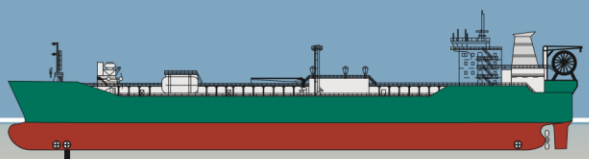
Plan for utbygging og drift av Volve

Utvinningstillatelse 046

February 2005

Plan for Development and Operation by Volve

Production license 046



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Contents

1 Introduction and summaries

This report presents the Plan for Development and Operation (PDO) for the Volve field in block 15/9, Production license 046 (PL046). The report summarizes results from studies, analysis and tenders that have led up to the recommended bid solution. The decision-making team is described in greater detail in support volumes in geology, reservoir, manufacturing, engineering, drilling and concept description as well as in an impact assessment that has been submitted to the authorities. This chapter provides a brief summary of the PUD for Volve field.

1.1 Location and ownership

1.1.1 Location

Volve is an oil field located in block 15/9 about 200 km west of Stavanger and about 8 km north of the Sleipner A platform, see Figure 1.1. The water depth in the area is approx. 90 m.

Oil fields and discoveries are marked with green while gas/condensate is shown in red

1.1.2 License Conditions

Production license 046 was awarded in the third licensing round 1976 with Statoil ASA as operator for blocks 15/8 and 15/9. The license includes Sleipner East, Sleipner Vest, Gugne and Loke fields as well as non-commercial area (defined as PL 046 "outside").

The distribution of ownership at Volve is the same as for Sleipner Øst and Loke, while much of the upside potential around Volve lies in the "outside" area that has the same ownership distribution as the Gungne field, see Figure 1.2 and Table 1.1

Figure 1.1 - Site Map

	Sleipner East/ Loki /Volve	PL046 Outside (Incl. Gungne)
Statoil ASA	49.6 %	52.6 %
ExxonMobil Exp.& Prod. Norway AS	30.4 %	28.0 %
Norwegian Hydro Production a.s.	10.0 %	9.4 %
Total Norway AS	10.0 %	10.0 %

Table 1.1 - Owner composition in PL 046 and Volve

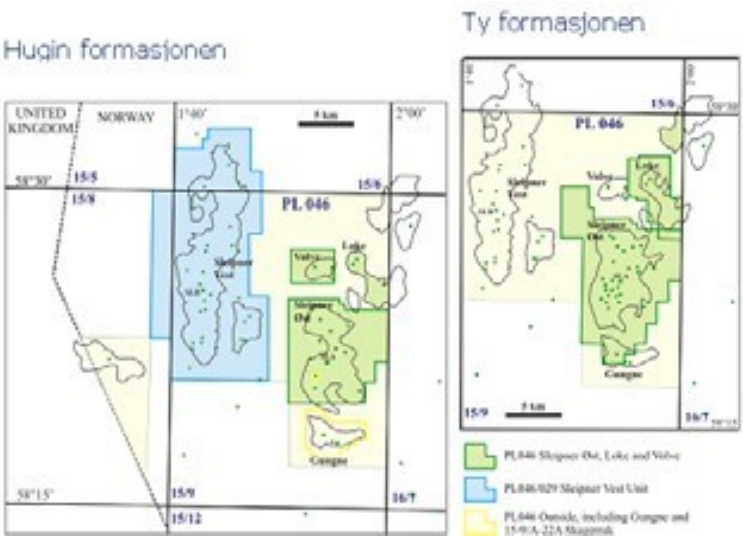

Figure 1.2 - Overview of PL 046 site with area definition at Ty and Hugin level

1.2 Exploration history

The Volve field is a smaller oil-bearing structure that is central to block 15/9. Well 15/919SR detected oil in 1993 in the structure and since then 2 appraisal wells have been drilled. Well 15/9-19A was drilled in 1996 and detected a much thicker reservoir than the discovery well. Well 15/9-19B was drilled in 1997 in a segment off the field and here the reservoir was water-filled. Both wells in the oil zone have been production tested and showed good production properties.

1.3 Geological evaluation

The Volve field is a 2x3 km, fault-limited structure where a total of 27.5 million Sm^3 is expected to be found. The reservoir is made up of the Hugin formation of the middle Jurassic age and is in the area developed as a sandstone package of varying thickness. The reservoir is located in the range 2750 – 3120 m depth below the sea surface. It consists of sandstone with a high net/gross ratio (93%), a 21% porosity and a well test permeability of about 1 Darcy. Water saturation in the oil zone is an average of 20%. No contacts have been penetrated in the field, which provides opportunities for an oil-water contact (OWC) significantly deeper than what is used in the base model (OWC of 3120 m below sea level).

The mapping of the field is based on seabed seismic data where the following reflectors have been interpreted; intra Hod, Bottom Chalk, Bottom "Hot shale", Top Hugin, Bottom Hugin, and Top Zechstein. In addition, the many faults have been detailed interpreted.

There is still uncertainty related to the interpretation of seismic data, especially this applies to the western flank of Volve. In retrospect, the work underlies this plan has been carried out further re-processing of the seabed seismic. These data will be interpreted, and any adjustments to the reservoir model and optimization of well paths will be made before drilling start.

1.4 Reservoir technical and extraction conditions

In the reservoir technical work, a dynamic reservoir simulation model based on the geological and seismic mapping is used. Reservoir pressure is 340 bar at 3060 m and reservoir temperature is here 110°C. The oil has a varying gas/oil ratio (GOF) from 111 to 157 Sm^3/Sm^3 and equivalent for the formation volume factor (Bo) from 1.33 to 1.45 m^3/Sm^3. The oil in the field is planned to be extracted using water injection with production wells placed high on the structure.

It is expected to produce a total of about 11.4 million Sm^3 oil and 1.5 billion Sm^3 rich gas for export to the Sleipner A platform. This is based on an economic rate of at least 2100 Sm3/d.

1.5 Production technology

The technical challenges of producing the oil in Volve fields are linked to the high content of Barium in the formation water, high content of the asphalt in the oil as well as production of water from the Utsira formation using electric pumps, ESP (Electrical Submersible Pumps). Utsira water is used to avoid deposits in the formation and process equipment.

1.6 Drilling and well technology

The Volve field is planned to develop with three oil production wells and three water injection wells. In addition, two water production wells are planned to drill for the Utsira formation for the production of injection water.

The planned drilling start-up at Volve is year-end 2006/07. There is a risk of delayed start-up due to the possible delay with tow of installation in the winter.

Volve will have valve trees on the platform and have available drilling facilities during the production phase. This will provide easy access to the wells for interventions, sidestep drilling or drilling to nearby prospects.

The three production wells are planned to be completed with gas lifting equipment. The drilling location is chosen to minimize the risk of shallow gas, as well as providing drilling access to all identified prospects for Volve.

Drilling is planned with water-based mud in the top hole sections, and with oil-based mud in the 8" and 12" sections.

1.7 Development solution

The development solution (see Figure 1.2) is based on the rental of the existing jack-up platform Maersk Inspirer (MI) which is built as a drilling rig. The platform will be equipped with a processing plant for the separation and export of oil and gas and a wellhead area that allows to pull up to 13 wells according to the contract that underlies this plan. The platform enables drilling or well intervention with simultaneous oil and gas production. The rig was completed at a shipyard in Korea in 2004, and has arrived in the North Sea. It will start on a contract on the English side before the Volve contract. The rig will thus be considered as "hot" and run-in as a drilling rig when it starts work at Volve.

The gas will be exported to Sleipner A while the oil will be exported to the navion saga warehouse ship.

The processed oil will be transferred to the storage ship via a flexible 8" pipe. The warehouse ship, with a capacity of 1 mill barrels,

Figure 1.2 - Volve development concept

The processing system on the jack-up platform is designed for the following capacities.

Oil production	9.000 Sm^3/d	Rich gas	1.5 MSm3/d
Water treatment	10.400 m^3/d	Gas lift	0.45 MSm3/d
Total fluid treatment	13.000 m^3/d	Water injection	16.000 m3/d

is anchored on the field using an Submerged Turret Loading (STL) buoy with 9 anchors. The ship is rented from Navion Offshore Loading (NOL), a subsidiary of Teekay Norway.

The gas is transferred in a 7.4" pipeline via subsea frame D on the Sleipner East field and further into the SLA facilities. There, the gas is processed and exported as dry gas to Europe and wet gas/condensate to Kårstø.

1.8 Operation and maintenance

Operation and maintenance of the production platform will be carried out by Maersk Contractors as the owner and operate the plant on behalf of Statoil as operator of PL046. Operation and maintenance of the warehouse ship is carried out by Teekay Norway.

The supply and base services will be coordinated with similar services in the Sleipner fields so that economies of scale are achieved.

1.9 Health, Safety and Environment

The development and operation of Volve is based on the main objectives of Statoil's HSE poster and principles for zero environmentally harmful emissions.

The safety objective for the Volve development is based on the requirements and regulations of the authorities, as well as in Statoil's own guidelines.

The consideration of health, the environment and the environment (HSE) has been central to checking out the requested concept and the choice of suppliers, and forms the basis for further watching activities.

Great emphasis has been placed on safe, prudent solutions and limiting the consequences in the event of an accident. The installation staffing consists of Maersk Contractor's own employees. Maersk Contractors management systems are based as much as possible, filled in with Statoil's field specific additional requirements. Statoil attaches great importance to establishing good HSE work on board, and to ensure that the requirements and objectives of the authorities and Statoil for health, safety and safety is fulfilled.

1.10 Organization and implementation

The exercise of Statoil's operatorship in the development phase will be taken care of by a dedicated organizational unit within the Technology and Projects (T&P) business area.

It will be close cooperation with the Sleipner organization throughout the project industry as pl046 license responsibility is there. The production director for Sleipner is chairman of the steering committee for PL046.

At the start of production, the plan is to transfer Volve to Sleipner operating organization in the Exploration and Production business area.

1.11 Closing Schedule

Once the licensees and the authorities agree that the Volve field can no longer be operated financially, the contracts will be terminated using agreed mechanisms for cancellation and the wells will be closed. The actual removal of the installations and the closure of wells will be carried out in accordance with applicable regulations. The regulations provide guidelines for both the shutdown of wells and the removal of the installations.

STL buoy with anchoring will be removed using an anchor handling vessel. The oil and gas export pipelines will be considered removed. Due to the fact that the pipes are buried, this can be difficult. Alternative to removal and reuse will be to stone dump the roughs.

1.12 Economic analyses and Assessments

Profitability analysis based on 22 USD/barrel oil price Brent Blend (estimated 18.70 USD/barrel for Volve oil) provides a present value of 2350 MNOK 2005 at 7% before tax and 443 MNOK 2005 at 8% after tax. Where one assumes a "forward" oil price of an average of 35 USD/barrel Brent dazzle, the profitability analysis shows a present value of 1190 MNOK 2005 by 8% after tax.

The project is not robust with low prices and provides negative present value at an oil price

of 15 USD/barrelBrent Blend. The zero point price at 8% after tax is USD 17.50/barrel. The development concept with the rental of a jack-up platform with associated warehouse ships provides a positive economy at low reserves (P90). In addition, the risk of cost overruns is reduced due to the fact that large parts of the concept have already been built.

1.13 Site Rating

Volve field is located in a typical gas/condensate dominated area of the North Sea. In an area development, the selected development solution is considered to be the best solution because an oil processing plant has been established in the Volve area. Access to its own drilling facility also allows for cost-effective exploration of oil prospects in the area.

There are no documented concepts that can economically exploit existing infrastructure in the council with the exception of gas exports to the Sleipner A platform via the Sleipner D bottom frame.

The platform is designed to draw up more wells if discoveries are made in any of the mapped prospects in the surrounding area. A position will be taken on any drilling of the nearby prospects in PL 046 at a later date.

2 Exploration history

The Volve field is a smaller oil-bearing structure that is central to block 15/9. The block was awarded in the third license allocation round (1976). In the block there are a total drilled 22 exploration- and appraisal wells and large amounts of gas/condensate are detected in Sleipner West, Sleipner East, Loki and Gungne fields. The gas/condensate fields have now been developed and about 50 production wells have been drilled for this purpose.

The Volve field was detected in 1993 with well 15/9-19SR. The well was drilled from Loke seabed frame into a structure then called Theta Vest.

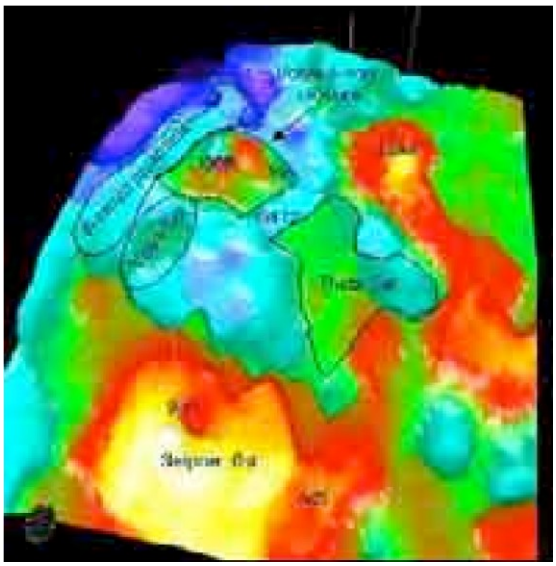

Figure 2.2 - Bottom Hugin horizon with Volve structure and main prospects recorded

Table 2.1 - Discovery wells and discoveries are listed including:

Well	Years	Discoveries	Condensate / NGL / oil reserves (MSm^3)	Gas reserves (GSm^3)
15/6-3	1974	Sleipner Vest	44	108
15/9-9	1981	Sleipner East	51	63
15/9-15	1982	Gungne	5	10
15/9-19SR	1993	Volve	11.4	1.5

The purpose of the well was to produce gas/condensate from the Heimdal formation [of the Paleocene age]. However, the formation turned out to be water-filled and the well was then drilled into the Hugin formation of the Mid-Jurassic age.

The Hugin formation turned out to be oil filled and had a thickness of 18 meters in the well. The reservoir was production tested and provided a unsaturated 29^0 API oil. The test interval showed good production characteristics and flowed at rates up to 1358 Sm3/d and a productivity index of 143 Sm3/D/Bar.

One new seismic dataset was collected over the site in 1994 (ST9407) and since reprocessed.

In 1996, well 15/9-19A was drilled. The purpose of the well was to verify the resource base, clarify the reservoir thickness and oil/water contact. The well was drilled as a side branch well from 19SR and encountered oil-filled reservoir. However, the reservoir came in significantly deeper than expected and was much thicker (88 m). No oil/water contact was observed in the well. A production test gave rates up to 528 Sm3/d of 27^0 API oil and with a productivity index of 63 Sm^3/D/Bar.

Based on the positive information from the 15/19-19A well, the top reservoir was reinterpreted on the seismic. The understanding at the time was that this well had detected oil close to the spill point between the Volve structure and Theta south structure southeast of Volve.

In 1997, well 15/9-19B was therefore drilled in the saddle area between the two structures. The purpose of the well was to find the oil/water contact and also detect oil in Theta South. However, the top reservoir was hit very deep in the well and was water-filled. However, the thickness of the Hugin formation is greater than expected (about 120 m) and had good porosity and permeability properties. Pressure measurements indicate sealing between the well and Volve structure and also between the well and Sleipner East and Loki so that 15/19-19B gave a good eastern demarcation of Volve structure.

The collection of subsea data was done in 2002 (ST0202). The purpose was to improve the structural imaging and reduce uncertainty of the resource base. The dataset has provided a major improvement compared to the past and forms the basis for the current mapping of resources.

3 Geological evaluation

3.1 Summary

The Volve field is a 2x3 km large, fault-limited structure and is formed as a result of salt movements and stretching during and immediately after the deposition of the reservoir. The reservoir is made up of the Hugin formation of the middle Jurassic age and is in the area developed as a package of mainly sandstone. The deposition environment was tidal-dominated which has resulted in a large lateral extent of the sandstone layers. Oil has only about 5-10 million years ago begun to migrate into the structure. The oil has been formed in the Sleipner Graben area about 10 km NV for Volve and migrated from the graben into the Volve structure.

The mapping of the field is based on new seabed seismic. Depth conversion is carried out based on "stacking" speeds to top Chalk, and interval speeds in the following intervals, top Chalk-bottom Chalk, bottom Chalk top Hugin, and top Hugin -bottom Hugin. The uncertainty of the interpretation especially on the western flank of the structure is significant, while the field is only to a small extent affected by the uncertainty of the depth conversion model.

Reservoir interval is 2750 – 3120 m depth below the sea surface. It consists of sandstone with a high net/gross ratio (93%), a 21% porosity and a well test permeability of about 1 Darcy. Water saturation in the oil zone is an average of 20%. This gives an average hydrocarbon pore fraction of 15.6%. which gives the possibility of an oil water contact significantly deeper than what is now considered most likely (OWC of 3120 m below sea level).

Mapping of the present volume has been carried out in a 14 layer model with the use of zone averages adapted to well values. The layer model is based on the top and bottom reservoir surfaces from the seismic as well as mapped fault plans. The outer, limiting faults on the field are modeled as oblique, while faults internally on the field are modeled as vertical. Possible additional volume west of Volve and Volve South has been incorporated into the volume calculation, while volume in other prospects is calculated in other contexts.

An uncertainty study indicates higher P50 and average volume than the base model. This is mainly due to the fact that deeper contact is more likely than shallower contact. As regards the total uncertainty, contact uncertainty is the largest impact, but one also has a significant contribution from the uncertainty of seismic interpretation. As a result of this uncertainty, depth-migrated data has been processed, and will be used for optimizing the well location leading up to the start of drilling. In the reservoir technical work it used a dynamic reservoir simulation model based on the geological and seismic mapping. Reservoir pressure is 340 bar at 3060 m and reservoir temperature is 110°C. The oil has a varying gas/oil ratio (GOR) from 111 to 157 Sm^3/Sm^3 (corrected for process simulations) and corresponding for the formation volume factor (Bo) from 1.33 to 1.45 m^3/Sm^3.

Table 3.1 - Uncertainty in the present volume (all figures in mill. Sm^3)

	Basis	Average	P90	P50	P10
Volve	24.5	27.5	20.9	26.7	35.2

3.2 Seismic database and mapping

The seismic interpretation of the Volve field is completed on a 4 component, 3D seismic dataset (ST0202), which is a subsea seismic data collection with significantly increased quality compared to regular seismic . ST0202 has limited coverage and in the areas outside the used ST98M3, a common 3D seismic dataset, which is a "post stack" composition of a total of 7 individual seismic datasets. The area's coverage with seismic is shown in Figure 3.1. A zero phase, trapezoid-wave signature is used to calibrate seismic with the well observations.

The Volve structure is structurally complex and the geological evaluation has been necessary to map the main geological horizons in addition to the top and bottom reservoir. Mapped horizons are: Top Chalk, Top intraHod reflector, Bottom Chalk, Bottom "Hot shale", Top Hugin, Bottom Hugin, Top Zechstein (Top Salt), and Top Rotliegendes. The purpose of the relatively extensive mapping has been to understand the tectonic and stratigraphic development as best as possible, as well as facilitate a good depth conversion. A seismic section along the 15/9-19SR well path is shown on Figure 3.2 and illustrates the main horizons.

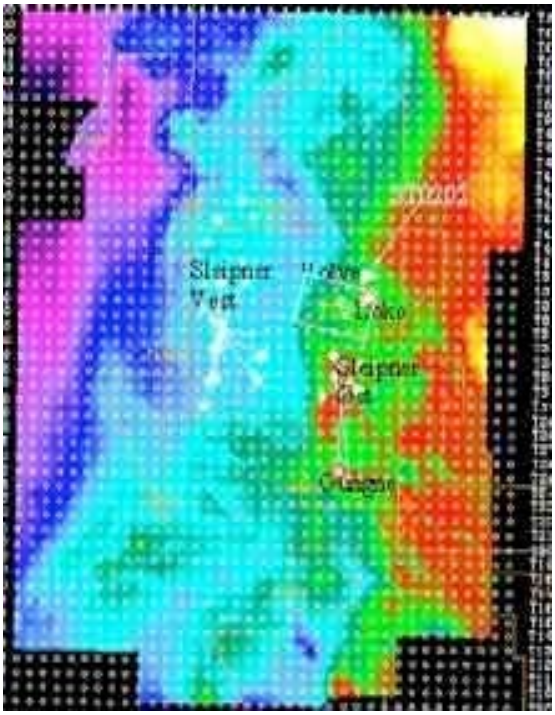

Figure 3.1 - Coverage of ST98M11 (colored area) and ST0202 (white square around Volve)

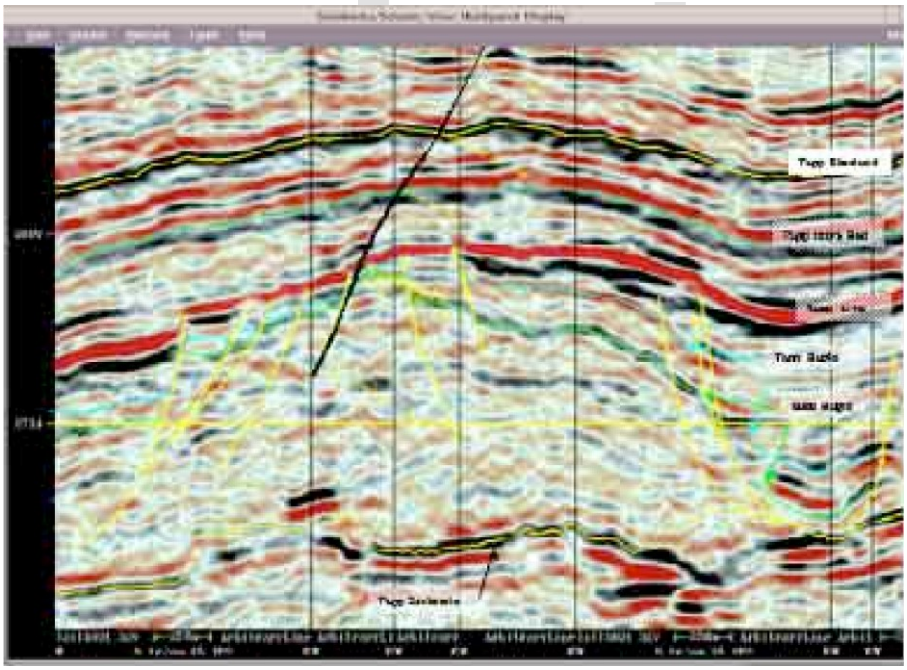

Figure 3.2 - Seismic section from ST0202 along 15/9-19SR well path. Main reflectors are indicated.

During the work on the geological model for Volve, the seismic data has become depth-migrated. Based on a quick assessment/interpretation of these data, no major deviations have been identified in relation to the documented model.

However, further improvement in data quality has been confirmed and the new data will be interpreted before drilling starts. This can lead to optimizations of the reservoir model and changes to well paths etc.

3.2.1 Deposition environment, sedimentology and stratigraphy

The Hugin reservoir in the Sleipner area is very well known through a variety of exploration and production wells. Extensive work is done in connection with semi-regional studies in both biostratigraphy, sedimentology and sequence stratigraphy (see Figure 3.3). On this basis, a common zone for the area has been established and this is also used on Volve (see Figure 3.4).

In the wells at Volve, the Hugin formation consists of relatively clean sandstone deposited in shallow water in a tidal-dominated system with an alternation of tidal canals, tidal surfaces and mouth banks. Compared to other tidal reservoirs, however, there are only few clay layers or other heterogeneities to see. The sandstone is dominated by quartz grains with only small amounts of clay and mica minerals. Reservoir temperature is around 110°C and thus smaller amounts of quartz cement between the grains have been formed.

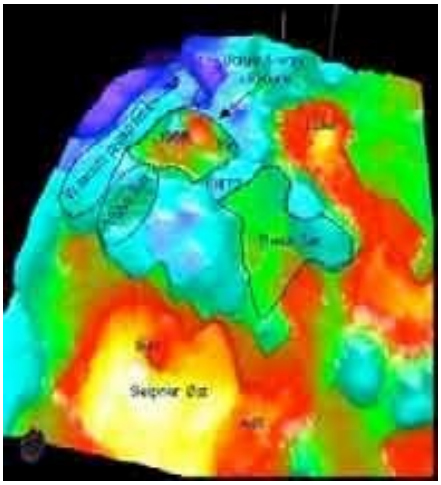

Figure 3.3 - Bottom Hugin horizon with Volve structure and main prospects recorded

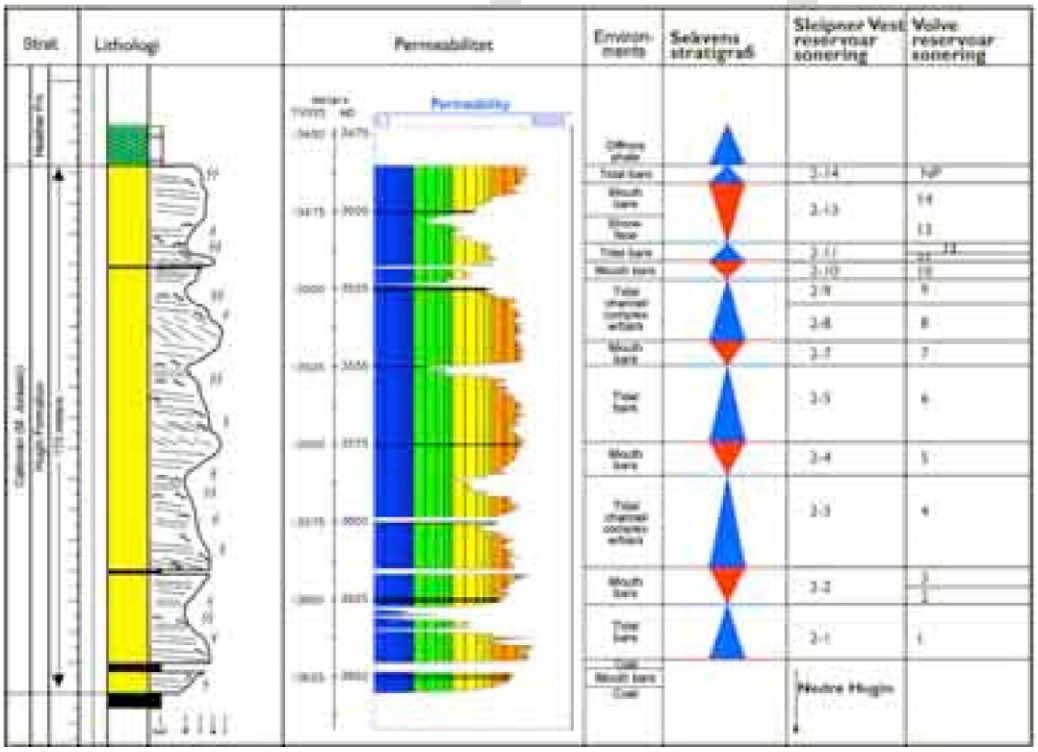

Figure 3.4 - Principle sketch for reservoir zone at Volve. based on 15/9-2 (Sleipner Vest)

3.3 Tectonic and Stratigraphic development

The structural development of Volve is as in the rest of the Sleipner area largely controlled by salt movements that both affect the thickness of the mesozoic reservoir units and which have created the oil and gas/condensate conduction structures. In addition, the late-Jurassic extension tectonics have affected the area and, among other things, created the Sleipner-graben system just west of Volve. Some faults, especially on West flank- is formed as a

combination of salt movements. Extension Wells at Volve show major differences in the thickness of the Hugin reservoir (18-112 m) and a lot of effort is laid down in understanding and predicting the thickness development. Studies show that the salt in the area previously stood up in a variety of diapires, walls and pillows. As a function of increased rainfall in Jurassic, these began to dissolve, thus creating major differences in subsidence when the Hugin reservoir was deposited. The dissolution of salt continued further in the upper Jurassic time and over the early salt structures are seen today pools at the bottom chalk level (salt collapsing basins). Of salt, there is little left in the area. (see Figure 3.5).

In Callov's time when the Hugin formation was deposited, Volve was in the middle of an area with mainly the deposition of sand, while 5-10 km further north was marine clay and 5-10 km southwest were delta plain clay and siltstone as well as peat that was deposited. Within the sand deposit area there were powerful tidal currents that could transport the sand around and move it to areas with the most subsidence. It was thus possible to deposit a unit of thickness varying from 200 m on Sleipner West to 2 m at Loki with almost identical net/gross ratio.

The major differences in subsidence during and immediately after the deposition of the reservoir led to the formation of many faults from the areas without salt (Triass heights) descend towards the collapsing pools. These faults evolved at a time when there was little over-camping and thus little pressure into the fault plane. The grains of sand were therefore only crushed in the faults and this means that the potential for faulting is generally low as long as there is sand to sand contact. In addition, the faults are typically limited in length so that although the maximum throw is often large, there are flow paths around many of the faults. Despite the many faults internally in the field, communication is therefore considered good.

This has been detected when production in well test in 15/9-19SR and 15/9-19A. However, it is clear that the flow paths on the field are not precise and that measures such as reperforation, lateral drilling and new wells may be necessary to ensure optimal drainage in the field.

3.4 Geochemistry and migration history The Volve field contains an undersaturated 27-29° API oil with a gas/oil ratio of 111 - 157 Sm^3/Sm^3. The oil is characterized by a high content of asphalt (2-6%), sulfur (2%), and aromatic component (52% C10+) and is relatively unusual compared to other North Sea oils. The oil is formed from a type II-S kerogen that typically appears in basins with small clay and sandstone and thus is characteristic of carbonate rocks.

In the Volve area, type II-S kerogen is detected in the top part of the Draupane formation which has a very high "gamma-log" response,a very high content of organic matter and which is a very rich source rock. The Type II-S kerogen is becomes mature and forms oil at significantly lower temperatures than other oil and gas kerogen. Thermal maturity modelling of Sleipner Graben west and northwest of Volve shows that the top part of Draupne here has started forming oil only about 10 million. years ago. Studies of fluid inclusions in Volve indicate that the structure first began to fill up about 5-6 million years ago. The studies also show that migration from the source area into Volve must take place via sandstone layers in the upper Jurassic package. The migration of gas/condensate into Sleipner East has followed a much longer route via Sleipner Vest and Gungne (see Figure 3.5). Gas/condensate in Volve and Theta South area can probably not exist at a deeper level than is now seen in Sleipner East.

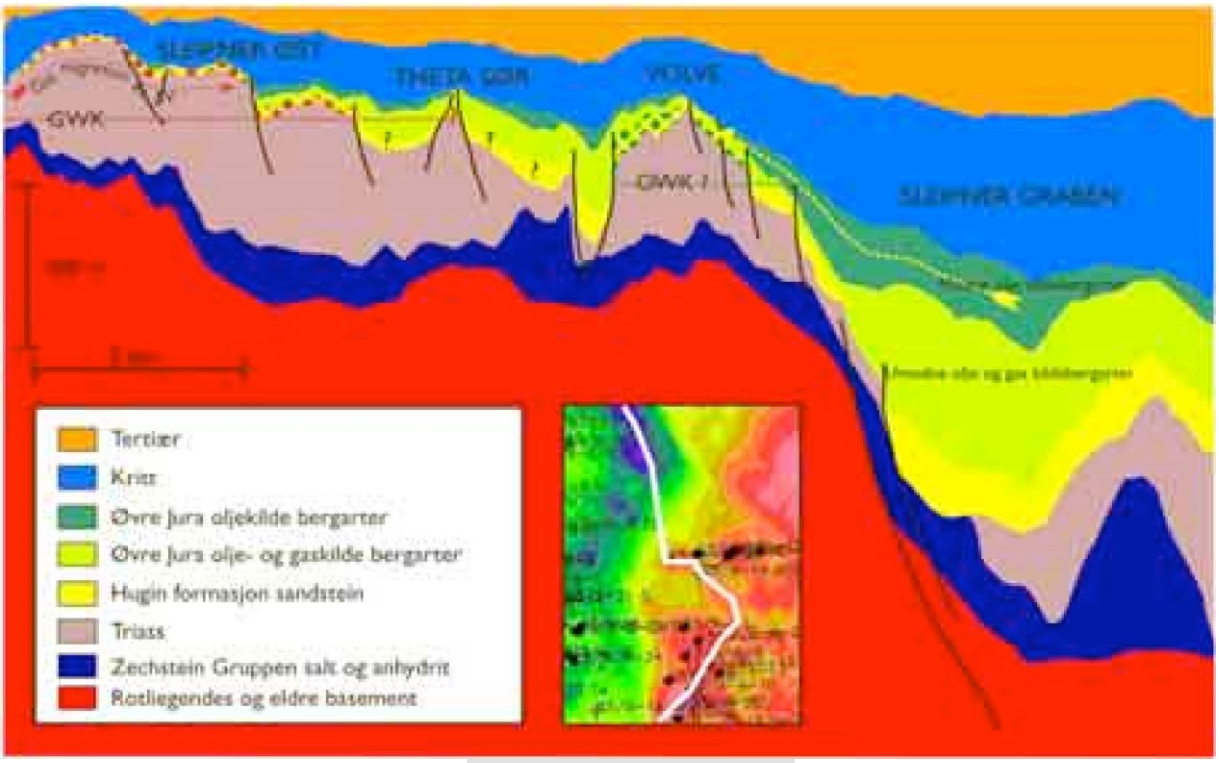

Figure 3.5 - Geosection over Sleipner East, Volve and Sleipner Graben. It is seen that the oil in Volve is formed in a local source range NW for Volve

3.5 Petrophysical evaluation

Data from logs and cores are used to calculate net sand, porosity, permeability and hydrocarbon saturation in Volve wells (15/919SR, 15/9-19A and 15/9-19BT2). Data from production tests, fluid samples and formation pressure measurements are also used in the general petrophysical interpretation that, by the way, is based on methods and algorithms used for evaluation of the Hugin formation elsewhere in the Sleipner area. Total of 164 m of Hugin formation cores in the 3 wells. The cable logs are of good quality, while formation pressure measurements are only taken in 15/9-19BT2. The analysis of rock properties is done for the wells to ensure the greatest possible compliance between core and log data.

The porosity is calculated by calibrated log data with values measured in the cores and then correlates to reservoir conditions.

Permeability is calculated based on a multivariable correlation between core permeability corrected to reservoir conditions with calculated porosity and shale volume.

Producible net sand is determined based on an iterative procedure where manual picking of net sand at core intervals has been used to determine the deposition criterion on cross plots log and core data. The final curves correspond approximately to a criterion of net sand if the porosity is greater than 10% and shale volume is less than 0.5%.

Water saturation parameters are determined by Archie's equation calibrated with data from core analysis. Averages for the 3 wells are shown in Table 3.2.

The pressure and temperature of the field is determined to 340 bar and 110^{0}C at a referanse depth of 3060 m below sea level.

Table 3.2 - Formation parameters from the petrophysical evaluation (well average)

Well	Top M SVD	Bottom M SVD	Thickness m	Porosity	Permeability (mD)	Net sand	Water saturation
15/9-19SR	2864	2883	19	0.23	1923	1.00	0.19
15/9-19A	3013	3101	88	0.20	522	0.93	0.21
15/9-19BT2	3149	3275	126	0.21	630	0.92	------

3.6 Geological model

For volume calculation purposes, a geological model based on the seismic mapping, sedimentological and stratigraphic understanding as well as the petrophysical evaluation is built. The framework for the model consists of the interpreted and depth converted top and bottom of reservoir surfaces where 14 reservoir zones have been established using stratigraphic modeling based on regional isochores from the Sleipner area together with the well data. Figure 3.6 shows top Hugin reservoir. In the model, the outer limiting faults on the field are modeled as oblique, while internal faults are modeled as vertical. The resolution of the grid is 25 m in the horizontal plane, while there is 1 m in the vertical plane.

The establishment of petrophysical parameter maps (net/gross, porosity and permeability) was done using geostatistical prediction (Krigging). As neither geological nor petrophysical evidence could determine significant lateral or vertical trends, such a procedure will provide maps that honor the well data within a given correlation distance and which has average values in other areas. This provides relatively smooth maps that are suitable for volume calculation purposes, but that do not capture the full scale of reservoir heterogeneities.

Water saturation was calculated on a grid cell for grid cell basis. The calculation is based on a summation of irreducible water saturation and Leverret J-function water saturation and therefore based on grid cell permeability and height above free water level. An oil/water contact was used the most likely contact which is 3120 m below sea level.

For volume calculation, the field was divided into a number of areas. The areas differ especially in seismic uncertainty. Base volume is calculated for each area and then summed for the main areas.

The present volume in Volve and nearby prospects are given in Table 3.3.

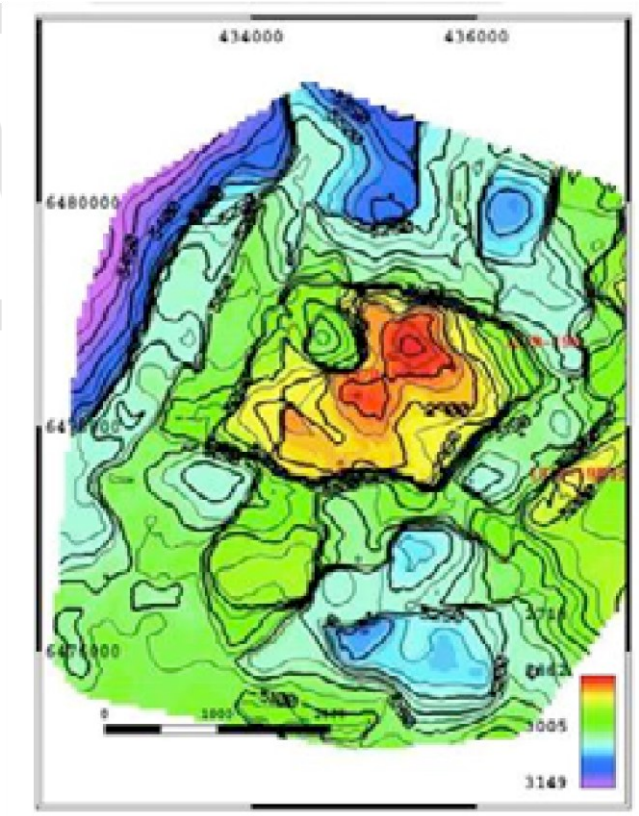

Figure 3.6 - Top Hugin in deep (m)

Table 3.3 - Present volume in Volve and nearby prospects. (BRV: Bulk Rock Volume, NRV: Net Rock Volume, HCPV: Hydrocarbon Pore Volume, STOOIP: Stock Tank Oil Originally In Place = Present oil at surface conditions)

Area	BRV Mill. m^3	NRV Mill. m^3	Pore Volume Mill. m^3	HCPV Mill. m^3	STOOIP Mill. Sm^3
Volve 4-way closure	217.4	201.7	40.3	34.1	24.5
Volve South	57.6	52.5	10.4	8.2	5.9
Other prospects	5.2	4.7	0.9	0.6	0.4
Total	280.1	258.9	51.7	42.9	30.8

3.7 Calculation of uncertainty

The uncertainty study is based on specified uncertainties in seismic interpretation, depth conversion, petrophysical variable and expansion factor (Bo). The uncertainties are combined to provide a probability distribution for the amount of present oil at surface conditions (STOOIP), see Table 3.4 which provides uncertainty present in oil volume in Volve along with mapped prospects.

Table 3.4 - Results from the study of uncertainty (CV is varied)

	Basis Mill. Sm^3	Average Mill. Sm^3	P90 Mill. Sm^3	P50 Mill. Sm^3	P10 Mill. Sm^3	Standard deviation	CV
East	19.9	19.2	15.9	19.1	22.8	2.6	14
West	4.6	8.3	3.4	7.5	14.6	4.3	52
Volve closure	24.5	27.5	20.9	26.7	35.2	5.5	20
Prospects	6.3	13.8	5.0	9.9	30.0	11.6	84
Risky Prospects	3.9	9.4	0.2	6.7	24.3	11.1	118
Total	30.8	41.3	27.2	36.4	64.7	15.8	38
Total risked volume	28.4	36.9	23.0	32.8	58.2	14.8	40

The uncertainty in gross rock volume is handled using stochastic modeling of the uncertainties in seismic interpretation and depth conversion. For each run, values have been deducted from each area and these values have resulted in a new set of top and bottom reservoir maps. Volume in this model has so been calculated and a total of 2500 models have been run.

Since no wells have encountered a contact, there is great uncertainty in the level of oil/water contact. Therefore, 3 different models for contact have been established and through a weighting of these, the probability of various discreet contacts has been specified (see Table 3.5). The probability is greatest for a contact 5-35 m under oil down to the situation in well 15/9-19A (3101m), but it also opens up the possibility of significantly deeper contacts.

Table 3.5 - Probability of different contacts

Possible OWC (m)	Probability %
3105	24
3120	21
3135	28
3170	14
3260	7
3330	6

The uncertainty in petrophysics values is low by virtue of good data from the wells and a good knowledge of the distribution of sandstone and shale in the Hugin reservoir in the area around Volve.

The uncertainty is assessed at +/- 12% on the hydrocarbon pore fraction (HCPF) correlated to all zones and areas of the field (see Table 3.6).

Table 3.6 - Uncertainty in hydrocarbon pore fraction

	P90	Model	P10
HCPF	0.132	0.15	0.168

The uncertainty in the Bo factor used for converting hydrocarbon pore volume to surface volume is shown in tabel 3.7. Input is based on oil and gas analyses from 2 wells in oil zones as well as assessments of how representative they are for the structure.

Table 3.7 - Uncertainty in Bo factor (m3/Sm3)

Bo	1.27	1.365	1.385	1.415	1.5
Probability	5 %	25 %	40 %	25 %	5 %

Sensitivities have been studied to assess which factors contribute most to the uncertainty (Figure 3-7). Overall, there is the possibility of a deeper contact which is the most important factor. This also applies to the Volve structure in isolation, although the uncertainty here overall is less and the uncertainty of seismic interpretation is relatively significant. Uncertainty in petrophysics, depth conversion and Bo factor are less important. For the prospects around Volve, there is also a great deal of uncertainty as to whether they contain oil or not (risk factor).

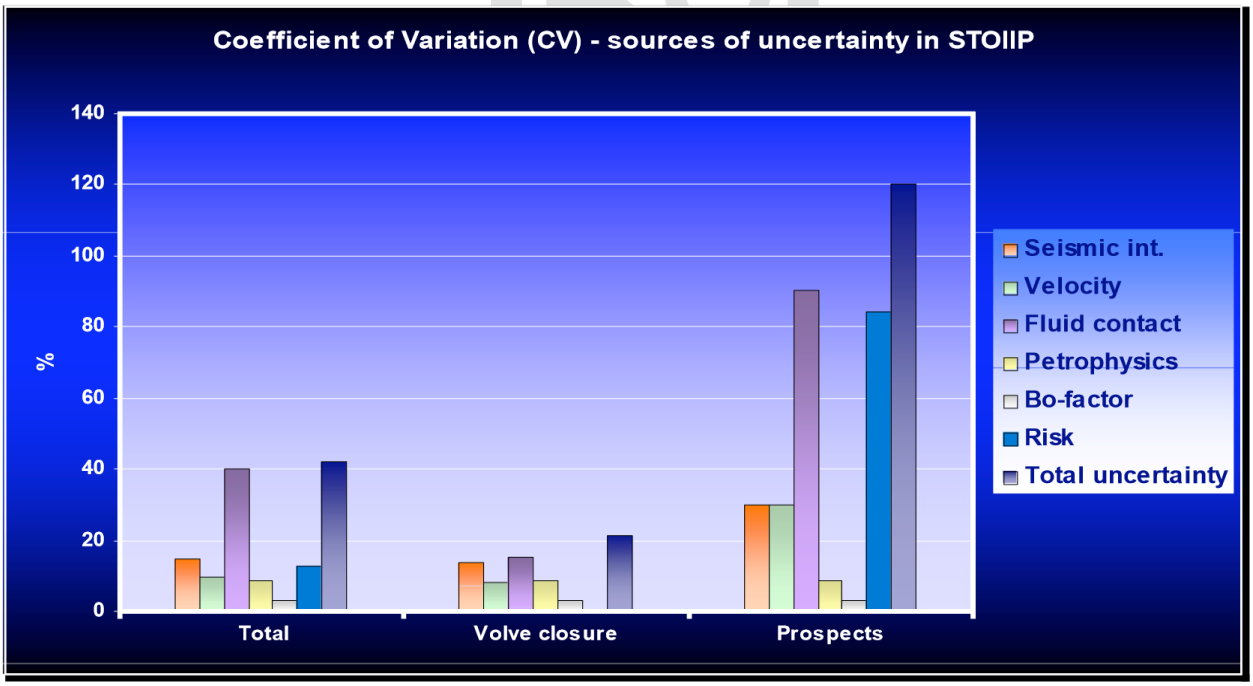

Figure 3-7 - Various factors' contribution to the uncertainty picture

4 Reservoir technical and extraction conditions

4.1 Introduction

In the reservoir technical work, a dynamic reservoir simulation model based on the geological and seismic mapping prepared in 2002/03 has been used. The model has 14 layers of reservoir parameters in each layer based on petrophysical analysis of the three wells. The top of the Volve reservoir is 2750 m below the mean sea level (MSL). Reservoir pressure is 340 bar at 3060 m (MSL) and reservoir temperature increases by the depths from 106 to 110°C. The oil/water contact (OWC) is set to 3120 m MSL. The oil has a fluctuating gas /oil ratio (GOR) from 111 to 157 Sm^3/Sm^3 (corrected for process simulations) and equivalent for the B_o factor from 1.33 to 1.45 m^3/Sm^3. Based on fluid properties and test results, the reservoir is divided into two non-communicative segments, with a northern and a southern part.

4.2 Well testing

Four well tests have been performed on the Volve field. The main results from the oil production tests are shown in Table 4.1. The highest production rate was 1,358 Sm3/d with the estimated productivity index of 142.5 Sm^3/d/ bar and average permeability was 1300 md. This shows that the reservoir has very good production properties. A comprehensive interpretation of the production tests has been carried out to supplement the geological modelling of volumes and faults. The result of this work has been important in the creation of the dynamic reservoir model.

Table 4.1 - Results from well test.

Well	Test	Years	P(bar)/ Depth(m) (TVD MSL)	Max Rate Sm^3/d	PI (Sm^3/d/bar)	Permeability md	Skin
15/9-19SR	DST 1	1993	317 2719.9	1358	142.5	1300	0.85
15/9-19A	DST 2A	1997		300			
	DST 2B	1997	335 2986.7	528	62.8	670	7.4

4.3 Fluid data

Reservoir fluid is collected during production tests and main data is shown in Table 4.2. PVT properties indicate most likely two systems and this is implemented in the reservoir model.

Table 4.2 - Fluid properties

Properties	15/9-19A	15/9-19SR
Bubble point pressure [bar]	235.5	273.8
Viscosity by boiling punk [mPa s]	0.79	0.55
Simple flash Stay at boiling point [m^3/Sm^3]	1.39	1.5
Simple flash Gas-Oil- Ratio [Sm^3/Sm^3]	111.8	159.1
CO_2 [mol%]	1.6	4.9

4.4 Production strategy

The simulation model is used to establish a drainage strategy for the field and prepare production profiles. Volve is planned to be produced from three manufacturers high on the structure along with three water injectors placed on the flanks. Throughout the production period, reservoir pressure is expected to be higher than the bubble point of the oil because pressure support is added through water injection. Gas lift is included to ensure the start-up of wells after maintenance. The two non-communicative segments will be developed with dedicated production and injection wells. Water injection contributes pressure support but in addition, the slope of the reservoir (10°-20 °) and the gravity means that the water will distribute well along the flanks and thus contribute to a rapid and efficient displacement of the oil. Figure 4.1 shows well and platform locations.

In the western parts of the field, fault throws may be greater than expected and reduce the communication in the reservoir. It is thought that drilling horizontal wells through the faults can improve the drainage of the reservoir. In addition, the model shows good communication in the north-south direction so that the water injector can provide good displacement of oil against the horizontal producer.

However, an update of the reservoir model will be made based on in-depth migrated seismic data and if necessary, the well paths will be optimized based on new reservoir information.

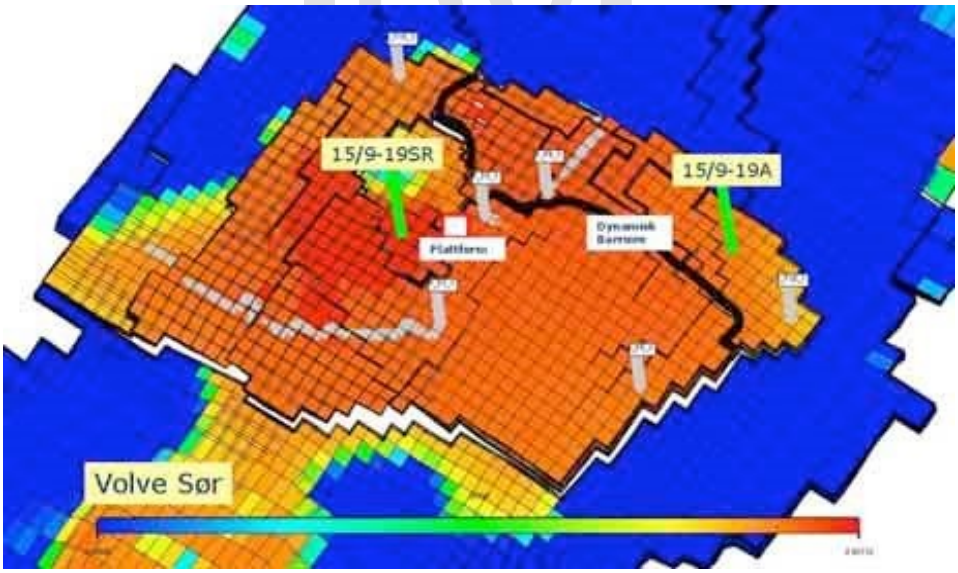

Figure 4.1 - Brønn and platform locations

4.5 Production forecasts

The proposed drilling program addresses reservoir uncertainties in the reservoir model. A producer is prepared for production start- while the rest of the wells are drilled during the period. This enables the collection of dynamic data that helps optimize the placement of the remaining wells.

Production restrictions for fields and individual wells are granted in Table 4.3 and Table 4.4.

A 94% regularity is based on calculating the production profiles. Gas lift is included to ensure the start-up of wells after maintenance and ensures production if communication in the reservoir is inferior to expected.

Table 4.3 - Field Limitations

Estimated production start-up	March 2007
Liquid capacity	13000 Sm^3/d
Oil capacity	9000 Sm^3/d
Gas capacity	1.5 M Sm^3/d
Water injection capacity	16000 Sm^3/d
Maximum water cut	0,80
Max gas lift rate	0.45 MSm^3/d

The estimated production start in March 2007 is based on the contract with Maersk. Due to weather risk when tow, production start-up can be postponed.

Table 4.4 - Well Limitations

Oil rate	2500-4500 Sm^3/d
Minimum Oil Rate	100 Sm^3/d
Minimum wellhead- Press	40 bar
Max gas lift rate	0.15 MSm^3/d

4.5.1 Forecast for oil production

The field will be started when the first well is prepared and after a start-up period of approximately 1 year, the field will produce at plateau rate. The plateau of 9,000 Sm^3/d will last about 19 months. Production decreases due to increasing water rates. Cumulative oil production at a minimum economic rate of 2,100 Sm^3/d (given Volve oil price of 18.7 USD/barrel) is reached is 11.4 MSm^3. Oil rate and cumulative production are shown in Figure 4.2. This is based on expected production (average) estimated from the study of uncertainty, see chapter 4.6.

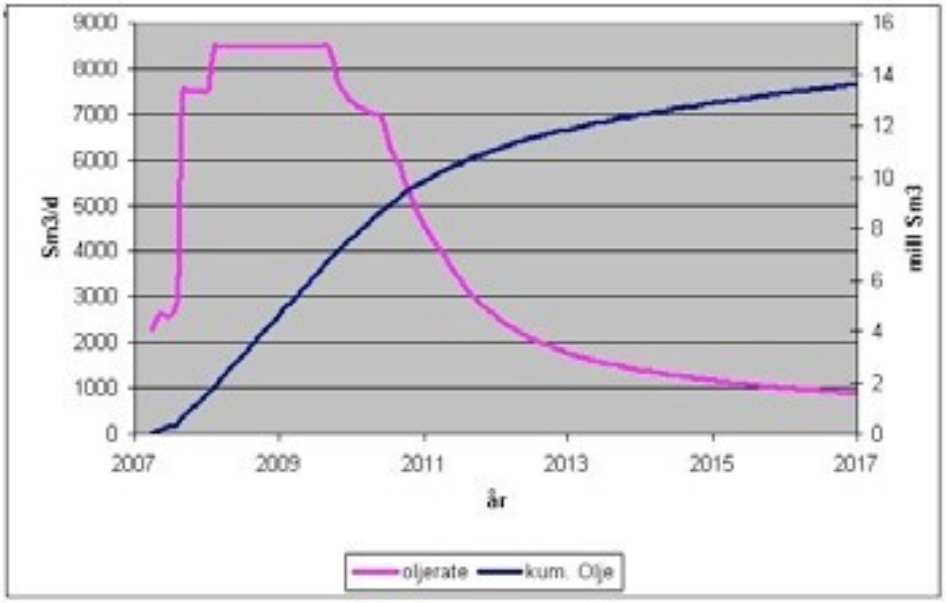

Figure 4.2 - Volve oil rate and cumulative production

4.5.2 Water production forecast

Water production comes primarily from the injection water that breakthrough in the wells after about 2 years. At that point, cumulative oil production is approximately 6 MSm^3 .

The need for water from the Utsira formation for injection is about 12,000 Sm3/d. When water production increases, the need for Utsira water decreases. Produced water and injected water are shown in Figure 4.3.

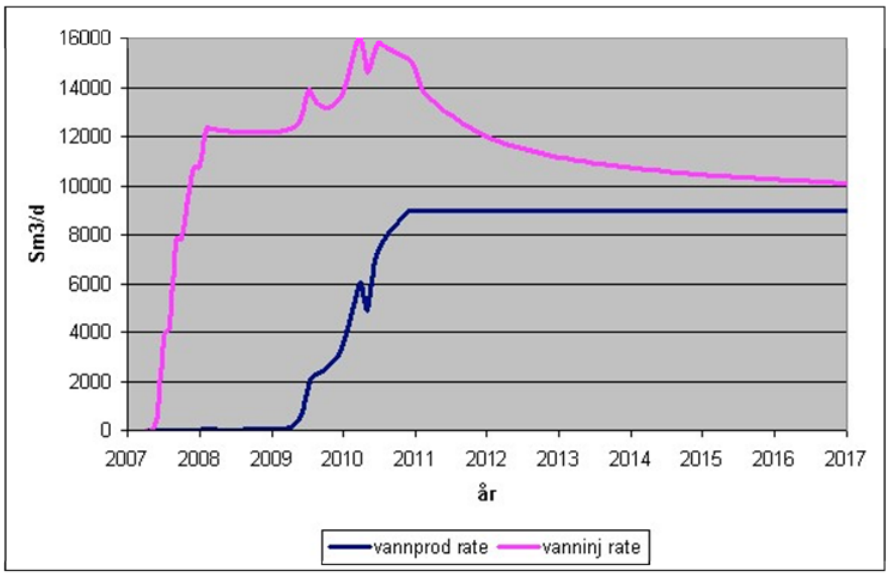

Figure 4.3 - Produced water- and water injection rate

4.5.3 Forecast for gas production

Throughout the production period, reservoir pressure is expected to be higher than the bubble point of the oil . This means that gas production comes from dissolved gas and no free gas is established. Maximum gas production is expected on plateau to be 1.2-1.3 MSm3/d, see Figure 4.4 Cumulative rich gas production is estimated at 1.5 GSm^3

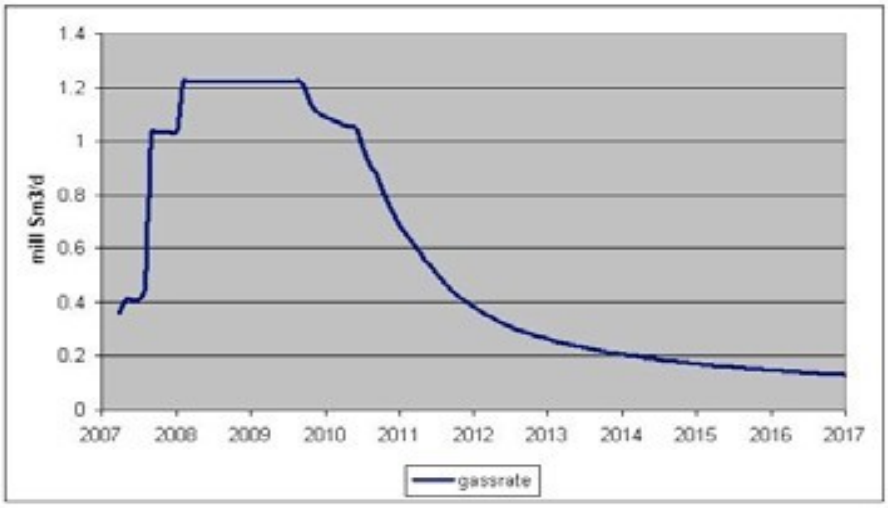

Figure 4.4 - Gas production rate

4.6 Sensitivity and uncertainty analysis

The effect of permeability, mobile oil, type of accrual environment, segment limits and variation in relative permeability as function of water saturation is included in the uncertainty calculations.

The greatest effect on recovery has present resources and permeability. An uncertainty analysis of the production profiles is carried out with Monte Carlo simulation. Uncertainty in recovery level includes vertical communication, type of accrual environment, horizontal communication and relative permeability. Gas lift ensures the production in the downside cases. The result of the uncertainty analysis is summarized in Figure 4.5 and Table 4.5.

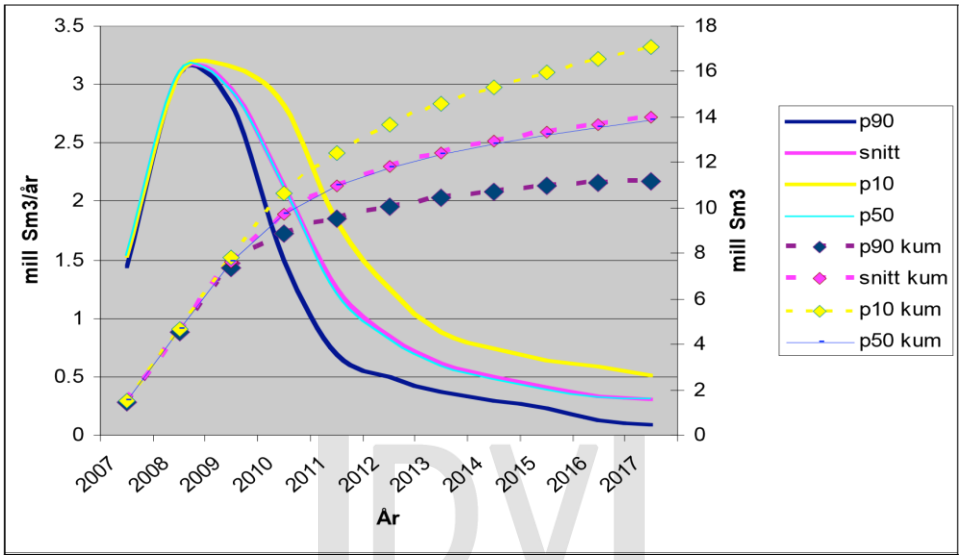

Figure 4.5 - Production profiles from the uncertainty analysis

Table 4.5 - Results from uncertainty study; reserves and production profile based on min. oil rate of 2100 Sm3/d

	Average	P90	P50	P10
Reserves (MSm³)	11.40	9.0	11.35	15.31
STOOIP (MSm³)	27.50	20.9	26.70	35.2
Years	**Oil production (MSm³)**			
March 2007	1.53	1.44	1.53	1.54
2008	3.10	3.10	3.10	3.10
2009	2.96	2.83	2.96	3.15
2010	2.14	1.49	2.13	2.82
2011	1.25	0.10	1.22	1.82
2012	0.40	-	0.40	1.25
2013	-	-	-	0.88
2014	-	-	-	0.75
2015	-	-	-	-
Total	11.40	9.00	11.35	15.31

In Table 4.6, The expected sales products from Volve gas processed on Sleipner A and Kårstø are given .

Table 4.6 - Expected sales products from gas

Expected sales products from Volve gas				
Years	**Dry gas**	**NGL**	**Condensate**	**Ethane**
	Mill Sm^3	**Tons**	**Tons**	**Tons**
06.03.2007	170	25570	10228	1705
2008	371	55608	22243	3707
2009	359	53874	21550	3592
2010	272	40844	16338	2723
2011	133	19921	7969	1328
2012	33	5015	2006	334
Total	1338	200832	80334	13389

4.7 Data collection in the drilling and production phase

No details have been taken on data collection in the drilling and production phase. However, the need for all common logs in the reservoir section has been identified that will be measured using equipment on the drilling string during the drilling phase. There will also be measurements for calibration of the seismic. Collecting bottom hole pressure data both before the start of production and during the production phase will also be carried out using permanent pressure gauges placed in the wells. Production logging will be carried out based on well behavior/assessment of needs continuously during the production phase. Measuring the well potential for the individual wells will be done by flow over test separator monthly.

4.8 Methods of increased oil extraction

Expected oil recovery from the field amounts to 43%. With the chosen concept, a number of activities can be done to increase recovery.

- Drilling new wells
- Drilling of side branches wells from wells with a high water production rate
- Shutting off high water production rates
- Lowering the input pressure in the processing plant
- Drive the field longer if new resources in the area can be phased in
- Better distribution of injected water into the reservoir using smart wells

Gas based extraction methods such as water alternating gas injection (WAG) or simultaneous water and gas injection (SWAG) have been assessed, but provide little extra recovery. At the same time, significantly increased investments are required on the platform. A key element of a successful strategy for increased oil extraction is the access to its own drilling equipment so that the drainage of the field can be optimized at any given time. The possibility of the use of gas lifts in wells has been implemented and this will ensure production by poorer reservoir communication than expected.

5 PRODUCTION TECHNOLOGY

5.1 Introduction

The production technical challenges of producing the oil in the Volve field are related to the high content of Barium in the formation water, high content of the asphalt in the oil and the production of water from Utsira formation using Electrical Submersible Pumps (ESP). Produced water from the Utsira formation is used for injection to avoid deposits.

Wax deposits or hydrates are not expected under normal production conditions. Hydrates can only be formed during the closure of the wells.

The Hugin formation on the Volve field is a well-consolidated reservoir where there are no special challenges related to sand production. The Utsira formation is unconsolidated, here it is therefore planned with open hole screens.

5.2 Well hydraulics

The pressure in the reservoir should be maintained by water injection. In the case of expected well and reservoir behavior, there should be no need for artificial lift, but gas lifting is nevertheless included to ensure the start-up of wells after maintenance. It is planned for deviated wells in the reservoir, it entails a relatively high productivity which maintains a high bottom hole pressure that in turn reduces the need for artificial lift.

Reservoir simulations show that the well potential is in the range of 5000 Sm^3/d in liquid rate, calculations then show that it is optimal to install 7" tubing. The minimum wellhead pressure is 40 bar, while the maximum wellhead temperature is estimated at about 100 degrees C.

5.3 Production chemistry

5.3.1 Deposits

The barium content of the formation water at Volve is uncertain as there are no water samples from Hugin formation. A water sample taken in well 15/9-19A from the Sleipner formation just below the reservoir has a low content of Barium, but the content of sulfates is to a extent that suggests that the specimen has been contaminated with seawater. Uncontaminated water samples from the Hugin formation in Sleipner West show very high concentrations of Barium and Strontium. These samples are assumed to be representative of the Volve field, see Table 5.1 for water analysis.

Table 5.1 - Water analysis

Ion	15/9-19A	Sleipner Vest	Utsira	Sea water
Na (mg/l)	44610	44620	10800	11150
K (mg/l)	1790	2740	200	420
Mg (mg/l)	2240	1740	650	1410
Approx (mg/l)	7240	8380	430	435
Sr (mg/l)	290	355	10	6
Ba (mg/l)	27	510	1	0
Fairy (mg/l)	0,1	2,5	-	0
Cl (mg/l)	94560	92050	18800	20310
SO4 (mg/l)	90	14	0	2800
HCO3 (mg/l)	355	625	720	150
Organic Acids (mg/l)	176	191	-	0
TDS (mg/l)	151202	151228	31611	36675

Calculations show that there is very great potential for precipitation when injecting untreated seawater. This is due to the fact that a mixture of formation water and seawater will result in precipitations of Barium and Strontium sulfate. These precipitations can cause major problems in both the reservoir, well and process equipment and should therefore be avoided. Utsira water will be injected along with produced water as pressure support in the reservoir.

Potential for precipitation of carbonate deposits is considered moderate and will only be in well head. It is therefore planned to facilitate the injection of deposition inhibitor into the well head.

5.3.2 Hydrates

There is potential for hydrates at production shutdowns. A hydrate philosophy will be prepared with shut-down procedures and injection of chemicals (glycol and methanol)

5.3.3 Emulsions

Characterization studies indicate that relatively stable water in oil emulsions can be expected in water. Without the injection of emulsion switch and coalesces into the process, the desired water quality might not be achieved. It should therefore be planned for the injection of chemicals on the well head and that electrical exfinement of water from the oil in the process equipment is included.

5.3.4 Asphalt precipitation

The Volve oil is undersaturated and contains quantities of asphalt. Studies show that there is a potential for asphalt precipitations when producing 10 – 20 bar under initial reservoir pressure. Precipitation of asphalt in the reservoir causes to experience few problems. On the other hand, precipitation in the well and process must be avoided and therefore plan for the injection of the asphalt inhibitor. In addition, injection points should also be prepared in the upstream process.

5.3.5 H_2S

No H_2S has been detected and therefore no action with respect to H_2S in the produced oil and gas quantities. Injection of Utsira water prevents the acidification of the reservoir.

5.3.6 Wax

During normal production, the liquid temperature will be higher than wax formation temperature (WAT). However, in the event of closures, some wax will form but this is limited and is expected to be rapidly dissolved during production.

5.4 Water Management

Analysis of the formation water show a great potential for Barium and Strontium precipitations when mixing seawater and formation water. It is therefore decided that seawater injection should not be used for pressure maintenance in the reservoir.

It will therefore be produced Utsira water for injection purposes, this will in time be mixed with an ever-increasing amount of produced water, which is being reinjected.

5.4.1 Utsira water production

The Ustira water shall be produced with electrical submersible Pump (ESP). These pumps will be installed as part of the completion and result in a water production rate of 8000 Sm^3/d per. water producer.

5.4.2 Re-injection of produced water

Utsira water is injected from the start of production. In case of water breakthrough in the reservoir, produced water will be cleaned and reinjected along with Utsira water. To avoid plugging the reservoir, it is planned that the injection will take place with higher pressure than fracturing pressure to ensure good injectivity throughout the production period.

5.5 Gas handling

Under normal operating conditions, all surplus gas will be exported to the Sleipner A platform via the Sleipner D bottom frame. Maximum export pressure from Volve is 100 bar at

export to Sleipner A. This is based on simultaneous maximum production from the SLD wells and Volve, and a reception pressure of 48 bar at Sleipner A.

In the event of a production shutdown at Sleipner A, the Volve gas will be injected via the D – bottom frame into the reservoir. Maximum injection pressure at D-bottom frame is 155 bar. The injection compressor also used for gas lift has the same capacity as the export compressor of 1.5 MSm^3/d. Gas lifting can be useful if production decreases as a result of reduced pressure or increased water holding in the wells. The injection compressor therefore has sufficient capacity for simultaneous gas lift and injection into the D-bottom frame so that production does not have to be throttled down at production stoppage time at Sleipner A.

6 Drilling and Well Technology

6.1 Introduction

It is planned to drill 3 oil production wells, 3 water injection wells and 2 water production wells for the Utsira formation. The well quantity is determined based on the reserve basis, drainage efficiency, planned production plateau and water injection requirements.

The injectors are drilled with a deviation of a maximum of 30 degrees, while the manufacturers are drilled horizontally or with high deviations through the reservoir. The location of the drilling and production facility in relation to the reservoir is chosen based on minimizing the risk of shallow gas, as well as achieving the easiest possible well paths. In addition, the locations are within drilling range for all identified prospects in the area. A wellhead module will be located on the outside of the platform under the drilling tower. It will be adapted with well slots and manifold for drilling up to 13 wells. Further possibility of 2 more wells will be considered. The wells will be drilled through a simplified bottom frame with 3 x 5 well slots. The minimum distance (center to center) between wells will be 1.5 m.

6.2 Drilling program

Drilling is planned to start at the end of 2006/2007 and scheduled to finish in the second quarter of 2008.

Table 6.1 provides a summary of the well paths. Optimization of the drilling program, including well tracks and casing programs will continue in close cooperation with reservoir engineer until the completion of the single drilling and completion programs.

Table 6.1 - Summary of the planned well *paths*

Well	Start deviated construction [mTVD/mMD]	Stop deviated construction [mTVD/mMD]	Deviation building rate [degrees /30 m]	Sailing angle [degrees]	Total depth [mTVD/mMD]
I-F10	300/300	634/649	2.5	29	3228/3618
I-F15	300/300	479/481	2.5	15	3110/3206
I-F5	300/300	570/577	2.5	23	3125/3355
P-F2	300/300 2168/2268 2862/3813	486/490 2867/3332 2891/4049	3 3 3	19 91 75	3081/4804
P-F9	300/300 2186/2209	409/409 2804/3010	2.5 3	9 73	2991/3641
P-F5	300/300 2190/2231	483/485 2871/3130	2 3	12 78	2959/3538

The following casings are planned to use on Volve:

- 30" casing
- 20" casings (in oil production wells)
- 13 3/8" casing
- 10 ¾" x 9 5/8" casing
- 7"Casings.

The water production wells of the Utsira formation are planned with 30" and 13 3/8" casings.

6.2.1 Basic gas

Based on data from the drilling site survey, due gas assessments have been carried out for each specific well path. No signs of ground gas were found in the area for the planned well locations. Based on due gas experiences in the

area, a pilot hole will still be drilled to investigate for shallow gas.

6.2.2 Drilling fluid

It will be planned used water-based drill sludge for all hole sections up to and even the 17" section. In the two lower hole sections, 12" and 8", used oil-based drilling sludge is planned due to the risk of unstable clay above the reservoir.

6.3 Cutting shears handling

Oily cuttings are planned to be collected in containers for submission to land for destruction. In the further planning phase, it will be sought to achieve a solution for injection of oily cuttings during the Utsira formation. This will depend on whether it is possible to find a technical solution for this with the selected well head solution.

6.4 Completion

The production wells and injection wells are planned to be completed with 7" production pipes. Sketches of wells and completions are shown in figures 6.1 to 6.3.

6.4.1 Downhole completion equipment

The oil production wells and water injection wells are complimented with production gaskets and safety valves in the production pipe.

Production wells are also planned to be completed with gas lifting equipment including annulus safety valve, downhole pressure and temperature gauge and a downhole chemical line for the inconsistent injection of the asphalt precipitation inhibitor (see Figure 6.1).

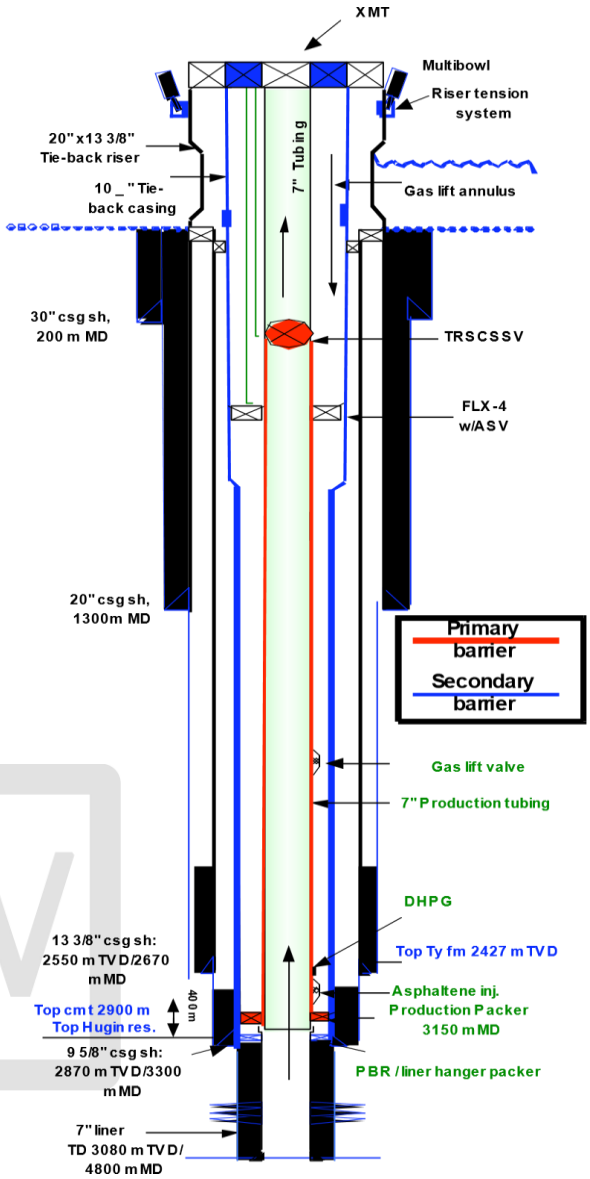

Figure 6.1 - Oil producer w/gas lift

The two water production wells are planned completed by submerged electric powered pumps to pump the water to the surface

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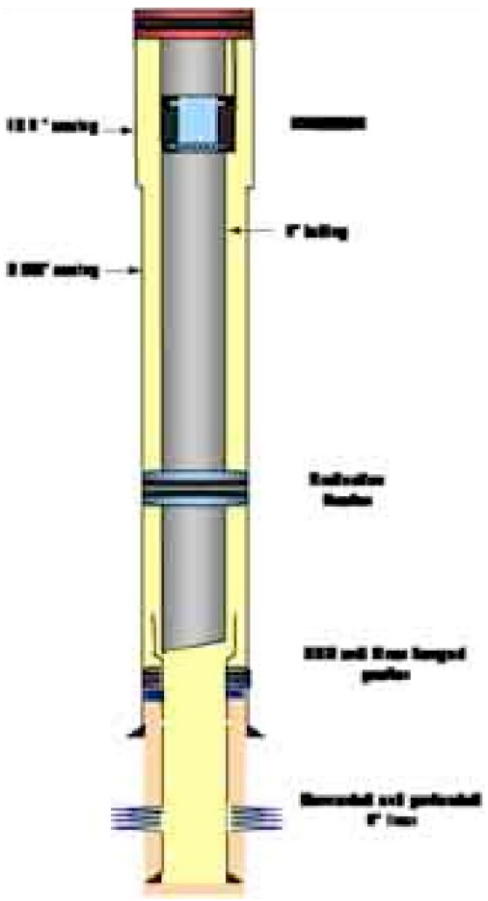


Figure 6.2 - Water injection well

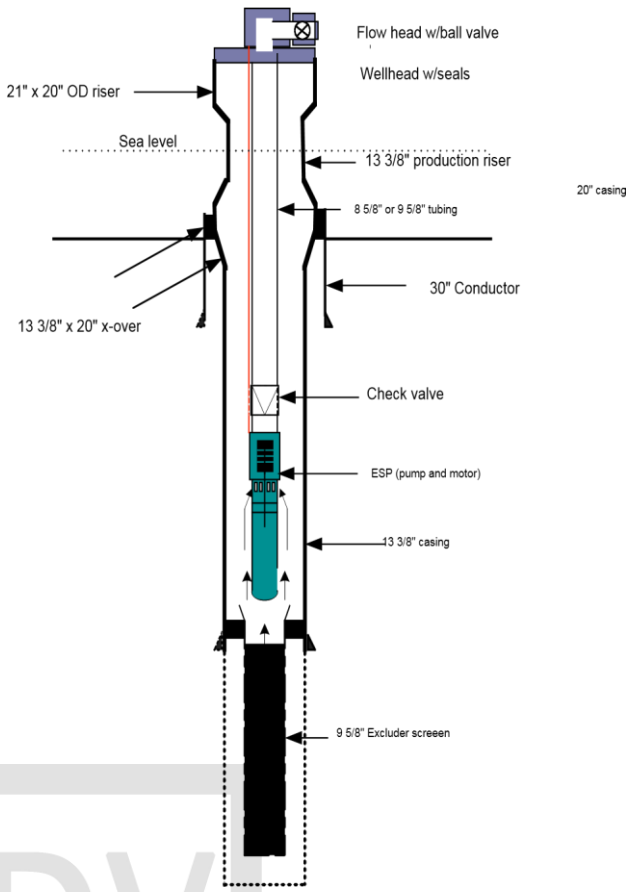


Figure 6.3 - Utsira water production well

6.4.2 Sand control

The Hugin reservoir is well consolidated, there is thus no need for any special sand control measures. One of the production wells is planned to be completed with pre-perforated casing through the reservoir. The other two production wells are planned cemented and perforated with oriented perforations in the reservoir. The injection wells will also be perforated with oriented perforations in the reservoir.

The Utsira formation is a particularly poorly consolidated sand. The two water production wells are planned complete with 9 5/8" openhole screens through the Utsira formation.

6.4.3 Wellhead, valve tree and riser system

The wells are planned developed with a to part wellhead system where the weight of the casings are hung off on the seabed. During the drilling phase, 30 and 20" drilling risers are planned. After the drilling is completed, the wells will be secured and the drilling riser will be removed. Then a 20" x 13 3/8" production riser will be installed with a wellhead on the surface. 10 ¾" casings are then reconnected from seabed to the surface. The production pipe will be hung off in the wellhead of the surface. One will thus get surface safety valve trees with 6 3/8" dimension. Simple flow heads are planned for the water producers.

6.4.4 Drilling rig

Drilling and completion operations are carried out from the selected development solution with the platform Mærsk Inspirer. This platform has a blowout safety vent that has been pressure tested to 1035 bar, which is more than sufficient for Volve.

The largest hole diameter will be 37 ¼" for drilling the top section. The rig is equipped with one top drive and three regular sludge pumps and is built to handle oil-based drilling sludge for injection.

6.4.5 Well control and emergency preparedness

Drilling, completion and other well maintenance will be carried out in accordance with Statoil's established procedures and procedures and in accordance with regulatory requirements. All drilling and completion operations will take place with two independent barriers to hydrocarbon-carrying formations.

6.5 Time and cost estimate

Time and cost estimate are based on previous drilling operations in the area and other relevant field experience. The cost estimates are based on contract pricing for rent by Mærsk Inspirer in drilling mode and drilling and production mode respectively.

Drilling and completion costs include both expected downtime, technical tolerance and waiting for weather. Time and cost estimates are shown in Table 6.2.

Tabell 6.2 - Time and cost estimate for drilling and completion, costs in M NOK 2005

	I5	I10	I15	P5	P9	P2	UP1	UP2	Technical tolerance	Total
Days Drilling	38	36	36	40	40	53	12.5	12.5	39	307
Days completion	19	19	19	22	24	23	10	10	19	165
Installation of bottom frame	-	-	-	-	-	-	-	-	-	3
Total days	57	55	55	62	64	76	22.5	22.5	58	475
Cost Drilling [MNOK]	88	66	65	132	91	113	25	25	69	674
Cost Completion [MNOK]	33	33	33	70	52	56	24	24	31	356
Installation of template	-	-	-	-	-	-	-	-	-	6
Total Cost*	121	99	98	202	143	169	49	49	100	1036

*If changes in well targets are identified based on the revised reservoir model that includes re-processed seismic, the cost of the wells may be changed. Technical tolerance in the form of geological or technical sidesteps is included with 99 MNOK 2005. These costs are transferred as unforeseen costs in Table 12.1.1.

7 Description of the development solution

7.1 Introduction

Extensive assessments of many development options have been carried out for Volve. For the two most profitable development options, the hiring of production vessels with subsea wells or jack-up platform with process module, offers were obtained from market. The development solution that provides the best profitability for the Volve field is jack up platform with processing plants where rich gas is exported to Sleipner A and the oil is exported with shuttle tanks via a storage ship.

7.2 Alternative development

Development concepts have been considered based on both owning and renting production facilities for Volve.

The following alternative development concept is considered in connection with the rental concept:

- Production and Storage ships (FPSO) with subsea wells
- Production and Storage ships (FPSO) with wellhead platform
- Jack-up platform with process module and storage vessel (FSU)

The following concepts are assessed for owning the production facility:

- Platform with fixed steel jacket at Volve location
- Platform with fixed steel chassis with connection of subsea wells at Volve
- Platform with fixed steel underframe connected to Sleipner A with wellhead platform on Volve
- Modification of Sleipner A with subsea wells at Volve
- Subsea development of Volve connected to Sleipner A

Various gas export events are considered:

- Export of rich gas to Sleipner A (SLA) via Loki or SLD subsea frame
- Export of rich gas to Sleipner T (SLT) via Alpha Nord
- Installation of CO_2 reduction facilities for Volve gas and export via Loki
- Deferred gas exports using Simultaneous water alternating gas injection (SWAG)

The following oil export opportunities are for Volve:

- Export to Sleipner
- Export via shuttle tankers
- Export via Forties piping system in the UK sector

The alternative development solutions are assessed in the Volve Field Development Concept Screening Report dated 20.11.2003. The recommended solution is provided in the document "Volve concept selection report" dated April 4, 2004.

7.3 Basis for development

The basis for the development is the selected drainage strategy, functional requirements, ocean depths, environmental and geotechnical conditions as well as available existing equipment.

7.3.1 Functional requirements

The installations shall satisfy the authorities requirements for fixed installations as well as Statoil's specifications and safety regulations. Production is expected to last three to four years while the design life is 10 years.

7.3.2 Deep sea

The water depth at Volve is 90m.

7.3.3 Environmental data

Environmental data (wind, wave height etc.) is provided in "Design basis and functional requirements" and is based on measured data in the Sleipner area.

7.3.4 Geotechnical conditions

A basic survey has been carried out on the field with respect to the anchoring of warehouse ships and the foundation for jack-up platform. No basic surveys of the route for the gas export

pipeline have been carried out, but these will be carried out well before installing pipelines.

7.4 Description of the selected concept

7.4.1 System description and design capacity-

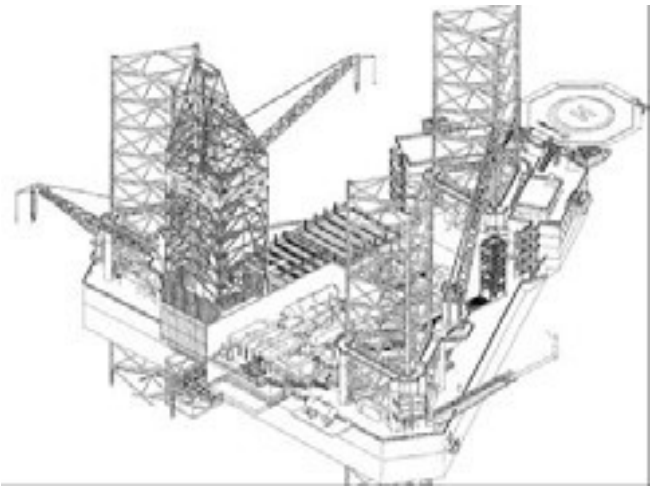
A jack-up platform should be able to take care of the following functions:

- Position and jack up platform at location
- Drill and complete production and water injection wells in the Volve Reservoir and water producers from the Utsira formation.
- Process the well flow to stable anhydrous oil according to specification
- Export surplus gas to Sleipner A via the Sleipner D base frame
- Treat produced water for reinjection
- Inject Utsira water and produced water into the Volve Reservoir to maintain reservoir pressure
- Export stable oil to storage ships
- Accommodate all personnel who normally needed to operate and maintain production, auxiliary, and maritime functions. In Table 7.1, the design capacities of the plant are described.

Table 7.1 - Design capacity

The design capacity for the platform will be the following:	
Total fluid treatment:	13.000 Sm^3/d
Oil rate:	9.000 Sm^3/d
Max water content	80 %
Gas compression rate:	1.5 MSm^3/d
Gas export pressure:	100 bara
Gas injection pressure/gas lift:	160 bar
Water injection rate:	5.000 – 16.000 Sm^3/d
Water injection pressure:	330 bara
Beds:	120 personnel

7.4.2 The Production platform



Location of production plant - The platform

Maersk Inspirer is the second in the series Maersk Contractors latest generation of jack-up platforms. It was built in Korea and was completed in 2004. The rig is designed for a maximum depth of 150 meters and will be successfully installed on Volve 26 meters above sea level. The rig is designed like an equilateral triangle with a jack-up leg in every corner. The distance between each legs are about 70 feet. A processing plant will be installed to process the well stream to stable oil and rich gas. The platform will have dry well heads and during the entire production have possibility of drilling or well intervention. The processing plant will be located next to the drill module, see Figure 7.1

The living quarters are like helicopter decks and lifeboats located on the outside of the

jack-up leg with the greatest distance from the process module. The flame tower is located outside the rig leg closest to the process module.

7.4.3 Processing plants and auxiliary systems

The processing plant will contain systems for separation and oil stabilization, fuel gas plant, gas export compression module, produced water treatment and water injection. (See Figure 7.2) The separation system consists of three separator steps; the first two are three phase separator and while at the third stage there is a water separator. 1. The pressure ratios in the first. and second separator steps are 40 barg and 0.2 barg. A requirement of 5 minutes minimum stay time for the oil due to strong oil/water emulsions is set. There is heating options upstream. 2. separator. Fuel gas is taken from the first separation stage. The fuel gas system has options for cooling, liquid precipitation and heating before distribution to consumers. The gas from the second separator stage is compressed to first-stage separator pressure and fed to the export compressors together with the gas from the first-stage separator.

A centrifugal compressor has the capacity to compress 1.5 MSm3/d gas from a suction pressure of 40 bara to an outlet pressure of 100 bara.

Produced water treatment will consist of dedicated hydro-cyclones and degassing tanks for the water flows from each separator. Produced water will, together with water from the Utsira formation, normally be reinjected into the reservoir for pressure support. After purification to specifications and gas removal, the water can be dumped overboard if the water injection system is down. Gas from degassers is sent to torch.

Power generation occurs in two 50% "dual" fuel gas turbine generators. Each generator has the capacity to supply all process cones outside the ESP and water injection pumps. If one of the generators is down, the water injection system can be powered by the generators in the drilling module if any drilling activity is stopped. The drill module has 4 diesel generators.

Other auxiliary systems include:

- Two 100% circulation pumps heat pumps and two 100% waste heat recovery units.
- Freshwater plant, capacity: 20 m^3/h
- Seawater system, capacity 347 m^3/h
- Fire water, capacity: 1000 m^3/h
- Compressed air, continuous capacity: 350 m^3/h
- Diesel system
- Hydraulic system
- Nitrogen system
- Flooding, foam and halon system for fire protection

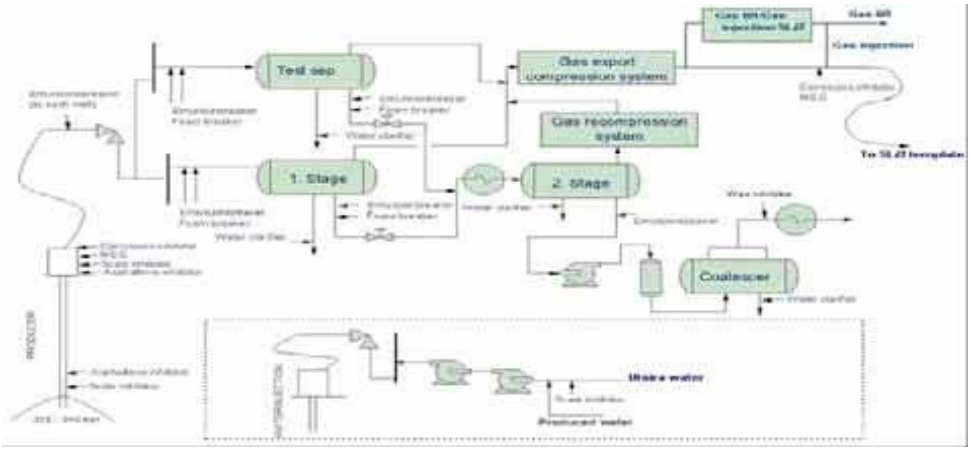


Figure 7.2 - The processing plant

The maximum number of planned wells for Volve are 13 wells:6 production wells,5 water injection wells and two Utsira water wells.

7.4.4 Export of oil

Stable oil is exported to the bearing ship "Navion Saga" via an 8" flexible export pipeline. The load capacity corresponds to the production capacity of 9.000 Sm^3/d. The warehouse ship is anchored to an STL buoy 2.5 km from the production rig and has a storage capacity of 1 million barrels of oil and a unloading capacity of 6000 Sm3/hour. The oil is fiscally transferred from the storage ship to shuttle tankers. The warehouse ship is equipped with VOC facilities.

7.4.5 Export of gas

The gas is exported to Sleipner A via the Sleipner D subsea template. A 5.5 km long 7.4" flexible pipeline will be installed from Volve to Sleipner D. The maximum design rate is 1.5 MSm3/d, while the highest expected rate is 1.2 MSm3/d. The gas exported is wet rich gas from 1. and 2. step separator. The gas export line is isolated to avoid the gas being cooled to the temperature of hydrate in connection with the export to Sleipner. To prevent hydrate problems at low gas export rates towards the end of the field's lifetime, methanol can be injected continuously. Procedure for hydrate handling will be prepared before the start of production.

7.4.6 Gas lifting/gas injection

To ensure a high production regularity for Volve, the extraction gas from Volve has been set up in the SL wells at production stoppage at SLA. An injection compactor compresses the gas from the export compressor to the required injection pressure of about 160 barg to inject into the injection well which has a maximum closure of 130 barg. Compressor can also be used for gas lift in the production wells at Volve, which may be necessary for wells with high water cuts.

7.4.7 Fiscal measurement of oil and gas

The oil is being measured by unloading from the storage vessel to the shuttle tankers. There will also be measurement on the jack-up platform rig to have continuous control over the production rate, but the measurement does not have fiscal quality. Measurement accuracy will be better than ± 2%. The gas is being measured in connection with exports from Sleipner A. Due to Volve and Sleipner A being placed in the same license with the same owners, fiscal measurement of the gas will not be required before it is sent into the gas plant at Sleipner A. There will also be measurement of the export gas at MI, but the measurement does not have fiscal quality. Gas that is flared or used for power generation will be measured in accordance with The Norwegian Petroleum Directorate's requirements for calculating CO_2 emissions tax.

7.4.8 Modifications, installations and marine operations

Statoil will be responsible for all marine operations in connection with the installation of export systems for oil and gas on Volve. The development of the Volve field is based on as many marine operations as possible when the platform and storage ship arrive on the field. The gas export pipe will be installed and connected to the Sleipner D bottom frame. STL bend with anchoring and attachment to the oil export pipeline will be installed. The STL buoy will be submerged ready for retraction and connection to the storage ship.

The distance between Maersk Inspirer (MI) and Navion Saga will be about 2.5 km, while the distance from MI till Sleipner East is about 5.5 km. Both export pipelines will be buried.

Before MI can be installed and start production of oil and gas, the rig will be modified so that class inspection can be carried out at location if necessary.

7.4.9 Manufacturing chemicals

It will be facilitated for the use of production chemicals to handle fluid issues. Mixing produced water and Utsira water for injection can entail a deposition potential that will require the injection of deposition inhibitor.

It is facilitated for the injection of chemicals such as emulsion switch, asphalt inhibitor, wax inhibitor, foam damper, methanol, corrosion inhibitor, biocide and flocculant. There will most likely be no need for continuous injection of all these chemicals, but the possibility of injection will be present. Oil-soluble chemicals will follow the oil product, while water-soluble chemicals will accompany produced water that is injected back into the reservoir.

The Volve chemical spill will thus be minimal. Normal chemical consumption is expected on Volve compared to other oil fields.

7.4.10 Testing and startup

Offshore and start-up testing will be carried out by Maersk Contractors and tekay for the respective platform and storage ships.

7.5 Regularity of produced oil

Regularity of produced oil is estimated at about 96% on the processing plant alone. The total regularity analysis for the entire plant is estimated at 94%.

8 Operation and Maintenance

8.1 Introduction

Statoil is operator of Production License 046. Under the cooperation agreement, the operator maintains the day-to-day management of the business performed in connection with the production license on behalf of the owner group. The Steering Committee is the top body of the owner group and the operator performs its duties according to decisions of the Steering Committee.

8.2 Organization and staffing

Volve will be part of Statoil's Unit for Exploration and Production, Norway (UPN) and will be established within the existing Sleipner operating organization. The organization will be responsible for all activities related to the operation and termination of the field. During the operational phase, the organization will include 12-16 people. Operating preparations and start-up will be completed in the construction project.

Statoil, as operator, will usually be present in the field with only one representative during production. The representative takes care of Statoil and other licensees' interests that operations are carried out in an efficient, safe, and environmentally sound manner. I

In drilling operation, Statoil will have a larger organization on board as well as more representatives from our subcontractors.

The contractors will be added to a large degree of independence with the associated delegation of responsibilities and authority to carry out the assignment under the contract. The contractors will be the main employer for their own and subcontractors' personnel.

8.3 Operation of the facilities

Statoil's land organization for Volve will take care of tasks related to the operation of the facilities in cooperation with the contractors. Contractors will be instructed by Statoil on production and injection plans as part of reservoir management. All contact with authorities and partners will be carried out by Statoil.

Statoil will take responsibility for emergency vessels and oil spill protection. Volve will be connected to Statoil's second line emergency response centre at Sandsli. All logistics functions such as helicopter transport and supply service will also be taken care of by Statoil.

Existing supply bases and helicopter terminals in Stavanger, already used in the Sleipner area, will also be used for Volve. It will also facilitate effective cooperation with Statoil's other units, other operators in the area and owners of the production facilities.

The Contractors, Maersk Contractors and Tekay will carry out all offshore activities in connection with the operation of the production facility, such as processing, storage, fiscal measurement, and export, as well as necessary onshore support features. The operation will be carried out within the regulatory framework of the authorities and Statoil's requirements for health, safety and safety.

Monitoring and control of the processing plant and other functions on board will take place from the central main control room. Normal operating staffing on the platform is approximately 34 people when drilling is completed and normal operating staffing on the warehouse ship is approximately 14 people.

8.4 Maintenance

Preparation and management of maintenance and inspection programs in line with established procedures at Maersk Contractors and Tekay shall ensure that the plant meets operational standards in accordance with authority and company requirements.

Maintenance and inspection activities shall be based on functional criteria assessed against safety and the environment, production regularity and consequential costs. Optimization of maintenance and inspection programs is carried out to ensure that production targets are achieved. In order to achieve that, a contract has been developed between Statoil (on behalf of PL046) and Maersk Contractors based on compensation format that rewards high operational regularity that depends on a high level of security.

9 Health, Environment and Safety

9.1 Introduction

Attitudes, activities, and decisions at all levels of the organization have an influence on HSE, and HSE management is an integral part of the activities in the project and the operational phase. The plans are to deliver a total production facility (platform, export system, warehouse ships) that meet the authorities HSE requirements as well as specific operator requirements included in contract.

However, some deviations have been identified from government requirements on the already built facilities (platform and storage ships). The identified deviations are handled in accordance with Statoil's procedures and will be admitted with the Petroleum Safety Authority Norway during the treatment period for this PDO.

Safety requirements include the protection of people's lives and health as well as the protection of facilities, manufacturing, knowledge and material values. Requirements for environmental includes protection against pollution and unacceptable interventions in nature. HSE is considered in all technical, financial, operational and administrative activities both in Statoil and at OIC. In connection with the construction phase, contractors are required to conduct various risk analyses that may result in corrective measures.

If changes and updates to the selected technical solution are required, safety and environmental requirements will be emphasized.

9.2 Goal description

The overall HSE objective for the development and operation of Volve is that the business shall not cause accidents, personal injury, occupational illnesses, material losses or damage to the external environment.

The following sub-objectives are established:

- HSE shall be integrated into all relevant activities, strategies and plans
- Implement the target of zero injuries to people and environment as well as zero accidents or losses ("0 philosophy")
- ensure qualified personnel and sensible resource management
- ensure experience transfer and close cooperation with similar projects
- ensure good communication between the project and partners/authorities
- the same requirements for our suppliers as to Statoil's own employees.

9.3 Acceptance criteria and requirements

The technical solution is subject to risk assessments and is designed/verified so that the risk level meets Statoil's and the authorities' acceptance criteria.

It will continuously be sought to develop solutions that will reduce the risk of personnel, environment, and material values beyond the acceptance criteria.

9.4 Management of health, environment and environment

Volve project manager has the overall responsibility for health, safety and environment during the development phase. An HSE program has been prepared and will be updated and agreed with the contractors' HSE program. The program will then be revised at different milestones in order to have a common attitude towards this both in the development and operational phase.

A requirement has been made to the owner of the facility at Volve to establish a separate HSE program. Additionally, any subcontractors shall be able to document a separate HSE management system with an activity list.

9.5 Safety

9.5.1 Principles

The following principles are emphasized in the safety work:

- Maersk Inspirer is a new facility and it will be focused on limiting risks associated with this
- technical solutions will be assessed against best safety practices
- systematic use of risk analysis and "ALARP" principles in design

- use of assumptions from risk analyses during the operating phase
- focus on high-risk activities and risk areas

9.5.2 Risk analysis

In the preparation phase, Volve project has carried out a concept risk analysis, with the intention of highlighting the risks early in the project. Results show an average FAR on the field of 8.1, which is below Statoil's acceptance criterion of 10. It is estimated that all safety features meet 10^{-4} criteria. Concept risk analysis is used as a basis for improving risk picture and focusing on high risk activities during the modification phase.

A total risk analysis (TRA) with the following main objectives is performed:

- map risk levels after modifications for Volve are implemented
- map which elements contribute most to personnel risk on board
- map the need for modifications to meet Statoil's acceptance criteria
- make sure the modifications that result in new design requirements are designed in a security-optimal manner.

The risk analysis will be updated in the subsequent modification work. In particular, it will be focused on risk-reducing measures in terms of :

- Emergency preparedness and evacuation
- Fire and explosion
- Improved detection
- Implementation of ignition source switch-off
- Placement of new equipment

9.5.3 Security Strategies

A fire and explosion strategy has been prepared - as well as an evacuation, escape and rescue strategy based on the relevant hazard and accident incidents. This should be updated to include process module in connection with modifications.

9.5.4 Explosion

An explosion analysis based on the latest knowledge of explosions with the latest version of simulation tools will be carried out.

9.5.5 Emergency preparedness

An emergency assessment for Volve has been completed, but a detailed emergency analysis will be prepared based on scenarios from TRA. The exact dimensioning of the accident preparedness on board will be done according to the results of that analysis and will meet the authorities' and operator's requirements.

The field-specific preparedness for handling any emissions of hydrocarbons at sea will be coordinated through NOFO with other fields in the area and as a minimum be in accordance with recognized norms and will be concreted in the further work.

9.5.6 Safety in the further work

Follow-up of results, assumptions, and recommendations from completed inspections and analyses becomes an important activity in the upcoming modification phase. At the same time, detailed HAZOP studies will be conducted for the modifications, which must be seen in the context of existing process and design solutions. Priority topics are:

- Preparation of the total risk analysis, including a thorough assessment of identified hazard and accident situations
- Preparation of contingency analysis
- Implementation of a detailed evacuation study
- Detailed reviews and modifications to existing detection, emergency shutdown, and fire water system
- Risk and emergency analysis for drilling wells
- Review of operation and maintenance procedures on safety critical equipment
- Focus on the use of temporary equipment

Planned verification activities and technical reviews will be given priority to ensure that all requirements are met.

9.6 HSE aspects of drilling and completion

Potential pollutants from drilling and completion operations are related to:

- Emissions of cuttings and drilling fluids.
- Discharge of complementary fluids
- Well cleaning
- Unwanted emissions

During drilling and completion operations, precautions should be taken at all times to avoid blowouts, pollution, explosions and other incidents harmful to personnel, installation and external environment. When choosing suppliers, the companies' ability to achieve good HSE results will be part of the evaluation.

9.7 Working environment

9.7.1 Working environment assessments

Mærsk Inspirer has been carefully assessed based on working environment aspects. A compliance poll has been conducted against Mærsk Innovator, which is the sister rig of Mærsk Inspirer against current regulations. The working environment aspects that become particularly focused are:

- noise and vibrations
- access and availability
- material handling and transport streets
- stairs and tenants
- ventilation and air quality
- working and living areas

9.7.2 Follow-up of the working environment in the further work

Statoil has established working environment area requirements for single rooms and areas on board the platform and warehouse ship. In the future, work will be emphasized on studies, where assessments of the deviations from the area requirements are evaluated in relation to criteria and functionality.

9.8 Environmental assessment of the selected solution

According to Statoil's basic principles of environmental protection, all activities must be carried out in such a way that the impact on the external environment becomes minimum as possible and within technical and economic acceptable frameworks. Emissions to air and water should be minimized and the chemicals used and discharged should be the least harmful to the environment as possible. Estimated emissions from the Volve field include emissions from drilling and production.

9.8.1 Emissions to air

Emissions to air will primarily consist of CO_2 and NOx from gas turbines and processing of oil. The main power supply will be from its own power generation on board the platform.

In addition, there will be some emissions from VOC related to the storage and loading of oil as well as diffuse emissions. Calculated maximum amounts of air flow in the production phase (for top production for approx. 1 year) are shown in Table 9.1.

A conventional flare system will be installed with pilot flame. During normal operation there will be no production flaring, but one has the option of fusing gas by stopping the recompression compressor or export compressor to avoid production shutdown.

Table 9.1 - Emission quantity CO_2, NOx and VOC to air (tonnes per. years) in connection with production

Emission component	CO_2	NO_X	VOC
Tonnes per year	93.60	375	990

In accordance with the requirements of the authority, a facility will be installed for the reduction of VOC on the warehouse ship. Emissions to air from the drilling operations in connection with power generation from diesel engines on the drilling rigs as well as from well cleaning. to air in connection with drilling and completion of the wells are shown in Table 9.2.

Table 9.2 - Emission quantity CO_2, NOx and nmVOC to air (tonnes) in connection with drilling and completion of 8 wells

Emission component	CO_2	NOx	VOC
Tons	20.500	450	32

9.8.2 Emissions to sea

Planned emissions at sea from the platform will be emissions of produced water only if the water injection plant is out of service. Moreover, there will be discharge of drain water, sanitary wastewater, cooling water.

Produced water:
Produced water volumes are expected to be relatively limited. The water will be injected along with Utsira water as pressure support in the reservoir. In the event of operational disruption, less volume will be released, but the water will be cleaned with hydro cyclones to ensure that emissions are made to the current regulatory requirements. Any water-soluble chemicals added to the process will follow the fluid phase.

Drain water:
Drain water from non-oil-contaminated areas will be led to sea, while drain water from contaminated areas is led to a reinjection collection tank. Oily drainage from high pressure processing equipment will be collected in a closed drainage system and be applied to the separation process.

Cooling water:
Seawater from the cooling of oil and gas will be released to sea. The water will contain remnants of hypochlorite.

Emissions of drilling *fluid and cuttings:*
The drilling sludge program for Volve will be developed so that emissions be minimized. Continuous discharges of drilling sludge and cuttings at sea will only occur from drilling of the wells' top sections where water-based sludge is used. The drill sludge will be attempted for reused. There will be no emissions to sea of oil-based sludge or cakes. Shafts with an oil-based sludge appendage are transported to shore for treatment and disposal, option reinjected if practically possible. Expected emissions of cuttings and drilling fluid when drilling three production wells and three water injection wells are available in Table 9.3.

9.8.3 Waste

A separate waste management plan shall be prepared for Volve. Measures to reduce waste amounts will be focused, and sorting before final disposal will be taken.

9.8.4 Environmental risk analysis

An environmental risk analysis of Volve has been carried out to ensure that the selected development and operational solutions are within Statoil's operating-specific acceptance criteria with respect to the environment.

The environmental risk to Volve is linked to accidents that may result in acute oil emissions. Accidentally, oil will be able to float to the surface like a flake. Field readiness for handling any emissions is coordinated with Sleipner installations and other fields in the area and as a minimum be in accordance with recognized norms and will be detailed in the further work.

Environmental risk analysis will be updated in advance of drilling operations.

Table 9.3 - Planned discharge of water-based drilling fluid and cuttings drilled with water-based drilling fluid (m^3)

3 production wells		3 injection wells		2 water producers	
Muds	Cuttings	Muds	Cuttings	Muds	Cuttings
5673	1137	4485	2115	2304	710

9.8.5 Impact assessment

In reference to the Petroleum Act and guidelines set out by the Ministry of Petroleum and Energy, an impact assessment has been prepared to describe the effects of the environment, natural resources, and society. The impact assessment has been submitted earlier to the OED and mainly takes the "Regional impact assessment for the North Sea" prepared by Statoil in cooperation with other oil companies in 1999.

The regional impact assessment for the North Sea (RKU North Sea) is part of the documentation for Volve impact assessment. In total, RKU covers the North Sea and Volve KU requirements for investigating the effects of the Volve development.

10 Organisation and implementation

10.1 The project's management system

10.1.1 Goals and instruments

Development of Volve shall be carried out in accordance with Statoil's group document AR05 "Project Development" as well as the guides defined in Norsok.

The project will be targeted where handling uncertainty is to be added to particular emphasis. The project's main objective is related to:

- Health, safety and environment
- Profitability
- Implementation
- Quality

Important instruments for achieving the goals are:

- Vendor selection and "on-sea" activities
- Continuous focus on uncertainty elements related to the goals defined
- A fully governing document system
- Quality as an integral part of management responsibility at all levels
- Quality built into products and activities using correct and documented management systems and routines.

10.1.2 Documentation of management system

The project's management system is based on:

- government laws and regulations
- licensing terms and license agreements
- Statoil's governing documents

The quality system for the project consists of:

- Contract agreement between Troll / Sleipner Operations Director and T&P/Director of Projects
- Project agreement between T&P/Director of Projects and Volve Project Manager
- This PDO with support documentation and the Impact Assessment
- The contract with the provider of jack-up platform
- The contract with supplier of warehouse ships (FSU)
- Project implementation strategy (PGS)
- Project implementation plan (PGP)
- The project's other governing documentation and plans
- Contracts with external suppliers (Statoil framework agreements)
- Agreements with internal vendors (such as Sleipner B&B)
- Relevant procedures for operations on the Sleipner field.

10.2 Organization description

10.2.1 Operator liability

Under the cooperation agreement, Statoil maintains the day-to-day management of the business carried out in connection with production licence 046 on behalf of the owner group. The operator performs its duties according to decisions of the steering committee, which is the supreme body of the ownership group.

10.2.2 Planning and development organisation

The daily exercise of Statoil's operatorship for the planning and development of Volve is taken care of by a project organization. The project is organized with a core team that has the consistent responsibility for planning and development of Volve until the end of the project.

The project will extensively use the main suppliers' resources in addition to having close cooperation with Statoil's competence units.

In connection with drilling and implementation, a separate drilling project will be established with responsibility for the completion of the wells. The drilling project will report to Volve project manager.

Experience from Yme and Glitne the fields' operating organisation has been used and will be exploited in the planning and implementation of the project.

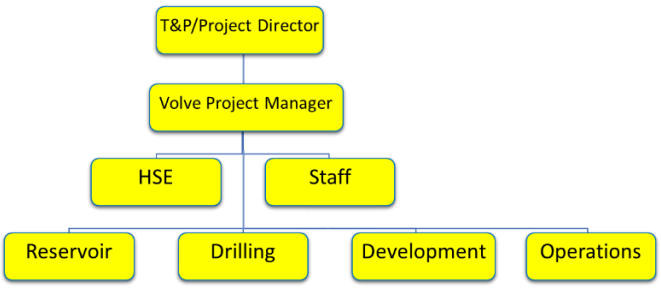


Figure 10.1 - Operator's organization in the mobilization phase

10.2.3 Operating organization

Statoil, as operator of Production License 046, is responsible for all activities above authorities and partners. Daily operational and maintenance responsibilities are regulated through the contract between the main supplier and Statoil. The installations shall be operated in accordance with the current government and company requirements.

The Land Organization for Volve is in Stavanger including operational support functions such as helicopter base and supply base. Volve will integrate in the operating phase with Sleipner operating body

10.2.4 Coordination with other fields

The project will actively cooperate with basic organizations and other development organizations and operating organizations to take advantage of economies of scale in the conclusion of contracts, joint services, technical support functions and transport.

Supply and base services as well as emergency preparedness will be coordinated with other Statoil fields in the southern part of the North Sea.

10.2.5 Recruitment to the development and operations organization

Recruitment to the core team has been made internally in collaboration with the resource owners in Statoil.

Recruitment of resources for development and operational tasks is done by the main suppliers as agreed in the contract.

The operator has nominated a company representative with responsibility and authority to provide all formal communication with the main suppliers.

In areas where special expertise is needed, for example, in the "on-sea" activities of the operator, the process owners and managers in Statoil will be used.

10.2.6 Competence needs and training measures

Statoil currently holds personnel with expertise to manage the planning and development of Volve. Through the contract, the main supplier has committed to providing competence and carrying out training measures required and necessary to achieve the intentions of the contract in accordance with laws and regulations.

10.2.7 Personnel needs

During the operational phase, the Operators' land organisation will constitute about 16 man-years as well as the contractors land organisation. Man-years related to offshore activities will be 100 to 150 man-years, depending on the level of drilling activity on the platform.

The total employment corresponds to approximately 3,400 man-years, of which 550 are direct man-years, 2200 in subcontractors and 650 will be consumer effects. Of the total employment effect in Norway in the period 2005 to 2012 of 3,400 man-years, oil and gas activities will account for 15% of employment, equivalent to 500 man-years. The largest thing is business activities and transport activities with 950 and 600 man-years respectively.

Volve is expected to be operated from Stavanger.

10.3 Relationship with industry and society

10.3.1 Socio-economic consequences

The provision of Volve production facilities is carried out as a rental concept of partially existing facilities and nyanskaffels through a main supplier.

The development of Volve is planned to be completed in the period December 2004 to January 2007. Total investments are estimated at 1968 Mill. NOK 2005, including drilling and completion of wells.

The assembly of the production facilities will take place at a norsk shipyard and will secure contracts for the Norwegian shipyard industry.

10.3.2 Acquisitions

The choice of concept/contractor was based on market assessments conducted in the summer/autumn 2004. It showed that only the selected concept provides the basis for economically robust recovery of the Volve field and the facility is planned secured for this purpose.

In its other acquisitions, the project will leverage the company's total expertise and market position, as well as the company's framework agreements and normal tender procedures.

10.3.3 Application of research & development results

Statoil has an active and extensive involvement in research and development. When designing and choosing solutions, results from this research and development will be used to the extent appropriate.

The development is based on known technology and has for this reason not defined special technology development in the project implementation phase.

10.4 Project implementation plan

The project is based on the start-up of detailed engineering studies in connection with the conclusion of letter of intent with the selected suppliers in December 2004. These studies form the basis for ordering equipment with a long delivery time, and this equipment will be ordered upon decision on the submission of the PDO. The following milestones apply to the progress of the project:

• Engineering and construction of • processing plants	Feb. 2005 – May 2006
• Engineering and construction of • export system	Feb. 2005 – March 2006
• Installation of • export pipes and bending	April – Oct. 2006
• Platform for shipyards	Sept. 2006
• Hooking up • processing plants	Oct. – Nov. 2006
• Platform towing	Des. 2006
• Production start-up	1st half year 2007

Under contract, the towing of the platform will take place in December 2006. The weather risk in the event of a lag is the contractor's risk of costs. Because of the fact that possible delays related to exhausting of the platform in winter and generally tight implementation plan, licensees have assessed the risk of delays so that production start-up may be delayed , and has therefore indicated start-up during the first round of the 1st six months. If the contractor holds its plans, the expected start is March 2007.

10.5 Verification and follow-up of main contracts

From the PDO submission, Statoil will continue with a Volve project team that has the overall responsibility, ref. chapter 10.2. In this team, led by the company's representative of the contracts, dedicated personnel will be responsible for verification and follow-up of the main contractor activities according to the project's supervision plan and Statoil's governing documents.

The team will focus on the suppliers deliveries meeting requirements under the regulations. Statoil will, through regular meetings and on-see activities, follow up HSE, quality, progress and the implementation plan of the contractors.

Close dialogue with the authorities, mainly the Petroleum Safety Authority Norway, the Norwegian Petroleum Directorate and the SFT will be required.

11 Closing schedule

11.1 Introduction

Production at Volve is shut down when the project gives negative cash flow. Based on expectation prices and estimated production profile, this will happen after approximately 5 years of production.

The owners of Volve can terminate the contract on the lease of Mærsk Inspirer and Navion Saga with 6 months' notice provided that the total time on the field will be a minimum of 36 months. Based on production developments and oil prices, the timing of cancellation will change. Reporting on the cancellation of the contract to end Volve production will be taken up with authorities in good time. The main goal is to achieve the highest possible recovery of the field. The actual removal of the installations and the shutdown of wells will be carried out in accordance with applicable regulations. The regulations provide guidelines for both the shutdown of wells and the removal of the installations.

11.2 Production facilities When the Volve field can no longer be operated economically, wells will be shut down. STL buoy with anchoring will be removed using an anchor handling vessel.

The oil and gas export pipelines will be considered removed. Since the pipes are buried, this can be difficult. Alternative to removal and reuse will be to stone dump the relatives.

The platform will plug the wells and remove production tubing and casings according to applicable regulations.

The platform will secure the wells in accordance with existing regulations. Once securing the wells is carried out, only cuttings with water-based sludge content will be left on the seabed.

11.3 Costs of shutdown and removal

The total cost of plugging wells is 93 Mill. NOK2005.

Removal of jack-up platform, risers, pipelines and anchors is estimated at 51 Mill. NOK2005, based on the current rate level for the various vessels expected to be used.

12 Financial analyses and assessments

12.1 The costs of Development and operation

The development costs have been prepared in accordance with Statoil's guidelines and are based on experiences from previous projects and offer/contract price from the contractors / suppliers.

12.1.1 Investments

Volve tenants' investments are mainly related to well costs (drilling and completion) as well as procurement of pipelines, marine installations and mobilization of drilling, production platform and teamship. Table 12.1 shows an overview of all costs.

Table 12.1 - Investments

Investments in Mill. NOK2005	
Wells	937
Mobilization platform	291
Export system including stock ships	391
Project management costs including project reserve	349
Total	1968

12.1.2 Rental costs for production facilities-

Rental costs for Mærsk Inspirer with associated equipment and operation of the plant are based on contract price from Mærsk in the form of fixed day rate compensation and tariff for produced oil and gas as well as agreed mobilization and demobilization sum.

The costs are divided into four elements:

- investment element for jack-up platform
- operating expenses covering the contractor's crew as well as operation and maintenance
- investment element for stock ships
- operating expenses for stock ships

The contract is based on a 3-year lease with a 6-month notice of contract. Both investment elements are stated in nominal USD, i.e.they will not be inflation-adjusted. Process plant at Mærsk Inspirer will be paid via a unit tariff given in different currencies (NOK, EUR, USD/barrel oil equivalent.)

Operating costs in the contracts are given in respective NOK, EUR, USD2004 and will be subject to wage/index regulation. In addition, it is assumed that the warehouse ship is hired by the owners of Volve. The warehouse ship's rental costs are given in the contract with Teekay Norway. Rental costs to the contractor converted to USD/d are shown in Table 12.2.

Table 12.2 - Rental costs to the contractor per. day in the drilling/production period (not inflation-adjusted)

Rent of the jack-up platform Mærsk Inspirer / warehouse ship Navion Saga	
Investment element platform	92,500 USD NOM/day
Investment element stock ships	38,590 USD NOM /day in 3 years, then 18,076 USD NOM
Operation and maintenance costs platform	95,313 USD 2004/day (drilling phase)/ 109,638 USD 2004/day (drill & prod. phase) 72,467 USD 2004/day (production phase)
Operation and maintenance costs warehouse ships	22,444 USD 2004/day

Table 12.3 - Rental costs to contractors per barrel of oil equivalents (not inflation-adjusted)

Hiring of processing plants	55 million boe	55 -65 million barrels oe	65 -75 million boe	75 -85 million boe	Then
	2.75 USD nom/bbl oe	2.25 USD nom/ bbl oe	2.0 USD nom/ bbl oe	1.75 USD nom/ bbl oe	1.50 USD nom/ bbl oe

12.1.3 Operator's operating expenses

The following operating costs will have to be covered by Volve owners in addition to the rental costs of the contractor, see Table 12.4.

Table 12.4 -Operator's annual operating expense at plateau rate

Operating expenses per 12 month production in mill NOK 2005	
Logistics (helicopter, supply etc.)	31
Operator's operating organization	37
Production chemicals	12
Well intervention costs	27
Co^2 - fee / Nox fee	19
Various	29
Sum	155

12.1.4 Removal and plugging costs

When the Volve field is fully produced, that is, when the revenue is less than the expenses (before tax), the field's production will be terminated. Estimated costs that will apply to demobilize production facilities and ensure wells are shown in Table 12.5.

Table 12.5 - Removal and plugging costs

Removal and plugging costs Mill. NOK 2005	
Removal of Jack-up/ FSU/Riser / Pipelines	51
Plugging wells	92
Total	143

12.1.5 Cost profile to the financial calculations

Estimated text profile is based on 94% regularity. The expenses are assumed with the same regularity, but today the rate is included with 365 days per. years. Total costs per year are presented in Table 12.6.

Table 12.6 - Costs per. year, Mill. NOK (nominal NOK)

	2005	2006	2007	2008	2009	2010	2011	2012*)	Total
Wells	7	67	828	189					1091
Mob., sub sea equipment, project management	156	720							876
Unforeseen costs		76							76
Total investment costs	**163**	**863**	**828**	**189**					**2043**
Rent platform and FSU (investment) including tariff process facilities /			508	734	717	513	384	142	2998
Rental platform and FSU (operation and maintenance)			157	250	261	268	275	116	1327
Statoil operating costs land support	5	32	170	165	167	168	173	74	954
Closing costs								61	61
Plugging wells								110	110
Total operating costs	**5**	**32**	**835**	**1149**	**1145**	**949**	**832**	**503**	**5450**
Total costs	**168**	**895**	**1663**	**1338**	**1145**	**949**	**832**	**503**	**7493**

*) Pre-tax expenses are higher than pre-tax income in May 2012. The expenditure in Table 12.6 in 2012 is therefore only 5 months of uptime.

12.2 Economic analyses

12.2.1 Financial assumptions

The calculations are carried out with financial assumptions as specified in Table 12.7.

Table 12.7 - Economic assumptions

Financial assumptions		
Expected oil price Brent blend	USD/barrel	22
Low price range	USD/barrel 2004	15
"Forward" price path	USD/barrel nom. as of 15.12.04	35 average
Price penalty for Volve oil	USD/barrel 2004	3.3
Exchange rate	NOK/USD	6.75
Inflation Norway and the United States		2.5 %
Production start-up	March 2007	

A price reduction compared to Brent Blend. This is because Volve has an inferior oil technical quality and low total volume. Due to the short production time at Volve, it's economic production time is calculated from production per. month. For the base case, it results in an economic production time of 63 months down (given oil price of US $ 18.70 2004 / barrel in 2012).

12.2.2 Profitability

Table 12.8 shows the profitability of the project. Present value after tax is calculated on the total real cash flow to total capital as a result of loan financing (WACC).

Cash flows are discounted to mid-term 2005.

In the present value calculations after tax, the investment equivalent method is used (the capital portion of the lease rate for a 3-year period).

12.2.3 Zero point price

The zero point price (NPP) both 7% before tax and 8% after tax are estimated at 17.50 USD/barrel 2004 for Brent Blend quality.

Table 12.8 - Profitability with expectation price and 18.70 USD/barrel

Present value (Mill. NOK 2005) and internal interest			
	Before tax	After tax	
Price path	NV 7%	NV 8%	IRR %
Expected oil price 18.7 USD/barrel	2534	443	18.3
"Forward" price 15.12.04	5565	1196	38.7

12.2.4 Cash Flow Profile

The project's cash flow before tax is shown in Figure 12.1. Before the project has produced for one year, it is estimated cash flow positive (early 2007). This is due to rapid development and the cost of Platform and storage ship hire does not start until production starts

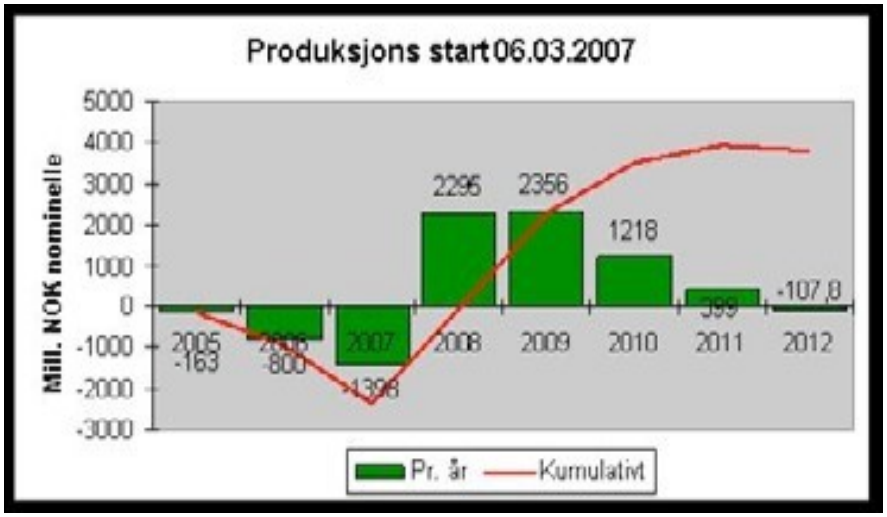


Figure 12.1 - Cash flow before tax

12.3 Project uncertainty

12.3.1 Uncertainty in economic analyses

The main factors affecting the outcome of the economic analyses are uncertainty in reservoirs, costs, and markets.

***Reservoir**:* Reservoir uncertainty is understood by using the P90 and P10 production profiles in the financial calculations. Risks related to deposits in the reservoir are considered to result in production within P90 - P10 estimates and are not included as separate sensitivities.

***Cost**:* Uncertainty in cost estimates is included in the upside/downside financial calculations. ± 300 MNOK. In addition, the effect of any need for more wells is assessed.

***Market**:* Unsecurity in the market is described by showing the economic performance with a high price trajectory of 35 USD/barrel Brent blend and low price range 15.0 USD/barrel Brent blend.

12.3.2 Sensitivity

The result of the most important sensitivities is summarized in Table 12.9.

Volve is sensitive to oil prices, and is slightly negative at low price trajectory. At current prices, the upside in the project is large.

Table 12.9 - Sensitivity financial calculations (present value)

Present value (M.NOK 2005)		
	Before tax NV 7%	After tax NV 8%
Volve with expected oil price of USD 18.7/barrel	2534	443
Reservoir		
P90 production profile	1520	203
P10 production profile	3677	718
Costs		
Investment costs + 300 Mill. NOK	2247	359
Investment costs - 300 Mill. NOK	2822	526
2 additional wells	2295	373
Market		
Price range 15 USD/barrel Brent blend	-211	-233
Price range 35 USD/barrel Brent blend avg. section "forward" 15.12.04	5565	1196

13 Area rating

13.1 Introduction

Volve has potential additional volumes in nearby structures located both within and outside Volve defined range, ref figure 1.2. Availability of drilling and processing equipment at Volve allows for a cost-effective exploration, demarcation, and production of oil in these structures. Further exploration is expected to be done late in the drilling phase or while the platform produces on plateau so that additional volume can be phased in when there is spare capacity.

The development plan for Volve only has been added production and costs to proven oil, exploration costs are kept out of the development plan.

13.2 Additional volumes and appraisal strategy

In this documentation, it is only with oil prospects and "leads" at the drillable distance from Volve installation, see table and Figure 13.1.

Volve South is a small, but well-defined structural height between Volve and Sleipner East. There is a high probability of further migration of oil from Volve into Volve South so that the probability of discovery becomes relatively high. Given the discovery, the structure can be developed with a producer and an injector. The most obvious thing is to drill a dedicated exploration well from Volve with the possibility of complementing the well as a producer, given the discovery.

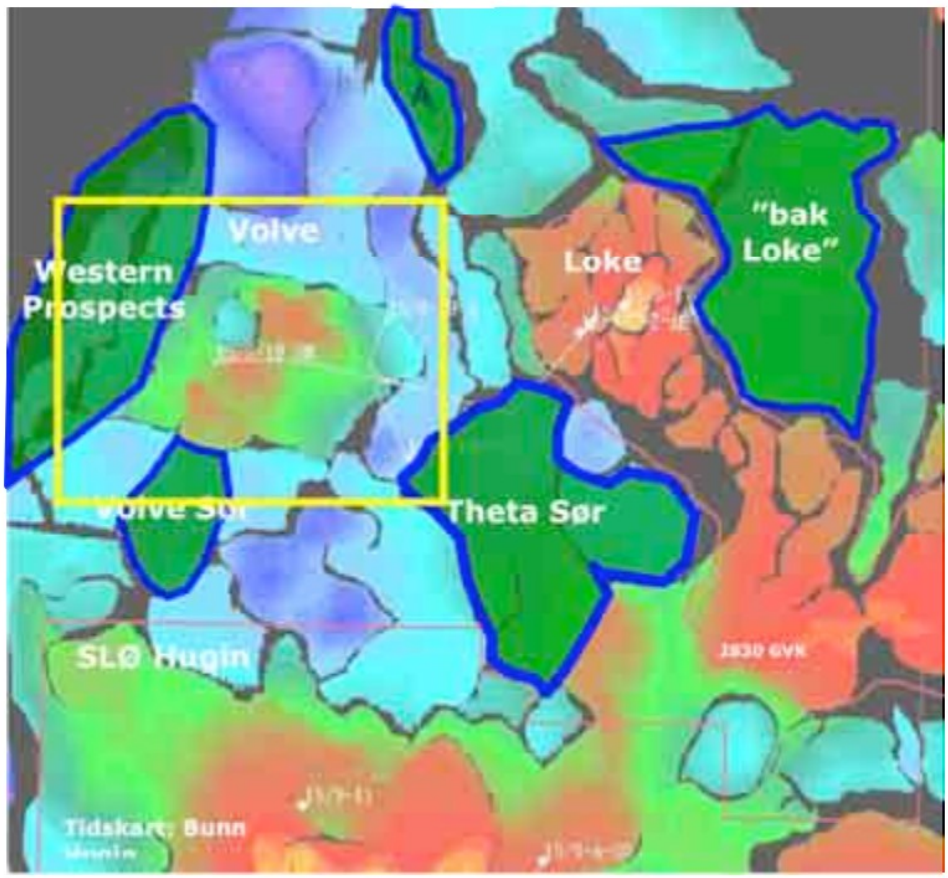
Theta South is a structure the size of Volve. There is considerable uncertainty related to the possibility of migration into the structure and the trap also depends on fault seal. There are also opportunities for segmentation of the structure so that exploration must take place stepwise, while there must be a great focus on exploration and appraisal wells further used as a producer or injector wells.

West of Volve and Volve South, Hug's formation is mapped in a number of smaller and partly rotated fault blocks. The presence of oil here depends on an oil/water contamination that lies significantly deeper than what has so far been observed. The probability of discovery is therefore relatively low. The possibility of a deep contact can be refined using a sidestep on the injector well in the west. Given the findings, 4-6 wells will be required to develop the best prospects.

On the western part of Volve, the structure of high amplitude seismic reflectors is in the upper Jurassic package. Something similar is seen west of Loke structure, where well 15/9-C-2AH has detected the presence of porous sandstone in the Draupne formation. The migration of oil from the source area also depends on being able to take place in layers of sandstone in the Draupne formation. There is therefore a certain probability that the amplitudes in the west represents oil-filled sandstone, but it has not been possible to produce a satisfactory map and therefore no volume has been calculated for this prospectus. Upper Jurassic prospectively is assumed to be limited by the same sidelines as mentioned above

Table 13.1 - Probability of Discovery

Prospect	Probability of discovery	Resources	Risk resources
Volve South	0.56	5.9	3.3
Theta South	0.22	27.5	6.1
Western prospects	0.20	30	6
Total	-	63.4	15.4



Oil prospects and leads

Figure 13.1 Volve Sitemap with Prospects and Leads