The Regulatory Framework for Green Hydrogen Developments in the North Sea

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CHAPTER XIV

THE REGULATORY FRAMEWORK FOR GREEN HYDROGEN DEVELOPMENTS IN THE NORTH SEA

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1. INTRODUCTION

Historically the North Sea area has been an important source of economic growth for the countries surrounding it. The North Sea is one of the most heavily exploited marine environments in the world. There is fierce competition for space, with several economic activities, including fisheries, shipping, sand and shell extraction, recreational activities, hydrocarbon production and wind energy generation, taking place in the area. The existence of areas for military use and nature reserves adds to the congestion, as each activity claims part of the available space.[1]

The extent to which coastal States may regulate these activities depends on their location, and in particular whether they are taking place in territorial waters or the area beyond territorial waters, i.e. the continental shelf (CS) or the exclusive economic zone (EEZ).[2] While territorial waters are considered part of the land territory and thus the sovereignty of coastal States under the United Nations Convention on the Law of the Sea (UNCLOS),[3] coastal States

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1 The European Maritime Spatial Planning Platform, 'North Sea', available at <https://www.msp-platform.eu/sea-basins/north-sea-0> (accessed 4 January 2021).

2 For an elaborate analysis of the international law of the sea, see D.R. Rothwell and T. Stephens, *The International Law of the Sea*, Hart Publishing, Oxford, 2016.

3 United Nations Convention on the Law of the Sea, Montego Bay, 1982.

were given sovereign rights to explore and produce hydrocarbons if they have a CS[4] and to develop renewable energy sources if they declared an EEZ.[5] As the seabed of the North Sea is one CS and all North Sea States have declared an EEZ,[6] the development of hydrocarbons and renewable energy sources are subject to coastal States' sovereign rights and functional jurisdiction.[7] Based on their functional jurisdiction on the CS, North Sea States have explored for and produced large quantities of hydrocarbons using more than 600 offshore platforms and associated physical infrastructure. Given the gradual depletion of the offshore hydrocarbon resources and the need to meet the EU and national climate change goals, the North Sea States are now increasingly focussing on the development of offshore renewables and in particular offshore wind energy. Currently, 13 gigawatts (GW) of offshore wind capacity have been installed in the North Sea.[8] In the medium to long term, this capacity is projected to grow to 60 GW by 2030 and to approximately 180–250 GW by 2050.[9]

Such large-scale development of offshore wind energy faces many challenges, such as the need for appropriate offshore locations, sufficient capacity to bring the electricity to shore (grid congestion), and the management of intermittency and mismatches in demand and supply in order to avoid low or negative prices.[10] One of the means to overcome these challenges is to convert the electricity produced offshore into hydrogen.[11] Although attempts are made to convert electricity into hydrogen onshore, this option does not solve the problem of a potential lack of capacity in the offshore electricity cables. Therefore, the parties involved are also considering the possibility of converting electricity into hydrogen offshore. This chapter will focus on offshore hydrogen conversion.

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4 United Nations Convention on the Continental Shelf, Geneva, 1958.

5 The United Nations Convention on the Continental Shelf and UNCLOS have been signed and ratified by the North Sea States.

6 Several delimitation agreements have been concluded to delimit the borders of the coastal States bordering the North Sea; for these agreements, see C. Redgwell, 'International Regulation of Energy Activities' in M.M. Roggenkamp et al (eds.), *Energy Law in Europe: National, EU and International Regulation*, 3rd edn, Oxford University Press, Oxford, 2016, p 58.

7 Sovereign rights are understood as a collection of rights, which are limited and exist only where States have jurisdiction over particular sets of activities; see *Yearbook of the International Law Commission* (1956) vol. III, p 297.

8 F. Selot, D. Fraile and G. Brindley, 'Offshore Wind in Europe: Key Trends and Statistics' (2019) *Wind Europe*, p 19.

9 World Energy Council, 'Bringing North Sea Energy Ashore Efficiently' (2018), p 16, available at <https://www.worldenergy.org/assets/images/imported/2018/01/WEC-brochure_Online-offshore.pdf> (accessed 8 January 2021).

10 J. Matthijsen, E. Dammers and H. Elzenga, 'The Future of the North Sea – The North Sea in 2030 and 2050: A Scenario Study' (2018) PBL Netherlands Environmental Assessment Agency, no 3193, pp 11–12.

11 L.M. Andreasson and M.M. Roggenkamp, 'Regulatory Framework: Legal Challenges and Incentives for Developing Hydrogen Offshore' (2020) North Sea Energy Programme, Deliverable 2.2, 2.3, pp 10–11.

Consequently, the next section will present the process of producing hydrogen offshore using power-to-gas (PtG) technology and the classification of green hydrogen. The following section provides an analysis of legislation pertaining to the development of green hydrogen in the North Sea, which involves an analysis of the EU and national laws relevant for the production and transport of green hydrogen offshore. The analysis in this section is based on national laws of Denmark, the Netherlands and the UK.[12] The choice of these countries is based on the combination of existing hydrocarbon activities offshore as well as the current and future wind potential offshore. Each section of this chapter analyses the degree to which the current legal regimes create barriers to the development of green hydrogen in the North Sea.

2. GREEN HYDROGEN DEVELOPMENTS OFFSHORE: POLICY AND TECHNICAL BACKGROUND

2.1. EU AND NATIONAL HYDROGEN POLICIES

Hydrogen represents a modest part of the energy mix in Europe and is still largely produced from fossil fuels, notably from natural gas and coal.[13] In order for hydrogen to contribute to climate neutrality, it needs to become fully decarbonised. The EU launched its first Hydrogen Strategy in 2020, placing 'low-carbon' – and in particular 'clean' and 'renewable' hydrogen – front and centre as an enabler to meet the ambitious net-zero carbon targets across the region.[14] The strategy sets out a vision of how EU can turn clean hydrogen into a viable solution to decarbonise different sectors over time, including the energy sector. Several EU countries have followed suit in incorporating clean hydrogen into their decarbonisation strategies.[15] Although offshore hydrogen production can support large-scale offshore wind (renewable) energy developments, it is not mentioned in the EU hydrogen strategy.[16] Nevertheless, offshore production

12 The UK left the EU on 31 January 2020, but existing EU legislation will continue to apply in domestic law (by virtue of the European Union (Withdrawal) Act 2018) insofar as it is not modified or revoked by regulations under the 2018 Act.

13 G. Kakoulaki, 'Green Hydrogen in Europe – A Regional Assessment: Substituting Existing Production with Electrolysis Powered by Renewables' (2020) *Energy Conversion and Management*, p 2.

14 Communication from the Commission 'A hydrogen strategy for a climate-neutral Europe' COM (2020) 301 final.

15 See Hydrogen Europe, 'National Hydrogen Strategies', available at <https://hydrogeneurope.eu/sites/default/files/Map_%20National%20H2%20Strategies.pdf> (accessed 6 January 2021).

16 The European Commission merely acknowledges that the priority of the EU is to develop renewable hydrogen, produced using mainly wind and solar energy; see EU Hydrogen Strategy 5.

of clean hydrogen is part of the political ambition of some of the North Sea States, such as the Netherlands.[17] Throughout the wave of national hydrogen policies released in recent months, we therefore see an increased focus on the development of clean hydrogen both onshore and offshore.

2.2. POWER-TO-GAS TECHNOLOGY OFFSHORE

The classification of hydrogen is dependent on the method of production and the sources used for its production.[18] In short, hydrogen is classified as 'grey' when it is produced using fossil fuels (e.g. natural gas reforming).[19] If the carbon dioxide – which is a byproduct producing hydrogen from fossil fuels – is captured and permanently stored, the hydrogen produced is classified as 'blue' hydrogen.[20] When hydrogen is produced from renewable sources, it is often referred to as 'green' hydrogen.[21] This chapter focusses on the offshore production of green hydrogen, in which electricity generated from offshore wind farms is used as an input for the production of hydrogen through the decomposition of water molecules by electrolysis.

Hydrogen can be produced via electrolysers installed on existing offshore hydrocarbon platforms, which can contribute to the extension of the economic lifetime of these platforms.[22] In principle, it postpones decommissioning costs incurred by several North Sea States.[23] Furthermore, where hydrogen can be technically and safely injected into and transported through the existing offshore gas pipeline system, it could extend the economic lifetime of these pipelines and potentially avoid, or at least reduce, further investments in new offshore

17 Minister of Economic Affairs and Climate 'Kamerbrief over Kabinetsvisie waterstof', p 8, available at <https://www.rijksoverheid.nl/documenten/kamerstukken/2020/03/30/kamerbrief-over-kabinetsvisie-waterstof> (accessed 6 January 2021).

18 For a detailed analysis of the differentiation of hydrogen classification at the EU and national levels, see R. Fleming, 'Green Hydrogen Developments in the EU: Cross-border Cooperation between Germany and the Netherlands', Chapter XIII in this volume.

19 International Energy Agency, 'The Future of Hydrogen: Seizing Today's Opportunities' (2019), p 34, available at <https://www.iea.org/reports/the-future-of-hydrogen> (accessed 30 July 2021).

20 Ibid.

21 R. Fleming and G. Kreeft, 'Power-to-Gas and Hydrogen for Energy Storage under EU Energy Law' in M.M. Roggenkamp and C. Banet (eds.), *European Energy Law Report Volume XIII*, Intersentia, Cambridge, 2020, pp 101–102.

22 D. Drankier and M.M. Roggenkamp, 'Regulatory Framework: Barriers or Drivers for Offshore System Integration' (2018) North Sea Energy Programme, Deliverable B.1, pp 34–36.

23 For an elaborate analysis of the reuse of existing offshore energy infrastructure, see D. Drankier and M.M. Roggenkamp, 'The Regulation of Decommissioning in the Netherlands' in Roggenkamp and Banet (eds.), above n. 21, pp 303–306.

electricity cables.[24] Moreover, offshore hydrogen conversion and storage might have alternative benefits, such as reducing the need for onshore energy storage and associated spatial claims, societal resistance and safety risks.

In addition to installing electrolysers on existing offshore hydrocarbon platforms, new offshore platforms can be developed specifically for this purpose. The conversion of power to hydrogen requires access to water and electricity. Seawater can be converted into demineralised water, and electricity supply can be facilitated by connecting the offshore electrolyser to: (i) the onshore electricity grid; (ii) the offshore electricity grid; or (iii) an offshore wind farm.[25] As it cannot be guaranteed that the hydrogen produced is green when connecting an offshore electrolyser to the onshore electricity grid, only the second and third options are analysed in this chapter. Additional infrastructure is required to transport the hydrogen produced to shore where it is consumed, stored or reconverted. Several options can be identified for transporting offshore hydrogen to shore, such as: (i) using existing natural gas pipelines, i.e. blending hydrogen with natural gas; (ii) repurposing disused natural gas pipelines to exclusively transport hydrogen; and (iii) constructing new dedicated hydrogen pipelines.[26]

3. DEVELOPMENT OF GREEN HYDROGEN IN THE NORTH SEA: LEGAL FRAMEWORK

The development of green hydrogen offshore can be divided into three main stages: (i) electricity input for the conversion process; (ii) hydrogen production; and (iii) hydrogen transport. These three steps are explained in more detail below.

3.1. ELECTRICITY INPUT FOR HYDROGEN PRODUCTION

The electricity required for the conversion process can technically be supplied from two sources: (i) directly via cable from a nearby offshore wind farm; or (ii) from an offshore wind farm via a connection to the existing offshore electricity grid. From a legal perspective, it is therefore necessary to determine whether coastal States have jurisdiction to regulate the construction and use of such electricity cables and whether national law already facilitates their construction and use.

24 North Sea Energy, 'Hybrid Offshore Energy Transition Options – The Merits and Challenges of Combining Offshore System Integration Options' (2019) Synthesis Paper, North Sea Energy Programme II, p 2.

25 Andreasson and Roggenkamp, above n. 11, p 11.

26 Ibid.

3.1.1. *Jurisdiction Over and Regulation of Submarine Electricity Cables*

On the basis of UNCLOS, coastal States have jurisdiction to regulate the construction and use of submarine electricity cables in their territorial sea.[27] Beyond the territorial sea, there is only functional jurisdiction, which means that coastal States have the right to regulate activities that are related to the economic exploitation of their EEZ.[28] Thus, coastal States have jurisdiction to regulate the construction and use of electricity cables used for economic activity in the EEZ, e.g. park-to-shore cables.[29] As for cables that do not serve the economic exploitation of the EEZ (e.g. interconnection cables),[30] coastal States can only legislate as far as safety and environmental requirements are concerned.[31] The question is how the legislators in the Netherlands, the UK and Denmark have used their functional jurisdiction to regulate offshore wind farms and the cables connected to them.

In the current legal frameworks of the Netherlands, the UK and Denmark, three options are available for the connection of offshore wind farms to the onshore electricity grid. The first option is that the developer of the wind farm is responsible for the connection to the onshore grid (the 'wind farm developer model'). This is generally the case in Denmark for wind farms established under the open-door procedure,[32] and used to be the case in the Netherlands before legislative changes in 2016.[33] The second option for the connection of offshore wind farms is to make the (onshore) transmission system operator (TSO)

27 Articles 2 and 79(4) UNCLOS.

28 Ibid., Arts 56 and 77.

29 Submarine cables connecting offshore wind farms to the onshore electricity grid. These cables are essential for the exploitation of offshore windfarms and it can be argued that these cables are regulated under Art 60(1)b UNCLOS, which grants jurisdiction for the use of installations and structures and for other economic purposes; see H.K. Müller, *A Legal Framework for a Transnational Offshore Grid in the North Seas*, Intersentia, Antwerp, 2016, pp 38–39.

30 Submarine cables facilitating the transport of electricity from one State to another.

31 Article 79(1) UNCLOS.

32 The development of offshore wind farms and the transport of electricity in Denmark is regulated by the Renewable Energy Act (Lov om fremme af vedvarende energi) no 356 of 4 April 2019 and the Electricity Supply Act (Elforsyningsloven) no 840 of 15 August 2019, respectively. As a new approach, the wind farm developer model will also be used in the development of the next large offshore wind farm to be tendered out in Denmark; see Danish Energy Agency, 'New Danish Calls for Offshore Wind Farm Tenders: Information on the Thor Offshore Wind Farm Tendering Procedure', 2019, pp 14–15, available at <https://ens.dk/sites/ens.dk/files/Vindenergi/offshore_wind_tendet_thor_marketing.pdf> (accessed 20 January 2021).

33 The development of offshore wind farms and the transport of electricity is regulated by the Wind Energy at Sea Act (Wet windenergie op zee) of 24 June 2015 and the Electricity Act (Elektriciteitswet) of 2 July 1998, respectively. The park-to-shore cable was considered part of the offshore wind farm installation before amendments were made to the Electricity Act in 2016, when the responsibility was shifted to the TSO; see Art 24Aa, 15a and 1(1) and (4).

responsible for the connection of offshore wind farms to the onshore grid (the 'TSO model'). In this case, the TSO constructs, owns and maintains both the offshore converter station and the cable that carries the electricity to shore from the offshore wind farm.[34] This model is generally used for tendered wind farms in Denmark[35] and for wind farms developed after 2016 in the Netherlands.[36] In the third option, a third party is responsible for the connection to the onshore grid (the 'third-party model'). This is currently applied in the UK and involves a tendering procedure for the connection of the offshore wind farm to the onshore electricity grid.[37] This option utilises third-party ownership and operation of the offshore electricity assets. This third party is called the 'Offshore Transmission Owner' (OFTO).[38] The cable is either constructed by the wind farm owner and transferred to a third party when the wind farm becomes operational (generator build)[39] or a third party constructs the cable and operates it afterwards (OFTO build).[40]

National laws applicable to the development of offshore wind farms, and the cables connected to them, seem to qualify the cable connecting a wind farm to the onshore grid connection point either as part of the offshore wind farm installation or as a transmission asset of the TSO or the OFTO. The question is thus if the construction and use of electricity cables connecting (i) an offshore wind farm (generator) and an offshore electrolyser (customer),[41] or (ii) the offshore grid (at a sub-station)[42] and an offshore electrolyser (customer) is regulated by national law.

3.1.2. Cable Connecting an Offshore Wind Farm and an Offshore Electrolyser

An electricity cable that directly connects an offshore wind farm with an offshore electrolyser could potentially be qualified as a 'direct line' pursuant to

34 Converter stations are used to facilitate transmission of electricity over long distances by converting the high-voltage alternate current to a high-voltage direct current.

35 However, the TSO model will not be used in the development of the next large offshore wind farm to be tendered out in Denmark. Instead, the wind farm developer will be responsible for the development of the connection to the onshore grid; see Danish Energy Agency, above n. 32.

36 Articles 24Aa, 15a and 1(1) and (4) of the Electricity Act.

37 Müller, above n. 29, pp 182–183.

38 Section 6C–6D of the Electricity Act 1989 (1989 c 29).

39 Electricity (Competitive Tenders for Offshore Transmission Licenses) Regulations 2015, no 1555 2015, section 3 and part 2.

40 Ibid., section 3 and part 3.

41 A new converter station (sub-station) may need to be constructed to facilitate the connection via cable between an existing offshore wind farm and an offshore electrolyser.

42 A sub-station is a point of connection to an electricity grid, transforming voltage from high to low, or the reverse. A converter station is a specialised type of sub-station, see n 34 above.

Directive (EU) 2019/944 (hereinafter the 'Electricity Directive'). Article 2(41) of the Electricity Directive defines a 'direct line' as:

> either an electricity line linking an isolated generation site with an isolated customer or an electricity line linking a producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and customers.

Thus, direct lines are electricity lines solely used for providing electricity to an isolated site or a large customer, and may not be used by other market actors. As such, the cable connecting an offshore wind farm (generator) with an offshore electrolyser (customer) may qualify as a direct line. Given that existing offshore wind farms are already connected to the main electricity grid, it is questionable whether a cable can only be considered as a 'direct line' if both nodes (generator and customer) are remote. As the definition in the Directive does not explicitly stipulate that a direct line has to be complementary to the main electricity grid, it can be argued that the above cable would qualify as a direct line.[43]

The rules on direct lines have been incorporated into national electricity legislation. While the Netherlands has adopted a literal translation of the definition of direct lines in Article 1(1) of the Electricity Act, no definition of direct lines has been adopted in British electricity legislation.[44] Instead, the exemption system for electricity supply licences in the UK allows producers to supply electricity via direct lines.[45] This exemption system is based on the same principles as the rules for direct lines in the EU Electricity Directive. In line with the analysis above, it is therefore likely that a cable connecting an offshore wind farm with an offshore electrolyser would qualify as a direct line under Dutch and British electricity legislation. However, the provisions in the Dutch Electricity Act and the British Electricity Act, which are relevant to direct lines, are not applicable offshore.[46] Thus, there is no classification of such an electricity cable offshore in these laws. By contrast, the provisions on direct lines in the Danish Electricity Supply Act are applicable offshore.[47] Although this Act contains

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43 For a more comprehensive understanding, see H. Vedder et al, 'EU Energy Law' in Roggenkamp et al (eds.), above n. 6, p 294.

44 Annex I to the EU Third Energy Package Transposition Note Great Britain: Electricity Directive (2009/72/EC), p 23.

45 Section 5(1) of the Electricity Act allows energy companies that meet certain criteria to be exempted from obtaining such a licence; see Department for Business, Energy and Industrial Strategy, 'Electricity Generation, Distribution and Supply Licence Exemptions', 2017, available at <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/617786/Exemption_FAQs_updated_June_2017rg.pdf> (accessed 10 June 2020).

46 Article 1(5) of the Electricity Act (the Netherlands); section 4(5) of the Electricity Act 1989 (the UK).

47 Section 2(2) of the Electricity Supply Act.

no definition on a 'direct line', it defines a 'direct electricity supply network' in section 5(4) as a network intended for the supply of electricity from one electricity-generating undertaking to another electricity-generating undertaking, or to specific customers, and which replaces the use of the public electricity supply network *in whole or in part*. Contrary to the definition in the EU Electricity Directive, the provision explicitly opens up for the possibility of classifying a cable that connects an offshore wind farm (which is itself connected to the main electricity grid) and an offshore electrolyser as a direct line.

Furthermore, it is necessary to determine who is responsible to construct the aforementioned electricity cable: is it the wind farm developer, the developer of the electrolyser or an independent party? So far, no connection has been established directly between a wind farm and an electrolyser in the North Sea. Therefore, no guidance is provided in national law regarding who ought to be responsible for the construction and connection of such a cable. The party who will be responsible for the development of this particular cable must obtain a permit or licence to construct the cable. The construction of electricity cables in the EEZ is subject to separate permits in Denmark,[48] the Netherlands[49] and the UK.[50] This will be discussed in more detail in section 3.2.2 below.

3.1.3. Cable Connecting an Offshore Electrolyser to the Offshore Grid

When assessing the possibility of establishing a connection between the offshore electricity grid (at a sub-station) and an offshore electrolyser (the customer), it is necessary to first determine whether such a connection is legally permitted. As previously mentioned, the converter station of an offshore wind farm is part of the offshore electricity grid developed by the TSO in the Netherlands (since 2016)[51] and the TSO in Denmark (for tendered wind farms).[52] Similarly, the converter stations of offshore wind farms are part of the offshore transmission systems operated by OFTOs in the UK (since 2009).[53] In assessing whether it is possible to connect an electrolyser to the offshore electricity grid, it must be emphasised that the offshore grid in these countries is only intended for the transport of electricity from one or more offshore wind farms to the onshore

48 Ibid., section 22a.

49 Articles 6.2 and 1.1(3) of the Water Act (Waterwet) of 29 January 2009.

50 Sections 66 and 81 of the Marine and Coastal Access Act 2009 (2009 c 23) (England) and section 21 of the Marine Act 2010 (2010 asp 5) (Scotland).

51 TenneT is appointed as the TSO at sea in the Netherlands; see Art 10(3) of the Electricity Act.

52 Energinet is appointed as the TSO at sea in Denmark; see section 2(2) of the Energinet Act (Energinetloven) no 997 of 27 June 2018.

53 OFTOs are appointed to develop and manage offshore electricity cables connecting wind farms to the onshore electricity grid in the UK; see sections 6A–6D of the Electricity Act 1989.

electricity grid.[54] Therefore, the purpose of the offshore electricity grid is not to facilitate offshore electricity supply and consumption, but to bring to shore electricity generated offshore. The responsible parties for the development of the offshore electricity grid have thus not been assigned the responsibility to enable this form of connection offshore. The current regime is based on the assumption that only generation assets are connected to the offshore grid and that, in the absence of grid connection and transport fees, the financing of the grid is completely based on government subsidies, i.e. not taking into consideration connections and use by electricity customers.

At present, no connections have been established in the North Sea between the electricity grid and an electricity customer offshore, and there is no definition or qualification in national legislation of the cables establishing such connections. Although the construction of such cables will be subject to a permit or licence as mentioned in the section above, there are no rules on who ought to be responsible for their development and operation.

3.1.4. Assessment

To facilitate the production of green hydrogen in the North Sea, it should first be clarified whether an offshore electricity cable – connecting an offshore wind farm and an offshore electrolyser – is to be defined as a 'direct line', meaning it would be subject to the rules on direct lines in national electricity legislation. If not, a definition, and possibly a separate legal regime governing such cables must be adopted. Proposed amendments to the Dutch Wind Energy at Sea Act seem to promote the possibility of connecting offshore wind farms to offshore customers (e.g. electrolysers) through the introduction of a new type of connection.[55] Nonetheless, there is no clarification in this amendment as to how the cable establishing such a connection should be classified. Furthermore, it must be clarified in national legislation whether it is legally permitted to establish a connection via cable between the offshore electricity grid and an offshore customer. If so, rules on responsibility for the development, ownership and operation of such cables must be adopted to resolve legal uncertainty.

3.2. HYDROGEN PRODUCTION

The next step in the offshore PtG process is the construction of an offshore electrolyser. In exercising their sovereign rights, North Sea States have the

54 Articles 15a and 16(2)(n) of the Electricity Act (the Netherlands); sections 6A–6D of the Electricity Act 1989 (the UK); sections 5(11), (19) and (20), and 22a of the Electricity Supply Act (Denmark).

55 Paragraph 2.1.2 of the Act amending the Wind Energy at Sea Act (Wijziging van de Wet windenergie op zee) of 28 November 2018, Kamerstuk 35092 no 3.

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exclusive right to construct and to authorise and regulate the construction, operation and use of installations for the economic exploitation of their EEZ.[56] It is thus necessary to determine the national law applicable to the offshore construction of an electrolyser and the subsequent production of hydrogen in order to assess the legal effects of this. Three scenarios are foreseen by the author: (i) the electrolyser is installed on an existing offshore hydrocarbon platform, which still produces hydrocarbons; (ii) the electrolyser is installed on an existing offshore hydrocarbon platform, which is no longer producing hydrocarbons; and (iii) the electrolyser is installed offshore, but not on an existing installation. In the latter scenario, therefore, the electrolyser is considered as an installation *sui generis*.

3.2.1. Production of Hydrogen from Existing Platforms Producing Hydrocarbons

When installing an electrolyser on a hydrocarbon platform, which still produces hydrocarbons (primarily gas production installations), one must consider that the platform already operates under a hydrocarbon production licence. The question is therefore whether national laws applicable to the production of hydrocarbons also apply to the production of hydrogen.

Pursuant to the Mining Act (the Netherlands),[57] the Petroleum Act 1998 (the UK)[58] and the Subsoil Act (Denmark),[59] the extraction of subsoil resources offshore requires a licence. As such, these laws govern the extraction of hydrocarbons offshore, but also the equipment and installations (e.g. platforms) for the production of these hydrocarbons.[60] It is questionable whether the electrolyser will fall under the hydrocarbon licence that have been awarded pursuant to these laws, as the definition of 'mineral' (the Mining Act),[61] 'petroleum' (the Petroleum Act 1998)[62] and 'raw material' (the Subsoil Act)[63] are narrow enough to exclude hydrogen from their scope. In the Netherlands, for example, a hydrocarbon licence holder can request a modification of the licence. However, it is not possible to modify a licence in such a way that it covers other activities and minerals.[64]

Given that platforms which are still producing hydrocarbons are governed by the aforementioned laws, one must also consider whether the installation

56 Article 60 UNCLOS.
57 Mining Act (Mijnbouwwet) of 31 October 2002.
58 Petroleum Act 1998 (1998 c 17).
59 Subsoil Act (Undergrundsloven) no 1533 of 16 December 2019.
60 Articles 1(a) and 6 of the Mining Act (the Netherlands); sections 2 and 3 of the Petroleum Act 1998 (the UK); section 2 and Chapter 3 of the Subsoil Act (Denmark).
61 Article 1(a) of the Mining Act.
62 Section 1(a) of the Petroleum Act 1998.
63 Section 2 of the Subsoil Act; see also Chapter 3.
64 Article 18(2) of the Mining Act.

of the electrolyser and subsequent production of hydrogen on such a platform might be considered an ancillary service, and thus as falling within the scope of these laws. In order for a service to be considered an ancillary service under the Mining Act, the Petroleum Act 1998 and the Subsoil Act, it must be necessary to support the production of hydrocarbons from the installation.[65] It would appear that the production of hydrogen through electrolysis is not likely to clear this bar and it can safely be assumed that hydrogen production would not be considered an ancillary service.

Hence, national laws provide no guidance on the use of hydrocarbon platforms for purposes other than those linked to hydrocarbon activities. As a result, hydrogen production cannot be carried out on a platform under the existing hydrocarbon production licence applicable to the platform in question. The production of hydrogen is thus considered a production activity in and of itself. One must therefore assess whether there are other national laws governing the construction of an offshore electrolyser. This will be examined in the section below. In cases where hydrocarbons and hydrogen are produced on the same platform, the interplay between the hydrocarbon production licence and the licence applicable to the construction of an electrolyser should be clarified.

3.2.2. Reuse of Existing Platforms for Hydrogen Production

Hydrocarbon production in the North Sea is declining and hydrocarbon installations, when no longer in use, must be removed.[66] However, as an alternative, these installations can be reused for other purposes. A reading of international conventions and guidelines seems to leave room for the reuse of hydrocarbon installations.[67] Conversion of electricity into hydrogen can provide a valid reason for reuse and for leaving these installations in place. However, when a hydrocarbon installation is reused to convert electricity into hydrogen, it can no longer be considered a hydrocarbon installation. The legal challenges are thus: (i) under which legal regime and licence can such an installation operate; (ii) who will be the licensee and operate such an installation; and (iii) how will the transfer of liabilities and decommissioning costs be dealt with.

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65 Article 1(n) and (o) of the Mining Act and Art 2 of the Mining Decree (Mijnbouwbesluit) of 6 December 2017 (the Netherlands); sections 1(a) and 3 of the Petroleum Act 1998 (the UK); section 10 of the Subsoil Act (Denmark).

66 Article 60(3) UNCLOS. For an elaborate analysis on the decommissioning of hydrocarbon installations, see S. Trevisanut, 'Decommissioning of Offshore Installations: A Fragmented and Ineffective International Regulatory Framework' in C. Banet (ed.), *The Law of the Seabed: Access, Uses, and Protection of Seabed Resources*, Brill-Nijhoff, Leiden, 2020, pp 431–454.

67 Drankier and Roggenkamp, above n. 23, pp 293–297.

The provisions of the Mining Act (the Netherlands),[68] the Petroleum Act 1998 (the UK)[69] and the Subsoil Act (Denmark)[70] place an obligation on the licence holder to remove abandoned or disused offshore installations.[71] However, the British Petroleum Act 1998 seeks to reuse or preserve offshore hydrocarbon installations. These alternatives must therefore be considered before drawing up an abandonment plan for such installations.[72] Similarly, the Netherlands prepared a bill seeking to amend the rules on the removal of disused hydrocarbon installations.[73] The bill proposes to grant exemptions from the obligation to remove installations, arguing that removal under certain conditions should be postponed if installations can be reused for, *inter alia*, hydrogen production or any other offshore energy-related activities.[74] Reuse of offshore installations has also been investigated in Denmark, but was rejected because such possibilities proved to be too uncertain and opportunity-driven.[75] The Danish Subsoil Act therefore provides no guidance on the potential reuse of existing hydrocarbon installations.

As already concluded above, hydrogen production falls outside the scope of national hydrocarbon legislation. It is thus necessary to assess whether this activity is governed by another piece of offshore legislation. In the Netherlands, the only alternative would be a permit under the Water Act, which regulates (the development of) activities in onshore and offshore waters unless these activities are governed by specific sectoral laws such as the Mining Act.[76] The production of hydrogen on an offshore platform would thus depend on a water permit pursuant to Article 6.13 of the Water Decree.[77] Similarly, the UK has adopted provisions for general offshore activities (e.g. other than regulated by dedicated offshore legislation) in the Marine and Coastal Access Act (England)[78] and the

68 Article 44 of the Mining Act.

69 Section 29(1) of the Petroleum Act 1998.

70 Section 33 of the Subsoil Act.

71 For an elaborate analysis on offshore decommissioning in the North Sea, see Roggenkamp and Banet (eds.), above n. 21, Chapters XIV (the Netherlands), XV (the UK) and XVI (Denmark), pp 289–350.

72 Section 29(2B)(a) of the Petroleum Act 1998.

73 Act Amending the Mining Act (Wijziging van de Mijnbouwwet (het verwijderen of hergebruiken van mijnbouwwerken en investeringsaftrek)) of 25 February 2021, available at <https://www.eerstekamer.nl/behandeling/20210225/publicatie_wet_3/document3/f=/vlglfn43acz9.pdf> (accessed 16 July 2021).

74 For all documentation, see <https://www.eerstekamer.nl/wetsvoorstel/35462_het_verwijderen_of> (accessed 25 March 2021).

75 For an elaborate analysis of reuse of offshore installations in Denmark, see C.G. Brett, 'Regulation of Infrastructure Decommissioning in the Danish Offshore Oil and Gas Sector' in Roggenkamp and Banet (eds.), above n. 21, p 350.

76 Article 6(5)(c) of the Water Act.

77 See Art 6.13(c) and (d) of the Ministerial Water Decree (Waterbesluit) of 30 November 2009, which prohibits the installation or laying down of installations or cables or pipelines, and construction activities, in the North Sea without a water permit.

78 Part 4 of the Marine and Coastal Access Act.

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Marine Act (Scotland).[79] These laws require a marine licence for establishing an electrolyser on an existing offshore installation.[80] By contrast, Denmark does not provide for a general legal framework governing offshore activities that are not regulated by specific sectoral laws.[81] The lack of a general permitting regime in Denmark for new types of offshore activities (e.g. hydrogen production via electrolysis) creates legal uncertainty.

It follows from the above that in essence not only is a new or different permit or licence required to install an electrolyser on an existing hydrocarbon installation, but in addition, the reused installation will no longer be subject to the operational and safety rules applying to offshore hydrocarbon installations. At present, none of the aforementioned permit and licensing rules governing the construction of an electrolyser provide for such rules. This could result in a regulatory gap which needs to be addressed.

Decommissioning of disused offshore hydrocarbon installations should take place within a reasonable timeframe. However, as there is little experience in this area, it is unclear how long the decommissioning can be postponed. Furthermore, during the potential time period between the end of the original activity and the start of the new activity, the installation must be maintained and the holder of the hydrocarbon licence remains liable for any damage occurring during this time.[82] In cases where the new activity cannot yet start because certain infrastructure is not yet ready or investment decisions are pending,[83] this responsibility may limit the willingness of the original licence holder to keep in place the installation. The transfer of responsibility for the installation between the old licensee and the new licensee may therefore need to be clarified by law.

Finally, reuse of installations merely postpones the decision to decommission the installation, as eventually a reused installation can also become disused. In order to deal with such a postponed disuse and thus removal, the legislator and the parties involved are confronted with several questions. Of relevance is whether the original licensee is exempt from all, or still responsible for some, of the decommissioning obligations if the installation is reused. Furthermore, it must be determined whether it is sufficient to include decommissioning obligations in the new licence governing the reused installation or whether such

79 Part 4 of the Marine (Scotland) Act.

80 See section 66(1)(7) of the Marine and Coastal Access Act and section 21(1)(5) of the Marine (Scotland) Act, which stipulates that the construction, alteration or improvement of any works within the English and Scottish marine licensing area, in or under the sea, or on or under the seabed, requires a marine licence.

81 For laws applicable to offshore activities in Denmark, see Andreasson and Roggenkamp, above n. 11, p 74.

82 See Drankier and Roggenkamp, above n. 22, p 33.

83 This may be the case if, for example, the new use of the offshore platform is to produce hydrogen via electrolysis and the cable that will connect this platform to an offshore wind farm (or the offshore electricity grid) for electricity supply has not yet been completed.

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obligations should be governed by the laws that apply to the new use of the installation.[84]

3.2.3. Development of New Platforms for Hydrogen Production

Regarding the construction of a new dedicated offshore installation necessary to accommodate an electrolyser, the same permit and licensing rules apply as presented in the section above. As such, the offshore development of a new hydrogen production installation is subject to a water permit in the Netherlands and a marine licence in the UK.[85] On the contrary, Denmark does not provide a general legal framework for offshore activities that are not regulated by specific sectoral laws.

The water permit in the Netherlands and the marine licence in the UK can be awarded under certain conditions, such as the need to compensate for negative environmental impact and, if necessary, cease the permitted or licensed activity if any of the conditions in the permit or licence appear to have been violated.[86] Such permit or licence may also include a removal obligation and a requirement to provide a financial guarantee to fulfil obligations under the permit or licence.[87] Nonetheless, the relevant laws do not contain specific operational and safety rules, which results in legal uncertainty for the developers and operators of such installations.

3.2.4. Assessment

National laws do not provide for any specific procedures governing the production of hydrogen on a producing-hydrocarbon installation, which is carried out alongside the production of natural gas. The same applies for the reuse of offshore hydrocarbon installations for hydrogen production. Although some alternative legal arrangements may apply, which may provide some legal certainty for the development of hydrogen production offshore, these regimes are limited in their scope and provide only ad hoc solutions. The same applies to the development of new offshore installations for hydrogen production. None of these laws contains provisions for the operation of such installations or specific safety regulations. In order to remedy these legal uncertainties, it will be

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84 For a more elaborate analysis, see Drankier and Roggenkamp, above n. 23, p 305.

85 Article 6.13(c) and (d) of the Water Decree (the Netherlands); section 66(1)(7) of the Marine and Coastal Access Act and section 21(1)(5) of the Marine (Scotland) Act (the UK).

86 Article 6.20(1) of the Water Act (the Netherlands); sections 71–72 of the Marine and Coastal Access Act and sections 29–30 of the Marine (Scotland) Act (the UK).

87 Article 6.20(1) of the Water Act (the Netherlands); section 71 of the Marine and Coastal Access Act and section 29 of the Marine (Scotland) Act; for the statutory decommissioning scheme for offshore renewable energy installations, see also sections 105–144 of the Energy Act 2004 (2004 c 20) (the UK).

necessary to issue specific rules for the production of hydrogen and operation of hydrogen installations offshore.

3.3. HYDROGEN TRANSPORT

In the final step of the offshore PtG process, the produced hydrogen must be transported to shore. Several options are available to transport offshore produced hydrogen to shore, such as: (i) blending hydrogen into existing natural gas pipelines; (ii) reusing disused natural gas pipelines to exclusively transport hydrogen; and (iii) developing new dedicated hydrogen pipelines.

3.3.1. Use of Existing Pipelines

Electrolysers can be installed on existing offshore gas platforms. Since these platforms are already connected to pipelines, which in turn are connected to the national gas transmission network onshore, these pipelines can be used to transport hydrogen.[88] The characteristics of the gas transported through the pipelines changes when hydrogen is blended with natural gas.[89] Hence, the primary issue arising therefrom is whether national law grants the blending of hydrogen into the existing natural gas network.[90] In general, gas quality requirements apply to gas transport pipelines, but these requirements can be based on different regimes, i.e. upstream or downstream gas law. Pipelines that transport offshore produced gas to the onshore transmission network are usually qualified as upstream pipelines. The regulation of upstream pipelines is limited, and there is no regulation in the Netherlands, the UK or Denmark pertaining to upstream pipeline networks on gas quality standards.[91] Nevertheless,

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88 See NaturalHY, 'Using the Existing Natural Gas System for Hydrogen: Preparing for the Hydrogen Economy by Using the Existing Natural Gas System as a Catalyst' (2009), p 10.

89 Hydrogen and natural gas have different physical and chemical properties, such as *inter alia* density, calorific value and burning velocity; see K. Altfeld and D. Pinchbeck, 'Admissible Hydrogen Concentrations in Natural Gas Systems' (2013) *Gas for Energy*, GERG study no 3, pp 36–47.

90 Gas quality requirements are set under gas quality standards, which establish the maximum and minimum acceptable levels for individual parameters and components of gas. Gas quality requirements applicable to the national downstream gas networks are specified in national legislation; see D.G. Tempelman, 'Harmonising Gas Quality Standards: Obstacles and Challenges in an Internal Market' in M.M. Roggenkamp and M. Bjørneby (eds.), *European Energy Law Report X*, Intersentia, Cambridge, 2014, p 89.

91 National legislation only specifies gas quality requirements for the downstream natural gas networks; see Art 1.1(c) of the Gas Act (Gaswet) of 22 June 2000 and the Ministerial Decree on Gas Quality (Regeling Gaskwaliteit) of 11 July 2011 (the Netherlands); sections 16 and 48(1) of the Gas Act 1986 (1986 c 44) and the Gas Safety (Management) Regulations 1996 (1996 no 551) (the UK); section 6(19) and (20) of the Gas Supply Act (Naturgasforsyningsloven) no 1127 of 5 September 2018 and the Executive Order on Gas Quality (Bekendtgørelse om gaskvalitet) no 230 of 21 March 2018 (Denmark).

operators of such pipelines must ensure that the gas they deliver to the onshore pipeline network complies with the entry specifications (gas quality standards) applicable to that network.[92] Hence, upstream pipeline operators cannot accept off-specification gas, unless they can blend the gas in such a way that it meets the entry specifications. Producers with off-specification gas may thus be curtailed in their production.[93] Although there is no legal restriction as such to transport hydrogen via existing offshore natural gas pipelines, the characteristics of hydrogen and natural gas are different. Therefore, it must be assessed whether the injection of hydrogen into these pipelines complies with the entry specifications applicable to the onshore pipeline network. Since it is unlikely that hydrogen will be accepted for transport in upstream pipeline networks unless these entry specifications can be met, the gas quality standards for downstream pipeline networks are examined in more detail below.

Pipelines for the downstream transport of natural gas are regulated by EU Directive 2009/73/EC (hereinafter the 'Gas Directive').[94] Although the title and scope of the Directive indicate that it applies to natural gas, Article 1(2) provides that the rules of the Directive 'shall apply in a non-discriminatory way to … other types of gas'. The inclusion of 'other types of gas' suggests that the Directive also applies to hydrogen. At the time of writing, there is no European Court of Justice jurisprudence determining what is to be understood with 'other types of gas', and the regime applicable to such gases. However, a continued reading of the provision clarifies that 'other types of gas' will be subject to the Gas Directive if they can be 'technically and safely injected into, and transported through, the natural gas system'.[95] The applicability of national gas laws to the injection of hydrogen into downstream natural gas networks depends on how the term 'gas' is defined in the Gas Act (the Netherlands),[96] the Gas Act 1986 (the UK)[97] and the Gas Supply Act (Denmark).[98] One common requisite pertaining to the chemical state of the gas injected into natural gas networks in these laws is that the gas to be injected primarily consists of methane, or of another substance equivalent to methane in terms of its characteristics.[99] As the characteristics

92 Requirements for gas quality for upstream pipelines are included in the transport agreement entered into by the operator of the offshore pipeline and the gas producer.

93 Upstream pipeline operators can deny access to third parties where there is an incompatibility of technical specifications which cannot reasonably be overcome; see Art 34 of EU Directive 2009/73/EC (Gas Directive).

94 Ibid., Art 1(1).

95 Ibid., Art 1(2).

96 Article 1.1(b) of the Gas Act.

97 Section 48(1) of the Gas Act 1986.

98 Section 2 of the Gas Supply Act.

99 Article 1(b) of the Gas Act and Art 1 of the Ministerial Decree on Gas Quality (the Netherlands); section 48(1) of the Gas Act 1986 and section 2(1) of the Gas Safety (Management) Regulations 1996 (the UK); section 2(2) of the Gas Supply Act and section 1 of the Executive Order on Gas Quality (Denmark).

of natural gas and hydrogen are different, it can be questioned whether it is legally permissible to inject hydrogen into the downstream natural gas network. In order to determine this, it is necessary to seek guidance in national gas quality regulations. If legally permitted, it is also necessary to determine the admissible concentration levels of hydrogen admixture.

Although it may be technically feasible and safe to blend hydrogen into the downstream natural gas networks, neither the Netherlands[100] nor the UK[101] permits very high admixture levels. Furthermore, no admixture levels for hydrogen injection have been prescribed in Denmark.[102] This is attributable to safety concerns and the fact that the necessary technology has not yet been installed. An analysis of the legislation governing gas quality demonstrates that the Dutch legislation allows for the highest admixture level of 0.5mol% in certain parts of its downstream natural gas network, while the British legislation allows for 0.1mol%. However, ongoing projects in these countries indicate that it is technically feasible and safe to raise the permitted concentration level of hydrogen injection beyond the current limits.[103]

3.3.2. Reuse of Existing Pipelines

Pipelines that will no longer be used to transport natural gas can be reused to transport hydrogen. When a disused pipeline is used to transport hydrogen, the pipeline is no longer considered a pipeline within the meaning of hydrocarbon laws. The legal challenges are thus: (i) whether it is legally permissible to reuse such pipelines to transport hydrogen; and (ii) under which legal regime and licence such pipelines operate.

In essence, the obligation to remove disused installations under UNCLOS does not apply to pipelines. This is because pipelines are not considered to be installations.[104] Yet, some pipelines may be considered as being part of a (production) installation. In such cases, the removal obligation applying to installations may extend to some pipelines. Due to the absence of an applicable legal norm, it is within the competence of coastal States to determine whether offshore pipelines have to be removed once disused.[105] Irrespective of any removal obligations, disused pipelines may be reused to transport hydrogen.

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100 See Art 2(1)–(4) of and Annexes 1–4 to the Ministerial Decree on Gas Quality.

101 See schedule 3, part I(1) of the Gas Safety (Management) Regulations.

102 Section 27(1) of the Executive Order on Gas Quality merely prescribes the quality of the hydrogen to be injected into the natural gas distribution network.

103 For an overview, see Andreasson and Roggenkamp, above n. 11, pp 64–76.

104 Most provisions on installations in UNCLOS do not apply to pipelines; see Art 60(5) UNCLOS.

105 See M.M. Roggenkamp, 'Re-using (Nearly) Depleted Oil and Gas Fields in the North Sea for CO2 Storage: Seizing or Missing a Window of Opportunity?' in C. Banet (ed.), *The Law of the Seabed: Access, Uses, and Protection of Seabed Resources*, Brill-Nijhoff, Leiden, 2020, p 460.

However, reuse of pipelines will merely postpone a decision to decommission the pipelines, as reused pipelines may also become disused. Therefore, the legislator and the parties involved may be confronted with the same issues as for the postponed decommissioning of hydrocarbon installations described above.[106]

Pipelines transporting offshore produced natural gas to the onshore transmission network have been permitted under the Mining Decree (the Netherlands),[107] the Petroleum Act 1998 (the UK)[108] and the Subsoil Act (Denmark).[109] When reusing disused natural gas pipelines for hydrogen transport, these pipelines would no longer be regulated by these laws. Consequently, a similar situation arises as for the reuse of existing hydrocarbon installations for hydrogen production. Not only does a new permit need to be applied for, but where applicable, the reused pipelines would no longer be subject to the operational and safety rules of these laws. Instead, such pipelines would be subject to a water permit in the Netherlands and a marine licence in the UK.[110] However, the laws that require such a permit or licence do not contain any operating and safety regulations for such pipelines.[111]

3.3.3. Development of New Pipelines

An alternative to reusing existing natural gas pipelines is to develop new pipelines. At present, there is no dedicated onshore hydrogen network to which such pipelines can be connected. Instead, hydrogen can be supplied directly to onshore customers via dedicated hydrogen pipelines. The development of such pipelines in the EEZ would be subject to the general permitting regimes described above.[112] In territorial waters and on land, these pipelines would also be subject to national spatial planning regimes and any additional permits required. But again, there are no rules in national law on ownership, operation and safety for such dedicated hydrogen pipelines.

3.3.4. Assessment

To accommodate the transport of hydrogen to shore via existing offshore natural gas pipelines, it is necessary to adapt national admixing restrictions in

[106] See section 3.2.2 above.
[107] Article 94 of the Mining Decree.
[108] Section 14 of the Petroleum Act.
[109] Section 17 of the Subsoil Act.
[110] Article 6.5 of the Water Act and Art 6.13 of the Water Decree (the Netherlands); section 66(1) of the Marine and Coastal Access Act and section 22(1) of the Marine (Scotland) Act (the UK).
[111] See section 3.2.2 above.
[112] See section 3.3.2 above.

the onshore natural gas network to the levels that have proven to be technically feasible and safe in practice. With regard to the reuse of disused offshore natural gas pipelines, similar legal barriers as for the reuse of disused hydrocarbon installations have been identified. Thus, there is no standardised procedure in national legislation for the reuse of disused natural gas pipelines. Applicable laws merely provide ad hoc solutions and do not contain operational and safety rules for such pipelines. This is also the case for the development and operation of new dedicated offshore hydrogen pipelines. Finally, it is also uncertain who is entitled to operate reused natural gas pipelines and new pipelines for hydrogen transport. To remedy these legal uncertainties, it can be argued that specific rules for hydrogen pipelines should be adopted in order to create regulatory certainty.

4. CONCLUSION

Several legal issues relating to the development of green hydrogen in the North Sea become apparent when observing the existing national legal framework governing offshore energy activities in the Netherlands, the UK and Denmark. Three of the main stages of the offshore PtG process were analysed: (i) electricity input from offshore wind farms for the conversion process; (ii) offshore hydrogen production on existing (disused) hydrocarbon platforms and new platforms; and (iii) offshore hydrogen transport using existing (disused) natural gas pipelines and new pipelines. From this analysis, it can be concluded that the existing national regulatory regimes do not govern all of the above and thus do not provide the legal certainty necessary to sufficiently support the conversion of wind energy to hydrogen in the North Sea. This conclusion can be made for three reasons. First, it is questionable whether it is legally permissible to establish a cable connection between an offshore wind farm (or any part of the offshore electricity grid) and an offshore electrolyser. There is also little guidance in national legislation on how to qualify such electricity cables and who has the right to develop and operate them. Second, there is no specific authorisation procedure regulating the construction of an offshore electrolyser on an existing or disused hydrocarbon installation or a new installation. There are no specific international, EU or national rules on the operation of such installations and any specific rules on health and safety. Third, strict admixture concentrations of hydrogen in the onshore natural gas transmission networks have been imposed at the national level and there are no standardised procedures in national legislation for the reuse of disused natural gas pipelines or the development of new hydrogen pipelines. In conclusion, the development of green hydrogen in the North Sea encounters uncertainties and barriers in the legal framework that may hinder offshore operationalisation of hydrogen production and transport. In order to remedy these legal uncertainties, it may be necessary to adopt specific provisions on PtG in existing legislation or to adopt more specialised national hydrogen laws.

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