THE POTENTIAL OF THE NORTH SEA
- REALISATION THROUGH THREE GROWTH ENGINES
DRAWN UP BY QUARTZ+CO
OCTOBER 2013
In connection with establishment of the trade association Olie Gas Danmark (OGD) mid-2012, Quartz + Co was chosen to draw up a sector analysis which was named: The Danish oil and gas sector’s development and social impact (1992 to 2022). The purpose of the sector analysis was to provide a factual and short description of the Danish shelf, development of the sector and its social contributions. Finally, the analysis pointed out that a considerable social additional contribution is involved in realisation of part of the potential, which exists on the Danish shelf according to the Danish Energy Agency and the sector.

Further to the report from 2012, Quartz + Co has been chosen to draw up a new analysis and report which go a step further and identify what is needed to realise the potential of the North Sea. The report is named: “The potential of the North Sea – realisation through three growth engines”. The intention of the report is to contribute to a factual description of and a perspective on which ‘engines of growth’ and levers the players in and around the sector shall cooperate on to realise the potential.

The report is based on three key engines of growth: 1) Increased exploration activities, 2) Production of marginal fields and 3) Increase of the recovery rate. As it appears from the report, there is a natural link between the three engines of growth; that is why these should be seen as a whole. To hit a balance between describing some relatively complicated issues and at the same time do it in a brief and simple way, it is, however, decided to deal independently with the three engines of growth in a final synthesis. Thus, the report is divided into five chapters supported by a number of illustrations of the most essential analyses:

#1: The potential of the Danish shelf
#2: Engine of growth I – increased exploration activity
#3: Engine of growth II – production of marginal fields
#4: Engine of growth III – increase of the recovery rate
#5: Summary: Gearing for growth on the Danish shelf

Each of the independent chapters regarding the three engines of growth begins with a brief description of the historical development of Danish shelf, which is subsequently put into perspective through a description of the opportunities and challenges as well as potential levers which can contribute to create the conditions for supplying a sustainable additional social contribution.

Primarily, the descriptions and analyses of the report are based on input data from the sources; The Danish Energy Agency, Wood Mackenzie, GEUS, SPE International, Professor Erling Halfdan Stenby, Rafael Sandrea (IPC Petroleum Consultants), Oil & Gas UK and Oljedirektoratet in Norway.

Furthermore, OGD has put the member base – both oil companies as suppliers and service companies – at disposal for additional collection of primary data, surveys, inspiration workshops and validation sessions. This was done in order to compare the analysis and perspectives to the players’ experiences and technical insight.

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**SUMMARY**

There is a significant oil and gas potential left in the Danish sector of the North Sea. In addition to the reserves known and not yet produced, the latest figures from the Danish Energy Agency show that there is a resource potential corresponding to well over 1.4 billion barrels of oil and gas – or more than 40% of Denmark’s total production from 1972 until today. The potential consists of possible new oil and gas discoveries, existing discoveries, which have not yet been developed and put into production, and finally an increase in recovery from the producing fields.

If 50% of the estimated potential is realised, it corresponds to a fiscal additional contribution of approx. DKK 190 billion towards 2042.

Realisation of the potential of the North Sea requires a simultaneous acceleration of three key engines of growth – 1) Increased exploration activities, 2) Production of marginal fields and 3) Increase of the recovery rate. The three engines of growth are mutually self-perpetuating meaning that all the engines of growth must be running in order to ensure optimum performance of each.

The Danish shelf has reached a level of maturity which means that it cannot be operated and developed as thus far – we must think differently. All three engines of growth are tied to the infrastructure in the North Sea today, and which will be phased out during a foreseeable future unless further production is added. If the infrastructure is phased out before commencement of realisation of the resources, the resources will remain in subsoil forever, as it will not be justified economically to establish a new infrastructure for recovery – fast action is required.

A prerequisite for further production in the longer run is that more oil and gas is discovered. Historically, 185 exploration wells have been carried out on the Danish shelf and 35 discoveries have been made which have provided a total quantity of discovered oil and gas corresponding to more than 5 billion barrels. However, the number of active licenses and exploration wells has decreased over a period of time, and at present the number of exploration wells is at the lowest level since the 1960s. An increasing number of exploration wells result in discoveries. But at the same time, the size of the discoveries has become smaller, and it has become significantly more expensive to carry out exploration. All things considered, it has become more marginal and less attractive to search for oil and gas in Denmark. This trend must be changed if the potential of the Danish subsoil shall be realised.

Making new discoveries is only the first important step. A prerequisite for producing a discovery is that it is developed. Of the 35 discoveries, which have been made in the course of time, 18 have been developed – and one is being developed. About half of all discoveries have thus not yet been developed. Most of the discoveries are marginal - i.e. they are too small in relation to volume or their geological conditions are too complex to be profitable to develop the fields under the current conditions. With decreasing discovery size and increasing production costs the majority of the future discoveries may also be expected to be marginal.

If current and new marginal discoveries shall be developed, the economic uncertainty related to the development shall be reduced. Moreover, it is a prerequisite that the discoveries can be connected to the existing infrastructure. With decreasing production and increasing operating costs the producing fields will soon get to the point where production cannot finance its future operation. A large part of the fields and thus infrastructure will be phased out within the next 10-20 years unless new production is added and their costs are reduced. Therefore, the time perspective is a crucial factor - the longer the decision to develop the marginal fields is postponed, the more remote is the likelihood of development.

The producing fields are phased out, when it is no longer profitable to maintain production. Increase in the recovery rate of the producing fields (an expression of how much of the current quantities of oil in the field reservoir is expected to be recovered during its life) includes per se a large resource potential and can also contribute to extend the life of the existing infrastructure. Thus the time-wise window for connection of marginal discoveries is postponed.

The recovery rate depends on the geological conditions of a field and the investments made by recovering increasing measures – such as new production wells, optimisation of existing wells and construction of water injection. The number of new production and injection wells have strongly decreased in recent years and it has become harder to achieve further increases in the recovery rate (which is currently at 28% on average according to the operators). But
technically, a number of measures which may increase the recovery rate can still be taken on many of the fields. However, it requires that new recovery increasing investments are made in time or that the measures have a positive impact on the recovery rate of the fields prior to shutdown of these.

At present, realisation of the total resource potential on the Danish shelf is under pressure. The size of the potential depends on how quickly the key players in and around the sector have jointly accelerated the three engines of growth. There are a number of levers which can contribute to accelerate the activity of the three engines of growth – including

- Reduction of the current drilling, development and operating costs through closer operator cooperation
- Reducing the total time spent on planning and deciding new developments
- Establishment of an intensive joint effort between the sector and state regarding maturation and commercialisation to enhance recovery technologies
- Adjustment of the current licensing model of increased flexibility
- Arrangement of the regulatory framework in order to prevent unnecessary increase of the cost of activities – e.g. through standardisation of regulatory requirements on rigs across the EU countries bordering on the North Sea
- Establishment of measures to ensure that the sector can recruit the necessary skilled labour force in the future
- Establishment of a tax regime for new projects reflecting the current risk-/return profile of the shelf and thus encouraging new exploration, development of marginal fields and recovery-enhancing initiatives on producing fields
1. THE POTENTIAL OF THE DANISH SHELF

Development on the Danish shelf in recent years could give the impression that Danish oil and gas production is phasing out. Production has decreased significantly - on average 10% annually for the past five years - and in 2012 it reached 105 mmboe, which is the lowest level since 1995. The remaining reserves have been reduced - from 2002 to 2011, 1,658 mmboe have been produced but only 535 mmboe have been added in new reserves corresponding to the reserves having been reduced by 112 mmboe annually during this period. Development of a new field on the Danish shelf has not been made for 10 years and the number of wells has decreased significantly since the millennium - the five wells drilled in 2012 are the lowest number since 1979 and corresponds to 1/10 of the number in 2001. Recently, the Danish Energy Agency has noted the same tendency: “After 40 years’ production, the Danish territory in the North Sea can be described as a mature field focusing on optimisation of ongoing production and maintenance of existing installations”.

The Danish shelf has reached a mature stage. Basing, however, the future development of the Danish oil and gas sector on the assumption that the sector is being phased out - and further investments in this should therefore not be made - there is a risk to lose a large potential.

There is significant remaining production potential on the Danish shelf, which potentially will last for many decades. The Danish Energy Agency expects production of 1,065 mmboe oil and gas from existing, committed and probable developments in the Danish sector of the North Sea up to and including 2042.

In addition, the Danish Energy Agency has prepared a forecast for the remaining resources on the Danish shelf. The resources covering additional recovery of oil and gas, which all in all - and under the right conditions - can be achieved through exploration, maturation, commercialisation and production of new reserves, have been estimated to 1,398 mmboe by the Danish Energy Agency. The resource potential - corresponding to 41% of the total historical

BESIDES THE ALREADY KNOWN RESERVES, THE DANISH SHELF HOLDS FURTHER RESOURCE POTENTIAL EQUIVALENT TO 1.398 MMBOE

HISTORICAL AND EXPECTED PRODUCTION VOLUME AND RESOURCES (OIL AND GAS)

MMBOE

Note: 1972 to 2012 historical data from 2013 to 2042 is based on forecast made by the Danish Energy Agency.

* The contingent resources are taken from the expected production volume from the Danish Energy Agency and estimated on the basis of risk assessed numbers from the Danish Energy Agency. The volume of the contingent resources are estimated by Quartz+Co based upon the Danish Energy Agency’s volume for exploration and technological resources.

Source: Danish Energy Agency; Quartz+Co-analysis
production - is thus estimated to be almost 1/3 larger than the remaining expected production of reserves. Production-wise it is thus estimated that there is a larger remaining potential of the more immature and uncertain resources than of the reserves already known.

In the light of the development in recent years on the Danish shelf, realisation of the entire estimated potential must, however, at the same time be considered ambitious. Whether the realisation of the potential is realistic depends, however, on the effort made (in the form of investments, framework conditions, technological development, education, operator cooperation, etc.) and the timing of these efforts in relation to the time of shutdown of the existing production facilities which on average has reached an age of over 20 years and produced over 80% of their total reserves.

If investments in exploration, new field developments and technologies, which can increase recovery, are not made the resource potential is not realised. If the potential on the Danish shelf is realised – and is further maximised – an acceleration of development of the Danish oil and gas sector must occur.

1.1 THERE ARE THREE KEY ENGINES OF GROWTH FOR REALISATION OF THE POTENTIAL

The potential on the Danish shelf can be divided into three categories – exploration resources, conditional resources and technological resources, which according to the Danish Energy Agency’s estimates constitute 39%, 19% and 42%, respectively, of the total potential.

Realisation of exploration resources depends on increased exploration activity to drive new discoveries of oil and gas and on the fact that the discovered resources can be converted into commercial production. At present, the exploration activity is at a too low level to realistically be able to realise the estimated exploration potential.

Realisation of the conditional resources assumes that the increasing number of marginal discoveries, which under the present conditions is not commercial to develop, are developed and produced. Today, 1/3 of all Danish discoveries of 50 mmboe or less have been developed. Due to their limited size, most of the marginal discoveries depend on production via existing fields in order to be commercial. Therefore it is also assumed - indirectly - that the existing fields maintain sufficient production to remain profitable. These fields will to a greater extent become marginal themselves due to falling production.

Finally, realisation of the technological resources assumes that a significant effort is made on the Danish shelf to increase the current average recovery rate, which is how the technological resources are materialised.

It is thus natural to consider 1) Increased exploration activities, 2) Production of marginal fields and 3) Increase of the recovery rate as the key engines of growth during realisation of the potential on the Danish shelf. Although, the three engines of growth involve various links of the value chain and address each part of the resource potential, they are to a great extent complementary - increase in the activity compared to one of the engine of growth improves the attractiveness of increasing the activity compared to the other two.

Increased exploration activity provides potentially more discoveries, which increase the potential for overall development of the adjacent marginal discoveries which would not otherwise have been developed.

The production of marginal fields increases the incentive for exploration, as it improves the development potential of marginal discoveries and thus reduces the exploration risk. Moreover, development of new fields makes a breeding ground for new near-field exploration around the new fields. Additionally, connection of marginal discoveries to existing platforms can postpone the financial shutdown of these fields and thus maintain ‘tail-end production’ from existing wells for a long time or

4 Exploration resources are an estimate of the quantities expected to be recovered from new discoveries. The conditional resources are development of discoveries and new fields or further development of existing fields, where the technical or commercial basis is not yet in place for a final decision on development. Technological resources are an estimate of the quantities of oil and gas which are further estimated to be recovered by the use of new technology (the Danish Energy Agency classification system for oil and gas resources, June 2011).

5 The recovery rate expresses the part of the oil in a given reservoir ready for recovery, i.e. how much of the total present quantities of oil in the reservoir (STOIP) can be recovered during the life of the field under the given technical and financial conditions. It describes always the expected final recovery and not the recovery already obtained.

6 Tail-end production is used as a condition for the last part of production on a field beyond its life.
leave time to invest in new technologies such as CO₂-injection which can increase the recovery rate of the existing fields. Finally, increased field development – all things being equal – will increase the incentive for development of general techniques and technologies to increase the recovery rate, as more fields will benefit from it.

**Increase of the recovery rate** can postpone shutdown of existing fields, which extends the window of opportunity for connecting marginal discoveries. New general techniques and technologies to increase the recovery rate can increase the reserves of marginal fields and thus improve their development potential while it can increase the resource potential during exploration, as you get more out of a field/possible discovery.

Dependency and the synergies between the three engines of growth only increase the need for a coherent effort.
2. ENGINE OF GROWTH I – INCREASED EXPLORATION ACTIVITY

After several years of successful exploration, the exploration activity on the Danish shelf today is difficult. There are fewer active licenses and the number of exploration wells are today at a low level. Oil and gas are still discovered, but the discoveries are becoming smaller, at the same time as it has become significantly more expensive to explore, i.a. due to fewer available rigs. If the exploration targets are to be realised, an increase in the number of exploration wells is necessary – for example by introducing a differentiated tax-related inducement for exploration, a more flexible licensing model, standardisation of the Danish rules of drilling rigs with the other EU-countries and increased development of marginal discoveries.

2.1 THE EXPLORATION ACTIVITY IS AT THE LOWEST LEVEL SINCE THE 60’S

The exploration activity on the Danish shelf can be traced back to 1936 when the first exploration wells were drilled onshore. However, another 30 years passed before the first discovery was made and the exploration activity really began. The Kraka field was discovered offshore by the Danish Underground Consortium (DUC) in 1967, after A.P. Møller had been granted exclusive rights for exploration and production of hydrocarbons (oil and gas) on the Danish shelf in 1962 and soon after, DUC was founded together with Gulf Oil and later on Shell.

Since 1965, a total of 185 exploration wells have been drilled on the Danish shelf, of which the main part has drilled within a relatively limited geographical area in the most western part of the Danish part of the North Sea (west of 6°15’), where also all 35 discoveries have been made. Half of the exploration wells (94) have been drilled under the concession, while the other half has been carried out under the new licensing forms introduced by limitation of A.P. Møller’s concession in 1981, which paved the way for other players than DUC to explore and recover hydrocarbons in Denmark within the concession areas applied for and granted. The first licensing round on the Danish shelf took place in 1984 and so far six licensing rounds have been held, while a seventh is planned to be held in 2013.

The 1980s was the decade with the highest number of exploration wells on the Danish shelf (64) and  

FEWER EXPLORATION WELLS ARE DRILLED AND THE MAIN PART OF WELLS ARE TODAY DRILLED WITHIN THE KNOWN COMMERCIAL AREA

A LINE OF MILESTONES HAVE DEFINED THE DEVELOPMENT IN THE EXPLORATION ACTIVITY ON THE DANISH SHELF

NUMBER OF EXPLORATION WELLS FROM 1962-2013, N=185

- 1962: Shortly thereafter, DUC* was founded
- 1967: First discovery
- 1981: Limitation of the Sole concession**
- 1983: Licence rounds introduced
- 1984: Licence round 1
- 1986: Licence round 2
- 1989: Licence round 3
- 1995: Licence round 4
- 1998: Licence round 5
- 2006: Licence round 6
- 2010-2013

* Dansk Undergrunds Consortium – today consisting of APMM, Shell, Chevron and the oil- and gas company of the Danish state Nordsøfonden
** 50% area delivered back in 1982, a further 25% in 1984 and the rest in 1986. Areas, where exploration has begun or where new sources for commercial exploitation were excluded.

Source: The Danish Energy Agency; Nordsøfonden; Energy and Oil forum
1985 was the single year where most wells drilled (14). In the 1990s and 2000s, the total number of exploration wells was halved to 32. Seen in isolation of the last five years (2008-2012), the number of exploration wells was 11. We need to look back at the early 1960s to find a lower number of exploration wells during a five year period. An average (high) oil price during this period of USD 92 per bbl has apparently not affected the exploration activities.

Significantly fewer exploration wells are drilled on the Danish shelf than on the British and Norwegian shelves – both of which, however, have a significantly higher remaining prospectivity than the Danish shelf. From 2008-2012, 127 exploration wells were drilled in the UK, 182 in Norway and 11 in Denmark.

2.2 THERE ARE FEWER AND FEWER ACTIVE LICENCES ON THE DANISH SHELF

In 2012, there were a total of 20 active licenses west of 6°15’ – a decline from 25 in 2007 and 35 in 2000, when the licensed activity peaked.

Today, licensing rounds are the primary mechanism of the Danish authorities for issuing new licenses for exploration, but over a period of time, the intervals between the licencing rounds have become longer. All in all, the licensing rounds have resulted in allocation of 76 licenses and 72 exploration wells on the Danish shelf. The latest licensing round resulted in allocation of 14 licenses, but only seven exploration wells, which is the lowest number of wells during a licensing round, half as many as in round five and almost only a third of the number in round four. There is thus a tendency that the licensing rounds do not result in the same number of exploration wells as previously.

THE SOLE CONCESSION AND THE LICENSE ROUNDS ACCOUNT FOR 90% OF ALL EXPLORATION WELLS AND 94% OF ALL DISCOVERIES ON THE DANISH SHELF. THE LICENSE ROUNDS ARE FEWER, WHICH ALSO RESULTS IN LESS WELLS.

THE DEVELOPMENT OF LICENSES AND EXPLORATION WELLS AS WELL AS THE TIME INTERVAL ACROSS THE DIFFERENT TYPES OF LICENSES*

<table>
<thead>
<tr>
<th>Type of License</th>
<th>Licenses</th>
<th>Wells with findings</th>
<th>Wells without findings</th>
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<tr>
<td>Sole concession</td>
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<td>19</td>
<td>75</td>
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<tr>
<td>License rounds</td>
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<td>25</td>
<td>58</td>
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<tr>
<td>Open door</td>
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<td>4</td>
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</tr>
<tr>
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<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Neighbor block approval</td>
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<td>1</td>
<td>3</td>
</tr>
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</table>

AVG. TIME INTERVAL ON EXPLORATION WELLS**

- 4 yrs 5 yrs 4 yrs 2 yrs

THE DEVELOPMENT OF LICENSES AND EXPLORATION WELLS AND THE TIME INTERVAL ACROSS THE FOR LICENSE ROUNDS 1-6

<table>
<thead>
<tr>
<th>License event</th>
<th>Licenses</th>
<th>Wells with findings</th>
<th>Wells without findings</th>
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<td>9</td>
<td>11</td>
<td>11</td>
<td>3 yrs</td>
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<td>6 yrs</td>
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<td>16</td>
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<td>7</td>
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<td>8 yrs</td>
</tr>
<tr>
<td>License round 6</td>
<td>14</td>
<td>5</td>
<td>2</td>
<td>2 yrs</td>
</tr>
</tbody>
</table>

AVG. TIME INTERVAL ON EXPLORATION WELLS**

- 2 yrs 4 yrs 6 yrs 5 yrs 4 yrs 4 yrs

* Additionally 9 wells have been classified as exploration wells by the Danish Energy Agency, which, however, do not match the types of licenses mentioned. This concerns “waste/gas storage investigation” and “geothermal concession”.

** From granted license to start of drilling. Based on dates and estimates from the Danish Energy Agency. Year is calculated as number of days divided with 365.

Source: Danish Energy Agency; Members of Oil Gas Denmark; Quartz+Co-analysis
In addition to the licensing rounds, licenses via mini rounds, neighbouring block licenses and “open door” licenses can be granted. Mini rounds and neighbouring block licenses are relatively rarely used on the Danish shelf and each of these has resulted in issuance of four licenses and three exploration wells. “Open door” was introduced in 1997 in all non-licensing areas east of 6°15', where oil and gas discoveries have not previously been made. License may be applied for on a first come, first served basis and all in all 25 licenses have been granted in the “open door” area. The area today seems, however, relatively unattractive. Only four exploration wells have been carried out in the “open door” area and commercial discoveries of oil or gas have not yet been made.

The weighted average time interval from a granted license to commencement of drilling across the different license allocations is four years. The interval has decreased over the past licensing rounds, but there is still a long way down to the interval of the first round, where the 12 exploration wells on average were drilled 1.7 years after allocation of the license.

Both our oil-producing neighbours, the UK and Norway, have a significantly higher licensing round frequency than in Denmark. In the UK, 27 licensing rounds have been held – of which seven have been held during the last 10 years. During the same period, one licensing round has been held in Denmark. In Norway, where 22 licensing rounds have been held so far, ordinary licensing rounds are held including immature parts of the shelf, every two years. Additionally, allocations are made every year in predefined areas which are more mature areas with known geology and well-developed infrastructure. In Denmark, the approach is the reverse - here the mature and well-known areas are put out to licensing rounds, while immature and unexplored areas are put out to tender according to an open door principle. In the UK and Norway they also have stricter regulatory requirements than in Denmark in relation to how soon licenses, which have been inactive, must be returned. However, the licensing requirements on British and Norwegian continental shelf may also be expected to be more restrictive than the Danish due to higher remaining prospectivity of these shelves, which, apart from anything else makes them more attractive to invest in.

2.3 A LARGER SHARE OF WELLS LEADS TO DISCOVERIES, BUT THE DISCOVERIES ARE GETTING SMALLER

DUC was responsible for the majority of the exploration wells on the Danish shelf during the 1960 to 1980s, whereas DONG Energy was the operator that drilled most wells during the 2000s. Over the last decade, there has been a tendency that new, minor players account for a larger share of the exploration wells.

During previous decades, wells were drilled with relatively large spread in the area west of 6°15'. During the last decade, fewer 'wildcats'9 have been drilled and closer to the existing infrastructure in the western part of the area where the previous discoveries are relatively close. It is also in this area where you have the best seismic studies of the subsurface. 2D seismic surveys have been made of most of the area west of 6°15', but the most western part of the area has been mapped most densely. In addition, this western area has also been mapped with 3D seismic data, providing operators with an improved characterisation of the subsurface in this area. On several producing fields, 3D seismic is furthermore used to create (time lapse) 4D images of the reservoirs of the fields to optimise recovery (see also chapter 4).

Using seismic surveys wells can be drilled with less risk but conversely also with higher costs. The operators themselves have seismic studies conducted and in this connection they have 5.5 years of confidentiality after which data will typically be released so that these can be bought by other players. A predominant part of the data is old. 73% of the 2-D seismic data are more than 20 years old and most of the 3D seismic surveys have been carried out in the

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8 Licenses for exploration in the area west of 6°15' (the only area where commercial discoveries have been made) are usually granted only through licensing rounds, but the mini rounds and neighbouring block licenses allows in a few cases granting of licenses outside the licensing rounds due to an urgent need to drill exploration wells within the lifetime of existing nearby infrastructure (mini round) or when geological or production-related considerations call for holders of licenses for adjacent areas being granted licenses (neighbouring block licenses).

9 “Wildcats” is a term for exploration wells drilled in relatively unexplored areas where oil/gas has not yet been discovered.

10 Seismic surveys are made by transmitting a blast wave from a sound source into the subsoil. The blast wave hits various layers in the subsurface and part of the blast wave will as a result be reflected back to the surface and be picked up by special receivers. In this way, an image of the geology of the subsurface is obtained, which can be used to locate oil and gas. 2D seismic data shows a cross section of the subsurface. 3D seismic data shows a three-dimensional image of the subsurface which is made by combining the 2D seismic surveys in a fine mesh network.
1990s when quality of the seismic was poorer than what can be achieved today. The 2000s were at the lowest level of activity with regard to the number of seismic surveys - on average, two 2D seismic surveys and one 3D seismic survey were made per year during this decade.

The success rate - the share of exploration wells resulting in real discoveries of oil or gas - is 19% of the total Danish shelf\(^{11}\), while the success made for the area west of 6°15' is 26%. Overall, less than one in every five wells has resulted in a discovery. The success rate was declining during the decades after the first discoveries were made in 1960 and over the past three decades, the success rate has been below the total average. In recent years, there has been a tendency to increasing success rates and especially during this decade, drilling has been carried out with great accuracy - of the 7 wells drilled until now, 6 wells have resulted in discoveries corresponding to a success rate of 86%. Thus presently, few wells are drilled with a high success rate.

A high success rate is, however, not synonymous with commercial success. Licensing round six, held in 2006, is an example of this. During no previous licensing round has the success rate been close to the level of the sixth round (71%), but the average size of the discoveries was 77% lower than in the fifth round. Where the fifth round has resulted in two new developments (Cecilie and Hejre), the sixth round has not yet resulted in a complete development or submission of a development plan.

Relatively more discoveries are made, but at the same time the discoveries made are becoming smaller. The average size of discovery has decreased substantially in recent decades, at the same time the difference between the discovered quantities have become smaller. During this decade, the average size of discovery is so far 28 mmboe – i.e. more than 7 times less on average per discovery than during the 90s.

The total quantity of oil and gas discovered is now considerably lower than previously, which is a natural development of a shelf over a period of time. In

\(^{11}\) Only exploration wells after 1965 have been included, i.e. the 32 onshore wells which had been drilled from 1936-1959 are not included.
the 2000s, a total of 362 mmboe were discovered corresponding to 36% of the quantities discovered in the 1990s and 19% of the quantities discovered in the 1970s. In total, discoveries of 4,967 mmboe have been made on the Danish shelf; of this, 67% were discovered by the first third of the exploration wells. 4,265 mmboe – or 86% of the total discoveries found – have been discovered under the Sole concession while the licensing rounds generally speaking account for the remaining part.

In particular, three discoveries have increased the total quantities discovered – with the discoveries of Dan and Gorm with a total of 1,360 mmboe in 1971 and the discovery of Halfdan of 882 mmboe in 1999. In total, the three discoveries account for almost half of what has been discovered on the Danish shelf and therefore they form a significant part of the total “creaming curve” of the shelf¹² (see the next page).

Despite the fact that large discoveries have been made and that the discovery sizes are generally decreasing, new resources still exist on the Danish shelf – in this decade, discoveries corresponding to 46% of what has been discovered totally in the 2000s, have thus been discovered so far.

Discoveries on seven different play types have been made on Danish shelf.¹³ Historically, most discoveries have been made on the play type ‘Danian and Upper chalk limestone’. However, increasing exploration wells are drilled with new play types which aim to explore new potentials in pace with the remaining potentials of existing play types being drained. The result of this has been that during the past 10 years, discoveries have primarily been made on the younger and older plays in the subsurface. 11 discoveries have been made in Upper Jurassic sandstone and the Middle Jurassic sandstone; both of those are typically environments with high pressure and high temperature (HPHT), which increase the complexity and thus the risk and cost associated with

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¹² A “creaming curve” describes how a shelf has been explored by looking at the ratio between the cumulative quantities of discoveries (mmboe) and the number of exploration wells over a period of time

¹³ A play is a categorized description of the geological conditions, which control a group of fields or prospects within a region.

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2.4 IT HAS BECOME MORE EXPENSIVE TO EXPLORE FOR OIL AND GAS ON THE DANISH SHELF – ESPECIALLY DURING RECENT YEARS

The average cost of exploration per well has increased by 2% annually (adjusted for inflation) during the past three decades to DKK 284 million for each exploration well in the 2000s. Especially in recent years, exploration has become significantly more expensive – during the period 2008-2012, the average cost per exploration drilling was DKK 445 million, which is 57% higher than the total average of the 2000s.

Due to heavy global demand and generally tougher environmental and safety requirements for drilling operations, the operators experience that the price for hiring of drilling rigs has increased significantly in recent years. At the same time, the availability is limited by virtue of the lack of harmonization of regulatory requirements in the EU-countries bordering
the North Sea. It takes a long time to upgrade a rig to the different countries’ standards which no rig owner wants to do in the present market without passing on all the related costs to the oil companies. At the same time, it is known that the more wells a rig is able to drill consecutively, the more attractive is the contract for the rig owner. From 1992 to 2013, 30 different drilling rigs have operated on the Danish shelf in relation to exploration wells, where they on average drilled less than two exploration wells during the period when they were on the shelf. It is thus rarely seen that rigs are hired for drilling campaigns with more exploration wells and also that more operators cooperate on drilling campaigns.

2.5 POSSIBLE LEVERS FOR INCREASED EXPLORATION ACTIVITY

It is central to the realisation of potential that the number of exploration wells is increased. With decreasing average discovery sizes and significantly increasing exploration costs, the licensees seem under the current applicable conditions to have limited appetite for the risk related to exploration which is indicated by the long time interval from granted license to the beginning of drilling, the low number of wells and the high success rate of the wells. It should thus be considered whether the current division of risk between the state and the licensees (investors) – during exploration for new resources on the Danish shelf – is appropriate to ensure an increase of the exploration activity.

An example from Norway shows that a change of the general framework conditions may have a cash impact on the exploration activity. In 2005, the Norwegian authorities implemented a system of cash repayment of the tax effect of exploration costs, which more than quadrupled the exploration activity over three years to the highest level ever on the Norwegian shelf. Despite the major increase in the number of wells, the success rate was above 50%, at the same time. In May 2013, the Norwegian government announced, however, that a reduction of the tax deductions related to capital investments would occur, a.o. with regards to create a renewed cost focus in the industry, where the exploration costs have increased considerably in recent years.

A differentiated incentive structure – rather than a general incentive for exploration – linked to e.g. specific geographic areas, play types or size field could potentially contribute to target activities towards new and more marginal resources. There are still areas in the Danish sector of the North Sea – also west of 6°15’ – which are relatively unexplored; there are play types which are untested and others which are...
difficult to commercialise (e.g. Danian, Lower chalk and HPHT) and there is an increasing number of marginal discoveries which are undeveloped.

In the UK, the authorities have repeatedly used changes of the tax system to affect the exploration activity in a specific direction. In 2009, a “small field allowance”, expanded in 2012, was implemented. This provides a tax deduction for development of fields less than 50 mmboe and moreover a ’HPHT allowance’ was implemented. Since then, it has been relaxed (see also chapter 3). In 2012, deduction was implemented for new large fields in deep water west of Shetland and for fields with recovery of gas in swallow water. While it is still too early to estimate the effect thereof, the Oil & Gas UK have made calculations showing a probably positive effect on the activity15.

It should also be considered whether the current Danish licensing model to a sufficient extent encourages initiative and propensity to invest. There are gradually fewer active licenses on the Danish shelf, the licensing rounds are few and far between, which at the same time yield fewer and fewer wells, the open door area does not seem attractive and the period from granted license to beginning of exploration drilling is long. If the exploration activity shall be increased, it is an essential element to get more flexibility into the licensing model in order to increase the number of active licenses.

In the short term, increased flexibility can be achieved in two ways – by increasing the frequency of the licensing rounds or by opening the entire Danish shelf as an open-door area. Where the first solution gives the licensees opportunity more often to apply for a license in the current commercial area, the other solution gives opportunity to freely apply for a license in all non-licensed areas throughout the Danish shelf. The licensees on the Danish shelf think that both initiatives may have a positive impact on the exploration activity16.

Prior to implementation of such models, the Danish authorities should, however, consider – within the framework of the EU-Licensing Directive – whether the models will have the intended impact without a simultaneous tightening of how fast a license must be returned, in case of no activity on the license. The limited size of the Danish shelf – and particularly the current commercial area – necessitates constant activity on licenses granted if a more flexible and dynamic licensing model shall work. Conversely, such tightened requirements must not impede the desire to apply for a license at all. It is expected that reinforced incentives for exploration do not only have a positive impact on the number of exploration wells, but also on how quickly they are implemented.

Availability of drilling rigs, which in these years is limited by heavy global demand and the European authorities’ different requirements for rigs, is another factor affecting the planning period of wells, but also the overall exploration costs. A standardisation of the authorities’ requirements for rigs across the EU-countries, bordering on the North Sea, which would mean that if a rig is authorised to enter one national water it is also authorised to enter the others, would have a beneficial impact on the number of rigs available for the Danish oil and gas sector.

From an activity point of view, it is a big problem that it is becoming increasingly expensive to well still less oil/gas – the exploration costs per well soar, while the average size of discovery is decreasing. To a great extent, the exploration costs are driven by costs for hire of rig and increased availability of rigs will have a positive impact on the exploration costs. Typically, prolonged drilling campaigns increase the attractiveness of the contract for the rig owner, affecting the hire of rig and availability positively. Therefore, it seems obvious to establish closer cooperation among the operators on the Danish shelf regarding drilling campaigns. Closer cooperation could also include collection of seismic data, as seen in Norway, as well as joint training efforts to ensure that the necessary resources and skills are available to increase the exploration activity.

Finally, it is critical that an increased development of marginal discoveries occurs (see also chapter 3) – i.e. discoveries which are too small or cost-intensive to develop to be commercial under the current conditions. Failing this, the exploration activity will only result in the number of undeveloped fields piling up as the discoveries on the Danish shelf increase.

15 Oil & Gas UK Fiscal Insights October 2012
16 Quartz+Co oil and gas sector survey and workshop, June 2013
HIGHLIGHTS: ENGINE OF GROWTH I  
- INCREASED EXPLORATION ACTIVITY

**KEY FACTS**

- From 1965 to 2013, a total of 185 exploration wells have been drilled on the Danish shelf, of which 135 have been made in the most western part of the Danish North Sea (west of 6°15’), where all 35 discoveries are made. It is thus only about every one in five wells in the Danish North Sea, which has led to the discovery of oil and gas.

- The number of exploration wells is decreasing and during the period 2008-2012, the exploration activity in Denmark was the lowest since the 1960s.

- There will be fewer active licenses. In 2012, there were totally 20 active licenses west of 6°15’ – decline from 25 in 2007 and 35 in 2000, where the license activity peaked. Licensing rounds do not result in the same activity as previously.

- The number of exploration wells, which resulted in discoveries, is increasing, but at the same time, the size of the discoveries is also decreasing considerably.

- The total discovered are 4,967 mmboe of which 4,265 mmboe (86%) have been discovered under the Sole concession.

- The exploration costs have increased considerably in recent years. During the period 2008-2012, each exploration well has had an average cost of DKK 445 million, which is 57% higher than the total average for the 2000s.

**LEVERS**

- Establishment of a more flexible licensing model through increased frequency of licensing rounds or by opening the entire Danish shelf as an open-door area.

- Closer cooperation among the operators on the Danish shelf concerning drilling campaigns.

- Harmonization of the authorities’ requirements for drilling rigs across the EU-countries bordering on the North Sea.

- Special incentives in the tax system linked to specific geographical areas, play types (including Danian, Lower Chalk and HPHT) or field size.

- Increased development of marginal discoveries which justify continued exploration despite of decreasing discovery sizes.
3 ENGINE OF GROWTH II  
- PRODUCTION OF MARGINAL FIELDS

A large part of the minor discoveries on the Danish shelf has been developed, but development of marginal discoveries – which aggregated account for a significant quantity of resource – has been at a standstill in recent years, and almost half of all discoveries on the Danish shelf have not yet been developed. Due to their limited field size and significantly increasing development costs, development of marginal discoveries requires connection to existing infrastructure, but this is a challenge despite good conditions in relation to distance, infrastructure and law. Great economic uncertainty is related to development of marginal discoveries meaning that it will be difficult to compete for investments. If the marginal discoveries shall be developed, it requires connection to the existing infrastructure. However, it is most likely that large parts of the existing infrastructure will shut down in the years to come due to lack of production to maintain an expensive operation, which reduces the window of opportunity for connection of marginal discoveries. If marginal discoveries shall be connected to the existing infrastructure in the years to come, the total period of planning and economic uncertainty must be reduced. At the same time, it must be attractive to both existing and new players to invest further in the ‘tail production’ of the producing fields, which can prolong their financial life and thus the window of opportunity for connection of marginal discoveries.

3.1 DEVELOPMENT OF MARGINAL DISCOVERIES IS AT A STANDSTILL

Only about one in every five wells results in discovery of oil and gas, and even though a discovery is made, it is not certain that the discovery will be developed and thus the oil and gas recovered. Historically, it has on average required well over 10 exploration wells to make one commercial discovery on the Danish shelf.

Of the 35 discoveries made of oil and gas, 18 have been developed and one is being developed. Well over half of all the discoveries have thus not yet been developed.

UNDEVELOPED DISCOVERIES ARE SMALL AND LOCATED AT A HIGH DEPTH COMPARED TO THE DEVELOPED FIELDS. AN INDEPENDENT FIELD LESS THAN 85 MMBOE HAS NEVER BEEN DEVELOPED

FIELD SIZE AND RESERVOIR DEPTH FOR ALL FIELDS ON THE DANISH SHELF

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Size of Field (mmboe)</th>
<th>Reservoir Depth (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dan</td>
<td>950</td>
<td></td>
</tr>
<tr>
<td>Halfdan</td>
<td>900</td>
<td></td>
</tr>
<tr>
<td>Tyra</td>
<td>850</td>
<td></td>
</tr>
<tr>
<td>Gorm</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Skjold</td>
<td>750</td>
<td></td>
</tr>
<tr>
<td>Syd Arne</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>Harald</td>
<td>650</td>
<td></td>
</tr>
<tr>
<td>Hejre**</td>
<td>600</td>
<td></td>
</tr>
<tr>
<td>Siri</td>
<td>550</td>
<td></td>
</tr>
<tr>
<td>Roar</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td>Valdemar</td>
<td>450</td>
<td></td>
</tr>
</tbody>
</table>

**Note:** Below the line, a stand alone field has never been developed

* For existing fields, where reservoir depth varies for the same field, the average field depth is used. For undeveloped finds the reservoir depth is equal to the depth at which it was found.

** The Hejre field is being developed and is expected to commence production during 2015.

Source: The Danish Energy Agency: The members of Oil Gas Denmark
46% of all discoveries have not been developed and presently only one development is planned

**Development Plan for Discoveries on the Danish Shelf**

<table>
<thead>
<tr>
<th>AMOUNT AND PERCENTAGE</th>
<th>YEARS SINCE DISCOVERY</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Discovery on the Danish shelf</strong></td>
<td><strong>YEARS SINCE DISCOVERY</strong></td>
</tr>
<tr>
<td>Developed discoveries*</td>
<td>Elly</td>
</tr>
<tr>
<td>Not developed discoveries</td>
<td>Amalie</td>
</tr>
<tr>
<td>Ongoing development</td>
<td>Svane</td>
</tr>
<tr>
<td><strong>35</strong></td>
<td><strong>100%</strong></td>
</tr>
<tr>
<td><strong>18</strong></td>
<td><strong>51%</strong></td>
</tr>
<tr>
<td><strong>5</strong></td>
<td><strong>15</strong></td>
</tr>
<tr>
<td><strong>16</strong></td>
<td><strong>46%</strong></td>
</tr>
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</tbody>
</table>

* South Arne was developed based on an appraisal well in the tail of an exploration well I-IX, which was drilled in 1969 under the Sole Concession
** As Hibonite is a very recent find, there is extraordinarily high uncertainty around the estimate of the size of the find.

Source: Wood Mackenzie; The Danish Energy Agency; Members of Oil Gas Denmark; Quartz+Co-analysis

There are a number of reasons why these discoveries have not yet been developed. The primary reasons are their limited field size and/or their geological conditions (play type and depth of reservoir)\(^\text{17}\). The undeveloped discoveries have an average size of 30 mmboe and are at approx. 3,700 meters depth. The size of five undeveloped discoveries – Sofie, Alma, Boje, Rau and Sara – is below 10 mmboe, while the largest – Svane – has a size of 138 mmboe, but at the same time a depth of reservoir of above 5,800 meters. By comparison, the developed fields on the Danish shelf have an average size of 242 mmboe and depth of reservoir of 2,319 meters. The undeveloped discoveries are thus burdened by being small and at the same time expensive and complex to develop due to the pressures and temperatures caused by their depth. The majority of these discoveries are therefore marginal, i.e. it is not economic to develop these under the present conditions.

Of the 16 discoveries, which have not been developed, only one field is currently planned to be developed - the Adda field. Seven fields are not planned to be developed at present as they are far from being commercial, according to the operators. These fields account for a total of 238 mmboe. Eight fields - which account for a total of 212 mmboe - are estimated by the operators as potential developments, but where the possibility of a commercial development is being examined. Half of these fields, such as e.g. Solsort and the recent discovery Hibonite, have been discovered less than three years ago. The other half was discovered more than 20 years ago, without being closer to a development. Several discoveries have thus been made in recent years, which may be developed, but significantly older discoveries in the same category clarify that it is unlikely that a potential development may result in a fast development. Today, it is 10 years ago that production started on the recently developed Danish fields below 50 mmboe.

\(^{17}\) Based on input from the operators of the undeveloped fields, June 2013
3.2 A STILL SMALLER COMMERCIAL BASIS FOR DEVELOPMENT WILL NEED MORE CONNECTIONS TO EXISTING INFRASTRUCTURE

Decline in the average discovery size will make the decisions on development increasingly difficult in the future. The average size of discoveries during this decade has been 28 mmboe – corresponding to less than half of the size of discoveries in the 2000s and only 14% of the size of discoveries in the 1990s (see also chapter 2). In the analysis of the Danish shelf drawn up by the independent information house IHS, a future average size of discovery size of 15 mmboe is estimated – that is considerably lower than the present one and also considerably lower than the expected discovery sizes on Norwegian and British shelf\textsuperscript{18}.

The discovery sizes have reached a level where they are on the border of feasibility as regards being able to lead to development of new independent fields (stand-alone). The operators on the Danish shelf estimate that a new independent development – such as Dan, Syd Arne and Siri – as a minimum requires a field size of 40-100 mmboe, while a near-field development with a connective solution – as Nini, Valdemar and Dagmar – requires at least 10-15 mmboe. There are thus several existing discoveries which are not expected to be developed under the present conditions, and only a few discoveries – if any – which can be expected to be independently developed.

With still falling discovery sizes, there is still a smaller commercial basis for new developments on the Danish shelf. Development of the fields will thus prospectively increasingly require connection to existing fields, as this will be a significantly less cost-intensive development form than establishment of new independent platforms.

This need is intensified by the fact that the development costs in general have increased significantly in recent years driven by major global exploration and development activity, which a.o. have caused significantly increased costs of hiring drilling rigs (see also chapter 2). On the UK shelf, where the conditions and the maturity are similar to the Danish shelf, the development costs have increased from USD 13 per boe in 2006 to USD 21.5 per boe in 2012, corresponding to an average increase of 9% per year during this period.

Connecting the smaller discoveries to existing platform is not new to the Danish shelf, and compared

A LARGE PART OF THE SMALLER DANISH DISCOVERIES HAS BEEN DEVELOPED COMPARED TO NORWEGIAN AND BRITISH DISCOVERIES, AND ALL ARE DEVELOPED WITH CONNECTION TO A LARGER PLATFORM

\textbf{DEVELOPED DISCOVERIES OR DISCOVERIES BEING DEVELOPED ON 50 MMBOE OR LESS}

\begin{tabular}{lcc}
& \textbf{NO*} & \textbf{UK*} & \textbf{DK} \\
\hline
\textbf{Share developed via tieback} & 8\% & 19\% & 32\% \\
\textbf{Unmanned Production platform} & 5 & 7 & 7 \\
\textbf{Underwater-installation} & 1 & 1 & 1 \\
\textbf{Production drilling from stand-alone} & & & \\
\hline
\end{tabular}

\textsuperscript{18} IHS Global Windows 2013

\textbf{DEVELOPMENT CONCEPT FOR DEVELOPED FIELDS ON 50 MMBOE OR LESS ON DANISH SHELF}

\begin{tabular}{lcc}
& \textbf{Share developed via tieback} & \textbf{Unmanned Production platform} & \textbf{Underwater-installation} & \textbf{Production drilling from stand-alone} \\
\hline
\textbf{NO*} & 7 & 1 & 14\% \\
\textbf{UK*} & 7 & 1 & 14\% \\
\textbf{DK} & 5 & 1 & 14\% \\
\hline
\end{tabular}

* Discoveries in the part of the North Sea next to the Danish shelf

Source: Wood Mackenzie; Maersk Oil; DONG Energy; HESS
with Norway and the UK, a relatively large part of the smaller Danish fields has been developed. In Denmark, a total of 22 discoveries of 50 mmboe or less have been made; seven of these have been developed giving a development rate of 32%. The corresponding development rates for British and Norwegian fields in the North Sea bordering on the Danish sector are 19% and 8%, respectively.

Of the 18 developed fields on the Danish shelf, 11 are connected as tiebacks to larger neighbouring platforms – including all seven fields with a size of less than 50 mmboe. Five of these seven fields have been developed with an unmanned recovery platform (e.g. Nini), a single field with an underwater installation (Regnar) and the last one with long production wells directly from an independent platform (Lulita).

Historically, tiebacks have been developed using several different technical concepts. However, more creative commercial solutions for development of marginal discoveries, of which examples are seen from other shelves, have never been used. This applies to “clubbing”, where an operator of a marginal discovery connects to a further development of an existing field of another operator or “clustering” where operators of nearby marginal discoveries share a common development. The latter is seen in the British part of the North Sea, where seven different operators of their respective marginal field share the ETAP-development.

### 3.3 IMMEDIATE GOOD CONDITIONS FOR FURTHER DEVELOPMENT OF MARGINAL DISCOVERIES THROUGH EXISTING INFRASTRUCTURE

In 2011, the current §16 of the Danish Underground Act was adopted to ensure that other licensees got access to existing infrastructure, if considerations...
related to resources, economics or society dictate this. The regulatory framework is in place to encourage usage of the existing infrastructure. However, the effect of the new legislation cannot be documented yet.

Until now, a discovery as tieback, which is not operated by the same company operating the adjacent process platform, has not been developed on the Danish shelf. Today, all tiebacks are thus operated by the same companies which also operate the process platforms to which they are attached. However, the Norwegian Trym field, which is operated by DONG Energy, and the Lulita field, which is a coordinated development between more licenses via the Maersk Oil-operated Harald platform. In addition, discussions concerning additional tiebacks are ongoing.

The distance to existing infrastructure does not represent a direct barrier for further development of marginal discoveries. All oil and gas recovery on the Danish shelf occurs within a geographically defined area and therefore the infrastructure is relatively close with 140 km between the two developed fields which are farthest from each other. The average distance from existing tiebacks to the process platforms to which they are attached is 18 km and the maximum distance from an existing satellite to process platform is more than 60 km (Svend to Tyra via the Harald-Tyra pipeline). On average, there is 12.8 km from the undeveloped discoveries to the nearest existing process platform or satellite, and only two fields have a distance of above 20 kilometres. All 16 undeveloped discoveries are thus located within a distance with which tiebacks have previously been established.

There are platforms on the Danish shelf, which at present have processing capacity available. Whether or not a discovery can be developed with a connection to an existing system will, however, always be based on a specific assessment of the type and nature of the discovery in relation to the facilities of the recipient field. It is, however, reasonable to assume that if a connecting possibility is sufficiently attractive to all parties, the necessary capacity - regardless of the current utilisation - will be put at disposal or will be established.

The regulatory, geographic and infrastructure related preconditions are thus directly present for further development of marginal discoveries as connection to existing fields. Two important factors pull, however, in opposite directions.

### 3.4 Economic and Commercial Uncertainty is Large for the Marginal Fields

1) Development of marginal discoveries involves large economic uncertainty. Seven of the 11 existing fields on the Danish shelf, connected to a large process platform, have a size of 50 mmboe or less (which also apply to 15 of the 16 non-developed discoveries). According to Wood Mackenzie, these seven fields have an average payback time which is almost six times higher and based on significantly larger fluctuations than the fields above 50 mmboe. Fields below 50 mmboe involve thus a significantly larger economic uncertainty than fields with more reserves. There are fields below 50 mmboe with a payback time of less than five years, but at the same time there are fields with a payback time over 80 years.
years. The reserves of the smaller fields are so limited that some wrong investments or price-raising incidents can ruin the overall economy of the field. The licensees on Danish shelf must consider this economic uncertainty in their assessment of the marginal discoveries.

2) The operators of marginal discoveries are forced to relate to the planning- and production period of the marginal fields versus the remaining life of the existing producing fields, if the discoveries must be developed through the existing infrastructure.

More of the currently producing fields are going to be marginal due to a significantly declining production. In 2012, the Danish fields produced an average of 1/4 of what each of them did when their production peaked, and 14 out of the 15 fields from which production was carried out in 2012, get more water than oil up from their wells. In 2012, water amounted to 74% of the total liquid production - for the three fields it was above 90%. 12 out of the 15 producing fields can, according to Wood Mackenzie, be described as mature as less than 1/3 of their reserves remain. On average, 18% of the field's reserves remain; of this less than 10% remain in five fields.

Whether water or oil is produced through the wells, it has minimal impact on the current operating costs to keep the production facilities running - approx. the same quantities of liquid must still be processed through the facilities, but an increasing part of this gives no direct earnings. The operating costs per produced barrel of oil or gas have also increased significantly in recent years and the increase is expected to continue in the years to come. From 2007 to 2012, the average costs have increased by 102% in the Danish fields and Wood Mackenzie expects that they increase further by 44% up to 2017.
to USD 21 per boe. Both major and minor fields experience increasing operating costs per produced unit; however, they have increased mostly on small and medium-sized fields and these are also expected to increase mostly in the years to come.

The smaller the field, the higher the operating costs. There is a clear connection between the total and remaining reserves of a field and its operating costs per produced unit. On average, the fields Dan, Halfdan, Tyra, Syd Arne and Valdemar have a total of reserves of 607 mmboe, of which 32% have not yet been produced. In 2012, these fields had an average operating cost of USD 9.8 per boe. By comparison, the other 10 producing fields have a total of reserves at an average of 135 mmboe – 11% of these remain. In 2012, these 10 fields had an average of operating cost of USD 17.3 per boe – i.e. 77% higher than the five fields previously mentioned.

If the production decline of the existing fields is not checked by adding new reserves, it may be expected that their relative operating costs continue to increase. This will affect the financial life of the fields adversely. During the remaining life of the field there will be a constant need for the operators to do what is possible to further reduce the absolute operating costs year after year of each of the Danish fields which have totally increased by 32% over the past five years. However, without adversely affecting the significantly improved personal- and process safety and reduced environmental impact achieved in the Danish fields in recent years.

3.5 IT IS EXPECTED THAT THE PRODUCING FIELDS WILL SHUT DOWN CONSECUTIVELY IN THE YEARS TO COME DUE TO LACK OF PRODUCTION

Today, three fields – Dagmar, Regnar and Rolf – have no production, because they are currently not economic to repair or operate. The production facilities of these fields will be permanently removed if production of new reserves through the facilities does not materialize within the years to come, or other solutions are identified to justify operation. Wood Mackenzie expects that another five fields must shut down within the next eight years due to lack of production to finance the continued expensive operation.
FOLLOWING THE EXISTING FIELD’S EXPECTED SHUT DOWN IT WILL BE DIFFICULT TO CONNECT NEW DISCOVERIES

LIFE TIME FOR THE FIELDS IN THE NORTH SEA*

YEAR PER FIELD

Dagmar
Regnar
Rolf
Siri
Nini
Cecile
Svend
Lulita
Kraka
Roar
Gorm
Skjold
Harald
Valdemar
Syd Arne
Dan
Halfdan
Tyra
Hejre

TIME INTERVAL (FIELDS UP TO 50 MMBOE)

YEAR

LICENSE FOR EXPLORATION WELL (N=12)**

DISCOVERIES FOR DEVELOPMENT (N=7)

DEVELOPMENT FOR PROD. START (N=7)

TOTAL

5
7
2
14 yrs
20 yrs
34 yrs

2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2013
2043
2035+

* Financial shut down is when a field is shut down because it is no longer profitable to produce. Technical shut down is when a field is shut down because it is no longer profitable to maintain the technical integrity of the production.

** Does not include exploration wells within the Sole Concession, as they do not need a separate approval.

Source: Wood Mackenzie; Danish Energy Agency; Oil Gas Denmark; Maersk Oil; DONG Energy; HESS
In this context, it is interesting that the fields shut down on financial and not on technical reasons. There is a big difference between the financial cut-off year of the Danish fields – i.e. the year when a field is shut down as it is no longer profitable to maintain production – and its technical cut-off year i.e. the year a field is shut down because it is no longer profitable to maintain the technical integrity of its production facility. The average financial cut-off year of the Danish producing fields is 2023 according to Wood Mackenzie, while the technical cut-off year is 2039 according to the operators of the producing fields. On average, there is thus a difference of 16 years between the year of the financial and technical shutdown. The production facilities on the Danish shelf are thus expected to be decommissioned several years earlier than the technical integrity allows.

Shut down of the existing production facilities means fewer development opportunities for the current undeveloped discoveries and future discoveries which by the expected decreasing sizes to a great extent will require development through connection to the existing infrastructure. In 2020, the distance from the current undeveloped discoveries to the nearest producing platform or satellite will be 18.6 kilometres compared to the present distance of 12.8 km. In 2030, this distance will be increased to 29.8 kilometres. The increasing distance will increase the price of development of the fields.

At the same time, the total planning and production period for new smaller fields is considerably longer than the remaining period up to the financial shutdown of the producing fields.

On the present developed discoveries on Danish shelf with reserves less than 50 mmboe, an average of 14 years has passed from the granted license to start-up of production; Seven years have passed from discovery was made until a development decision was taken. As the same fields are expected to produce for an average of 20 years, the total planning and production period for the minor fields is 34 years. Only four fields – including Hejre – are expected to have a remaining financial life of more than 20 years; that is why just production of the discoveries already made, which have not been developed through existing infrastructure, may prove to be a challenge. For new marginal discoveries, development – based on the historical figures – will be practically impossible. Almost half of the producing fields will be taken out of service before a new, minor field has reached production start. And even if the field reaches production start by connection to the existing producing field with the longest financial life (Tyra), it will be able to produce only approx. half of the typical period for this type of field.

To increase the likelihood of connecting more minor discoveries to the existing infrastructure in the future, the time interval from granting the licensing to production start and the total economic uncertainty of marginal discoveries should be reduced. The very fact that marginal field developments involve large economic uncertainty makes them at the same time resource demanding to plan, as several iterations will typically be throughout the basis for decision, prior to any investment decision in order to reduce the risk associated with the investment. Reducing the planning period for marginal discoveries therefore requires that it will be possible to attract and retain sufficient qualified resources in the future.

Additionally, there will – to increase the likelihood of connecting more marginal discoveries to the existing infrastructure – be a need for further investments in “tail production” of the producing fields, which can extend the financial life of these fields.

3.6 NEW INVESTMENTS CAN POSTPONE THE SHUTDOWN OF THE PRODUCING CYCLE

Investments in production-enhancing actions on existing fields can initiate a positive cycle in relation to their life. Based on estimates from the operators of the producing fields on the Danish shelf, a 20% increase in a field’s reserves over the past 10 years of its financial life postpone the financial shutdown by up to five years. On the other hand, a five-year postponement of the financial shutdown can result in an increase of the production-enhancing actions by up to 50%, which again can be expected to increase the reserves of the field21.

In these years, investments of considerable amounts are made in development of field on the Danish shelf – including in further development of the fields Syd Arne and Tyra, and not least in development of the new Hejre field. Over the past 10 years, according to figures from the Danish Energy Agency, an average of annually DKK 5.6 billion have been

21 Based on input from the operators of the producing fields, June 2013
invested in field developments. From 2013-2016, the Danish Energy Agency estimates that this amount will be DKK 9.8 billion. Thus, it cannot be said that investments in the Danish shelf will not continue. To a greater extent, the amount seems to better reflect major investments in individual fields rather than a general propensity to invest across the Danish fields. As an example, the investments in development of Hejre and the further development of Syd Arne and Tyra alone are more than well over DKK 25 billion.

In 2012, the number of new production and injection wells, which can be used as a partial expression of the investments being made in optimising the production from existing fields - reached the lowest level in 15 years, with two production wells and one injection well. In the last 10 years, the number of new production and injection wells has declined by an annual average of 23% and 16%, respectively. During the same period, an increasing number of comprehensive repair and maintenance projects (work overs) of existing wells has been carried out. It can thus be stated that the focus is increasingly on ensuring optimal operation of the existing facilities rather than optimising through further development of the fields.

**FOCUS HAS CHANGED FROM FURTHER DEVELOPING EXISTING FIELDS WITH NEW PRODUCTION AND INJECTION WELLS TO REPAIR AND OPTIMIZATION OF EXISTING WELLS**

**DEVELOPMENT IN NUMBER OF NEW PRODUCTION WELLS FROM 2003-2012**
Number 2003-2012

- New production wells*
- New injection wells

**DEVELOPMENT IN NUMBER OF NEW INJECTIONS WELLS FROM 2003-2012**
Number 2003-2012

- New injection wells

**DEVELOPMENT IN NUMBER OF WORKOVERS FROM 2003-2012**
Number 2003-2012

- Workovers***

<table>
<thead>
<tr>
<th>Year</th>
<th>New production wells*</th>
<th>New injection wells</th>
<th>Workovers***</th>
</tr>
</thead>
<tbody>
<tr>
<td>'04</td>
<td>21</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>'06</td>
<td>13</td>
<td>7</td>
<td>9</td>
</tr>
<tr>
<td>'08</td>
<td>15</td>
<td>3</td>
<td>6</td>
</tr>
<tr>
<td>'10</td>
<td>14</td>
<td>2</td>
<td>4</td>
</tr>
<tr>
<td>'12</td>
<td>13</td>
<td>2</td>
<td>2</td>
</tr>
</tbody>
</table>

* Wells used for production of oil and gas  
** Wells used for pumping water down to maintain the pressure in the reservoir  
*** Repair and maintenance of wells requiring a rig  

*Source: Danish Energy Agency*
A comparison of the total investments in the Danish producing fields throughout their lifetime with equivalent investments in Norwegian and UK fields located in the North Sea bordering on the Danish part shows at the same time that the investments are relatively less in the Danish part during the later stages of the field lifetime. 20% of the investments on the Danish fields are made after 30 years compared to 34% and 29%, respectively, for the Norwegian and UK fields. The investment profiles for the Norwegian and UK fields illustrate very well that the fact that a field is mature does not mean that increasing investments cannot be made in further development and optimisation of the field. Where the profiles of the Norwegian and UK fields have a relatively dynamic process with several investment intensive periods, the investment on the Danish fields peak after 11 to 15 years (if you ignore the original development investments) and is steadily declining afterwards. During this period, considerably larger investments are made in the Danish fields than in the British and Norwegian fields relatively.

One reason for the difference in the investment profiles may partly be that the Danish licensees relatively early invest in comprehensive developments of the production facilities and long-term capacity construction, which exhaust the need for substantial subsequent investments in pace with new reserves being added to the field. But the limited late-life investments in the Danish fields may partly also be an expression of the fact that there are not sufficient incentives for late investments in the Danish fields either for existing or new players, which otherwise can have a significant positive impact on the total production and financial life of a field.

Oil & Gas UK has estimated the impact of the change of ownership on mature fields – since 2000, 19 fields have been traded on the British shelf – to an average increase in investment of DKK 3 billion per field, an increase of a field’s reserves by 19 mmboe and an extension of the life of a field by 10 years. Apache’s acquisition of the British Forties field in 2003 is an example of the positive impact which can be achieved. At present, the Danish producing fields do not seem
to be attractive investment opportunities to new players. Thus, in Denmark we have no examples of changed ownership on mature fields and all in all we have seen only one example of an operator who has acquired a producing field - DONG Energy’s acquisition of Siri from Statoil in 2002, which at the time had been in operation for three years.

3.7 POTENTIAL LEVERS FOR PRODUCTION OF MARGINAL FIELDS

According to figures from Wood Mackenzie and the operators of the marginal discoveries, the 16 discoveries on the Danish shelf, which have not yet been developed, amount to a total of 483 mmboe. This is significantly more than the 264 mmboe risk weighted conditional resources, which the Danish Energy Agency has estimated, and thus a possible upside is indicated if all undeveloped resources are realised. The key point is, however, whether the marginal discoveries can be developed profitably - at present, development of only one out of the 16 undeveloped discoveries is planned and this discovery is less than 7% of the total undeveloped resources.

It is crucial to the overall realisation of potential that the development of marginal discoveries is initiated - both directly in relation to realisation of the conditional resources and indirectly in relation to the continued exploration activity which with increasing probability will result in discovering new marginal fields. Lack of development may thus undermine the incentive for continued exploration.

The development of marginal discoveries is, however, limited by more significant conditions which must be corrected if new developments are to be carried out.

The licensees on the Danish shelf have an international portfolio of prospects, discoveries and producing fields, against which the Danish marginal discoveries must compete for investments and skills. The large economic uncertainty in relation to development of marginal fields on the Danish shelf - both absolutely and relatively - weakens the probability of development of the Danish marginal discoveries and affects competitive conditions considerably. At present, there are no incentives which compensate for this financial risk by development of marginal discoveries. Thus, the players on the Danish oil and gas sector also state that lack of such incentives as the framework condition with the highest importance and which require the greatest change, if an increased development of the marginal discoveries is to be made22. With the current maturity stage of the shelf, according to the sector, there is a need for a regime which recognises that the Danish oil and gas fields are different in nature (size, reservoir depth, play type, etc.) and therefore also have different economic conditions. That is why there is a need for special incentives, if some types of fields are to be developed within the lifetime of the existing infrastructure. Due to the marginal nature of the fields, it is moreover crucial that by investing in their development there is certainty about the subsequent stability of the applicable framework conditions - uncertainty about this risks to dilute the effect of positive incentives.

There is a general need for making small fields commercial to develop as they all in all represent an attractive and increasing quantity of resources. The “small field allowance’, which was introduced in Britain in 2009 and extended in 2012 to give a deduction of up to DKK 1.3 billion for development of fields less than 50 mmboe, is just one example of such an incentive for investment in developing minor marginal discoveries. In Denmark, 13 non-developed discoveries are under 50 mmboe and would thus qualify to receive the deduction. To exemplify the impact of this small field allowance and the general differences between the British and Danish tax regime, an operator, who is active in both the Danish and British shelf, has taken a typical North Sea field of well over 30 mmboe23 and run it through their economic models for Denmark and the UK, respectively, where all factors are constant (CAPEX, OPEX, gas, etc.) except tax. For the British field, an NPV1024, which was approx. 60% higher than the Danish field, would be obtained.

In addition to limited field size, there are several of the undeveloped Danish discoveries (including Svane, Luke and Amalie) which are burdened by being located in deep reservoirs with high pressure and high temperatures (HPHT), making the development technologically complex and expensive. In

22 Quartz+Co oil and gas sector survey and workshop, June 2013
23 Gas field, 30-40 metre water depth, tieback to larger process platform
24 NPV10 means that 10% probability of realising a net present value (NPV) with this value has been estimated
Britain, where they have more of the same field type, a ‘HPHT allowance’ was introduced in 2009, which was relaxed in 2010 to apply to the development of fields with pressures and temperatures above 862 bar and 166°C, respectively with a linear increase of the deduction at higher pressures and temperatures.

The significant increase in the development costs in recent years has worsened the economic climate for the development of marginal discoveries. Despite the fact that the CAPEX market is global, it is necessary that efforts are made to reduce the development costs where possible. The focus should be on reducing soaring drilling costs (see Chapter 2) in order to reduce the costs for establishment of production wells in connection with development and make it cheaper to carry out appraisal wells, where it is necessary to clarify the potential for development. At the same time, the Danish operators should be open to all possible technical and commercial development solutions, such as use of facilities from where there is no production today (Dagmar, Regnar and Rolf) and clubbing and clustering.

However, it does not seem realistic that the development costs can be reduced to a new structural level where the marginal discoveries can be developed with independent platforms. Development and production of current marginal discoveries and future discoveries seems to be entirely dependent on the continued presence of infrastructure through which they can be produced. Despite the realistic distance to existing infrastructure and framework regulations giving other licensees access to this, is, however, a significant challenge.

Large parts of the producing fields have reached a maturity level where they soon become marginal and do not have sufficient production to maintain a profitable operation; therefore they must be shut down despite the fact that the technical integrity of the production facilities allows significantly longer production. If the marginal discoveries are to be developed and produced through the existing infrastructure, it is essential that the operators of the marginal discoveries and the operators of the producing fields cooperate to utilise the existing window of opportunity.

The previous total time interval from granting the license to production start of minor discoveries must be reduced – the current 14 years are too long – if the marginal discoveries shall have time to produce through the existing infrastructure. Particularly, there seems to be potential to reduce the seven years which have passed from discovery to development decision, especially if intensified incentives are involved in development, which improves the risk-/return profile of the investments. Furthermore, the five years which have passed from granted license for exploration drilling, seem to be long for future discoveries – taking the current circumstances into account.

If financial shutdown is to be postponed, the ‘tail production’ on the current producing fields must be extended. More elements can contribute to this. There is a need for continuous efforts to reduce the absolute operating costs of the fields, which have increased significantly in recent years. The players of the sector recognise that additional actions can be taken to facilitate such a development – including closer operator cooperation, e.g. in relation to logistics, where helicopters and supply vessels could be shared. In addition, still better ‘integrated operations’ technologies render it increasingly possible to move functions – which today are handled by expensive staff offshore – to onshore where they can be handled much cheaper. On the other hand, it cannot be excluded that there is technical potential for further production-enhancing ‘late-life’ investments. More initiatives can be taken to improve the recovery rate – and thus the reserves – on the producing fields (see chapter 4).

With the current maturity level of the Danish shelf it is a prerequisite for full realisation of potential that it is attractive to both existing and new players to invest in development of marginal discoveries and the ‘tail production’ of the producing fields.

In the UK, where oil and gas production has a maturity level very similar to the Danish field, a ‘brownfield allowance’ was implemented in 2012, which is a deduction to increase the attractiveness of the marginal investments on existing fields to ensure that the full potential is realised. The size of the deduction is determined on a sliding scale based on the cost of capital per barrel and is given to new investments on existing fields, creating new production which is not already included in the field development plan.

25 Integrated Operations’, which has been facilitated by development within information and communication technology, refers to establishment of new working- and cooperation processes in oil and gas production, where integrated processes are established between onshore and offshore allowing that more partial processes can be dealt with from ashore.
HIGHLIGHTS: ENGINE OF GROWTH II – PRODUCTION OF MARGINAL FIELDS

KEY FACTS

• Of the 35 discoveries of oil and gas made in the Danish North Sea, 18 have been developed and one is being developed. Well over 10 exploration wells have been carried out to make one commercial discovery – several of the DKK 22.4 billion have thus been invested in exploration on the Danish shelf, which have given no return

• 16 discoveries, which in total account for 483 mmboe, have not yet been developed. Only one of the undeveloped discoveries is currently planned to be developed

• The undeveloped discoveries are burdened by their field size and geological conditions – they have an average size of 30 mmboe and is located on a depth of approx. 3,700 meters compared to an average of 242 mmboe and 2,319 meters for the developed fields

• Historically, development of fields less than 50 mmboe have been marked by large economic uncertainty with a payback period of 39 years with a standard deviation of 44 years

• The majority of the undeveloped discoveries and future discoveries must be developed through connection to existing infrastructure due to their limited size

• More of the producing fields to which the marginal discoveries shall potentially be connected are going to be marginal due to declining production (an average of 10% annually over the past five years) and increasing operating costs (32% over the last five years). On average, only 18% of their reserves remain on the producing fields and all fields except one produce more water than oil from their wells

• On average, the producing fields will shut down in 2023, but if they had sufficient production, they could technically produce for an average of 16 more years. With the historical average time interval of the fields from granting license to production start of 14 years, it will be difficult to have time to produce new discoveries from the existing fields

• The investments in the Danish fields peak earlier than on British and Norwegian fields. Where investments are made relatively early on the Danish producing fields, investments are relatively small later on during the field life cycle – 20% of the field-life CAPEX of the Danish fields is after 30 years compared to 29% and 34%, respectively, for the UK and Norwegian fields

LEVERS

• Reduction of the total exploration and development period of smaller discoveries particularly focusing on the period from granted license to exploration drilling and the period from discovery to development decision

• Reduction of the development costs – including particular focus on drilling costs. In addition, all possible commercial development solutions for the Danish fields should be further examined

• Savings related to the operating costs of the producing fields – e.g. through closer operator cooperation in relation to logistics and moving more functions to onshore (integrated operations)

• Establishment of an incentive structure including special incentives linked to the development of fields which are marginal due to their field size or geological conditions (HPHT)

• Stronger incentives for recovery-enhancing (and thus life extension) ‘late-life’ investments on the producing fields
4 ENGINE OF GROWTH III - INCREASING THE RECOVERY RATE

The operators on the Danish shelf have continuously been able to increase the recovery rate through more horizontal production wells and water injection and expect today an average recovery rate of 28%. Each percentage point by which the recovery rate is increased is of significant value to the operators as well as to Danish society. Further increases of the recovery rate have become increasingly difficult and are made more difficult by the limited size of more fields and the difficult geological conditions of the Danish subsurface – by virtue of many chalk fields which generally have a significantly lower recovery rate than sandstone fields. There seems, however, to be further technical potential for increasing the recovery rate and when the recovery rate to a great extent is determined by the investments made in the recovery-enhancing initiatives, it can still be affected through additional investments. Realisation of technological resources requires that wide investments are made in recovery-enhancing initiatives of which special ‘brownfield’ taxation models could enhance the attractiveness. There is a need to reverse the decrease in the number of production and injection wells, to introduce conventional water injection to additional fields, and for an overall plan for the commercialisation of CO₂-injection on the relevant Danish fields to be established as soon as possible and that the general exploration efforts concerning tertiary recovery techniques are intensified.

4.1 INCREASE OF THE RECOVERY RATE HAS DECREASED DURING RECENT YEARS

At present, a final recovery rate on the Danish shelf of 28% is expected - this is the estimate of the operators of the producing fields and covers both historical and expected future production from the fields. There are large fluctuations of the recovery rates across the Danish fields and they range from less than 10% on the fields with the lowest recovery rate to above 50% on the fields with the highest recovery rate.

ACROSS THE DANISH FIELDS THERE IS A BIG DIFFERENCE IN THE LEVEL OF RECOVERY

OVERVIEW OF THE OIL ON THE DANISH SHELF* MMBBL**

<table>
<thead>
<tr>
<th>Field</th>
<th>STOIP MMBBL</th>
<th>Remaining oil at end of production</th>
<th>Oil reserves MMBBL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tyra + Tyra SE</td>
<td>2,253</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Halfdan</td>
<td>1,903</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Dan</td>
<td>1,949</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Syd Arne</td>
<td>1,191</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Valdemar</td>
<td>1,367</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Skjold</td>
<td>523</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Gorm</td>
<td>906</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Kraka</td>
<td>553</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Hejre</td>
<td>477</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Roar</td>
<td>379</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Rolf</td>
<td>282</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Svend</td>
<td>282</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Siri</td>
<td>133</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Regnar</td>
<td>321</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Harald</td>
<td>94</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Nagmar</td>
<td>379</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Lulita</td>
<td>379</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Nini</td>
<td>379</td>
<td>8%</td>
<td>4%</td>
</tr>
<tr>
<td>Cecille</td>
<td>379</td>
<td>8%</td>
<td>4%</td>
</tr>
</tbody>
</table>

* Due to a considerable amount of gas along with oil and difficult conditions in the subsurface, several fields primarily have a commercial focus on gas recovery, which impacts the level of oil recovery. An example of this is Tyra

** Source: Danish Energy Agency;Maersk Oil; DONG Energy; HESS; Quartz+Co-analysis
The expected final recovery of approx. 28% means at the same time that 72% of the oil on the Danish shelf – at present – is expected to remain in the subsurface when production has been discontinued and the last installation has been decommissioned. Measured in barrels, it corresponds to – with the current estimates of the total present quantities of oil – approx. 8,600 mmboe. An increase of the recovery rate by only a few percentage points will have considerable value. As clarified in the report “the Danish oil and gas sector’s development and social impact (1992-2012)”, which has been drawn up by Quartz+Co in spring 2012, an increase in the recovery rate by 1 percentage point for the entire Danish shelf has a production value of up to DKK 80 billion of which a large part goes to the Danish state.

Over the past 30 years, the operators on the Danish shelf have gained increasing knowledge and skills in relation to increasing the recovery rate. While the technical opportunities have been improved, this has led to significant boosts of the recovery rates on each field and thus also of the Danish shelf as a whole. In 1985, the expected recovery of the producing fields in the entire shelf was 11%; since then, an increase of the recovery rate by 17 percentage points has occurred or which on average corresponds to 3.6% per year. This constant improvement of the recovery rate has been crucial to the value creation of the shelf. The maturity and the technical stage achieved, however, that mean that similar increases cannot be expected to continue in the years to come. In recent years, the annual increases have thus declined – from 2003 to 2012 the annual rate has decreased to an average of 2.5% from 4.2% during the previous 10 years.

As further increases in the recovery rates become increasingly difficult to achieve, higher specialist skills are required to provide these. DTU has an engineering degree in oil and gas technology, but three out of four students in the program are now foreign students. At the same time, the operators experience

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**THERE HAS BEEN A CONSTANT INCREASE IN THE RECOVERY RATE OVER TIME, BUT IN THE PAST YEARS IT HAS DECREASED**

**HISTORICAL DEVELOPMENT OF RECOVERY PERCENTAGE**

Source: The Danish Energy Agency; Erling Halfdan Stenby, Head of Institute, professor DTU; Quartz+Co-analysis
that they have difficulty in attracting experienced Danish employees with the necessary qualifications, while 42% of the permanent reservoir engineers and petrophysicists today are foreign specialists – typically on a research scheme.26

4.2 LIMESTONE COMPLICATES THE RECOVERY CONDITIONS ON THE DANISH SHELF

Historically, in the North Sea region much greater focus has been on recovery rate and better utilisation of the resources than in most other regions globally, which is reflected in the expected recovery rates relative to the rest of the world. The recovery rate from the Danish shelf is relatively low compared for example to the Norwegian and British shelf, where the recovery rates are 46% and 41%, respectively. The significant difference can for a great part be attributed to the nature of the subsurface of the Danish shelf. Most of the Danish fields (13) are produced from dense limestone reservoirs, while a minor part of the fields (six including Hejre where production is expected to commence in 2015), like the majority of the British and Norwegian fields located in sandstone reservoirs. The sandstone fields on the Danish shelf have an average recovery rate of 38%, while the limestone fields have an average recovery rate of 25%.

Limestone fields dominate the Danish shelf, where they constitute 93% of the total oil reserves (historical and remaining). Therefore, the recovery rate of the limestone fields is decisive for the overall recovery rate on the Danish shelf. Limestone is a complexity-enhancing element in relation to the recovery rate as limestone is porous and has low permeability compared to the sandstone fields, meaning that oil has substantially more difficulties in flowing. The problem can be illustrated by imagining a bathtub filled with water. If a plug of sandstone is put into the bathtub, it takes about 14 days before the water has run out, while it takes 30 years

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**THE RECOVERY RATE ON THE SAND STONE FIELDS IS MORE THAN 50% HIGHER THAN ON THE CHALK FIELDS**

**AVERAGE (NON WEIGHTED) RECOVERY RATE FOR CHALK AND SAND STONE FIELDS**

<table>
<thead>
<tr>
<th>Year</th>
<th>Chalk</th>
<th>Sandstone</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>10.9</td>
<td>0.0</td>
</tr>
<tr>
<td>1995</td>
<td>14.3</td>
<td>19.5</td>
</tr>
<tr>
<td>2005</td>
<td>20.4</td>
<td>36.4</td>
</tr>
<tr>
<td>2012</td>
<td>37.8</td>
<td>24.6</td>
</tr>
</tbody>
</table>

**Source:** Danish Energy Agency; Maersk Oil; DONG Energy; HESS; Quartz+Co-analysis
THE DANISH CHALK FIELDS HAVE A LOWER TECHNICAL RECOVERY RATE POTENTIAL BUT ALSO A LOWER RECOVERY RATE THAN THE INTERNATIONAL FIELDS

EXPECTED FINAL RECOVERY RATE AND ESTIMATED TECHNICAL MAXIMAL RECOVERY RATE FOR DANISH AND INTERNATIONAL CHALK FIELDS

PERCENTAGE

<table>
<thead>
<tr>
<th>Average for chalk fields on the Danish shelf</th>
<th>Average for chalk fields on other shelves</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected recovery rate</td>
<td>Expected recovery rate</td>
</tr>
<tr>
<td>30</td>
<td>38</td>
</tr>
<tr>
<td>Estimated technical recovery potential</td>
<td>Estimated technical recovery potential</td>
</tr>
<tr>
<td>42</td>
<td>52</td>
</tr>
<tr>
<td>Utilization</td>
<td>Utilization</td>
</tr>
<tr>
<td>67%</td>
<td>75%</td>
</tr>
</tbody>
</table>

Note: The fields included in the analysis are not fully representative for the Danish shelf and some of the fields with lower levels of recovery are not included, which is why the average is higher than the real average for the Danish chalk fields with an average of 24.6%.

* calculated as average utilization per field in the analysis
Source: SPE; Maersk Oil; HESS; Quartz+Co-analysis

before the water has run out if the plug is of limestone. At the same time, the limestone fields have typically a smaller core (where the recovery rate is highest) and a larger flank area with poorer reservoir quality in the form of higher water saturation and lower porosity. Therefore, these elements must be kept in mind in comparison with the Norwegian and British shelf, where complexity generally is lower due to the larger proportion of sandstone fields. In this context, the other fields of the North Sea do not form the best basis for comparison with the Danish shelf.

In 2012/2013, Maersk Oil prepared in cooperation with the analysis and research company Foroil a complexity calculation model for chalk fields to determine the maximum technical potential of a specific limestone field. The model included 22 limestone fields of which 10 were Danish, as a basis for the analysis. Based on the analysis, it can be concluded that the Danish fields in relation to international chalk fields generally are at a lower recovery level - 30% in relation to 38% of the international fields – and that the technically feasible potential is also lower for the Danish fields - by 42% compared to 52% for the international fields. Relatively, the Danish chalk fields have thus generally a lower utilisation of the technical potential in relation to the international fields - 67% compared to 75% for international comparable fields. Despite the statistical uncertainty of the study, the results indicate that it should still be possible to increase the recovery rate further on the Danish fields, also when taking the complexity of the fields into account.

28 In relation to the study’s analytical data base, some of the Danish fields have been selected, e.g. Gorm was represented by 3 data points.
4.3 MAJOR FIELDS HAVE BETTER CONDITIONS FOR A HIGH RECOVERY RATE

There is a clear tendency that the largest fields – measured on oil reserves – have the best recovery rates. As an example, the three largest chalk fields have an average recovery rate of 41%, while the remaining chalk fields have an average recovery rate of 20%. This relationship applies to both limestone and sandstone fields, although the recovery rates are generally higher for the sandstone fields – both for smaller and larger fields.

This relationship between the smaller and larger fields is partly due to relatively larger flank area of the smaller fields which typically has a higher water saturation and poorer reservoir quality than the field core resulting in a lower recovery rate. According to Erling Halfdan Stenby, professor at DTU, the connection is, however, primarily an expression of the economically conditioned decisions which the operators take in relation to the development of the fields, rather than a result of the geological conditions of the fields. A larger field has simply more sound economic conditions for investments in production optimising initiatives (such as more and horizontal production wells, water injection and 4D seismic) benefitting the recovery rate.

Relatively larger investments must be made in small fields to recover relatively minor quantities. If the total CAPEX per boe is compared with the average recovery rates for each field, it appears that the smaller fields generally have higher CAPEX per boe contemporary with lower recovery rates.

4.4 SECONDARY RECOVERY HAS CONTRIBUTED MOST TO THE INCREASE OF THE RECOVERY RATE

Recovery of oil can be done in different ways, which can generally be divided into three different types or stages – primary, secondary and tertiary recoveries, respectively (see fact box below).

As previously mentioned, the operators of the Danish producing fields estimate at present the final recovery rate to be 28%. Of the 28%, 3/4 have already been recovered – corresponding to 21 percentage points. Of the historically recovered quantities of oil, only 5 percentage points have been recovered through primary recovery, while the vast majority – 16 percentage points – has been recovered through secondary recovery (water injection). Tertiary recovery (EoR) has historically never been used on the Danish shelf.

FACTS – THREE RECOVERY TYPES

Primary recovery comes from drilling of one or more production wells. When a well has been drilled and completed in an oil zone, the natural pressures at this depth will cause oil to flow towards the lower pressure at the well bore after which oil is lifted up to the surface. Quite often, the primary recovery results in recovery rates of between 5-15% depending on the number of production wells and type of subsoil.

Secondary recovery is generally recovery by methods for “improved oil recovery” (IOR), which covers the injection of liquids, which are already present in the reservoir – for example water and gas. These methods are used when there is insufficient subsoil pressure to move the remaining oil. Through the increased pressure, oil and the injected liquid are pressed through the reservoir. Secondary recovery results generally in additional increase in the recovery rate by 10-30 percentage points.

Tertiary recovery is generally recovery through methods “enhanced oil recovery” (EOR), which covers injection of liquids which are not usually present in the reservoir – e.g. liquid CO2 and dinitrogen. With EOR, external energy and materials are injected in a reservoir to be able to move and recover the residual oil in a controlled way. This is done primarily through change of moistening level, interfacial tensions, properties of liquid and pressure gradients. Tertiary recovery (EOR) has been used for the longest time in the United States, which on several fields has resulted in increases in the recovery rates of up to 15 percentage points.
SECONDARY RECOVERY HAS HISTORICALLY CONTRIBUTED MOST TO THE LEVEL OF RECOVERY ON THE DANISH SHELF AND IS EXPECTED TO DO SO ALSO IN FUTURE

OVERVIEW SHOWING PRESENT AND FUTURE RECOVERY AlLOCATED TO EACH RECOVERY TYPE

Source: Maersk Oil; DONG Energy; HESS; Quartz+Co-analysis
4.5 THE RECOVERY RATE IS CLOSELY CONNECTED WITH THE NUMBER OF PRODUCTION AND INJECTION WELLS

Historically, the introduction of horizontal (i.e. horizontal instead of the usually more vertical) production and injection wells on more of the particularly large limestone fields have had a significant influence on the recovery rate on the Danish shelf. Maersk Oil started with horizontal drilling at the end of the 1980s and together with the other players on the Danish shelf they have continuously developed the fields with more and more horizontal wells so that the majority of the Danish fields today have horizontal wells. The advantage of the horizontal wells is a substantially higher contact surface with the reservoir, which is particularly important in limestone fields, where the reservoir has low permeability.

Generally, there is clear correlation between the historical development of the recovery rate and the number of production wells (both vertical and horizontal wells). The total recovery rate has increased on average by 2.5% per year over the past 10 years, while the number of production wells during the same period has increased by 2.7% per year. The Danish fields have regularly been further developed with new production wells to optimise recovery and as an example, Dan field produces, as the largest field, from 62 production wells, today.

New production wells can be drilled with greater accuracy in relation to ensuring the optimal utilisation of a field’s remaining recovery potential. This is due to better drilling techniques and better knowledge of the changes made in the fields’ reservoirs over a period of time. On more fields - including the Dan field - 4D seismic surveys have been carried out, based on 3D seismic taken from the same reservoir at certain time intervals, that can describe the changes in the reservoir over a period of time (such as flow, pressure and saturation), whereby unexploited pockets of oil can be localised. The significant cost related to 4D seismic surveys means, however, that not all fields, which might benefit from them, make use of them.

Historically, water injection through separate injection wells has been a significant factor in relation to improving the recovery rate on the Danish shelf. By injecting water, the reservoir pressure is kept up to push the oil towards the lower pressure at the production well. Injection of water took place for the first time on the Skjold field in 1986 and in 1989, the Dan and Gorm fields followed. Today, water is injected on eight fields and these fields account totally for 82% of the total production on the Danish shelf.

As seen with the production wells, there is a clear correlation between the increase in the recovery rate and use of water injection. On fields with water injection, the recovery rate has on average increased by 4.3 % per year since the mid-1980s, while the recovery rate on fields without injection has increased by 2.9% during the same period. A clear correlation is also seen between the development of the recovery rate for fields with water injection and the total number of drilled injection wells.

The eight producing fields on the Danish shelf where water is injected have on average significantly better recovery rates than the 10 fields without injection. In 1985, the difference between the fields, which today have water injection and the fields without injection, was 4 percentage points. In 2012, the difference had increased to 20 percentage points, so the recovery rate for fields with and without water injection today is 40% and 20%, respectively.

Generally, it can be concluded that both the number of production wells, and whether water injection is used, historically have been important elements to increase the recovery rate. Looking forward, they must therefore be considered essential instruments if the recovery rate shall be further increased. This
is confirmed by the operators, who believe that the vast majority of the remaining recovery potential shall still be met through primary and secondary recovery. As an example, there are still challenging reservoirs (Lower chalk) on the limestone fields, where water injection generally speaking is not used today, but where water injection is expected to have a long-term positive impact on recovery.

As shown in Chapter 3, evolution of the number of new production and injection wells seems, however, to be in the wrong direction – during the past 10 years, the number of new production and injection wells has decreased by an average of 23% and 16%, respectively, per year to two and one in 2012. The potential related to further develop the Danish fields with more and more wells have undoubtedly become smaller as wells are located still closer, but the potential has not been exhausted. However, it appears that the focus of operators has changed from the drilling of new production and injection wells to the repair and optimisation of existing wells. During the last 10 years, 90 work-overs have been carried out, which are complex interventions in existing wells which are out of operation or which do not produce optimally, e.g. because of equipment, which has got stuck, or due to corrosion and wax in the well. Such interventions typically require a drilling rig and are often quite cost-intensive to implement. The number of work-overs has increased on average by 10% per year since 2003 and peaked in 2012 with all of 23. In spite of a quite large complexity related to work-overs, both establishment of new production and injection wells and intervention in existing wells are based on well-tested technologies with a well-known positive effect on the recovery rate. Drilling of new wells as well as continued ongoing optimisation of existing wells seem central to realising the technological resources.
4.6 TERTIARY RECOVERY – INCLUDING CO₂ INJECTION – WILL UNDER CURRENT CONDITIONS CONTRIBUTE MINIMALLY TO THE TOTAL RECOVERY

In relation to the remaining oil recovery potential on the Danish fields – corresponding to 7 percentage points up to the 28% – it is expected by the operators that the majority (58%) continues to come from secondary recovery. Primary recovery is expected to contribute 23% and tertiary recovery, for which the Danish Energy Agency otherwise has great expectations on the Danish shelf, is expected by the operators – under the current conditions – to contribute only about 19% of the remaining recovery.

The four fields, which have the largest remaining oil recovery potential, are Halfdan, Dan, Syd Arne and Hejre. These fields are expected to account for 84% of the remaining recovery. On the former three fields, secondary recovery is expected – primarily via water injection – to constitute 68% of the total recovery, while production on Hejre due to the high pressure of the reservoir alone will be based on primary recovery.

Dan and Halfdan are the only two fields on the Danish shelf, where it is at present assessed to be a commercial potential in the use of tertiary recovery techniques (EOR). Maersk Oil expects that CO₂ injection on the two fields can contribute a considerable volume. The operators’ current expectations for recovery through EOR are, however, considerably below the 470 mmboe, which the Danish Energy Agency expects can be recovered via CO₂ injection.

The operators’ restraint in relation to the use of EOR on the Danish shelf expresses to a great extent the complexity, the lack of technological maturity and the considerable investments related to EOR compared to the limited remaining life of the existing fields. In addition to CO₂ injection, there are more EOR methods, which have a technical potential to increase the recovery of the Danish fields – as an example injection of desalinated sea water, injection of dinitrogen (N₂) on HPHT fields and use of polymer flooding on sandstone fields with water injection. In a Danish context, these technologies are, however, at a too immature stage of development for a commercial potential related hereto to be taken into account, at present.

The operators and the industry as a whole consider increased technological development and maturation of techniques like those above as central to be able to introduce tertiary recovery to the Danish fields. The sector is thus using major resources on research and development for the purpose. Based on the social value related to continued increases of the recovery rate, it is, however, striking that Danish energy research policy practically excludes oil and gas recovery from the grant of research funds. In this connection, time is also a decisive factor for potential realisation.

4.7 THERE ARE GREAT BARRIERS IN CONNECTION WITH CO₂ INJECTION BUT IF THE POTENTIAL IS TO BE REALISED, IT IS URGENT TO ESTABLISH A COMMERCIAL MODEL

In a report drawn up for the Danish Energy Agency, Rambøll has estimated good opportunities to develop a model of combined carbon capture storage (CCS) and EOR with a considerable positive social value. It was, however, also concluded that the necessary incentives still need to be created in order that the largest CO₂ emitters, which must make large initial investments to be able to collect the CO₂, would be willing to participate in the project. Moreover, there are two other key and correlated issues related to EOR through CO₂ injection.

There is a significant time perspective in relation to how long it will be possible to utilise EOR considering the maturity stage of the Danish shelf. At present, Hess therefore does not consider CO₂ injection as an economically profitable option on Syd Arne. Recovery via EOR must necessarily take place while the fields are still in operation and must be commenced several years before expected production stop in order that the injection can have time to have the intended effect. These conditions leave a limited window for when production must take place (see also Chapter 3). Conversely, just these initiatives can contribute extension of the financial life of the Danish fields. The advanced time perspective is further accentuated by the fact that it is expected to take three to four years to establish the necessary

29 Quartz+Co oil- and gas sector survey and workshop, June 2013
30 CCS is a method to collect and transport CO₂ from CO₂ emitting plant and subsequently store this CO₂ in e.g. the reservoirs of the Danish oil producing fields
complex collection facilities on the first CO₂-emitting plant. After this, there is an expected need for at least one year of operation with collection of experience until more collection facilities can be installed.

At the same time, there is a need for considerable amounts of CO₂ to be able to carry out CO₂-injection of commercial nature and derived from this, there will be challenges in order to establish sufficient collection capacity in Denmark, while still having commercial potential on the shelf. If collection capacity on Denmark’s three most emitting plants is established, a significant volume could be produced. But in order to recover oil in addition to this, collection on additionally several smaller plants within a limited number of years shall be established. Alternatively, CO₂-sources must be found outside Denmark’s borders, but at present international legislation only allows CO₂-transport across national borders in special circumstances.

4.8 POTENTIAL LEVERS TO INCREASE THE RECOVERY RATE

According to the Danish Energy Agency, the technological resources – which must be exploited by improving the recovery rate – represent the largest remaining resource potential on the Danish shelf with a total of 593 mmboe – corresponding to 42% of the total resource potential. The estimate of the technological resources of the Danish Energy Agency is based on the expectation that it is possible to increase the average recovery rate – which the Danish Energy Agency has most recently calculated to 26% – by 5 percentage points. Of this, it is expected that the majority is achieved by implementing new technology for CO₂-injection on the large producing fields with water injection, while the rest are smaller contributions from other technological initiatives.

The operators of the producing fields on the Danish shelf are, however, considerably less optimistic compared to what can realistically be achieved under existing conditions. Partly, they consider that a final recovery rate of 28% and not 31% can be achieved, and partly they are significantly less cautious with regard to the contribution which must come from CO₂-injection. If the estimate of the technological resources of the Danish Energy Agency shall be realised, it is necessary that considerable efforts in relation to increasing the recovery rate are made, which are not limited to a single or few resources – such as CO₂-injection.

Through the years, the operators have shown significant ability to continuously increase the recovery

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**THE OPERATORS AND THE DANISH ENERGY AGENCY PRESENTLY VIEW THE POTENTIAL IN TERTIARY RECOVERY (EOR) DIFFERENTLY AND BECAUSE OF THIS ALSO HOW HIGH THE RECOVERY RATE CAN REACH**

**OVERVIEW OF HISTORICAL AND FUTURE RECOVERY ALLOCATED PER TYPE**

<table>
<thead>
<tr>
<th>PERCENTAGE</th>
<th>Operators’ estimate</th>
<th>Danish Energy Agency’s estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOTAL PRESENT AND FUTURE RECOVERY VIA PRIMARY AND SECONDARY RECOVERY</td>
<td>26.7%</td>
<td>26.0%</td>
</tr>
<tr>
<td>FUTURE TERTIARY RECOVERY</td>
<td>1.3%</td>
<td>5.0%</td>
</tr>
<tr>
<td>EXPECTED TOTAL RECOVERY</td>
<td>28.0%</td>
<td>31.0%</td>
</tr>
</tbody>
</table>

*Source: Danish Energy Agency; Maersk Oil; DONG Energy; HESS; Quartz+Co-analysis*
rate on the Danish fields and therefore it cannot be ruled out that continued increases hereof can be made also in the future, even though in recent years they have been made at a slower pace, and the majority of the fields today are very mature. As previously mentioned, it is moreover assessed to be an unexploited recovery potential on the Danish fields, which, if only a minor part hereof is exploited, can contribute significantly to realisation of the technological resources.

When the recovery rate of a field to a great extent is conditional on the investments made on the field and not only on its geological conditions, the recovery rate of a field is affected by changing the attractiveness of investments in the recovery optimising initiatives.

The players of the Danish oil and gas sector suggest the need for stronger incentives as the most essential instrument if the recovery rate is to be increased. As an example, this could be in the form of taxation models targeted use of new technologies (a.o. EOR-technology), which is becoming increasingly decisive if the recovery rate is to be continuously increased - or models targeted smaller fields where the recovery rate lags behind the larger fields, as it has not been profitable to establish the same production-enhancing facilities here. It could also be special ‘brownfield’ models where field-specifically lower taxation rates of reserve production could be negotiated over a given threshold. Moreover, inducement to spread 4D seismic surveys to more of the Danish fields should be made, all of which could benefit from the knowledge that these studies bring about unexploited recovery potentials in the reservoirs of the fields.

The operators estimate that the majority of the continuous recovery from the producing fields must come from primary and secondary recovery. However, this seems to assume that the significant decrease in the number of new production and injection wells in recent years is reversed so that new wells are established to the extent that there is a resource potential, which dictates this, at the same time as the operators continue their efforts to repair and optimise existing wells through work-overs.

Since the fields with water injection perform considerably higher recovery rates than fields without water injection and today it is only half of the producing fields, which inject water, there seems at present to be a resource-related potential associated with introducing conventional injection to more fields if it can be done under economically attractive conditions. At the same time, it must be attractive to introduce water injection to technically more challenging reservoirs on the existing fields with water injection.

If the resource potential related to CO₂-injection is to be utilised - and maximised according to the expectations of the Danish Energy Agency - there is a need that the operators of relevant producing fields, the owners of the most CO₂-emitting facilities in Denmark and the Danish state agree on a total plan hereof, as soon as possible. The plan must necessarily take into account the limited window of opportunity for establishment of an infrastructure for CO₂-injection and the current limited incentives and economic uncertainty related hereto for key players.

EOR-technologies undoubtedly include a significant recovery potential for the Danish shelf, which is also identified by the Danish Energy Agency. But the technological maturity makes them difficult to commercialise without significant research and development efforts. These efforts are currently driven almost only by the sector itself, but as time is crucial to the fact whether the potential can be realised, it is in the Danish society’s interest that the state joins this research.

In the same connection, it is essential that efforts are made to keep the window of opportunity for investment in CO₂-injection and other EOR-initiatives open for as long as possible by postponing the financial shutdown of the fields, through initiatives which can contribute to maintain production. Optimisation of the fields’ existing wells and further development of new wells will contribute to this; connection of marginal discoveries to the existing platforms will do the same, which at the same time is decisive for realising of the conditional resources (see also chapter 3).

31 Quartz+Co oil- and gas sector survey and workshop, June 2013
HIGHLIGHTS: ENGINE OF GROWTH III
- INCREASING OF RECOVERY RATE

KEY FACTS

- The operators on the Danish shelf have been able to continuously increase the recovery rate and today expect an average recovery rate of 28% compared to 11% in 1985. This corresponds to an annual improvement of 3.6%. 21% of the available oil resources are recovered today.

- 93% of the oil reserves on the Danish shelf are located on chalk fields where the reservoirs’ ability to transport oil (permeability) is significantly lower than that of the sandstone fields. The recovery rate of the Danish chalk fields is on average 25%, while it is 38% for the sandstone fields.

- Compared to international comparable chalk fields, the Danish chalk fields are generally located at a lower recovery rate and have a relatively larger technical unexploited potential.

- The recovery rate for the eight fields with water injection is today 40% while it is 20% for the 10 producing fields without water injection.

- The largest fields measured on oil reserves have the best recovery rates – the three largest chalk fields have an average recovery rate of 41%, while the remaining chalk fields have an average recovery rate of 20%.

- There is a close correlation between the number of production- and injection wells and development of the recovery rate. Forward-looking, the primary and secondary recovery is expected to account for above 80% of the recovery. At present, only a limited contribution from CO2-injection is expected.

LEVERS

- Drilling of new production- and injection wells to the extent there is a resource-related potential which dictate this and continuous efforts in repair- and optimisation of existing wells through work-overs.

- Spreading of water injection to more fields and to more challenging reservoirs.

- Speedy preparation of a comprehensive plan to utilise CO2 -injection on the Danish producing fields which takes into account the limited time-wise window for this.

- Establishment of research- and development efforts targeted maturation and commercialisation of EOR-technologies with participation of both the sector, high technology companies and state institutions.

- Establishment of an incentive structure which encourages recovery-enhancing initiatives – for example, with incentives targeted use of new technology, investments in smaller producing fields and introduction of 4D seismic surveys to more fields.
It is a fact that oil and gas production on the Danish shelf is decreasing. However, it is also a fact that, despite the level of maturity of the Danish shelf, there is still a large resource potential, which actually represents more than 40% of the total historic production.

If 50% of the estimated potential is realised, it corresponds to fiscal additional contribution of approx. DKK 190 billion towards 2042. If the ambition is increased and 80% of the potential is realised successfully, Denmark – in addition to a further additional fiscal contribution – will be able to maintain its status as a net exporter of oil and gas for the next 20 years.

An expected realisation of the future potential seems, however, to be under great pressure. The exploration activity is historically low and yields still lower discoveries, the development of marginal discoveries is at a stand still and seems to be without perspective and the increase of the recovery rate is decreasing and is far behind the estimated level.

On basis of a general national perspective, it seems that the framework conditions of the Danish oil and gas sector and the way in which it is operated and developed is out of step with the expected lifetime of the shelf’s maturity level and infrastructure. The licensing model limits the fast initiative, exploration wells and developments are planned and executed with long time intervals, there is no extraordinary incentive for marginal investments, investments in the producing fields ‘tail production’ is relatively small, development- and operating costs increase despite decreasing volumes and new perspectives on the development potentials of the producing fields fail to happen with the new players’ lack of interest in these fields.

At the same time, time is a crucial factor, as the size of the potential which can be realised, depends on how quickly the three engines of growth – Increased exploration activity, Production of marginal fields and Increase of the recovery rate – together gain speed. The more time passes before setting in, the sooner the current infrastructure will shut down due to lack of production for maintaining operation. This reduces the possibility of development of marginal discoveries and undermines thus the incentive for exploration. Sooner shutdown of the producing fields results at the same time in a lower recovery rate as investments in a continuous increase hereof depend on continued production. Being hesitant now, and then continue the activity later on is not an option – the necessary production facilities and competences will not be present. The efforts of the years to come are therefore critical to continued development of the Danish oil and gas sector.

There is thus a need to start working broadly and coherently across the three engines of growth and find new and alternative solutions within a number of the key levers that can increase activity on the Danish shelf, such as:

**Cost level:** Reduction of current drilling-, development- and operating costs through closer operator cooperation in relation to e.g. collection of seismic data, drilling campaigns, development of smaller fields, logistics services and maturation and standardisation of technology.

**Regulation:** Adjustment of the current licensing model for increased flexibility in order to promote exploration initiatives and reduce time which passes from a license has been granted until drilling is carried out under the license. This could for example be by increasing the number of licensing rounds or ‘open door’ on all non-licensed areas and if appropriately combined with stricter regulatory requirements to maintain constant activity on granted licenses. It should also be ensured that the regulatory framework does not increase the cost of activity on the Danish shelf unnecessarily; hereunder that regulations for drilling rigs should be the same in EU-countries bordering the North Sea in order to increase the availability of rigs and reduce the extra costs related to drilling (at present, different rules between countries mean that time-consuming and
costly modifications are made when a drilling rig enters another country’s waters).

**Tax regime:** Establishment of a tax regime for new projects, which recognise the maturity level of the Danish shelf and creates economic and socially sustainable incentives to invest in exploration targeting new play types and new areas, development of marginal discoveries and recovery-optimising actions on producing fields. This can be done in different ways, as in the Norwegian and UK tax regime. The Danish regime should, however, reflect the risk profile which characterises the Danish area.

In addition, the sector has a general problem in relation to educate, attract and retain sufficient labour force. It requires still more resources and higher competences to recover the remaining resources on the Danish shelf; while fewer persons are trained in relevant specialist areas, the Danish population’s interest in working in the oil- and gas sector is declining and competition for experienced employees are increasingly globally stronger. Approx. 1/3 of the expert jobs at the operators are today occupied by foreign labour, which gives the Danish oil and gas sector valuable information, but the foreign workers are hard to maintain for more than a few years. At present, there are thus approx. 70 long-term vacancies in critical specialist areas at the operators of the producing fields on the Danish shelf.

The above calls for the preparation of a national strategy where all key players in and around the sector contribute to establish a common vision and derived initiatives for the continued development of the Danish oil and gas sector. The national strategy should at least state specific solutions for accelerating the activities within the three engines of growth, which are the key drivers for realising and maximising the remaining potential of the shelf. With the current nature of the shelf, it is crucial that we think differently and that fast action is taken.
GLOSSARY

Conditional resources – developments of discoveries and new fields or further development of existing fields where the technical or commercial basis is not yet in place for a final decision on development

Clubbing – term used when an operator of a marginal discovery connects to another operator’s further development of an existing field

Clustering – term used when the operator of nearby marginal discoveries cooperate concerning a common development

Creaming Curve – a “creaming curve” describes how a shelf has been explored by looking at the relationship between the cumulative amounts of discoveries (mmboe) and the number of exploration wells over a period of time

CCS – Carbon Capture Storage (CCS) is a method to collect and transport the CO2 from CO2-emitting plants and storing the CO2 in e.g. the reservoirs of the Danish oil producing fields

DUC – DUC is an acronym for Danish Underground Consortium and consists today of A.P. Møller Maersk A/S, Chevron Denmark Inc., Shell Olie og Gazindvinding Danmark BV and Nordsøfonden

Exploration drilling – drilling carried out to investigate whether a mapped structure contains oil and gas

Exploration resources – an assessment of the amounts expected to be recovered from new discoveries

EOR – “Enhanced Oil Recovery”, see Tertiary recovery

EU ETS – “EU Emissions Trading System”

GEUS – Geological Survey of Denmark and Greenland – this is part of the Danish Ministry of Climate, Energy and Building

Tail Production – is used as a term for the last part of the production on a field above its life

HPHT – “High Pressure/High Temperature”

Recovery rate – the part of oil in a given reservoir, which is available for recovery; i.e. the part of the total amount of oil in the reservoir (STOIP) which can be recovered during the field’s life under the given technical and economic conditions. It always describes the expected final recovery and not recovery already achieved

Injection Well – well used to pump down water or gas in order to keep the pressure in the reservoir high enough so there still is recoverable oil and gas from the producing wells, see production well

Integrated Operations – has been facilitated by development within information and communication technology and refers to establishment of new work and cooperation processes in the oil and gas production, where integrated processes between onshore and offshore are established, which allow that more sub-processes can be handled from onshore

IOR – “Improved Oil Recovery”, see Secondary recovery

Marginal discoveries – discoveries which are not commercial to develop at present – e.g. due to the size of discovery, geological or geographical location

Mmbbl – one million barrels oil

MMboe – a million barrels of oil equivalent (mmboe). A barrel of oil equivalent (boe) is an energy unit that indicates the estimated amount of energy released by combustion of one barrel of oil (corresponding to 158.97 litres). Boe is used by the oil companies to combine the oil and gas reserves in one single and by that comparable entity

OGD – Olie Gas Denmark, the trade association for the Danish upstream oil and gas industry

Operator – the company which carries out exploration or production on behalf of the licensee

Play – a play is a categorised term of the geological conditions, which control a group of fields or prospects in a region
**Primary recovery** – drilling of one or more production wells

**Production Well** – well used to production of oil or gas

**Prospectivity** – prospectivity refers to the total amount of prospects in an area; i.e. (both known and hypothetical), but not yet drilled/discovered oil and gas deposits

**Reservoir depth** – the distance down to the discovered amounts of oil/gas

**Seismic surveys** – investigations carried out by transmitting a blast wave from a sound source into the subsoil. The blast wave hits various layers in the subsoil and a part of the blast wave will as a result be reflected back to the surface and will be picked up by special receivers. In this way, an image of the subsurface is obtained, which can be used to locate oil and gas. 2D seismic data shows a cross section of the subsurface, 3D seismic data shows a three-dimensional image of the subsurface which is made by combining 2D seismic surveys in a fine mesh network

**Secondary recovery** – often through recovery methods that for “Improved Oil Recovery” (IOR), covering the injection of liquid which is already present in the reserve reservoir – for example water and gas

**STOIIP** – “Stock Tank Oil Initially in Place”, see the recovery rate

**Success rate** – the percentage of the exploration wells resulting in real discoveries of oil or gas; i.e. more than just traces of deposits

**Technological resources** – an estimate of the quantities of oil and gas which are considered likely to be recovered by the use of new technology

**Tertiary recovery** – often recovery via methods “Enhanced Oil Recovery” (EOR) covering injection of liquids, which are not normally present in the reservoir – such as liquid CO2 and dinitrogen

**Tieback** – term for a connection of a small oil- and gas field to an existing production facility, where the oil/gas recovered from the smaller field is forwarded to the existing production plant for further processing/distribution. Tiebacks is a less cost-intensive development form than the development of new independent production plants

**Appraisal Drilling** – drilling carried out to qualify and increase knowledge about the size and nature of discoveries (is carried out on basis of exploration drilling, see Exploration Drilling)

**Wildcats** – designation of exploration wells being drilled in relatively unexplored areas which have not yet discovered oil/gas

**Work overs** – repairs and maintenance of wells that require a rig