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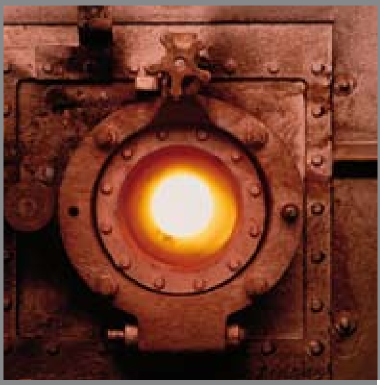


best access to dutch gas

Focus on Dutch gas 2009

1. Introduction

Commencing this year EBN will publish an annual report on the current and future state of exploration and production in the Dutch Oil and Gas Industry. This report will reflect EBN's view as a partner in the majority of Dutch E&P activities and strives to advance these as much as possible. The report aims to provide the reader with a forecast of potential exploration, investment and development opportunities in The Netherlands.

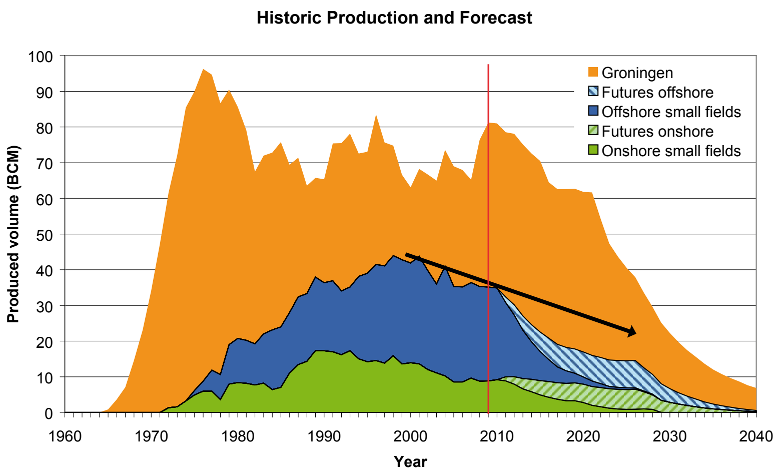
2. Resources

The Netherlands has played an important role in the international gas scene for many years. In 2008 Dutch gas production was about 80 billion cubic metres (BCM), of which almost 40 BCM, 90% of Dutch gas consumption, came from small fields. Not only have significant amounts of gas been discovered and produced - there still remain large volumes of gas to be found and developed. To illustrate this, EBN estimates the total expectation (probability of success multiplied with mean success volume) of all prospects known is at least 400 BCM (no cut-off applied).

Total Petroleum Initially in Place (BCM)	Discovered	Produced		2,887
		Reserves	On production	1,250
			Approved for development	38
		Contingent resources		52
	Undiscovered	Prospective resources	Prospects	>400
			Plays	>500,000
		Unrecoverable		>10,000,000

2.1 Reserves and production

With the offshore gas rush which started in the late sixties, offshore gas production became an important contributor to production in addition to onshore production. While onshore production from 'small fields' started to decline already in the nineties, offshore production continued to rise to a peak of 30 BCM in 2000. Since that time the production from small fields has slowly declined to 35 BCM now. This equates to a moderate overall decline rate of 1.5% per annum year on year.



In a 'no further activity' scenario, production from small fields would decline at a much higher natural rate of 10-15% per year. This decline rate can be much less, as is evident from the performance over the last 10 years, by bringing new fields on production and by properly managing well and field performance.

Use of state-of-the-art technology is essential to get the highest recovery out of oil and gas fields. At the same time it is useful to look at opportunities to extend the lifetime of wells, to be able to produce the reservoirs as long as possible. Examples are solving liquid loading problems in production wells (e.g. by foam injection), frac stimulation also at late life or huff-and-puff production. Another potential technique would be Enhanced Gas Recovery by injecting CO_2 in the gas reservoir. This keeps the pressure at a higher level and as such will allow more gas production, with the additional benefit that it will also aid in the reduction of CO_2 emissions. Responsible and innovative well and reservoir management can contribute to the optimal recovery of gas and oil from small and mature fields.

By unlocking the exploration potential, the rate of decline can also be held back considerably. A quick calculation (which assumes 15 exploration wells per year, a success ratio of 60% falling to 50% and an average find that starts with 1.3 BCM and ends with 0.8 BCM, adding up to some 250 BCM over the next 25 years) shows that the decline rate can be slowed down and significantly extends the production horizon. However the ambition level should be higher and with the historic decline rate of 1,5% per year we should be able to produce still 25 BCM form small fields in 2030.

2.2 Undeveloped fields

The total volume of undeveloped discoveries, in so-called stranded fields, is estimated at approximately 52 billion m^3 of gas, distributed over 80 discoveries. The fields are present in all known prospective geological horizons from Tertiary to Carboniferous. The undeveloped gas fields quite often consist of tight reservoirs. As such this volume is in EBN's view most likely a conservative estimate due to the nature of tight reservoirs. Fraccing, underbalanced drilling or radial drilling can help to unlock these reserves. Although these techniques have been widely applied around the world, these techniques are not commonly applied in The Netherlands. About 7% of the approximately 1000 gas production wells are hydraulically fractured and 4 wells were drilled underbalanced. In the near future though, multiple fraccing jobs are planned. This leaves plenty of opportunity for developing these resources and unlocking more reserves.

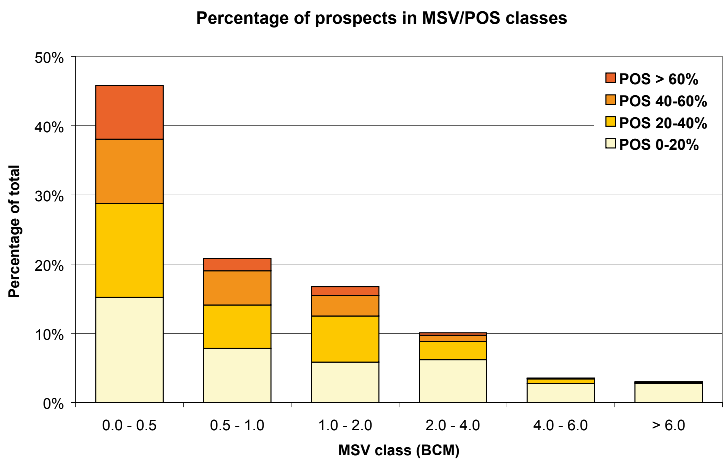
2.3 Prospects

Generally, The Netherlands is called a 'mature area': many gas fields have been discovered and developed over the last 50 years. In total nearly 3,000 BCM of gas have been produced and currently there is still over 1,000 BCM in reserves. Apart from the discovered resources, there is still a huge potential in traditional prospects.

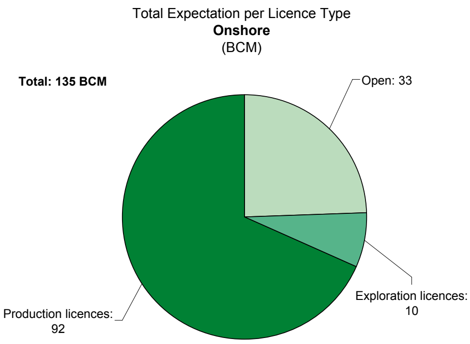
A portfolio of over a thousand known prospects has been analysed. The total expectation volume with a MSV cut-off adds for the offshore prospects up to some 137 BCM offshore and for the onshore prospects to 112 BCM (using an MSV cut-off per field of 2 BCM offshore and 0.5 BCM onshore). Applying an expectation volume cut-off instead the total volume remains approximately the same.

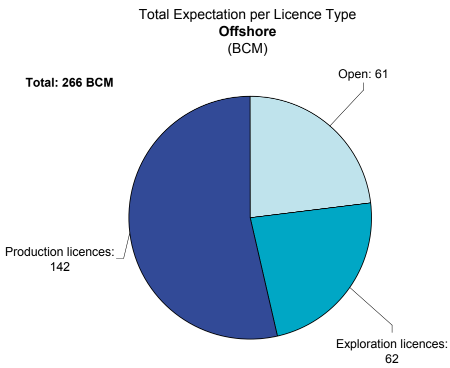
	Total	Onshore		Offshore	
	No cut-off	MSV >0.5	Expectation >0.25	MSV >2.0	Expectation >0.50
Number of prospects	>>1,000	>200	>100	>100	>100
Expectation volume	>400 BCM	112 BCM	105 BCM	137 BCM	143 BCM

The size distribution of prospects is not evenly spread over the different size categories. Most prospects can be found in the category less than 0.5 BCM and most of these will therefore more than likely not be drilled in the foreseeable future. However 55% of the prospects is larger than 0.5 BCM and there are still prospects in excess of 6 BCM. Within each category there is a probability of success distribution where in the two largest categories most prospects fall currently in the lowest POS category.

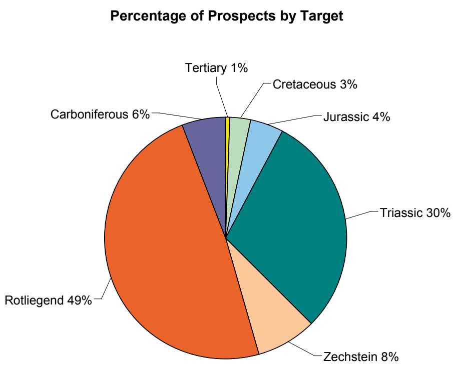


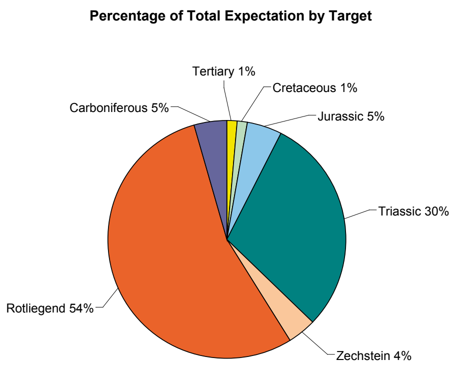
The largest number of the prospects (65%) are situated, not surprisingly, in production licences. Only 15% are located in exploration licenses and the remainder in open areas. Of all licences the production licences cover by far the largest area. It should be noted that the database is incomplete for open areas. Although many parts of both the Dutch on- and offshore, which are now open acreage, have been licensed at some time, many prospects which these contain have not been retained in the database.





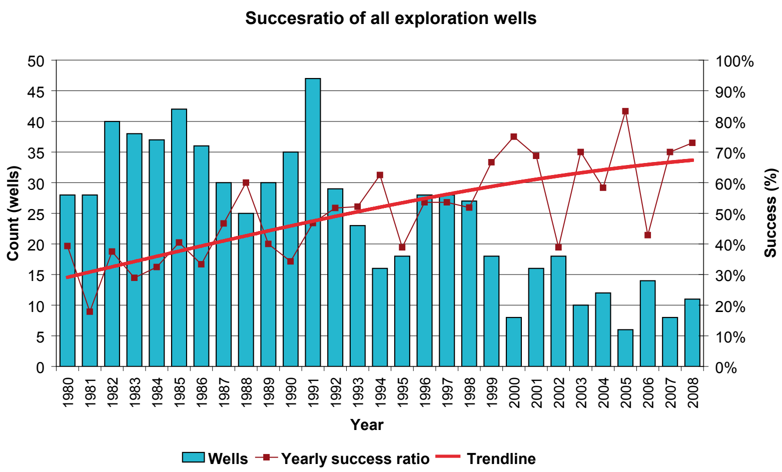
Analysis of the prospects by target reservoir clearly demonstrates that most prospects are located in the Rotliegend, and that these also have the highest expectations associated with them. The Triassic is an excellent runner up. Other targets are either considered less interesting or have received less attention. Some of the companies new to the Dutch exploration scene are looking into these possibly underexplored objectives.





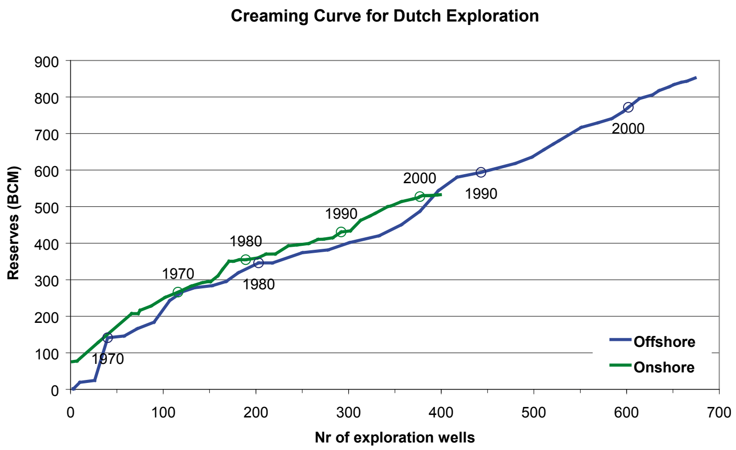
Success ratio

The success ratio of exploration wells in The Netherlands has risen continuously over the last 30-odd years. The success rate at finding economical volumes of gas has increased from about 35% in the early 1980's to over 70% last year. This is however not reflected in the POS as indicated below.



Creaming curve

The 'creaming curve' for Dutch exploration still shows a straight line with little evidence of creaming off. This is particularly true in respect of offshore. Onshore, some creaming seems to be evident - but this is partly due to the fact that most of the better prospects lie within sensitive areas such as the Waddenzee, where drilling is restricted. Also drilling activity onshore has lagged the offshore drilling activity: in 1980 both on- and offshore 200 wells were drilled. In 2008 just over 400 wells were drilled onshore and 670 wells were drilled offshore.



Average find

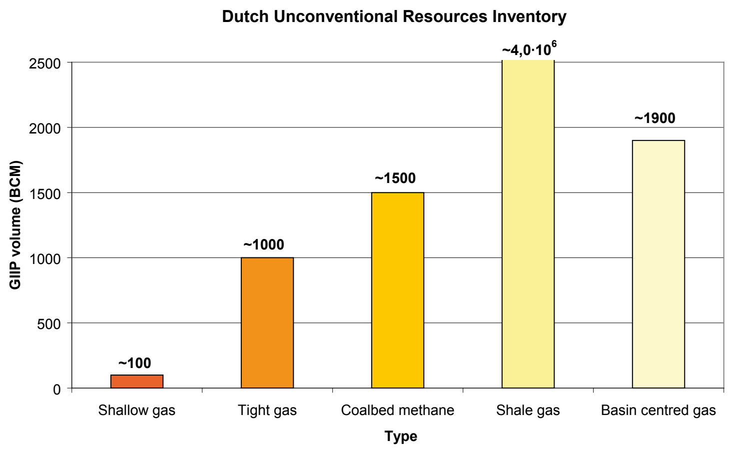
The average find per exploration well has remained fairly constant for more than 20 years at some 1.3 BCM both onshore and offshore. With the high success rate the average discovery size amounts to 2.5 to 3 BCM, field sizes than can easily be developed in The Netherlands with its well developed infrastructure.

Drilling activity

Despite these positive indicators the annual number of exploration wells has been dropping steadily over the last few years - from about 25 during the late 90's, to around 10 or less now. To make full use of the existing infrastructure a higher activity is required during the next 10 to 15 years. EBN estimates that at least 15 exploration wells per year are required to fully explore the conventional plays in The Netherlands. This is without the exploration effort required for the unconventional plays.

2.4 Unconventional resources

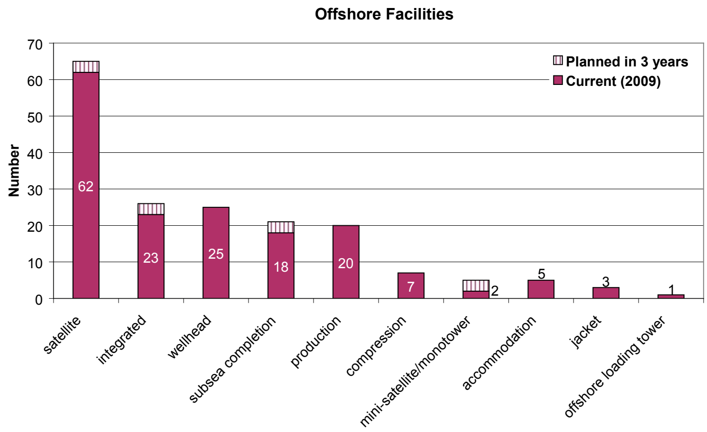
EBN initiated a study quantifying the unconventional gas potential in The Netherlands (in accordance with the SPE PRMS Classification). The numbers below are a first-pass inventory of estimated quantities. The study will focus on the potential of coalbed methane, gas in tight reservoirs, shale gas, shallow gas, basin centred gas and gas in stratigraphic traps. Volumes have been calculated probabilistically, assuming distributions for input parameters in those areas where the interval is present and shows favourable characteristics. The volumes are unrisked, which may result in an overestimation. Especially for the more exotic unconventional resources such as shale gas and basin centred gas. Even so, the 'less unconventional' resources like coalbed methane, gas in tight reservoirs and especially shallow gas (which is already being developed in the Dutch offshore) show significant potential.



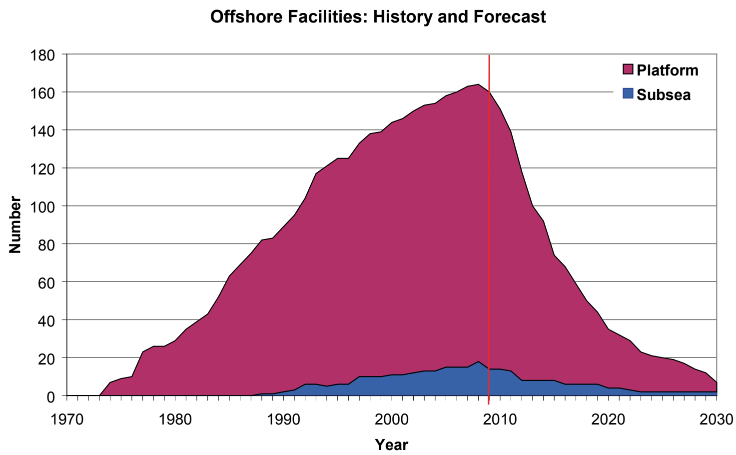
3. Infrastructure

3.1 High quality infrastructure

The Dutch offshore area (57,000 km^2) has a relatively dense high-quality infrastructure, extending from the wells via processing platforms and transmission lines into the onshore distribution networks. The figure below represents the current number of offshore facilities, as at end 2008.



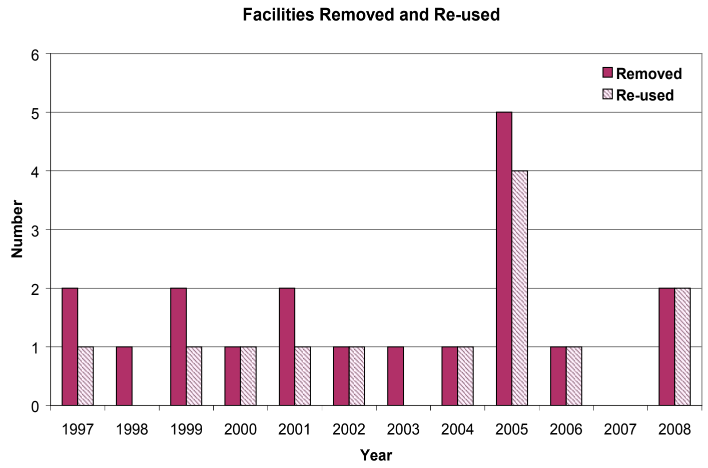
In the coming years existing offshore facilities and pipelines will gradually become less utilised, due to the decline in oil and gas production. Eventually at the end of field life the facilities will need to be dismantled. Unless new fields are discovered and developed the number of offshore facilities will decline sharply with the decline in production. The cost associated with the decommissioning of facilities is estimated at € 200 million per year between 2010 and 2030 in a 'no further activity' scenario.



However if the production ambition level can be realised also this decline will be less severe than forecasted below. A higher activity level in exploration should be undertaken as much as possible whilst the required infrastructure is still available. This evidently applies two ways. As long as the infrastructure is present, relatively small prospects can be drilled and developed at relatively low cost. This in turn extends the lifespan of the existing infrastructure. If the latter disappears prematurely considerable contributions to the Dutch energy supply and commercial opportunities will be lost.

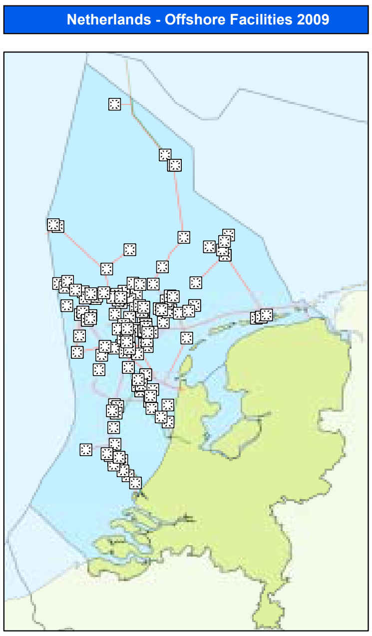
Sustaining economic production from the addition of new and/or smaller fields requires further use of unmanned platforms, monotowers, re-usable production decks and easily accessible subsea developments. The challenge is to cut costs, come up with novel ideas and make further changes across the industry, to unlock a whole new range of opportunities for development.

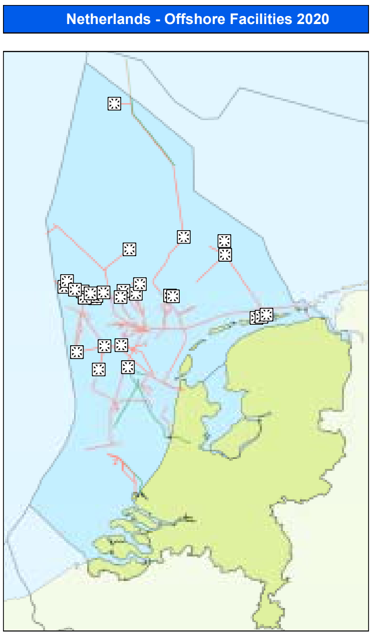
The relatively shallow southern North Sea (less than 40 meters) allows re-use of production facilities, which reduces the development cost of new fields. Over the last decade the re-use of facilities has proved very popular, not only because of cost reduction, but also because of significant reductions in lead times.

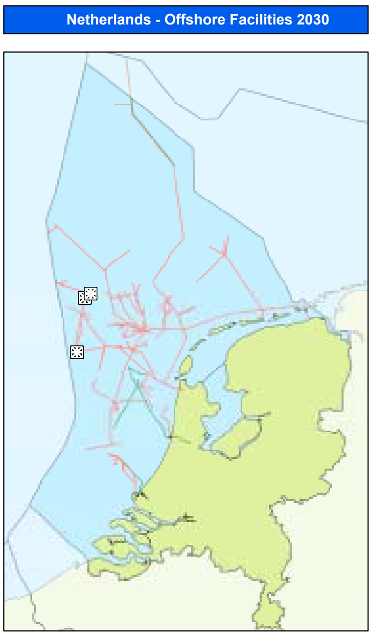


3.2 Trunk lines

The offshore network has many trunk lines with multiple tie-in locations. The total number of offshore facilities is now around 160, evacuating hydrocarbons through 5 gas trunk lines and 3 oil trunk lines. In a 'no further activity' scenario, the number of facilities evacuating via the trunk lines reduces drastically. In this scenario, the majority of the trunk lines will not be transporting hydrocarbons in 2030.







3.3 New field development technologies

Dutch territory is an innovative environment that is shifting its focus towards low cost, less conventional developments. This trend is illustrated by the introduction of light on- and offshore drilling installations, wind and solar energy powered monopiles and research into casing while drilling, and composite casing.

Eductors are expected to become more common in gas production, because they are economically attractive. They can combine the high pressure of new developed fields with the relatively low pressure of more depleted fields, resulting in an increased production from the depleted fields and reducing back out. Several have now been installed in The Netherlands.

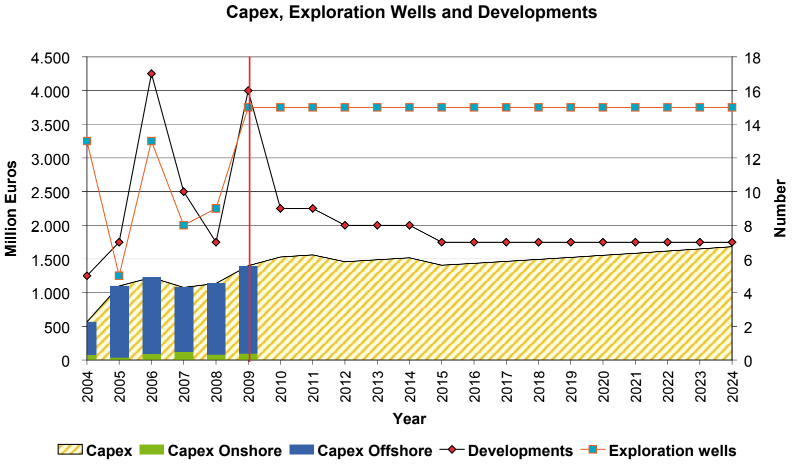
4. Revenues and Expenditure

The numbers shown in this section are based on EBN's interest, which is usually around 40%. Figures arising from the Groningen concession have been excluded, since these would distort the value of the picture presented as an indication of future Dutch upstream expectations. The Schoonebeek oil development has also been omitted because of its unique nature and impact on the capital expenditure (capex) trend.

4.1 Capital expenditures

Capital expenditure on the Dutch continental shelf has remained stable, though increasing rig rates and steel prices imply that the activity level has declined somewhat. The vast majority of expenditure is offshore. In particular, expenditure on drilling activity shows that the industry still sees ample exploration and development opportunities in The Netherlands. Over the last years the number of new fields brought on production varied between 6 in 2004 and 17 in 2006. The investment level in 2004 was indeed the lowest, but for the years thereafter has increased to around € 1,000 million.

Although the expenditure of E&P goods and services strongly fluctuates, latest figures show that costs of offshore exploration wells average to about € 25 million and development costs of a small field to around € 125 million. As an illustration for the projected capital expenditure needed to unlock the 250 BCM futures we have used the assumptions stated in the section on Resources – 15 exploration wells per year, with a decreasing average find and success ratio. This results in 9 developments per year reducing to 7, and with the number of exploration wells amounts to investing some € 1,500 million (100%) per year disregarding inflation, totalling € 25 billion over 15 years.



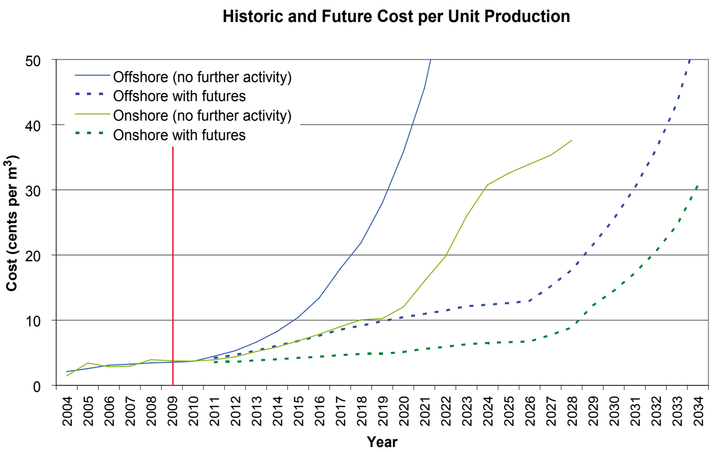
4.2 Operational expenditures

The general trend in operational expenditure (in cost per m³) over the recent years shows an annual increase in the order of 10%. This is clearly above inflation, and reflects the increasing prices of E&P goods and services which in turn correspond to some extent with the rising oil price. Nonetheless for long term sustainability this increase is to high taking into account that the production levels have only decreased by 1.5%.

A simple picture of the expected production life of existing fields can be obtained by assuming the same overall operating cost levels and field decline profiles. In the absence of further exploration and development activity production should stop when revenues no longer cover costs.

The figure below illustrates this expected unit cost development. It takes as a basis the cost level applying in 2008 (annually inflated from 2008 at 2%) - and a prediction of future production from existing developments with no further activity. Under these assumptions and assuming a gas price of 20 €cents per cubic metre, production would no longer be economic in 2017 offshore, and 2022 onshore. This forecast will be somewhat pessimistic as installations will be taken out of production at a certain point in time and no cost will entail from those thereafter.

Under the same assumptions but including future development, offshore production will be extended to 2029 and further. New developments in the near future can be seen to be key to the extension of the economic production horizon. These will be able to use existing infrastructure, so that cost per unit production can be held at an acceptable level.

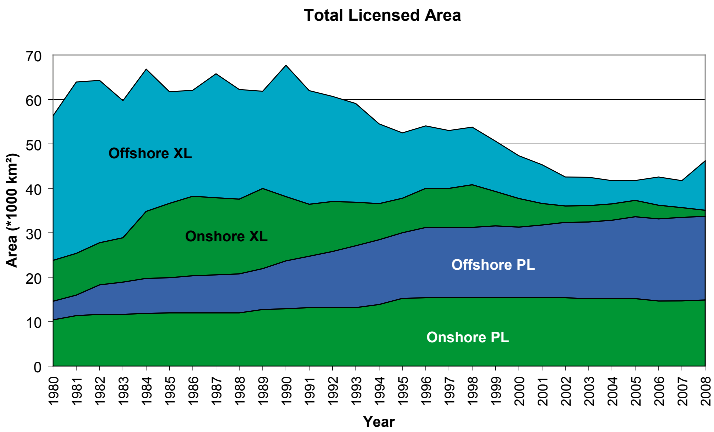


5. Mining Climate

5.1 Licensed area

The total area under licence has decreased by some 20% the early 90's. Due to the high exploration success, an increasing number of exploration licenses have been turned into production licenses. This is particularly the case for offshore licences. Over the last 6 years, the licensed area has remained fairly stable, with a change in trend in 2008. Companies have applied for a significant number of exploration licenses - during the last 2 years about 25 in all. In 2008 and 2009 a number of additional applications have been filed.

An important characteristic of the Dutch mining climate has been its relative stability. Although terms and conditions for application and awards have been adapted to changed circumstances, adjustments have in general been mild. And retro-active changes to these terms have been avoided. Companies have been given the assurance that those financial terms, as laid down in the Royal Decrees for offshore licenses and attached to onshore concessions, will remain unchanged during the lifetime of a production license. In 2003 the financial terms were incorporated in the new Mining Act.



5.2 Activities

The activity level at this moment (some 10 exploration wells per year) is too low to unlock the remaining futures offshore. To boost the activity level, the Minister of Economic Affairs announced an amendment to the Mining Act in 2008, designed to make the exploration for, and production of, marginal fields offshore more attractive. This measure will make it possible to deduct an extra 25% of the investments (including exploration drilling costs) from the company profits for tax purposes. The proposed measure applies for exploration and production of marginal fields offshore which qualify for two out of the three following criteria:

1. Size of the reservoir
2. Anticipated productivity
3. Distance to existing infra structure

The way that these criteria will be worked out in detail is currently a matter under study.

The government take for new investments in the upstream oil and gas industry is an important issue for the industry. When the effective government take (tax and royalty) for new investments in The Netherlands is compared with some of neighbouring competitors (Denmark, Norway, UK), it appears that The Netherlands is an attractive country in which to invest in oil and gas projects. This was also concluded in Woodmac's 2005 report (The Netherlands - The Quiet Value Generator - Woodmac, Europe Upstream Insights, March 2005).

5.3 The Small Field Policy

The basis for the good and stable Dutch mining climate is the so called Small Field Policy (SFP). The policy follows from the decision of the Dutch government in 1965 (“Nota De Pous”) that the Groningen gas field should be conserved for future use as much as possible, and that priority should be given to the development of small fields which had already been discovered. The result of this policy is many small fields have been discovered and developed and that the balancing role of the Groningen field is still in effect. And still today this is at the core of the SFP. The balancing role, or swing supply role, of the Groningen field gives the flexibility to meet the differences between supply and demand. Because the Dutch gas buyer GasTerra has the duty to buy the production of the small fields (with a fair market price and rules for the allowed depletion of the gas fields) producers have the certainty that their discovered gas field can be on stream in a very short period with guaranteed offtake. In other countries gas sellers may have to wait many years before their gas reserves can be taken into production, which clearly affects the economics of such projects in a detrimental way.

The success of the SFP can be illustrated by the number and the (small) size of the fields that has been discovered and taken into production since the early 1970’s. In a period of more than 30 years some 250 reservoirs have been taken into production. It is also worth noting the size of these reservoirs: since the start of the SFP close to 100 gas fields with reserves less than 1 BCM were put on-stream. The Netherlands holds a unique position worldwide in the economic production of these very small fields.

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