THE OXFORD INSTITUTE FOR ENERGY STUDIES

July 2021

Dutch Gas Production from the Small Fields:
Why extending their life contributes to the energy transition

OIES ENERGY COMMENT

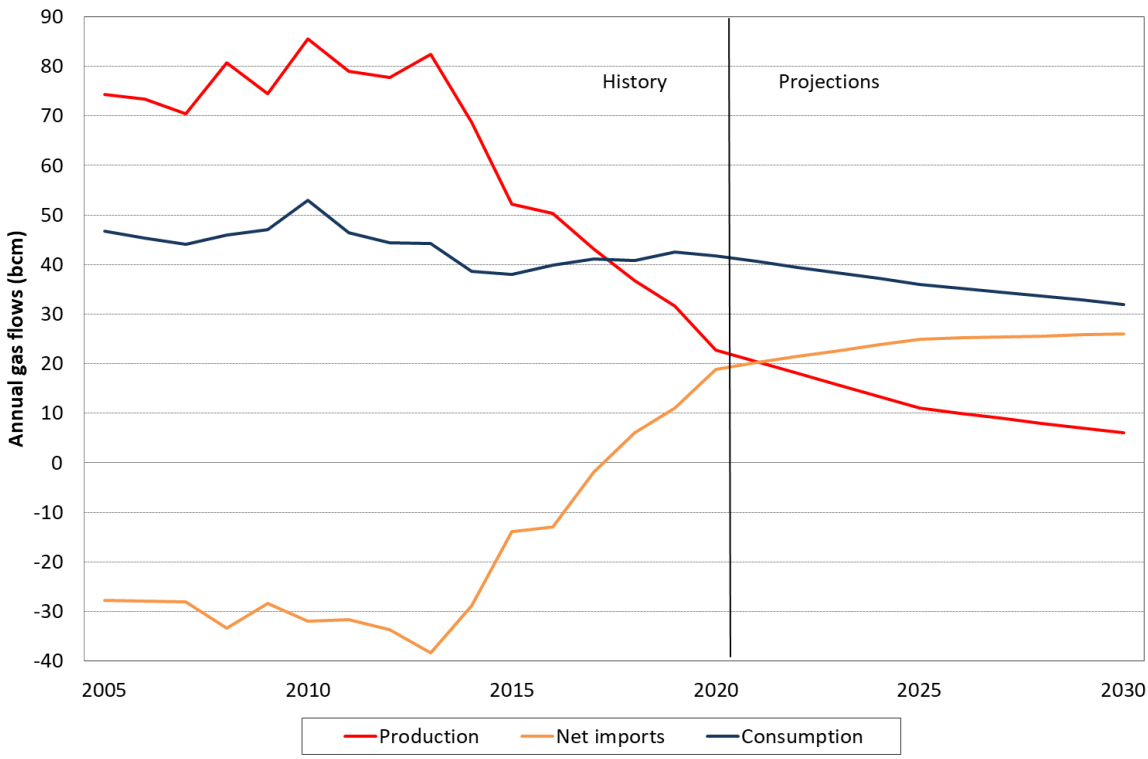
Marshall Hall, Senior Research Fellow, OIES

Introduction

The Netherlands can justly claim to be the cradle of the modern European gas industry and remains one of the European economies most dependent on natural gas to meet energy demand in heating, industry and power generation. In 2019, natural gas met 41% of Dutch primary energy demand, matched only by Italy among EU member states. It also has one of the most ambitious plans in Europe to decarbonise its economy, setting out in its 2019 Climate Law (*Klimaatwet*) a target to reduce greenhouse gas (GHG) emissions from 221 mtCO_2e in 1990 by 49% by 2030 and by 95% by 2050. In 2020, GHG emissions fell 8% to an estimated 166 mt CO_2e, due largely to the effect of the coronavirus pandemic, but were still only 25% below the level in 1990. The size of the Dutch agricultural and industrial sectors makes the 2030 target particularly demanding but the introduction in 2021 of a new national carbon tax on industrial emissions to supplement the EU ETS signals a political willingness to pursue decarbonisation with a range of new policies and instruments.

Domestic production of natural gas has been in steady decline since 2010, a trend accelerated by the restrictions imposed from 2014 onwards on Groningen production because of damage caused by local earth tremors, the government decision in March 2018 to cease all production from Groningen by 2022 and growing political ambivalence and policy neglect towards the other 'small fields'[1]. The historical trends in Dutch gas production and consumption, and published projections to 2030, are shown in Figure 1. Natural gas accounts for almost all Dutch upstream production of hydrocarbons (195 million boe in 2019) and is directly responsible for 1.6 mt CO_2e, or less than 1 per cent of national GHG emissions. The GHG emission intensity, and methane emission intensity, of Dutch gas production is exceptionally low by international standards. Almost half current Dutch gas production and two-thirds of small field production come from the North Sea. Plans for the energy transition include increased wind generation, hydrogen production (green and blue) and CO_2 storage using existing upstream gas infrastructure.

Figure 1: Dutch gas production, consumption and net imports 2005-30



Source: Statistics Netherlands (CBS), PBL Environmental Assessment Agency, EBN (projections)

[1] In this paper, we refer to all non-Groningen fields as the 'small fields'.

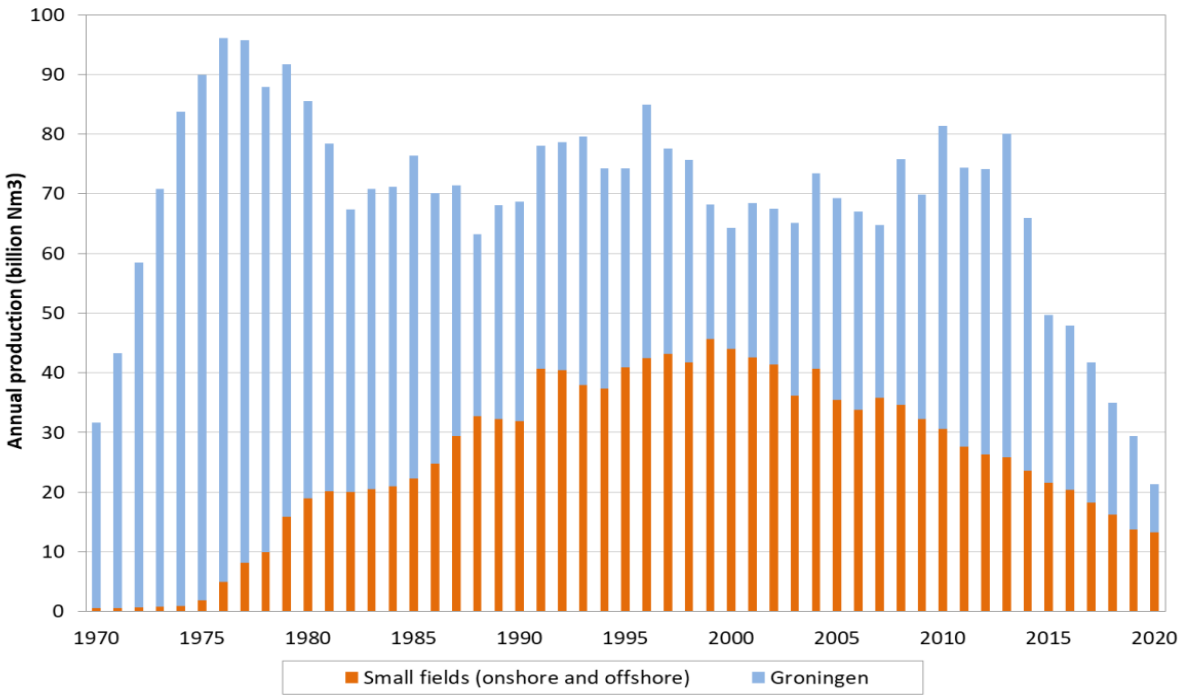
Small fields policy and Groningen phase out

In the late 1970s, at a time when the giant Groningen field was producing 75-85 bcm per year[2], the Dutch government adopted its successful 'small fields policy' designed to promote the development of other domestic gas resources and to allow the huge reserves of the Groningen field to be managed as a long-term store of economic value and secure domestic supply.

As shown in Figure 2, gas production from the 'small fields', found both onshore and in the shallow waters of the North Sea, rose steadily to peak at more than 40 bcm per year between 1995 and 2003, exceeding production from Groningen for a decade. Thereafter, the gradual depletion of existing discovered reserves and fewer new discoveries led to a progressive decline in output at an average rate of about 6% per year. This expected contraction of small field production was compensated by increasing output from the Groningen field which produced an average of 50 bcm per year in 2010-13. With the exception of some smaller onshore fields, almost all gas produced from the small fields is H-cal gas with a higher energy content than L-gas or 'Groningen equivalent' gas (35.17 MJ/m^3).

The frequency and intensity of earth tremors at the NAM-operated Groningen field had been increasing in the years leading up to 2012, causing damage to local buildings and presenting a risk to local residents. The Huizinge earthquake in August 2012 marked a key turning point and led to progressive tightening of restrictions on annual Groningen output. This lengthy political and legal process amid continuing seismic events culminated in the government decision of March 2018 to halt Groningen production by 2022[3]. In 2020, Groningen output had fallen to 8 bcm. The government plans to cease 'normal production' in 2022 and to keep the field for back-up production in cold winters until about 2025-26 by which time all new nitrogen injection capacity should be in operation and all L-cal gas consumers will have been converted to H-cal gas supply or to other energy sources. Negotiations between the government and NAM on this back-up phase are still continuing.

Figure 2: Dutch Gas Production 1970-2020



Source: Ministry of Economic Affairs and Climate Policy (EZK) annual reports, TNO

[2] All gas volumes in this paper, drawn from Dutch government sources (Ministry of Economic Affairs and Climate Policy, TNO and CBS) are expressed in normal cubic metres (Nm^3) based on 0^0 C and 101.3 kPa.

[3] 'Groningen gas: the loss of a social licence to operate', J van den Beukel and Lucia van Guens, Hague Centre for Strategic Studies, February 2019.

As the restrictions on Groningen were introduced, it might have been expected that government policy would seek to extend the productive life of the small fields to mitigate the impact on gas imports and upstream tax revenue and to maximise the local supply of H-cal gas. Instead, the operating environment and investment climate for the small fields gradually became more difficult as growing public concern over climate change was expressed as opposition to all domestic gas production and hostility to oil and gas company operations. Even though onshore small fields have not been the cause of local earth tremors on the scale experienced at Groningen, they suffered from 'guilt by association' and successive coalition governments were unable or unwilling to promote continued investment in the small fields[4]. Local and provincial authorities, though not responsible for gas production, began to obstruct onshore developments by delaying permitting procedures.

The investment climate deteriorated progressively from about 2015, and the decline in small field output began to accelerate just as the curbs on Groningen production pushed the Netherlands to become a net importer of gas, for the first time ever, in 2018. The period of decline in small field output to about 2015 was largely attributable to unavoidable resource depletion but since 2015 the small fields have suffered from government inaction, policy neglect and periods of low gas prices. In just three years, between 2016 and 2019, small field production fell 32%, from 20.4 bcm to 13.9 bcm. Aside from the financial consequences of this trend (lower tax revenues and earlier decommissioning costs, borne in part by the state), there are also adverse consequences for global GHG emissions and the Dutch energy transition. Premature cessation of offshore production could lead to the earlier decommissioning of infrastructure (platforms and pipelines) which may be of value to future carbon capture and storage (CCS) projects and offshore generation of renewable electricity and hydrogen.

Current production from the small fields

In 2020, marked by the start of the coronavirus pandemic, a contraction in demand and low gas prices, gas production from the small fields fell for the 13th consecutive year to 13.3 bcm, comprising 9.4 bcm from offshore fields and 3.9 bcm from onshore fields mainly in the north of the country. The fall of 4 per cent in small field production in 2020 represented a slowing of the rate of decline seen in recent years[5]. Production from the Rotliegend and Triassic reservoirs dominates onshore output but offshore there is a much larger and rising contribution (3.4 bcm in 2020) from other reservoirs, notably from the 'shallow gas' Tertiary deposits in the northern offshore area and from the Carboniferous reservoirs.

The small fields really are indeed very small individually, comprising 93 producing fields onshore and 144 offshore in 2020. Production from the largest onshore field (Nes) averaged just 1.2 mcm/d in 2020 and the largest offshore field (A18-FA) produced only 1.6 mcm/d. NAM, a joint venture between Royal Dutch Shell and ExxonMobil, operates more than 82% of onshore production (3.2 bcm per year) whereas offshore licenses and production are more widely spread among major companies (NAM and Total), independents such as Wintershall and ONE-Dyas and private equity-backed operators such as Neptune Energy and Tulip Oil (recently acquired by Kistos).

At the end of 2020, there were 40 existing onshore production licences, held mainly by NAM, expiring between 2024 and 2038 and 11 valid exploration licences. No new *onshore* exploration licences have been granted since 2014 as the government has sought to distinguish between socially acceptable offshore activity and more intrusive and more visible onshore activity. Offshore, there were 106 production licences at the end of 2020, held by a wide variety of operators, expiring between 2021 and 2049 and a further 28 exploration licences. The award of offshore licences has continued without interruption in recent years but there was in 2020 a significant increase in the rate of relinquishment of licences or reduction in the licence area or duration. The area covered by valid hydrocarbon licences both onshore and offshore has diminished steadily since 2016 as the reduced appetite from upstream

[4] 'The deteriorating outlook for Dutch small natural gas fields', Jilles van den Beukel and Lucia van Geuns, Hague Centre for Strategic Studies, January 2020.

[5] Small field production in the first four months of 2021 fell 3 per cent compared to the corresponding period in 2020 and the rate of decline onshore continued to exceed the rate of decline at offshore fields.

investors has been accompanied by the government's desire to encourage only new *offshore* hydrocarbon activity and to promote onshore geothermal and offshore wind generation.

Figure 3: Summary of Small Field Resources and Production in 2020

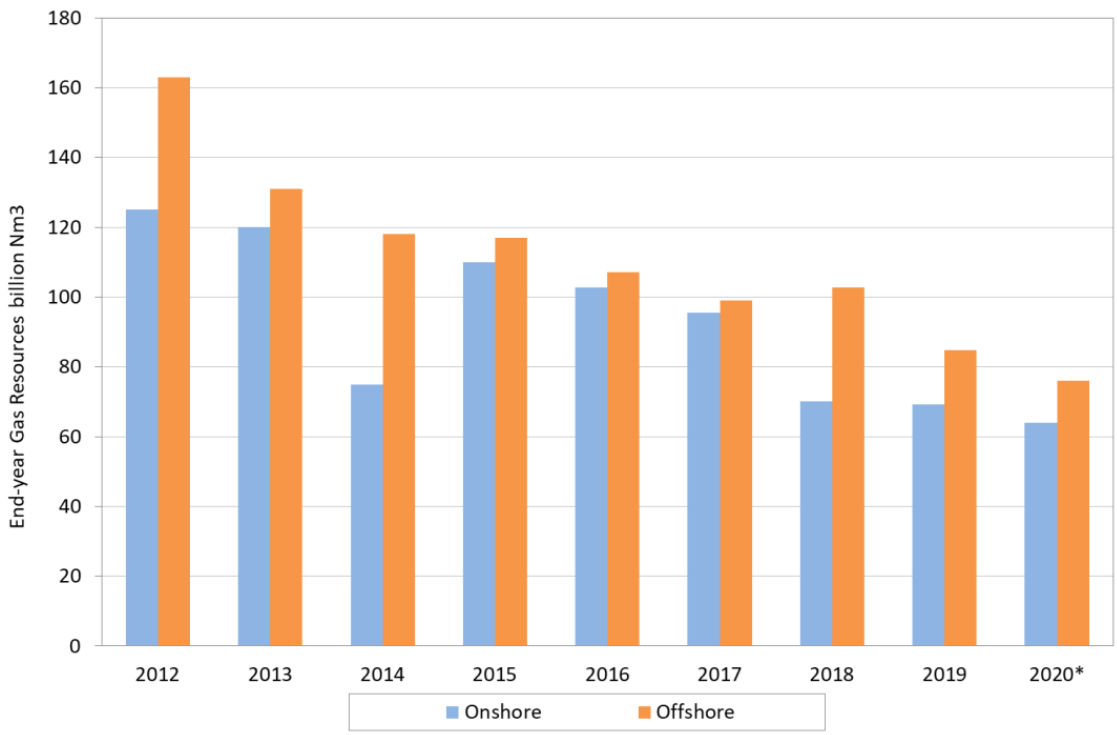
billion Nm³	Onshore	Offshore	Total
Gas resources (1 Jan 2020)			
Reserves	48.7	66.3	115
Contingent resources	20.5	18.5	39
Total resources	69.2	84.8	154
Production (bn Nm³)	3.9	9.4	13.3
Number of producing fields	93	144	237
Number of wells drilled	4	8	12

Source: EZK annual report 2020 and TNO database 2021

Remaining gas resources, exploration and future production

The remaining resources in the small fields have long been in decline as production has not been matched by reserve additions through successful exploration and appraisal drilling. Figure 4 shows the steady downward trend in annual end-year resource estimates since 2012, including the impact of two notable downward re-evaluations of onshore resources in 2014 and 2018. Over the same period, offshore resources have benefited from a modest net upward re-evaluation but have still shown a steady downward trend.

Figure 4: End-Year Gas Reserves and Contingent Resources in Small Fields 2012-2020

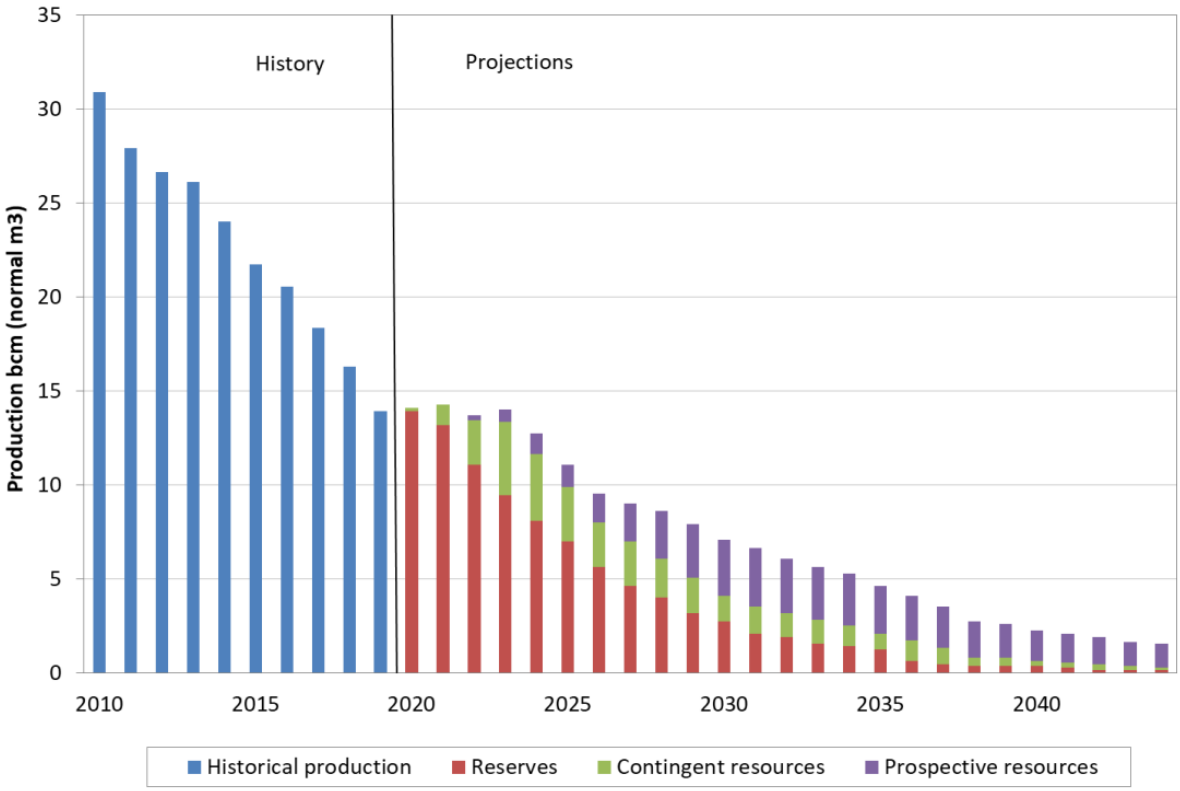


Source: EZK annual reports, TNO and author's estimate for end-2020, based on reported production.

The latest available estimate by TNO, the government's technical sub-surface advisor, of remaining gas resources (comprising reserves and contingent resources) in the small fields at the beginning of 2020 stood at 154 bcm[6]. The breakdown between resource categories and onshore and offshore is shown in Figure 3. Based on its sub-surface modelling, TNO put undiscovered or prospective gas resources in the small fields at a further 115 bcm.

TNO also derives and publishes annual projections of gas production from the small fields based on its threefold classification of resources (reserves, contingent resources and prospective resources), submissions from operators and its own sub-surface modelling. The latest projections for production, published in June 2020, are shown in Figure 5[7]. Production from existing resources is expected to decline steadily to about 4 bcm in 2030 and to cease in the mid-2040s. Possible production from development of currently undiscovered resources would raise output in 2030 to 7 bcm[8]. Total production from existing resources between 2021 and 2044 is estimated to be 114 bcm, or 159 bcm if prospective resources are included.

Figure 5: Projections of Small Field Gas Production 2020-44



Source: Natural Resources and Geothermal Energy Annual Review 2019, TNO, 2020

Over the last decade, out-turn production from the small fields has not matched TNO's projections. For example, as recently as 2017, production from reserves and contingent resources in 2020 was expected to be 18 bcm; the out-turn figure was 13.3 bcm. There are some technical reasons for the optimistic bias of past projections but the harsh reality is that the investment and political climate facing operators of small fields has deteriorated and few have been willing to deploy more capital in such an environment, especially in exploration. Long-established operators such as Total have chosen to sell their small field stakes to new private-equity backed investors such as Neptune Energy and late-life

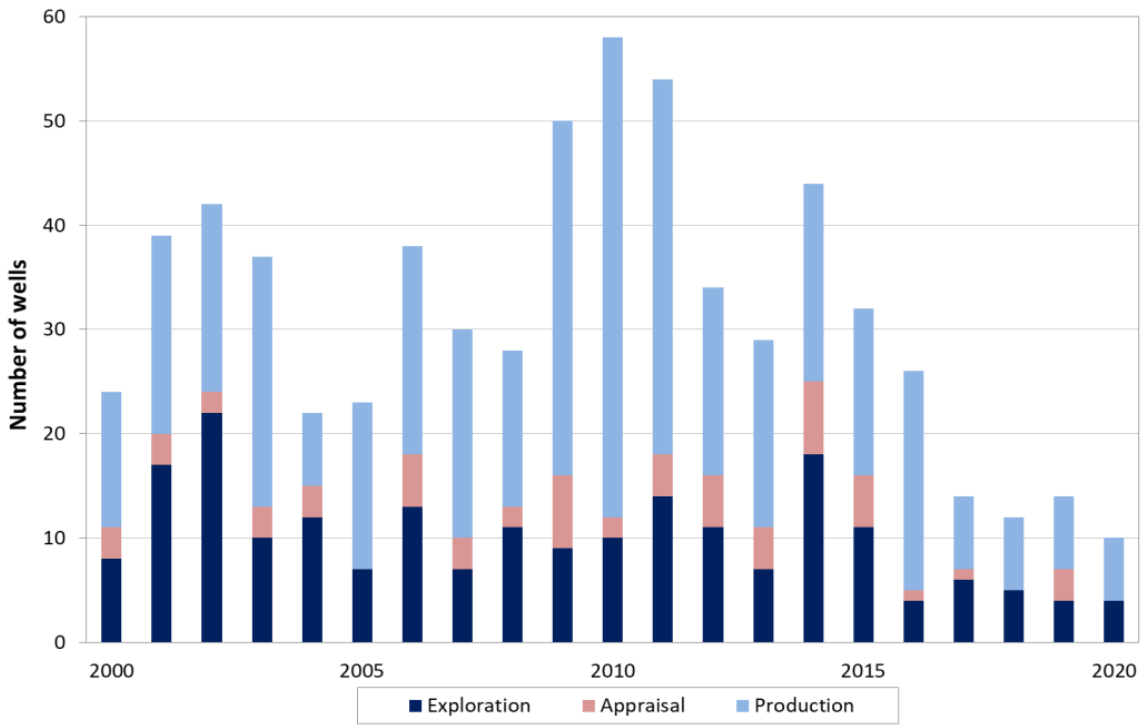
[6] Natural Resources and Geothermal Energy in the Netherlands: 2019 Annual Review, TNO, 2020. An update of the resource estimates is due to be published in mid-2021.
[7] Revised estimates of both resources and future production will be published in the forthcoming review of 2020.
[8] EBN, the state-owned upstream company, projects output of 11 bcm in 2025 and 6 bcm in 2030, reproduced in the PBL's Climate and Energy Outlook 2020 (KEV).

specialists. Some of these new investors have shown a willingness to invest in new offshore field developments and exploration if the economic and fiscal conditions are favourable but the overall upstream investment climate has for some years not been encouraging for investors.

Investment climate: fiscal reform, nitrogen restriction and carbon taxation

As in other highly mature gas-producing provinces, the economic viability of both existing production and future investment is sensitive to tax rates and investment incentives. If taxes do not take account of the gradual deterioration of underlying economics as fields are depleted, then operators may cease production and indirectly undermine the continued operation of existing infrastructure and the viability of other fields. The Dutch upstream tax regime comprises onshore royalty, corporate income tax and a state profit share (SPS). In addition, the state-owned company EBN is a 40% equity participant in almost all production licences onshore and offshore. The interaction of the corporate income tax rate and SPS delivers an effective tax rate of 45-50% on upstream profits, which since 2016 has been significantly higher than the effective rate in the adjacent UK Southern North Sea but lower than in Norway.

Figure 6: Dutch Oil and Gas Drilling Activity 2000-2020



Source: Natural Resources and Geothermal Energy in the Netherlands 2020, TNO 2021

Figure 6 shows the number of oil and gas wells drilled over the last 20 years and illustrates the progressive decline in activity over the last decade. The introduction in 2010 of a marginal field tax incentive gave a short-lived boost to exploration and production by allowing 25% of investment costs to be deducted from SPS but since 2014 activity has declined steadily due to a loss of international competitiveness and the fall in commodity prices and cash flows in 2015-16. A proposal to increase the marginal field tax incentive to promote new investment was announced in 2018[9] but was not presented to Parliament until June 2020 because of disagreement within the four-party coalition government and protests by climate activists over fossil fuel use and development. The increase in the marginal field

[9] Letter from Eric Wiebes, Minister of Economic Affairs and Climate, to Parliament, 30 May 2018

incentive from 25% to 40% was finally passed in January 2021 but was accompanied by a covenant agreement that it would not be used by onshore operators.

Just 10 wells were drilled in 2020, the lowest level for more than 40 years. Four exploration wells were completed, two onshore and two offshore, and six production or development wells were completed offshore. Appraisal and development drilling has all but ceased onshore. Activity last year was restricted by the coronavirus pandemic and low gas prices and some plans to drill were deferred to 2021. It is too early to say whether there will be a sustained recovery in investment and drilling activity in response to either the additional tax relief or the recovery in TTF prices. Without a significant increase in drilling activity in the next 2-3 years, the outlook for small field production will remain bleak.

The delay to fiscal reform and the collapse in prices were not the only reasons for the downturn in investment activity in 2020. In May 2019, the highest administrative court in the Netherlands confirmed a ruling by the European Court of Justice (ECJ) that the government's Nitrogen Action Programme (PAS) was insufficient to protect designated nature areas from excessive nitrogen deposition. Most of the Dutch nitrogen emissions responsible for the deposition in such areas come from the highly intensive agricultural sector, in particular livestock farming, with much smaller contributions from NOx emissions in construction, transport and industry. The ruling led to temporary measures to limit nitrogen emissions in specific non-agricultural sectors, including upstream oil and gas operations. This meant that public authorities were not able to issue new permits unless operators could demonstrate there would be no indirect effect on onshore nitrogen deposition. Drilling plans onshore and offshore had to be shelved and activity in building construction also slowed dramatically in late 2019 and 2020. Finally, in December 2020, a new 'nitrogen law' to address the livestock sector was agreed but until it passes the Senate in 2021 and a new government is formed to review the restrictions on other sectors, upstream operations and investment will continue to be adversely affected.

By the mid-2020s, Dutch gas producers, like other CO_2-emitting industries, will face the additional cost of the new domestic carbon tax which will rise from €30/tonne CO_2 in 2021 to €125/tonne in 2030. It is designed to top-up the EU ETS cost for CO_2 emitters when the EU ETS price is lower than the minimum national tax. Some installations within the current EU ETS will be exempt from the new tax, notably districting heating and electricity generation.

A system of 'dispensation rights' based on EU sectoral benchmarks of emission intensity and a 'reduction factor' set by the government will alleviate the early impact of the tax for installations which fall within its scope. However, beyond 2025, the new tax will begin to bite, raising the operating costs of domestic gas production in a way which will amplify the impact of field depletion and falling production on unit costs. In the absence of an EU carbon border tax or border adjustment (CBAM), the new tax will also put domestic gas producers at a growing cost disadvantage vis-à-vis pipeline and LNG imports. It may incentivise further efforts by Dutch operators to reduce CO_2 emissions but there is clearly a risk of carbon leakage if it leads to earlier cessation of late-life, small field production, unless an EU border tax or CBAM is implemented.

Dutch upstream GHG emissions

The Netherlands is a highly mature gas-producing province with a long record of good operating practice and high environmental standards regarding emissions to air, soil and water of both local pollutants and GHGs. The GHG emission intensity of Dutch gas production is exceptionally low by international standards at 8 kg CO_2e/boe (barrel oil equivalent)[10], reflecting the relatively low energy intensity of onshore and shallow water offshore gas production and a long history of stringent emission regulations. About 90 per cent of Dutch upstream CO_2 emissions fall within the scope of the EU ETS.

Upstream emissions of both CO_2 and methane have fallen progressively since 2010, and more rapidly since 2015, as production has declined and operators adopted measures to cut emissions, especially of methane. In 2019, total GHG emissions arising from drilling, processing and transportation in

[10] The international average upstream emission intensity is about 20 kg CO_2e/boe, according to survey data from IOGP. This indicative figure excludes emissions in transportation, liquefaction and regasification.

producing 195 million boe of oil and gas were 1.61 mt CO_2e, comprising 1.4 mt of CO_2 and a reported 0.22 mt CO_2e of methane emissions (8.7 kt CH_4)[11]. The entire upstream oil and gas sector accounted for less than 1 per cent of total Dutch territorial GHG emissions of 181 mt CO_2e. The low methane intensity of Dutch production is attributable mainly to very limited flaring and venting of gas, the electrification of many field and pipeline operations and the proximity to the GTS downstream pipeline network. TNO, the state's technical and scientific advisor, has undertaken onsite monitoring and measurement of methane emissions at onshore and offshore installations to ensure that reported data are reliable[12].

In many countries, the co-production of natural gas and liquids and the lack of reliable segregated emission data make estimation of the GHG emission intensity of natural gas supply a difficult task. However, the dominance of gas in the Dutch upstream production, accounting for 97% of total hydrocarbon output, makes the task much easier. The relatively high quality of reported emission data in the Netherlands allows us to be reasonably confident in the estimate of upstream emission intensity of 8.3 kgCO_2/boe (or 1.3 gCO_2/MJ). This puts Dutch gas production among the lowest-emission sources of gas in Europe, matched only by Norwegian gas. As long as Dutch consumers are burning natural gas, they can be confident that their own home-produced gas supply has the lowest possible carbon footprint.

The emissions case for maximising small field production

In recent years, it is the supply of gas to the Dutch market which has been changing rapidly, not the demand. The reduction in Groningen output and the accelerated decline in small field output led the Netherlands to become a net importer of gas in 2018, much of it destined for conversion to L-cal gas. In 2020, net imports rose to 19 bcm and may rise further in the short term as coal is displaced from power generation in pursuit of the 2030 decarbonisation target. Only later will gas demand begin to decline in heating, industry and power generation. The dramatic recent rise in gas imports has notable consequences for geopolitics and Dutch energy supply security but the consequences for global GHG emissions are those which concern us here.[13]

As Dutch gas imports increase, so do the global GHG emissions in the gas supply chain to the Dutch market. Gas imports come directly or indirectly by pipeline from Russia or Norway, or as LNG delivered to the GATE terminal. In 2020, the GATE terminal imported 5.8 mt of LNG (equivalent to about 7.8 bcm of gas), of which 2.6 mt came from Russia, 1.7 mt from the US and 1.3 mt from other sources[14]. Since both pipeline imports from Russia and all sources of LNG have much higher GHG emission intensity in production and transportation than local supply from the small fields, replacement of domestic production will, at the margin, raise global GHG emissions.

Quantifying the increase in global GHG emissions associated with gas imports faces a number of difficulties:

- the lack of transparency and inadequate monitoring and reporting of upstream GHG emissions
- the allocation of emissions between gas and oil streams where the two are co-produced
- systematic under-reporting of methane emissions from flaring, venting and leaks
- separation of emissions related to gas exports from those related to domestic gas supply where exports have some dedicated facilities e.g. Gazprom exports from Russia.

The result of this lack of transparency is that estimates of emission intensity of Russian pipeline gas and LNG delivered to NW Europe are highly uncertain and, at present, unverifiable. Both long-haul

[11] The calculation is based on a GWP_{100} for methane of 25, as adopted by the IPCC AR4. Some sources use GWPs as high as 80 to reflect the global warming potential methane over a much shorter period, typically 20 years.
[12] 'Measuring methane emissions at sea? TNO has a solution', TNO Insights, 21 April 2021.
[13] Gas Supply Security in the Netherlands: Geopolitical and Environmental Dilemmas, Patrahau and van Geuns, HCSS, March 2021 provides a comprehensive analysis of rising Dutch import dependence.
[14] IGU World LNG Report 2021 edition.

Russian pipeline gas and LNG sources in the US Gulf have in recent years been identified as high-emission sources of gas imports on account of, respectively, pipeline leakage of methane and high levels of flaring, venting and methane emissions, especially from fracking operations in the Permian Basin[15]. The sensitivity of the LNG industry to such climate-related concerns about the CO_2-intensity of liquefaction and the methane emissions from fuel gas production lay behind the emergence of 'carbon-neutral' LNG cargoes in 2020, backed, so it is claimed, by purchases of nature-based carbon offsets. However, the fundamental problem of reliably measuring upstream GHG emissions in producing the feed gas to LNG plants remains unresolved.

The estimated GHG emission intensity of pipeline gas and re-gasified LNG delivered to the Dutch GTS network is set out in Figure 7 below. The range associated with pipeline imports, mainly Russian, reflects the uncertainty over upstream emissions and methane leaks from long-distance pipelines. The equally wide range of estimates for LNG emission intensity 'from wellhead to market' arises from the wide range of emission intensity in liquefaction plants (0.2-0.8 tCO_2/tonne LNG), the uncertainty over upstream methane emissions and differences in shipping emissions between long-haul and short-haul sources. This is an area of emerging interest for both industry participants and policy-makers and the estimates in Figure 7 are subject to revision. The estimates are consistent with those published by the UK Oil and Gas Authority in 2020, based on work by Wood Mackenzie. It estimated that the emission intensity of LNG imported into the UK in 2019 was 59 $kgCO_2$/boe, compared to 22 $kgCO_2$/boe for gas produced on the UK Continental Shelf[16]. In the Netherlands, the disparity in estimated emission intensity between domestic gas production and imported LNG is even greater than in the UK.

Figure 7: Estimated GHG Emission Intensity of Gas Imports to Netherlands

	kg CO_2/boe	g CO_2/MJ
Dutch production	8 – 10	1.3-1.6
Pipeline imports		
Norway	8 – 10	1.3-1.6
Other sources	25 – 80	4 – 13
LNG imports	45 – 105	7 – 17

* assumes GWP of methane of 25; ranges reflect uncertainty over upstream emissions

In estimating the effect on global emissions of the replacement of declining Dutch gas production by imports, we have assumed a portfolio of Norwegian, Russian and LNG sources with an average emission intensity of 30 $kgCO_2$/boe (4.7 gCO_2/MJ). Based on this conservative assumption, a simple calculation shows that a net reduction of 1 bcm per year in Dutch small field production, replaced by imported gas, leads to an increase in annual global GHG emissions of about 135,000 tonnes CO_2e.

The carbon penalty of replacing low-emission gas from the small fields with imported gas can also be considered over the remaining life of the small fields. If, for any reason, only an additional 64 bcm of gas were recovered from the existing resources in the small fields from 2021, rather than the TNO's projected figure of 114 bcm, the cumulative global GHG emissions increase would be about 7 million tonnes CO_2e. Under carbon accounting rules and international agreements, the Netherlands would not be responsible for these extra-territorial emissions but they would represent a small detriment to worldwide emission abatement efforts.

It should be emphasised that these figures are at best rough estimates but they provide an indication of the likely beneficial effect on global emissions of maximising the output from the small fields as long

[15] The feed gas to the six US LNG export terminals (four on the USGC and two on the USEC) comprises both conventional output and shale gas from numerous plays and basins, not only the Permian.
[16] 'North Sea gas has lower carbon footprint than imported LNG,' UK Oil and Gas Authority, 26 May 2020.

as the Netherlands continues to consume natural gas. The estimates above are based on a GWP_{100} for methane of 25. Any increase in the GWP_{100} to 30-35, or the adoption of a shorter time horizon of 20-30 years and a GWP for methane of 60-85 for abatement policy purposes, would increase the benefit of extending small field gas production because of the exceptionally low methane intensity of Dutch gas production.

Offshore infrastructure value in the energy transition

In the Dutch Climate Agreement, carbon capture, utilisation and storage (CCUS) plays a major role in future industrial decarbonisation. In the public-private CCS projects currently being developed, involving GasUnie, EBN, TNO and direct public funding, the re-use of existing offshore platforms, gas pipelines and depleted fields for transportation and storage plays a central role. The most advanced is the Porthos project to capture 2.5 mt CO_2 per year from refineries and hydrogen plants in the Rotterdam area for storage in the depleted offshore P-18 field. In May 2021, the Dutch government agreed to grant up to €2 bn in public subsidies over 15 years via the sustainable energy transition scheme (SDE++) to bridge the gap between the price of CO_2 in the EU ETS and the cost of CCS in the project. A final investment decision by the public and private investors is expected in 2022.

A similar concept involving onshore capture and offshore storage underpins the Athos CCUS project in the Amsterdam-Ijmuiden area. Separately, Neptune Energy, the largest offshore gas producer, is conducting a feasibility study to store CO_2 in several depleted offshore fields in its L-10 area and to develop a full-chain CCS project. Despite the momentum behind CCS, the scale of its contribution to Dutch decarbonisation will be limited before 2030. Retaining access to existing offshore infrastructure may be needed well into the 2030s if these early CCS projects prove technically and commercially successful and the Dutch government wishes to embark on expansion in the 2030s. Maintaining future CCS options by extending the productive life of offshore gas fields seems, at this early stage, a desirable low-cost measure.

The Netherlands has also emerged as perhaps the most promising location in Europe for future green hydrogen production, based on its extensive natural gas infrastructure[17]. Initial plans for the NorthH_2 and Shell-Eneco projects incorporate new offshore wind capacity and power transmission lines to onshore electrolysis plants, using only existing *onshore* gas infrastructure for hydrogen transport and storage. The ambitious PosHYdon project, initiated by Neptune Energy, is based on offshore wind generation and offshore hydrogen production, using existing *offshore* gas pipelines in the NOGAT and NGT systems to transport hydrogen to onshore facilities. Commercial-scale hydrogen production is not expected before the late 2020s at the earliest and the competitive position of hydrogen as a route to decarbonisation in industry and transport is still not proven. However, ensuring that existing onshore and offshore gas infrastructure is not prematurely decommissioned and can be re-used for hydrogen is an essential element of Dutch decarbonisation strategy.

Conclusions

The stated aim of the Dutch government remains to maintain domestic gas production, especially offshore, but division within the coalition government, Parliament and society have, in recent years, prevented it from pursuing policies which would further this aim. Overshadowed by the experience of Groningen phase-out and popular opinion demanding action to address the 'climate emergency', the Dutch government has been unable or unwilling to mount a successful defence of the small fields despite recognising the global GHG emissions benefit of continued domestic production and the value of the existing gas production infrastructure for the long-term energy transition. By default, the Netherlands has pursued an uncomfortable middle way among European gas-producing countries, neither promoting responsible development and upstream emission reduction as in Norway and the UK, nor prohibiting future exploration and setting an end-date for production, as in Denmark, Ireland and France. This policy towards the small fields is all the more surprising given the participation of the

[17] 'Contrasting European hydrogen pathways: an analysis of differing approaches in key markets', M Lambert and S Schulte, OIES, March 2021.

state via EBN as a 40% shareholder in all upstream fields, their generally good environmental record and the interest of the government in deferring as long as possible its share of decommissioning costs estimated at €7 billion.

The value of domestic gas production no longer lies primarily in its financial contribution to public finances or security of supply, but in its contribution to lower global emissions of both CO_2 and methane. Dutch gas output has a lower GHG emission intensity than all imported sources, with the possible exception of Norway. Indeed, some of the sources of imported gas, particularly of LNG and possibly long-haul Russian gas, have an emission intensity many times greater than the output from the Dutch small fields. Dutch consumers are expected to continue to use natural gas well into the 2040s. As long as they do so, it would be optimal from a climate perspective to consume gas from sources which have the lowest GHG emissions in production and supply to the point of consumption. Public policy should seek to maximise the economic production from the small fields over their remaining 20-25 years. A policy which offers no incentive to extend the life of producing fields and to develop the remaining gas resources, especially offshore, make no sense from an environmental point of view as long as the Netherlands continues to consume natural gas.

The existence of physical offshore gas infrastructure and depleted fields and the accumulated expertise of its offshore operators means that the Netherlands enjoys options in its energy transition that are available to few other EU member states. CCS projects are proceeding towards FID with the assistance of strong private-public co-operation and state and EU funding. Longer-term plans to develop blue and green hydrogen production offshore, possibly from the late 2020s, could complement offshore generation from new wind farms and help to manage constraints on the electricity grid. Beyond 2025, when the most advanced CCS project (Porthos) may be in operation, the options to reuse existing infrastructure will diminish rapidly if investment in gas production offshore ceases entirely and facilities are decommissioned prematurely. The energy transition in the Netherlands, as elsewhere, will be a long and difficult journey. As the country embarks on this journey, the strong case for maximising economic recovery from the small fields and retaining future decarbonisation options deserves to be made and heard in the national policy debate.