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The Dutch Upstream Fiscal Regime

In Northwest European Context

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Introduction

The Netherlands has been successful in developing its domestic gas reserves. In 1959 the giant Groningen gas field was discovered. This marked the start of a transition of the energy base of the Netherlands and, to a lesser extent, that of the neighbouring countries. In the seventies the so-called small field policy was introduced, which aimed to optimise the exploitation of the Dutch gas reserves. Over time, reserves of about half the volume of the Groningen field have been added, with production from these small fields reaching a peak in 2000. The production from the small fields is, however, rapidly declining. The remaining exploration potential is perceived to be limited, and some of the incumbent parties are leaving the Netherlands or divesting some of their assets. The latter is only in part being compensated by the emergence on the scene of new, mostly smaller, players.

This background, in combination with developments in the international gas market and the increasing attention paid to security of supply, has triggered discussion around the questions as to whether Dutch natural gas reserves are being exploited optimally and, in particular, whether adjustments to the country's fiscal regime should be considered in order to stimulate new upstream gas activity. Among others discussing these issues is Netherlands Oil and Gas Exploration and Production Association (NOGEPA), for whom it is currently a key theme. Clingendael International Energy Programme (CIEP) organised an expert workshop on 29 November 2006 to make an inventory of the exploration and production outlook, technology and cost developments and current policies in the Netherlands. In August 2007 a report was published by Policy Research Corporation, which had investigated options for a more efficient exploitation of the gas resources of the Netherlands, under contract for GasTerra.[1] The report makes a number of recommendations and discusses some of the proposals for adapting the fiscal regime to provide incentives for the development of small and difficult fields. In April 2008 the topic of fiscal incentives for small fields was debated in the Dutch Parliament.[2]

The question could be asked as to how the Dutch fiscal regime compares with the regimes of neighbouring countries. This paper provides a high-level overview of the Dutch fiscal regime and those of other Northwest European countries. Characteristics of a number of fiscal regimes are summarised, indications of the State share in the upstream revenues are given, and some of the unique features of the Dutch system in this context are highlighted. Finally, possibilities for adapting the fiscal regime to prepare for basin maturity are discussed.

Developments in global gas markets and their impacts on Europe

Gas demand is increasing globally, albeit a bit more slowly than expected earlier this decade due to the strong increase in world oil and natural gas prices. This holds true for European gas markets as well. At the same time, gas production in the European Union (EU) is declining, making the EU more and more dependent on imports. Many new infrastructure projects are under development, aimed at bringing additional Russian, Norwegian and Algerian pipeline and various Liquefied Natural Gas (LNG) supplies to European markets.

But rising import dependency appears to be more problematic today than it was a decade ago. Security of supply has climbed the political agenda in Europe, pushed by rising concerns about insufficient investments taking place in global gas exploration and production, about the (political) reliability of natural gas exporters and about the attractiveness of European markets to those producing countries. Worries are mostly centred around Russia. Western analysts have repeatedly argued that current investment levels in Russia will probably be insufficient to fulfil expected demand from Russian and European markets, hinting that even existing export commitments might not be honoured due to capacity constraints. Moreover, Russian officials have stated their intention to diversify supply markets, and initial agreements have been signed with China for the delivery of natural gas.

LNG supplies are growing quickly, and Europe appears to be well prepared for receiving significant quantities of LNG, given the development of a rather large number of LNG regasification terminals. However, regasification capacity being developed globally far exceeds the liquefaction capacity under development. Other markets, such as the United States (US) and Asia, might be able to divert supplies that were originally intended to contribute to the diversification of European gas supplies. Finally, slight fears of a cartelisation of the European gas market by the major gas producers complements the worries of European policy makers and gas market participants.

Against this background, there is an obvious interest among governments to maximise the exploitation of domestic gas reserves.

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[1] Policy Research Corporation, 2007, *Naar een doelmatige winning van kleine velden gas*. (Towards an efficient exploitation of small field gas), report published for GasTerra B.V.

[2] Energeia, 'Schiet nou eens op met fiscale stimulans voor winning uit kleine velden' (Hurry up with fiscal incentives for exploitation of small fields), *Energeia*, 17 April 2008.

The maturity of the Dutch gas basin

Dutch gas production is composed of winnings from the large Groningen field and the output of the so-called 'small' (i.e., non-Groningen) fields. Gas production in the Netherlands has always been subject to a government depletion policy. The output of the small fields has been optimised through various measures worked into the commercial arrangements between Gasunie (now GasTerra) and the operators. The government has maintained a cap on total production, and the Groningen field has in the past filled the gap between the production ceiling and the small fields output.[3] The aim of this set of measures has been to provide incentives for the production from small fields in order to maximise the use of overall gas resources. This policy has clearly been successful. However, small fields production reached a peak in 2000, and has since been declining.[4] The Netherlands has become a highly mature gas province, similar to other Northwest European countries – notably the United Kingdom (UK) and Germany – albeit that the unique Groningen field still holds considerable reserves: about 1100 billion cubic metres (bcm) as of 1 January 2007. The remaining exploration potential is quoted to lie between 160 bcm and 350 bcm.[5] However, a substantial part of these volumes will not be economical to recover, even in a high gas price environment. In addition, part of the remaining potential lies underneath environmentally sensitive areas. Exploration activity level has dropped from approximately 15 wells per year in the nineties to around 8 per year in the first part of this decade and is likely to gradually decline further.

In the light of the above, discussions have ensued about whether the current fiscal regime and related policies are still adequate for such a mature gas province as the Netherlands. For example, NOGEPA has submitted several proposals to improve the upstream fiscal climate. Policy Research Corporation has also concluded that certain measures should be considered.[6]

Government policies and fiscal climate

The upstream oil and gas industry is treated differently than most other industries in terms of fiscal policies. Whereas many businesses are subjected to Corporate Income Tax (CIT) and other general taxes only, for the production of oil and gas complex and specially-tailored fiscal regimes have been developed and implemented. The reasons for this include the strategic nature of the oil and gas industry, the volatility of the oil price, the very high capital investments and substantial risk, but also the potential for high rents and the obvious desire among governments to maximise the benefits for the State.

[3] In 2006 the government has imposed a cap on the Groningen production.

[4] Policy Research Corporation, 2007, *Naar een doelmatige winning van kleine velden gas* (Towards an efficient exploitation of small field gas), report published for GasTerra B.V., p. 30.

[5] Ministry of Economic Affairs, *Olie en Gas in Nederland, Jaarboek 2006* (Oil and Gas in the Netherlands, Yearbook 2006).

[6] Policy Research Corporation, 2007, *Naar een doelmatige winning van kleine velden gas* (Towards an efficient exploitation of small field gas), report published for GasTerra B.V.

Although other constructs exist, there are two principal fiscal regimes: Production Sharing Agreements (PSAs) and Tax-Royalty systems linked to concessions or production licenses. PSAs are predominant in Southeast Asia, Africa and South America. The principle is that only a portion of the hydrocarbon product stream is allocated to the International Oil Company (IOC) or operator, whereas the remainder – often the largest share – is directly allocated to the State, normally channelled through the National Oil Company (NOC). The operator, however, will be allowed to recover its exploration and development costs before the production sharing starts, although more recent schemes cap this recovery allowance to a percentage per year. In addition, of course, operators pay CIT and other regular taxes and levies. Also, the production sharing may be made dependent upon the oil price, whereby the State effectively creams the rent in a high oil price environment. In general, aggressive PSA schemes are found in resource-rich countries.

The predominant model in Northwest Europe, however, is the tax-royalty system. In that model the CIT is supplemented by special petroleum taxes and royalties in order for governments to achieve their desired share of revenues. Royalties are direct payments to the State resulting from the revenues of the hydrocarbon product stream, often expressed as a certain percentage thereof. Companies can treat these payments as operating costs for their tax return, hence it is not correct to add up the tax and royalty rates to obtain the overall government share. The special petroleum taxes can be implemented in a variety of ways, including specific interactions with the CIT.

Clearly, the level of the combined CIT, special petroleum tax and royalties is important to operators. However, there are more aspects that contribute to the attractiveness of a fiscal regime:

- depreciation method: fast depreciation of capital investment is important, as IOCs use high discount rates when evaluating their projects. For governments, fast depreciation has less effect, as they generally use lower discount rates;
- booking reserves and equity production: operators will generally favour tax-royalty systems, as these generally offer better reserves and production metrics even when the net government take in monetary terms would be the same;
- exposure to price upside: creaming of the rent in a high-price environment is not welcomed, especially since costs, too, will rise with oil price. Tax-royalty systems generally provide more exposure to price upside than PSAs;
- fiscal stability and predictability is a very important criterion.

In addition, there are a number of other political, legal and commercial considerations that can also be considered to be part of the investment climate – for example, the presence of markets, the permitting and licensing procedures, availability of a skilled workforce, etc. However, these are beyond the scope of this paper; we will focus here primarily on the fiscal regime.

Governments have the task to design and maintain a fiscal regime that optimises the extraction of hydrocarbons in a responsible manner for the benefit of the country. This is a delicate balancing act: on the one hand terms and conditions must be attractive enough for companies to invest; on the other hand the objective should be to secure a fair share of the revenues for the State, while honouring various legal and political boundary conditions.

Historic development of the Dutch fiscal regime

In the sixties, after the discovery and start-up of the giant Groningen field, the financial conditions for both onshore and offshore oil and gas exploration and production were developed.[7] The conditions for the Groningen field were tailor-made and thus not applicable to other fields, but they did serve as a basis for the framework that was established for licences under the offshore mining law enacted in 1965[8] and were subsequently applied to onshore concessions granted after 1965. In following years the law was complemented by royal decrees (1967, 1976, 1995) and superseded by the new mining law, which has been effective since 1 January 2003.

The financial conditions presently include a fifty percent State profit share, royalty payments for some fields and surface rentals. State profit share is calculated at fifty percent of the positive balance of the annual profit and loss account and was introduced for the continental shelf in 1965 in view of the uncertainty surrounding the applicability of CIT to offshore activities. It was set at the CIT level that prevailed at the time but never followed subsequent decreases of the CIT level. It was even temporarily increased to seventy percent in 1976 during the oil crises.

Royalty payments are calculated over the income from production, based on a sliding scale. In 1995 royalty for offshore licences was reduced for small production volumes, followed by a decrease in 2001 to zero payments for all offshore licences. Royalty payments are still due for production from some onshore licences.

In essence, the current fiscal regime in the Netherlands for gas production can be subdivided into the following categories: Groningen, 'Oude Gassen', Onshore (other) and Offshore.

The **Groningen** regime is tailor made for the giant Groningen field, in which Nederlandse Aardolie Maatschappij B.V. (NAM) (50% Shell, 50% ExxonMobil) has a 60% share and Energie Beheer Nederland B.V. (EBN)[9] 40%. Apart from CIT, additional applicable taxes are the so-called Government Share ('Staatsaandeel'), Additional Payment ('Aanvullende Betaling') and a supplemental tax levy ('Extra Betaling'). The calculation of these taxes is complex, but together with the EBN share they imply a total State share of the Groningen gas revenues of about 83%-84%.

The '**Oude Gassen**' regime is applicable to a few older concessions that pre-date the royal decree of 1967: Schoonebeek, Rijswijk, Tubbergen and Rossum/De Lutte. These are concessions with a relatively modest production volume and no EBN participation.

For the other (non-Oude Gassen) **onshore** production licenses a combination of CIT and State profit share applies. These interact arithmetically, resulting in an effective tax rate of 50%. A change in the CIT will not change the effective tax rate for these licenses. For some onshore licenses a royalty scheme is also applicable.

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[7] Before that time financial conditions for onshore concessions on a relatively low level existed.

[8] *Mijnwet continentaal plat*, Stb. 1965, 428.

[9] Previously DSM Aardgas B.V.

For all **offshore** production licenses a similar combination of CIT and State profit share is applicable, again with an effective tax rate of 50%.

The various regimes also have specific depreciation schedules for capital investments, implying that it is not possible to rapidly deduct such investments from the revenues for tax calculations in the same year (which would be called 'depreciation at will'). This is a disadvantage of the Dutch fiscal regime from the perspective of the operators compared to, for example, that of the UK. There is also an important implication for the trading of assets: the selling party is taxed at the relevant effective tax rate for the income received from a sale, whereas the buying party has to depreciate its expenditure over a number of years. Essentially this means that in net present value terms the Dutch government benefits from an asset sale.

An important and rather unique feature is the way in which the State participates in the upstream activities. For the Groningen field it was structured as a partnership under civil law, whereas for the other licences a legal obligation to conclude an Agreement of Cooperation with a dedicated State-owned company, EBN, became one of the licence conditions. The involvement of the State in the sector as a partner rather than only as a national oil company has certainly brought advantages to both the industry and the authorities.

For the State such involvement has ensured a degree of influence in mining activities through actively participating in and directly gaining knowledge and data of practically all licensed activities that could not be matched by mere supervision or reporting. As for the industry, EBN was initially a partner imposed by law, participating only in development while taking no exploration risks, but it is now generally viewed as a knowledgeable and active partner which shares the risk in all activities. EBN's position has evolved over time, and was adapted to prevailing economic circumstances. Initially State participation was forty percent and only concerned development of gas discoveries. In 1976, when oil was scarce and prices were high, State participation was increased to fifty percent and was extended to oil discoveries. In 1995 the percentage was again changed, this time decreased to forty percent, as the need was felt to encourage more developments. As the Netherlands became a mature area and exploration activity started to decrease, EBN, in 1995, began to participate in exploration activities within production licences. Five years later, in 2000, EBN was also allowed to take part in exploration activities in offshore exploration licences.

Another important characteristic of the Dutch mining climate has been its relative stability. Although conditions have been somewhat adapted to changed circumstances, the adjustments have not been extraordinary, also not in comparison to other countries. In addition, companies were given the assurance that financial conditions that were laid down in Royal Decrees for offshore licences and attached to onshore concessions would remain unchanged during the lifetime of a production licence. In 2003 the financial conditions were incorporated in the new Mining Act.[10]

Low activity levels in the second half of the nineties led to an improvement of the mining climate, including better purchase conditions by Gasunie;[11] changes in the State participation conditions as

[10] *Mijnbouwwet*, Stb. 2002, 542.

[11] Gasunie, now called GasTerra, is the buyer of most of the gas in the Netherlands, based on a public service obligation.

mentioned above; and a tax incentive, depreciation at will, which was granted to the upstream industry effective July 1995 to stimulate upstream investments.[12] This incentive was introduced at a time of low oil prices to stimulate exploration and development which were both at a very low level. It was felt that the tax burden in the Netherlands needed relief, given the small size of the remaining Dutch hydrocarbon accumulations. The incentive was abolished in 2003, much to the regret of the upstream industry sector.

Fiscal regimes in other European countries

It is interesting to compare the Dutch fiscal regime and overall investment attractiveness to those of other European countries. When considering the differences, these must be put in the context of the total available resources, development stage and history. In the summary below, only the main features of the tax regimes are highlighted. This overview is not comprehensive and does not cover other important aspects such as legislative framework and commercial arrangements.

The **United Kingdom** is in a situation similar to that of the Netherlands in respect to the non-Groningen fields, in that gas production in the UK is in steep decline. Over time the UK has had quite a number of changes in the fiscal regime. There is currently still a category of (older) producing fields that are quite heavily taxed at an effective rate of 75%, the so-called PRT paying fields. Fields that received development approval after 1993 were exempt from PRT and only paid CIT of 30%. However, in 2002 a supplementary charge of 10% was introduced which was increased in 2006 to 20%, resulting in an effective tax rate 50%, which is similar to the current rate in the Netherlands for the small fields. Capital expenditures in the UK for field development can be written off immediately (depreciation at will, DAW), which is a considerable advantage. The UK has no participating State oil companies, and upstream government revenues are realised solely through taxes. The UK licensing authority (The Department for Business, Enterprise & Regulatory Reform – BERR), however, is very active regarding the effective use of the license acreage by the operators through the so-called fallow acreage policy.

Norway is a resource-rich country which still has a significant future gas production level, although its oil production is already in decline. The fiscal regime is fairly straightforward, with a 28% CIT and a 50% special petroleum tax, giving a total effective rate of 78%. This is a comparatively high rate which, combined with the high costs especially in deep water, means that only larger fields (say, 30-60 bcm gas and above) can be economically attractive to operators. There is no depreciation at will, but the depreciation period is relatively short (6 years).

In addition to the direct tax income, the Norwegian government also enjoys revenues through State participation. The portfolio of assets 'State's Direct Financial Interest' (SDFI) is managed by Petoro, acting as a non-operating licensee on behalf of the State. Petoro holds some 41% of the gas reserves and 24% of the oil reserves of the country. The Norwegian State also has a 62.5% share in Statoilhydro, which owns around 35% of the country's reserves. Through the high tax rate and these two participation mechanisms, Norway secures a very high portion of the oil- and gas revenues for the benefit of the State.

[12] Royal Decree of 26 March 1996, Stb. 1996, 214.

Austria has very limited hydrocarbon resources. The gas fields that are in production are small (generally in the 0.2 – 2 bcm range), but the costs are low and the tax regime is attractive to operators. There is no special petroleum tax, only CIT at 25%. There is also a royalty which is weakly linked to the prevailing oil/gas price that amounts to 11-13% of the revenues from gas production. Thus some degree of creaming is effectuated at higher oil price levels. The depreciation period is 8 years. The State owns 31.5% of the shares in OMV, which produces most of Austria's oil and gas.

Italy still has some gas resources and modest production (~11 bcm per year). There is no special petroleum tax. There is a CIT of 33% and also some regional taxes of about 4-5%. Also royalties are payable. Together, the overall government take amounts to some 40%. However, the Italian State also has a 30% interest in ENI, which owns about half of the country's reserves.

Germany has a very mature hydrocarbon system with a declining production and limited remaining resources. The German tax system is convoluted, with taxes imposed at federal, state (Lander) and municipal level. The effective corporate tax rate has recently been reduced to 15.83%. Royalty levels vary from state to state and are also adjusted frequently, where a link to oil price developments can be observed. Most gas is produced in Lower Saxony, where currently a royalty rate of 35% applies. The effective tax rate (corporate plus municipal taxes) amounts to approximately 31%. The Lower Saxony royalty rates, however, can be reduced for field specifics, in particular reservoir quality, for the first 5 years of production, thus stimulating production of marginal and difficult fields (e.g. tight gas). Municipal trading taxes are similar to those in other industries and vary from region to region. There is no depreciation at will. Germany has no State participation. As a consequence of the above, the effective government take (tax plus royalty) varies. It is slightly above 50% for gas onshore but lower than that offshore.

Ireland has modest hydrocarbon resources. Developments offshore represent a high-cost environment. The tax regime is therefore aimed at stimulating exploration activity. The CIT is 25%, and until recently there were no special petroleum taxes or royalties (except for some older licenses). Development expenditure can be written off against tax in the first year of production. There is no State participation. Ireland recently introduced an additional taxation that is dependant on the oil price to upgrade government take at higher prices. This is called the 'profit resource rent tax', which adds 5%, 10% or 15% on top of the 25% CIT rate, depending on the field profitability. As the latter not only depends on operating costs but also on oil or gas price, this can be considered as creaming.

Denmark has a medium-sized reserves base (some 90 bcm in remaining gas reserves) but produces more gas than it consumes. The annual production is around 8 bcm, one tenth of that of the Netherlands. Considering the remaining exploration potential, Denmark has a relatively harsh fiscal regime. In addition to CIT of 25%, there is a hydrocarbon tax (52%) and a State profit share tax (20%) that, combined, result in an approximately 72% effective tax rate (and thus government take). As of 2012, the 20% State profit share tax will be abolished and replaced by direct State participation in Nordsøfonden (The Danish North Sea Fund). Nordsøfonden will then be a 20% State-owned partner in licenses, thus paying its share of the investments and receiving 20% of the revenues. The effective overall State share will remain approximately the same as before 2012 (~72%). In Table 1 the key characteristics[13] of the fiscal regimes of the various countries are summarised, as they apply to *new investments*.

Table 1: Key characteristics of the fiscal regimes of the various countries for new investments

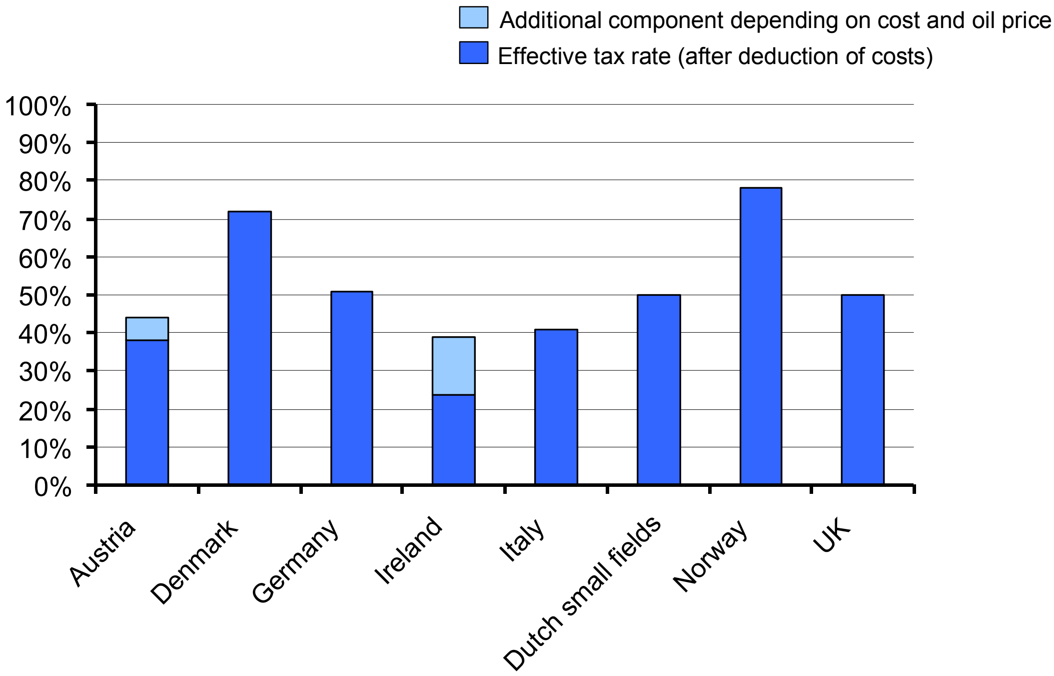
Country	Tax (combined corporate tax and special petroleum taxes)	Royalties/Fees	Depreciation of capital investments[14]	Specials
Austria	25%	Variable, depending on oil price; ~12% for gas, ~6% for oil	8 years	State interest in OMV
Denmark	~72%	5% oil fee	4-7 yrs	20% State participation as of 2012
Germany	~31% (depends on region)	0-35% depending on region (35% for Lower Saxony)	8-14 years	Royalty reductions for tight gas; effective government take region dependant
Ireland	25%	None	DAW, ringfenced	New oil price dependant tax introduced
Italy	38%	0-7% depending on production rate	5-8 yrs	30% State interest in ENI
NL onshore	50%	0-7% depending on production	5-14 yr	EBN (State) participation0-40%; other regimes for 'Oude Gassen', Groningen
NL offshore	50%	None	11 yr	EBN (State) participation 40%
Norway	78%	None	6 years	State participation through Petoro and Statoilhydro
UK	50%	None	DAW	50% PRT on older fields

Source: CIEP analysis

The overall effective government take (taxes plus royalties) is shown in Figure 1.

[13] Various more detailed characteristics, such as uplift and treatment of abandonment costs, are not considered here.
[14] Depreciation schemes can vary depending on type of expenditure, timing and license terms.

Figure 1: Effective government take (tax and royalty) for new investments



Source: CIEP analysis

State value share

In the previous section the fiscal attractiveness from the perspective of the operator was presented in terms of the effective government take of the revenues for new investments, combining tax and royalty. For most countries this also approximately represents the overall State share in the revenues.[15] For some countries, the State receives dividends from upstream activities through participation: in Austria and Italy through shares in private companies, in the Netherlands and as of 2012 in Denmark through a State enterprise, and in Norway through both. For these countries, the total State share in revenues from the upstream industry is larger. A comprehensive and accurate analysis of the total State share is a complex activity, which also would need to be conducted on the basis of an economic multi-year model generating net present values. This would result in an allocation of the total gross upstream revenues to three components: costs, operator value and State value. 'Value' would be expressed as a net present value of the discounted future cash flow, which would need to encompass all existing assets. From this, the relative State value as part of the total value can be calculated. This is well beyond the scope of this paper. Nevertheless, an indication of the overall State share will be given, because in some countries direct taxes and royalties account for only part of that and do not provide the full picture.

[15] The State also enjoys other indirect taxes as a result of the upstream activities, for example the CIT that service companies are paying, which represents a cost to the operator.

The consultancy firm Wood Mackenzie has conducted such a comprehensive analysis for fiscal regimes worldwide as a proprietary multi-client study in 2007, although this does not include State shares in private enterprises. Below, some references will be made to this study.[16]

For the Netherlands we must make a distinction between Groningen and the small fields. For Groningen the State share of the revenues after deduction of the costs is approximately 83%-84%. For small fields this would generally be operator share (60% in most cases) times a tax rate of 50% plus the EBN share (40%), hence 70%. EBN pays its share of investments and operating costs; therefore in value terms the share will be less than that, but only slightly. Test calculations have been performed using a proper economic model for a typical offshore field in the Netherlands. Depending on assumed oil price and costs, the State value share ranges between 68% and 70%. To estimate the total value share the Dutch State realises from the upstream hydrocarbon, a reserves-based weighted average could be taken of the typical Groningen and small fields State value shares. On this basis, an estimate of the overall Dutch State value share of the remaining production would be approximately 79%. From the Woodmac study, based on a much more comprehensive calculation, a share of about 78% could be inferred.[17] In this way, the overall State share in the Netherlands in the upstream revenues is one of the highest in Europe.

The Norwegian State receives, apart from the direct taxes at 78%, dividends through Petoro and Statoilhydro. The total Norwegian State's share in reserves is about 48%.[18] Hence the share of the Norwegian State in the *revenues* is 48% + 78% x 52% = 88%. However, for the generation of revenues resulting from participation (Petoro, Statoilhydro) also investment contributions need to be made, which is not the case for the direct taxes part of the revenues. Hence the effective State share in value terms will be less than 88%, perhaps around 85%. From the Woodmac study a share of 83% can be derived, but this does not yet include the Statoilhydro dividends.[19]

The UK only receives income from upstream activities through taxes. Most of the production will fall in the 50% tax bracket, but there are still a number of PRT paying fields. Hence the total State share will be higher than 50%. Woodmac data would indicate this is around 56%.[20]

In Italy the State has a 30.2% interest in ENI, which in turn owns about half of the country's reserves. This increases the State value share above the tax based government take of about 40% to about 49%. A similar consideration applies to Austria. For the other countries, the effective tax/royalty rates provided in Figure 1 are indicative for the State value share, as also confirmed by the Woodmac study data.[21]

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[16] Wood Mackenzie, 'Government Take: Comparing the attractiveness and stability of global fiscal terms', *Woodmac multi-client study*, June 2007.

[17] Ibid.

[18] This has been calculated from the information at the NPD website (www.npd..no), listing the reserves by company.

[19] Wood Mackenzie, 'Government Take: Comparing the attractiveness and stability of global fiscal terms', *Woodmac multi-client study*, June 2007.

[20] Ibid.

[21] Ibid.

Another way to review the government take is to consider the upstream State income as reported by the authorities. If we compare the Netherlands with Norway and the UK, Table 2 can be constructed on the basis of the earnings in 2006.

Table 2: Upstream State income, comparing the Netherlands with Norway and the UK

Country	Net revenues (2006)	Net revenues in bln €	Production Gas in bcm (2006)[22]	Production oil in mln sm3 (2006)	Net revenue in $ per boe
NO	356 bln NOK	43	87.6	161	37
NL	9.9 bln EUR	9.9	61.8	2	33
UK	9.072 bln GBP	13.3	80.0	95	16

Sources: BP[23]; NPD[24]; Dutch Ministry of Economic Affairs[25]; UK Oil and Gas Directorate[26]

Some considerations are important when interpreting these numbers. It is clear that the Norwegian State extracts considerable value from its hydrocarbon resources (which constitute about half the country's GDP). On the basis of barrels of oil equivalent (boe), the Dutch State captures a slightly lower but similar share. Yet there are differences. Development and operating costs in Norway are considerably higher, which might explain why there is not a larger difference, given Norway's higher average tax rate. Also in the UK, the costs are higher than in the Netherlands. At the same time, UK production is in decline and the share of the more highly taxed PRT fields is diminishing.

There is also clearly correlation between resource base and State value share. Countries with limited resources (Ireland, Austria) are obliged to impose low tax rates to attract investment. Refer to Figure 2, in which the total of countries' remaining proved reserves (both oil and gas, in billion barrel of oil equivalent) is plotted against the (approximate) overall State value share. These reserves are plotted using a logarithmic scale.

[22] Volumes are corrected for calorific value.

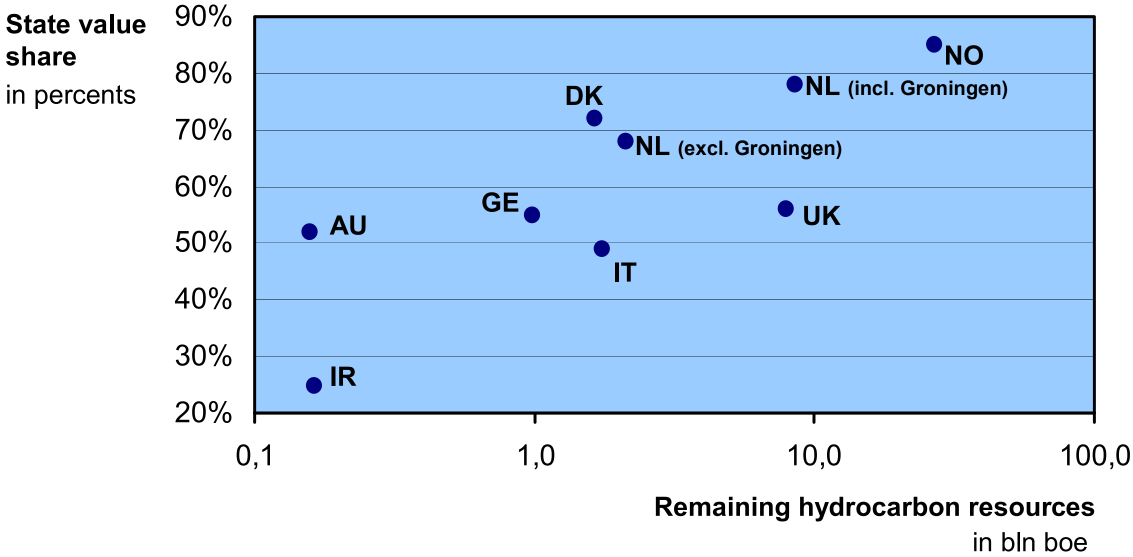
[23] BP, *Statistical Review of World Energy*, June 2007.

[24] NPD, *Facts 2007*, the Norwegian Petroleum Sector, Ministry of Petroleum and Energy.

[25] Ministry of Economic Affairs, *Olie en Gas in Nederland, Jaarboek 2006* (Oil and Gas in the Netherlands, Yearbook 2006).

[26] UK Oil and Gas Directorate, 'Government revenues from UK oil and gas production', <https://www.og.dti.gov.uk/information/bb_updates/appendices/UKCS_Tax_Table.pdf> (last reviewed: April 2008).

Figure 2: Relationship between State share and hydrocarbon resources



Sources: BP[27]; CIEP analysis

Although the Netherlands realises a high State value share as a result of EBN participation, the effective tax rate for new investments from the point of view of the operator is at the same level (50%) as, for example, in the UK, although there are various differences in other fiscal and legislative terms (such as depreciation and the treatment of decommissioning costs). *The key difference lies in the opportunity availability*. Because in the Netherlands EBN takes 40% in every license, the size of the cake left for operators is smaller. At the same time this can also be an advantage, as there is always a natural partner available to share the investment risk.

Adjustment of fiscal regimes

The proper design and maintenance of the fiscal regime, along with optimising various other investment conditions as part of the investment climate, is essential for the effective exploitation of a country's hydrocarbon resources. Although the stability of a fiscal regime is very important to investors, it can on the other hand not be expected that the fiscal regime is static. Circumstances change over time, and these may lead to adjustments to the tax regimes. For example, once the size of the Groningen field became fully understood, the Dutch government imposed a set of taxes that would ensure an adequate State share. From time to time, oil price developments also trigger adjustments in the fiscal terms, one example being the 2006 increase in supplementary tax in the UK.

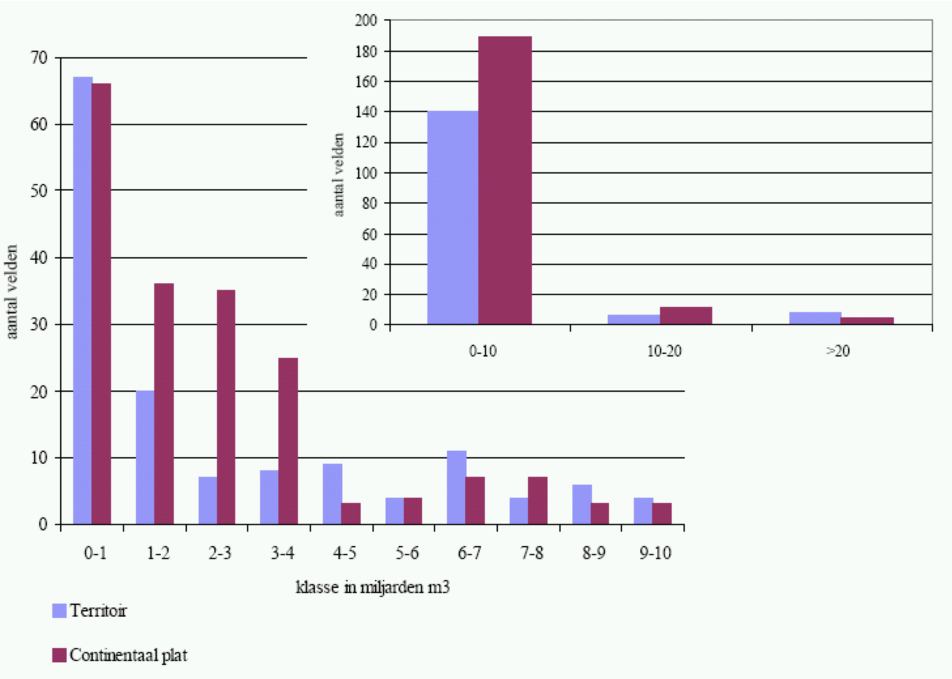
Over time, when more and more of the hydrocarbon resources have been produced and the remaining exploration potential decreases, governments struggle with the questions of whether and how to adapt the fiscal regime to maximise the exploitation of the remaining resources. Invariably, the fields that are left are smaller than the ones already in production. They will reach a point where they are no

[27] BP, *Statistical Review of World Energy*, June 2007.

longer economically attractive under the existing regime. Yet there are good arguments to also extract the hydrocarbons from such smaller fields (security of supply, State income). If the fiscal regime remains unchanged, no investments in such smaller fields will be made. On the other hand, governments would like to avoid introducing operator benefits for fields that would also be developed under more stringent terms (the so-called free rider effect).

One of the possibilities for achieving an improvement is to make use of the time value of money, which is higher for upstream operators than for governments. This is particularly relevant in respect to depreciation schemes, where a more rapid depreciation is a greater advantage to an operator than it is a disadvantage to a government.

Figure 3: Distribution of gas fields' size in the Netherlands, based on expected initial reserve in billion standard cubic metres (Sm^3)



Source: Dutch Ministry of Economic Affairs [28]

A key focus area in mature basins is the encouragement of the development of marginal or difficult fields. The idea is that specific allowances are made for marginal fields in order for these to be an attractive opportunity for operators to pursue. If this is successful, it could open up a substantial new resource base, as statistically there are more small fields than larger fields. The distribution of gas fields' size in the Netherlands, based on expected initial reserve in billion Sm^3, is shown in Figure 3. The difficulty is how to define a marginal field and to decide when such allowances would apply. Economic attractiveness of a field depends not just on volume, but also on proximity to infrastructure,

[28] Ministry of Economic Affairs, *Olie en Gas in Nederland, Jaarboek 2003* (Oil and Gas in the Netherlands, Yearbook 2003).

development costs, production rates, etc. Developing a threshold below which the allowances would apply needs to take all these factors into account and could make it administratively complex.

Incentives for marginal fields have been the subject of discussions in recent years between NOGEPA and the Dutch Ministry of Economic Affairs. This issue is being considered in other countries as well. In Britain, the UK Offshore Operators Association (UKOOA) has proposed to abolish the supplementary petroleum tax for marginal fields, but to date this has not been supported by the government. In Italy, a legislative amendment was made in 2004 to stimulate the exploitation of marginal fields, where marginality is defined by means of an Internal Rate of Return (IRR) criterion, the IRR being a project profitability metric. In Germany, lower royalty rates are applicable to tight – i.e., poorly producing – gas fields. This is a fairly straightforward mechanism. A lower tax or royalty rate for initially produced volumes is relatively easy to administer and implement. Use is then made of the time value of money, as the attractiveness to operators is much enhanced if they can realise additional earnings in the initial phase of production.

In the past few years the increased maturity and declining production in various basins in Northwest Europe have become apparent, but at the same time oil and gas price levels have steadily increased. These increased oil and gas prices have no doubt affected the pace at which these additional fiscal measures for marginal fields are being considered, although it should be realised that the screening prices operators use in evaluating projects are always substantially lower than actual prices. Smaller fields were becoming more economic and a number of them did not need to be stimulated by fiscal allowances. Nonetheless, this does not detract from the gradual decline in discovery sizes and production levels, and the question of how to stimulate small field development will continue to be relevant in the future.

It is interesting to point to two countries where creaming has recently been incorporated into the tax regime, which is more common in production sharing agreements. In Austria, where no special petroleum tax is applicable, the royalty formula contains an oil and gas price element. Ireland, too, is currently introducing a tax that is partly oil price dependent. The reason that both Austria and Ireland have introduced creaming is undoubtedly that these countries have tax regimes with a relatively low government share. At high prices and for government takes lower than 50%, the government revenues trail further behind in absolute terms. For regimes with high State shares, such as Norway, Denmark and the Netherlands, the opposite applies.

Conclusion

The careful design and maintenance of a fiscal regime for the upstream sector is essential for the effective exploitation of hydrocarbon resources. A sub-optimal system either generates lower revenues for the government than may be possible, or deters investment so that hydrocarbons are left in the subsurface and a reduced revenue stream results. In Northwest Europe the tax-royalty system is the predominant model. The way in which this is implemented differs widely from country to country. In part this is driven by different positions in terms of hydrocarbon resource availability and basin maturity.

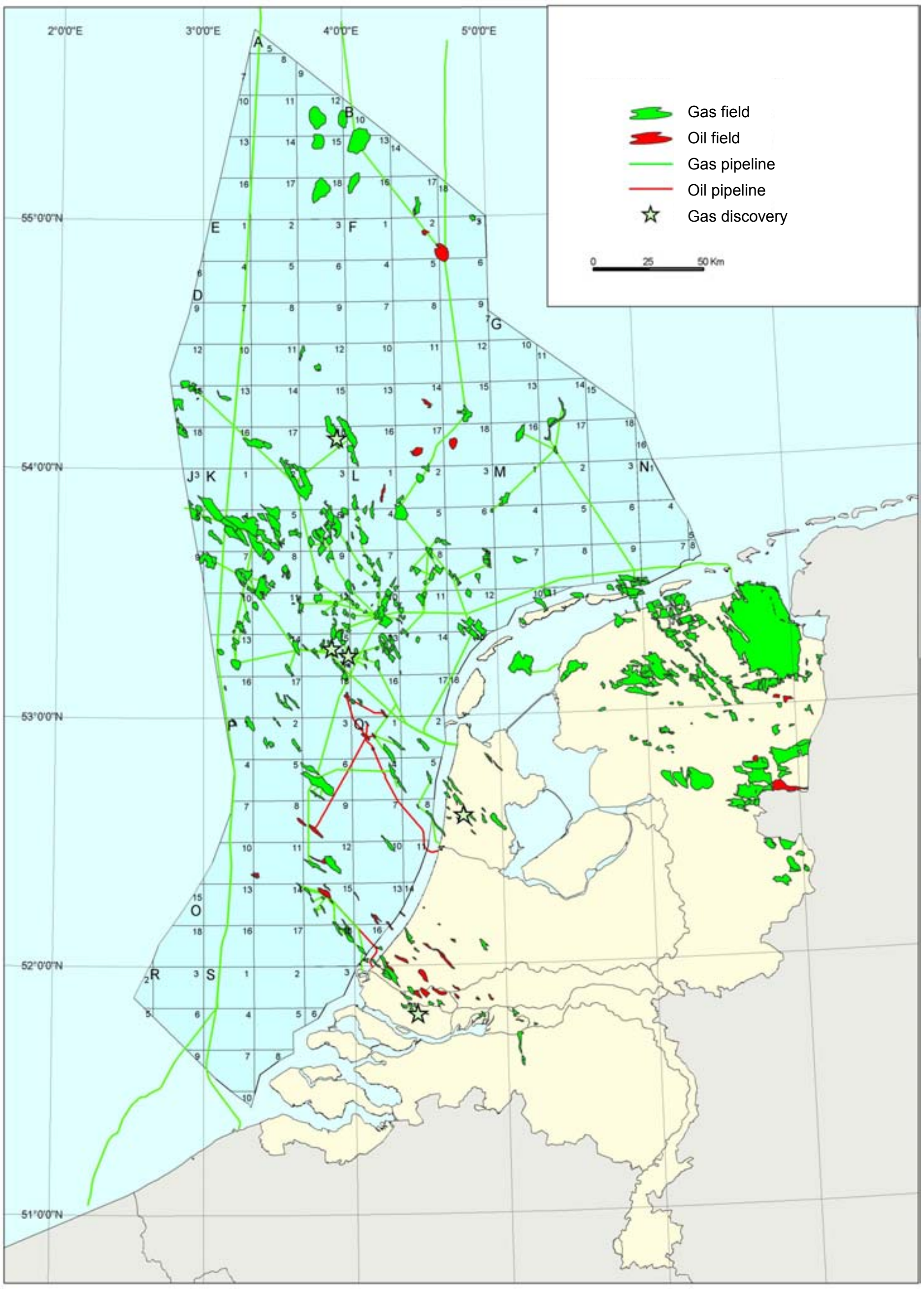
The fiscal regime in the Netherlands may be characterised as one of the more stable and consistent systems. Changes and adjustments have been made over time, but these can be considered as necessary maintenance in a continuously changing environment. Exceptions include the temporary increase of the EBN share to 50% in the seventies and the introduction in 1995 – and subsequent abolishment in 2003 – of the depreciation at will. The effective tax rate is 50% for small fields, which is currently similar to, for example, that in the UK. However, through the mandatory and historically consistent participation of EBN in all but a few licenses, the overall State share is one of the highest in Europe. This does reduce investment opportunities for operators, but at the same time supports risk sharing.

The historic and current role of EBN is unparalleled, though also Norway (Petoro) and Denmark (Nordsøfonden) have been developing the participatory role of government agencies as non-operating partners. It has allowed the Dutch authorities to secure a substantial part of the rent in addition to the normal taxation, but also to develop and maintain a good and comprehensive understanding of the hydrocarbon system in the Netherlands. EBN staff participates in almost all license partner meetings where the acreage potential is reviewed and investment options are discussed.

Nevertheless, the hydrocarbon system in the Netherlands is maturing, and production from small fields is in decline. Although the adjustment of the fiscal regime addressing this development has been postponed due to the increased high oil and gas prices, the issue of how to scale down the tax impact for the smaller and more marginal fields in order to stimulate their development remains on the table. This is an issue that does not just affect the Netherlands, but one that is high on the agendas of a number of other European countries as well.

Appendix

Figure 4: Gas & oil fields and offshore pipelines in the Netherlands (1 January 2007)



Source: Dutch Ministry of Economic Affairs [29]

[29] Ministry of Economic Affairs, *Olie en Gas in Nederland, Jaarboek 2006* (Oil and Gas in the Netherlands, Yearbook 2006).