Focus on Dutch gas **2010**

best access to dutch gas

Preface

Even though nearly 75% of the producing fields in EBN's portfolio are in decline or in the tail-end production phase, these fields still contribute almost 20 billion cubic metres (BCM) to the total gas production from small fields in the Dutch territory, which amounted to some 33 BCM in 2009.

This mature portfolio calls for a strategy of adding reserves throughout the lifecycles of the fields. Reserves may be added through exploration, reassessing the development of stranded fields, enhancing recovery by end-of-field-life activities, extending infrastructure life through cost effectiveness, to name but a few options. An industry-wide attitude of greater intercommunication and cooperation is also essential in order to generate as much value as possible from the mature hydrocarbon province of the Netherlands.

The time frame is largely dictated by the existing infrastructure (especially offshore). Extending the lifespan of this infrastructure is essential for the economics of both exploration and the development of stranded and more technically challenging fields. Once infrastructure has disappeared, it will be much more difficult to produce smaller pools economically and efficiently. This report discusses aspects that are of importance in shaping this strategy.

The main challenge over the coming decades is to continue exploring and developing conventional resources, while at the same time bringing unconventional resources on-stream. EBN has presented a challenging target to the industry: in 2030 we should still be able to produce 30 BCM/year from conventional and unconventional gas resources.

The Slochteren gas discovery of fifty years ago acted as a catalyst for the European gas market and the development of the E&P industry in the North Sea region as a whole. The pioneer mindset of those days still exists, and much of the potential is still there, but we need to turn these fifty years of research and experience to our advantage.

1. Current Reserves and Production: in decline

1.1 Resource base

The Netherlands is an important player in the international gas world. Dutch gas production in 2009 was over 70 billion cubic metres (BCM), of which almost 33 BCM (or around 90% of Dutch annual gas consumption) came from small fields.

Although large volumes of gas have already been produced, there are still large volumes to be developed, and considerable volumes to explore for. EBN estimates the total Expectation (defined as Probability Of Success [POS] multiplied by Mean Success Volume [MSV]) of all known prospects to be at least 400 BCM (no cut-off applied).

Resource base

Reserves and resources (BCM)

	Produced		2957
Discovered	Reserves	In production (cat. 1)	933
		Approved for development (cat. 2)	38
		Justified for development (cat. 3)	216
	Contingent resources	Development pending (cat. 4)	99
		Development unclarified/on hold (cat. 5)	52
		Development not viable (cat. 6)	52
Undiscovered	Prospective resources	Prospects (cat.7)	> 400

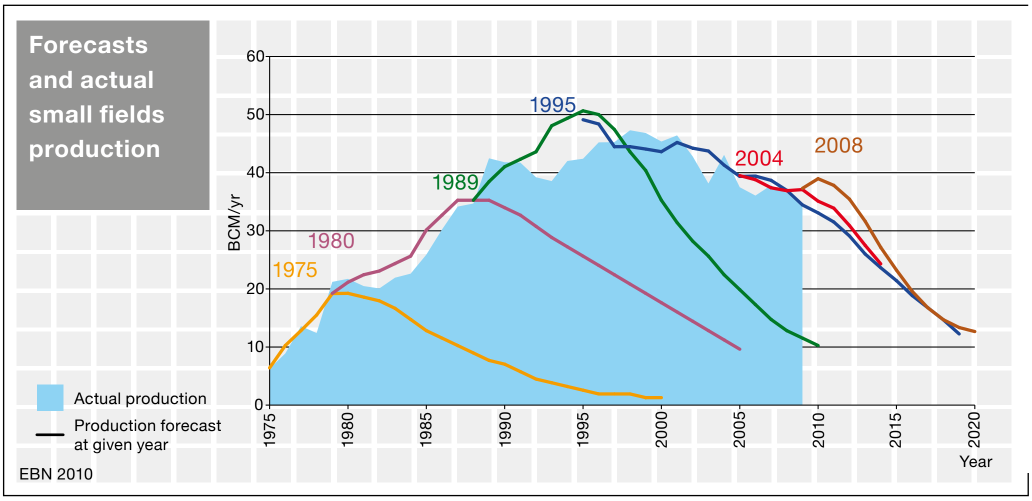
EBN 2010

Categories according to SPE PRMS 2007

1.2 Production

The offshore gas rush which started in the sixties brought with it significant additional production to add to the onshore production which was already established. Onshore small fields (all onshore production except Groningen) started to decline in the nineties, but offshore production continued to rise to a peak of 30 BCM in 2001. From that point onwards total small fields production has undergone a gentle decline of about 1 BCM per year.

History and forecasts



Historical forecasts of future production show that as fields become older, peak production is closer to the year in which the prediction was made. And the remaining production gradually becomes steeper, mimicking a breaking wave.

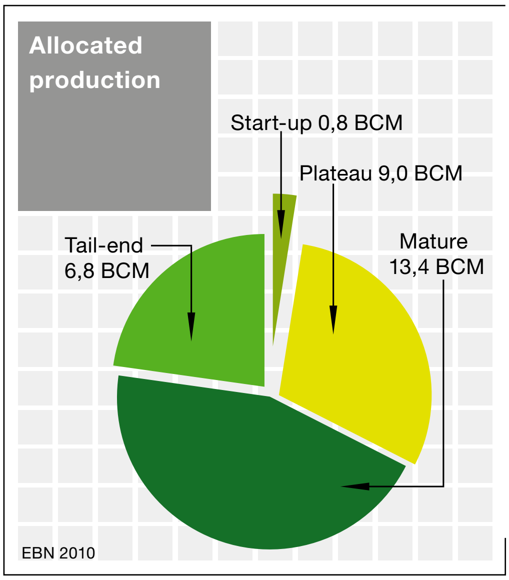
Dutch production started sliding down this breaking wave sometime between 2000 and 2005. In other words, insufficient new reserves were being added to sustain peak production. The inclusion of futures in the above graph shows there is scope for improving the outlook, but we do not see the decline stopping. The overall outline may follow the bell shape identified by M. King Hubbert (from Peak Oil, 1956).

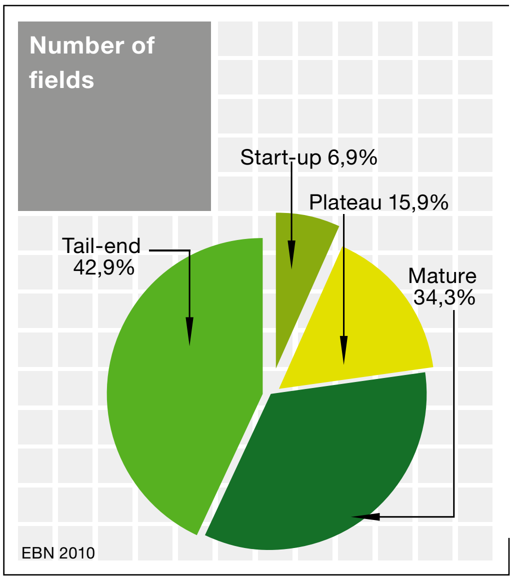
1.3 **Fields portfolio**

EBN has analysed its portfolio of producing fields from a maturity perspective, with maturity being classified on the basis of how much of a field's reserves has been produced relative to its ultimate recoverable volume (UR). A field is classified as being in the start-up, plateau, mature or tail-end phase, depending on whether up to 5%, 60%, 90% or 100% respectively of its ultimate recoverable volume has been produced.

To assess maturity within the mature-fields category, we subsequently identified tail-end production as starting at 80% of the UR. The number of tail-end fields then rises from 105 (43%) to 146 (60%) of the total of 245 fields. This indicates that almost half of the 84 fields in decline are nearing tail-end production.

Field portfolio



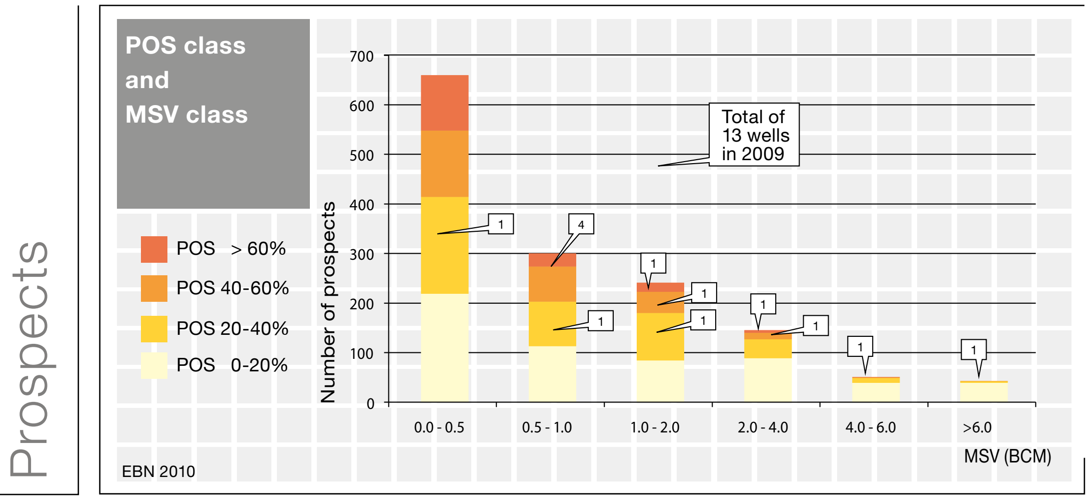


The fields currently producing clearly demonstrate that the Netherlands is a mature area. Over three quarters of the fields have produced at least half of their recoverable volumes, accounting for two thirds of the total produced volume of gas.

1.4 **Reserves: 2009 additions**

Exploration drilling

Thirteen on- and offshore exploration wells were drilled in 2009. Last year's report included a diagram showing the prospect portfolio in terms of POS/MSV classes. In 2009, wells were drilled in several of these classes. Half of those prospects had a POS of 40% or more. It should be noted that not all companies have access to all POS/MSV classes because of limited portfolios and/or limited access to acreage. Therefore some of the higher risk prospects were drilled rather than the lower risk ones.



Total volumes discovered by exploration wells in 2009 amounted to approximately 9 BCM, while total expectation for all drilled prospects was over 12 BCM. Of the successful prospects, the total actual size was over 30% higher than the sum of their pre-drilling expectations (6.5 BCM based on MSV). The total un-risked pre-drilling MSV amounted to nearly 12 BCM for these successes. These statistics indicate that the prospect volumes were overestimated (even though the MSV is generally somewhat higher than the P50 volume), whereas the POS was substantially underestimated, as is also evidenced in the section on Success Ratios. The added reserves by appraisal wells amounted to approximately 2 BCM.

Field development

Capital expenditure on the Dutch continental shelf increased in 2009 and is expected to remain at this level in 2010 (around 1.3 billion euro). This is quite remarkable in view of the 'credit crunch' and the lower gas prices. Despite high rig rates in the years to 2009, the number of wells continued increasing each year from 2007. The drop in rig rates during 2009 (to half the price seen at the 2008 year-end) resulted in a decrease in overall drilling costs. However, the total cost reduction, including well tests, was only 15% in 2010 as the cost of consumables and other services remained high. The activity level shows that the exploration and development potential of the Dutch continental shelf is still well recognised by the industry.

The number of new fields being brought into production each year is expected to increase from 5 in 2008 to 15 in 2013. A total of 19 fields were brought on stream in 2009, totalling some 3 BCM of onshore reserves and 16 BCM of offshore reserves. As a result of timing, the number of fields brought into production in 2009 and scheduled to be brought into production in 2010 seems atypical, but confirms the trend that appears to be the result of the industry's exploration efforts since 2007.

2. Infrastructure: add gas

The Dutch offshore area (57000 km^2) is a mature province, characterised by a dense, but rapidly ageing infrastructure. Depletion is well underway, with over 75% of all producing fields now in the declining phase. Drilling for new reserves and cost-effective tie-back of (especially small) new finds are highly dependent on the availability of this infrastructure.

2.1 Abandonment: historical forecasts & current status

In previous years the expectations were that many more platforms would have been abandoned by now than has transpired in reality. This has been largely because of the addition of new fields and/or reserves, gas prices and the use of innovative techniques to extend field life. But also by simply not removing the platforms immediately after production has ceased.

Earlier forecasts indicated that approximately ten platforms would stop production in 2009 and could therefore be abandoned. However, not a single facility was removed in 2009. A comparison can be drawn with the (historical) production forecasts and it can be suggested that abandonment forecasts for the coming years may also prove to be pessimistic, at least for those predictions based on proven reserve scenarios.

EBN has recognised the need to play an active role in maintaining the presence of infrastructure and is developing initiatives to convince the various operators to extend the life of their facilities. We believe that facility life can be extended by a two-pronged approach:
- ensuring cost-effective operations, thereby postponing the moment that a facility becomes uneconomic to operate, and
- developing more gas, with the aim of lowering the unit technical costs of producing the gas, thereby also postponing abandonment.

2.2 **Cost reductions**

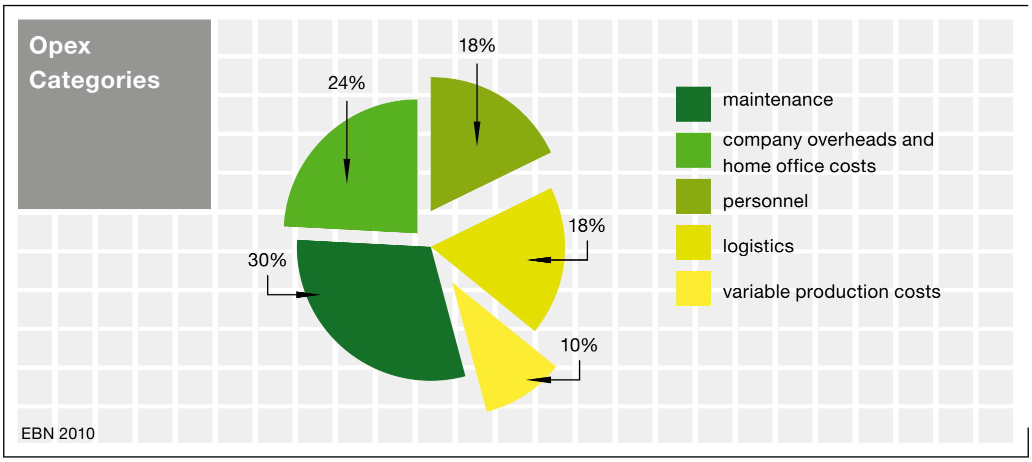
Cost reductions will increase the economic life of infrastructure since the lower the operating costs, the longer gas production will remain economic. This is confirmed by analysing the offshore facilities in the Dutch territory. It should be noted, however, that life-span extension will not result in much extra gas as the fields under consideration are in their tail-end maturity.

Analyses show that with Opex at its current level, varying the Opex level has a marked effect on the loss of reserves. That is, those reserves or, more accurately, resources that have to be left behind, because production rates and the resulting income do not outweigh Opex for a particular production facility. For the main trunk lines NGT, WGT and NOGAT, evacuating currently more than 150 BCM of reserves, reducing the Opex by half results in additional connected reserves of approximately 6 BCM. Doubling the Opex results in a loss of some 15 BCM of gas that needs to be left behind. Investigating even higher Opex levels, the effect is non-linear and very pronounced with losses rapidly accelerating at increasing Opex. This illustrates the importance of active cost management to limit escalation in Opex. And, where possible, try to reduce its level.

2.3 **Opportunities for Opex reduction**

Aggregated 2008 offshore Opex in the Netherlands has been subdivided into five categories. On average, two of these categories taken together, ‘maintenance’ and ‘company overheads/home office costs’ already represent more than 55% of the Opex allocated to a particular platform. Therefore, Opex reduction can best be achieved by focussing on these two categories. These two cost categories show great variation between different operators, ranging from -50% to +170% compared to mean Opex values, with the ‘best in class’ operators successfully managing to reduce their costs in these categories.

Opex



Company overheads/home office costs have a surprisingly large impact on Opex, which suggests that small, efficient companies have a significant cost advantage compared with large operators and may be better suited to exploit the tail-end production. Apart from reducing overheads, further cost reductions may be achieved by operators agreeing to pool and share personnel and logistics. On average, the latter two categories represent about 40% of Opex.

The complexity of a system greatly affects the effectiveness of Opex reduction. Cost reduction can significantly extend life spans in the case of production systems consisting of one or a few platforms connected to one of the main trunk lines. In the case of complex systems, however, the effect is less pronounced. If any of the production satellite becomes uneconomic, the entire system's Opex is reallocated to the remaining satellites, thus increasing the cost burden on these fields and eventually making them more uneconomic. This domino effect consequently results in a premature end of the entire cluster's life. Complex clusters are, therefore, the most vulnerable offshore systems. Hence, to extend overall facility life, we need to focus on clusters: the more complex a cluster, the more effort has to be invested.

2.4 **More gas**

Based on the EBN reserves position, we have assessed the effect of different scenarios on the remaining platform population. Here, we discuss two scenarios:

1. a 'no further activity' (NFA, current reserves) scenario, in which development and depletion will run their course, based on currently known and booked reserves (PRMS categories 1 to 3);
2. a scenario in which we have incorporated a number of contingent projects that are already recognised as probable future developments (PRMS categories 4 and 5)

Compared with the NFA scenario, the other scenario would yield approximately 30% more recoverable reserves. As expected, our analysis shows that this second scenario has a positive effect on extending field facilities' life spans. However, the effect of Opex reduction on complex systems is limited, whereas 'more gas' has a much more pronounced effect on such systems and is, therefore, an effective way of extending the window of opportunity in which the reserve base can be increased.

In addition to contingent projects, there is also substantial potential to increase reserves through the development of gas of a less conventional nature and by embracing innovative production techniques. Unlocking this potential will provide the change needed to extend life spans of the facilities and thus open a window of opportunity for both exploration and bringing discoveries on stream.

2.5 **Host opportunities and focus areas**

Battle for space

Although longer-term production forecasts show a sharp decline toward the end of the decade, developments planned for the near future are currently projected to produce to such a level that there will be competition for ullage in many of the offshore trunk lines. The NOGAT system is being utilised at or close to peak capacity, as is the WGT system. As a result, new developments have to compete for transportation capacity, which limits opportunities for development and, as a consequence, the much needed replenishment of the reserve base.

Although our projections indicate that ullage should become available again in a few years, such projections are in our experience notoriously unreliable and pipelines tend to remain fully utilised. This observation underlines the pivotal role of the trunk lines as the most important enablers for the addition of reserves. EBN is consequently firmly committed to remaining focused on continuing optimum exploitation of these systems.

Gas Act

An amendment to the Gas Act has been proposed (and approved) by the Dutch Second Chamber of Parliament. Gas Transport Services (GTS) is responsible for keeping the national gas transport system in balance. One of the most important changes in the Act is the introduction of a market-oriented balancing regime in the national gas-transport system, whereby all parties involved (in other words, both those supplying gas to the system and those withdrawing it) are granted straightforward access to the (virtual) trade point.

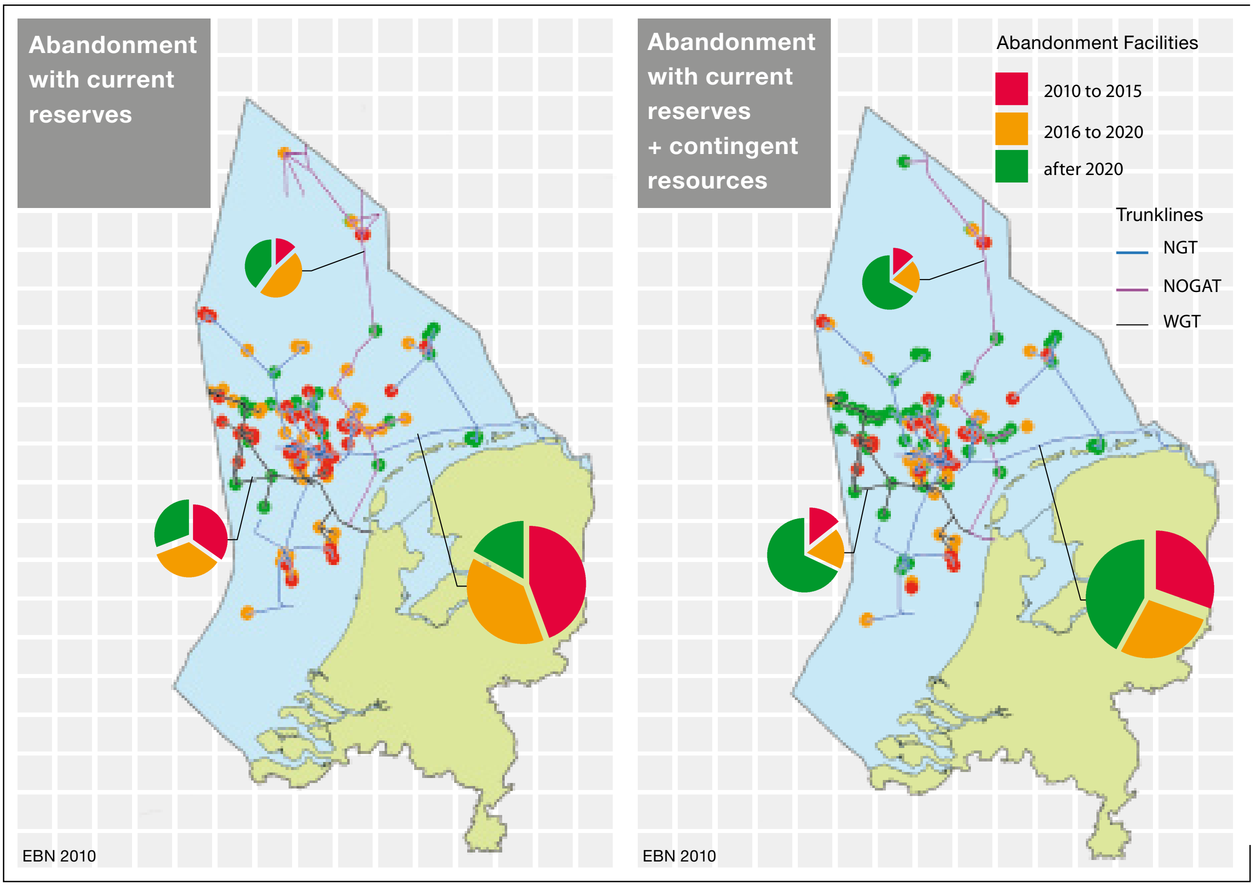
A market-oriented balancing regime means that all market parties are responsible for balancing supply and withdrawal. In the event of an imbalance in the system, GTS can introduce a bid-price ladder, which means that it can access the resources of the market parties involved at a certain price. GTS will pass on the costs of this to the party that caused the imbalance. This new system is expected to create a market in which parties will trade temporary shortages and surpluses.

Focus areas

Analyses have been performed of the offshore facilities, taking into account the interdependency in relation to the main trunk lines: NGT, NOGAT and WGT. The analyses are based on two scenarios: one that assumes current production forecasts without contingent resources being added (PRMS categories 1 to 3) and one that also takes contingent resources into account (PRMS categories 4 and 5). These analyses have been calculated on the basis of current economic parameters and the assumption has been made that abandonment will take place within a year after production ceases.

The largest system in terms of connected facilities, NGT, also shows the greatest imminent abandonment activity. In the scenario assuming current reserves, close to one half of its connected facilities are foreseen to be abandoned within five years. And a comparable number of facilities will be abandoned in the following five years. For this evacuation system, most abandonments are foreseen to take place in its heartlands, around the border between the K and L quadrants.

Abandonment



In both scenarios, the NOGAT system will experience abandonments of around 15% of its facilities in the next five years. Abandonments in the WGT system in the coming five years are expected to lie between that of the other two trunk lines.

At a general level, the number and scale of abandonments in the near future will be significantly affected by whether or not contingent resources are taken in account. And the effect is remarkably different for each trunk line. Effects are also driven by the maturity of connected fields, the extent of contingent resources and the complexity of the systems themselves.

3. Exploration: find gas

3.1 **Prospectivity**

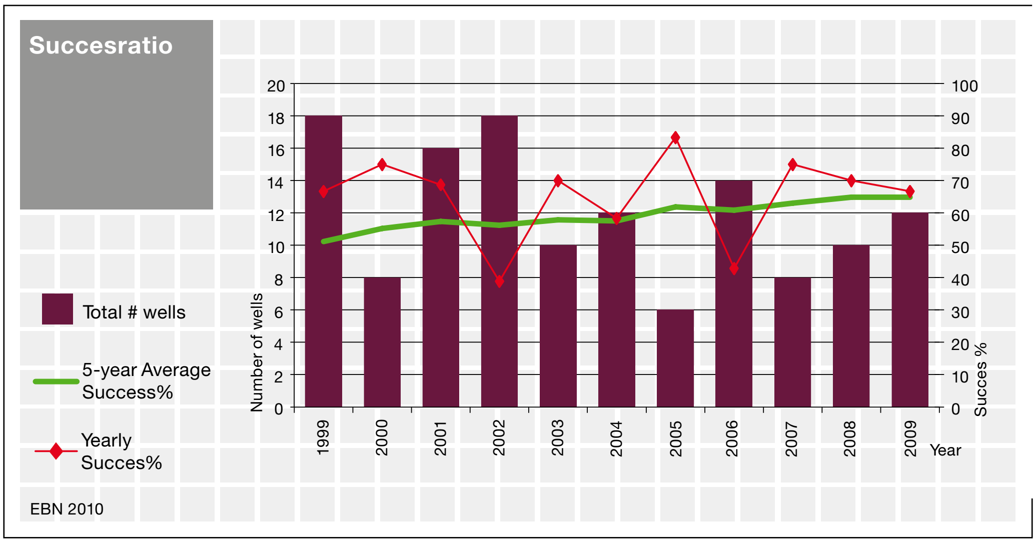
The Netherlands is a ‘mature area’ for exploration: many gas fields have been discovered and developed in the past fifty years. In total, nearly 3000 BCM of gas has been produced, with currently remaining resources amounting to 1500 BCM.

The 2009 Focus report analysed a portfolio of well over one thousand known prospects. Total expected volumes added up to some 137 BCM for offshore and 112 BCM for onshore prospects (using an MSV cut-off per field of 2 BCM offshore and 0.5 BCM onshore). If an expectation cut-off was applied instead of an MSV cut-off, total volumes remained approximately the same.

Success ratio

The success ratio for exploration wells in the Netherlands has risen continuously over the last thirty odd years. The success rate of finding economic gas volumes has increased from about 35% in the early 1980s to around 70% at present. Indeed, the success rate has remained fairly constant over the past ten years at an average of between 60 and 70%. This is not reflected in the prospects drilled in 2009: average unweighted POS was 52% for all prospects (dropping to 32% if volume-weighted), but the success ratio of the wells was 69%. This indicates that the risks of prospects are seen too negatively.

Successratio

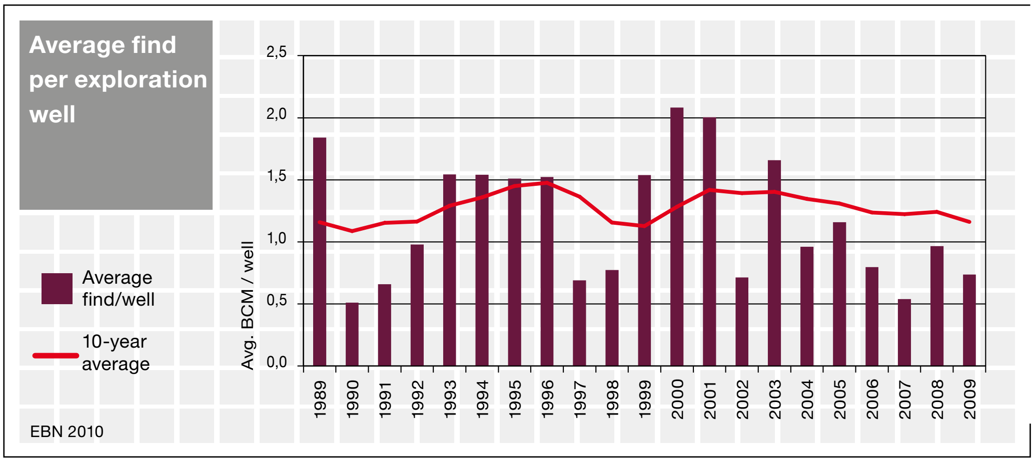


Creaming curve and average find

The cumulative creaming curve (total reserves discovered vs. all wells) for Dutch exploration wells is still showing a straight line, with little evidence of creaming off. Up to 2010, just over 572 exploration wells had been drilled onshore and 683 wells offshore.

The cumulative average find per offshore exploration well (defined as total reserves found divided by the total number of exploration wells drilled) has remained fairly constant at some 1.3 BCM for more than twenty years. If we take a closer look at the past twenty years and average out short-term fluctuations using a 10-year rolling average, a decline since 2000 is apparent: from around 1.4 to 1.2 BCM. Recognising the fact that around 2000 relatively high average finds were realised and that for the last 5 years the average find per exploration well rarely exceeded 1 BCM. Applying the success rate to the 10-year rolling average find, the average discovery size amounts to 1.6 BCM. Such fields can easily be developed in the Netherlands because of the country's well-developed infrastructure and guaranteed sales.

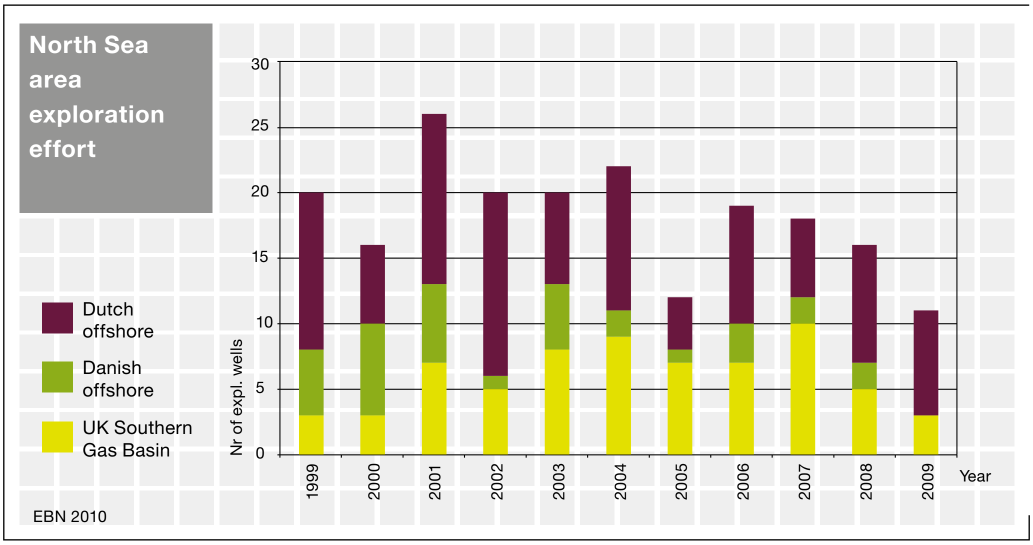
Average find



3.2 **Activity**

Despite these positive indicators, the annual number of exploration wells drilled (on- and offshore) has fallen in comparison to ten years ago – from about 25 in the 1990s to around 10 at present. A higher activity level is required in the next ten to fifteen years if we are to make full use of the existing infrastructure. Once infrastructure has gone, it is unlikely that smaller prospects can be drilled and developed economically. EBN estimates that at least 15 exploration wells per year will be required to explore conventional plays in the Netherlands fully within the time frame dictated by the availability of offshore infrastructure. This does not include the exploration efforts required for unconventional shale-gas and coal-bed methane plays.

North Sea



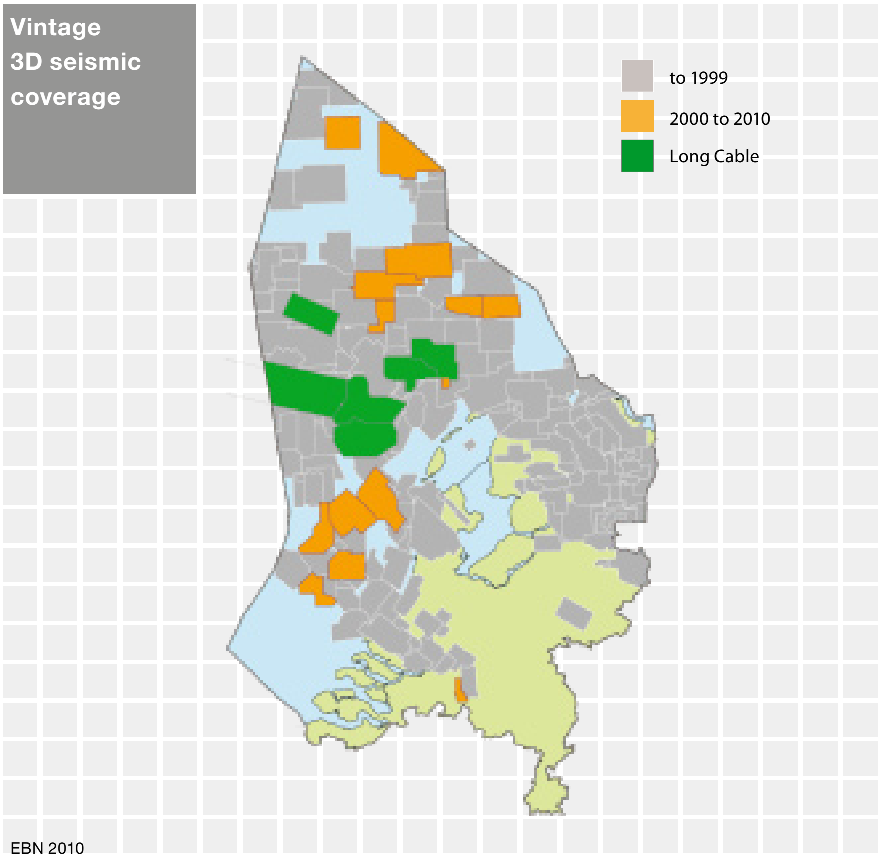
A comparison of offshore exploration drilling activity of the Southern North Sea area (1999 - 2009) shows considerably more activity in the Netherlands than in adjoining areas. The average number of wells per year for 1998 - 2008 (Danish 2009 figures are not yet available) was 10 for the Netherlands, 7 for the UK SNS and 3 for Denmark. In the German offshore area wells are drilled only sporadically and have consequently not been plotted. Despite some annual fluctuations, offshore exploration activity in the Netherlands has on average been comparable to or higher than UK and Danish exploration activities combined.

3.3 **3D seismic**

A total of 15800 km^2 of 3D seismic was acquired onshore between 1980 and 2009. The total for the offshore area is nearly 68000 km^2, while some 3500 km^2 was acquired in shallow water. Most of these surveys were shot between 1988 and 1995, mostly using acquisition parameters that were state-of-the-art at the time.

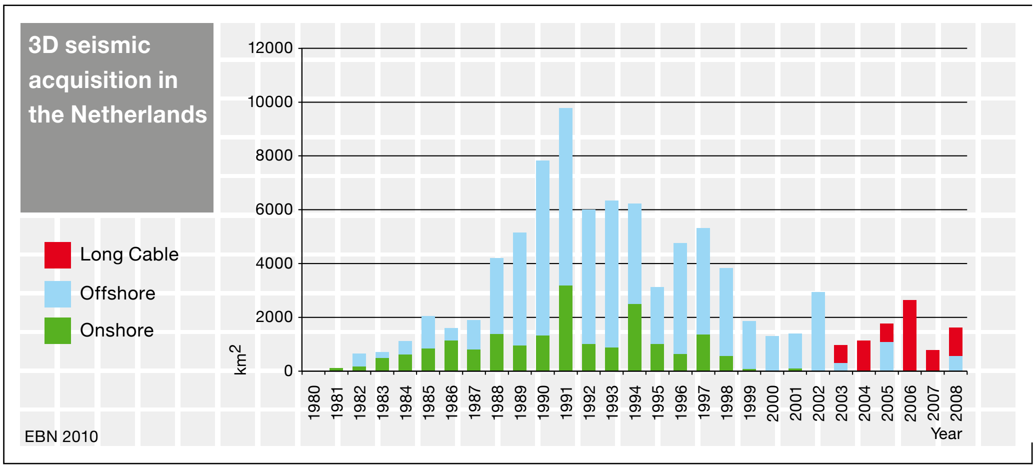
In general, the Dutch industry has been reprocessing these data ever since. Although the original acquisition parameters prevent a major breakthrough in quality improvement, a considerable enhancement of data quality can nevertheless be obtained through reprocessing.

3D seismic



In the past few years, some companies have started shooting or reshooting 3D data using long streamers (5-6 km or longer) over their acreage. Currently, some 10% of the total 3D survey area has been obtained by this long-cable technique. The improvement in data resulting from the use of long-cable surveys is far greater than reprocessing can yield. Using this technique, one company significantly upgraded its original portfolio of prospects, which was based on seismic data acquired in the early 1990s. Although overall volumes based on the new long-cable seismic became smaller, de-risking was quite significant: POS estimates more than doubled. On top of that, the number of prospects with an Expectation greater than 0.25 BCM quadrupled.

3D seismic surveys



Long-cable seismic data show a much better definition of faults and reservoirs for deeper targets (Rotliegendes and Carboniferous, for example). This is linked to superior structural imaging, especially underneath salt domes and other complex overburden geology, and may enable even deeper strata to become targets. EBN firmly believes that new seismic acquisition activities should in many instances be considered. Modern reprocessing certainly improves the older data, but the rather dated acquisition parameters are a strong impediment to significant quality improvement as compared, for example, to long-cable or wide-azimuth acquisition.

EBN has funded the Fugro/TGS long-cable 2D NSR acquisition in the A and B quadrants. To encourage activity in underexplored areas, EBN is currently investigating the possibility of participating in the planned Fugro 3D 2010/11 spec survey in the northern open acreage of the D, E and F quadrants, an area of over 6000 km2. In terms of acreage, the industry should also consider state-of-the-art 3D acquisition in areas designated for wind farms. Once these offshore wind farms are in place, access for long-cable/wide-azimuth surveys will be virtually impossible, and seismic noise from the windmills will certainly impair data quality.

3.4 **Legislation**

The Mining Act was amended on 1 January 2010 with respect to several topics that can be considered part of the ‘mining climate’.

Fallow acreage

To increase accessibility to Dutch acreage for the E&P industry, the Ministry of Economic Affairs (MEA) now has the power to reduce licence areas in which operators have been inactive for an extended period of time. This should reduce the acreage closed to exploration and production efforts and enable other parties to apply for these areas.

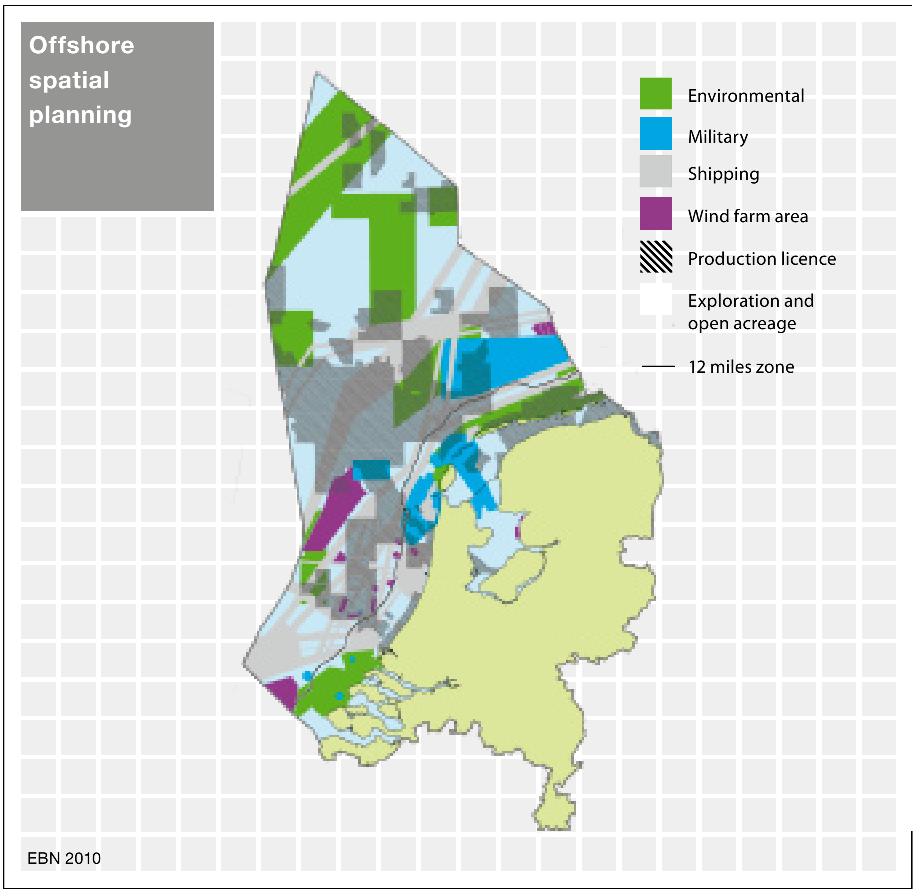
Exploration

In view of the desired increase in onshore exploration activities, EBN is now permitted to take part in exploration drilling on land. Operators seem to appreciate this increase in scope for EBN, and the majority of operators active in the onshore territory have invited EBN to participate in exploration projects.

3.5 **Competition for space offshore**

The offshore E&P industry in the Netherlands is currently experiencing strong spatial-planning competition from other uses of the sea and sub-sea. Maps show that large environmental areas in the central and northern part of the Dutch Continental Shelf (DCS) are currently zoned as potential nature reserves, while two others have been designated ‘ecologically valuable’. Whether the latter two environmental areas will become nature reserves will be decided in the next five years. If these areas are eventually zoned as nature reserves, licensing procedures will come under the Nature Conservation Act, possibly resulting in longer licensing procedures. As for wind farms, the current zoning plan allocates a considerable area for offshore wind farms, with potential growth paths into the K and E blocks northwards and another ‘search area’ in the M block in the easternmost part of the DCS.

Offshore the Netherlands



At this point in time it is difficult to predict what the effect of the planned offshore wind farms will be on the E&P industry. On the one hand, the presence of a wind farm may make seismic acquisition in those areas much more difficult, if not virtually impossible. On the other hand, however, the presence of wind farms could prove useful when performing grid drilling, which may be required for developing unconventional gas resources, or when applying gas-to-wire techniques in, for instance, the development of CO^2-rich natural gas.

Monitoring developments in spatial planning will become an increasingly important activity for EBN in the coming years so as to ensure that the benefits of potential synergies between oil and (unconventional) gas extraction, gas-to-wire, CO^2 storage and wind farms are achieved.

4. Development: Produce Gas

4.1 **Ambition**

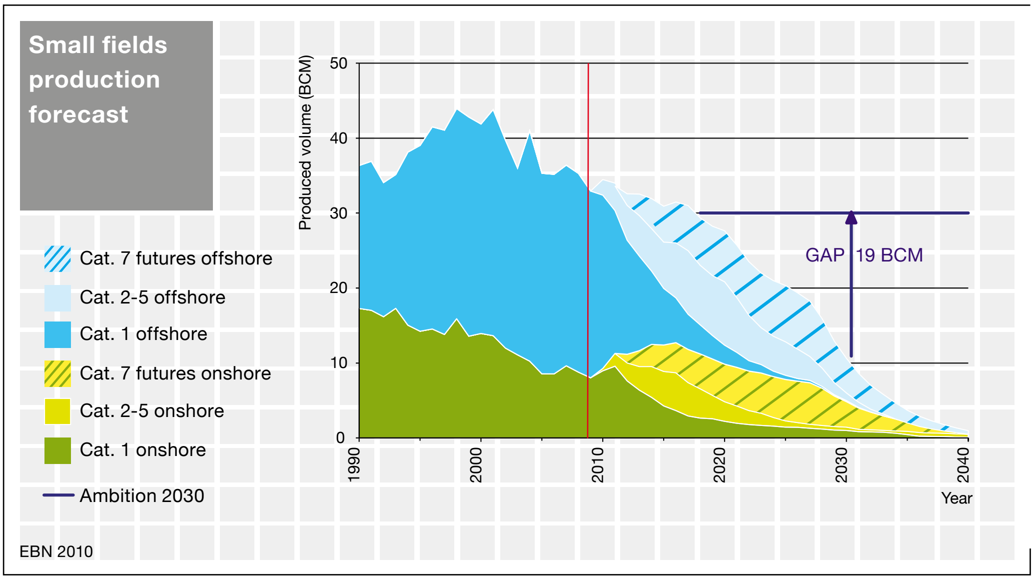
The challenge for the coming decades is to continue exploring and developing conventional resources, while at the same time bringing unconventional resources on stream. EBN has presented a challenging target to the industry: in 2030 we should still be able to produce 30 BCM per year from conventional small fields and unconventional gas resources. And we believe that this can be achieved by working towards this target along four paths:

1 Extending and increasing production from existing fields
2 Developing challenging fields
3 Drilling viable prospects and identifying new prospects
4 Bringing unconventional resources to reserves

4.2 **Production forecast**

In the ‘no further activity’ scenario, production from small fields will decline at a much higher natural rate of 10-15% a year. This decline rate may be slowed considerably – as evidenced by the performance over the past ten years – by bringing new fields into production and by proper management of well and field performance. Using state-of-the-art technology is essential to obtain the highest possible recovery from both oil and gas fields, as the exploration for new resources. Higher recovery will extend tail-end production and thus help slow the decline and increase the lifespan of existing infrastructure, which in turn will boost exploration. A quick calculation to assess likely future reserves additions assumes 15 exploration wells a year, a success ratio of 60% falling to 50% and an initial average discovery volume of 1.3 BCM which will gradually drop to 0.8 BCM. This adds up to some 230 BCM over the next thirty years (Category 7 in the profile below).

Production



Assuming that current plans for increased and extended production from existing fields are achieved and all currently viable prospects will be drilled, production in the year 2030 will still be 19 BCM short of the target of 30 BCM. However, this should be compared to the shortfall of 29 BCM in the 'no further activity' scenario. In other words, the expected shortfall is reduced by 10 BCM. The remaining shortfall of 19 BCM can then be filled by for example extending production, developing technically challenging fields and unconventional resources. The incremental shortage (i.e. the integral) between the production target for 2030 and the currently identified reserves, contingent resources and prospect volumes, amounts to some 100 BCM. Assuming a decline of 15% per year after 2030, the total reserves that must be added for the target is 250 BCM.

Legislation: two out of three rule

The two out of three rule is intended to encourage operators to develop offshore stranded fields or offshore prospects for which the economics are marginal. The measure will enable companies to deduct an extra 25% of investment costs from their taxable profits. Potential developments must meet at least two of the following three criteria:

1. Limited size
2. Low productivity
3. Remoteness from infrastructure

Analysis by EBN and TNO indicates that, over a period of ten years, an additional 20 BCM of gas can be produced economically from such sources.

Unconventional resources

As yet, there is hardly any production from unconventional resources from the Dutch subsurface. Unconventionals are defined as coal-bed methane (CBM), shale-gas and basin-centred gas, as well as tight and shallow gas. Some of the latter has recently been brought on stream in the Netherlands – some 20 years after being discovered. Although potentially large volumes of non-conventional gas exist, these are generally more challenging to develop.

A first step towards unlocking these resources is to make an inventory of where we can expect to find them and the potential volumes involved. To this end EBN commissioned a study in 2009, which was performed by TNO and resulted in an initial attempt to characterise and estimate the potential of several unconventional gas categories in the Netherlands.

Shale-gas exploration is still in its infancy in Western Europe. It was only very recently that a few companies took some initial steps by mostly acquiring shale gas licences, also in The Netherlands. Coal-bed methane has been around for somewhat longer in Europe, especially in the UK. The first coal-bed-methane licence in the Netherlands was awarded last year.

There are still many unknowns in these areas, particularly in respect of CBM, basin-centred gas and shale gas. Are the inferred volumes actually present, how do we risk them and what is their potential recovery? To date, no wells have been drilled in the Netherlands specifically designed to extract these resources. Challenges in exploring and developing unconventional resources can be grouped in terms of:

1. Subsurface: are the expected volumes really there and how are they contained?
2. Technology: can the gas be brought to the surface and can this be done economically? How can we achieve cost reductions?
3. Socio-economic: can we exploit these resources with an acceptable social and environmental footprint? To what extent will Dutch licensing issues hamper the economics of such projects?

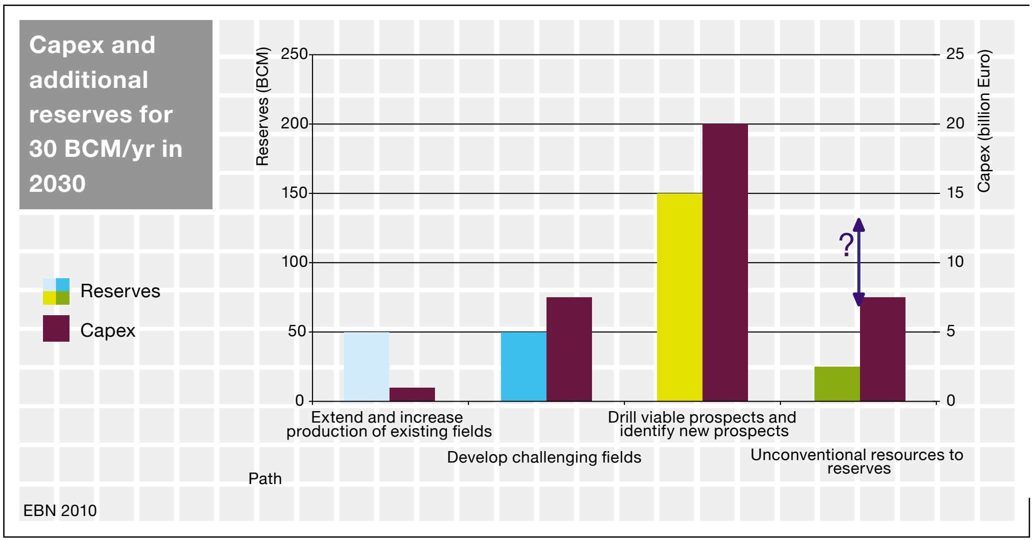
EBN is currently investigating these questions and the results of this study will be published in due course.

4.3 **Investment level / projected capex**

As stated earlier, full exploitation of undiscovered conventional resources in the coming decades will require at least fifteen exploration wells a year. The capital expenditure (Capex) required if the industry is to add the reserves and production needed to achieve this was estimated in last year's Focus report. It amounts to a minimum investment of 1.5 billion euro a year.

This amount is required in any case before extending and increasing production from existing fields, developing challenging fields and bringing unconventional resources to reserves. To estimate the Capex necessary for these new sources in order to realize the ambition to produce 30BCM in 2030, an estimate has been made of the additional reserves per Category. The large uncertainty associated with this assessment – both the potential of the unconventional resources in the Netherlands and the cost involved in exploiting these – must be recognized.

Investment / Capex



The results of this exercise show the level of investment that will be needed over the next twenty years for each of the four paths that can be followed as a means of achieving our 30 BCM/2030 target. To extend and increase production, it is estimated that for the applicable part of the EBN field portfolio potential reserves additions of 0.5 BCM to 1 BCM per field can be achieved. For the Capex involved in developing challenging fields, projected costs of the development of stranded fields in the EBN field portfolio are brought in. That is, development of stranded fields with 1 BCM and 2 BCM of reserves have been assumed to be respectively 150 million and 250 million euro, higher than the current level of Capex for field developments. While the costs of exploiting unconventional resources remain uncertain, the total estimated Capex then needed to achieve our 30 BCM target amounts to at least 35 billion euro to book the required additional 250 BCM of reserves. Effecting in an average annual expenditure of at least 1.8 billion euro for the coming 20 years.

Possible strategies if the Dutch E&P industry is to meet the 30 BCM/2030 target include maintaining the exploration trend of the last few years, taking advantage of the benefits of new technology, containing or even reducing costs, and other innovations such as novel ways of cooperating.

The Slochteren gas discovery of fifty years ago acted as a catalyst for the European gas market and the development of the E&P industry in the North Sea region as a whole. The pioneer mindset of those days still exists, and much of the potential is still there, but we need to turn these fifty years of research and experience to our advantage.

About EBN

EBN (Energie Beheer Nederland B.V.) is an independent company with the Dutch State as its sole shareholder.

EBN plays a central role in the exploration, production and sale of Dutch natural gas. In addition, EBN is also active in oil exploration and production. By participating in a large number of joint ventures with oil and gas companies, EBN contributes to the exploration and development of gas and oil reserves in an economically sound manner. The entire net result is paid out to the State

EBN is also involved in the sale of Dutch natural gas via an interest in the gas sales company GasTerra. In addition, EBN advises the Minister of Economic Affairs on Dutch energy policy and on issues relating to the stewardship of Dutch oil and gas resources, in particular. EBN also wishes to promote the development of the Dutch gas hub by, for example, contributing to the realization of gas storage facilities.

For more information: www.ebn.nl

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