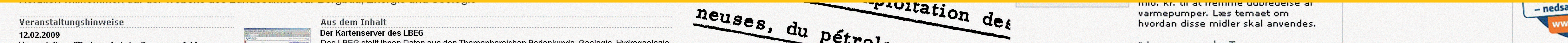
Sources of different country information on licensing and exploration history. The colour photo of the rig is the ConocoPhillips 44/23b-11 Kelvin platform drilling the development well in 2007, with the ConocoPhillips 44/19b-6 Harrison exploration well in the background. The black-and-white photo is of wooden drilling derricks in the Nienlagen region of Germany during the 1930s. Photo of TGS Nopec Northern Explorer seismic acquisition vessel.



Chapter 14 Licensing and exploration history

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Bibliographic reference
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1 Introduction

Exploration is intrinsically cyclical; responding to exploration success and commodity price and also reflecting geopolitical, economic and national fiscal and regulatory changes. This review of licensing and exploration history charts drilling and seismic trends, sets out each country's regulatory and fiscal framework and examines the success rates for discovering hydrocarbons in the SPB area.

Well statistics show that the exploration success ratio in the SPB area has been steadily climbing to about 50%. The most successful play overall is the Rotliegend, but Carboniferous, Zechstein and Triassic plays also contribute to this exploration success (Chapters 13 & 15).

The SPB area may be considered to be a mature province in terms of exploration, but commercially attractive new discoveries are still being made.

1.1 First onshore discoveries lead to licensing

Petroleum, in the form of oil seeps, has been known in western Europe for many centuries at places such as Péchelbronn in the Rhine Valley and along the shores of Lake Neuchatel, Switzerland, where Neolithic people are known to have used asphalt as an adhesive to attach horn or wooden handles to flint implements.

The first economically viable oil industry in Europe dates from 1851, when James 'Paraffin' Young distilled oil from Carboniferous (Visean) organic-rich shales in central Scotland. Pits and simple drilling in 1854 are reported from the Bóbrka-Rogi field in Poland. In 1858, a well was drilled to a depth of 35.5 m to test for coal near Wietze in western Germany (Figure 1.4). The well produced 1½ buckets of oil per day for the next year and the Wietze area became the centre of Europe's oil industry until after World War II. The first gas in Germany was discovered in 1910 from a well drilled for water into Tertiary sands near Hamburg.

Under the Defence of the Realm Act, passed to meet the fuel demands of World War I, the first UK oil discovery was in 1919 at the Dinantian Hardstoft well in the East Midlands (Chapter 6; Figure 6.1). The Kimmeridge shale-oil seeps along the southern coast of England in Dorset were first drilled in 1930. The UK Petroleum Act was passed in 1934 to establish a petroleum licensing regime, and the first licences were issued in 1935. Gas was discovered in Zechstein dolomites at the Eskdale field near Whitby, Yorkshire in 1939.

Belgium's first exploration well was drilled in 1935. Subsequent drilling has been beneficial for other applications such as water resources, geothermal and gas storage (see Chapter 16), but no hydrocarbons have been found to date. There has never been a licensing round in Belgium, although some concessions were awarded and expired before 1970.

Onshore licensing in the Netherlands started in 1948. In 1952, a wildcat in the Groningen area found 180 m of water-bearing Rotliegend sandstones (Section 6.2.1 in Chapter 7). A small gas discovery in Zechstein dolomites at Ten Boer in 1956 was followed in 1959 by the discovery of fully gas-bearing Rotliegend sediments in the Slochteren-1 well. At that time, Slochteren was thought to be part of a 70 bcm accumulation, but no-one wanted the gas as every small town had its own coal-gas plant. Further seismic surveys and the drilling of four appraisal wells led to the realisation that the gas had a common water table at a depth of about 2900 m, which was confirmed when the Ten Boer well was deepened in 1963. With an apparent ultimate recovery of some 1640 bcm of gas (now known to be nearer 2830 bcm), the giant field, which was renamed after the provincial capital Groningen, contained enough gas to change the fuel economy of north-west Europe and spurred offshore exploration.

Onshore exploration in Denmark began in 1935 when a licence to the entire land area was granted. The first well was drilled in 1936, but there were no discoveries until 1980 when Løgumkloster-1 encountered oil in Zechstein strata on the northern margin of the SPB.

Exploration drilling continued in western Germany throughout World War II, extending from the Zechstein Bentheim gasfield into the eastern Netherlands with the discovery of the Schoonebeek oilfield in 1943 (Section 4.1 in Chapter 11). In 1944, oil was found in the Arnhem-01 well from an unknown reservoir. The Goirle well had reported oil, but subsequent drilling did not confirm the discovery.

Exploration in Poland began in 1946, but it was not until 1964 that Permian Zechstein gas was found when drilling that targeted a Triassic sandstone structure in the centre of the Fore-Sudetic Monocline imaged on 2D-analogue seismic data. The first oil was discovered in the same area in 1961 in the Rybaki Zechstein Main Dolomite (Chapter 8).

Figure 14.1 summarises the first play penetrations and first successes in each play for each country. **Figure 14.2a**, which depicts the licensed acreage on 1st January 1960, only shows licences in Belgium and the Netherlands as records of early onshore licensing are not available for Germany. There was no licensing in Poland until 1993.

1.2 Framework for offshore licensing leads to offshore discoveries

The Convention on the Continental Shelf adopted by the United Nations Law of the Sea Conference in 1958 provided for coastal States to have the right to exploit the natural resources of their sectors of the shelf to 200 miles. The median-line concept was a key resolution of the Convention, defined as the locus of a point equidistant from the nearest base line or from each State from which the width of the territorial sea was to be measured. It was left to individual States to regulate exploitation in their sector.

The Danish Government was the first to initiate licensing in its offshore area in 1962, awarding the whole of its acreage, onshore as well as offshore, to the Danish concessionaire A.P. Møller, who established the Danish Underground Consortium (DUC). Subsequent partial relinquishments of the sole concession enabled licensing of the surrendered area to begin in 1983. The UK's first licence round was held in 1964. The German offshore area was granted to one consortium in 1964 and relinquishments of that area have been offered subsequently. The Netherlands first offshore round licences were awarded in 1968, but it was not until 1970 that disputes regarding the offshore boundaries were finally resolved. Belgium has never licensed its offshore area.

National differences in approach to the granting of licences include the number of blocks assigned to a Quadrant (1° by 1°). In UK waters, each Quadrant has been subdivided into 30 blocks; in Denmark there are 32, and 18 in both the Netherlands and Germany (see Figure 1.4). Discretionary licence award systems now apply in all four countries, although this has not always been the case. A steady release of acreage available for licence in each sector of the North Sea has enabled exploration to continue for more than 40 years.

1.2.1 First offshore discoveries

The first offshore UK well in the SPBA area was drilled in 1964 on the Mid North Sea High at well 38/29-1, which proved to be a dry hole with no Rotliegend reservoir. This was followed by more than 20 wells drilled in 1965 in the UK southern North Sea, when the first of many important gas discoveries was made at the West Sole field (Section 6.1.3 in Chapter 7). The first offshore gas discovery in the Netherlands was in 1964 when the Slootdorp-1 well drilled into the Rotliegend. In September 1966, the first well drilled in the Danish sector, Den A-1X (Anne), found Cretaceous oil. Gas was first discovered in the E-1X well in 1968. The first well drilled in the German sector in 1964, well B1 in block H15, was abandoned after a gas blow-out. Wells drilled in the 1960s made some gas discoveries in the Permian and Carboniferous plays, but none were economic due to the high nitrogen content and/or the amount of gas in place. The first gasfield (A6/B4) was discovered in 1974 but development did not start until 1999. Offshore exploration of the Polish Baltic Sea began in the late 1970s under the Petrobaltic Company's exclusive licence for exploration and exploitation. In 1981, oil was discovered in the B3-1/81 well, 80 km off the Rozewie Cape. In 1999, the Polish State Treasury became Petrobaltic's only shareholder.

2 Legislation, licensing and fiscal regime

The regulations that govern licensing, the methodology for selecting blocks, criteria for awards and the chronology of licence rounds, differ for each country and have varied through time. Descriptions of these differing aspects and licensing history are therefore summarised individually.

In 1994, the EU established 'Directive 94/22/EC Conditions for Granting and Using Authorisations for the Prospection, Exploration and Production of Hydrocarbons' defining the energy policy of the Community and the Member States. The Directive was introduced to ensure greater integration of the internal energy market, free from barriers to trade, with a view to improving security of supply, reducing costs and improving economic competitiveness. Since 1994, Member States have followed this directive when issuing petroleum licences covering factors that may (or may not) be taken into account when deciding whether or not to issue a licence and the minimum amount of public consultation. Poland has identified some areas that are not subject to the tender process.

Play	UK offshore				UK onshore		Belgium				The Netherlands			
	First well	Date	First discovery	Date	First discovery	Date	First well	Date	First discovery	Date	First well	First discovery	Date	Date
Cenozoic	39/16-1	Jul-1997	NA	NA	NA	NA	NA	NA	NA	NA	Wyk-01	1949	Wyk-01	1949
Cretaceous	39/07-1	Jul-1971	NA	NA	NA	NA	NA	NA	NA	NA	Losser-01	1942	Schoonebeek-02	1943
Jurassic	98/22-1	Dec-1978	39/02-2	Oct-1994	LS/26- 5	Jan-1955	NA	NA	NA	NA	Oldenzaal-01	1942	Rijswijk-01	1953
Triassic	53/12-1	Apr-1967	44/23-1	Jan-1968	NA	NA	NA	NA	NA	NA	Weerselo-01	1942	Wyk-01	1949
Zechstein	38/29-1	Mar-1965	53/04-1	Jul-1967	L41/17-2	Nov-1939	NA	NA	NA	NA	Weerselo-01	1943	Coevorden-02	1948
Rotliegend	49/13-1	Aug-1965	49/26-1	Mar-1966	L41/29-8	Jul-1987	NA	NA	NA	NA	Hoogkarspel-01	1950	Slochteren-01	1959
Carboniferous	41/18-1	Jul-1966	44/21-2	Nov-1984	LK/24- 3	Feb-1919	Mol-KB107	1935	NA	NA	Coevorden-03	1950	Coevorden-03	1950
Devonian	36/15-1	Aug-1967	NA	NA	NA	NA	Rosée	1964	NA	NA	NA	NA	NA	NA
Pre-Devonian	NA	NA	NA	NA	NA	NA	Houtem	1963	NA	NA	NA	NA	NA	NA

Play	Denmark				Germany				Poland			
	First well	Date	First discovery	Date	First well	Date	First discovery	Date	First well	Date	First discovery	Date
Cenozoic	Roxanne-1	May-2000	NA	NA	U	U	Neuengamme	1910	NA	NA	NA	NA
Cretaceous	A-1X	Sep-1966	A-1X	Sep-1966	U	U	Wietze	1874	NA	NA	NA	NA
Jurassic	Ringe-1	Apr-1951	U-1X	Nov-1975	U	U	Wietze	1874	NA	NA	NA	NA
Triassic	Ullerslev-1	Jun-1951			U	U	Wietze	1874	NA	NA	NA	NA
Zechstein	Tønder-1	Jun-1952	Løgumkloster-1	Oct-1980	U	U	Volkenroda	1930	Wschowa-1	1956	Rybaki-1	1961
Rotliegend	Stina-1	Jul-1989	NA	NA	Groothusen Z2	1962	Groothusen	1965	Uciechow-1	1964	Załęcze-2	1971
Carboniferous	NA	NA	NA	NA	U	U	Rehden	1961	NA	NA	NA	NA
Devonian	NA	NA	NA	NA	Rügen 4	1966	NA	NA	NA	NA	NA	NA
Pre-Devonian	NA	NA	NA	NA	Arkona 101	1962	NA	NA	Żarnowiec-IG1	1970	Żarnowiec-IG1 A	1971

NA Not applicable
U Unknown

Figure 14.1 First play penetrations and first successes in each play, by country.

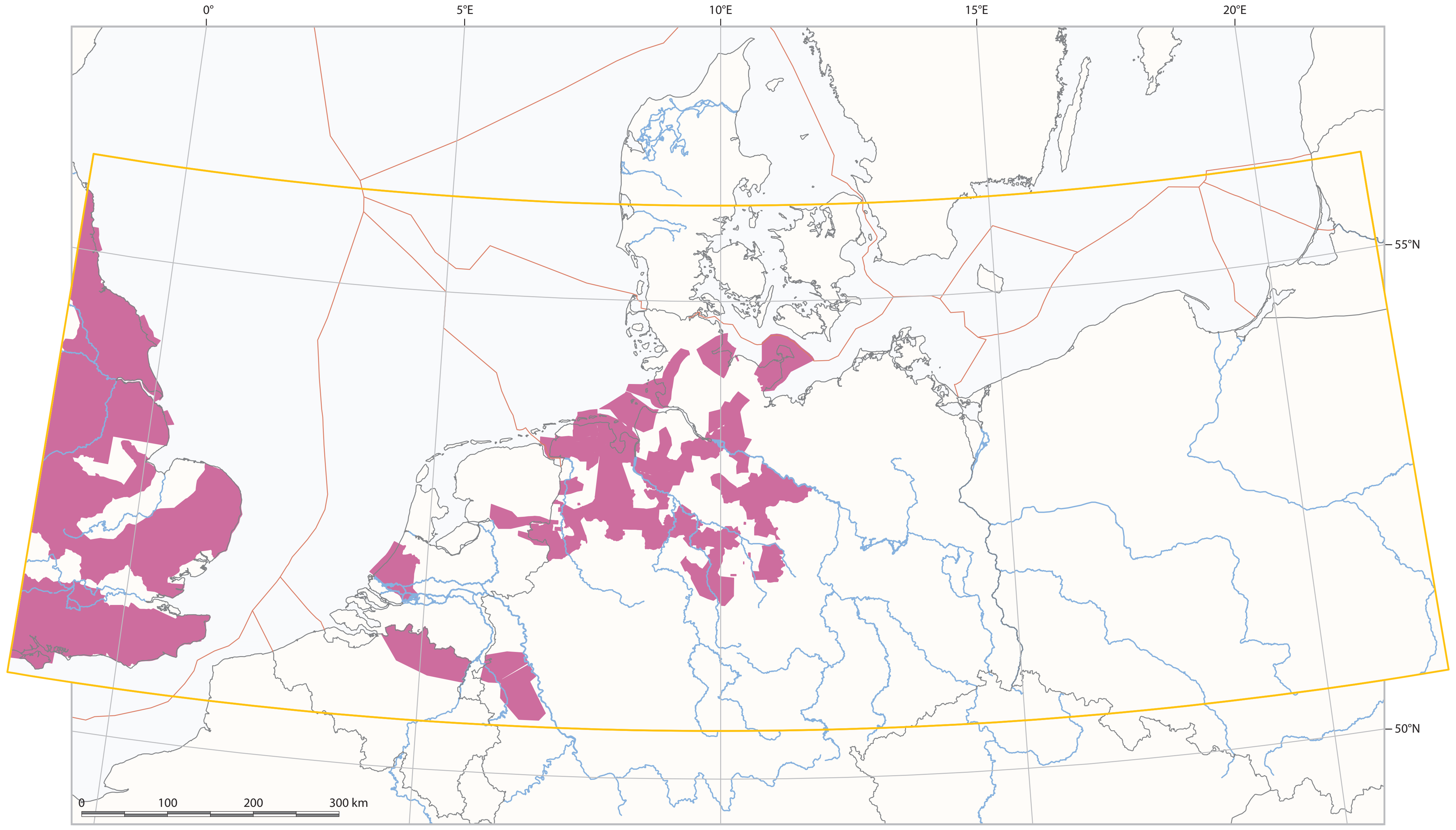


Figure 14.2a Licensed acreage at 1 January 1960. Note that records of early onshore licensing are not available for Germany and there was no licensing in Poland before 1993.

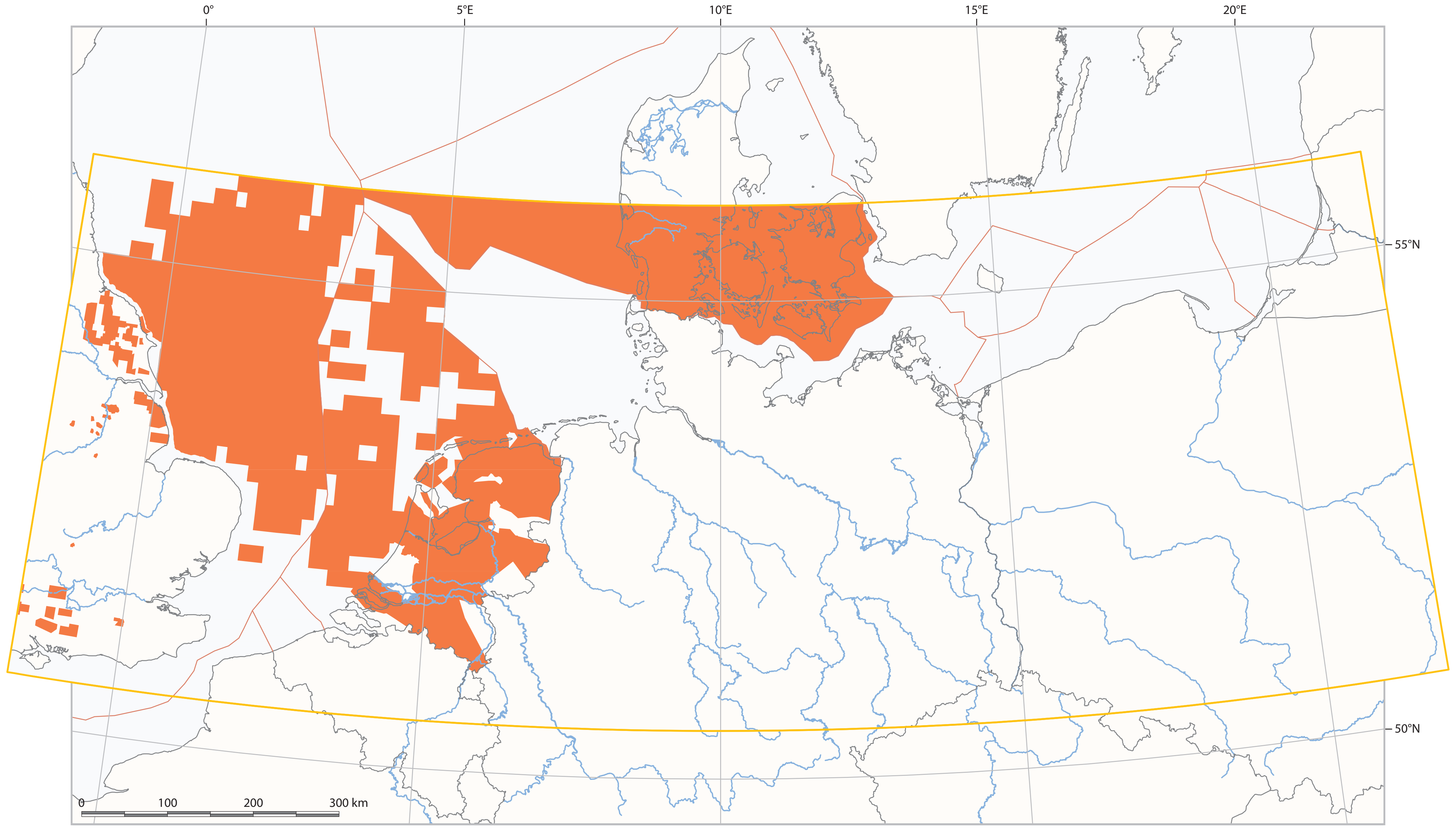


Figure 14.2b Licensed acreage at 1 January 1970. Note that records of early onshore licensing are not available for Germany and there was no licensing in Poland before 1993.

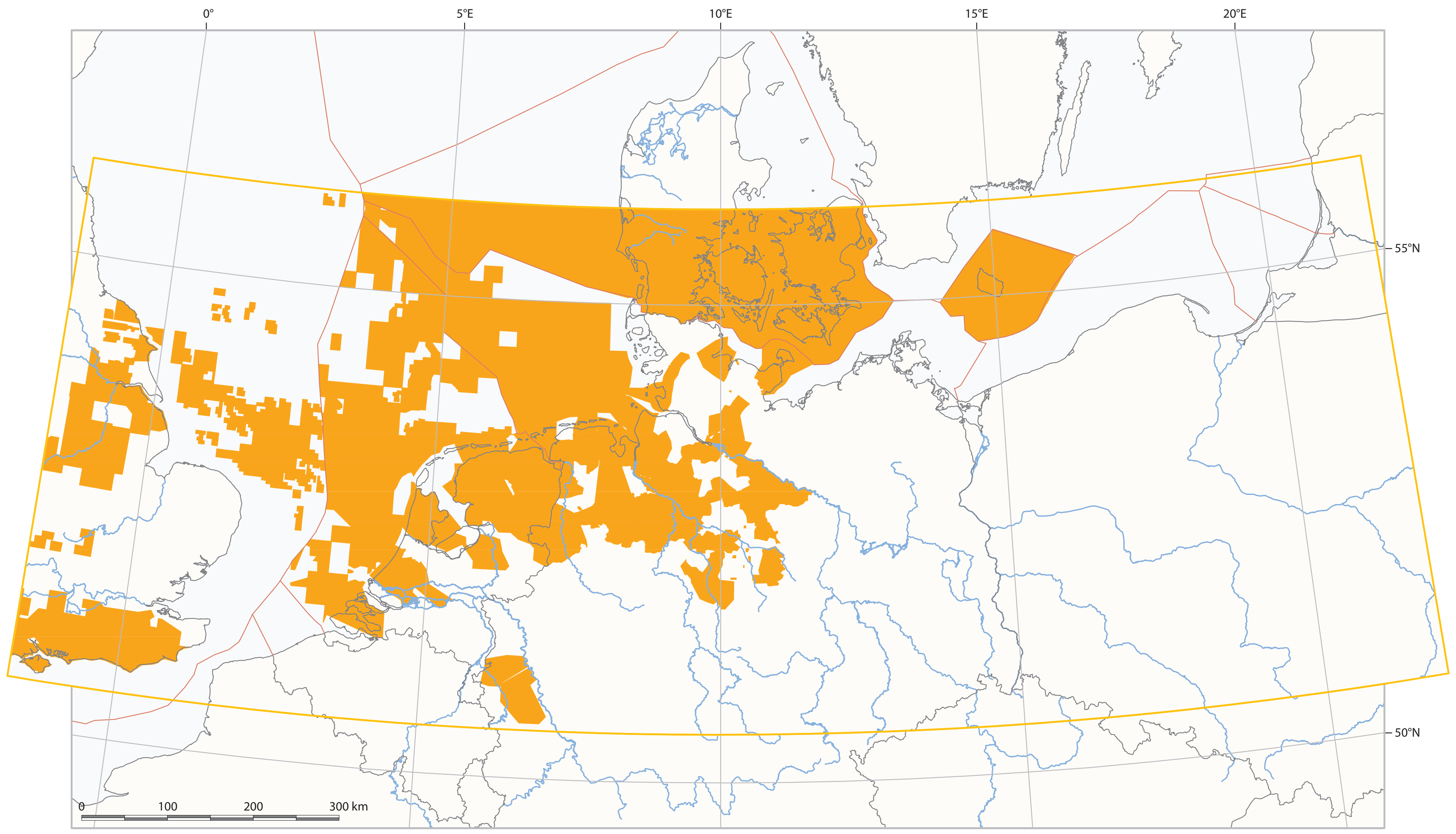


Figure 14.2c Licensed acreage at 1 January 1980. Note that there was no licensing in Poland before 1993.

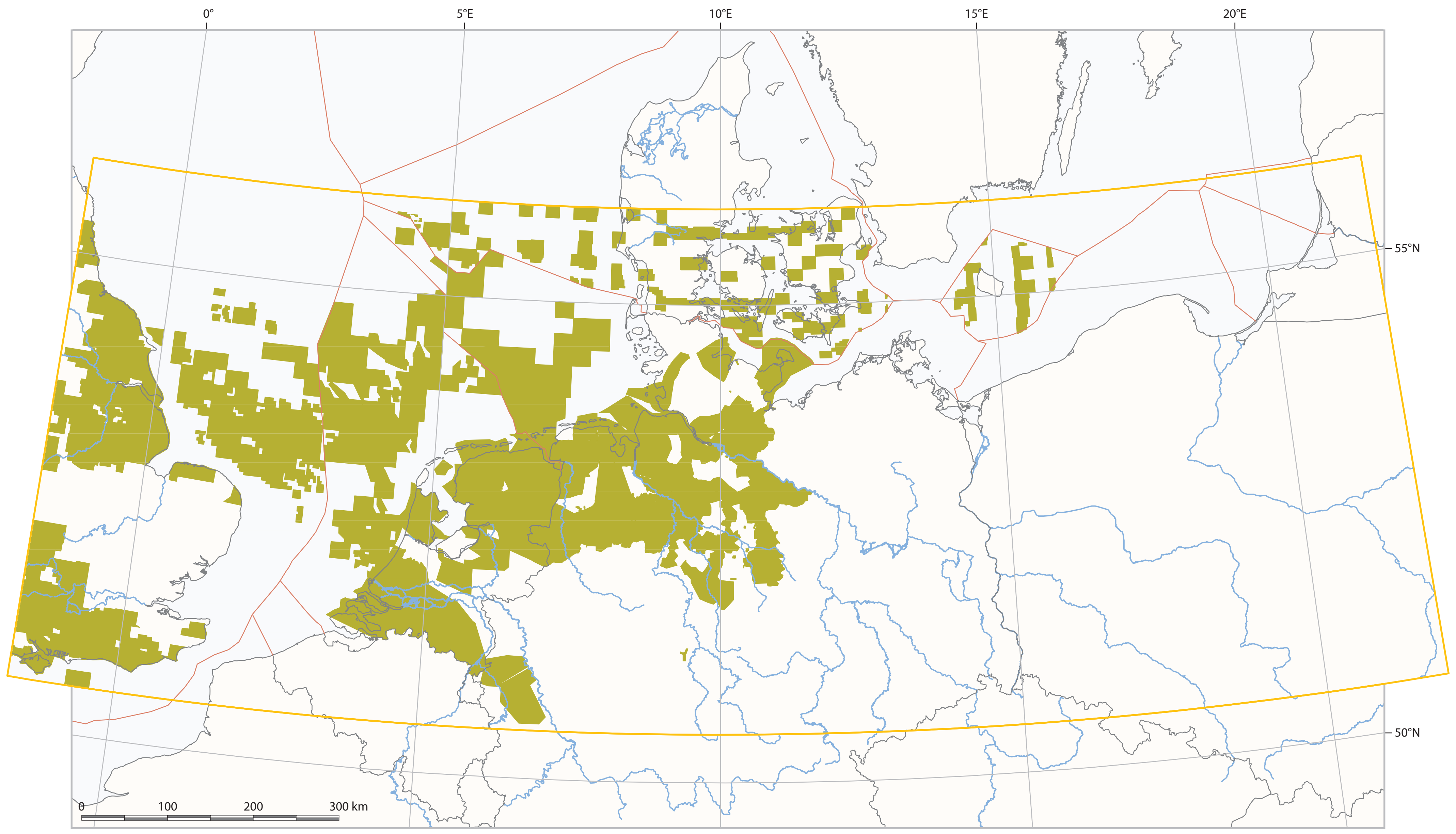


Figure 14.2d Licensed acreage at 1 January 1985. Note that there was no licensing in Poland before 1993.

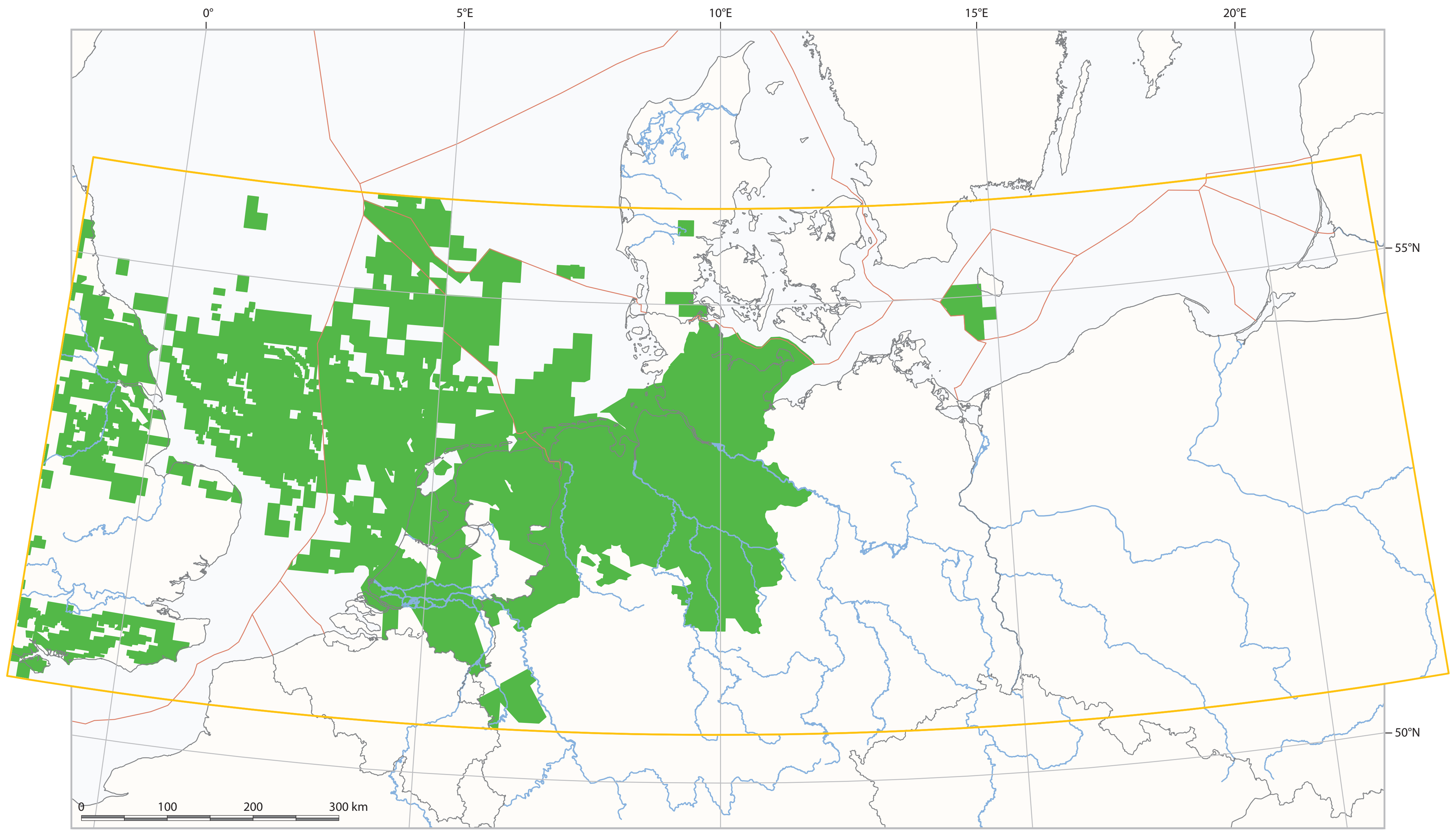


Figure 14.2e   Licensed acreage at 1 January 1990. Note that there was no licensing in Poland before 1993.

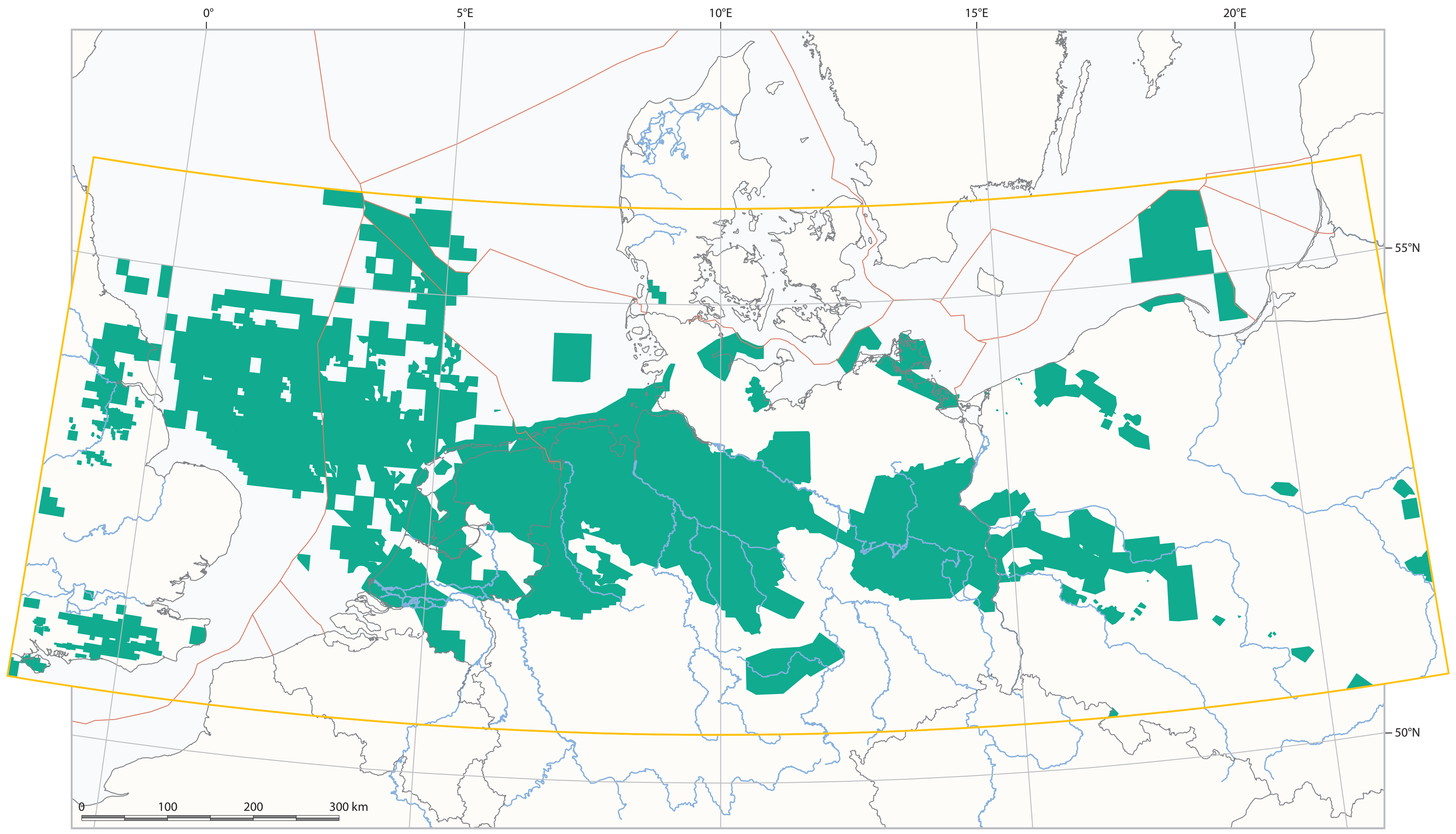


Figure 14.2f   Licensed acreage at 1 January 1995.

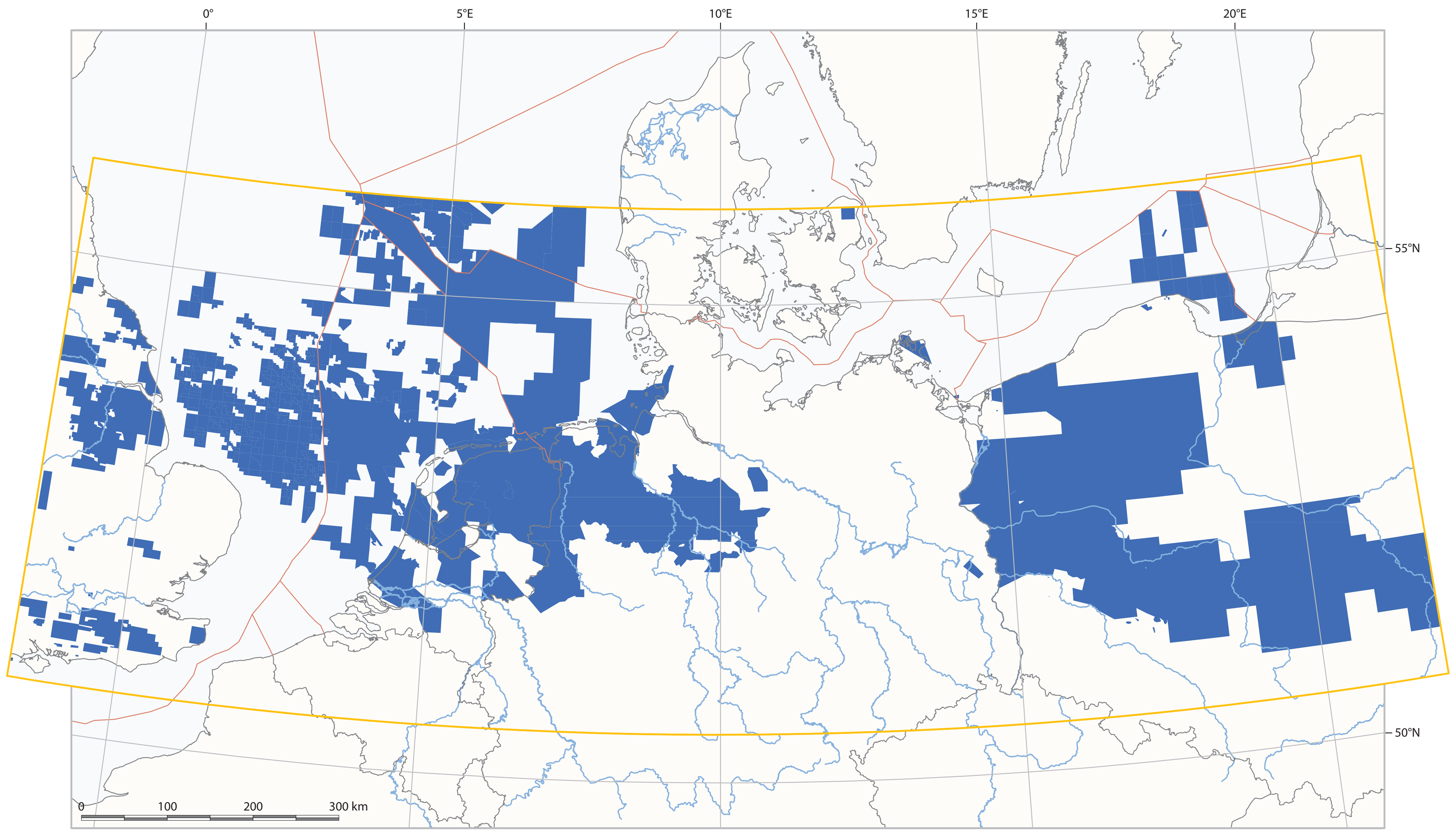


Figure 14.2g   Licensed acreage at 1 January 2000.

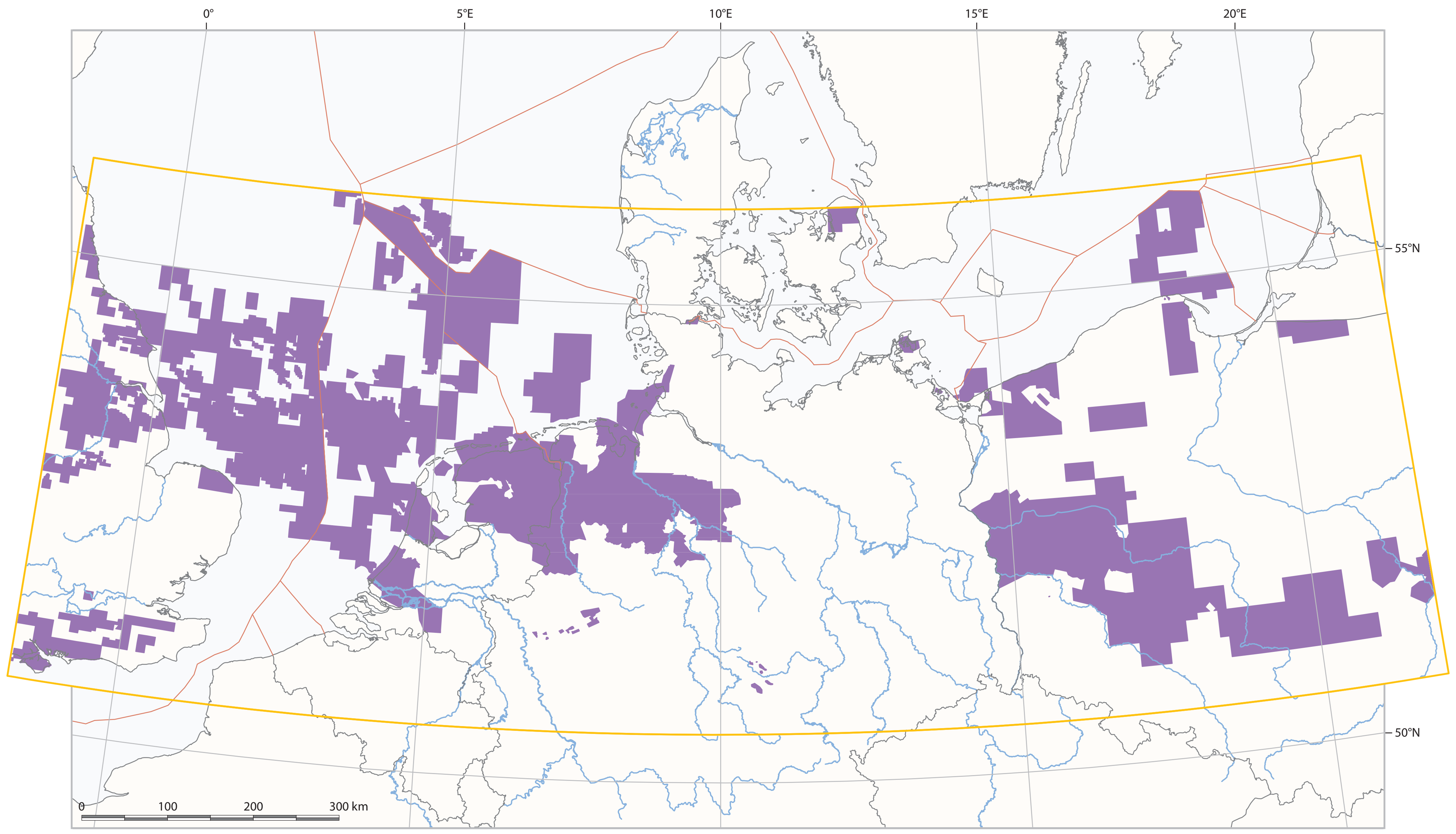


Figure 14.2h   Licensed acreage at 1 January 2005.

Article 9 states that each Member State shall publish and communicate to the Commission an annual report "which shall include information on the geographical areas that have been opened for prospecting, exploration and production, authorisations granted, entities holding authorisations and the composition thereof and the estimated reserves contained in its territory". However, this provision does not imply any obligation for Member States to publish information of a commercially confidential nature.

Figures 14.2b-h show the licence positions on 1st January 1970, 1980, 1985, 1990, 1995, 2000 and 2005. **Figure 14.3** depicts the distribution of licensed acreage on 1st January 2006, colour-coded for the countries that have held licence rounds, and **Figure 14.4** shows the years in which offshore rounds have been held.

2.1 Legislation, licensing and fiscal regime in the United Kingdom

Legislation and licensing information is available on the DECC (Department of Energy and Climate Change) website www.decc.gov.uk, and UKCS tax-regime details are found on the Energy Group of HM Revenue & Customs website at www.hmrc.gov.uk/oto.

2.1.1 UK legislation

The Petroleum (Production) Act 1934 (now consolidated in the Petroleum Act 1998) vested ownership in the Crown of petroleum (oil and gas) within the UK and its territorial sea. It also gave the Government powers to grant licences to explore for and exploit these resources.

Before 1996, the Department of Trade and Industry (DTI) issued a sequence of separate licences for each stage of an onshore field's life: an Exploration Licence, an Appraisal Licence, a Development Licence and a Production Licence. Petroleum Exploration and Development Licences (PEDLs) were introduced at the 8th Licensing Round to reduce the bureaucratic burden of issuing a series of licences.

For the offshore UK Continental Shelf (UKCS), the DECC issues a Production Licence that permits the holder to search, drill for and extract ('search, bore for, and get') any petroleum found in a specified area. In recent years, licences have been issued with variations of the 'Traditional' Production Licence: the 'Promote' Licence, the 'Frontier' Licence (but not in the SPBA area) and licences specially drafted to cover the redevelopment of a decommissioned field. Production Licences have usually been awarded through Licensing Rounds and their duration has varied from round to round. Recently, licensees wishing to progress developments have been able to apply for specific blocks 'Out-of-Round'.

The Exploration Licence allows exploration work (including the acquisition of seismic data), other than deep (greater than 350 m) drilling, in all areas of the UKCS that are not covered by a Production Licence. Exploration Licences may be obtained at any time and are valid for 3 years.

2.1.2 UK licence offers and criteria for awards

The first UK Licence Round took place in 1964 when a large part of the UK within the SPB area was licensed. More than 50 of those first 342 licences awarded are still extant, and no subsequent round has seen such a large number of blocks awarded (**Figure 14.5a**).

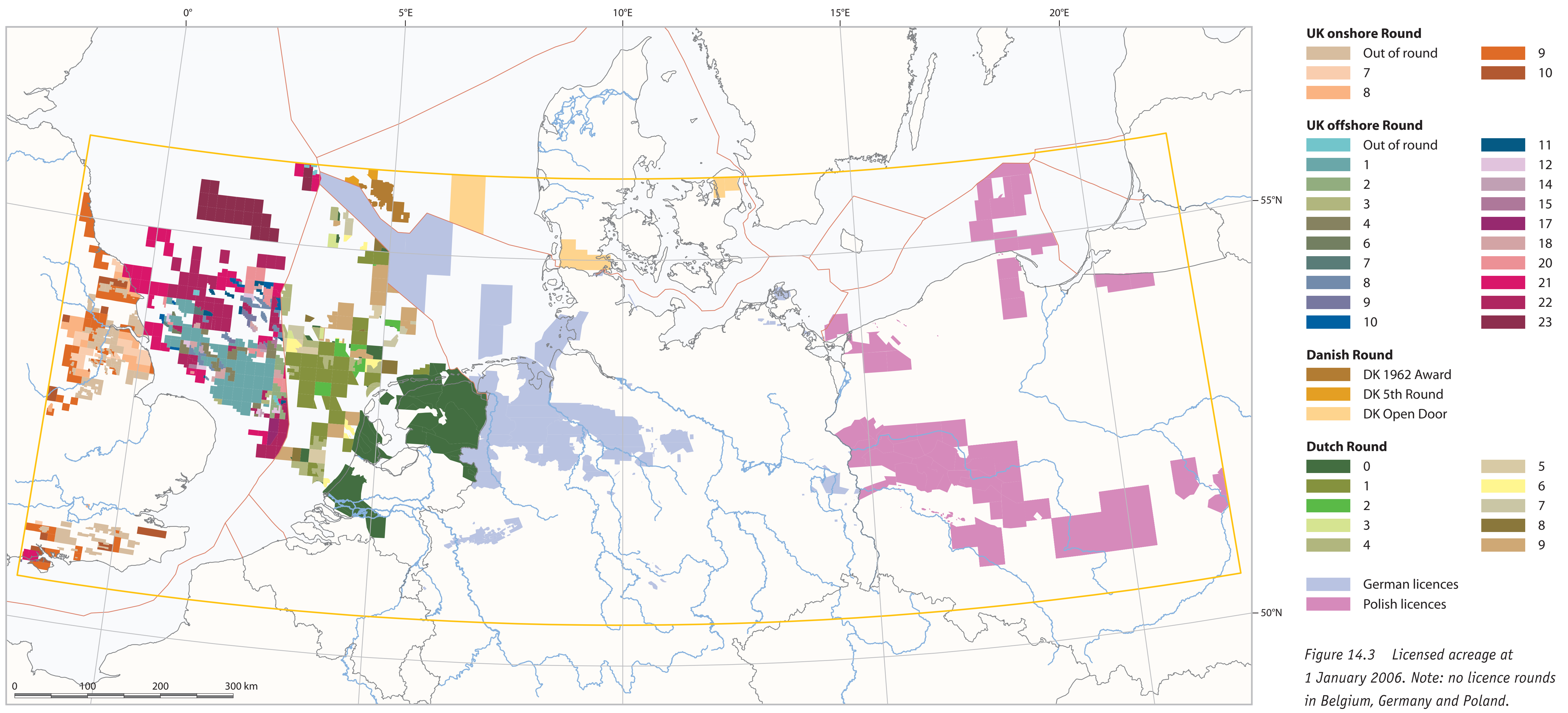


Figure 14.3 Licensed acreage at 1 January 2006. Note: no licence rounds in Belgium, Germany and Poland.

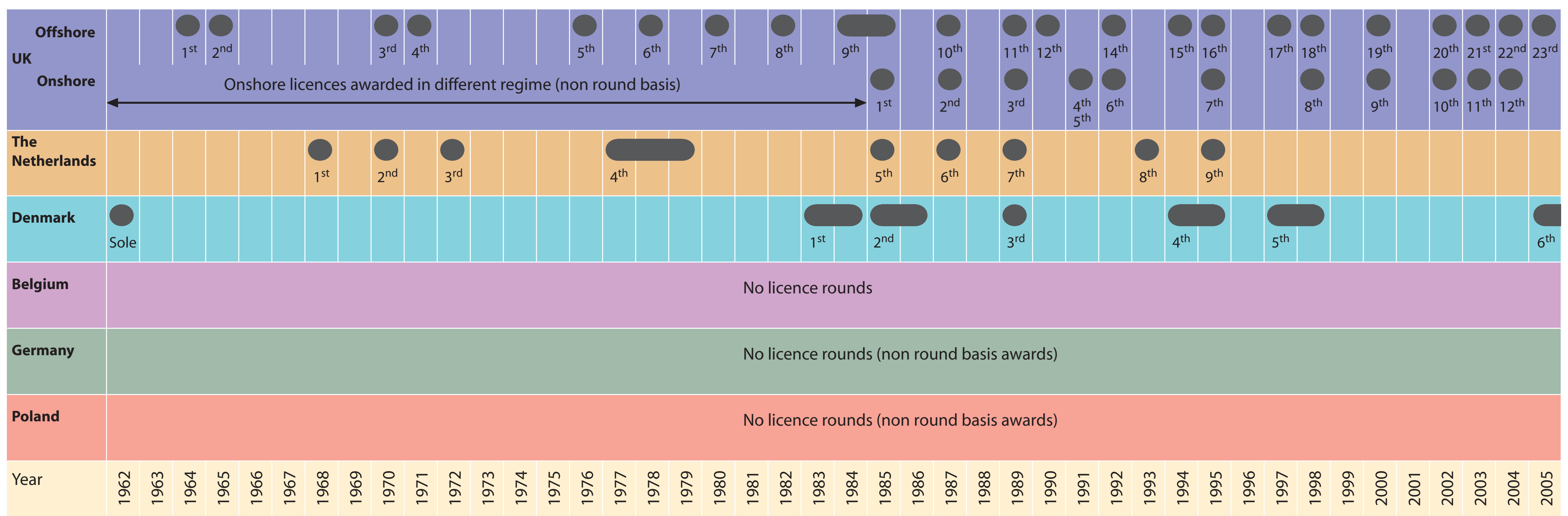


Figure 14.4 Licence round chronology.

Table 14.1 United Kingdom offshore licensing rounds 1964 to 2005.

Round	Year	All blocks applied for	Atlas area blocks awarded	Atlas area blocks still licensed	Cash bids / premiums (£ million)	Licence duration (years)	Next relinquishment date[4]
1st	1964	394	342	51		6 + 40	Licence expiry 2010
2nd	1965	127	55	8		6 + 40	Licence expiry 2011
3rd	1970	117	20	3		6 + 40	Licence expiry 2016-2017
4th [1]	1971-1972	271 + 15	61	14	37	6 + 40	Licence expiry 2017-2018
5th	1976-1977	51	3	0		4 + 3 + 30	Licence expiry 2014-2016
6th	1978-1979	46	9	4		4 + 3 + 30	Licence expiry 2016-2017
7th [2]	1980-1981	97	14	3	210	6 + 30	Licence expiry 2016-2017
8th [1]	1982-1983	76 + 8	97	18	32	6 + 30	Licence expiry 2019
9th [1]	1984-1985	107 + 13	54	7	121	6 + 30	Licence expiry 2021
10th	1987	61	35	7		6 + 30	Licence expiry 2023
11th	1989	115	63	9		6 + 12 + 18[3]	Licence expiry 2025
12th	1990-1991	116	74	9		6 + 12 + 18[3]	Licence expiry 2027
Frontier	1991	66	0	0		6 + 12 + 18[3]	2nd term ends 2015
14th	1992-1993	128	36	4		6 + 12 + 18[3]	2nd term ends 2011
15th	1994	34	23	3		6 + 12 + 18[3]	2nd term ends 2012
16th	1995	26 + 56	10	0		6 + 12 + 18[3]	2nd term ends 2013
17th	1997	127	10	2		3 + 6 + 15 + 24[3]	2nd term ends 2021
18th	1998	82	23	9		6 + 12 + 18[3]	2nd term ends 2016
19th	2000	12	0	0		6 + 12 + 18[3]	2nd term ends 2019
20th	2002	36	15	12		4 + 4 + 18	2nd term ends 2010
21st	2003	139	50	39		4 + 4 + 18[5]	2nd term ends 2011
22nd	2004	164	55	53		4 + 4 + 18[5]	2nd term ends 2012
23rd	2005	280	93	93		4 + 4 + 18[5]	2nd term ends 2013
Totals		**2764**	**1142**	**348**			

1 15 Blocks offered on cash bid basis.
2 Blocks in certain areas not specified in offer but open to application on payment of a premium fee of £5 million.
3 Licence continues into final period only if development approval is imminent.
4 No interim relinquishment requirements in Rounds 1-4. Thereafter usually 50% relinquishment after initial term, but sliding scale according to number of wells drilled applies to frontier acreage awarded in Rounds 12F and 17.
5 Traditional and Promote licenses have a four-year primary term, but the Promote Licenses are given only two years after award to attract the technical, environmental and financial capacity to complete an agreed Work Programme, or blocks are relinquished.

The UK criteria for awards have always been based on the exploration rationale and programme of work offered by the applicant and their ability and resources to carry it out. However, before the 16th and subsequent rounds, when the criteria were revised to take account of Directive 94/22/EC, there were also reciprocal treatment criteria, when the applicant was foreign-owned, as to how far British oil companies received equitable treatment in their country. Cash bids were also accepted in the 3rd, 4th and 8th Rounds.

Since the 19th Round, detailed geoscientific criteria and guidance notes for applicants have been announced with the round on the DECC website. Licences are usually awarded to those companies that meet the environmental, financial and technical capability threshold criteria and offer optimum work programmes to establish the prospectivity of the areas applied for. However, the UK licensing regime is discretionary: the Minister may grant licences to such persons as he thinks fit, provided that those persons have complied with regulations prescribing how applications for licences may be made.

Summaries of new licensing, exploration and development activity, as well as production data and reserve estimates, have been submitted to Parliament and were published annually between 1973 and 2000 in a report entitled 'Development of the Oil and Gas Resources of the United Kingdom' – colloquially known as the 'Brown Book'. This information is no longer compiled in a report, but is available on the DECC website.

Since 2002, the amount of acreage with no activity has become a matter of concern and has led PILOT (formerly the Oil & Gas Industry Task Force) to instigate the Fallow Initiative. The UK industry voluntarily agreed that blocks and undeveloped discoveries that are 3 years outside of their primary licence term with no activity are 'fallow' and must have significant activity or be relinquished. A list of identified fallow assets and detailed description of the process is also available on the DECC website.

2.1.3 UK fiscal regime and taxation

Successive British Governments have aimed to develop a fiscal regime that encourages exploration and development while at the same time ensuring that the nation as a whole receives an appropriate share of the benefits from its oil and gas. The UK tax regime has been kept under continuous review and minor adjustments have been made almost every year. Before 1975 there were two elements to the North Sea fiscal regime: Royalty, charged at 12.5% of the wellhead value of gross production less conveying and treating costs, and Corporation Tax at 50% of a company's taxable profits. However, it became apparent in the early 1970s that a fiscal regime based on only these elements would not achieve a Government income comparable with that being obtained by other oil-producing countries.

Consequently, the 1975 Oil Taxation Act introduced two new elements. First, the Petroleum Revenue Tax (PRT) was brought in to tax a high proportion of the economic rent, or 'super-profits', from the exploitation of the UK's oil and gas resources. PRT is charged on the profits arising from individual oilfields, not on the aggregate profits from all the oilfields owned by a particular company. The rate was initially set at 45%, but with a number of reliefs designed to ensure that it did not have a damaging effect on smaller or more marginal fields. Second, for Corporation Tax purposes, a 'ring fence' was built around any company's North Sea trade, which meant that losses from abroad, or from other activities, could no longer be set against profits from North Sea oil or gas production in order to reduce tax liability. Further rises in the oil price after 1975 were accompanied by increases in the rate of PRT to 60% in 1979 and 70% in 1982, while some PRT allowances were reduced or restricted. In addition, a fourth tier of tax, a 20% Supplementary Petroleum Duty, was levied for 1981 and 1982.

By the early 1980s, there was a significant decline in the number of new projects being brought forward by the oil industry. As a result, the PRT regime was changed in 1983 to allow new exploration and appraisal costs to be set against existing field profits, and the PRT oil allowance for new oilfields outside the southern North Sea was doubled. Also in 1983, a new Oil Taxation Act addressed the tax issues arising from the development of infrastructure in the North Sea and the growth in the sharing of assets, such as pipelines, between two or more fields. Income and capital sums received for the use or sale of North Sea assets were brought within the scope of PRT and changes were made to allow immediate PRT relief for the costs of most assets, even if they were to be used in more than one field. These changes resulted in increased interest in developing North Sea fields, and in a boost to exploration and appraisal activity.

By the early 1990s, PRT-paying fields faced a high marginal tax rate, providing an incentive for companies to shift income into fields that did not pay PRT and expenditure into PRT-paying fields. With a high level of immediate tax relief available in PRT-paying fields, there was little incentive for companies to control costs in those fields. As the North Sea matured, the average size of new fields was declining, with few expected to pay PRT. The combination of low oil price and the new PRT regime resulted in low yields from the tax, and in 1991/92 the yield was actually negative.

In 1993, the Government therefore reduced the PRT rate from 75% to 50% for existing fields and abolished the tax for fields given development consent on or after 16th March 1993. The rules that allowed 100% of expenditure on new exploration and appraisal to be set against profits of existing fields were also abolished. These changes increased the yield from PRT and were also designed to encourage further development of North Sea oil and gas resources by ensuring that companies bore more of the risks of their developments, although they were also allowed a greater share of the rewards.

A number of changes were introduced in the period 2002-2005 in response to the significant sustained increase in oil prices. As a consequence of these changes, the fiscal regime that currently applies to oil and gas exploration and extraction from the UK and the UKCS consists of three elements:

Ring Fence Corporation Tax
With some important modifications (e.g. relating to capital allowances and losses), this is the standard corporation tax applicable to all companies, with the addition of a 'ring fence' and 100% first year allowances for almost all capital expenditure. The ring fence prevents taxable profits from oil and gas extraction in the UK and UKCS being reduced by losses from other activities, or by excessive interest payments, by treating ring-fenced activities as a separate trade. The current rate of Corporation Tax is 30%.

Supplementary charge
This is an additional charge of 20% (10% prior to 1st January 2006) on a company's ring-fence profits excluding finance costs. The supplementary charge was introduced on 17th April 2002.

Petroleum Revenue Tax (PRT)
This is a special tax on oil and gas production from the UK and UKCS (see above). It is a field-based tax charged on profits arising from individual oilfields. PRT is deductible as an expense against Corporation Tax and the supplementary charge. From 1st January 2006, the marginal tax rate on new fields is 50% whereas the marginal tax rate on fields paying PRT is 75%.

A Ring Fence Expenditure Supplement (RFES) assists companies that do not yet have any taxable income for Corporation Tax or the supplementary charge against which to set their exploration, appraisal and development costs and capital allowances. The RFES increases the value of unused expenditure carried forward from one period to the next by a compound 6% a year for a maximum of 6 years. It applies to all unrelieved expenditure from 1st January 2006. The State does not participate in exploration or development in the UK.

2.2 Legislation, licensing and fiscal regime in Belgium

Information is available for the Belgian offshore from the Federal Ministry of Economy, Quality and Security Division, Plateau Continental Service, North Gate III, Bd. du Roi Albert II 16, B-1000 Brussels. For the onshore part of the SPBA area in Belgium (Campine Basin) contact the Flemish Dept. Environment, Nature and Energy 'LNE-ALBON', Koning Albert II-Laan 20 bus 20, B1000 Brussels.

2.2.1 Belgian legislation and licensing

Exploration and exploitation in Belgium was regulated by the Royal Decree No. 83 in 1939 "relating to search and the exploitation of bituminous rocks, oil and gas" and modified by the Decree of the Regent in 1948. As a result of the change to a Federal State, the regions of Flanders, Wallonia and Brussels-Capital are now the authorities in charge of licensing. As the Belgian part of the SPBA is in Flemish territory, the Decree of the Flemish Government, dated 23rd July 1997, "regulating the form and the methods of the examination of the requests for obtaining a licence for the prospecting and the exploitation of oil and gas" should apply; however, the decree is currently in revision. The Royal Decree of 1939 remains the constitutional base for the Belgian offshore sector.

2.2.2 Belgian fiscal regime

No fiscal regime has been established to date as there has been no oil or gas production in Belgium, apart from some coal-mine gas and attempts to extract oil from bituminous shales in the Jurassic of the Paris Basin.

2.3 Legislation, licensing and fiscal regime in the Netherlands

Further information is available from the NL Oil and Gas Portal www.nlog.nl.

2.3.1 Dutch legislation and licensing

The history of Dutch mining legislation started with the founding of the Kingdom of the Netherlands in 1813 when the French Mines Act of 21st April 1810 was brought under Dutch legislation. This French act, called 'Loi concernant les Mines, les Minières et les Carrières' (Bulletin des Lois, no. 285) was already in use in the parts of the Netherlands that belonged to France. In the Mines Act of 1903 there were some applications on the act of 1810. In 1918, both Mines Acts were used for the production of salt and, after 1948, for hydrocarbons. These acts could only be used in case of activities on land, such as the Groningen concession of 1963 concerning the Dutch Slochteren gasfield. As the mining industry became interested in activities offshore in the North Sea, a special act, The Continental Shelf Mining Act 1965, was introduced in 1965 to cover that specific case. This mining act was more modern than the older acts that regulated activities on land, and in 1995, when Directive 94/22/EC guidelines were implemented, the Government took measures to prepare a central mining act for both onshore and offshore activities. There have been nine Licence Rounds in the Netherlands since they started in 1968 (**Figure 14.5b**).

The new Mining Act, Mining Decree and Mining Regulation became effective as of 1st January 2003 and set out a clear framework for mining activities, replacing the very diverse acts that related to different mining activities. The main elements of the act have been elaborated in the Mining Decree (Mijnbouwbesluit) and the Mining Regulation (Mijnbouwregeling). This concerns the mining activities *sensu stricto*, e.g. reconnaissance, exploration, development of (natural) resources and geothermal energy and storage of substances, as well as complimentary elements such as working plans, removal plans for offshore platforms and subsidence monitoring. The Working Conditions Act of 1st January 2003 regulates health and safety in mining activities. Since 2003, approved field development plans (Winningplan) have been required for all fields.

Table 14.2 Dutch licensing rounds.

Round	Year	Licence duration (years)
1st	1968	10 + 5
2nd	1970	10 + 5
3rd	1972	10 + 5
4th	1977-1979	6 + 4
5th	1985	6 + 4
6th	1987	6 + 4
7th	1989	6 + 4
8th	1993	6 + 4
9th	>1995	WP dependent

Licences for exploration and production of mineral and geothermal resources require an appropriate licence from the Dutch Minister of Economic Affairs. There are Exploration Licences for drilling and two kinds of Production Licenses; one used for application by the holder of the exploration licence and the other in the case of an open area.

Exploration Licences
The procedure for applying for an Exploration Licence is outlined in Chapter 2 of the Mining Act (Articles 14-17) and detailed in Chapter 1 of the Mining Regulations. Section 1.3 and Appendices 1 and 2 of the Mining Regulations contain a summary of the information that must be provided with a licence application.

An application for an Exploration Licence for an open area can be submitted to the Ministry of Economic Affairs at any time. Once the application is received, an invitation for counter-applications is placed in the Official Journal of the European Union (OJEU) (only in cases of hydrocarbon exploration) and in the Staatscourant, the Dutch Government Gazette (Article 15 of the Mining Act). Interested parties have 13 weeks from the date of publication in the OJEU and/or Staatscourant to submit a competitive application. Once the 13 weeks have passed, the Ministry of Economic Affairs solicits the advice of TNO Built Environment and Geosciences, Energie Beheer Nederland (EBN), the State Supervisor of Mines and, if the area for which a permit is being requested falls under the dominion of a provincial government, the Provincial Executive (GS) of the province in question. If possible, they issue their recommendations for the application within 6 weeks of the end of the period for submitting counter-applications. The Minister of Economic Affairs then seeks the advice of the Mining Advisory Council (Article 105, third paragraph, of the Mining Act) with regard to the permit that has been requested. The council meets once every 2 to 3 months.

In accordance with the provisions in Article 17 of the Mining Act, the Minister of Economic Affairs must issue a decision on the application for an Exploration Licence no later than 6 months after the period for submitting counter-applications has ended. The Minister can extend the decision-making period one time, but by no longer than 6 months. The decision to issue the exploration permit is announced in the Staatscourant (Article 17 of the Mining Act). If the decision is not contested, the permit becomes irrevocable after 6 weeks.

Production Licences
For the holder of an Exploration Licence, the procedure for applying for a Production Licence is outlined in Chapter 2 of the Mining Act (Articles 14-17, in particular) and Chapter 1 of the Mining Regulations. Section 1.3 and Appendices 1 and 2 of the Mining Regulations contain a summary of the information that must be provided with a permit application. If the applicant already holds an exploration permit, counter-applications are not accepted. As part of the application, the applicant must be able to demonstrate that the mineral or geothermal resources found in the permit area are economically viable.

An application for a Production Licence for an open area (called a 'spontaneous' Production Licence) can be submitted to the Ministry of Economic Affairs at any time. The procedure is the same as that for Exploration Licences. An abbreviated procedure applies in cases when the application for a spontaneous Production Licence concerns an overlapping section of a proven field that was identified in an Exploration or Production Licence.

2.3.2 Dutch fiscal regime and taxation

The Mining Act came into effect on 1st January 2003. It details the taxes and fees on exploration and production of hydrocarbons, as well as the mandatory financial State participation in production.

2.3.2.1 Corporation Tax and Royalty (*Vennootschapsbelasting and Winstaandeel*)

Companies pay regular Corporation Tax. The standard rate has decreased from 29.6% to 25.5% with effect from 2007. The holder (or all co-holders) of a Production License pays Royalty based on the profit as reported in the profit and loss account of activities attributable to the licence. The licensee can prepare a consolidated profit and loss account for their licences.

Royalty is basically 50% of the profit, i.e. income minus costs, but there are two additional factors that lower the Royalty:
1. In calculating the profit, an extra 10% of the costs can be deducted, the so-called cost uplift.
2. Corporation Tax can be fully deducted from Royalty.

This results in the following equation:

Royalty = 50% of (income – costs – 10% of the costs) – Corporation Tax

The Royalty owed serves in turn as a deduction from the Corporation Tax. The extra cost allowance of 10% does not apply to the Corporation Tax. Therefore, in formula:

Corporation Tax = 25.5% of (income – costs – Royalty)

As Corporation Tax and Royalty depend upon each other, they can only be calculated in combination. If the profit margin is under 16.95%, only Corporation Tax is due (25.5%); above that, the percentage of Corporation Tax and Royalty gradually increase together. For example, at a profit margin of 30%, 38% of profits are due in Corporation Tax and Royalties combined.

*Area Fee (*Oppervlakterecht*)*
The owner of any Production Licence pays an annual Area Fee. The rate is €26 per km^2. The holder of an offshore Exploration Licence also pays an Area Fee. This is the only taxation for an Exploration Licence. The rates vary according to the duration of the permit: 1 to 6 calendar years = €209 per km^2; 7 to 9 calendar years = €418 per km^2; 9 or more calendar years = €626 per km^2.

*Severance Tax (*Cijns*)*
The Severance Tax only applies to onshore licences. It is a fee on the turnover generated by a Production Licence. The turnover is determined by production volume (excluding volume used during exploration/ production for processing and transport) and selling price. The rate is determined according to the following volume brackets:

Amount of gas (in 10^6 m^3) or oil (in 10^6 m^3) produced	Tax rate
0-200	0%
200-600	2%
600-1200	3%
1200-2000	4%
2000-4000	5%
4000-8000	6%
>8000	7%

Example: If 1 billion (1000 × 10^6) m^3 gas is produced, the percentage in Severance Tax owed is (600-200) × 2 + (1000-600) × 3 = 2.5%. At a selling price of for example €0.20 per m^3, the fees are €5 million.

The Severance Tax rate is increased by 25% if the average cost for crude oil imported into the Netherlands in a year rises above €25 per barrel.

*Fees to the province (*Afdracht aan de provincie*)*
A production licensee producing hydrocarbons in an area under the dominion of a province pays a one-time fee to the province. The basis for the fee is the size of the area involved. The rate for 2003 was €4.50 per m^2 and it is index-linked.

2.3.3 Dutch State participation

The Minister of Economic Affairs may designate a company in a Production Licence granted by the Minister to participate on behalf of the State in the exploration and production of hydrocarbons. In practice, the state-owned company Energie Beheer Nederland B.V. (EBN) is designated. Participation applies to all Production Licenses, both onshore and offshore. EBN can also participate in offshore Exploration Licences at the request of the licensee. This option is not available for Exploration Licenses on land. In addition to these activities under the Mining Act, EBN is as partner in six offshore pipelines and three gas-storage facilities and has a 40% interest in Gasterra, the gas-trading company.

2.3.4 EBN participation in exploration activities

Under the Mining Act, a company needs an Exploration Licence for any hydrocarbon exploration. The Mining Act determines that EBN may participate in offshore exploration activities at the request of the licensee. A detailed Co-operation Agreement between the licensee and EBN is made and needs Ministerial approval. The EBN interest is always 40%. EBN is not a licensee and will not carry out exploration activities on its own initiative, nor will it act as the principal; however it does hold the same yield and risk position as the licensee. Such State participation in Exploration Licences lowers the financial risk for exploration drilling.

2.3.5 EBN participation in production activities

If an Exploration Licence leads to economically feasible discovery, the licensee may apply for a Production Licence. The Mining Act determines that the State can designate a company (always EBN) to participate in the mining activities under this Production Licence. Similar to exploration, the EBN interest is 40%. Participation is laid down in a Co-operation Agreement between EBN and the licensee. The agreement requires the approval of the Minister. EBN participation in production is standard. The Minister can only waive this participation if production seems financially disadvantageous to the State, or if the risks involved seem too high.

If EBN has not participated in the exploration preceding the Production Licence, the agreement states that EBN pays the licensee 40% of the costs incurred in discovery of the hydrocarbons, their further exploration and the further investments for mining activity, referred to as the reimbursement.

A Production Licence (in which EBN usually participates) allows further exploration in the licence area. EBN participates automatically if a licensee carries out such further exploration.

2.4 Legislation, licensing and fiscal regime in Denmark

Current detailed information is available on the Danish Energy Agency website www.ens.dk.

2.4.1 Danish legislation and licensing

Since the Act of 1932 on Exploration and Production of Resources in the subsoil of the Kingdom of Denmark, such resources have belonged to the Danish State, and the Government has had the right to grant licences. These principles have been maintained in subsequent legislation on the subsoil; cf. Consolidated Act No. 889 of 4th July 2007 on the use of the Danish Subsoil.

Danish licensing started in 1935, when DAPCo (Danish American Prospecting Company) was granted a licence to the entire onshore area. The licence was initially managed by the American F.F. Ravlin. In 1938, DAPCo was taken over by Gulf Oil and by Standard Oil in 1957 until the licence was surrendered in 1959.

Exploration in the Danish North Sea started in 1962 when the Government granted a 50-year Sole Concession for the entire offshore and onshore area to the company of ship owner A.P. Møller. As it had no experience with oil exploration, the company formed a business relationship, the Danish Underground Consortium (DUC), with the Gulf Oil Company. Today the DUC consists of A.P. Møller-Mærsk, Shell and Chevron.

The conditions of the Sole Concession have been amended by subsequent agreements between the Danish Government and A.P. Møller. An agreement in 1981 led to the gradual relinquishment during 1982-1986 of most of the Sole Concession area except for the 'Contiguous Area' that contains many of the important Danish chalk fields, and a number of other fields outside the Contiguous Area.

According to the provisions in the Sole Concession the Danish Government was obliged to enter into negotiations for possible continuation of the activities after the concession expires in 2012. As a result, an agreement between the Government and A.P. Møller-Mærsk was reached in 2003, extending the concession until 2042. The agreement included amongst other things provisions on a 20% profit sharing with the State from 2004, subsequently to be replaced by a 20% State participation in the DUC from 2012.

The areas relinquished from the A.P. Møller Sole Concession since 1981 formed the basis for subsequent Danish licensing rounds starting with the 1st Round in 1983/84. Since the 1st Round, licences for 'Exploration of and Production of Hydrocarbons' have been granted with an initial exploration term of 6 years. The Danish Energy Agency may extend the term of a licence for exploration by up to 2 years at a time, provided that there are special circumstances.

A licensee, who has made a discovery and carried out the appraisal work necessary to file a declaration of commerciality, has the right to be granted a 30-year extension, with the purpose of production, to the field-delineated part of the licence.

The annual report published by the Danish Energy Agency, 'Oil and Gas Production in Denmark', is available on their website and summarises licensing and other activities.

2.4.2 Danish licence offers and criteria for awards

Since 1983, open areas have been offered to interested oil companies in a system of licensing rounds. Six rounds have been held with intervals dependent on the results from the previous round, availability of open acreage, and the interest among the companies. The 6th Round was held in 2005/2006. Since 1996, the licensing rounds have comprised only the open areas west of 6°15'E and an Open Door procedure has applied to areas east of this longitude. The eastern areas include the onshore area, the inner Danish waters and the eastern part of the Danish North Sea. Applications are considered in the order they are received.

Selection criteria in both the licensing round area and the Open Door area require that the applicant has the requisite expertise and capital base, and that the proposed work programme and attendant documentation demonstrate the applicant's willingness and ability to explore thoroughly for hydrocarbons in the area comprised by the application.

2.4.3 Danish fiscal regime and taxation

Danish legislation aims to achieve a reasonable share of benefits from exploitation of oil and gas on the Danish Continental Shelf, while at the same time encouraging companies to continue exploration and development efforts in mature as well as frontier areas.

The current (2007) Danish fiscal terms include:

Corporate Income Tax
Corporate Income Tax is the most important source of State revenue related to oil and gas. The tax rate is 25%, the tax payment being deductible from the Hydrocarbon Tax base.

Hydrocarbon Tax
This tax was introduced in 1982 with the aim of taxing windfall profits, for example due to high oil prices. With effect from 1st January 2004, the Hydrocarbon Tax Act was amended in respect of the Sole Concession and licences granted after 1st January 2004. The tax rate was reduced from 70% to the current 52%, and the allowances were changed from 25% over 10 years to the current 5% over 6 years. Special provisions apply for investments made before 2004.

Royalty
Only a few of the older licences include a condition regarding the payment of Royalty, which is payable on the basis of the value of hydrocarbons produced after deducting transportation costs.

Oil pipeline tariff / compensatory fee
Licensees in the Danish part of the North Sea are obliged to connect to and to transport crude through the oil pipeline from the Gorm field onshore to Fredericia (see Figure 16.32). Apart from contributing to capital costs and operating costs, the users pay a fee that includes a profit element of 5% of the value of the crude transported. Any parties granted an exemption from the obligation to use the oil pipeline are required to pay the State a fee amounting to 5% of the value of the crude comprised by the exemption.

For licences granted after 1st January 2004, and for the Sole Concession, the 5% oil pipeline tariff / compensatory fee is to be paid until 8th July 2012, after which no tariff/fee is payable.

2.4.4 Danish State participation

Whereas in the earlier licensing rounds State participation was carried, a fully paying State interest of 20% has been applied in all licences granted in the 4th and later rounds.

State participation has been exercised by the national oil company (DONG) in licences granted between 1984 and 2004. Following the Danish Parliament's decision to privatise DONG in 2004, State participation was reorganised in 2005 when the Danish North Sea Fund (Nordsøfonden) was set up to take responsibility for the State's 20% participation in future hydrocarbon licences. The Nordsøfonden will also be responsible for the State participation in DUC from 2012. The Nordsøfonden is independent and will defray costs and receive income from the new licences. The Danish North Sea Partner (Nordsøenheden), an entity under the Ministry of Transport and Energy, was also set up in 2005 to administer the Nordsøfonden.

2.5 Legislation, licensing and fiscal regime in Germany

The legislation, licensing and fiscal regime in Germany are the responsibility of the local State Authorities for Mining of the Federal States. Further information about the regions within the SPBA area can be found on the following websites:

- www.lbeg.niedersachsen.de for Lower Saxony, Hamburg, Bremen and Schleswig-Holstein.
- www.bezreg-arnsberg.nrw.de/bergbau-und-energie for Nordrhein-Westfalen.
- www.bergamt-mv.de for Mecklenburg-Vorpommern.
- www.mw.sachsen-anhalt.de/gla for Sachsen-Anhalt.
- www.lbgr.brandenburg.de for Brandenburg and Berlin.
- www.rp-darmstadt.hessen.de for Hessen.
- www.tlba.de for Thüringen.
- www.bergbehoerde.sachsen.de for Sachsen.

2.5.1 German legislation and licensing

There is a long tradition in Germany concerning the right to explore and produce minerals. The oldest known legal basis can be found in the so-called 'Ronkalische Konstitution' from Emperor Friedrich Barbarossa dating from 1158. During the next 700 years, the mining rights were held by the local sovereign. A new Mining Law was issued in 1865 and the sovereign lost his nearly exclusive rights concerning mineral resources, allowing anyone to explore for or produce minerals. However, this changed in 1900 when licences for important minerals (such as coal or potash) could only be issued by the State.

Hydrocarbon licensing falls under the Mining Law passed in 1865, but after World War II the jurisdiction in minerals matters was decentralised to the eleven States in western Germany and centralised to the Government in Berlin in the eastern part.

In eastern Germany the most important minerals (salt, oil, gas or ore) were expropriated by the State in 1947, and only State companies or nationally owned enterprises had the right to explore and produce. The companies or enterprises carried out their work based on yearly targets that were specified by the State.

The exploration and production of hydrocarbons in Germany is today regulated under the Federal Mining Law of 1982. There are three different kinds of licences: 'Erlaubnis' (Permit), 'Bewilligung' (Concession) and 'Bergwerkseigentum'. A Permit is required for those planning to explore for hydrocarbons in an area without Concession status. A Concession must be granted to anyone producing hydrocarbons. Permit and Concession are the licences used predominantly in Germany. A 'Bergwerkseigentum' is similar to the Concession for producing hydrocarbons, but with other rights.

The licensing system in Germany is organised on a State rather than on a Federal level. Based on this, the responsible agency granting licences differs from State to State. More than 90% of Germany's gas and oil production is from the States of Lower Saxony and Schleswig-Holstein where the local State Authority for Mining, Energy and Geology in Hannover is responsible for granting licences.

There are no formal licensing rounds in Germany. Individuals, corporate bodies or commercial partnerships can apply for licences at any time. Within these applications the field proposed for exploration or envisaged for production must be specified, a work programme has to be proposed and evidence of financial resources must be provided. The application for a Concession also has to include information about the reservoir and a technical evaluation that demonstrates that the field can be developed.

The Permit for exploration covers an initial 5-year period with possible renewals of maximum 3-year duration. Every year the licence holder has to inform the relevant mining authority about their progress on the work programme. The Permit for exploration is revoked if, for reasons for which the licence holder is responsible, the exploration has not commenced within 1 year after the Permit was granted or if systematic exploration has been interrupted for more than 1 year.

The Concession for production is generally granted for a period that is determined by the applicant based on reservoir content, basic technical conditions and economic calculations. The term of 50 years may only be exceeded if it is considered to be indispensable because of the investments normally required to carry out the production activities. The Concession is revoked if production has not commenced within a term of 3 years after Concession was granted or if systematic production has been interrupted for more than 3 years. This will not apply as long as an efficient technical or economic plan makes it necessary to delay the commencement or resumption of production in the field or if interruption was caused by reasons beyond the control of the licence holder.

According to Article 9 of Directive 94/22/EC of the European Parliament and of the Council of 30th May 1994, Germany publishes an annual report with information on the conditions for granting and using authorisations for prospecting, exploring and producing hydrocarbons.

2.5.2 German fiscal regime and taxation

Royalties are determined at State, not Federal level. Based on the Federal Mining Law, the local Government can set the Royalty rate up to 40% based on the market value.

In 2005, the Royalty for gas and oil production from the only producing offshore field was set by the Government of Schleswig-Holstein to 10% for gas and 12.5% for oil or condensate. The same Government set the Royalty for oil and gas production from a nearshore field to 12.5%. In 2006, the Government of Lower Saxony set the Royalty rate for onshore gas production to 32% and 15% for onshore oil production.

Royalties are levied on the market value of oil and gas at the time of production. Royalty is calculated on a quarterly basis, payable 4 weeks after the preceding quarter. The licence holder is allowed to offset field-handling charges against Royalty payments. These comprise transport costs from well to treatment plant, preliminary treatments, and the disposal of waste water. There is no State participation in Germany.

2.6 Legislation, licensing and fiscal regime in Poland

Further information is available on the Department of Geology and Geological Concessions of the Polish Ministry of the Environment website www.mos.gov.pl/dgikg/english.

2.6.1 Polish legislation and licensing

Poland's Ministry of the Environment grants authorisation for prospecting and exploration of hydrocarbons. In 2006, a map was published in the Official Journal of the European Union (OJEU), and is available on the Department of Geology and Geological Concessions website, noting concession areas which are the result of obligatory tender and areas where concessions are granted without the tender process.

The obligatory tender areas are subject to the procedures provided for in Article 3(2) of Directive 94/22/EC, where a competent authority of Poland draws up a notice inviting applications, which are sent to the European Commission for publication in the OJEU. These specify the types of authorisation, geographical area(s) in part or all of which an application has been or may be made, and the date or time limit for the submission of applications. Interested parties are bound by the provisions of the Geological and Mining Law Act (Prawo geologiczne igórnicze) (2) of 4th February 1994 (Journal of Laws (Dziennik Ustaw) 2005, No 228, item 1947), the Regulation of the Council of Ministers of 21st July 2005 concerning the tender procedure for the acquisition of mining rights (Rozporządzenie Rady Ministrów w sprawie przetargu na nabycie prawa użytkowania górniczego) (3) (Journal of Laws No 135, item 1131) and the other legal acts specified in paragraph 4a.

The Ministry has also identified areas where mining is granted on a permanent basis with regard to authorisations for prospecting and exploration of hydrocarbons, according to Article 3(3) of Directive 94/22/EC.

Concessions are granted for areas with a total maximum acreage of 1200 km^2. The concession fee is based on the amount of acreage in the concession and type of mineral. For oil and gas exploration, the concession fee is 200 PLN/km^2 per year. In addition, a Mining Fee is paid as a result of mining activity concerning exploration and production. The fee is individually negotiable for every licence, but for exploration it is ≥200 PLN/km^2 per year.

2.6.2 Polish fiscal regime and taxation

Poland levies a fee on hydrocarbon production based on a percentage of the recoverable reserves multiplied by the unit price of the mineral and by the average utilisation factor, with the fee ranging from 0.1% to 2%. Royalties are also levied based on multiplication of the Royalty rate and the amount of product exploited in the period under consideration (in most cases 1 year) for example, 5.04 PLN/1000 m^3 of high methane natural gas; 4.19 PLN/1000 m^3 of other natural gases; 30 PLN/metric ton of oil.

Legal provisions regarding the current rates of the royalties can be found on the website of the Department of Geology and Geological Concessions of the Polish Ministry of the Environment.

Corporate Income Tax on income calculated in accordance with the tax provisions is taxed at a flat rate of 19%. Depreciation is based on a straight-line method and there are eight depreciation classes. Depreciation commences when the assets come into active use. The base VAT rate of 22% is charged on most goods. Reduced rates of VAT (7% and 3%) are imposed on sales of some products and services.

There is no State participation in exploration or development onshore in Poland, but the Baltic Sea acreage is held by Petrobaltic, whose only shareholder is the Polish State Treasury.

3 History of seismic surveying

Figure 14.5 charts the amount of 2D- and 3D-seismic data acquired annually in each country versus the oil price since 1960. The advent of digital seismic-data recording in 1965 is reflected in the increase in seismic acquisition, peaking in the 1980s following the oil-price rise, and waning in the late 1980s to be replaced largely by 3D-seismic acquisition. Breakthroughs in 3D-seismic imaging and migration technology have been critical to the success of many Permian and Carboniferous plays.

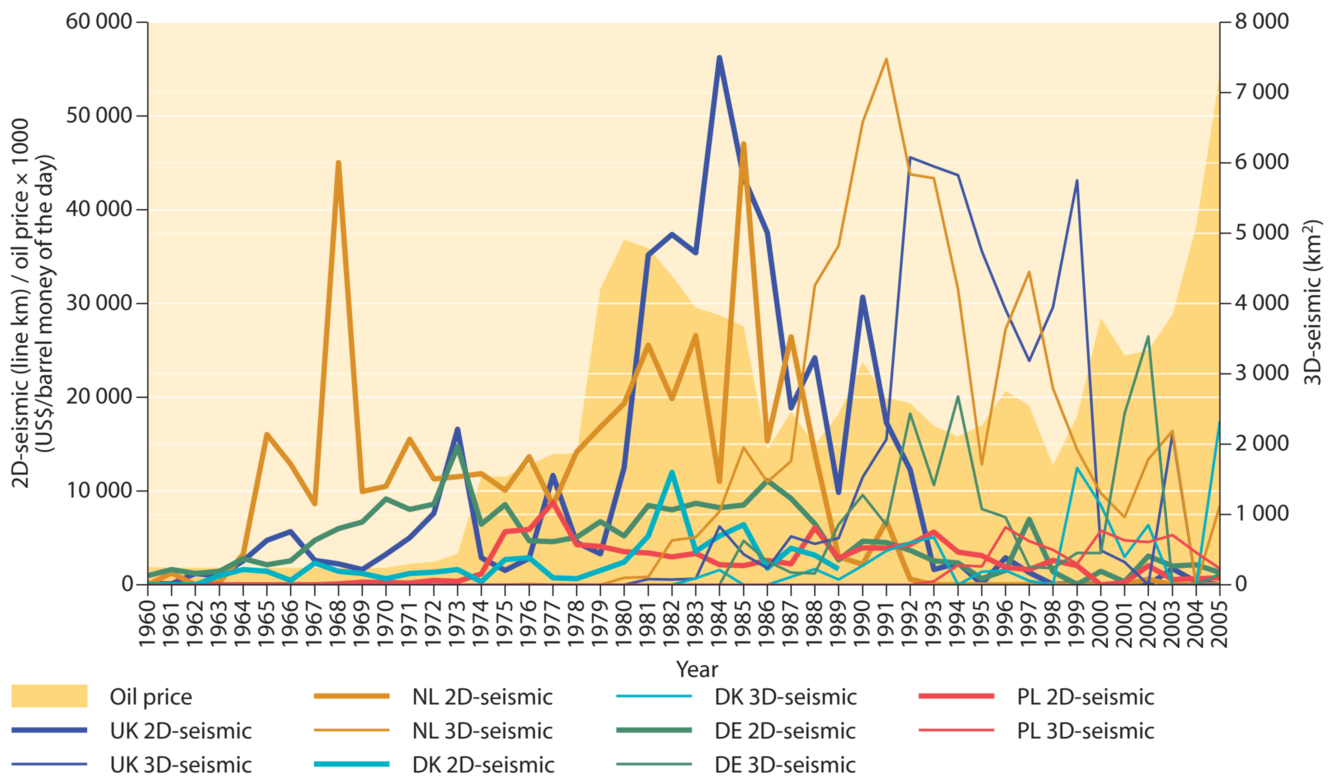


Figure 14.5 Amount of 2D- and 3D-seismic shot annually and oil price. Note: no data on post-1989 Danish 2D-seismic.

3.1 2D-seismic data

Maps of 2D-seismic data shot before 1970 and then by decade (1970-2000) in the SPBA area are shown on **Figures 14.6a-e** (where data are available). Early acquisition in the Netherlands, peaking in 1968, was in response to appraisal drilling on the Groningen gasfield, which was identified as a giant field in 1963 when the Rotliegend series was penetrated near the gas-water contact.

Offshore activity stimulated by the offer of new licensing began in 1964, increased in 1973 in the UK and Germany in response to exploration success, and reached a peak in the mid-1980s as the momentum for exploration in the North Sea increased following the increase in oil price. In the 1970s, the Polish Government purchased seismic-acquisition equipment in an effort to increase exploration. As better delineation of traps was required, increasingly closer-spaced 2D-seismic data were acquired before being overtaken by 3D-seismic acquisition in the 1990s.

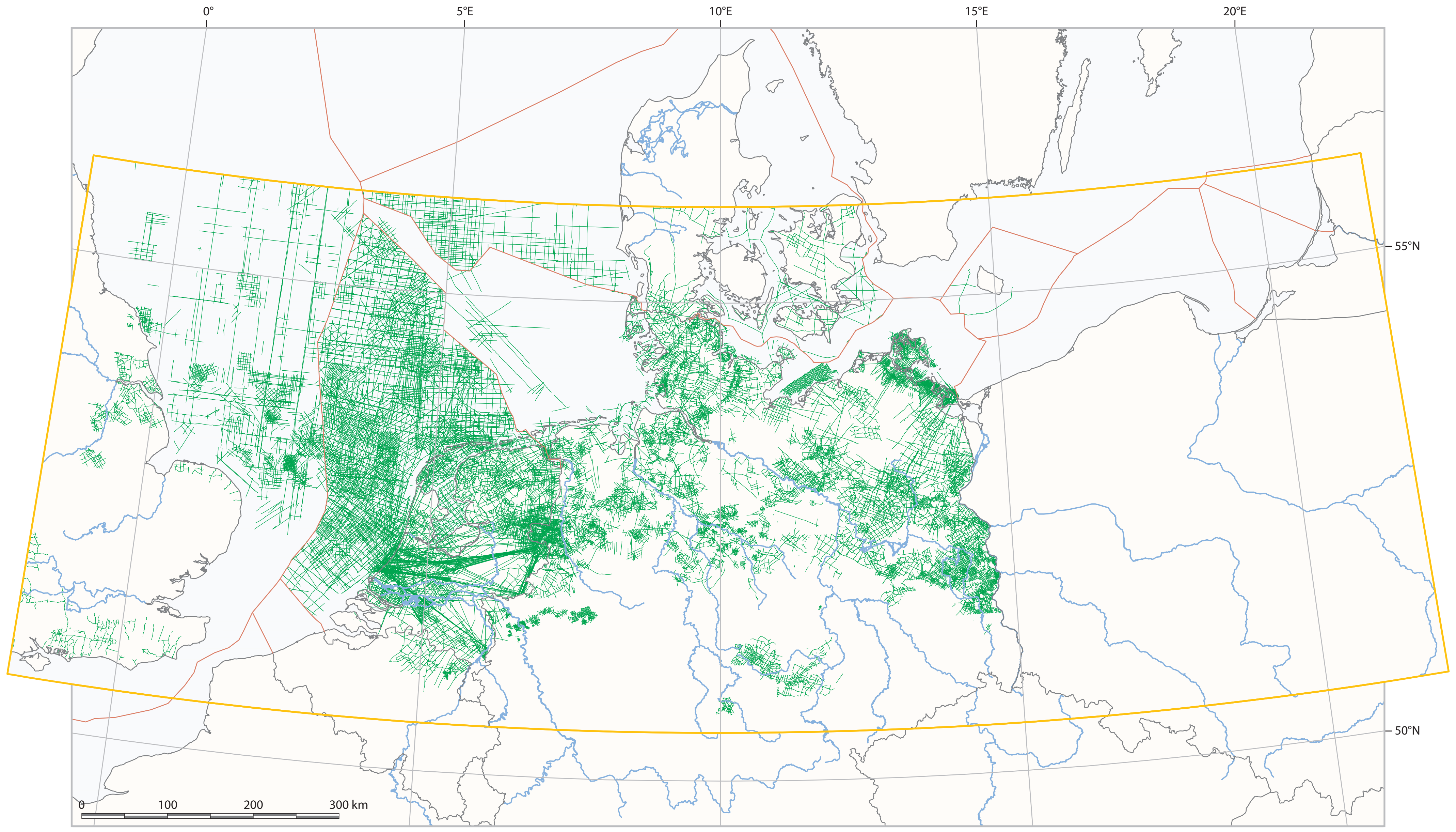


Figure 14.6a 2D-seismic data acquired before 1970.

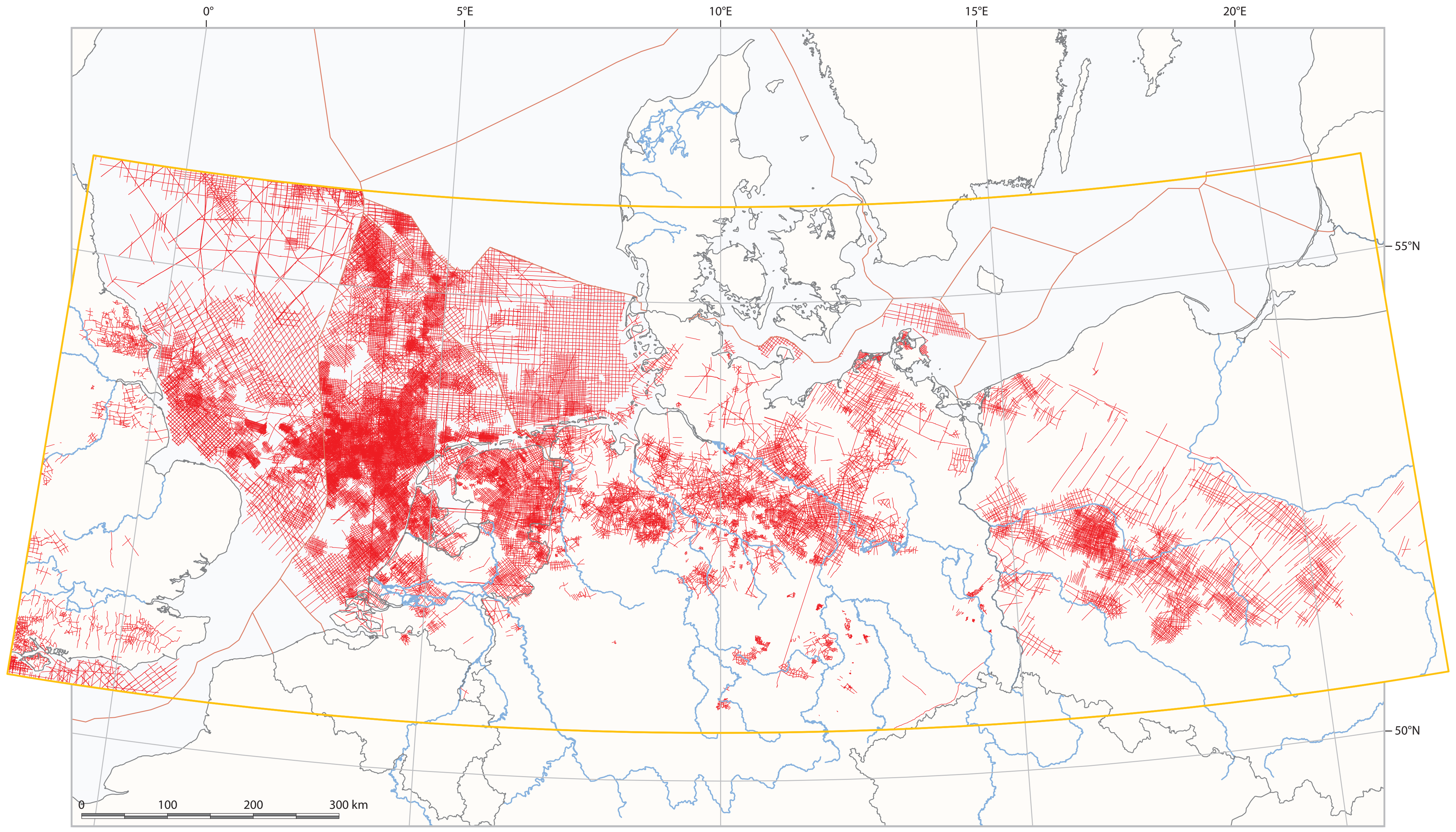


Figure 14.6b 2D-seismic data acquired between 1970-1979.

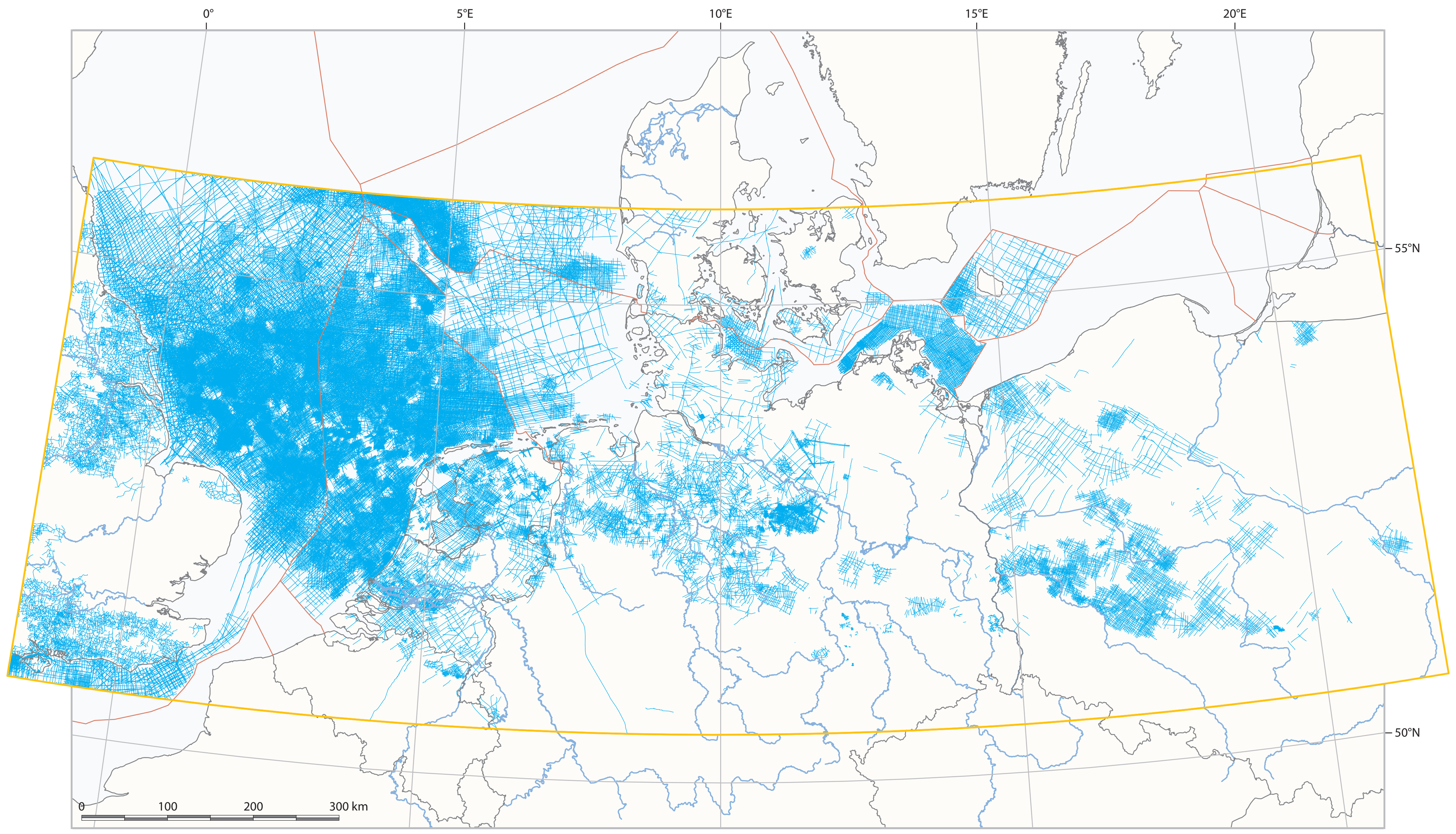


Figure 14.6c 2D-seismic data acquired between 1980-1989.

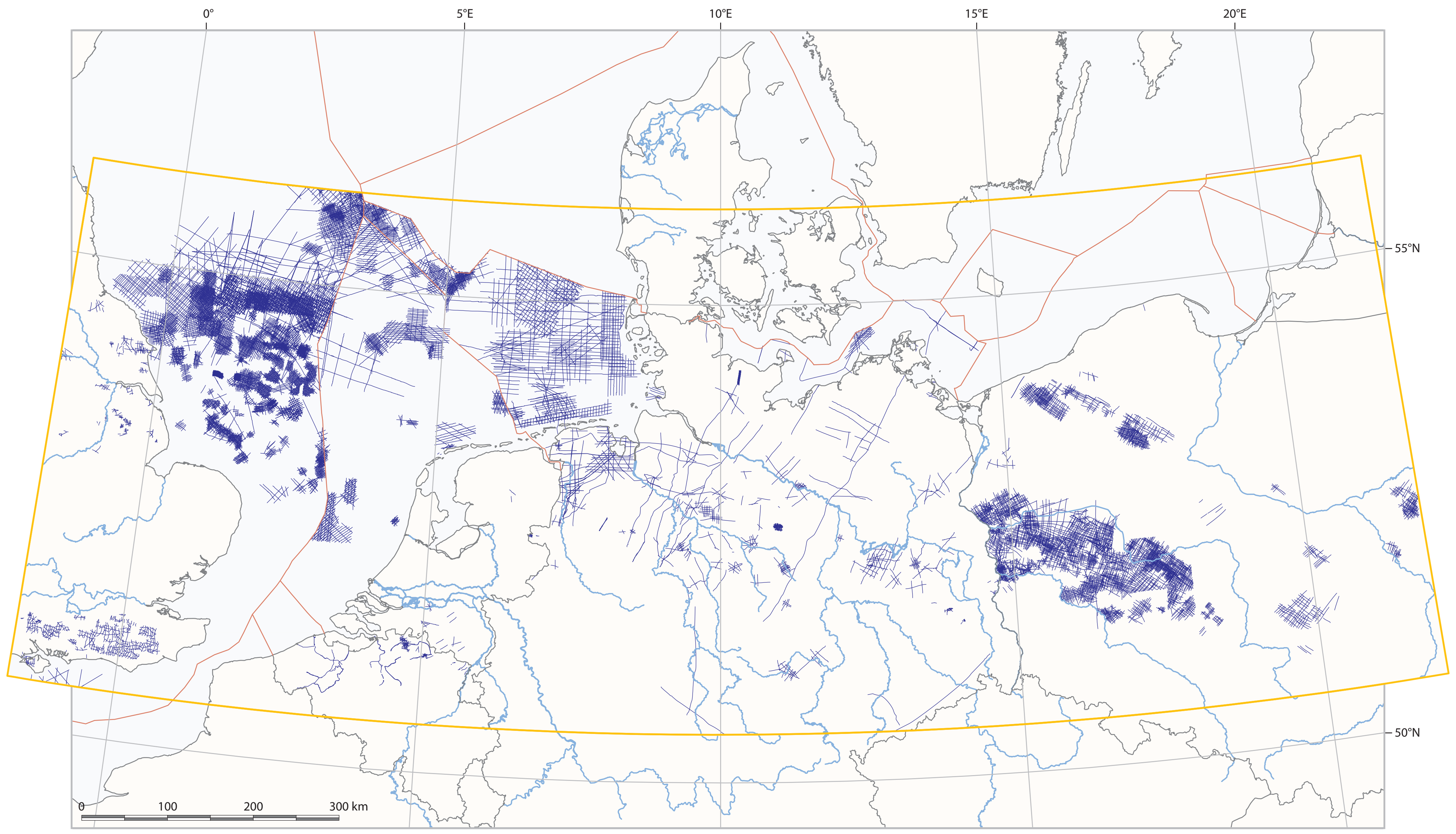


Figure 14.6d 2D-seismic data acquired between 1990-1999.

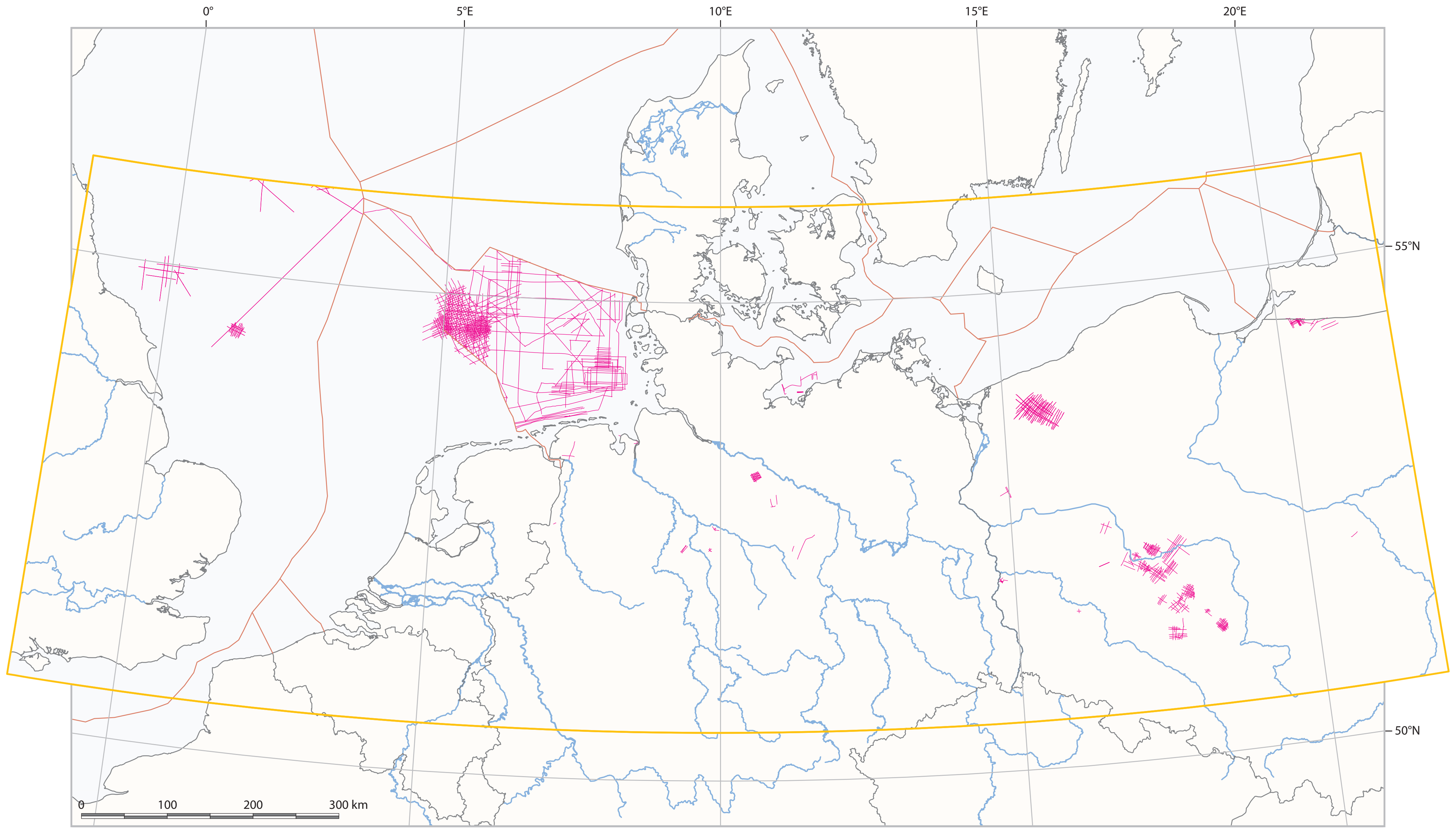


Figure 14.6e 2D-seismic data acquired between 2000-2006.

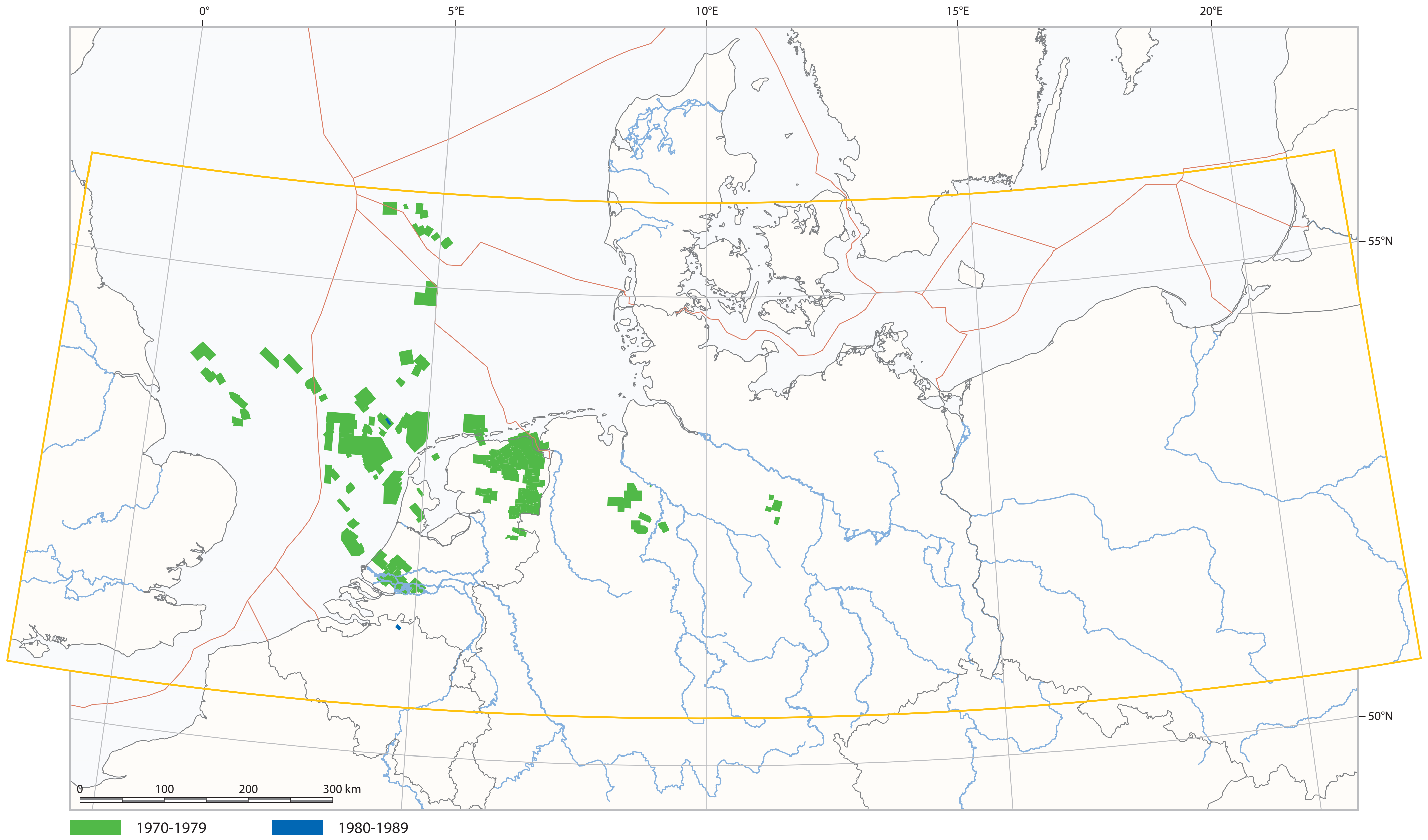


Figure 14.7a 3D-seismic data coverage, 1970-1989.

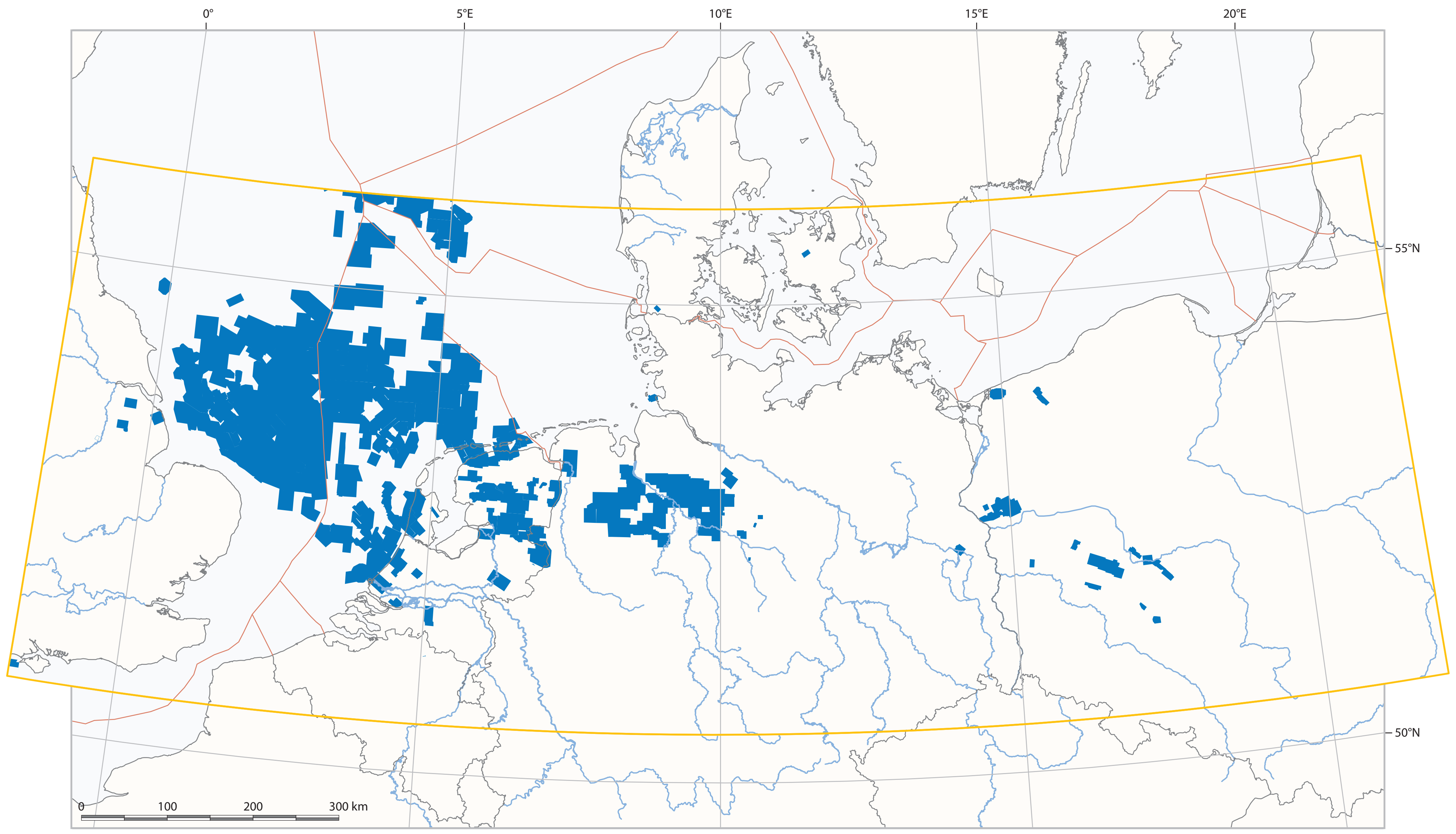


Figure 14.7b 3D-seismic data coverage, 1990-1999.

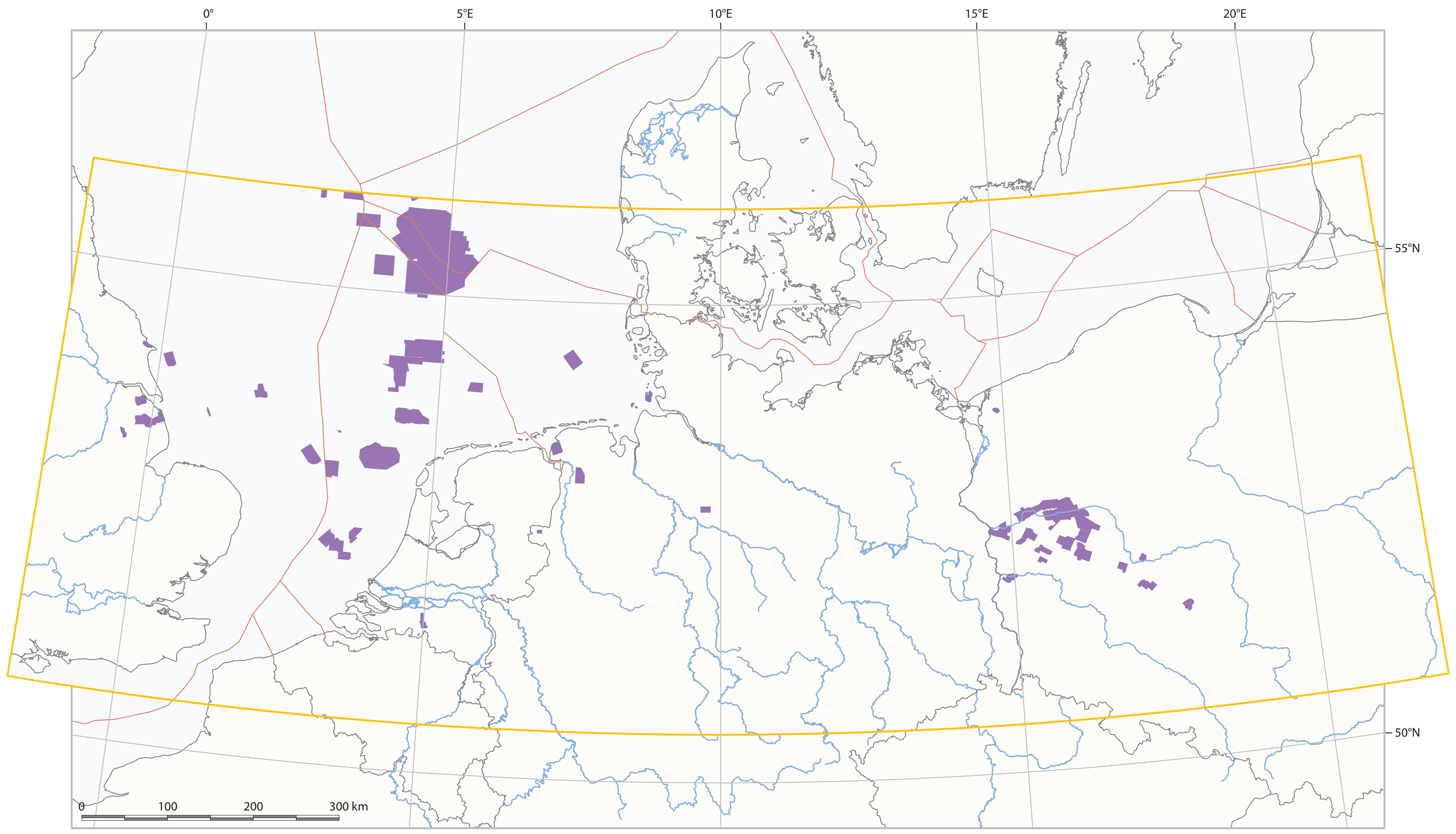


Figure 14.7c 3D-seismic data coverage, 2000-2006.

3.2 3D-seismic data

Maps of 3D-seismic data shot by decade (1970-2000) in the SPBA area are shown on **Figures 14.7a-c** (where data are available). The first 3D-seismic survey in the SPBA area was acquired in 1976 in the Dutch North Sea sector in Quadrant L, followed by Belgium's first 3D-seismic survey onshore northern Belgium in 1978 (**Figure 14.7a**). It was not until 1983 that 3D-seismic data were acquired in Danish North Sea waters in Quadrant 5504, followed by the UK Sole Pit 3D-seismic survey in 1984 and 'Oldenburg-Sued' in onshore Germany in 1985.

In the 1980s, 3D-seismic data were generally considered to be a field-delineation/development tool, with large surveys only acquired in the Netherlands and no acquisition in Belgium or Poland. That approach was superseded in the 1990s by large-area surveys that created an overlapping 'carpet' of surveys in the UK and infill areas not previously covered in the Netherlands. In Germany, the Lower Saxony Basin was covered by large 3D-seismic surveys, and the Danish Central Graben was subject to widespread 3D-seismic data acquisition. Poland's first 3D-seismic data were not acquired until 1993 when the World Bank funded purchase of 3D-seismic equipment and training, which were first used to delineate the Rozansko field.

Since 2000, 3D-data acquisition has been more limited, generally infilling gaps in coverage except for two large-area surveys in German North Sea waters, and surveys of increasing areal extent acquired in Poland. Some new 3D-seismic data have been acquired in areas previously surveyed with new acquisition parameters.

A change in investment from acquisition to reprocessing efforts has been seen in the last 10 years, with seismic contractors merging overlapping surveys pre-stack and then re-migrating the data with a variety of time- and depth-migration techniques with ever more complicated algorithms to more accurately image horizons underlying structural complexity and lateral velocity variations. Seismic inversion, amplitude analysis and AVO (amplitude variation with offset) processing have been increasingly utilised in field development and to reduce risk on exploration prospects.

4 Exploration and drilling history

About 17 000 wells have been drilled in the German part of the SPB area, of which more than 6000 are exploration wells, mostly in the Mesozoic Lower Saxony Basin. There are more wells in Germany than in any other country in the SPBA area; more than four times more than in Poland (4198 exploration, appraisal and development wells since 1960, which includes wells drilled for salt, copper, and lignite (brown coal)) or the Netherlands (4079) and five times more than the number of wells drilled in UK part of the SPB area (3290). 149 exploration and appraisal wells were drilled in the Danish part of the SPB area, but sidetracks are not counted as separate wells. Only seven exploration wells have been drilled in Belgium. However, these numbers can be somewhat misleading as much of the early onshore drilling was very closely spaced and shallow.

4.1 Exploration

The number of exploration wells drilled since 1900 is plotted by year in **Figure 14.8a**, which shows the limited exploration drilling before World War II, except in Germany, where the 'Reichsbohrprogramm', Government aid to encourage oil exploration started in 1934. Exploration drilling in Germany started to decline in the 1960s as the oil plays became mature, despite new exploration drilling for gas.

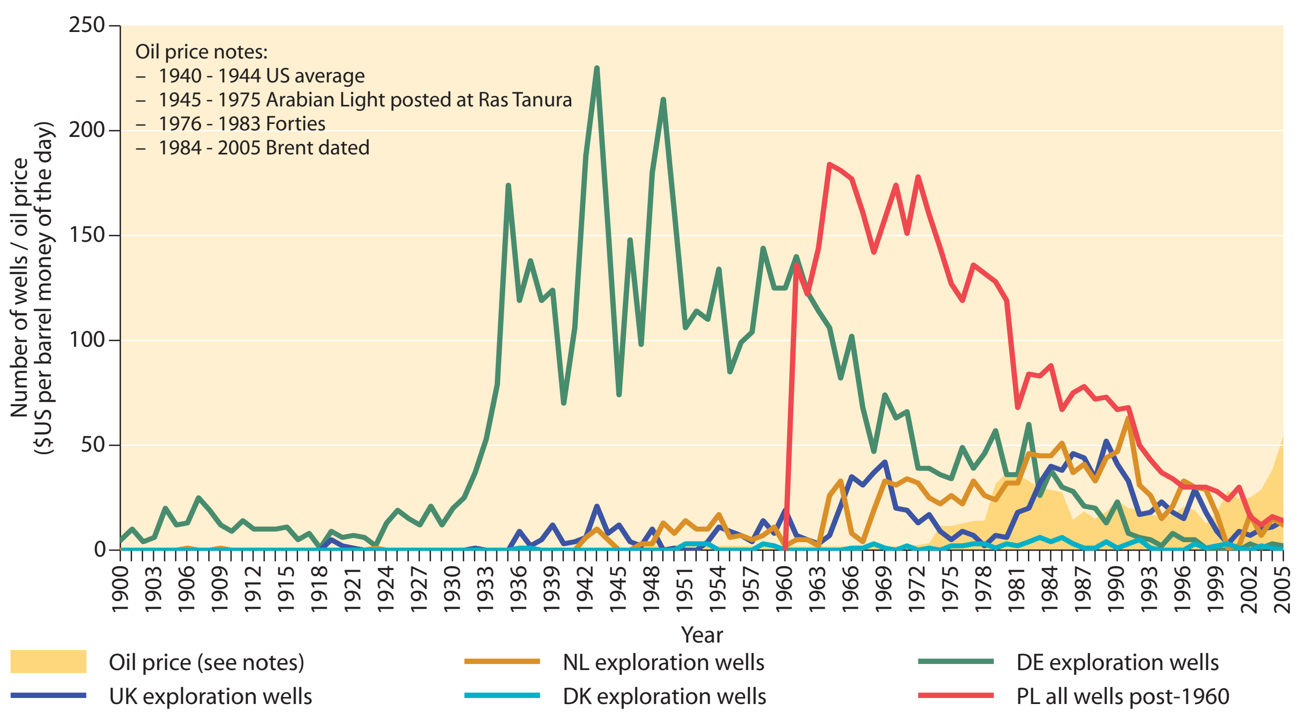


Figure 14.8a Comparison of exploration wells drilled and the price of oil.

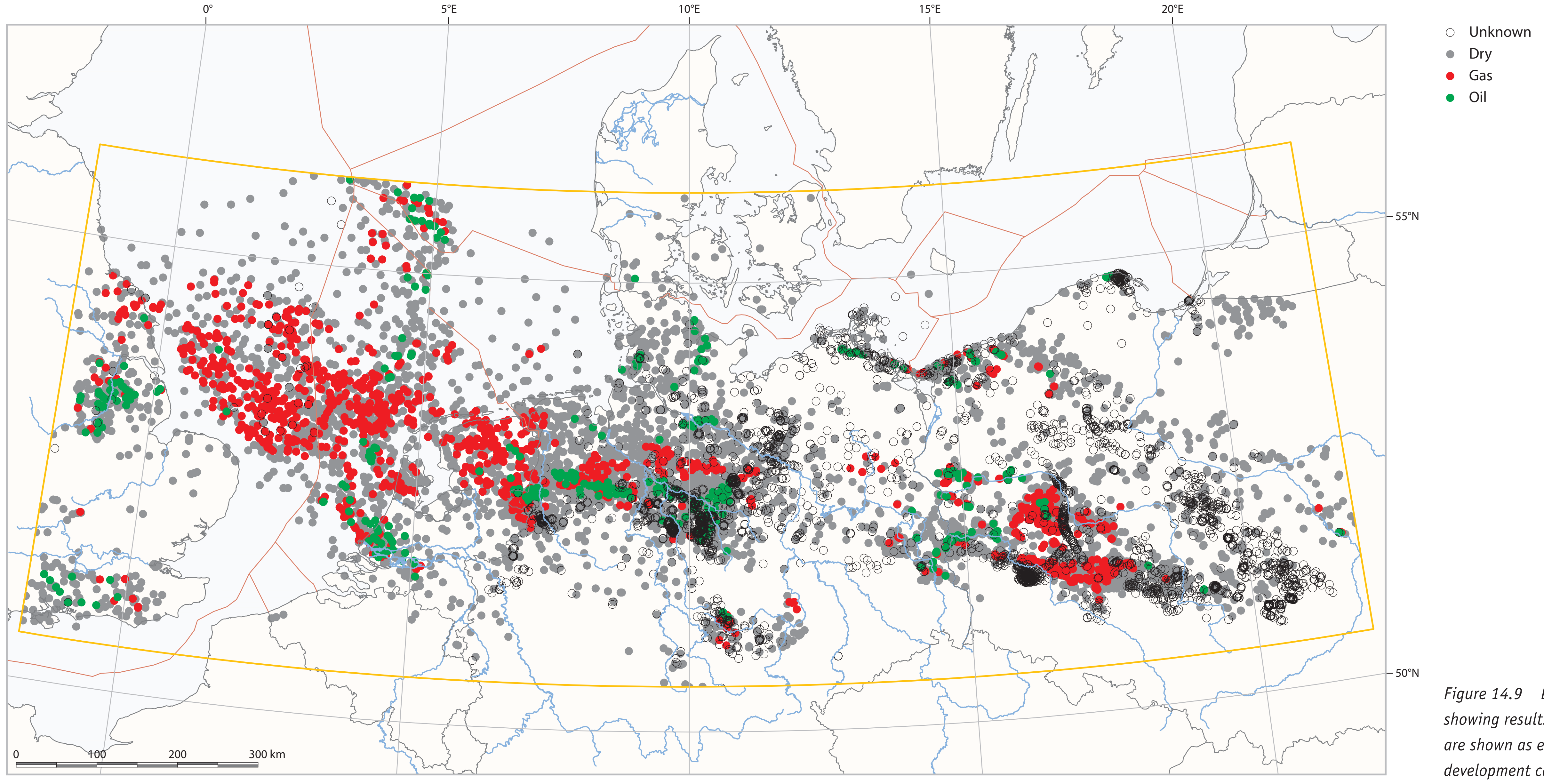


Figure 14.9 Exploration wells drilled showing results. Note all Polish wells are shown as exploration/appraisal/ development can not be differentiated.

Geopolitical events and linked oil-price increases in the 1980s spurred increased exploration activity (**Figure 14.8b**) in the UK and Netherlands, but peak activity lagged by 5 years. The drop in exploration drilling in the UK after 1992 may have been the response to the removal of PRT relief for exploration wells that was announced after the 14th Round (see above). The low oil prices seen in 1998 were followed by a lower rate of exploration within only 2 years. Exploration has not seen a dramatic increase in the SPB area since the upturn in price after 2000.

Figure 14.9 shows all exploration drilling in the SPB area (all Polish wells are shown because they can not be differentiated into exploration, appraisal or development), reflecting the productive gas and oil trends. The bottom-hole stratigraphy of the wells is depicted on **Figure 14.10** and demonstrates that most wells in the North Sea drilled to the Carboniferous, even in the heart of the Rotliegend fairway.

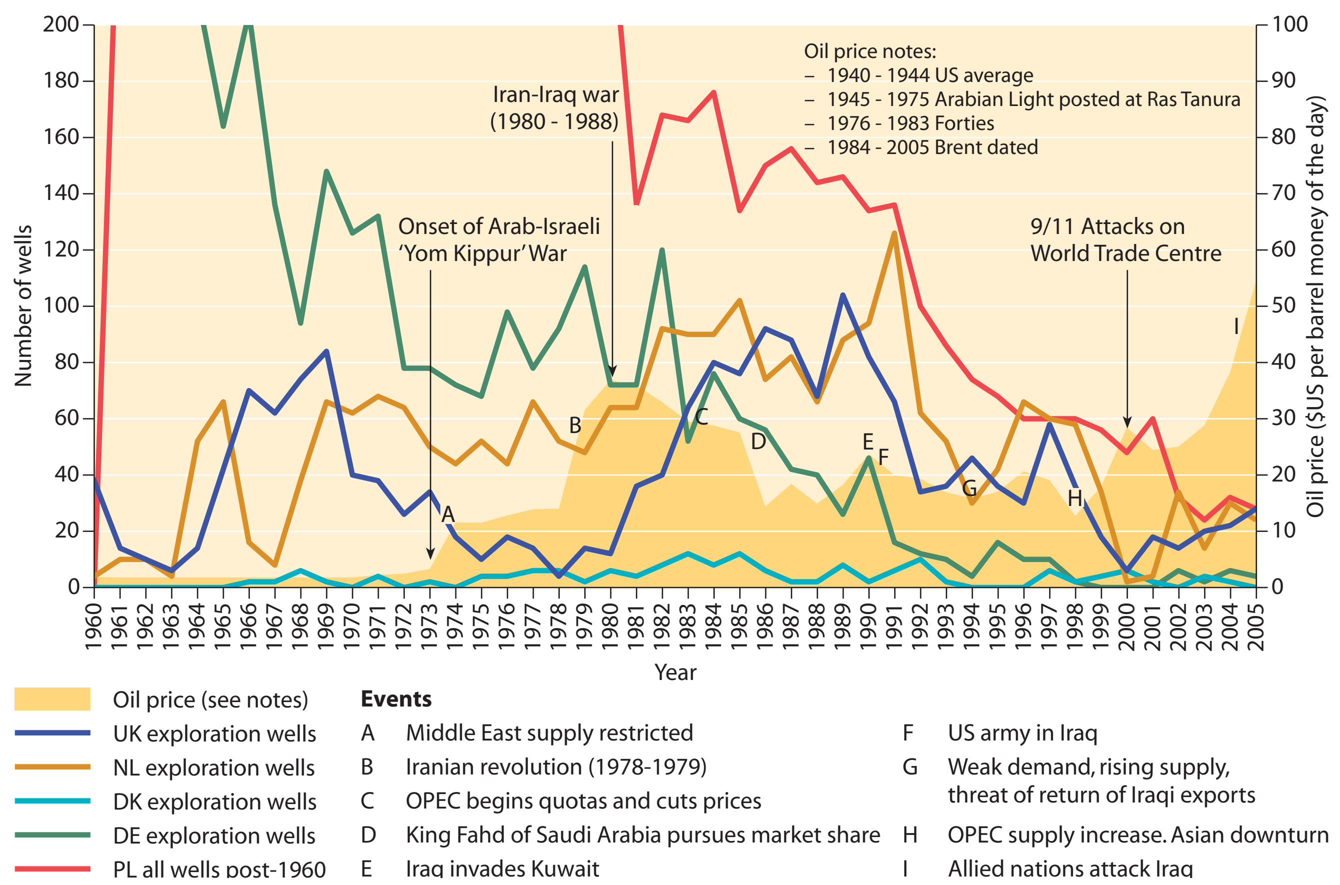


Figure 14.8b Comparison of exploration wells drilled, the price of oil and world events: 1960 onwards.

An exceptional cluster of wells that terminated in Cretaceous or Jurassic strata lies in the Danish Central Graben, and a significant number of wells terminated at the same stratigraphic levels across central Netherlands and Germany, extending into northern Germany. In Poland, the three provinces, Fore-Sudetic Monocline, Pomeranian and Cambrian (**Figure 14.11**) are easily distinguished, with wells mostly terminating at Rotliegend, Zechstein and pre-Devonian levels respectively. The north-west-south-east oriented Jurassic play trend can also be seen crossing central Poland.

The pattern of target horizons for these exploration wells (**Figure 14.11**) is markedly different to the distribution of bottom-hole stratigraphy (**Figure 14.10**). The Rotliegend and Carboniferous trends in the UK, with interspersed Triassic Bunter targets offshore, are easily identified with the Rotliegend play trend forming a lobate, north-west–south-east-oriented area across the southern and central parts of the Southern North Sea Basin, and with the Carboniferous play trend lying across the northern part of the basin. The UK Triassic play trend also lies mostly across the northern part of the basin, but there have been a number of wells with Triassic targets across the southern and central parts of the UK Southern North Sea Basin. In the UK onshore, the southern England Jurassic and East Midlands Carboniferous play trends are easily distinguished.

The Rotliegend play extends across most of the Netherlands offshore sector. Few wells appear to have targeted the Carboniferous in the sector, but note that there are many Dutch offshore wells for which the target stratigraphy is unknown. The Danish Central Graben trend is shown by a linear cluster of wells with Cretaceous and Jurassic targets. In Belgium, the pre-Devonian and Carboniferous plays lie in the west and north-east of the onshore area respectively.

In Germany, different trends overlie one another, although the Carboniferous/Zechstein and Rotliegend trends can be differentiated across central/northern Germany, with the Carboniferous/Zechstein play trend lying mainly to the south of the Rotliegend play trend. Within the narrow gooseneck of the German offshore waters is the Outer Rough Basin, bounded in the east by an inversion high called the Mads High, in which the A6/B4 field is located with gas accumulations in a complex setting of reservoirs consisting of Jurassic sandstones and carbonates, Zechstein carbonates, Rotliegend clastics and volcanics. Wells targeting Jurassic and Cretaceous strata south of the Rotliegend fairway reflect the oil plays of the Mesozoic Lower Saxony Basin. The cluster close to the southern border of the SPB is related to the Zechstein play of the Thüringian Basin. Unfortunately, the target horizon of most of the east German wells is not available (including most of the Thüringian Basin wells).

No information is available with respect to play target for the Polish wells; however, drilling falls into three main exploration provinces; the Fore-Sudetic Monocline (Zechstein play), Pomeranian (Zechstein play) and Cambrian (Cambrian Main Dolomite play).

Figures 14.12a-e examine exploration drilling through time from pre-1970 and in subsequent decades. **Figures 14.13a-e** highlight the results of these wells. All Polish wells are shown as exploration wells because they can not be differentiated into exploration, appraisal or development.

The maps of wells drilled before 1970 (**14.12a** and **14.13a**) and exploration drilling histograms (**Figures 14.8a** & **b**) do not include wells drilled in Poland before 1960. This shallow drilling was carried out by the 'Petroleum Exploration Company' (PEC), a special institution organised after World War II for planning, preparation and running of exploration projects in an attempt to locate salt diapirs, which were analogous to the discoveries made in Germany. Drill locations were selected using gravimetric and magnetometric surveys, followed by analogue seismic-reflection and refraction surveys in the 1950s. Exploration wells were located more conventionally in the 1960s, as early oscillographic data were replaced by analogue-seismic and then by digital-seismic recording in 1970.

Activity in Poland was maintained at a high level from 1954 to 1970 when exploration, appraisal and development drilling was focused on the Polish Trough, the Fore-Sudetic Monocline and a scatter of wells along the Baltic Sea coast. Exploration drilling has been in decline since 1964. However, POGC, the only Polish oil and gas exploration and production company working onshore, was started in 1982 and there has been recent licensing by multinational oil companies.

Pre-1970 UK exploration drilling reflects the early onshore activity, when drilling in the East Midlands, southern England and the Cleveland Basin was fostered by the need for wartime production, and tax breaks for indigenous oil in 1953-1961. After 1965, the peak on **Figure 14.8b** reflects new offshore exploration wells resulting from the large number of blocks awarded in the 1st Round. Most of the large Rotliegend fields were discovered on these 1st Round licences drilled between 1966 and 1976 (**Figure 14.17**). There were a number of unsuccessful Mid North Sea High wells drilled before 1970, and the area has only recently seen renewed interest. A second phase of UK exploration followed the price rise in the early 1980s when most of the Carboniferous fields were discovered. The drop in the oil price in 1998 was followed by a decline in exploration drilling to a minimum level in 2000, which has only slightly improved despite the trend of oil-price escalation since 1998.

Belgium's first oil exploration wells were drilled in the 1930s, stimulated by discoveries in Germany. A wildcat drilled in 1962 on the Heibaart Dome in the Lower Carboniferous (Dinantian) karstified limestone of the Campine Basin resulted in the development of the site for gas storage after 1978.

Pre-1970 exploration in the Netherlands was almost entirely onshore, extending the 1959 Groningen discovery and chasing the same Rotliegend gas play. The Dutch part of the continental shelf was opened up for this search in 1968. The drilling rate shows a trend very similar to the UK sector, driven by increasing oil prices (and linked gas prices) peaking in the mid-1980s. In the 1990s, the drilling rate gradually decreased to a low level in about 2000 following decreasing oil prices and also reflecting more focussed and efficient exploration because of the availability of the then-modern 3D-seismic data on an exploration scale. Since 2000, the offshore drilling rate has been maintained at a level of about ten wells/year; however onshore drilling has further decreased to only a few wells per year. This can be explained partly by the more mature stage of exploration onshore compared to the larger more prospective offshore area, but also because environmental constraints have become very severe; permission to drill may take several years in some locations. Recently, after a process of some 15 years, new gas production has started from under the Wadden Sea, a protected tidal-flat area. It remains uncertain if further exploration in or near environmentally sensitive areas will be feasible in the Netherlands.

Pre-1970 exploration drilling in Denmark began in the mid-1930s with the drilling of two wells on the Jylland peninsula for raw materials in general. No further wells were drilled until the 1950s when a number of onshore wells were drilled targeting various plays. No hydrocarbons were discovered during this period.

With the award of the Sole Concession in 1962, exploration in Denmark also moved offshore and the first oil discovery in Denmark, and in the North Sea, was made in 1966. The majority of the later wells have focused on the offshore area and most have targeted the Chalk play. With the gradual relinquishments of the Sole Concession areas and the introduction of licensing rounds at the beginning of the 1980s, exploration drilling peaked in the mid-1980s. The drilling rate has subsequently levelled out at two to four exploratory wells per year, approximately half of which have been drilled in the SPBA area.

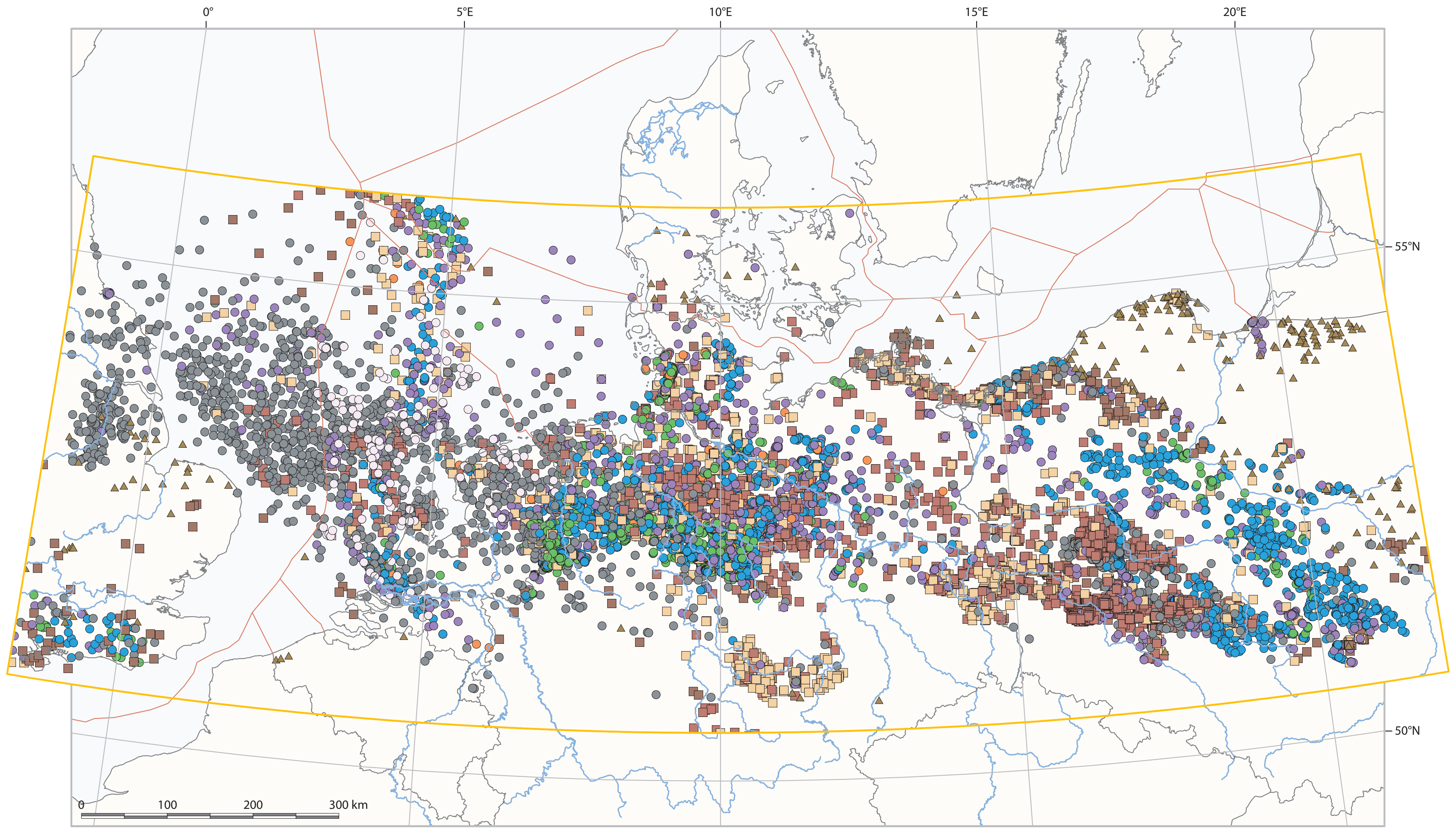
4.2 *Appraisal and development drilling*

The trends in exploration drilling (**Figures 14.8a** & **b**) are largely reflected in appraisal and development drilling (**Figures 14.14** & **14.15**), where times of heightened exploration activity are associated with increased appraisal and development drilling. However, this can be misleading, because many early discoveries in the North Sea are only marginally economic now that that gas prices have increased since 1998, and recent development drilling has delineated these older discoveries. **Figure 14.16** shows that almost half of the UK 'Significant Discoveries' (where the well was deemed capable of testing more than 1000 bopd/day or 15 Mmcfd) and field discovery wells in the SPB area were licensed in the 1st Round, although some of these discoveries are only now being developed.

4.3 *Success rates by country and by play*

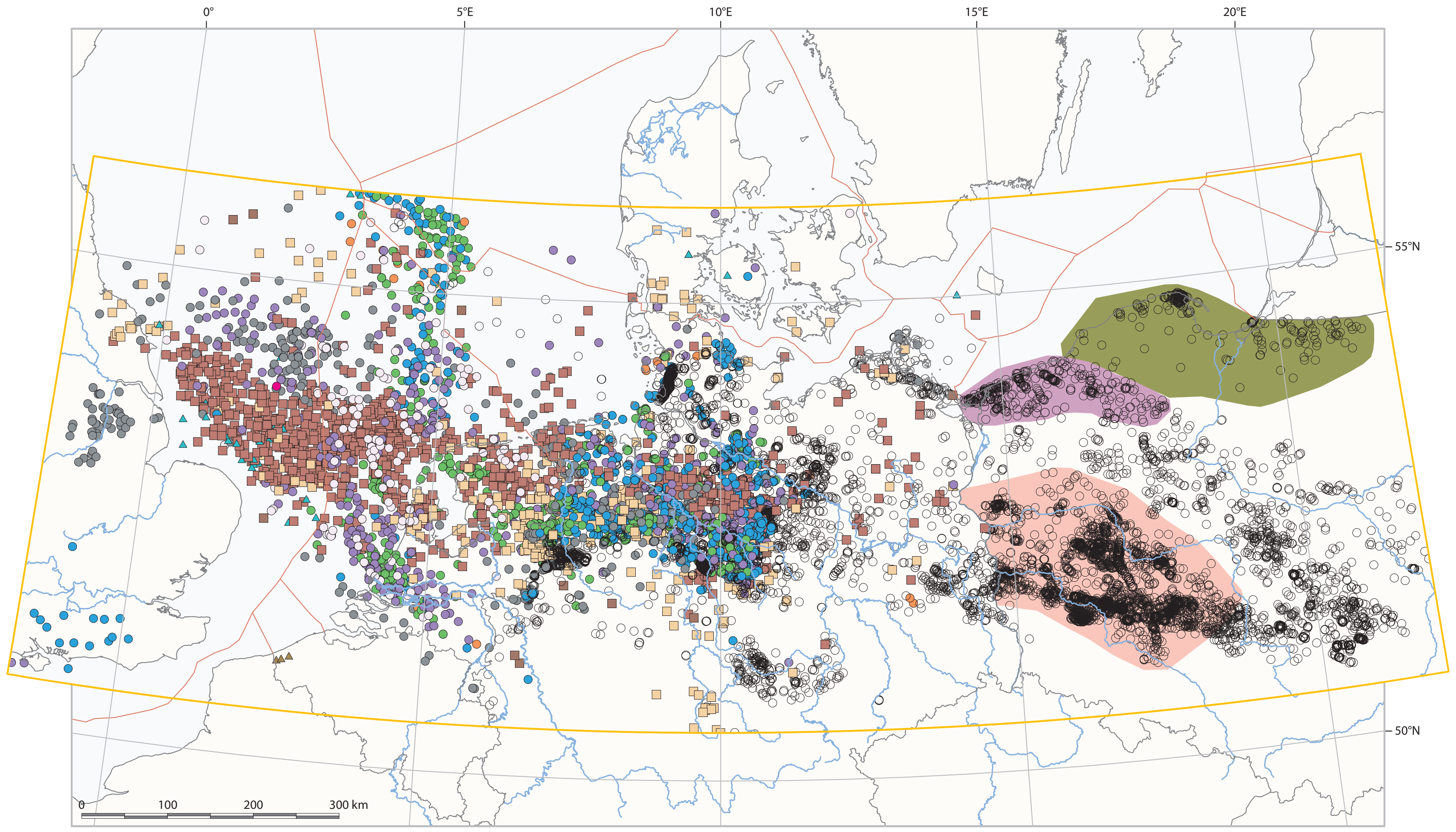
A very simple success ratio can be calculated by dividing the number of discoveries in a year by the number of exploration wells drilled in the same year (error is introduced by wells that started in one calendar year and finished in the next). **Figures 14.17a-e** chart exploration drilling versus the exploration success rate. These success rates show a large degree of scatter on a year-by-year basis and lump together very different discovery sizes, from sub-economic finds to giant fields. Note that the UK discoveries comprise only the 'Significant Discoveries' published in the 'Brown Book'. **Figures 14.18a-e** chart the exploration success rates in individual plays for each country and **Figures 14.19a-e** show in which age play their successes are found (except for Poland, where all discoveries are shown in every age play).

For the UK, **Figure 14.17a** depicts a generally increasing trend in exploration success rate from about 20% in the 1960s and 1970s, to about 35% in the 1980s and 1990s. After the number of wells drilled fell dramatically in 1992, the success rate began to climb to about 45% following the rise in oil price. In recent years, the success rate has been improving in the SPB area, although exploration-well drilling in 2005, the last year included in the data presented in this chapter, yielded a disappointing number of 'Significant Discoveries'. **Figure 14.18b** shows that the Rotliegend is the most drilled play in the SPB area with a 42% chance of finding a 'Significant Discovery'. Rotliegend wells comprise 71% of the Significant Discoveries, followed by the Carboniferous with 18% (**Figure 14.19a**).



Cenozoic
Cretaceous
Jurassic
Triassic
Zechstein
Rotliegend
Carboniferous
Devonian
Pre-Devonian
Unknown

Figure 14.10 Exploration well bottom-hole stratigraphy. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.



Cambrian Province
Fore-Sudetic Monocline Province
Pomeranian Province
Cenozoic
Cretaceous
Jurassic
Triassic
Zechstein
Rotliegend
Carboniferous
Devonian
Pre-Devonian
Unknown
Multiple
Stratigraphic test
No data

Figure 14.11 Exploration well targets. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

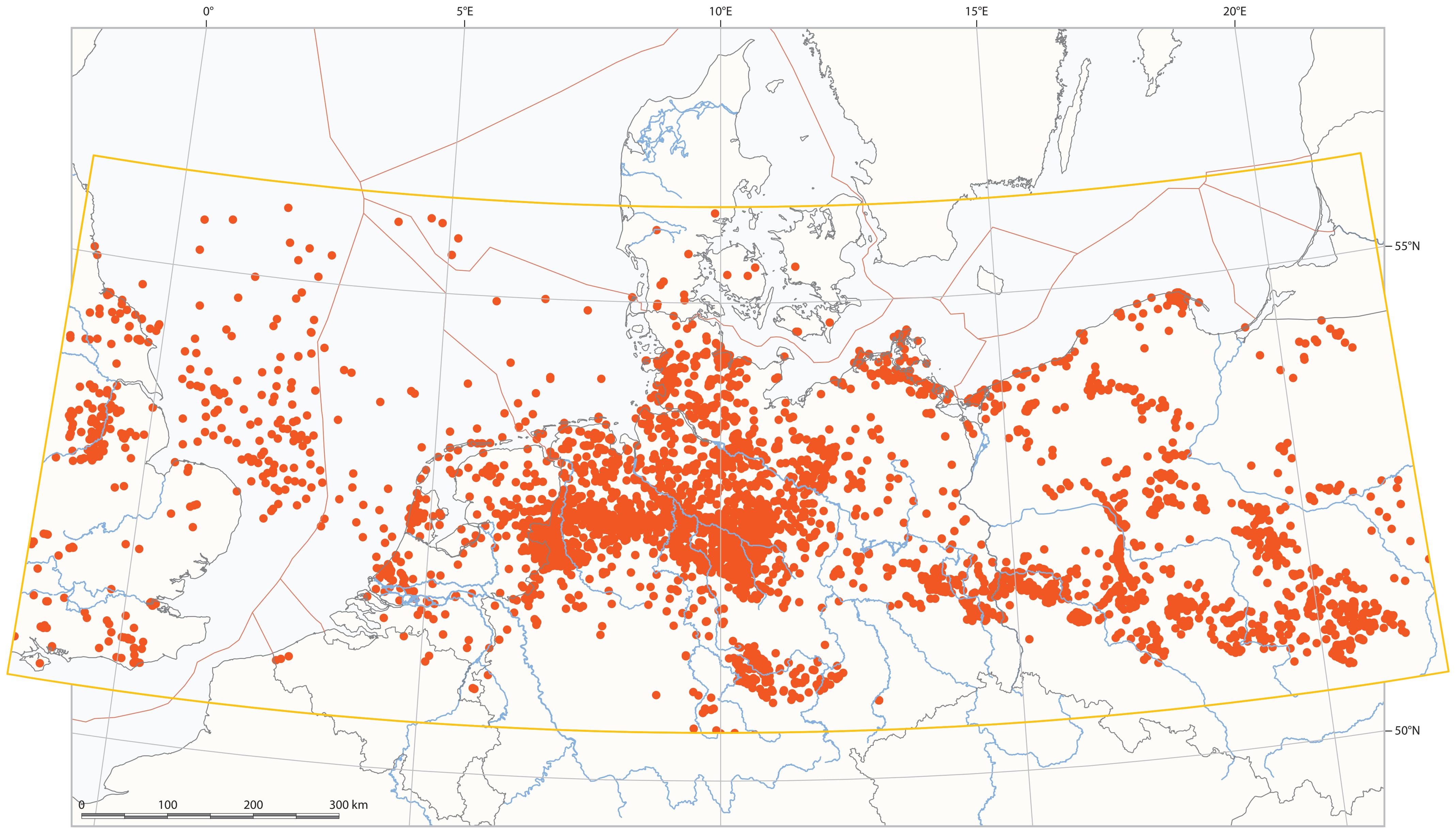


Figure 14.12a Exploration wells drilled pre-1970. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

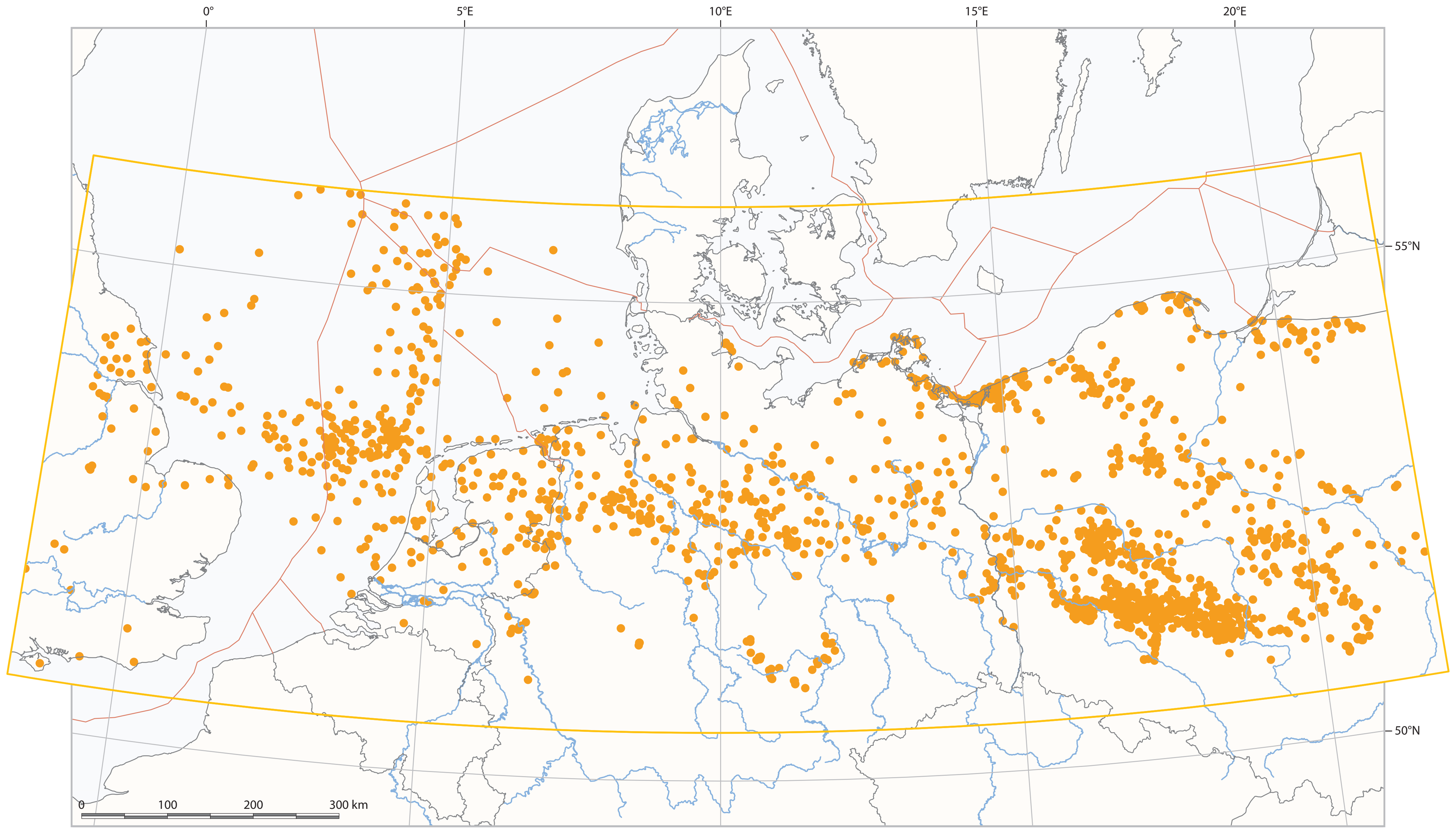


Figure 14.12b Exploration wells drilled between 1970-1979. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

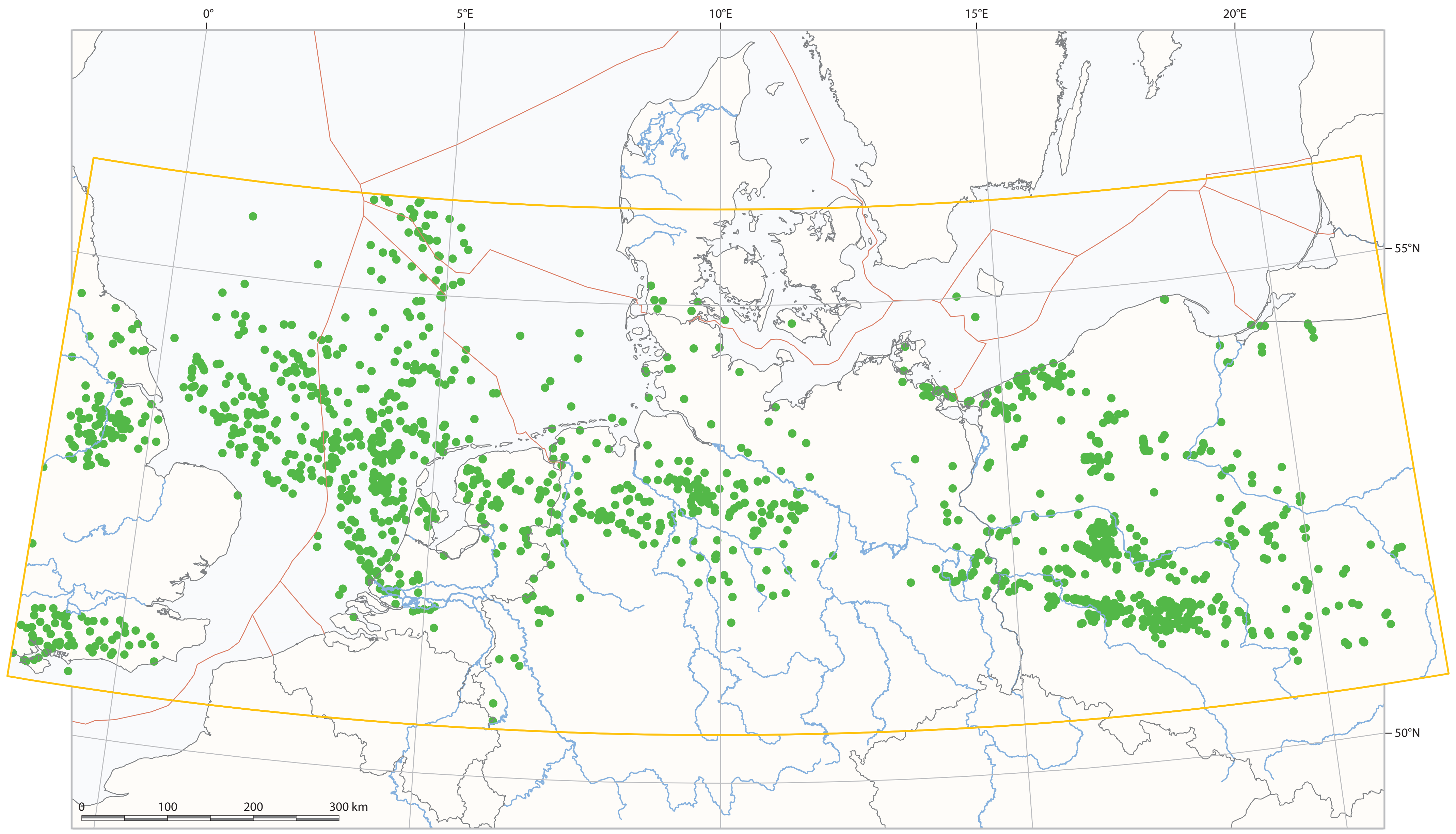


Figure 14.12c Exploration wells drilled between 1980-1989. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

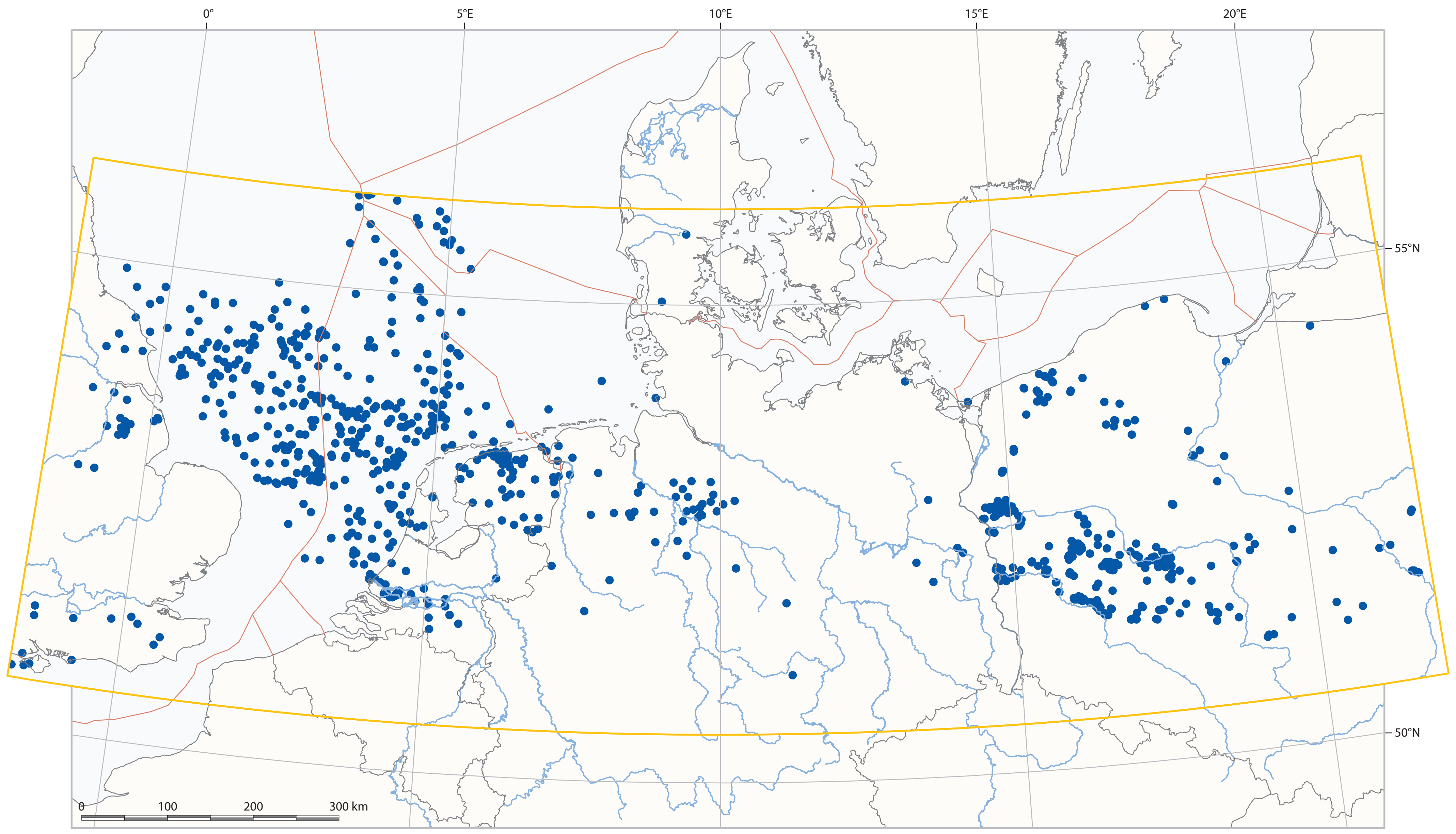


Figure 14.12d Exploration wells drilled between 1990-1999. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

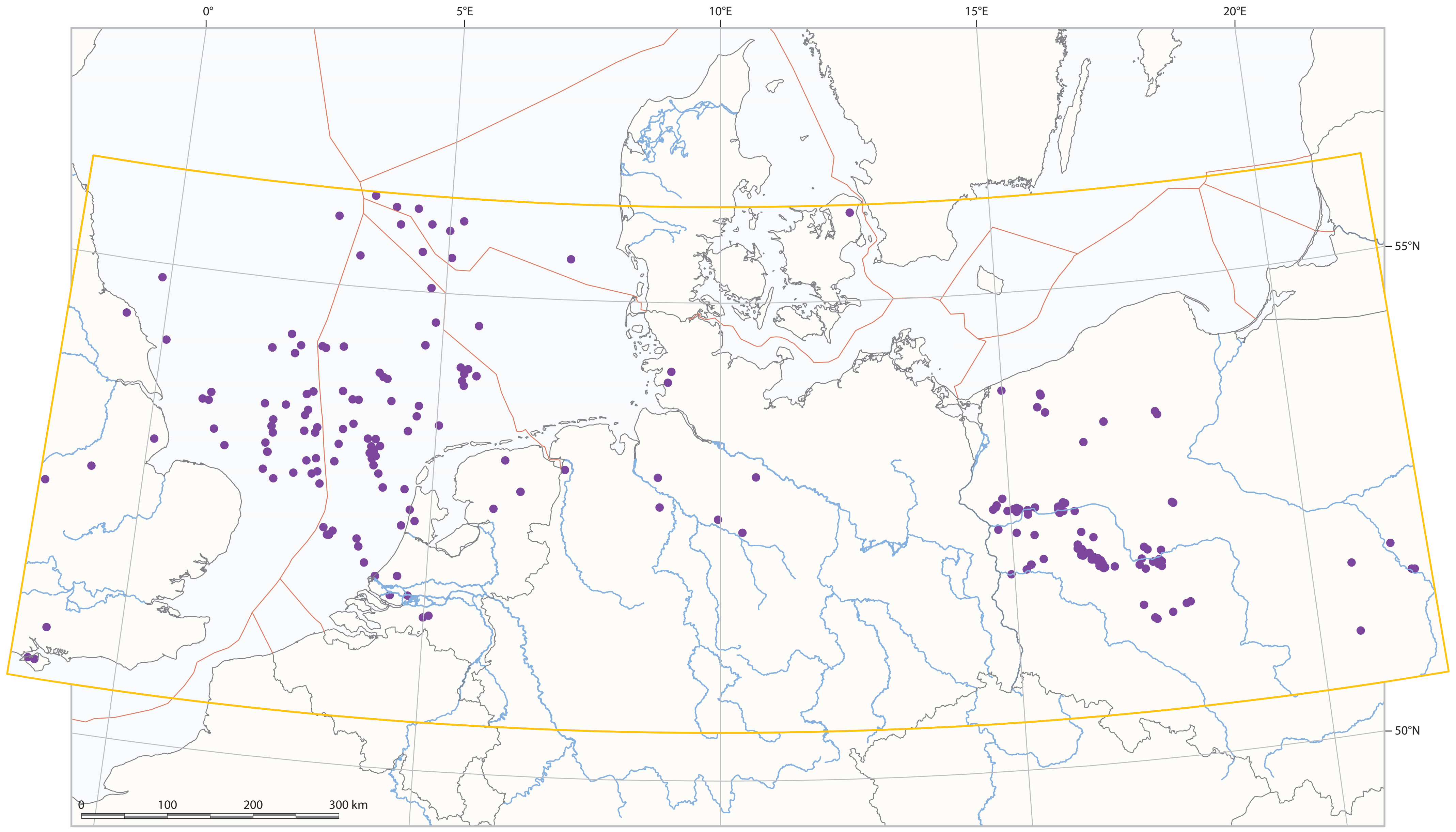


Figure 14.12e *Exploration wells drilled between 2000-2006. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.*

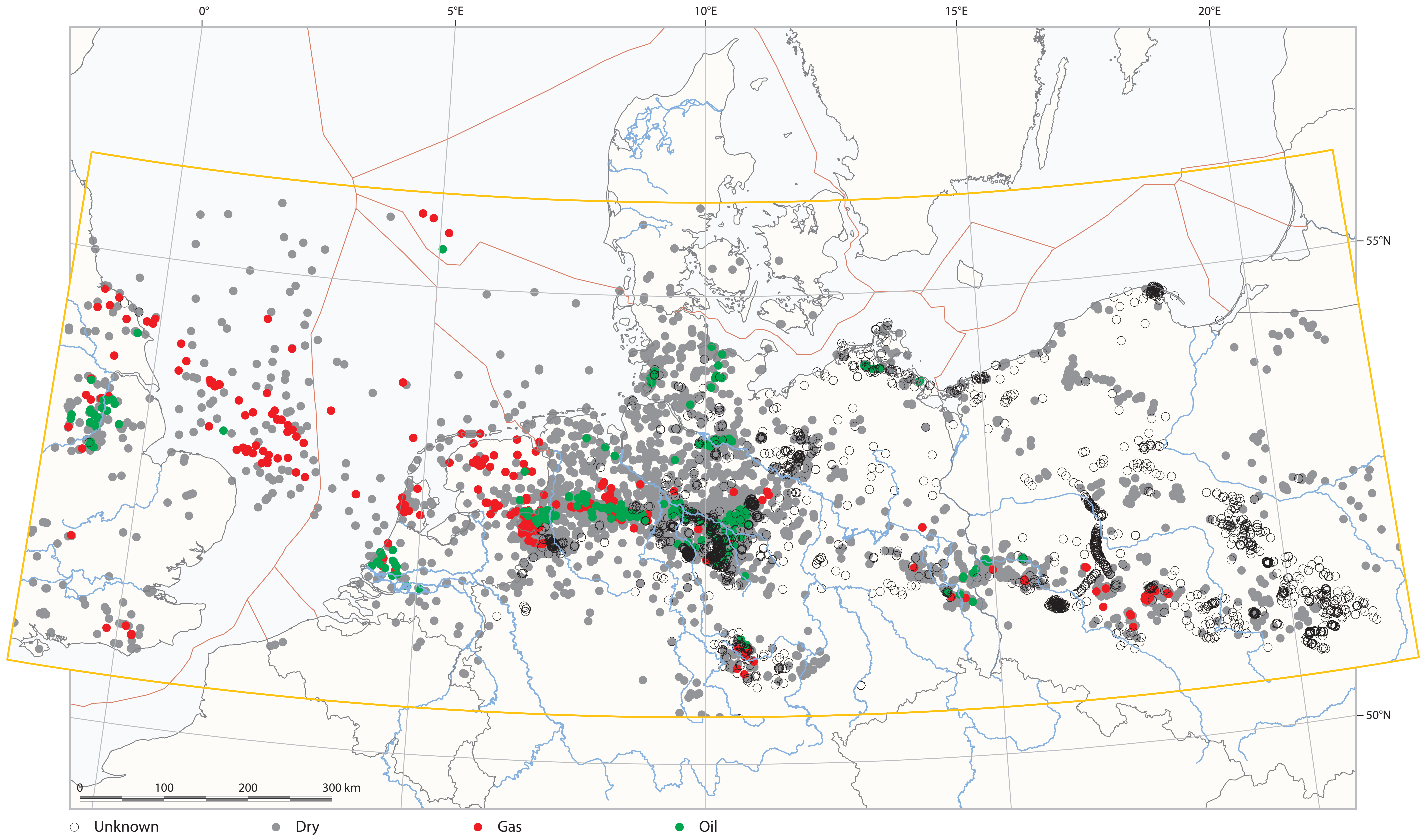


Figure 14.13a *Exploration wells drilled pre-1970 showing results. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.*

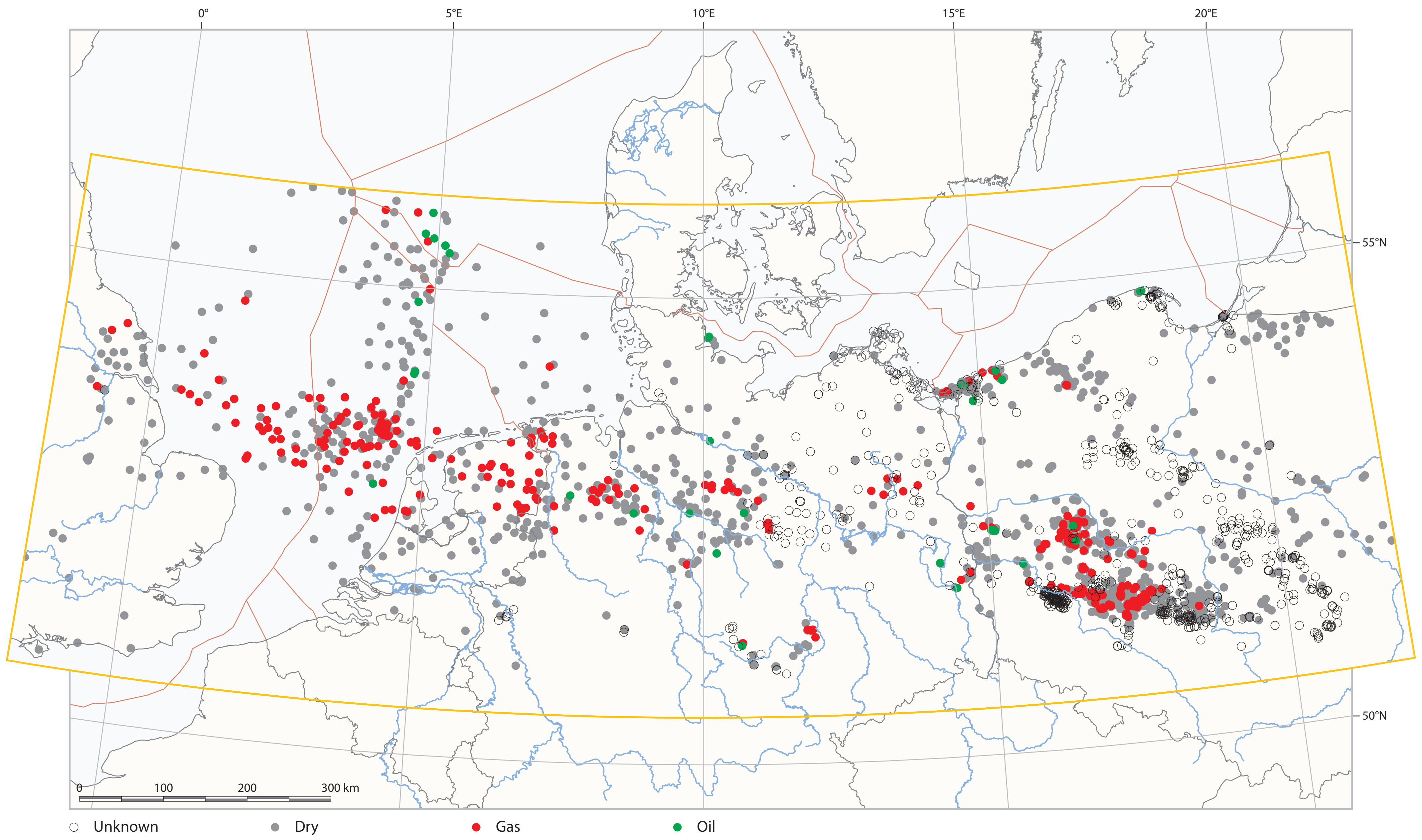


Figure 14.13b *Exploration wells drilled between 1970-79 showing results. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.*

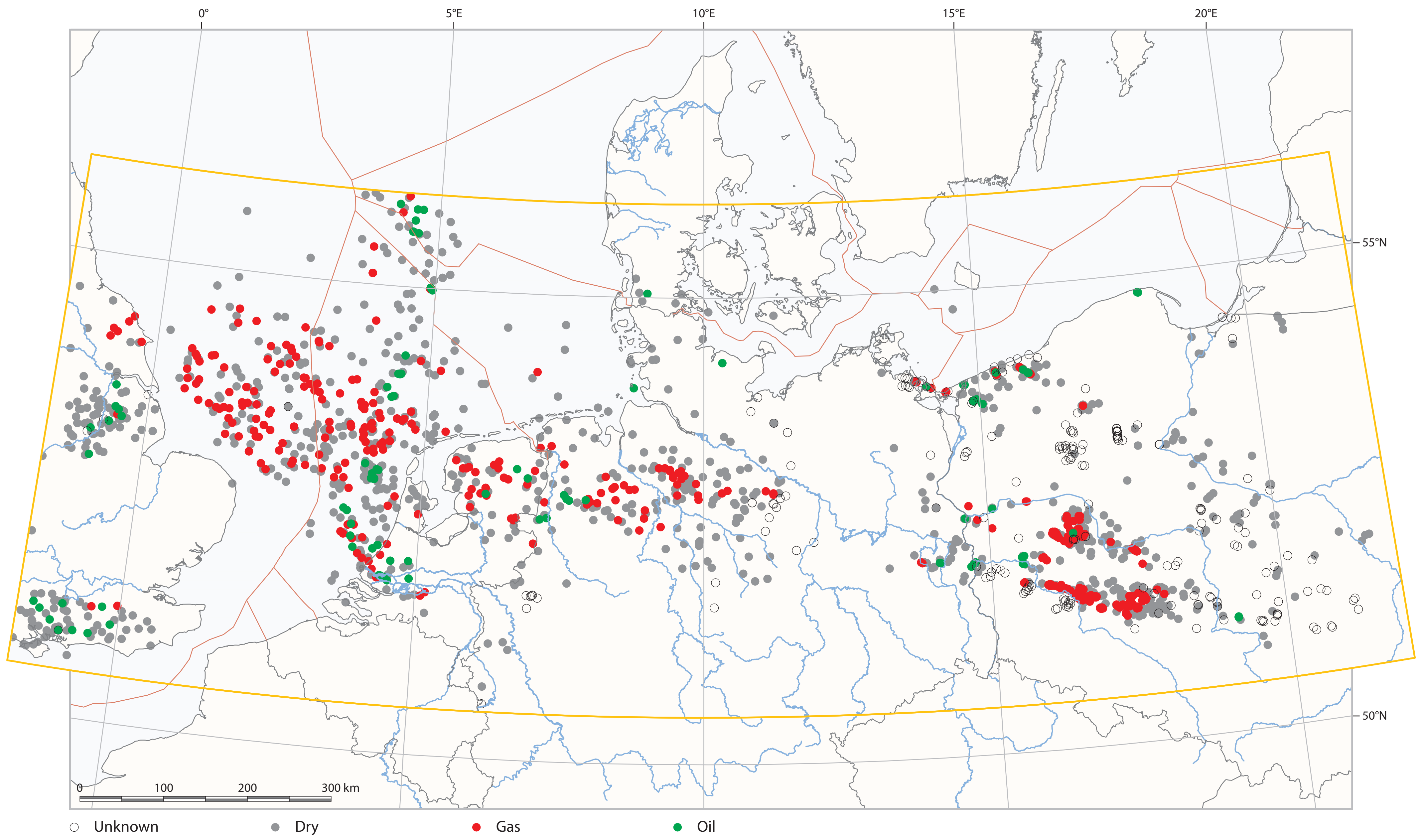


Figure 14.13c *Exploration wells drilled between 1980-89 showing results. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.*

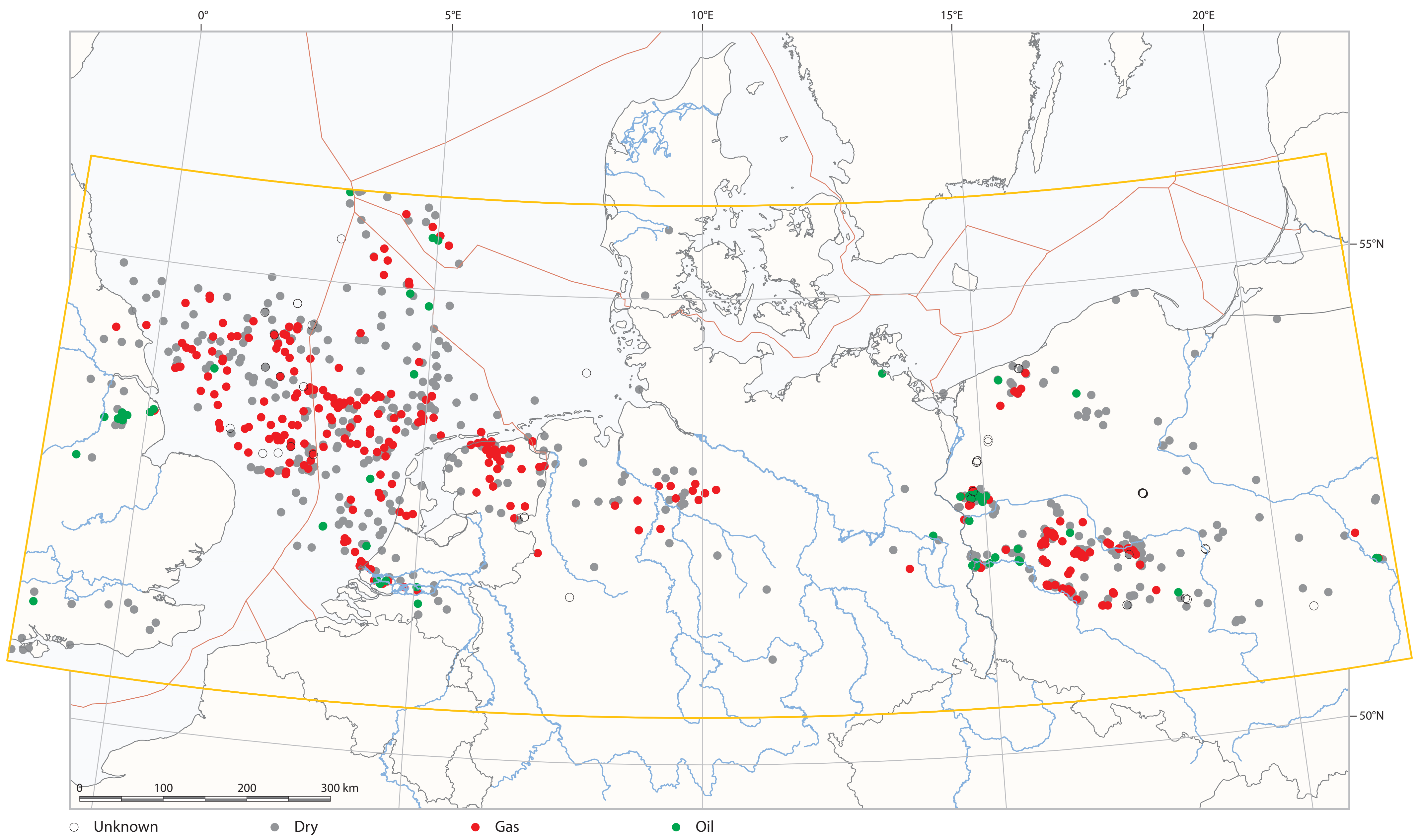


Figure 14.13d Exploration wells drilled between 1990-1999 showing results. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

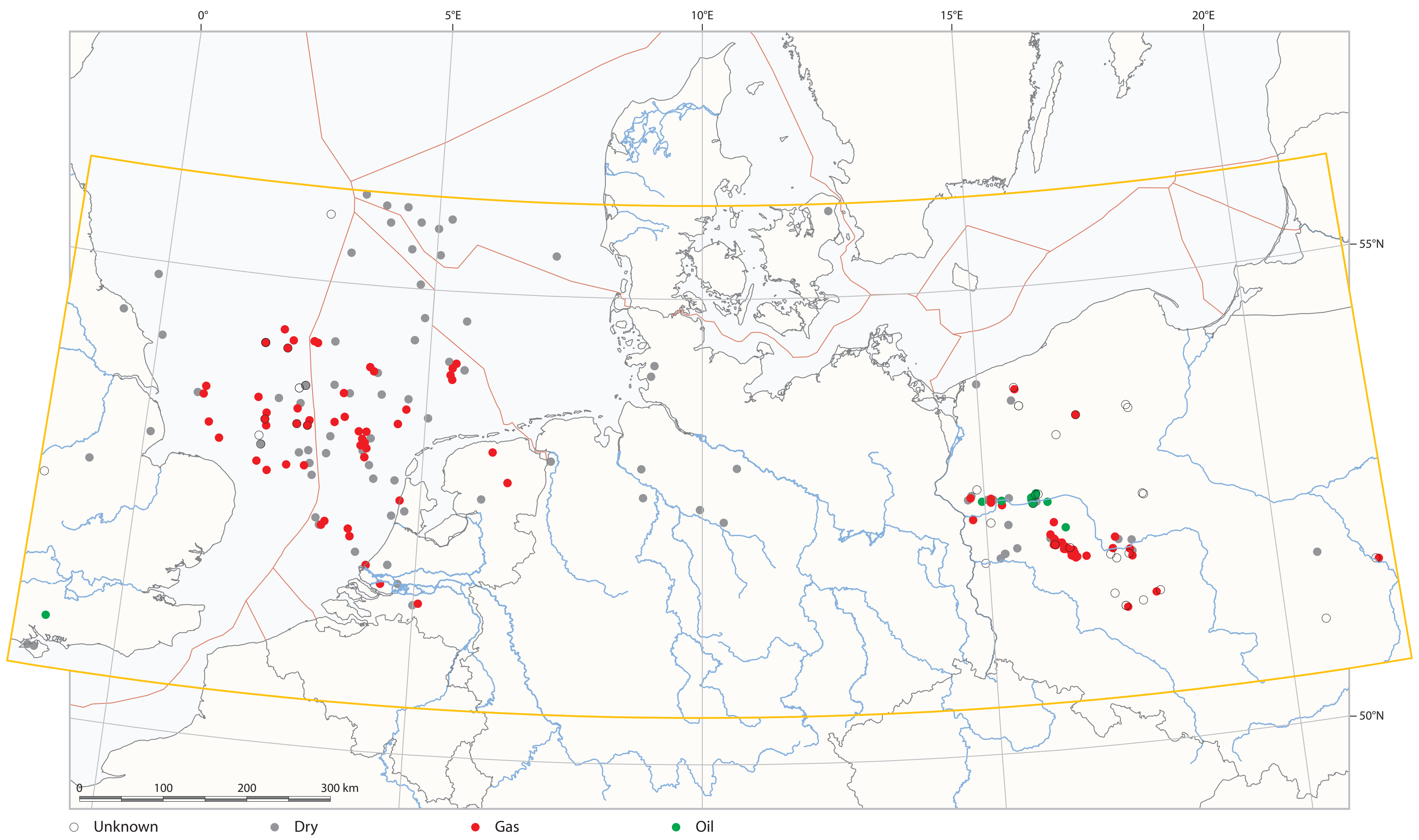


Figure 14.13e Exploration wells drilled between 2000-2006 showing results. Note all Polish wells are shown as exploration/appraisal/development can not be differentiated.

The Dutch exploration success rate (**Figure 14.17b**) also shows an inverse relationship; when fewer wells were drilled after 1992, they were more successful, and an overall increasing success ratio trend that topped at 75% in 2005. The Rotliegend has the highest number of play penetrations with an average 42% success, but Triassic, Cretaceous and unknown age plays have been drilled (**Figure 14.18b**). There is a diverse age of successful wells in the Netherlands and the Rotliegend comprises only 38% of the discoveries (**Figure 14.19b**).

The SPBA area includes only the southern part of the Danish exploration area. Since the discovery of the Halfdan (Section 4.2 in Chapter 11) and Sif fields in 1999, newer discoveries have been made north of the SPBA, which explains the apparent recent decline in success. The Cretaceous is the most successful play, with a 50% success rate, followed closely by Jurassic plays with a 30% success rate and some Zechstein and Triassic plays with lower success rates (**Figure 14.18d**). Looking at the number of wells drilled in each play, Cretaceous wells comprise 66% of the discoveries, followed by Jurassic successes comprising 30% (**Figure 14.19d**). The exploration success rates in Germany (**Figure 14.17c**) have shown a steady increase since the application of modern geoscience; most of the wells drilled before 1970 had low (<10%) success rates. A success rate up to about 50% was achieved as drilling continued in the mature basin in the mid-1990s. The play-penetration data are not complete for the German wells, so most of the wells are noted as 'unknown' on **Figure 14.18c**, but by excluding these wells on **Figure 14.19c** the diverse age of successful wells in Germany can be seen.

Exploration drilling can not be differentiated from appraisal or development drilling in Poland, but **Figure 14.17e** shows the poor success rate of early drilling before the advent of modern exploration technology in the 1970s and an increasing success rate through time. **Figure 14.16e** shows that the Fore-Sudetic Monocline petroleum province is the most drilled with a greater than 30% success rate. Wells from this province make up 92% of the successful wells, excluding the 712 wells with unknown result (**Figure 14.19e**). An analysis of the number of exploration-well penetrations into each of the age stratigraphic plays, and whether or not the wells were successful in finding hydrocarbons, is shown in **Figure 14.20**, which shows that the Rotliegend is the most successful play and demonstrates the poor success rates of early German drilling, which pre-dated modern seismic acquisition and imaging technology.

4.4 Factors that influence drilling investment and success

The amount of exploration has fluctuated in response to many factors, both globally (e.g. oil price, perceived prospectivity in other international basins) and locally (e.g. prospectivity, regulatory and tax change) influenced. Together, these components interact to produce a complex response to market conditions including the access to acreage in licence rounds and commercial deals, changes in the tax and fiscal regime, the availability and cost of drilling rigs, commercial barriers and enticements, the availability of infrastructure, State participation, perceived technical risk and reward and, more recently, environmental considerations.

Exploration drilling in Germany and all drilling in Poland is largely decoupled from oil prices and reflects the trend of gradual decline in activity since 1960 (**Figure 14.8b**). Exploration activity in the UK, the Netherlands and Denmark is more closely related to oil price. It is interesting to note that the oil price

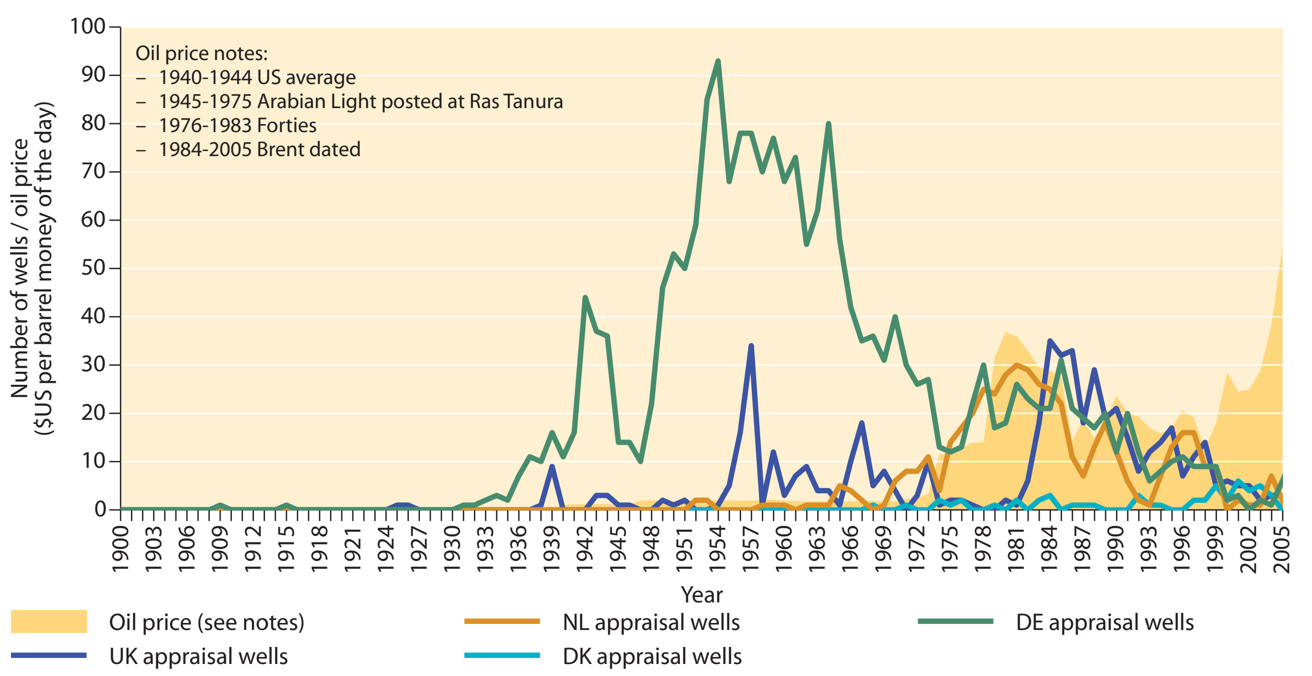


Figure 14.14 Comparison of appraisal wells drilled and the price of oil.

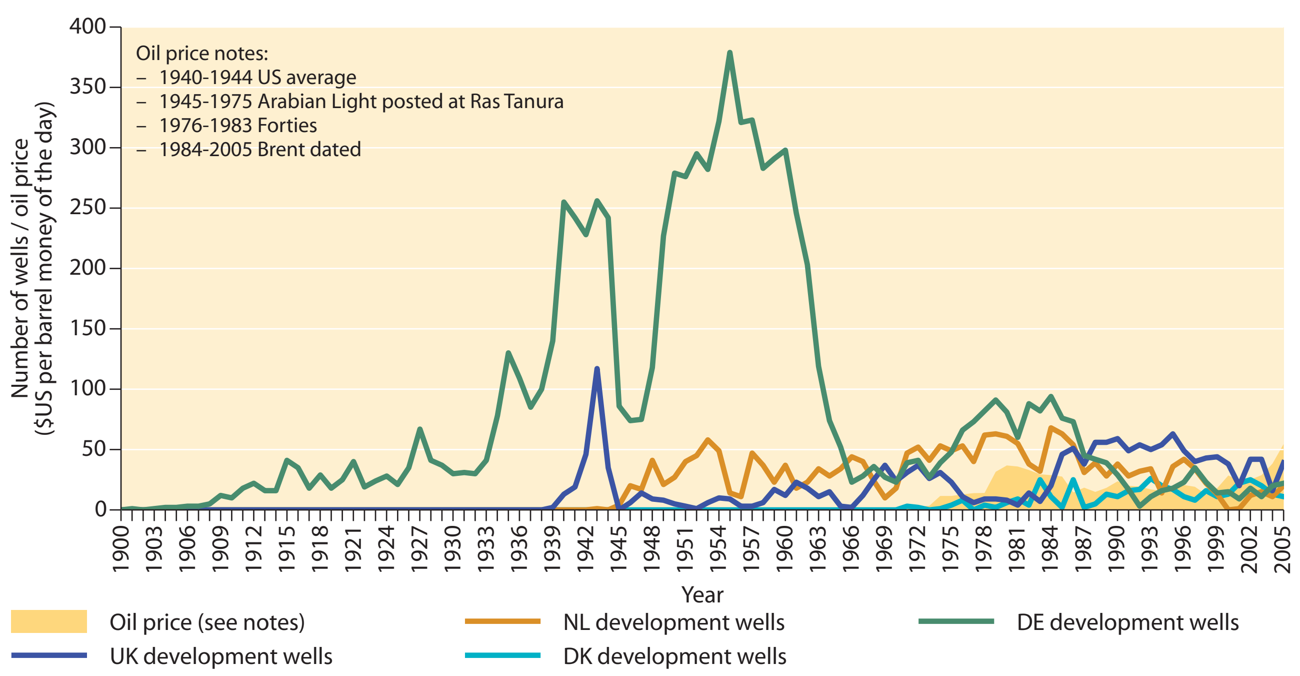


Figure 14.15 Comparison of development wells drilled and the price of oil.

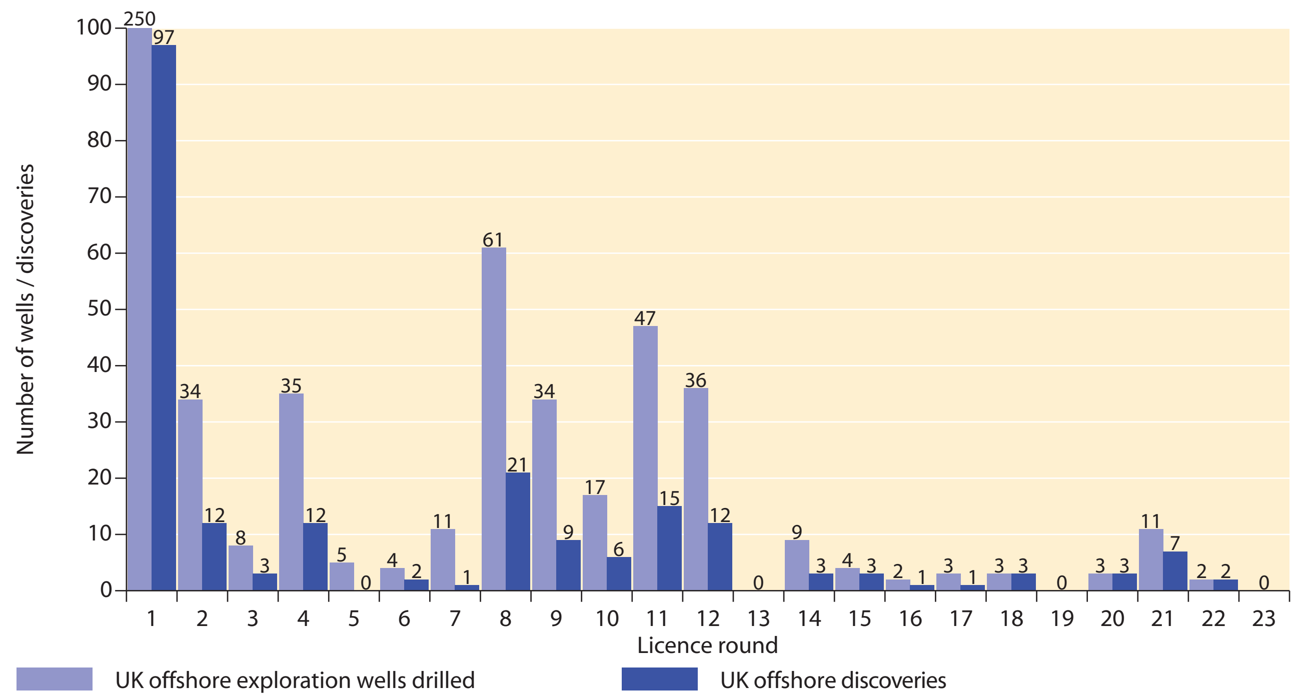


Figure 14.16 Comparison of exploration wells and discoveries by licence round: UK (offshore only).

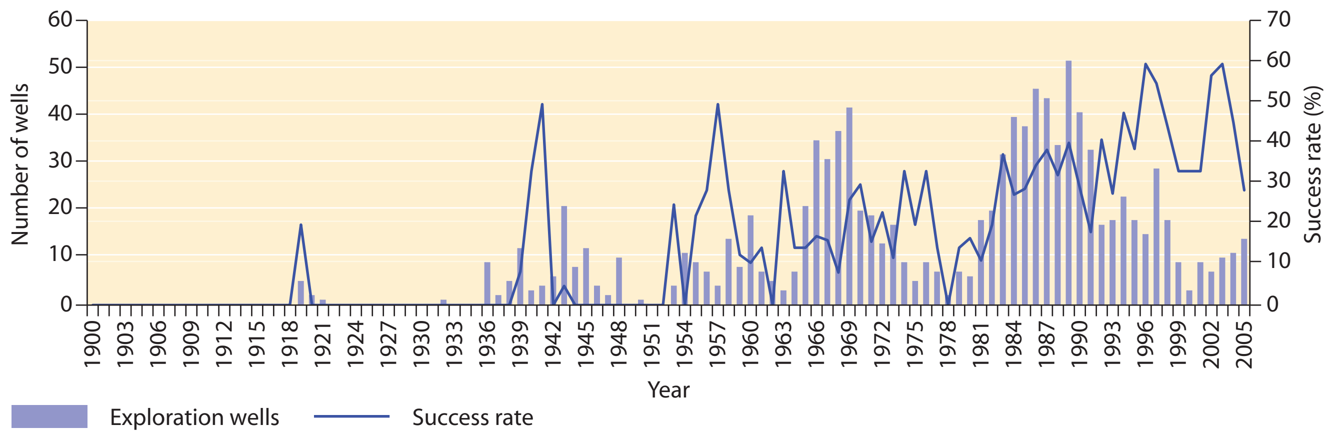


Figure 14.17a Comparison of exploration wells and discoveries by year: UK.

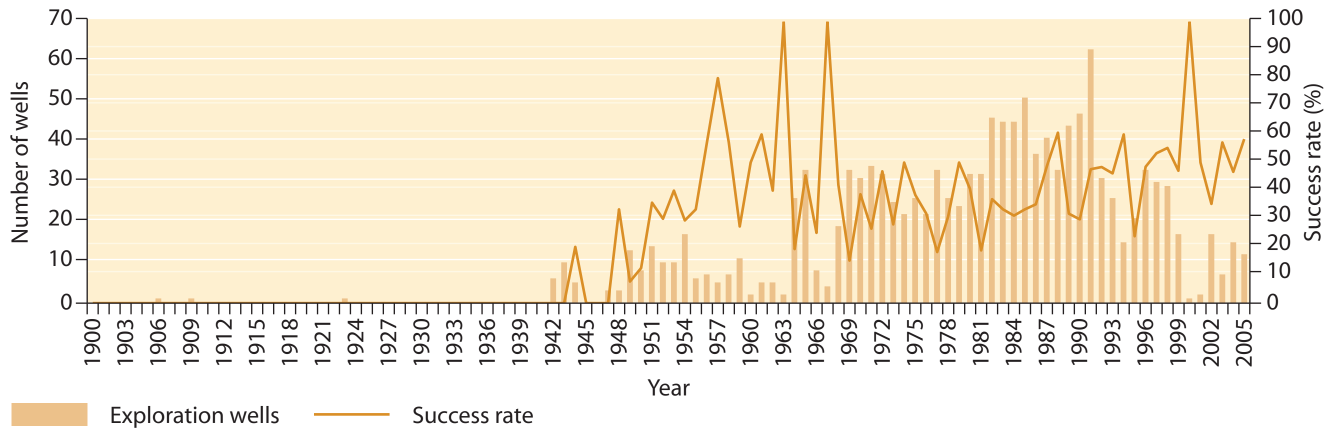


Figure 14.17b Comparison of exploration wells and discoveries by year: NL.

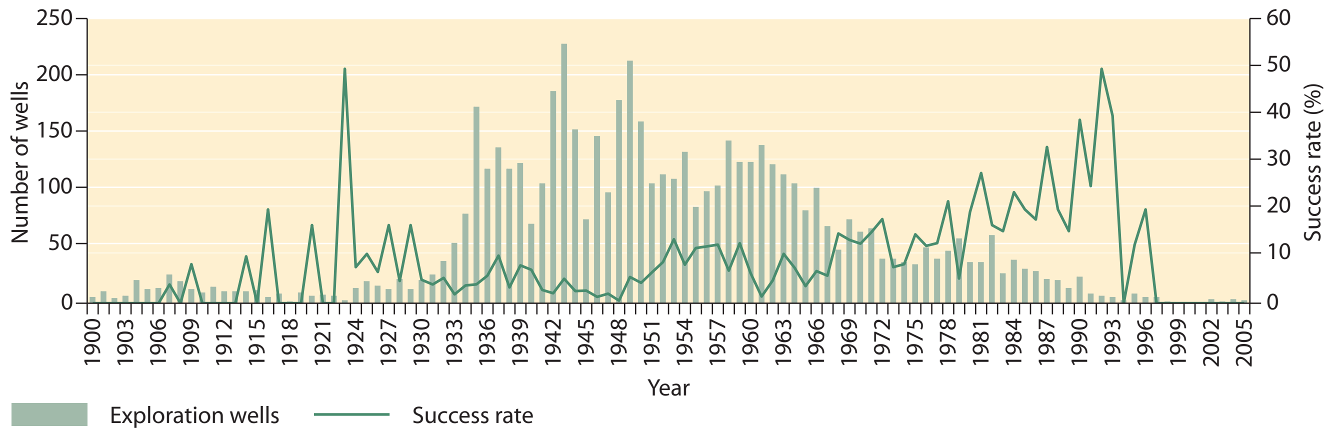


Figure 14.17c Comparison of exploration wells and discoveries by year: DE.

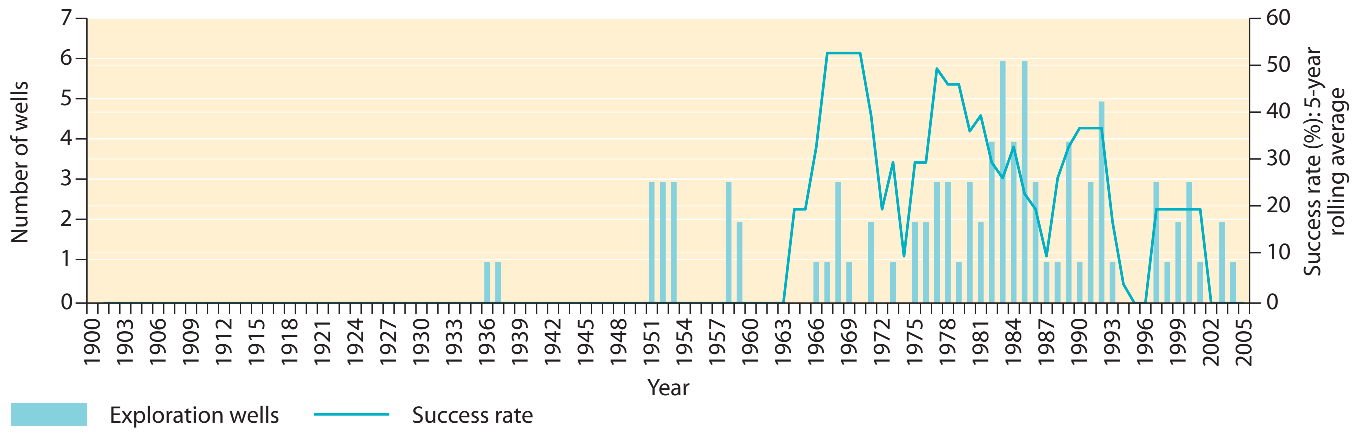


Figure 14.17d Comparison of exploration wells and discoveries by year: DK.

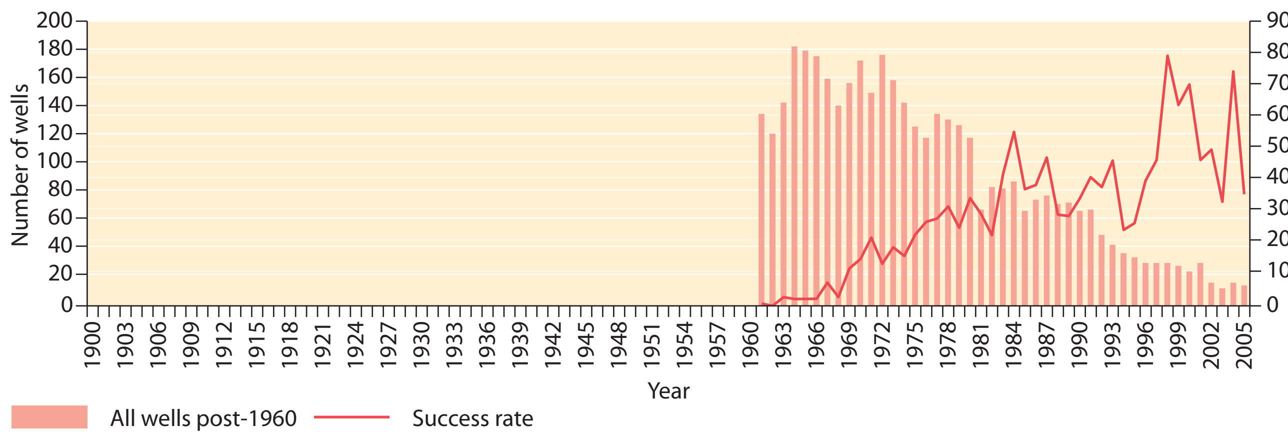


Figure 14.17e Comparison of all wells and discoveries by year: PL (Note: cannot differentiate between exploration, appraisal and development wells).

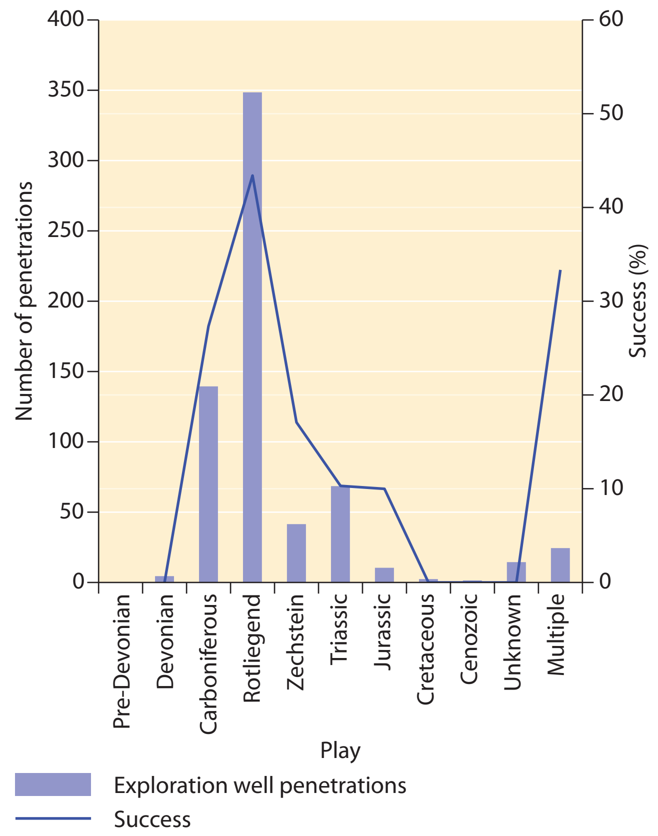


Figure 14.18a Total number of play penetrations and percentage success in individual plays: UK (offshore only).

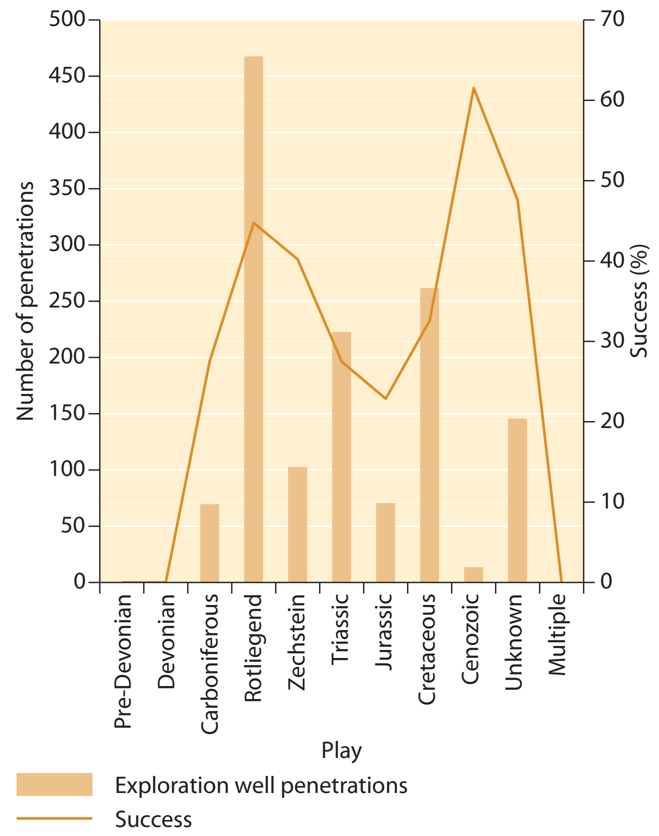


Figure 14.18b Total number of play penetrations and percentage success in individual plays: NL.

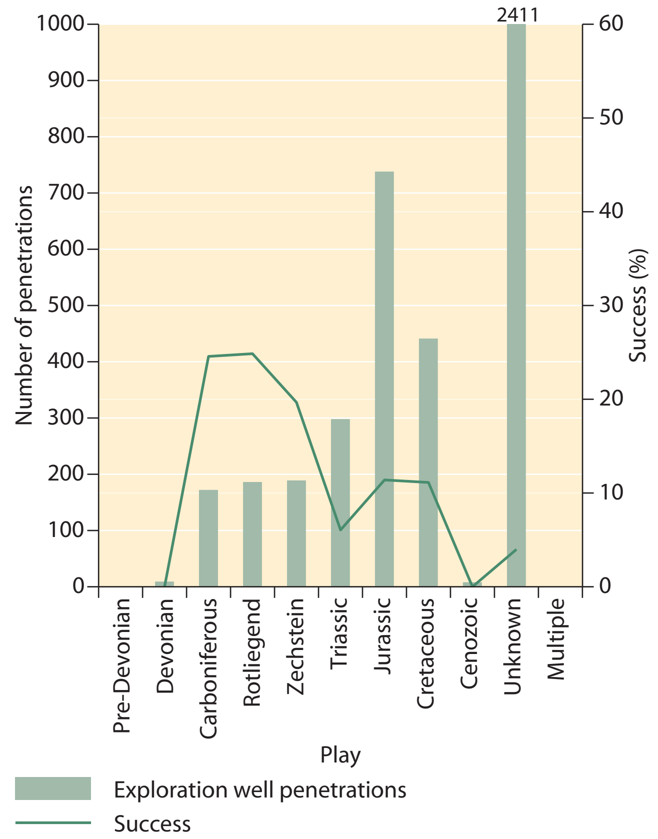


Figure 14.18c Total number of play penetrations and percentage success in individual plays: DE (excludes 1558 wells with unknown result).

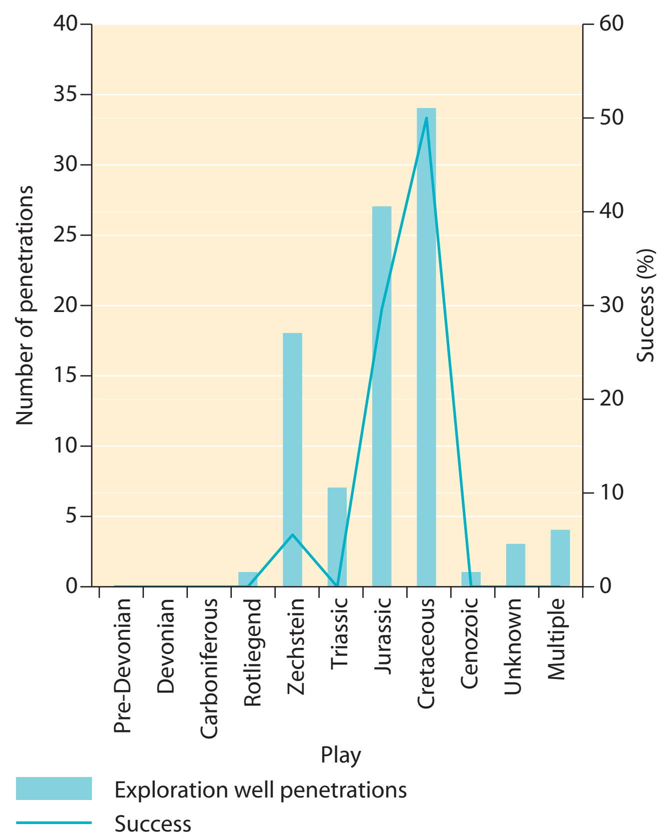


Figure 14.18d Total number of play penetrations and percentage success in individual plays: DK.

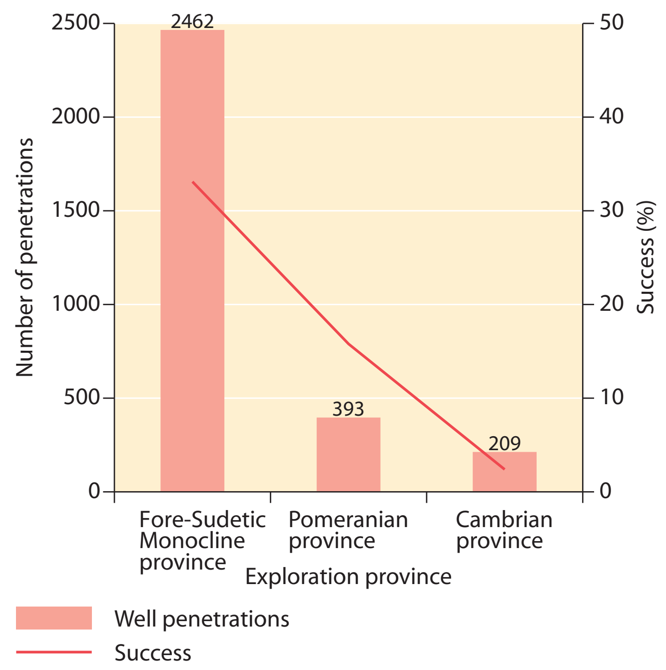


Figure 14.18e Total number of play penetrations and percentage success in exploration provinces: PL (post-1960; excludes 712 wells with unknown result).

increase in 1979-80 was reflected by a gradual increase in exploration drilling that peaked in about 1990 fuelled by exploration success, but it was restrained by relatively conservative price forecasts predicted by the industry. However, in contrast to the slow response to oil-price rise, the oil-price drop in 1998 was soon followed the next year by a drop in exploration drilling from which the industry has yet to recover, despite the dramatic increase in oil price seen in recent years. The worldwide demand for drilling rigs and development hardware, increased environmental requirements, and the shortage of experienced geoscientists and engineers, has made the SPBA area an expensive place to operate (particularly offshore), although new large discoveries are still being made.

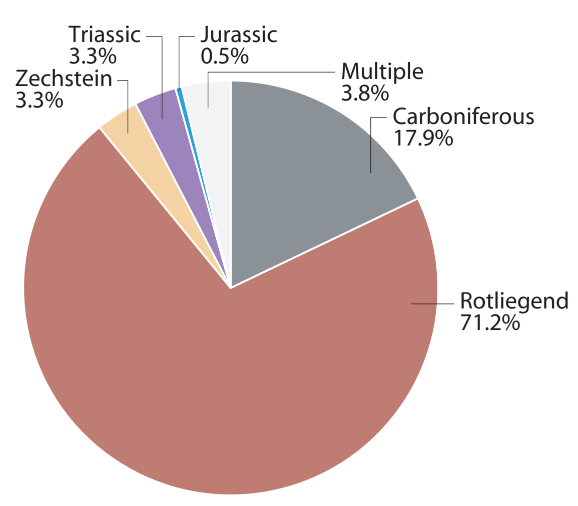


Figure 14.19a Play success: UK (offshore only).

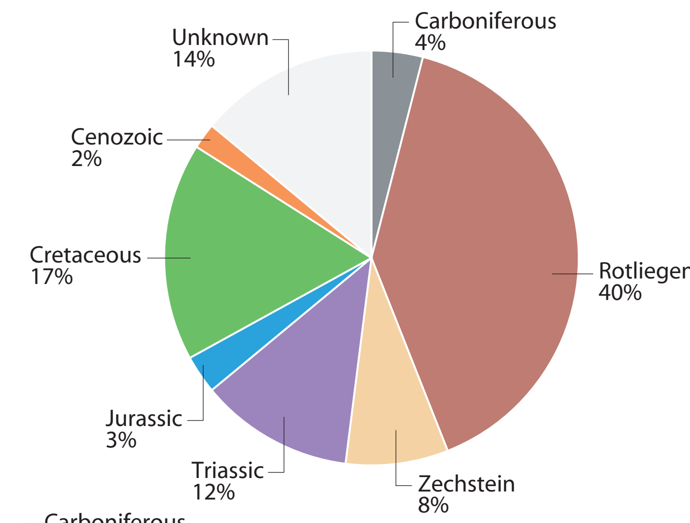


Figure 14.19b Play success: NL.

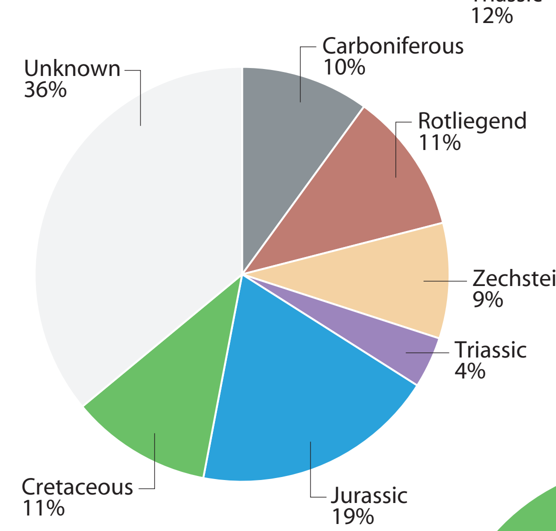


Figure 14.19c Play success: DE (excludes 1558 wells with unknown result).

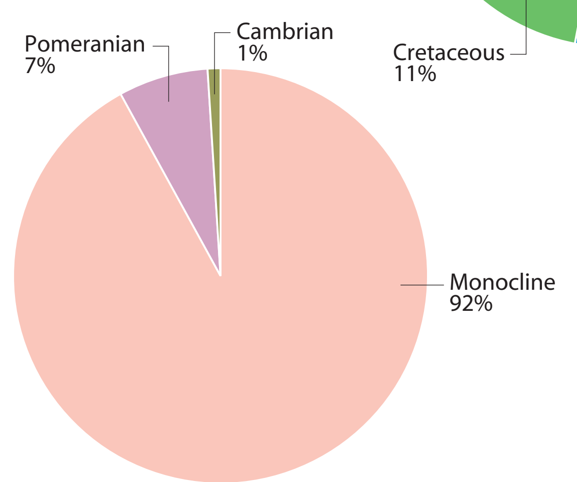


Figure 14.19d Play success: DK.

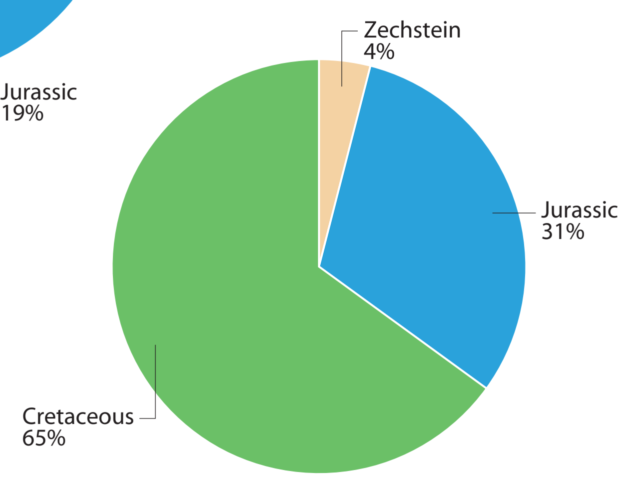


Figure 14.19e Province success: PL (excludes 712 wells with unknown result).

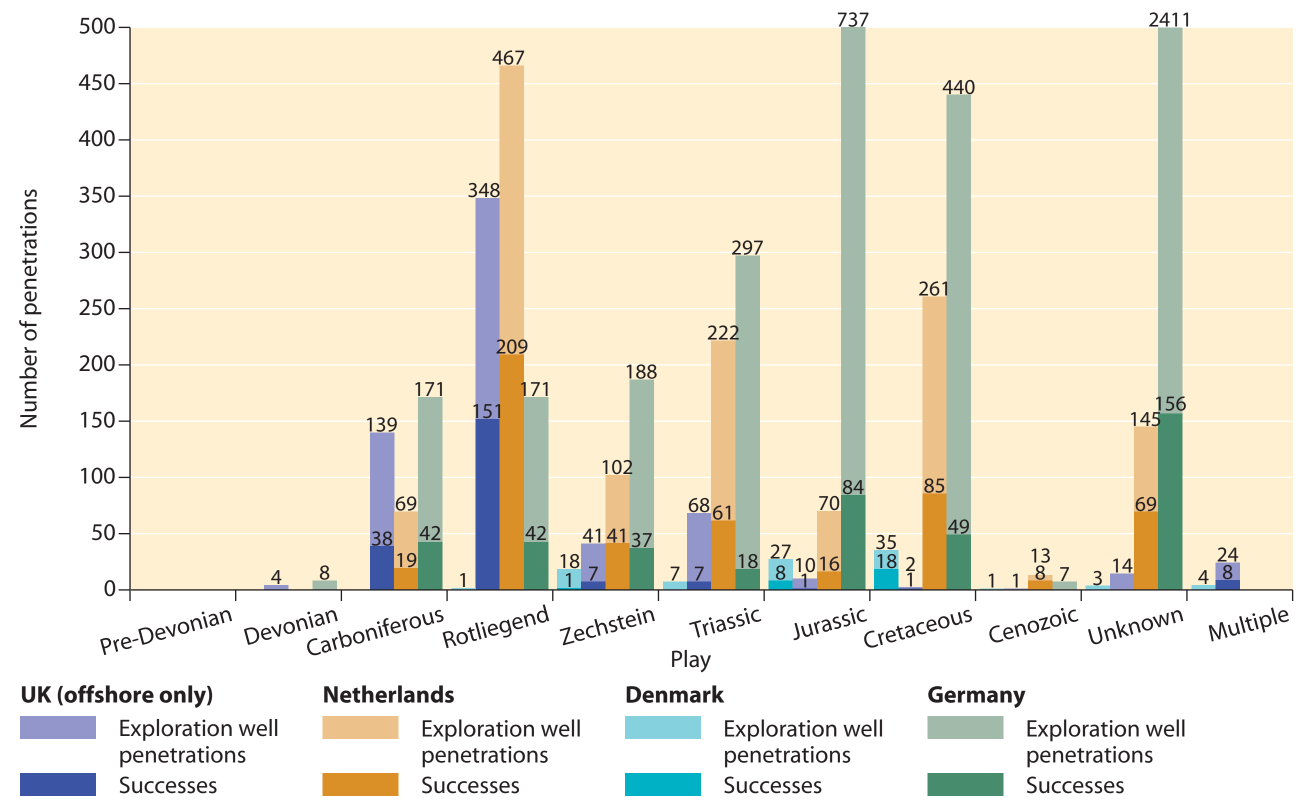


Figure 14.20 Comparison of each country's success in each play.