

## Brexit and its implications for British and EU Energy and Climate Policy

**Project Report** 

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### **Executive Summary**

The aim of the paper is to examine the potential implications of Brexit from the perspective of both the UK and EU-ex UK (EU-27) with particular attention to neighbouring states, with physical energy interconnections with the UK – currently Ireland, France and the Netherlands in electricity and Ireland, Belgium, and the Netherlands in gas.

We focus on the economic implications and do so in the context of the emerging negotiating positions of the UK and the EU-27, following the commencement of formal negotiations about Brexit between the UK and the EU-27 on 19 June 2017.

The EU has been in a long-running process of creating single markets for electricity, gas and carbon, in line with the objectives of the overall European Single Market project. This is currently happening within the context of the EU's 2020 targets for energy and climate. A new set of targets have been agreed, involving tightening and giving pre-eminence to the carbon market target out to 2030 (and hence the tradability of existing permits), relaxing the renewable energy target so that it is no longer decentralised to individual member states and an aspiration on the energy efficiency target. The UK will leave the EU with its high-level energy and climate targets fully aligned to the EU-27.

On the basis of the experience of Switzerland, we suggest that the UK will experience some loss of influence in shaping EU energy and climate policy and further integration following Brexit will be delayed. However, it will likely continue to be a member of ENTSO-E, an observer at ENTSO-G and in certain committees of ACER. It can continue to be a member of the electricity system operator group, Coreso.

Publicly available quantitative studies on the impact of Brexit on energy trade between the UK and the Continent are rather limited. We have listed all the studies we have found. The evidence seems to suggest that any likely reduction in trade in electricity will have a limited impact. There is no published evidence on gas and limited evidence of the impact on the price of carbon in the EU-ETS.

We present original modelling of potential trade interruption scenarios on electricity and gas prices on both sides of interconnectors in 2025. The modelling suggests limited price impacts on both sides on average and peak day prices. This is because the UK is a net exporter of gas to the EU and electricity interconnection is limited and electricity interconnection also exists via Norway.

One Brexit impact scenario we model could be a delay to a future electricity interconnector. This has a negative impact on consumer welfare for both the UK and its interconnected markets (e.g., Ireland, France, Belgium, the Netherlands and even Norway), if we assume no mitigating capacity investments in the UK. However, these gains are dwarfed by the substantial amount of electricity interconnector capacity which is currently under construction.

We consider possible changes to UK energy policy post Brexit. Several large potential areas of benefit are identified from rethinking domestic energy policy. They are not directly related to Brexit, but they do suggest that the current benefits from rationalising the expensive subsidy regime and abandoning the smart meter roll out for gas (let alone electricity) are large.

A mutual desire to maintain current levels of energy security suggests the value of interconnection, for both electricity and gas, with the rest of Europe. Low prices (and hence energy security with respect to oil and LNG) suggests the primary importance to both the UK and the EU-27 of access to global fossil fuel markets and to global equipment markets.

Environmental targets, particularly with respect to carbon, suggest the value of UK membership of the EU ETS, where the UK is a substantial net purchaser of permits and hence is buying cheap abatement from overseas via its membership of the trading system.

It is difficult to discern the impact of Brexit on the energy policy of the EU-27. This is because there are 27 countries in the remaining block and they represent most of the energy demand in the current EU-28. The EU's energy policy is evolving with a new package of measures announced in winter 2016. The UK has been significant in shaping the direction of EU energy and climate policy in certain areas. One can therefore speculate that the loss of the UK's voting weight might have some significant effect in the areas where influence has been felt in the past. There might be less willingness across the EU-27 to support nuclear, rationalise renewables policy, preserve and promote the EU ETS and for using market mechanisms generally.

At this stage of the negotiations between the EU-27 and the UK, little can be discerned as to the final nature of the UK's membership of the single market in energy and climate. This is because energy is not a special case; rather it would seem to be a representative single market issue. What is decided on the UK's relationship to the EU single market more generally, is likely to play out in electricity, gas and carbon permit markets. Representativeness also applies to the case of energy trading across the Island of Ireland, where both parties are agreed that different arrangements could apply. It seems highly likely that 'a unique' solution will be found to maintain current levels of Irish cross-border co-operation and trading.

We discuss outside energy options for both the EU-27 and the UK. These include more interconnection from the UK to Norway and Iceland and interconnection from Ireland to France. All outside options are expensive and mutually undesirable alternatives to the current arrangements.

We discuss five models of non-EU membership and how they might impact on UK-EU energy relations. None of them would seem to be consistent with the stated negotiating positions of the EU-27 and the UK. We suggest that some new arrangement seems the most likely one to arise from the negotiations.

We conclude that both the UK and the EU-27 benefit substantially from mutual participation in the current electricity, gas and carbon market arrangements. They also rely on being part of an



integrated electricity and gas transmission system for energy security. The EU ETS underpins both the EU-27 and the UK's world-leading role on decarbonisation.

Relative to other sectors, energy is a fairly peripheral issue in Brexit, with short-term trade disruption likely to be limited in size and impact. The UK is a small part of the EU-27's energy system and only significant in the case of Ireland. Similarly, the UK is less exposed to changes in its relationships with the EU in energy than in other sectors. For the UK, energy costs are already several times more sensitive to changes in domestic energy policy.



### 1. Introduction

On 29 March 2017, the UK triggered Article 50 of the Treaty on the European Union (EU)<sup>2</sup> and formally applied to leave the EU, having been a member since 1 January 1973. The UK is the first country to apply to leave the European Union, which currently has 28 member countries (EU-28). This 'Brexit' has set in process a timetable for the UK ceasing to be a member of the EU on 30 March 2019. This paper examines the potential implications of the UK leaving the European Union, for both the UK and its near neighbours in the EU, in the area of energy and climate policy.

We will focus on electricity, gas and carbon policy (and ignore oil and coal) as these are the areas where EU policy has developed in a distinctive way and where EU-wide single markets have emerged for wholesale electricity and gas and for carbon permits. These developments have proceeded incrementally over many years, and have been significantly led and supported by the UK.

The aim of the paper is to examine the potential implications of Brexit from the perspective of both the UK and EU-ex UK (EU-27) with a particular attention to neighbouring states, with physical energy interconnections with the UK (currently Ireland, France and the Netherlands in electricity and Ireland, Belgium, and the Netherlands in gas). We will focus on the economic implications and do so in the context of the emerging negotiating positions of the UK and the EU-27, following the commencement of formal negotiations about Brexit between the UK and the EU-27 on 19 June 2017.

Total final energy expenditure in the UK in 2016 was £139 bn, of which 43% was petroleum products, 25% was electricity, and 16% was gas.<sup>3</sup> The remainder was coal, crude oil and other fuels. Energy is a significant source of tax revenue in the UK, raising £38bn, or 6% of the total tax take,<sup>4</sup> though most of this is on transport fuel. The UK is a substantial net energy importer, with net imports of £11bn in 2015, however electricity net imports from the same period were only valued at £680m.<sup>5</sup> Energy import costs are substantially affected by exchange rate movements and international commodity prices. The UK is a net importer of electricity from the EU. It is currently a net exporter of gas to the EU in 2016 (+ 43 TWh on 897 TWh of domestic consumption), though the gross trade is significantly higher with seasonal imports of 64 TWh.<sup>6</sup>

<sup>&</sup>lt;sup>2</sup> Available at: <u>http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:12016M/TXT&from=EN</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>3</sup> See market value of inland consumption in DUKES (2017, Table 1.4, p.33).

<sup>&</sup>lt;sup>4</sup> See HM Treasury (2016, p.58) reports total tax receipts for 2015/16 of £628.6bn. DUKES (2017) reports total fuel duties + VAT + carbon price floor + climate change levy of £38.0bn in 2016, of which the tax raised on petroleum products is £33.6bn.

<sup>&</sup>lt;sup>5</sup> See DUKES (2017, Table G.7 (BOP basis)).

<sup>&</sup>lt;sup>6</sup> See DUKES (2017, Table G.5) and DUKES (2017, p.89).



The UK produced 496m tonnes of CO2e in 2015, of which 172m related to the EU ETS fixed installations.<sup>7</sup> The UK is a significant net purchaser of allowances in the EU ETS with net purchases of 28.5m (172m allowances presented, against 143m allocated).<sup>8</sup>

In 2014<sup>9</sup> the UK accounted for 15% of the EU-28's GDP, and constituted 12% of its total final energy consumption, 16% of its gas consumption, 11% of its electricity consumption and 13% of its production of CO2e (and redeemed 8.5% of the EU ETS permits). In terms of net imports, the UK's share of the EU's net imports of all fuels was 10%, and 11% and 6% for gas and electricity respectively. The small relative size of the UK to the EU-27 immediately suggests that a focus on the impacts on near neighbours (with physical interconnection) is likely to be easier to model and discuss in an informed way.

The UK shares a land border with the Republic of Ireland and within the island of Ireland both electricity and gas networks are physically interconnected, with final demand roughly split 1:5 between Northern Ireland<sup>10</sup> and the Republic Ireland<sup>11</sup> for electricity and gas. Electricity is traded within a single wholesale market, the I-SEM, and subject to a joint governance structure approved by the EU. GB electricity consumption in 2015 was 292.2 TWh, while gas was 489.3 TWh.<sup>12</sup>

The overall figures suggest that in terms of its GDP, the UK was not particularly energy intensive or import dependent relative to the EU-27. This reflects its post-industrial economy and continuing (but declining) domestic production of oil and gas.

The paper proceeds as follows. We will begin by examining the EU energy and climate policy environment. We will proceed to review the literature on the quantitative impacts of Brexit in the energy sector and present some original modelling of the potential impact in 2025 of various scenarios for the electricity and gas sectors. Here, we examine both the impact on annual average prices and the impact of some plausible security of supply events. We follow this with a discussion of UK energy policy and how it might be impacted by Brexit, before proceeding to a discussion of the emerging post-Brexit negotiating positions on both sides. We go on to look at outside options for the energy and climate sectors. We then review possible overarching frameworks for the UK's relationship with the EU and how these relate to the energy and climate sectors, before offering some conclusions.

(<u>http://ec.europa.eu/eurostat/data/database</u>) while gas consumption was 43.64 TWh (<u>http://ec.europa.eu/eurostat/data/database</u>).

<sup>&</sup>lt;sup>7</sup> See BEIS (2017, p.7, 18).

<sup>&</sup>lt;sup>8</sup> See BEIS (2017, p.18).

<sup>&</sup>lt;sup>9</sup> See European Union (2016).

<sup>&</sup>lt;sup>10</sup> electricity consumption in Northern Ireland was 7.82 TWh in 2015 (<u>https://www.economy-ni.gov.uk/sites/default/files/publications/deti/Issue%204%20-</u>%20Electricity%20Consumption%20and%20Renewable%20Generation%20in%20Northern%20Ireland%20January%20

<sup>&</sup>lt;u>2015%20to%20December%202015.pdf</u>) while gas consumption was 5.37 TWh in 2014 (<u>https://www.economy-ni.gov.uk/sites/default/files/publications/deti/energy-northern-ireland-2016.pdf</u>)

<sup>&</sup>lt;sup>11</sup> Electricity consumption in the Republic of Ireland was 25.55 TWh in 2015

<sup>&</sup>lt;sup>12</sup> https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/579203/Subnational\_electricity\_and\_gas\_consumption\_summary\_report\_2016.pdf

### 2. The European Policy Context

The EU has been in a long-running process of creating single markets for electricity, gas and carbon, in line with the objectives of the overall European Single Market project. This is currently happening within the context of the EU's 2020 targets for energy and climate. These targets can be summarised as the 20-20-20 targets: a 20% reduction in CO2e on 1990 levels; the achievement of 20% of gross final energy consumption from renewables; and a 20% reduction in energy intensity of GDP relative to 2005 (see Pollitt, 2009, 2016). The Union has agreed to 2030 targets of 40-27-27.<sup>13</sup> These have involved tightening and giving pre-eminence to the carbon market target out to 2030 (and hence the tradability of existing permits), relaxing the renewable energy target so that it is no longer decentralised to individual member states and an aspiration on the energy efficiency target.

Successive European Commission electricity and gas directives (in 1996, 2003 and 2009) have promoted the creation of competitive multi-country (and pan-European) wholesale markets for electricity and gas (see Jamasb and Pollitt, 2005, and Pollitt, 2009). They have also ensured unbundling of networks and competitive services within electricity and gas supply. This has resulted in regulated third party access to transmission and distribution networks for electricity and gas, and non-discriminatory access to cross-border wires and pipelines. The directives have also sought to promote retail competition and the deregulation of ownership restrictions on wholesale and retail assets through free-entry into both wholesale and final retail markets. The directives have also required the existence of an independent national energy regulator with certain duties to promote competition and regulate third party access to networks.

The EU Emissions Trading System was created in 2005 and covers around 45% of greenhouse gases produced in the EU, including all of the emissions from the electricity sector (under EU Directive 2003/87/EC). This has resulted in a single price for a permit for CO2e across the EU-28 for the covered sectors. The trading scheme was extended in 2013 to cover domestic emissions from the aviation sector and full auctioning of permits (and hence an end to free allocation to historic polluters) for the electricity sector. Recent developments include a proposal to create a market stability reserve to reduce excess permits in the system.<sup>14</sup>

There have been a significant number of other directives relating to energy efficiency and energy security. In addition, the nuclear industry is covered by the 1957 Euratom Treaty<sup>15</sup> which ensures freedom of movement and regulation of the movement of nuclear material and nuclear personnel across the EU.

<sup>&</sup>lt;sup>13</sup> See <u>https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2030-energy-strategy</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>14</sup> For a discussion of the phase 4 (2021-30) proposals see <u>https://ec.europa.eu/clima/policies/ets/revision\_en</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>15</sup> See <u>http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:12012A/TXT&from=EN</u>, accessed 15 September 2017.

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The move to create single markets for electricity, gas and carbon has been accompanied by the creation of pan-European institutions, in addition to the strengthening of national regulatory agencies. The Agency for the Cooperation of European Energy Regulators (ACER) has been created to resolve disputes between national energy regulators, oversee the network code review processes and the assessment of projects of common interest (PCI) lists. This is in addition to the Council of European Energy Regulators (CEER) which discusses regulatory issues and makes recommendations to the Commission and ACER. CEER and ACER work closely with the associations of system operators for electricity and for gas in Europe (ENTSO-E and ENTSO-G) who have taken initiatives on co-ordinating cross border transmission rules across the EU.

There is currently a large set of streams of work co-ordinating network codes in individual countries across Europe led by ACER and working closely with ENTSO-E and ENTSO-G.<sup>16</sup> This process is aimed at standardising the detailed network rules across the EU-28. It is largely due for completion in 2019.

Norway and Switzerland are substantially physically integrated into the European electricity and gas system. Neither are EU member states. Norway is a significant gas producer and exporter to the EU. Switzerland is a key transit country for both electricity and gas. Norway is a member of the European single market, while Switzerland is not. Both are members of the European Free Trade Area (EFTA). Neither are members of ACER as this is an EU institution but they are observers in ACER working groups. CEER is open to all members of the European Economic Area (the single market) and so Norway is a member of CEER. Norway and Switzerland are members of ENTSO-E and observers of ENTSO-G.

The case of Switzerland is interesting. Switzerland is currently in dispute with the EU over further integration of its electricity sector into the single electricity market. Further integration was explicitly stopped following the Swiss referendum on freedom of movement in February 2014<sup>17</sup>, which ended freedom of movement of people between the EU and Switzerland. Thus, progress towards full market coupling, joint allocation of forward transmission capacity, intraday market coupling, cross-border balancing and cross-border transmission capacity allocation has been halted. The reason for this is partly to do with Swiss unwillingness to agree to the ultimate jurisdiction of the European Court of Justice and partly due to explicit punishment by the EU for the referendum decision. It is to be noted that under World Trade Organization (WTO) law market coupling is a 'regional economic agreement' within the EU and hence Switzerland does not have the automatic right under WTO most favoured nation (MFN) status (under WTO rules) to participate in it simply because it exists between EU MSs.<sup>18</sup>

<sup>&</sup>lt;sup>16</sup> See Dale (2016) for a review.

<sup>&</sup>lt;sup>17</sup> See Shotter and Oliver (2014). The referendum asked the following Yes/No question, '*Do you accept the federal popular initiative 'against mass migration'*, which 'Yes' won. This was interpreted by the EU as a unilateral withdrawal by Switzerland from its bilateral treaty with the EU on freedom of movement which had been in force since 2002. <sup>18</sup> See Cottier et al. (undated) for a general discussion of the WTO rules on energy. Their basic conclusion is that WTO rules are 'highly fragmented and largely incoherent' (p.1).

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The EU ETS includes the EU-28 plus Norway, Liechtenstein and Iceland. The scheme is administered by the European Commission with compliance delegated to individual member states. The overall quantity of emissions is set by the Commission and allocated to individual member states. The scheme is subject to the ultimate jurisdiction of the European Court of Justice.

Switzerland has been discussing linking its national scheme, which became compulsory in 2013, to the EU ETS for some time and until recently this process had stalled. However, in August 2017 it was announced<sup>19</sup> that there were firm plans to link the two schemes. According the European Commission, this would lead to 'mutual recognition' of one another's allowances.<sup>20</sup>

In addition to the market arrangements around electricity, gas and carbon it is worth noting that physical integration and extension of networks has been an important priority of the EU, especially with regards to the European periphery. Thus, there has been substantial EU support for electricity and gas interconnectors between Great Britain and Ireland, with the EU budget paying around 1/3 of the cost of some interconnectors. If a project is designated a project of common interest (PCI) this accelerates regulatory permitting and promotes access to finance from the Connecting Europe Facility (CEF).<sup>21</sup> It is worth noting that a PCI can involve connecting the EU to a third country if there is benefit to at least two EU MSs. Current PCIs include a gas storage facility in Northern Ireland and an electricity link between Iceland and Scotland.<sup>22</sup> A new list of PCI projects is due to be published in October 2017.

Since the process of creating a single EU market in energy was begun, there has been substantial progress with market integration of electricity and significant progress on gas.

According to ACER (Pototshnig, 2015) some 85% of EU electricity is now market coupled in dayahead electricity markets. This means that the prices guoted on 7 of the day-ahead power exchanges across Europe are resolved by a single algorithm (EUPHEMIA)<sup>23</sup> which in the absence of binding transmission constraints could lead to a single day-ahead price across the coupled area. In addition, there is joint regional security coordination between electricity transmission operators – including National Grid from GB - in part of western Europe via Coreso<sup>24</sup>. Market coupling, combined with competitive allocation of cross-border electricity transmission capacity,

<sup>&</sup>lt;sup>19</sup> See https://ec.europa.eu/clima/news/eu-and-switzerland-join-forces-emissions-trading en, accessed 15 September 2017. <sup>20</sup> See <u>https://ec.europa.eu/clima/policies/ets/markets\_en</u>, accessed 13 September 2017.

<sup>&</sup>lt;sup>21</sup> See <u>http://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest</u>, accessed 13 September 2017.

<sup>&</sup>lt;sup>22</sup> <u>http://ec.europa.eu/energy/infrastructure/transparency\_platform/map-viewer/main.html</u>, 13 September 2017. <sup>23</sup> EUPHEMIA stands for the 'Pan-European Hybrid Electricity Market Integration Algorithm'. See

https://nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf, accessed 15 September 2017.

<sup>&</sup>lt;sup>24</sup> Coreso is jointly owned by 7 EU TSOs: 50 Hertz (Germany), Elia (Belgium), National Grid (Great Britain), Red Electrica, (Spain) REN (Portugal), RTE (France) and Terna (Italy). See https://www.coreso.eu/mission/our-mission/, accessed 15 September 2017.

has resulted in substantial improvements in the economic efficiency of cross-border power flows, with electricity increasingly flowing 'in the right direction' from low to high price areas.<sup>25</sup>

On gas, the picture is much more mixed with good progress being made on market-driven price flows between the core European countries and rather less progress in central and eastern Europe – CEE (see Pototshnig, 2015)<sup>26</sup>. The European Commission is well aware of the need to make further progress on the creation of a genuine wide-area market in gas as a way of enhancing energy security in those CEE countries which are dependent on Russian gas imports.<sup>27</sup>

The benefits of the single market in terms of reduced wholesale electricity and gas prices are hard to quantify, because they are tied up with simultaneous and somewhat related improvements in national regulation of networks and restructuring of state-owned utilities. However, the overall benefits are perhaps of the order of a 5% reduction in wholesale and final prices (see Pollitt, 2012). While there have been substantial improvements in the efficiency of gross flows of electricity and gas as a result of day-ahead market integration, as noted by ACER above, the flows are only efficient given the interconnector capacity declarations of the system operators, which can be subject to manipulation by system operators seeking to minimise intracountry constraints. There also remain substantial intra-day inefficiencies<sup>28</sup>. The EU has generally preferred wide area zonal energy pricing to deep market signals (e.g. on nodal congestion pricing in PJM) in order to promote competition.

In terms of climate progress, the EU ETS is an impressive institutional achievement by global standards (see Pollitt, 2016). 31 countries are covered by a single emissions market trading instrument is a great example of what Boasson and Wettestad (2012) call an example of 'international institutional entrepreneurship'. Annual allowances issued (at c.2200 tonnes including aviation emissions)<sup>29</sup> represent around 5% of global CO2e emissions. The scheme has demonstrated that multi-country schemes can work and it has provided a model for emissions trading arrangements across the world, including the new Chinese national emissions trading scheme currently due to start at the end of this year (which should be twice the size of the EU ETS).<sup>30</sup> The low prices we have observed in the EU ETS recently are not a function of its institutional set up, but of the unwillingness of national governments to tighten quantity targets against which the mechanism then determines prices.

Within the specific area of renewable energy, the EU has established a leading position in the installation of renewable energy technologies. By 2016, 32% of global installed capacity of wind,

<sup>&</sup>lt;sup>25</sup> See ACER (2015, p.191).

<sup>&</sup>lt;sup>26</sup> See also ACER (2015, p.254).

<sup>&</sup>lt;sup>27</sup> In January 2017, the European Commission published a number of consultation papers under its 'Quo vadis gas market regulatory framework'. See

https://ec.europa.eu/energy/en/content/study-quo-vadis-gas-market-regulatory-framework-discussion-papers, accessed 14 September 2017.

<sup>&</sup>lt;sup>28</sup> See Newbery et al. (2016) for a discussion of the benefits of further market integration in electricity.

<sup>&</sup>lt;sup>29</sup> See <u>https://ec.europa.eu/clima/policies/ets/cap\_en</u>, accessed 17 September 2017.

 $<sup>^{30}</sup>$  See World Bank and Ecofys (2017).

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solar and bio energy was installed in the EU-28.<sup>31</sup> This is against a background where the EU produced only 5.6% of the world's energy and consumed only 11.4% of the world's energy (in 2014)<sup>32</sup>. This capacity has been promoted by the 2001 Renewable Electricity Directive (2001/77/EC), which set ambitious targets for the share of renewable electricity in total electricity output in each member state by 2010, and the 2009 Renewable Energy Directive (2009/28/EC) which set the national 2020 targets for the share of renewable energy in gross final energy consumption (as part of the 20-20-20 targets).

Increasing market and physical integration of European energy systems gives rise to significant shared security benefits. National Grid (2017) give a good example of this in the context of the UK's interconnector with France. Normally this interconnector facilitates a flow from France to the UK as electricity prices are generally higher in the UK than in France. However, when 20 French nuclear reactors were offline for maintenance in autumn 2016, the interconnector was fully utilised in the opposite direction as the system in Great Britain provided power to support demand in France. Likewise, the island of Ireland has derived significant energy security benefits from its two gas and two electricity interconnections with Great Britain, with the Irish system being wholly dependent on Great Britain to meet its gas demand. The closure of Great Britain's largest gas storage facility, Rough, announced in June 2017, will make the UK more dependent on gas storage capacity in the rest of Europe to meet its winter peak demand (though demand can currently be met from a combination of imports from Norway, the EU-27 and LNG import facilities in Great Britain). Thus, gas interconnection between the UK and Europe also contributes to security of supply and economic efficiency, since having multiple sources of gas reveals the most efficient way of utilising gas infrastructure while maintaining security standards for the UK.

The EU energy system continues to develop. Gas demand is falling across Europe as a result of increased energy efficiency, deindustrialisation and increases in renewable electricity. This is leading to rationalisation of gas assets by reducing compressor, pipeline and storage capacity. This will give rise to further opportunities for mutually beneficial international trading of gas in order to manage overall system costs in the face of competition with other fuels. In electricity, peak demand remains flat or falling across Europe (see Sioshansi, 2016). However, the rise of renewables and the closure of coal-fired power plants have increased the value of international interconnection. Great Britain currently has 4 GW of electricity interconnection capacity with Ireland, France and the Netherlands. There is currently 7.3 GW of planned future interconnection by 2022<sup>33</sup>, of which 2 GW (to Belgium and France) is under construction and

<sup>&</sup>lt;sup>31</sup> REN21, 2017, p.34.

<sup>&</sup>lt;sup>32</sup> European Union, 2016, p.10, 12.

<sup>&</sup>lt;sup>33</sup> See <u>https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors</u>, accessed 14 September 2017.

due for completion in 2019<sup>34</sup>; 1.4 GW (to Norway) is under construction and due for completion in 2020<sup>35</sup>.

It is important to note that UK has been a key participant, advocate for and leading country in implementation in all of the above market and institutional developments. The UK was the first country in the EU-28 to create wholesale markets for electricity, gas and carbon, and it served as the model for the subsequent EU Directives mentioned above.<sup>36</sup> The UK has promoted shared market-based security of energy supplies and increased interconnection. The UK's institutional arrangements for regulating the energy sector via independent energy regulators (first OFGAS and Offer, now Ofgem) have provided examples for the rest of the EU to follow.

EU energy and climate policy is moving on. In November 2016 (i.e. after the Brexit vote), the European Commission published a winter package of draft further reforms, mainly of the electricity sector, under the title 'Clean Energy for All Europeans'<sup>37</sup>. This ambitious set of further reform documents (and in due course a new set of Directives) seeks to further extend market integration in the context of rising shares of renewable energy and mutual energy interdependence. Some of the controversial issues raised by the Winter Package include the need to standardise and coordinate capacity mechanisms for electricity, remove priority dispatch for renewables, harmonise network tariffs, and extend regional cooperation between system operators. Importantly the Winter Package suggests the need for each member state to submit a national energy plan for approval by the European Commission<sup>38</sup>. This is an attempt to begin to resolve some of the conflicts between national actions in the area of energy and the wider interests of the EU, which will become more acute as national systems become more physically and financially integrated.

Meanwhile some national governments within the EU-28 will continue to promote even more ambitious energy policies, some of which seem likely to shape European energy policy developments. In July 2017, France<sup>39</sup> and the UK<sup>40</sup> announced that they intend to ban the sale of new fossil fuel cars from 2040. This is a substantial impetus to the ongoing roll out of electric vehicles, provides support for smart investments in power grids and the encouragement of local sources for flexibility services within the power system.

<sup>&</sup>lt;sup>34</sup> See <u>http://www.nemo-link.com</u> and <u>http://www.eleclink.co.uk/</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>35</sup> See <u>http://northsealink.com/</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>36</sup> For example, see Bergman et al. (1999) on electricity and Hepburn and Teytelboym (2017) on climate policy.

<sup>&</sup>lt;sup>37</sup> See <u>https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>38</sup> See <u>http://eur-lex.europa.eu/resource.html?uri=cellar:ac5d97a8-0319-11e7-8a35-</u> 01aa75ed71a1.0024.02/DOC 1&format=PDF, accessed 15 September 2017.

<sup>&</sup>lt;sup>39</sup> See BBC News website, 'France set to ban sale of petrol and diesel vehicles by 2040', 6 July 2017,

http://www.bbc.co.uk/news/world-europe-40518293, accessed 15 September 2017.

<sup>&</sup>lt;sup>40</sup> The UK announced a ban on sales of fossil fuel cars and vans by 2040, see BBC News website, 'New diesel and petrol vehicles to be banned from 2040 in UK', 26 July 2017, <u>http://www.bbc.co.uk/news/uk-40723581</u>, accessed 15 September 2017.

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### 3. Literature Review of Possible Brexit Impacts

Quantitative studies on the impact of Brexit on energy trade between the UK and the Continent are rather limited. We have listed all the studies we have found. We see two primary reasons for this: (i) no consensus on how Brexit may, in reality, impact the way the UK trades electricity and gas with the rest of Europe, and (ii) hence any quantification of potential impact is subject to a degree of uncertainty and subjectivity in choosing Brexit scenarios and their 'parametrisation' in simulation models.

For example, the Oxera (2016) white paper (which was released before referendum day) modelled a Brexit scenario and how this may impact Great Britain (GB) consumers. In particular, Oxera (2016) considered a scenario whereby the UK could impose a tariff on electricity imports that would 'correct' for (i) a higher CO2 tax (carbon price in the UK is of magnitude higher than the current EU ETS prices), and (ii) higher balancing tariffs and transmission loss levies. It is said that these two factors add ca. £8.5/MWh to the variable costs for gas-fired generation (CCGT) in GB, of which 75% is due to higher carbon price and the rest is due to balancing charges and transmission losses. So, the logic behind Oxera's (2016) Brexit scenario is that a UK government could impose an additional import tax to correct for these two factors allowing domestic generators to compete on par with interconnection from France and the Netherlands. Thus, their modelling results suggest that net imports are reduced by 33% of the current average net imports or 24% of interconnection capacity with France and the Netherlands if such a tax were to be introduced. Lower net imports resulted in higher domestic generation and slightly higher wholesale prices. This results in an average annual electricity bill rises by ca. £2/household.

Aurora Energy Research's (2016) white paper has a similar perspective to the Oxera (2016) paper in that their analysis suggests that additional interconnection depresses wholesale prices in GB (reduction of 3-7% to 2025), but when the full welfare impact of interconnectors is calculated by including subsidies (higher carbon tax in the UK, higher transmission and distribution use of system charges - TNUoS and BSUoS) the net benefit of additional interconnection is <u>negative</u>.<sup>41</sup> Thus, Aurora Energy Research (2016) concluded that the long-term impact of Brexit could be less interconnection with Europe but, in their view, this is not necessarily a net welfare negative outcome for GB.

Another consulting study by Vivid Economics (2016) for Great Britain's National Grid, considered the wider implications of Brexit on short-term electricity trade and long-term investment in the energy sector. For example, they pointed out that a higher cost of financing - of the order of 50 basis points - would result in an increase of 'hundreds of millions of pounds' or 'deferral of investment' until uncertainties resolve. On short-term impact, Vivid Economics (2016) pointed

<sup>&</sup>lt;sup>41</sup> Aurora Energy Research pointed out to the same issue identified by Oxera (2016) – interconnectors enjoy a £10/MWh price advantage over domestic generation as they receive exemptions from both the Carbon Price Support and GB network charges (TNUoS and BSUoS).

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out that other impacts of Brexit on the UK electricity sector could be: (a) a loss of market coupling benefits of the order of £160m p.a., (b) extra balancing services costs of £80m p.a., (c) extra capacity market costs - due to interconnectors not being part of capacity markets - of £20m p.a., (d) the loss of future interconnectors such as Viking Link, IFA2, and FAB, which may not proceed, equal to £160m p.a. Thus, if one includes both the short- as well as the long-term value of having interconnection for both the GB and Continental Europe then the case for greater interconnection and free trade in electricity and gas seems stronger than just looking at the loss to domestic GB generation from higher carbon and network charges, as argued by both Oxera (2016) and Aurora Energy Research (2016).

Indeed, Newbery et al. (2016) pointed out that apart from short-term gains from trade (baseline case of national self-security in which the only gains are short-term arbitrage on day-ahead markets) there are additional benefits of market integration in electricity which includes sharing balancing, reserves and demand side response. For example, Newbery et al. (2016) stated that the potential balancing benefits for GB-France interconnection is roughly €3m p.a. and for GB-Netherlands, €82m p.a. Other benefits from interconnection in the electricity sector, according to Newbery et al. (2016), include reductions in (i) unscheduled flows (loop flows and unscheduled transit flows), and (ii) curtailment at borders. In total, Newbery et al. (2016) estimated total gains from further market integration for the EU-28 at around €3.3 bn p.a. Thus, if in 2012-2013 there were 23 GW of interconnection capacity in Europe, of which 4 GW, or 17.4% of the total, is between GB and France, the Netherlands and Ireland then the benefits for the four trading countries could be €574m p.a.

We are not aware of any publicly available quantitative studies that estimate the potential impact of Brexit on the carbon market in Europe. In general after the Brexit referendum, the carbon market reacted rather bearishly – there was downward adjustment to the expectation of carbon price in the range 9-18% from the base level prior to the referendum results, according a survey of analysts by Reuters<sup>42</sup>. Although this short-term market reaction seems to suggest a rather bearish attitude towards Brexit and the European carbon market, most market analysts expect little impact on the fundamentals of the market other than loss of confidence which was already priced in the short-term reduction of carbon prices post-Brexit.

Regarding the gas market and possible trading arrangements post-Brexit, there are not many publicly available quantitative studies analysing potential impact of Brexit on gas trading between the UK and the Continent. Aurora Energy Research (2016) mentions that in the short-term Brexit may increase relative gas prices as a devalued pound will mean less Euro-denominated gas imports. However, over the long-term there are limited impacts because GB is well-connected to the global gas market via LNG terminals and it still enjoys domestic production from the UK continental shelf (UKCS) (albeit production is declining rapidly) as well as imports via direct pipelines with Norway.

<sup>&</sup>lt;sup>42</sup> http://uk.reuters.com/article/eu-carbon/poll-analysts-slash-eu-carbon-price-forecasts-following-brexitidUKL8N1B00YF

# 4. Modelling of potential impacts of Brexit on wholesale Power and Gas prices

For this analysis, we use electricity and gas market models (see Annex 1 for details) to assess the potential quantitative impact of Brexit on average annual wholesale electricity and gas prices in the UK, as well as providing an analysis of the impact on prices and market fundamentals on a peak day. We undertake this quantitative analysis for 2025 because we want to measure any potential impact over a longer term. In 2025, one may expect any negative macroeconomic impact – from loss of trade / uncertainty of investment – arising from Brexit to fully materialise. At the same time, global commodity markets may be tighter and, hence, any costs and benefits of market integration in gas and electricity between the UK and the Continent will be fully appreciated under those circumstances. For the rest of this section, we proceed with presenting modelling for gas and then for electricity.

### 4.1. Gas modelling

For gas, the 2025<sup>43</sup> timeframe is particularly interesting, beyond and above the abovementioned reasons. The UK and continental Europe are connected by two gas interconnectors – IUK, a bidirectional pipeline connecting the UK with Belgium, and BBL, an import pipeline from the Netherlands to the UK. Both pipelines were financed on the back of a series of long-term shipping contracts, some of which are believed to expire starting late 2018 and, hence, the question of the business model and regulatory arrangements around these two interconnectors are currently under discussion. If anything, Brexit will complicate and create greater uncertainties for these two interconnectors in terms of capacity provision, pricing and indeed commercial model of operation (e.g., merchant vs. regulated entity).

Against this background, we have simulated several scenarios representing possible states of the world in 2025, with respect to demand growth for gas in GB, and available capacities of the two gas interconnectors (Table 1). Then, we compare annual average wholesale prices and peak day prices against the baseline scenario – in which no changes are expected in terms of capacity and tariffs through the interconnectors – as well as gas demand in GB, which follows the projection of the IEA (2016) World Energy Outlook 2016 New Policy Scenario. We should note that, in line with the recent announcement, the analysis assumes that the UK's largest seasonal gas storage facility – Rough – which accounted for ca. 70% of UK's storage capacity, is closed and no new storage facilities are opened by 2025.

<sup>&</sup>lt;sup>43</sup> For gas, we report storage year – 1 Apr 2025 until 31 March 2026.

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Furthermore, following the recent announcement of merging the BBL gas pipeline into the TTF market area,<sup>44</sup> we apply only commodity charges on the BBL line. We also assume that IUK's import and export capacity are priced at commodity charge level which is a good approximation for short-run marginal cost (SRMC) for using the pipeline. This is a reasonable assumption so long as long-term shipping contracts are renewed by 2025, or that the IUK asset base will be *socialised* (similar to the recent case of BBL pipeline being merged with TTF market area). In a very unfortunate circumstance, IUK could divest/close a compressor station reducing cost and capacity, or indeed close the facility altogether. The latter two cases are covered by our modelling and sensitivity analyses through reduction in capacity levels being available for market participants to book in both directions (import and export, see Table 1). Furthermore, the gas model is a short-run model hence usage of SMRCs for gas infrastructure capacity is the correct way of conducting analyses. If the capacity is saturated, then the model would reveal a positive premium, thus approximating the real capacity auction process.<sup>45</sup>

|            | Demand       | IUK export | IUK import | BBL import |  |  |
|------------|--------------|------------|------------|------------|--|--|
|            | growth rate, | capacity,  | capacity,  | capacity,  |  |  |
|            | CAGR         | bcm/year   | bcm/year   | bcm/year   |  |  |
| Baseline A | 0.3%         | 19         | 24         | 15         |  |  |
| Baseline B | -1.2%        | 19         | 24         | 15         |  |  |
| Case A1    | 0.3%         | 5.7        | 7.2        | 4.5        |  |  |
| Case A2    | 0.3%         | 0          | 0          | 0          |  |  |
| Case B1    | -1.2%        | 5.7        | 7.2        | 4.5        |  |  |
| Case B2    | -1.2%        | 0          | 0          | 0          |  |  |

| Table 1: Main ass | imptions for gas | modelling |
|-------------------|------------------|-----------|
|-------------------|------------------|-----------|

One can see from Table 1 that Baseline A reflects 'business as usual' in terms of interconnector capacity and underlying assumptions around gas demand growth in GB (which is a function of economic activity); whereas Baseline B reflects our assumption that Brexit may impact GB's economic activities and, hence, demand for gas could be lower than expected by 2025. Apart from the demand growth assumption, Baseline A and Baseline B have no other differences. Further, Case 1 and Case 2 represent different levels of gas interconnection between the UK and the Continent. In Case 1, we assume a 70% reduction in capacity for both the IUK (export and import) and BBL (import) pipelines.<sup>46</sup> Case 2 is an extreme scenario in which we assume gas interconnections are not available at all (hence, their import/export capacities were set to zero).

<sup>&</sup>lt;sup>44</sup> Essentially BBL becomes part of TTF and its asset base is cross-subsidised by entry/exit charges into and out of TTF market area. For details see

https://www.ofgem.gov.uk/system/files/docs/2017/09/bbl modified access rules decision letter 0.pdf

<sup>&</sup>lt;sup>45</sup> The model will show positive shadow price/congestion rent for using a pipeline link when demand for capacity exceeds its supply. However, there is no guarantee that the resultant congestion premium may be high enough to cover CAPEX of the facility.

<sup>&</sup>lt;sup>46</sup> Note that we have also conducted analyses of two more scenarios whereby gas interconnectors' capacities were reduced to 80% and 50% of the original capacity level. However, the results show that reducing gas interconnector capacities to those levels does not affect market prices in the UK and Europe.

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We consider Case 2 to be highly unlikely, but we analyse this situation to see what might have been impact on prices. One can understand Case 2 as being a situation where both interconnectors are in a world of fierce competition between sources of supplies and flexibility (storage, upstream pipelines and LNG deliveries into the UK and Europe) and they could both be 'out of merit order' and hence divest and shut down (the UK Rough gas storage facility is one such real example of asset divestment in a competitive setting, albeit this was predominantly because of aging infrastructure and safety issues).<sup>47</sup>

Table 2 below highlights our results from running the gas model for the baselines and alternative scenarios. Firstly, our results indicate that the UK is net exporter of gas to Europe but at the same, time the average wholesale gas price in the UK is higher than those on the Continent – price differentials under Baseline A (B) is \$0.23/mmbtu (\$0.04/mmbtu) (Table 2, column 3). The reason for this is that UKCS gas producers have a choice of either sending gas into UK's NBP market area (and hence paying full costs of the GB transmission system) or sending gas to the Continent through IUK paying a discounted tariff of using only part of the GB transmission system.<sup>48</sup> Therefore, should export capacity through IUK be partially (Case A1) or fully divested (Case A2) then UKCS producer will have no choice but to send gas to NBP in the first instance. This will, ceteris paribus, increase average wholesale gas prices in North-West Europe, albeit very marginally (from \$3.94/mmbtu to \$3.96/mmbtu), while reducing average prices in the UK (from \$4.17/mmbtu to \$4.01/mmbtu). Thus, one can conclude that maintaining gas trade between the UK and the Continent may be largely beneficial to European consumers (lower prices), cross-border pipeline owners, UKCS producers and LNG importers using the UK as a re-export hub back to Europe. For example, benefits to Belgium and Dutch consumers would be ca. \$42mn p.a. given that their combined annual gas consumption in 2015 was ca. 57 bcm (IEA, 2016).<sup>49</sup> Our results show that imports from the Continent back to the UK is minimal on average across the year (Table 2, column 13), although the security of supply benefits to the UK is not insignificant.

<sup>&</sup>lt;sup>47</sup> Though one can still argue that aging infrastructures could be maintained to meet safety standards at increasing operating expenditure (OPEX). However, increasing OPEX may not be justifiable given low seasonal spreads.

<sup>&</sup>lt;sup>48</sup> The so-called short-haul tariff – a tariff offered by UK's gas transmission system operator – National Grid – in response to a potential threat by UKCS producers building a pipeline loop that would allow them to send gas from UKCS fields to Bacton and from there through IUK to the Continent, bypassing NBP altogether.

<sup>&</sup>lt;sup>49</sup> 57 bcm x \$0.02/mmbtu (TTF price differences between Case A2 and Baseline A) assuming that one billion cubic metres of gas is 36,964,868 mmbtu.

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### Table 2: Results from gas modelling – impact on average and peak wholesale gas prices

|               | TTF     | NBP     | NBP<br>average <sup>a</sup> | NBP<br>average <sup>a</sup> | NBP       | NBP   | NBP   | NBP         | NBP  | NBP  | NBP            | NBP                 | NBP      | Average <sup>a</sup><br>price | Chai<br>relati<br>Base | nges<br>ve to<br>lines | TTF NBP | Peak price | Changes<br>relative to<br>Baselines |  | Peak prices relative to annual average prices |  | Import Flows, | Export<br>Flows, | Correlation<br>between TTF<br>and NBP |
|---------------|---------|---------|-----------------------------|-----------------------------|-----------|-------|-------|-------------|------|------|----------------|---------------------|----------|-------------------------------|------------------------|------------------------|---------|------------|-------------------------------------|--|---|--|---------------|------------------|---------------------------------------|
|               | uveruge | uveruge | differential                | TTF                         | NBP       | 1 Cuk | T Cuk | unrerentiur | TTF  | NBP  | TTF            | NBP                 | ben p.u. | bcm p.a. <sup>c</sup>         |                        |                        |         |            |                                     |  |   |  |               |                  |                                       |
|               | [1]     | [2]     | [3]=[2]-[1]                 | [4]                         | [5]       | [6]   | [7]   | [8]=[6]-[7] | [9]  | [10] | [11]=[9]/[1]-1 | [12]=[10]/[2]<br>-1 | [13]     | [14]                          | [15]                   |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Baseline<br>A | 3.94    | 4.17    | 0.23                        | n/a                         | n/a       | 4.33  | 4.86  | 0.53        | n/a  | n/a  | 10%            | 17%                 | 0.05     | 1.58                          | 0.953                  |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Case A1       | 3.94    | 4.17    | 0.23                        | 0.0%                        | 0.0%      | 4.33  | 4.86  | 0.53        | 0.0% | 0.0% | 10%            | 17%                 | 0.04     | 1.41                          | 0.953                  |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Case A2       | 3.96    | 4.01    | 0.05                        | 0.4%                        | -<br>3.9% | 4.33  | 4.86  | 0.53        | 0.0% | 0.0% | 10%            | 21%                 | 0.00     | 0.00                          | 0.919                  |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Baseline<br>B | 3.92    | 3.96    | 0.04                        | n/a                         | n/a       | 4.33  | 4.39  | 0.05        | n/a  | n/a  | 11%            | 11%                 | 0.00     | 5.28                          | 0.967                  |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Case B1       | 3.93    | 3.83    | -0.10                       | 0.2%                        | -<br>3.3% | 4.33  | 4.39  | 0.05        | 0.0% | 0.0% | 10%            | 15%                 | 0.00     | 2.32                          | 0.951                  |                        |         |            |                                     |  |   |  |               |                  |                                       |
| Case B2       | 3.95    | 3.74    | -0.21                       | 0.8%                        | -<br>5.6% | 4.33  | 4.39  | 0.05        | 0.0% | 0.0% | 10%            | 17%                 | 0.00     | 0.00                          | 0.923                  |                        |         |            |                                     |  |   |  |               |                  |                                       |

Note: Price Differential = NBP – TTF (positive means NBP is higher than TTF); <sup>a</sup> average across the storage year – 1 Apr 2025 until 31 March 2026; <sup>b</sup> one peak day-ahead price taken from the period 1 Oct 2025 until 31 Mar 2026; <sup>c</sup> flows (imports into the UK and export to Europe) for one storage year – 1 Apr 2025 until 31 March 2026.

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It is also worth mentioning that gas trade between the UK and Europe does not affect peak prices in both markets – there is no impact of reducing gas interconnection capacity on peak day prices in the UK or TTF market area. This means that gas interconnectors are not setting prices on those peak days and this reduces their value as security of supply assets on peak days and in managing price spikes on those peak days. LNG import and short-range storage facilities in the UK and continental Europe will be increasingly setting prices on peak days and therefore access to extra-European markets are more important for managing peak prices. This does not mean that gas interconnectors will have diminishing role in prolonged security of supply events.

What is interesting is that, should the UK economy be impacted by Brexit such that it affects the overall demand for energy (decline in gas demand - Baseline B), then potentially lower gas demand in the UK would put downward pressures on wholesale prices both in the UK and North-West Europe (compare price under Baseline B with those under Baseline A), although the impact on Europe is rather marginal. Under the assumption of lower economic growth in the UK, and hence lower gas demand, the UK would export even more gas to Europe (5.3 bcm p.a. vs 1.6 bcm p.a., column 14 in Table 2). This means that gas trade between the two parties could be even more beneficial to European consumers, interconnector owners, UKCS producers and potentially LNG importers into the UK. Another interesting observation from our modelling results is that, should there be no trade in gas while UK's gas demand falls due to negative macroeconomic conditions after Brexit (Case B2), then price differential change signs and the UK prices become lower than those in North-West Europe. This is principally because the surplus gas that was meant to be exported to Europe now stays within the UK (and this is a large volume: 5.28 bcm or 7% of UK's 2015 gas consumption). As in case A, interconnector capacity and trade does not seem to affect peak prices in the UK and Europe (Table 2, columns 6 and 7).

It is worth noting that TTF and NBP prices are highly correlated in all our scenarios; however, as less interconnection capacity is available (case A1 and A2), price correlation reduces (Table 2, column 15), suggesting that on some days NBP and TTF could decouple.

We can also note that the impact on the BBL pipeline will be minimal because, as noted earlier, it was merged into the TTF market area and its asset base is now socialised and cross-subsidised by all shippers booking Dutch entry and exit capacities. The model results show that import flows through BBL to the UK in 2025 are minimal, which could have negative consequences for the owner of the pipeline should it stay as a merchant project. However, now that BBL is part of TTF market area, the implication of this to the Dutch transmission system operator would be minimal since the asset base of BBL is relatively small compared to the overall asset value of the entire Dutch transmission system, and hence additional top-up to the entry-exit tariffs resulting from adding BBL would be minimal. The important question is that, with minimal flow through BBL, cost-reflectivity

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of entry-exit tariffs of TTF market area could become more distorted and it seems that the UK could only benefit from having an import pipeline from Europe to the UK in terms of security of supply. This security value has been underwritten by European shippers. Thus, the value of BBL pipeline for the UK will be more in terms of security of supply and managing peak prices.

In general, we should note that gas flows between the UK and Europe will be more responsive to very short-term variations in demand due to growing share of intermittent capacity on both sides, rather than being 'base load' flow. Both UKCS and Dutch gas production is declining rapidly and their share in gas consumption by 2025 will be lower – meaning greater economic incentives to sell gas to 'home' markets. This is because nondomestic higher cost gas sources will set prices in both markets and hence infra-marginal rent for domestic producers will increase, if selling to 'home' markets rather than exporting to a neighbouring market involves paying additional transport cost. In the case of IUK export capacity, the only strong economic incentives for UKCS to flow gas to the EU-27 has been short-haul discount. Should this be removed, then the profit from selling into the NBP would be higher than from selling into the TTF market area, based on existing (2015) tariffs and on a netback basis. This will have negative consequences for the IUK export volumes.

If short-haul tariffs are removed, then we can make some inferences on the future of IUK by looking at price spreads between the two market areas. For example, price differentials in Case B2 is \$0.21/mmbtu (Table 2, column 3) which roughly covers both commodity and capacity charges that IUK published in 2015.<sup>50</sup> According to the model, the annual export in the 2025/26 storage year through IUK is 5.28 bcm (Baseline B), which is roughly 26.5% of annual utilisation rate. If \$0.2/mmbtu can be captured as an export tariff by IUK (thus leaving \$0.01/mmbtu as a margin to traders/shippers), the annual revenue from exporting 5.28 bcm (under Baseline B) at \$0.2/mmbtu would be roughly \$41mn or £32.3mn (at a £0.79/USD rate). This is compared to £65mn of annual OPEX for IUK in 2014/15 reporting period.<sup>51</sup> Thus, to cover that level of OPEX, IUK would have to export at least 10 bcm/year, assuming this higher level of exports would not move the price spread of \$0.21/mmbtu and assuming no imports through IUK. Under Baseline A, average price spreads suggest no export from the UK to the EU-27 based purely on price differentials.

The above implications for gas interconnectors are based on average wholesale prices or average price spreads. However, as we discussed above, the gas trading dynamics between the UK and Europe are changing dramatically with flows between the two market areas becoming more volatile in response to day-ahead variations in demand and

 $<sup>^{50}</sup>$  Based on 2015 data, IUK export charges were: 0.05125 p/kWh/h/day for commodity-related charges and 0.8350 p/kWh/h/day for capacity-related charges.

<sup>&</sup>lt;sup>51</sup> http://www.interconnector.com/media/115974/2016\_financial\_statements.pdf



supply in both markets. Business models for gas interconnectors between the UK and Europe will unlikely be based on securing 'base load' gas flows or long-term shipping contracts, as used to be the case when IUK was built as a merchant pipeline. It will be based on gas interconnector being able to capture higher value in the short-term market timeframes. To illustrate this point, Figure 1 shows the distribution of price spreads between the UK and North-West Europe under Baseline A Case A2, under which no gas interconnection capacity exists between the two markets in 2025-2026.



Figure 1: Price differentials in USD between UK and Europe under Baseline A Case A2.

Note: these price spreads are for storage year Apr-25 until Mar-26; positive means that NBP is higher priced market and hence the UK should be in a net import position; negative means that NBP is lower priced market and hence the UK should be in a net export position.

If the export tariff through IUK is \$0.234/mmbtu (commodity and capacity charges) then there are more than 120 days when IUK can make profit – during those 120 days price differentials are between \$0.35/mmbtu and \$0.75/mmbtu (the first two left bars in Figure 1). Similarly, if the import tariff through IUK is \$0.312/mmbtu (commodity and capacity charges) then there are at least 100 days when IUK can make a profit on import flows – during those 100 days, price spread is \$0.45/mmbtu-\$0.65/mmbtu. Clearly allowing more flexibility for merchant gas interconnectors to price their capacity products would allow



IUK to transition to new trading arrangements. According to IUK,<sup>52</sup> it has made a substantial effort to convince the European authorities to include wording in the 2016 Tariff Code that would allow a merchant pipeline to be exempted from certain provisions relating to tariffs. Under Baseline B, when the UK's economy may be negatively impacted by Brexit and hence lower energy demand, the distribution of daily price spreads (Figure 2) suggests an even stronger case for export from the UK to Europe, and the business case for merchant interconnectors could be improved if they are allowed greater flexibility in setting prices for their capacity products that would fit with the needs of shippers who would require access to capacity on a shorter-term basis.



Figure 2: Price differentials between UK and Europe under Baseline B Case B2.

Note: these price spreads are for storage year Apr-25 until Mar-26; positive means that NBP is higher priced market and hence the UK should be in a net import position; negative means that NBP is lower priced market and hence the UK should be in a net export position.

As for the gas interconnection between GB and Ireland, the two markets are connected by two sub-sea pipelines linking Ireland with Scotland – Interconnector 1 with capacity of 17 mcm/d (mcm/day) and Interconnector 2 with 23 mcm/d. However, the combined capacity at Moffat entry point is 23.4 mcm/d because of the technical limitations on the Scottish

<sup>&</sup>lt;sup>52</sup> http://www.interconnector.com/media/115974/2016\_financial\_statements.pdf



side of the interconnection. It is worth mentioning that there is a sub-sea spur supplying gas to the Isle of Man (a self-governing UK Crown dependency) from Interconnector 2.<sup>53</sup>

Currently, GB supplies around 90% of Irish annual gas demand and with the start-up of the Corrib gas field off the northwest coast of Ireland, this dependence will be lower for the next ten years (its estimated producing life is just over 15 years).<sup>54</sup> However, by 2025 the level of dependency on GB gas imports would be similar to the current level with a rather strong gas demand projection for Ireland (12% p.a. over the period to 2021/22).<sup>55</sup> It is unlikely that Brexit will result in any restrictions on the supplies of gas to Ireland, at least from an economic point of view. The supplies to Ireland are ca. 4 bcm, if GB supplies around 90% of Irish annual demand of ca. 4.4 bcm in 2015. Although this flow is just over 5% of GB's annual demand, in the context of GB's key import infrastructure this is not insignificant. For example, assuming that the IUK import flows or LNG from Isle of Grain are marginal during winter days, then peak flow capacity to Ireland corresponds to 45% of peak import flow through IUK<sup>56</sup> or 40% of daily send-out rate of LNG at the Grain terminal.<sup>57</sup>

Thus, having supplies to Ireland supports the utilisation of these key infrastructure assets for GB, which supports security of supply to both GB and Ireland. In the global context, having Ireland, essentially as part of the GB market, increases GB's attractiveness to external suppliers. The gas system is interconnected between Northern Ireland and the Republic of Ireland, which makes any attempt to limit capacity and trade to the island of Ireland unlikely given the mutual commitment of the EU-27 and the UK to find Brexit solutions which work across the border in Ireland (discussed below).

Lastly, experience of 'risky' and 'unreliable' transit countries or external suppliers suggests that these can and will be 'bypassed' – Ukraine is one such example of large transit state being bypassed by Russia or Lithuania, who secured a substantial discount off its contract import price in negotiations with Gazprom after building an LNG regasification terminal, thus breaking Gazprom's monopoly. An outside option for Ireland would be an LNG terminal, and in the context of oversupplied global markets and increased international competition could become credible should GB 'misbehave'. This is especially relevant given the rapid development of flexible and relatively less expensive floating regasification terminals, which can be deployed at fraction of cost and time compared to

<sup>&</sup>lt;sup>53</sup> https://www.iea.org/media/freepublications/security/EnergySupplySecurity2014\_Ireland.pdf

<sup>&</sup>lt;sup>54</sup> https://www.dccae.gov.ie/en-ie/natural-resources/topics/Oil-Gas-Exploration-Production/corrib-gasfield/Pages/Corrib-Gas-Field.aspx

<sup>&</sup>lt;sup>55</sup> <u>https://ec.europa.eu/energy/sites/ener/files/documents/2014\_countryreports\_ireland.pdf</u>

<sup>&</sup>lt;sup>56</sup> If IUK's import capacity is 19 bcm p.a. then its average daily flow rate is 19/365 \*1000 = 52.05 mcm/d. Then, maximum daily flow capacity to Ireland is 45% of that average flow rate on the IUK imports (23.4/52.05 = 0.45).

<sup>&</sup>lt;sup>57</sup> Maximum daily LNG regasification rate at the Grain terminal is 58 mcm/d or 645 GWh/d – see <a href="http://grainlng.com/operational-information/terminal-characteristics/">http://grainlng.com/operational-information/terminal-characteristics/</a>

onshore, large and fixed LNG import terminals. To sum up the GB-Irish gas trade, we believe it is both in energy security and economic terms that the mutual trade in gas will be sustained. Therefore, we consider status quo, no disruption, as the most plausible post-Brexit scenario for gas trade between GB and Ireland.

### 4.2. Electricity modelling

Now we turn to discuss some of the findings from our electricity market modelling. In particular, we used a detailed UK unit commitment model to simulate impact of possible delays in bringing more interconnection capacity between the UK and Continental Europe. As was noted in the literature review section, some of the studies have pointed out that one implication of Brexit could be greater uncertainties around investment in new interconnection and generation capacities. Thus, we have modelled three scenarios for the year 2025:

- 1. **Baseline** (the status quo), in which all generating capacity and demand for electricity follow government projection, while interconnection capacity is kept at the same level as currently (i.e., 2GW of interconnection with France, 1GW with the Netherlands and 1GW with Ireland and 3.4 GW of interconnection capacity under construction (with Belgium, with Norway and with France)
- 2. **Case 1**: the same as Baseline, but with additional interconnection capacity of 1GW between France and the UK. Thus, there is 8.4GW of interconnection in total by 2025.
- 3. **Case 2**: the same as Baseline, but we assume that Brexit will have a negative impact on UK's economy and hence, electricity demand in the UK in 2025 will be 5% lower than in 2015.

Thus, under the Baseline scenario, average wholesale electricity price in 2025 is ca. £ £39.94/MWh while under Case 1 (i.e., having 1GW of additional interconnection with France), the price would drop quite marginally to an annual average of £39.86/MWh, or just £0.08/MWh. This is principally because having one extra GW of interconnection beyond those already in operation (4GW) and those that will be built by 2025 (3.4GW) would have a diminishing value, on average across a year. Secondly, our model suggests that having interconnection with Norway reduces average wholesale price for the UK to the point that more interconnection with Europe will have marginal impact on wholesale price in the UK (the Norwegian price is substantially lower than in European markets, with which UK have or will have an interconnection). Thirdly, using this number to infer the benefits of interconnection is rather misleading, since there are only 1763 hours (out of 8760) when prices in two scenarios (Baseline and Case 1) differ (see Figure 3 for distribution of differences in prices for those 1763 hours). Thus, in some hours, having additional 1GW of capacity (Case 1) will reduce electricity prices in the UK by as much as £27/MWh. If peak consumption is 53.7GWh (in 2015), then this will amount to around



 $\pm$ 1.45mn in savings for UK consumers for that particular peak hour. If we sum up all the hours (both negative and positive price differences), then the total benefit for UK consumers of having one more GW of connection with France would be around  $\pm$ 7.54mn p.a.



Figure 3: Differences in UK electricity wholesale prices under Baseline and Case 1

Note: positive means that wholesale price under Case 1 (1GW of additional interconnection with France) is higher than the price under Baseline; negative means the opposite

Moreover, Figure 3 also suggests that wholesale prices can also rise under Case 1, relative to the Baseline. This means benefits to France, because in some hours, due to that extra 1GW of interconnection capacity, GB exports electricity to France and hence wholesale prices in the UK rise relative to the baseline. To show this point, Figure 4 highlights the marginal benefit of having one extra MW of export capacity (on the existing IFA line) in 2025. Note that, according to our modelling, there were 4297 hours in 2025 (out of 8760) for which export capacity (UK->FR) of the IFA line were binding. The marginal price – or congestion rent – at those hours reflects the difference between UK's future system marginal price and historical French wholesale electricity prices for those hours. It is immediately clear from Figure 4 that electricity interconnector owners would benefit from continued trade, and so would UK generators. Since our electricity market model is UK-focused it cannot directly estimate impact of export flows from the UK to France and hence wholesale prices there. However, we can reasonably assume that, if by 2025 French

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electricity generation mix will not change dramatically, then for most of the time marginal prices in France are set by prices in neighbouring countries (such as Germany, Italy or indeed the UK). France is connected to markets in which marginal plants are fossil-fuel based (and mostly gas-fired by 2025). Therefore, if we assume that gas-fired plants are setting prices in France, then based on our gas modelling results (Figure 1 and 2 in particular), for some days UK export flows to France will set prices in France displacing slightly more expensive electricity coming from gas generation in other neighbouring markets with France. Thus, consumer benefits to France of having interconnection with the UK can be deducted from Figure 4. For example, the mean of the marginal price distribution shown in Figure 4 is £9.3/MW. If we assume that the UK will set prices in France 5% of the time when exports to France are at the maximum capacity (i.e., 5% of 4297 hours), then the benefit to consumers in France is £97.2 mn p.a. (Table 3, column 13).<sup>58</sup>



Figure 4: Marginal price for one extra MW of export capacity from UK to FR

Note: the model shows that in 2025, out of 8760 hours, there were 4355 hours for which export capacity (UK->FR) of the existing IFA line was binding. Hence, the chart shows the shadow prices for those hours.

Assuming that a new 1GW interconnection line between the UK and France (say IFA2) costs around £614mn or at 10% discount rate over 25 years economic life time would result in equivalent annual cost of £67.6m p.a. with £11.5m p.a. in opex. Then, under a conservative estimate, the benefit of having one more GW of interconnection between

<sup>&</sup>lt;sup>58</sup> Assuming that in 2015 final electricity consumption in France was 425 TWh – <u>http://ec.europa.eu/eurostat</u>

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the UK and France (on top of existing and all the projects which are already under construction) would be of £97.2mn for France (but could be substantially larger, see Table 3) and £7.54mn for the UK, giving total benefit for the two countries at ca. £89.66 mn p.a. Thus, net welfare for the UK and FR is roughly £10.56mn p.a. (£89.66 mn p.a. less £79.1 mn p.a. for the cost of the interconnector) or ca. 1.5p/MWh for whole UK and France.<sup>59</sup> But this is a rather conservative estimate. If the UK prices are going to set prices in France for more than 5% of the time when exports to France are at maximum capacity, then the benefits should be substantially larger to the consumers in France (see Table 3, column 14).

As for the benefits to other markets of having interconnections with the UK, Table 3 highlights our calculations of benefits to Ireland, to the Netherlands, to Belgium, and to Norway, based on a similar logic as the one we discussed for the benefits of interconnection to France (above). We should note that the columns 12-14 show benefits to consumers in those respective markets, assuming different periods when the UK prices will set prices in those respective markets. This is the case if the UK export flows through the interconnectors are the marginal source of supplies to those markets. Hence, consumers in those countries will benefit more if they enjoy potentially lower import prices from the UK for longer (e.g., column 12 assumes 1% of the time when export capacity is binding; see column 4 Table 3). However, if prices in the two connected markets are similar then that would mean no profit from arbitrage for traders and producers located in those two markets. Thus, columns 15-17 show profit from arbitrage between those countries and the UK. One can see that the higher is the number of times when prices converge, the lower will be annual profit from arbitraging (this takes also into account annual cost of interconnectors, column 11).

The overall conclusion from Table 3 is that having interconnection with the UK is beneficial to consumers in Ireland, Belgium, the Netherlands and even Norway (because although Norway is substantially lower price market, there are 76 hours in a year when prices in the UK could be lower than in Norway, column 4 Table 3). The Irish impact is for consumers in Northern Ireland and the Republic of Ireland, and is relatively large in relation to the size of the market. The interconnections also bring arbitrage profit (i.e., price differentials time interconnection capacity, less all capex and opex of these interconnections) for traders and producers. The only exception are profitability of arbitrage between France and the UK and between Belgium and the UK, beyond the level of interconnection that these countries already have or those already under construction. However, this is based purely on the logic of merchant interconnectors (arbitrage price differentials, less all costs) but as we discussed above, further interconnection between these countries brings benefits to consumers on both sides of the market (e.g., in case of

<sup>&</sup>lt;sup>59</sup> Assuming that in 2015 final electricity consumption was 303 TWh in the UK while consumption in France – 425 TWh.



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UK-FR: £26.98 mn p.a. for the UK and potentially up to £194.4mn p.a. for France, column 14 Table 3). One final observation from Table 3 columns 5 and 7 is that connection to Norway has substantial value to the UK. Column 7 shows that there is 98.6% of time in a year (8636 hours) when the value of having one extra MW of import capacity from Norway is positive. Its average value is £20.4 MW, which is at least twice as high as having additional interconnection with the other markets (column 5, Table 3). Similarly, arbitrage profit stemming from the UK-Norway connection is substantially higher than profits from further arbitrage between the UK and Continental Europe.

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### Table 3: Results – impact on countries connected with the UK

|    |                         | margina        | narginal value for export marginal value for import |            |                |      |            |                     |                   | average net benefit to<br>consumers, £ mn p.a. |         |            | Average profit from arbitrage, £ |            |            |            |            |
|----|-------------------------|----------------|---|------------|----------------|------|------------|---------------------|-------------------|--|---------|------------|----------------------------------|------------|------------|------------|------------|
|    |                         | capacity, £/MW |   |            | capacity, £/MW |      |            | Assumed             |                   |  |         |            |                                  | equival    | mn p.a.    |            |            |
|    |                         |                |   |            |                |      |            | capacity of         |                   |  | ent     | 1% of      | 5% of                            | 10% of     | 1% of      | 5% of      | 10% of     |
|    | Final                   |                |   |            |                |      |            | one                 |                   | OPEX <sup>d</sup>                              | annual  | time       | time                             | time       | time       | time       | time       |
|    | consumpt                |                |   | N hours    |                |      | N hours    | additional          |                   | over 25  | cost, £ | intercon   | intercon                         | intercon   | intercon   | intercon   | intercon   |
|    | ion 2015 <sup>ª</sup> , |                | std.  | constraint |                | std. | constraint | interconnect        | CAPEX,            | years, £                                       | mn      | nector     | nector                           | nector     | nector     | nector     | nector     |
|    | TWh                     | Mean           | dev.  | binding    | Mean           | dev. | binding    | or, MW <sup>b</sup> | £ mn              | mn   | p.a.    | sets price | sets price                       | sets price | sets price | sets price | sets price |
|    | [1]                     | [2]            | [3]   | [4]        | [5]            | [6]  | [7]        | [8]                 | [9]               | [10]   | [11]    | [12]       | [13]                             | [14]       | [15]       | [16]       | [17]       |
| IE | 25.1                    | 15.0           | 20.0  | 3763       | 10.3           | 6.9  | 4698       | 500                 | 150 <sup>g</sup>  | 70   | 19.3    | 1.6        | 8.1                              | 16.2       | 32.8       | 30.7       | 28.0       |
| FR | 424.9                   | 9.3            | 6.9   | 4297       | 9.2            | 7.1  | 3754       | 1000                | 614 <sup>†</sup>  | 286  | 79.1    | 19.4       | 97.2                             | 194.4      | -5.4       | -8.4       | -12.1      |
| NL | 103.1                   | 10.3           | 7.7   | 4336       | 9.3            | 7.3  | 4203       | 1000                | 522 <sup>e</sup>  | 243  | 67.2    | 5.3        | 26.3                             | 52.6       | 15.6       | 12.2       | 8.0        |
| BE | 81.7                    | 10.7           | 7.8   | 4244       | 9.3            | 7.1  | 4262       | 1000                | 703 <sup>c</sup>  | 327 <sup>c</sup>                               | 90.5    | 4.2        | 21.1                             | 42.2       | -6.5       | -9.9       | -14.2      |
| NO | 110.8                   | 2.5            | 2.1   | 76         | 20.4           | 8.1  | 8636       | 1400                | 1208 <sup>h</sup> | 562  | 155.6   | 0.0        | 0.1                              | 0.2        | 89.2       | 79.3       | 66.9       |

Notes:

<sup>*a</sup> this comes from Eurostat;*</sup>

<sup>b</sup> this is our assumed additional capacity which corresponds to the original project which are either operating currently or are being built;

<sup>c</sup> this is full CAPEX of the NEMO project calculated based on OFGEM's estimate of UK's 50% share in the project

https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/nemo\_cost\_assessment\_consultation.pdf

<sup>d</sup> apart from the OPEX of the NEMO (UK-BE interconnector) project, OPEX of the other assumed interconnectors were derived based on share of OPEX as % of CAPEX of the NEMO project;

<sup>e</sup> this is CAPEX of the BritNed taken from OFGEM paper <u>https://www.ofgem.gov.uk/sites/default/files/docs/2014/03/bpi\_nemo\_cost\_report.pdf;</u>

<sup>*f*</sup> taken from <u>http://www.4coffshore.com/windfarms/interconnector-interconnexion-france-angleterre-(ifa2)-icid11.html;</u>

<sup>g</sup> taken from <u>http://www.4coffshore.com/windfarms/interconnector-moyle-icid20.html</u>;

<sup>h</sup> this is full CAPEX of the NSL project calculated based on OFEGM's estimate of the UK's 50% share in the project <u>https://www.ofgem.gov.uk/ofgem-publications/104964</u>

As for the results from Case 2, should Brexit impact the UK's economy negatively and hence lowering energy demand, then the average wholesale price would be £39.61/MWh (Case 2), or £0.33/MWh lower than the average price under the Baseline (£39.94/MWh). To put this in the context of additional interconnection means that lower demand in the UK could potentially balance out potential negative effect from not having more interconnection with Europe.

Discussion so far has been focused on average hour but what is also interesting to note is the effect of additional interconnection on peak prices. Figure 5 below outlines the highest price periods in the UK under the Baseline scenario – there are ca. 2% of 8760 hours when the UK prices are higher than £50/MWh. Note that these 2% of 8760 hours are distributed randomly across the year (2025) and are not necessarilyconsecutive hours. Figure 5 also plots prices for those 2% of 8760 hours under Case 1 (one additional GW conneciton with France) and Case 2 (lower demand in the UK).





Note: Figure 5 shows 160 hours for which prices under the Baseline scenario are higher than £50/MWh; this represents around 2% of 8760 hours or one year. These hours with highest prices are spread randomly across the year and so are not necessarily representative sequences.

Given the above discussion and highlights from Figure 5, we can conclude that although the benefit of further interconnection for the UK could be rather marginal (£9.24 mn p.a. in case of 1GW more interconnection with France, Case 1) the effect on peak hours could

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be significantly positive for UK consumers. For example, between hours 19 and 28 in Figure 5, we can see a drop in wholesale prices under Case 1 (red line) relative to the prices under the baseline (blue line). The reverse is also true - the impact of having additional interconnection on French peak prices are rather similar. One can come to this conclusion by looking at the 'thin tail' of the distribution shown in Figure 4.

Finally, what is striking, and re-confirms the above conclusion about lower electricity demand, is that Case 2 (lower electricity demand) could have quite a similar (positive) impact on UK wholesale electricity prices - there are even more hours when prices under Case 2 (dashed green line in Figure 5) are lower than the baseline peak prices.

All in all, we can conclude that the majority of interconnection benefits for the UK seems to be with Norway. If these benefits with Norway are materialised as shown by our modelling, then further interconnection between the UK and Continental Europe might be marginally positive, on average, for the UK. We can also conclude in this case that interconnection also benefits Continental Europe, on average. Further, interconnection may have substantial positive impact on peak days for the UK and other connected markets. Thus, if Brexit delays the construction of electricity interconnector capacity, this has a negative impact on consumer welfare for both UK and its interconnected markets (e.g., Ireland, France, Belgium, the Netherlands and even Norway), if we assume no mitigating capacity investments in the UK. However, another way of looking at this is that the gains from increased electricity interconnector capacity under construction are currently not insignificant, but that this it is highly unlikely that they will be affected by Brexit. We should also note that our analysis does not consider the sort of benefits that Newbery et al. (2016) discussed in their paper, namely benefits of interconnection for balancing and ancillary services.

### 5. How UK Energy Policy could develop after Brexit

UK energy policy, as for the EU-27, is focused on three over-arching objectives: energy security, low prices (competitiveness) and meeting environmental targets<sup>60</sup>. As part of this, the UK remains committed to its climate change targets, as enshrined in its 2008 Climate Change Act. These three objectives together form the energy trilemma facing every country. There have been no significant changes in the objectives of energy policy of either the UK or the EU-27 since the UK referendum vote on Brexit on 23 June 2016.

The objective of energy security suggests the value of interconnection for both electricity and gas with the rest of Europe. Low prices (and hence energy security with respect to oil and LNG) suggests the importance of access to global fossil fuel markets and to global equipment markets. Environmental targets, particularly with respect to carbon, suggests the value of its membership of the EU ETS, where the UK is a substantial net purchaser of permits and hence is buying cheap abatement from overseas.

One can put these policy benefits in material perspective and compare their value to the impact of UK domestic energy policy choices. Interconnection, as we have noted above, might be capable of lowering wholesale system costs by approximately 5% for electricity and gas, albeit at some costs for the increased interconnection. For the UK in 2016 the wholesale cost of electricity was around £17bn and the wholesale cost of gas was around £10bn<sup>61</sup>. 5% of these values would be £1.35bn p.a. The UK's net purchasing of EU ETS permits was 28m in 2015 at say €6 (£5) per tonne. If this abatement had to be met from additional domestic abatement at £31.25 per tonne CO2 (roughly the extra cost of offshore wind in the latest government procurement auction<sup>62</sup>), this would be £875m p.a. Thus, a complete loss of integration into the EU electricity, gas and carbon markets might involve a cost of the order of £2.2bn p.a. There would be corresponding losses on the part of the EU-27, though these would likely be smaller in total due to the more elastic internal response of the EU-27 to the loss of trading with the UK. The impact would also be spread over the much larger size of the EU-27, though the proportionate effect might be higher in Ireland because of its energy dependence on the UK. However, these values are upper bounds and the experience of Switzerland is that trading has continued even in the absence of full incorporation into EU markets and that following the Swiss referendum

<sup>&</sup>lt;sup>60</sup> UK energy policy is stated as being 'ensuring that the country has secure energy supplies that are reliable, affordable and clean', see <u>https://www.gov.uk/government/organisations/department-for-business-energy-and-industrial-strategy/about</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>61</sup> See DUKES (2017, p.33).

<sup>&</sup>lt;sup>62</sup> The government is paying £57.50 / MWh (2012 prices) for offshore wind in 2022/23 (see <a href="https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/643560/CFD\_allocation\_ro\_und\_2\_outcome\_FINAL.pdf">https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/643560/CFD\_allocation\_ro\_und\_2\_outcome\_FINAL.pdf</a>, accessed 15 September 2017) against current power exchange prices of around £45 / MWh (see <a href="https://www.apxgroup.com">https://www.apxgroup.com</a>, accessed 15 September 2017) against current power exchange prices of around £45 / MWh (see <a href="https://www.apxgroup.com">https://www.apxgroup.com</a>, accessed 15 September 2017). Thus the government is paying an additional £12.50 / MWh (or £31.25 / tonne CO2) to save roughly 0.4 tonnes CO2 saving per MWh. This is on top of the EUETS price which is already included in the current wholesale power price.

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existing trading arrangements were frozen rather than changed. Thus the likely worst case is that integration benefit losses will be a fraction of the maximum potential loss and will at worst only emerge as a divergence from business as usual over time. A 25% loss of energy and climate integration benefits would thus be £550m p.a.

We now turn to potential changes in the UK's energy policy. Looking at the UK's actual energy policy and how it should be rationalised puts the above numbers in perspective. We begin with domestic policies related to current EU energy and climate directives, before going on to more clearly domestic energy policy choices.

The EU has substantially restricted the UK's ability to introduce fully merchant electricity interconnectors and to have competitive capacity allocation for gas interconnectors. The EU has favoured regulated electricity connectors, where the revenues of the interconnector are effectively underwritten by both sets of electricity consumers on either side of the interconnector. This relies on long-term cost benefit analysis of welfare benefits where costs are socialised across system users rather than exposing investing parties to market risk. Ofgem, currently, has a cap and floor regime for the allowed return on new electricity interconnectors and a merchant regime, where the owners simply rely on arbitrage revenue.<sup>63</sup> The argument for merchant interconnectors to the UK is that current capacity is a long way short of optimal and that merchant interconnections can get quite close to the social optimal level.<sup>64</sup> Similarly, the UK has also favoured competitive allocation of gas interconnector capacity, but the EU has favoured regulated returns on gas interconnector assets based on a public investment approach.

EU rules have put restrictions on the UK's ability to have a pricing regime for electricity that does not discriminate against domestic electricity generation. In the UK, unlike domestic generators, electricity interconnectors are not subject to locational transmission charging according to their point of connection to the domestic transmission system. This is because this would be deemed to be a restriction on cross border trade within the EU. This has created a distortion within Great Britain between onshore generators and generators selling into the UK across interconnectors at the same transmission grid supply point, as one is subject to locational transmission charges and the other is not.

This applies to both the electricity interconnectors from Ireland (including the one from Moyle in Northern Ireland) as they are part of the Single Electricity Market (I-SEM) in Ireland. It is possible that the Moyle interconnector at the very least would become subject to transmission charges for injection into the GB system if the I-SEM were to end following Brexit. This might be efficient in terms of reflecting underlying system costs. It might also lead to lower prices for Northern Irish consumers (and lower profits for NI

<sup>&</sup>lt;sup>63</sup> See https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors, accessed 15 September 2017.

<sup>&</sup>lt;sup>4</sup> See Parail (2009) who analyses the Nor-Ned interconnector and makes this point.



generators) assuming the interconnector represents a demand in a constrained part of the network.

Membership of the EU has also prevented the UK from imposing a border tax adjustment on imported electricity to correct the distortion coming from the UK's carbon floor price, which imposes a further £18 / tonne of CO2 on fossil fuels used in onshore electricity generation, raising the marginal cost of onshore electricity generation relative to electricity supplied across the interconnectors. If this distortion raised imports by 5% of gross demand (330 TWh) and had an efficiency cost of half of the value of the tax (say £3.6/MWh<sup>65</sup>), that would be £60m p.a<sup>66</sup>.

The 2001 EU Large Combustion Plant Directive (LCPD, 2001/80/EC) had significant implications for the UK. The UK had one of the oldest and largest coal-fired power plant fleets in Europe. Many of its plants opted out of the Directive's requirement to install a flue gas desulphurisation (FGD) unit and hence had to shut by 1 January 2016. The closure of around 11.55 GW of capacity as a result of the Directive<sup>67</sup> (some of it at a time when fossil fuel and carbon prices were favourable towards coal) was a reason for the introduction of the UK Capacity Mechanism from 2018/19. This pays plants an availability payment in return for being able to provide power following the declaration of a 'capacity event' by the system operator. The capacity market involves an estimated NPV cost of £289m<sup>68</sup>, which might have been avoided if older coal-fired power plants could have remained open for longer.

We now look at some of the UK's fully domestic energy policy choices.

The UK's renewable subsidy policy currently costs of the order of £4bn per year. The policy has been widely criticised as being inefficient and expensive relative to the excellent renewable energy resources that the UK has. The UK has had more generous onshore wind subsidies than Germany, adjusting for the quality of the wind resource in the UK. The UK introduced one of the world's highest feed-in-tariffs for residential PV in 2010 resulting in the rapid uptake of nearly 1 GW of domestic solar by 31 March 2012. The policy was uncapped and is currently costing around £1bn p.a. (Ofgem, 2015). The solar subsidy regime, combined with the substantial reduction in PV installation costs, has resulted in nearly 12 GW of solar capacity being installed in the UK by 2017. The solar subsidies have contributed to a projected £1.5bn p.a. overspend on the maximum allowed subsidy towards the electricity sector (itself capped at £7.5bn p.a.) (NAO, 2016, p.4).

 $<sup>^{65}</sup>$  The tax is £18 per tonne of CO2. If the marginal fuel is gas and this emits 0.4 tonnes of CO2 per MWh, then half the value of the tax would be £18\*0.4\*0.5 = £3.60 / MWh.

<sup>&</sup>lt;sup>66</sup> £3.6\*330,000,000 MWh\*0.05=£59.4m.

<sup>&</sup>lt;sup>67</sup> See <u>http://www.nationalgrid.com/NR/rdonlyres/DD31ED99-F769-4995-84E3-</u> 809E29CE2E19/19877/pp07 32 LCPD revised.pdf, accessed 15 September 2017.

<sup>&</sup>lt;sup>68</sup> See, <u>https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf</u>, accessed 15 September 2017.

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The UK ran a very successful contract for difference auction for renewable electricity in February 2015 which resulted in significant price reductions (of the order of 25%) in the required subsidies for offshore and onshore wind.<sup>69</sup> This indicated that auctions should have been used much earlier for the allocation of subsidies to meet the UK's EU renewable energy directives (as they had been in the 1990s, see Pollitt, 2010). In August 2017, the UK had another successful CfD auction for renewables. However, this auction only targeted less mature technologies and did not allow solar and onshore wind to compete in the auction.<sup>70</sup> £290m p.a. of subsidy was allocated and much of this could have been saved if more mature RES technologies could have been allowed to compete in the auction. Savings (or increases in low carbon MWh for the same budget) of the order £500m-£1bn p.a. are certainly possible from a complete rationalisation of renewable support in the UK.

The EU Energy Services Directive of 2012 (2012/27/EU) provided the backdrop to the UK's smart meter roll out. The Directive specified that 80% of new electricity meters for nonhalf hourly metered customers (i.e. residential and small business users) should be 'smart' - capable of two-way real time communication with the grid - by 2020, subject to a costbenefit test of whether they were worth installing on the system. Several EU countries (including Germany) have chosen not to implement a general early roll out of fully functional smart meters following a negative cost benefit assessment<sup>71</sup>. However the UK decided to have a 100% roll out of both electricity and gas smart meters to all households and small business users by 2020. This programme has an estimated cost of £11bn (or £200 per meter). The programme has been widely criticised on the grounds of its technology choices and overall cost.<sup>72</sup> It is quite clear that it could have been implemented (if at all) with at least half the cost (certainly by dropping all of the 23m gas meters). This is equivalent to a cost saving of the order of £500m p.a.

The striking thing about the above examples of the rationalisation of domestic policy is their relative materiality. The possible loss of EU market integration benefits following Brexit might be worth of the order of £550m p.a. While EU integration has imposed some costs on the UK by restricting its use of some market mechanisms with respect to interconnectors, it is unclear whether these are strictly due to membership of the EU rather than the normal outcome of a bilateral negotiation (and hence would have had to be accepted anyway as a price to pay for gaining interconnector benefits). However, these costs are dwarfed by the UK's domestic policy capacity to add to its own energy costs. With around £7bn p.a.<sup>73</sup> of current energy subsidies and significantly higher subsidies in

<sup>&</sup>lt;sup>69</sup> See NAO (2016).

<sup>&</sup>lt;sup>70</sup> See

https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/598824/Budget\_Notice.pdf, accessed 15 September 2017.

<sup>&</sup>lt;sup>11</sup> See European Commission (2014).

<sup>&</sup>lt;sup>72</sup> See Haney et al. (2011) and Henney (2015).

<sup>&</sup>lt;sup>73</sup> OBR (2016, p.132).

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prospect (£13bn by 2021-22), together with expensive technology choices around nuclear and smart meters, the potential to add to energy consumers costs is an order of magnitude higher as a result of domestic policy choices than it is dependent on post-Brexit relations with the EU-27. To emphasise this materiality point further, it is worth noting that in August 2017 only 36% of the current domestic electricity bill in Great Britain and 39% of the current domestic gas bill is made up the wholesale price.<sup>74</sup> Thus, for domestic consumers especially, energy specific relations with the EU will not be the material determinant of what they pay.

In closing this section, it is important to state that energy systems are now at a new crossroads. The challenge is to scale up renewables still further and to electrify transport and heating, while managing a likely steady decline of gas (at a somewhat unpredictable rate). The EU-28's 2030 targets for CO2e imply an electricity sector which is 55% renewables by energy (in addition to 20% nuclear).<sup>75</sup> The UK's own national targets imply a 90%+ low carbon electricity system by 2030. This sort of development of low carbon requires new designs for the electricity market to support high capital cost, low running cost systems and a highly competitive and flexible gas market. The EU's success in integrating short-term energy markets has come at the same time as the near complete nationalisation of investment decisions in the electricity system. A high renewables energy future for Europe suggests that we are on the cusp of moving away from a system where marginal fossil fuel costs will be the key driver of investment and operational decision making.

What is required, and is recognised by the Winter Package, is a completely new market design which decentralises low carbon investment decisions in the energy system (see Newbery et al., 2017). This might require a return to much more extensive vertical integration to reduce exposure to price volatility for capital intensive generation investments and to internalise multiple sources of value for flexibility investments such as electrical energy storage. There may also be a need to have contracts with the whole of the supply base for large investments in nuclear, storage and interconnectors (following Keisling, 2009). Given the technological challenge of complete decarbonisation with high renewables penetration of the energy system, there is clearly a need for massive local experimentation on ownership and contractual forms. This is especially the case as we look beyond the power system to promoting heating and transport decarbonisation and innovation.

The UK led the way on the introduction of an unbundled electricity and gas system; however it is in a position to the lead the way on the development of the new high renewables electricity system, given its plentiful renewable energy resources (see Jamasb

<sup>&</sup>lt;sup>74</sup> See <u>https://www.ofgem.gov.uk/consumers/household-gas-and-electricity-guide/understand-your-gas-and-electricity-bills</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>75</sup> See Newbery et al. (2017).

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et al. 2008). New York and California have been experimenting in new ways of promoting distributed energy resources and local markets for electricity products; this is very different from the emphasis on wide area markets we have seen in the recent past (see Pollitt and Anaya, 2016). What seems clear is that it is parts of the US, China and Australia that are likely to lead the world in new energy technologies and in market design. The UK would like to be part of these new electricity system developments which emphasise local production and balancing and it is still the 6 or 7<sup>th</sup> largest country by public energy R+D expenditure. Ofgem continues to support large scale experimentation in electricity and gas networks via its Network Innovation Competition (NIC)<sup>76</sup> and the UK's recent industrial strategy commits the UK to further research in the area of batteries, storage and grids (BEIS, 2017).

<sup>&</sup>lt;sup>76</sup> See <u>https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-</u> innovation-competition, accessed 15 September 2017.

# 6. How EU-27 energy and climate policy might develop after Brexit

This is much more difficult to discern than the potential impacts for the UK. This is because there are 27 countries in the remaining block and most of the energy demand in the current EU-28. The EU's energy policy is evolving with a new package of measures announced in winter 2016<sup>77</sup>.

The UK has been significant in shaping the direction of EU energy and climate policy in certain areas. One can speculate that the loss of that voting weight might have some significant effect in the areas where influence has been felt in the past. We consider the impact on further market integration, the EU ETS, nuclear policy and renewables subsidy.

There is potential for further integration of both electricity and gas markets across the EU. This would involve the extension of intra-day trading of electricity and gas across borders. In electricity, the integration of markets for ancillary services across borders would bring further benefits, as noted above. Gas markets need to become more efficient across the EU-27. The UK would undoubtedly have been a key advocate for further market integration of EU-28 electricity and gas markets. It is unclear how the loss of the UK from the EU will exactly impact future market developments, but it is difficult to see how the loss of the UK will speed up improvements in the operation of EU-27 energy markets relative to continuing membership.

The EU ETS has been advanced by the UK and the UK has been a significant supporter of it continuing beyond 2020. The UK certainly supported tightening the targets to 2030 and extending the EU ETS to cover more sectors. Frustration with the lack of tightness of the EU ETS prompted the UK to introduce an additional carbon tax on fossil fuels for electricity production in 2013 (the carbon price floor). It seems likely that support for continuing or extending the EU ETS will be weakened by the UK leaving the EU and the EU-ETS. If the UK stays in the EU-ETS, its influence on its future development may still be reduced, and that would also weaken the strength of the mechanism going forward.

Of the large EU countries only France and the UK are actively supporting the continuation of and new investment in nuclear power. The loss of the UK from the EU will likely continue to undermine support for nuclear power in the EU-27<sup>78</sup>, leaving France largely isolated on the issue. Within the EU-27 only Finland would have a new reactor under construction. The practical implications of this for nuclear policy are unclear, but the EU citizenry will be more hostile to nuclear power than it is at moment.

<sup>&</sup>lt;sup>77</sup> <u>https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition</u>, accessed 15 September 2017.

<sup>&</sup>lt;sup>78</sup> See <u>https://www.imeche.org/news/news-article/new-survey-majority-of-the-public-support-uk-nuclear-power</u> Accessed 3 November 2017.

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The UK has championed limited but competitively allocated subsidies for new renewables. Indeed, the EU has recently moved away from supporting feed-in-tariffs towards renewable auctions for subsidy premia. There have been major subsidy cost reductions observed within the EU-27 (notably Germany's offshore wind auction which delivered a zero-subsidy result in the auction<sup>79</sup>). The use of market-based mechanisms has been championed by the UK in the face of the need to subsidise new technologies. However, given the speed of cost reduction in RES technologies and the adoption of auctions within the EU-27 the immediate impact of the UK leaving in this area may be limited.

From a simple budgetary perspective, the UK will be excluded from energy subsidies and subsidy payments it might have received or made in the past. Thus the total amount of EU subsidy money for projects of common interest (PCIs) in energy may be reduced, and the UK's ability to qualify for (and receive subsidy for) PCI projects may be reduced.

<sup>&</sup>lt;sup>79</sup> See <u>https://windeurope.org/newsroom/news/1-4-gw-offshore-wind-announced-in-germany-with-zero-</u> public-financial-support/ Accessed 3 November 2017.

# 7. Possible negotiating positions of the UK and the EU-27 on energy

It is important to start the discussion in this section with a statement of the obvious. The current negotiations are ongoing and it is difficult to discern clearly what the likely endpoint is on the basis of the current state of the negotiations. This is because as with any negotiation, nothing is agreed until the final agreement and much of what is said in the interim reflects what might be desirable for one side, rather than the likely final point of agreement.

The UK's basic starting position is that it would like to continue with all of the existing beneficial trading arrangements that it has with the EU, while the EU's position is that leaving the EU must involve some 'cost' to the UK and hence business as usual is not its default option. It is also the case that although there are mutual benefits of the current trading arrangements in energy, they are relatively much smaller for the EU-27 than they are for the UK, so the 'cost' of punishment in energy, from the point of the EU, is small. It is possible that, whatever the desirability of reaching agreement to continue with the current trading arrangements in energy and climate, these may be sacrificed within the broader Brexit agreement.

Both the UK and the EU have started publishing documents relating to their negotiating positions and some of these relate to energy. There have also been some UK policy statements (and notable silences to date) on specific aspects of energy policy. We discuss what an economically sensible negotiating position might look like rather than focusing on what the actual position might be.

The UK should continue to seek for a continuation of the current electricity, gas and carbon trading arrangements. As we have seen these are mutually beneficial and there is no good economic reason to change them, even if they are themselves something of a compromise developed over the 44 years of UK membership of the EU. As we noted above, while they have restricted the UK's freedom of action over certain aspects of energy policy, it is not clear that non-membership of the EU would not also have resulted in compromise on the operation and regulation of joint interconnectors. The current arrangements involve tariff-free trading of electricity, gas and carbon permits. WTO maximum tariffs for electricity and gas are €0.05 per MWh and 0.7%. These are levied on energy imports from Russia.

The UK should therefore seek to remain full members of CEER, ENTSO-E, ENTSO-G and the EU-ETS and continue participating in the stakeholder negotiations behind the developing codes and regulations. The UK should also seek to continue to offer unrestricted access to the ownership of its energy assets.

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There are various related deals and actions which might be brokered after the UK leaves the EU, but which are difficult to take forward before actually leaving the Union. This is because of the conditions of EU membership and the 'principle of sincere cooperation'. These prevent bilateral deals between the UK and third countries being done while the UK is still an EU member.

The UK could seek a 'Common Energy Security Treaty' with various neighbouring countries with whom it is interconnected. This might govern access to interconnectors and management of crisis events. However, it is not possible for individual members of the EU-27 to negotiate on any matters relating to the single market, so it is not clear how any economically meaningful regional energy security deal could be concluded. The one exception to this is the case of Ireland, where the UK and the EU-27 have both committed the maintenance of an open border between Northern Ireland and the Republic of Ireland and the EU have recently invited the UK to propose 'a unique solution' to the general issues of unrestricted trade and people movement in Ireland.<sup>80</sup> This would seem to make it unlikely that the I-SEM or the current trade flows in electricity and gas within Ireland or between Ireland and GB will be affected.

The UK might also look to impose border tax adjustment on electricity imports in the absence of tariff free access to EU electricity and gas markets; given the net trading position of the EU, this would disproportionately affect EU electricity exporters. However, given the likely potential for retaliatory border taxes if the UK were to do this, border tax adjustment, even if desirable in theory, seems unlikely.

The UK government has already announced its intention to exit from the Euratom Treaty (1957) at the same time as leaving the EU<sup>81</sup>. This is in line with its desire to remove the UK from the jurisdiction of the European Court of Justice. This has significant implications for the freedom of movement of nuclear material and personnel across Europe and impacts on its ability to participate in the global nuclear industry, due to exiting the trade agreements between Euratom members and other countries. The UK is seeking a replacement arrangement<sup>82</sup> but in principle this could halt movements of nuclear material between the UK and France in the absence of a mutually agreed replacement agreement. The UK and Euratom countries will however remain members of the International Atomic Energy Agency and subject to its oversight.

The EU-27 published its overall negotiating position on Brexit on 29 April 2017.<sup>83</sup> It reiterated the need for the four freedoms on goods, capital, services and people to be

<sup>81</sup> See

<sup>&</sup>lt;sup>80</sup> See HM Government (2017b) and European Commission (2017).

https://www.gov.uk/government/uploads/system/uploads/attachment\_data/file/604079/Prime\_Ministers\_le\_ tter\_to\_European\_Council\_President\_Donald\_Tusk.pdf, accessed 15 September 2017.

<sup>&</sup>lt;sup>82</sup> See HM Government (2017a).

<sup>&</sup>lt;sup>83</sup> See <u>http://www.consilium.europa.eu/en/press/press-releases/2017/04/29-euco-brexit-guidelines/</u>, accessed 15 September 2017.

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respected for current arrangements to continue. It also stated that 'nothing is agreed until everything is agreed'; a future trade arrangement must wait until the terms of leaving are agreed; the financial settlement is important; bilateral treaties are not allowed between EU MSs and the UK; a separate agreement on defence and security is possible; and it reconfirmed its support for the Good Friday agreement in Ireland. Given that an explicit objective of the UK is to regain control of immigration and end freedom of movement of workers (violating one of the four freedoms), this implies that some 'cost' will be imposed on the UK and some deviation from the current arrangements is likely in energy.

There has been no explicit mention so far of either side's position on the electricity, gas or carbon. However, it is important to say that electricity and gas are integral to the European single market project and hence what happens on them in the negotiations is likely to be fully in line with the overall position on the UK's relationship with the single market. On carbon, there have been no government statements on the part of the UK to seek to remain part of the EU ETS. The EU has undertaken two interesting, but conflicting actions. One is to reanimate the coupling of the EU ETS and the Swiss carbon market (noted above), thus suggestive of a likely openness to continuing to trade with the UK on carbon permits. The other, is a plan in the European Parliament to pre-emptively cancel the outstanding permits of any nation that leaves the EU ETS<sup>84</sup>. This would have the effect of not allowing UK holders of permits to sell them in the carbon market ahead of the UK leaving the scheme and suggests contingency planning for possibility of the UK leaving the EU ETS.

What will actually happen after Brexit is hard to discern. It is possible for UK private parties to continue to sign contracts (e.g. National Grid) with EU-based entities after Brexit. However private entities based in the UK cannot voluntarily sign up to abide by single market rules and be bound by the ECJ. Bilateral network access arrangements can continue and evolve after Brexit. This was the situation before the current network code review process. However private agreements are subject to a potential legal challenge to the EU party's signature before the ECJ and to regulatory approval from both sets of energy regulators. This would mean for instance that an EU party to an agreement (e.g. between the French transmission system operator, RTE, and Great Britain's National Grid) could be challenged. In practice, this has never happened in the case of agreements between Swiss Grid and other EU network operators. What seems clear is that the UK's potential to shape the future market design and network operator arrangements will be reduced by Brexit.

<sup>&</sup>lt;sup>84</sup> See Jim Brunsden and Alex Barker, *Financial Times*, 'EU makes contingency plans to protect carbon market from Brexit', 10 September 2017.

### 8. Outside Energy Options

It is important to explore whether there are any outside options available to the UK or the EU-27 which strengthen their hand in the energy negotiations, by making it less costly not to agree to what the other side might want.

On the UK side, it can go ahead with additional electricity integration with Norway and Iceland without any agreement from the EU. This would certainly allow it to capture much of any potential energy security value from further interconnection. These would be more expensive interconnection options due to the distances involved (the current link under construction to Norway is already the longest subsea electricity cable in the world). In terms of gas security, it would be possible to negotiate bilateral deals with the US and Canada for access to LNG from North America. This might reduce the cost of natural gas coming to the UK (and to the rest of Europe, given the UK's position as a gas hub).

Overall the UK is in weak position on energy negotiations, with respect to EU-27, due to their relative impact. This is because the trading benefits are roughly balanced in absolute terms but the UK is roughly one seventh of the EU-27's energy demand. However, this is not true with respect to Ireland, which is a key country on the European periphery. The UK is in a good position to leverage whatever mutually beneficial arrangements its comes to with Ireland as a precedent for what happens to its relationships with the rest of the EU-27. Although the EU has invited 'a unique solution',<sup>85</sup> it is difficult to see how this cannot set a legal precedent.

The UK will likely wish to continue accessing skilled labour in the energy sector from the EU-27.<sup>86</sup> However should this become difficult, perhaps due to the withdrawal of EU-27 companies from the UK or a reduced willingness of EU nationals to work in the UK, there is still a global talent pool in the energy sector from which the UK can benefit. Skills shortages are a potential issue for specific energy projects: Hinkley C will require a peak of 1800 'steel fixers', of which the UK currently has a total of 2400.

The UK has benefited substantially from collaborative EU research projects in the area of energy (c.  $\leq 125$ m p.a. 2007-13)<sup>87</sup>. However even if it is forced to exit from future collaborative projects due to a failure to agree to overall participation in EU research projects, it could reorient its energy research collaboration towards the US, China and Japan who already spend 2.5 times more than the EU OECD excluding the UK on public RD+D on energy.

<sup>&</sup>lt;sup>85</sup> European Commission (2017, p.2).

<sup>&</sup>lt;sup>86</sup> The UK does have a significant number of EU engineers in its workforce (Royal Academy of Engineering, 2016), but energy is not one of the most heavily EU dependent sectors (Migration Advisory Committee Secretariat, 2010).

<sup>&</sup>lt;sup>87</sup> See The Royal Society (2015) and HM Government (2017c).

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Should EU companies no longer wish to own assets in the UK, there would seem to be no shortage of non-EU investors (both utility and non-utility) who would wish to buy them. The ownership of the UK gas and electricity sectors is already very diverse. French and German ownership of assets in the UK energy industry (via EdF, E.ON and RWE) is very significant and hence they have a strong vested interest in the continuation of the current arrangements. They significantly rely on current and future UK government contracts, most significantly the Hinkley C contract with EdF (itself 84.5% owned by the French government). These companies have a strong incentive to lobby their governments for ways to facilitate continuation of frictionless trade and solutions to continuing UK involvement in freedom of movement of nuclear material etc.

On the EU ETS, the UK could either set up its own trading system and/or join an existing scheme in North America, e.g. RGGI in the North Eastern US, or the California-Quebec scheme. If it were to set up its own scheme, the UK government could still maintain a private trading link with the EU ETS (any qualifying private party can set up a trading account). A wholly national scheme would have the advantage of having the potential of greater coverage and higher prices than the existing EU ETS. However, coupling with North America would raise its own jurisdictional issues and potentially restrict freedom of action in other ways in the future.

On the part of the EU-27, the UK is, for the most part, a peripheral country in terms of energy. Norwegian gas and electricity can be accessed directly if necessary. Ireland has recently reopened its investigation of the feasibility of electricity interconnection with France and EU support for an LNG import terminal<sup>88</sup>. These are expensive outside options, but with EU support under the PCI framework they could be made viable for Ireland. This would remove the ability of UK to use Ireland as a precedent for what happens in its wider negotiations. The EU-27 could move to make use of the EU ETS's market stability reserve mechanism to remove more excess permits from the carbon market in the event of the UK leaving the carbon market.

<sup>&</sup>lt;sup>88</sup> The Irish Government is concerned about the impact of Brexit on its energy security (see Irish Government, 2017, p.38). For a discussion of Irish energy policy post-Brexit, see Lynch (2017).

# 9. Possible models of non-EU membership for the UK & their implications for energy

While we have already discussed specific policy implications of Brexit above, it is useful to think about overarching frameworks for future UK – EU27 relations and how these relate to energy. We discuss five models of non-EU membership and how they might impact on UK-EU energy relations.<sup>89</sup>

The UK could remain a member of the European Economic Area (EEA). This is the 'Norway model' and involves full access to the single market including European electricity and gas markets. This would involve no change to the current arrangements, but as detailed above this does not involve membership of ACER and reduces the UK's role to taker of EU-27 rules. The Norway model has currently been ruled out by the UK government because it does mean accepting the four freedoms, including freedom of movement of people. One point to note is that non-EU EEA members are subject to the jurisdiction of the EEA court in the event of disputes, providing a way of exiting from the oversight of the ECJ, while paradoxically accepting the jurisdiction of another international court.

The UK could rejoin the European Free Trade Area (EFTA). The UK was a member immediately before it joined the EU. Both Norway and Switzerland are EFTA members. EFTA membership would put the UK in the position of Switzerland and so would probably guarantee continuation of the current arrangements, but freeze them at the date of leaving the EU and make them subject to continuing bilateral negotiations.

The UK could join the European Energy Community which includes EU and candidate countries (e.g. Albania) seeking to harmonise their energy market arrangements with those of the EU. This arrangement is focused on South East Europe and is specific to candidate countries. It would not seem to offer a way forward for the UK, which is leaving the EU.

The UK could remain in a customs union with the EU (like Turkey). This means that the level of tariffs it imposes is harmonised with that in the EU. The problem here is that it prevents the UK signing trade deals with third party countries to lower tariffs below those already agreed with the EU. This arrangement would avoid the imposition of WTO level tariffs on imports of electricity and gas (and on energy equipment) should that be a possibility.

Finally, the UK could seek a separate Free Trade Agreement with the EU on energy. The EU is already party to the 1994 Energy Charter Treaty which does regulate trade between signatories. The UK could seek some protection from punitive tariffs, especially on energy

<sup>&</sup>lt;sup>89</sup> See Froggatt et al. (2017) for a discussion of models of non-EU membership and energy.



equipment, through being a separate signatory to this Treaty. The Energy Charter Treaty does provide a dispute arbitration mechanism between members.

None of these arrangements would seem to ideally fit the size and significance of the UK and its current relations with the EU-27. If the UK were to join EFTA, it could substantially increase its significance and might lead to a closer and more significant relationship between EFTA and the EU going forward.



### 10. Conclusions

It is straightforward to see that both the UK and the EU-27 benefit substantially from mutual participation in the current electricity, gas and carbon market arrangements. They also rely on being part of an integrated electricity and gas transmission system for energy security. There are no easy alternatives to a continuation of the current arrangements on energy and climate.

However, the UK is less exposed to changes in its relationships with the EU in energy than in other sectors. The UK is a net energy exporter to the EU-27 and has relatively little exposure to EU energy markets. Energy costs in the UK are already several times more sensitive to changes in domestic energy policy. Our modelling focused on the effects on markets in the northern EU-27. This shows the price impact and overall welfare impact of any likely reduction of trade in electricity and gas is small in relation to the size of the sector. Such impact will likely drive up wholesale prices in the EU-27 for electricity and for gas and drive them down in the UK, while reducing energy security for both parties. Trade reduction hurts interconnector owners, while higher prices benefits generators / gas suppliers in the EU-27. Slower demand growth effects and exchange rate effects (due to Brexit related macroeconomic slowdown in the UK) have the potential to be more significant for UK wholesale prices.

The UK can largely continue to mirror changes in EU regulations and codes via industry bodies such as ENTSO-E, ENTSO-G and Coreso, and possibly via the regulatory body, CEER, after leaving the EU. However, its influence will be reduced by losing its membership status of ACER (though it might continue as an observer on some issues) and exclusion from the work of the European Commission itself. It is currently unclear how its relationship with the EU ETS will change.<sup>90</sup>

The opportunities of Brexit for the UK are that it can rationalise its internal energy policy, redesign its wholesale and ancillary services markets for high renewables penetration and seek outside integration opportunities with Norway, Iceland, Ireland (with whom the EU-27 will likely allow a special arrangement) and North America.

As with all other aspects of Brexit, the loss of EU obligations in its energy policy could expose the UK to more domestic policy volatility. A future UK government could now more easily abolish its independent regulator, Ofgem, and reintroduce energy price caps, than before. These possibilities continue to be actively discussed in the UK.

The EU-27 has relatively little exposure to the loss of integration benefits with the UK, apart from via Ireland, where only expensive outside options exist. The loss of the UK from the EU seems likely to increase support for a renewable subsidy led 'Energiewende'

<sup>&</sup>lt;sup>90</sup> See Lockwood et al. (2017) for a discussion of the trade-off between being a member of the single energy market and loss of influence over policy.



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with reduced emphasis on market-based decarbonisation, and a likely increase in the use of coal for power generation in parts of eastern Europe. The loss of the UK's voting weight on energy issues will likely mean energy policy will be more hostile towards nuclear, the EU ETS and fully market-based solutions, all things championed by the UK.



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### Annex 1 – Gas and Electricity Market Models

In order to analyse the possible impact of Brexit and in particular reduced capacity to trade gas and electricity between the UK and Europe, we used gas and electricity market simulation models. We outline a basic description of the gas and electricity models in turn.

### Global Gas Market Model

The gas model examines and analyses the interaction of supply and demand on a daily basis at a global scale. On the supply side, the model includes all the main gas producing countries, such as Russia, Norway, Qatar, Australia, Algeria and other producing regions such as North America, Central and South America, the Middle East, Central Asia and so on. The model therefore covers all existing gas producers in the world. On the demand side, the model covers all existing consuming countries and regions, such as GB, Continental European markets, Russia and other countries of the Former Soviet Union, China, India, North America, the Middle East and so on.

To match demand with supply, the model also covers the entire gas value chain from production regions down to the transmission level. Therefore, it captures various gas infrastructure assets such as pipelines, LNG facilities and gas storage facilities. It is an economic and optimisation model and therefore does not include some real-world characteristics of gas infrastructure (such as pressure drop in gas pipelines, management of linepack, gas quality limits, etc.). In this model, two main parameters characterise gas infrastructure assets and differentiates between them – physical capacities and the unit cost for utilising those assets.

Given the inputted cost structure and capacities for these infrastructure assets, the objective of the model is to find a least cost solution to meet global demand taking into account various physical constraints, such as gas production capacities, transmission network capacities, LNG liquefaction and send-out capacities, storage injection, withdrawal and maximum working volume capacities, as well as minimum and maximum daily demand profiles and contractual obligations (e.g. annual contract quantity and minimum take-or-pay).

The outputs from the model are projections of supply, demand, equilibrium prices,<sup>91</sup> pipeline and LNG flows, storage injection and withdrawal at daily resolution. In other words, the model approximates the operations of day-ahead gas markets. The model considers all existing cross-border interconnection points in Europe, as well as disaggregating European demand regions into individual markets according to their national borders (EU28). This resulted in around 1,320 pipeline connections (or 'arcs') in

<sup>&</sup>lt;sup>91</sup> The notion of *'equilibrium'* prices simply means that prices are determined at the intersection of demand with supply.



total. The physical capacities of these interconnection points were taken from ENTSO-G's 2015 capacity map,<sup>92</sup> whereas their entry and exit charges were taken from ACER's most recent market monitoring report.

### **Key assumptions**

Since the model was run for a future year (2025/2026), expected gas demand and infrastructure capacities were taken from IEA's 2016 World Energy Outlook (2016) and ENTSO-G's 2015 Ten Year Network Development Plan, or TYNDP (2015). In particular, new cross-border capacities and LNG regasification capacities in the EU were added in the model based on their final investment decision (FID) status – those projects which took FID as outlined in ENTSO-G's 2015 TYNDP report were added into the model with start time and capacities as reported by these projects. All existing storage sites are aggregated to regional/country level. New storage capacities are also taken into account according to their FID status (as reported in ENTSOG's 2015 TYNDP).

The model also takes into account all LNG projects that took FID before 2016, such as those from Australia or the USA. Where information about future infrastructure capacities are not publicly available, such as the majority of non-EU gas infrastructure (pipelines, LNG and storage facilities), we rely on capacities taken from another long-term gas capacity expansion model with annual time resolution to 2035.<sup>93</sup> The capacity expansion model is a partial equilibrium model that only takes into account the interaction of demand and supply for natural gas and hence, such issues as inter-fuel competition (e.g. coal-gas-oil switching) and income effect (e.g. GDP growth and total energy demand) and how they may alter demand for natural gas is not explicitly modelled (in the manner that general equilibrium models would do).<sup>94</sup>

Thus, to overcome this shortcoming the capacity expansion model was calibrated to run based largely on IEA's World Energy Outlook 2015 '450/CPS' scenarios to account for high-level energy policies and general equilibrium effects (i.e. inter-fuel competition, income effect etc.). Marginal supply cost curves are derived from publicly available information for the last ten years, as well as proprietary information obtained from gas industry stakeholders.

All other assumptions related to physical capacities of existing infrastructure assets were obtained from IEA's World Energy Outlook 2015, IEA's (2016) Natural Gas Information 2015, or from the official sources of owners of those infrastructure assets.

<sup>&</sup>lt;sup>92</sup> Capacity map version May 2015, available at: <u>http://www.entsog.eu/maps/transmission-capacitymap</u> (accessed March 2016).

<sup>&</sup>lt;sup>93</sup> A detailed description of an earlier version of the long-term gas market model without investment decisions can be found in Chyong and Hobbs (2014).

<sup>&</sup>lt;sup>94</sup> The drawback of using general equilibrium models for analyses of gas pipeline competition issues is that these models are aggregated at a high level, representing entire regions and not necessarily representing the gas network in sufficient detail.

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It is also important to note that the entry and exit charges that were used for the European network (taken from ACER) in the model are annual tariffs, hence flow patterns from the model should be treated as annual contracted flows, adjusted for daily fluctuations in supply and demand conditions. In reality, there are different transportation products (e.g. daily, monthly) with corresponding tariff structures which may (or may not) result in additional flows for some entry and exit points in Europe. Furthermore, when running the model for future years, it is implicitly assumed that the relative cost structure of gas networks in Europe, and hence their tariffs for entry and exit points, stay at the current level.

Also, it is worth mentioning that the European pipeline network in the model does not take into account the differences between high- and low-calorific gas, and therefore some of the physical constraints resulting from such differences are not captured in the network flow. However, it is understood that conversion facilities between high and low-calorific gas are in place at the majority of the interconnection points of the two systems (e.g. in the Netherlands), so these differences may have a limited impact on the flows from the model.

Finally, daily gas demand profiles are the average of daily gas demand in the last 5 years and hence, the impact of weather on gas demand in future years is assumed to be the average impact witnessed in the last 5 years. The model was run for one and a half years or 546 days starting from 1 January 2025. Since the model determines storage injection and withdrawal profiles based on the cost structure of the assets in the model, together with supply and demand conditions, at the beginning of each model run it was assumed that all storages are half-full, reflecting that 1 January is roughly the mid-point through the winter season.

### **UK Unit Commitment Electricity Market Model**

The model has a detailed representation of all existing generation units in the UK which are connected to the transmission level. It captures major supplies of electricity in the UK at unit level. This includes:

- **Biomass plants** 1.
- 2. CCGT plants
- 3. Coal plants
- 4. Peaking plants
- 5. Nuclear
- Pump storage facilities 6
- 7. All existing interconnectors

It has detailed representation of most power engineering constraints:



- 1. Ramp up and ramp down of thermal units
- 2. Minimum up and down time of thermal units
- 3. Operating reserve and system demand constraints
- 4. Pump storage charge and discharge as well as maximum and minimum energy storage level
- 5. Interconnection capacity and flows

The model has hourly resolution and is setup to meet hourly load, less intermittent generation. Interconnector flows are modelled explicitly in the model using market prices in Europe and Ireland as marginal prices for import flows to the UK. The model is a 'copper plate' model but transmission network and balancing charges could be applied in the model. This reflects actual market operations from generators' point of view. We ran this unit commitment model for the year 2025 assuming:

1. Decommissioning of all coal plants in the UK by 2025 (in line with policy announcements in the UK).

2. The total annual demand does not change between 2015 and 2025 because there is an expectation that underlying demand growth will be offset by greater energy efficiency (see CCC, 2015; BEIS, 2016). Thus, total electricity demand remains at 336 TWh/year and we use the same demand profile as in 2015.

3. We also assume that the annual wind generation profile in 2025 is similar to 2015 and hence we use the latter one and scale up the projected increase in wind and solar capacity in 2025 (based on BEIS 2016 projection) to arrive at total renewables generation.