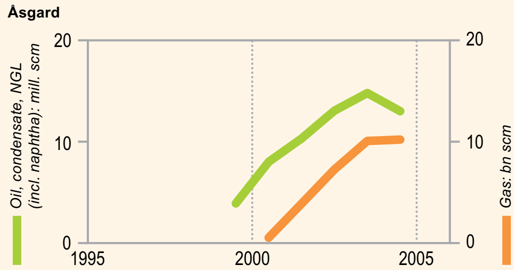
Development:
Norne is an oil field located around 80 km north of the Heidrun field and around 200 km from the Helgeland coast in about 380 metres of water. The field has been developed with a production and storage vessel tied back to five wellhead templates. Flexible risers carry the wellstream up to the vessel. The vessel carries processing facilities and tanks for oil storage before being transferred to shuttle tankers. The Norne vessel does not carry drilling and completion equipment.

Reservoir:
The Norne field consists of two separate segments. The oil and gas at Norne is contained in Jurassic sandstone in the Fangst and Båt groups. Oil is mainly found in the Ile and Tofte formations, gas in the Garn formation. The reservoir is 2,525 metres deep at its shallowest.

Recovery strategy:
The oil is recovered using water and gas injection.

Transport:
The oil is transferred to shuttle tankers for transport. Gas export started in February 2001 through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Around 70 percent of estimated reserves have now been produced, and production has fallen from plateau, mainly because of increased water production. Various measures to increase recovery have been implemented, including Microbial Enhanced Oil Recovery (MEOR). The potential for further increases in recovery will lie in strategies such as efficient well solutions and optimum use of gas at the field.



Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B. Awarded 2002.	
	Block 6407/2 - production licence 074. Awarded 1982.	
	Block 6407/3 - production licence 237. Awarded 1998.	
	Block 6506/11 - production licence 134. Awarded 1987.	
	Block 6506/12 - production licence 094. Awarded 1984.	
	Block 6507/11 - production licence 062. Awarded 1981.	
Discovered	1981	
Development approval	14.06.1996 by Parliament	
On stream	19.05.1999	
Operator	Statoil ASA	
Licensees in Åsgard	Eni Norge AS	14.90%
	Mobil Development Norway AS	7.35%
	Norsk Hydro Produksjon AS	9.60%
	Petoro AS	35.50%
	Statoil ASA	25.00%
	Total E&P Norge AS	7.65%
Recoverable reserves	**Original:**	**Remaining as at 31.12.2004**
	73.6 million scm oil	32.7 million scm oil
	195.3 billion scm gas	163.4 billion scm gas
	38.3 million tonnes NGL	33.0 million tonnes NGL
	46.2 million scm condensate	34.7 million scm condensate
Production	**Estimated production in 2005:**	
	Oil: 102,000 barrels/day Gas: 10.84 billion NGL: 2.0 million tonnes	
	Condensate: 4.06 million scm	
Investment	Total investment is likely to be NOK 59.1 billion	
	NOK 55.7 billion had been invested as at 31.12.04 (2005 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Åsgard is in 240 – 300 metres of water and has been developed with subsea completed wells linked to a production and storage vessel, FPSO (Åsgard A), for production and storage of oil, and a floating, semi-submersible facility (Åsgard B) for gas and condensate processing. The gas centre is tied back to a storage vessel for condensate (Åsgard C). The Åsgard facilities are an important part of the Norwegian Sea infrastructure. In addition to processing their own production, the facilities process gas from Mikkel. The Åsgard field has been developed in two phases. The fluids phase came on stream on 19.05.1999 and the gas export phase from 01.10.2000. The field includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard.

Reservoir:
6506/12-1 Smørbukk is located on a rotated fault block, bordered by faults in the west and north and structurally deeper areas to the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are Jurassic and contain gas, condensate and oil with a relatively high gas/oil ratio. The reservoir is at depths down to 4,850 m. 6506/12-3 Smørbukk Sør, with reservoir rocks in the Garn, Ile and Tilje formations, is from the Early to Mid-Jurassic period and contains oil, gas and condensate. The petroleum trap in 6507/11-1 Midgard is a standing fault block (horst). The Midgard discovery is divided into four structural segments with the main reservoir in the Mid-Jurassic Garn and Ile formations.

Recovery strategy:
Recovery from 6506/12-1 Smørbukk and 6506/12-3 Smørbukk Sør uses gas injection. 6507/11-1 Midgard uses depletion. There is a thin oil zone (11.5 m) below the gas cap at 6507/11-1 Midgard, which is not commercially viable to produce.

Transport:
Oil and condensate are temporarily stored at the field and shipped to the mainland by shuttle tankers. The gas is exported through a gas pipeline (Åsgard Transport) from Åsgard to Kårstø.

Status:
Most of the production wells have been drilled, and active efforts are being made to increase recovery from the field.

Fields which have ceased production

The following fields had ceased to produce at 31 December 2004:

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
On stream	26.05.1979
Production ceased	26.08.1998
Total production over field lifetime	Oil: 7.4 million scm Gas: 15.5 billion scm NGL: 1.0 million tonnes

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
On stream	26.12.1977
Production ceased	05.08.1998
Total production over field lifetime	Oil: 2.9 million scm Gas: 7.3 billion scm NGL: 0.5 million tonnes

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and in Report no. 47 (1999–2000) to the Parliament
On stream	02.12.1979
Production ceased	05.08.1998
Total production over field lifetime	Oil: 4.8 million scm Gas: 2.0 billion scm NGL: 0.2 million tonnes

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 26 September 2003, and in Parliamentary Bill no. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Total production over field lifetime	Gas: 116.2 billion scm Condensate: 0.5 million scm

Frøy

Block	25/2 and 25/5
Development approval	18.05.1992
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 29 May 2001, and in Report no. 47 (1999–2000) to the Parliament
On stream	15.05.1995
Production ceased	05.03.2001
Total production over field lifetime	Oil: 5.6 million scm Gas: 1.6 billion scm Condensate: 0.1 million scm

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/Decommissioning	Parliamentary Bill no. 53 (1999–2000) and Report no. 47 (1999-2000) to the Parliament
On stream	13.05.1994
Production ceased	25.03.1999
Total production over field lifetime	Oil: 1.3 million scm Gas: 2.2 billion scm

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/Decommissioning	Parliamentary Bill no. 15 (1996–1997) and Report no. 47 (1999–2000) to the Parliament
On stream	25.10.1990
Production ceased	04.11.1993
Total production over field lifetime	Oil: 0.4 million scm Gas: 0.1 billion scm

Nordøst Frigg

Block	25/1 and 30/10
Development approval	12.09.1980
Cessation plan/Decommissioning	Parliamentary Bill no. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Total production over field lifetime	Gas: 11.6 billion scm

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/Decommissioning	Parliamentary Bill no. 50 (1995–1996) and Report no. 47 (1999–2000) to the Parliament
On stream	01.04.1984
Production ceased	01.08.1994
Total production over field lifetime	Gas: 27.3 billion scm Condensate: 0.2 million scm

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/Decommissioning	Parliamentary Bill no. 53 (1999–2000) and Report no. 47 (1999–2000) to the Parliament
On stream	03.10.1988
Production ceased	05.08.1998
Total production over field lifetime	Oil: 3.9 million scm Gas: 9.7 billion scm NGL: 0.6 million tonnes

Vest Ekofisk

Block	2/4
Development approval	04.05.1973
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 21 December 2001, and Report no. 47 (1999-2000) to the Parliament
On stream	31.05.1977
Production ceased	25.08.1998
Total production over field lifetime	Oil: 12.2 million scm Gas: 26.0 billion scm NGL: 1.4 million tonnes

Yme

Block	9/2 and 9/5
Development approval	06.01.1995
Cessation plan/Decommissioning	The cessation plan was approved by Royal Decree on 4 May 2001.
On stream	27.02.1996
Production ceased	17.04.2001
Total production over field lifetime	Oil: 7.9 million scm

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/Decommissioning	Parliamentary Bill no. 8 (1998–1999) and Report no. 47 (1999–2000) to the Parliament
On stream	01.10.1988
Production ceased	22.12.1997
Total production over field lifetime	Gas: 9.2 billion scm Condensate: 0.1 million scm