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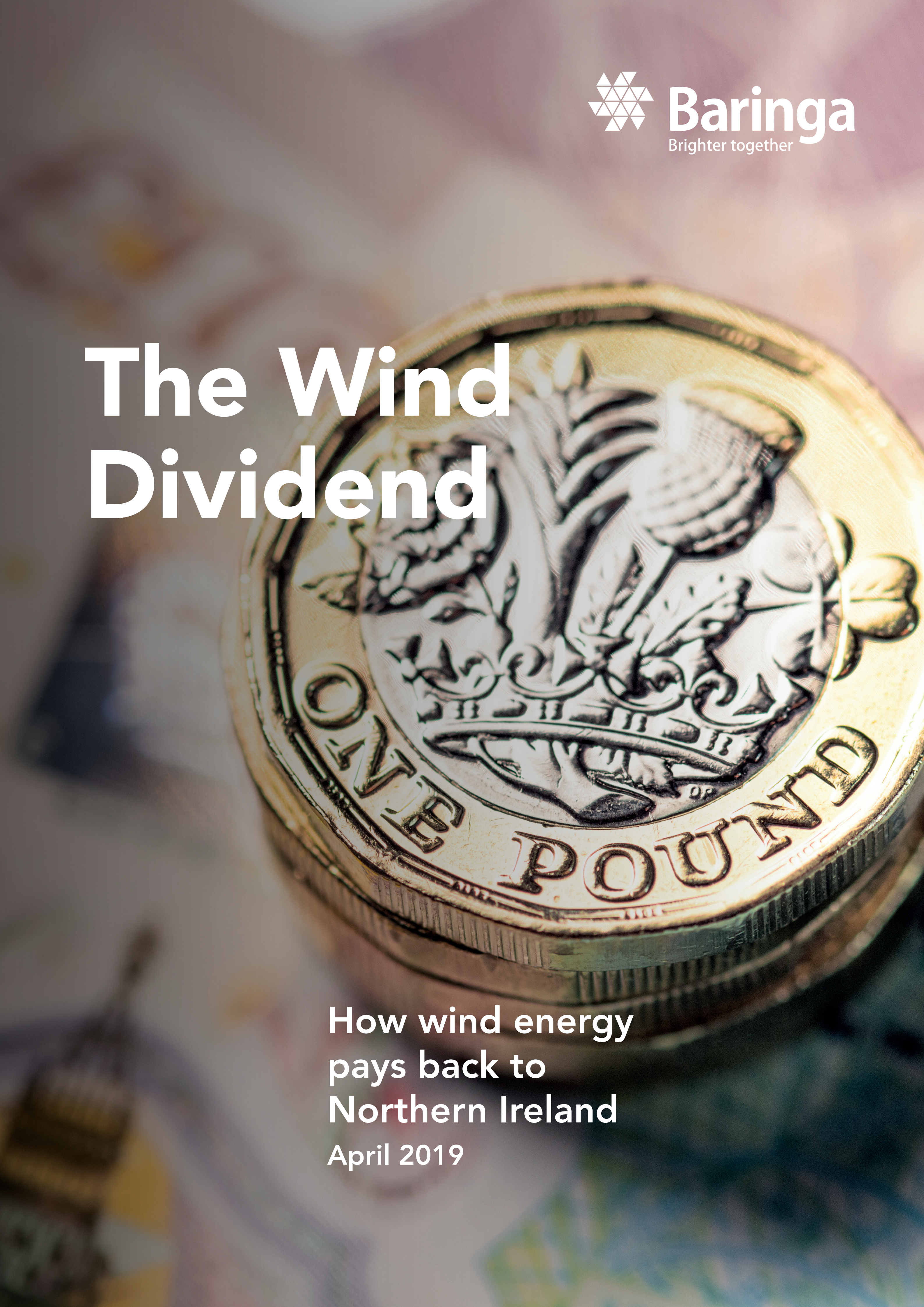

The Wind Dividend

How wind energy pays back to Northern Ireland

April 2019

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Executive summary

From a starting point of near zero in 2000, total wind generation capacity in Northern Ireland (NI) has grown significantly, and is expected to reach 1.4 GW in 2020.[1] By then, wind will contribute around 3.8 TWh of electricity generation each year – this will be equivalent to approximately 42% of all NI electricity consumption. Outturn data for 2018 shows that 38.2% of all NI electricity came from renewable sources[2].

In this study, Baringa Partners LLP ("Baringa") has analysed the financial impact for end consumers of the deployment of wind generation in Northern Ireland over the period 2000-2020. We have used our advanced in-house models of the all-island electricity market to calculate how the costs and benefits for end consumers would have differed if no wind farms had been built. We have also calculated the impact of wind farms on carbon emissions and fossil fuel consumption. The analysis is based on historical data for the years 2000-2017, while the years 2018, 2019 and 2020 are based on a projection, as the study was carried out during 2018.

Figure 1 presents a summary of our analysis of the total costs and benefits for end consumers of wind development in Northern Ireland over the period 2000-2020. Wind energy has increased end consumer costs in some areas and resulted in significant benefits and savings in others.

Wind farms require no fuel to run and therefore, once built, generate electricity at very low cost. As a result, wind generation displaces more expensive electricity sources such as gas or coal-fired power stations or electricity imports. This dynamic means that wind generation reduces power prices across the entire electricity market, which also lowers end costs for all consumers.

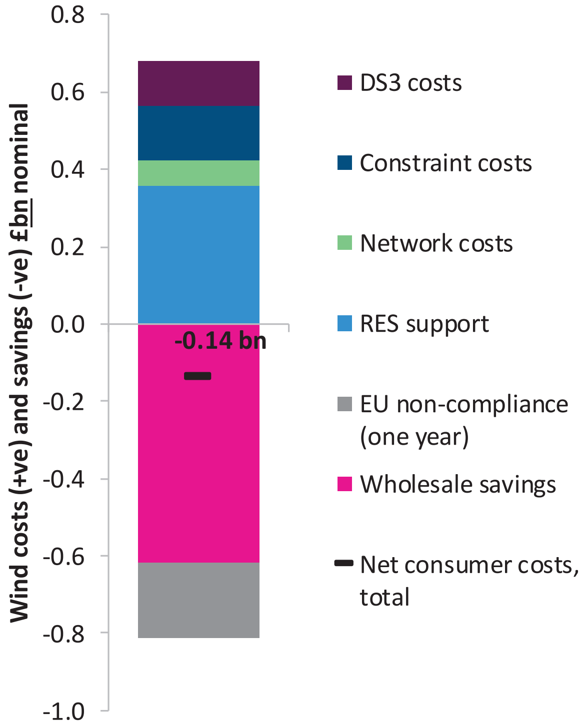
Our analysis indicates that the deployment of 1.4 GW of wind generation capacity in Northern Ireland between 2000 and 2020 will result in a total net benefit to consumers, over 20 years, of £0.1bn (£135 million to be exact), which equates to a net benefit of about £4 per person per year[3].

[1] Digest of UK Energy Statistics table 5.8. Following the restructuring of the electricity supply industry in 1990, the term "Major generating companies" was introduced into the electricity tables to describe the activities of the former nationalised industries and distinguish them from those of auto-generators and new independent companies set up to generate electricity.

[2] https://www.economy-ni.gov.uk/articles/electricity-consumption-and-renewable-generation-statistics

[3] The total cumulative benefit over 20 years of £135 million was divided by 20 and then divided by the population of Northern Ireland in 2017 (1,876,695) as per the latest census.

Figure 1 **Cumulative costs and benefits of wind farms for Northern Ireland consumers 2000-2020 (£bn)**



This total net benefit arises as the gross costs of £0.7bn are outweighed by a gross benefit of £0.8bn. These benefits consist of wind-driven reductions in wholesale power prices, and avoidance of EU non-compliance costs.

Aside from the financial costs and benefits, we calculate that the deployment of wind generation in Northern Ireland avoids:

- 9 million tonnes of power sector CO_2 emissions. The total carbon emissions from energy supply in Northern Ireland in 2016 was 4.0 Mt, so a saving of 9 Mt is equivalent to over 2 years of total carbon emissions in the energy sector[4].
- 72 TWh of fossil fuel consumption at a saving of £1.0bn

It is important to note that our analysis does not take account of the broader socio-economic benefits of wind. For example, we have not included the benefits of job creation, cleaner air, or the full societal benefit of lower carbon emissions as a result of using domestic wind energy instead of imported fossil fuels.

[4] Northern Ireland greenhouse gas inventory 1990-2016 statistical bulletin

The remainder of this report is structured as follows:

- **Section 1** lists and explains the costs and benefits of wind considered in this study
- **Section 2** discusses the key results of the cost-benefit analysis
- **Section 3** outlines other wind benefits: lower fuel costs and emissions savings
- **Section 4** presents our detailed methodology

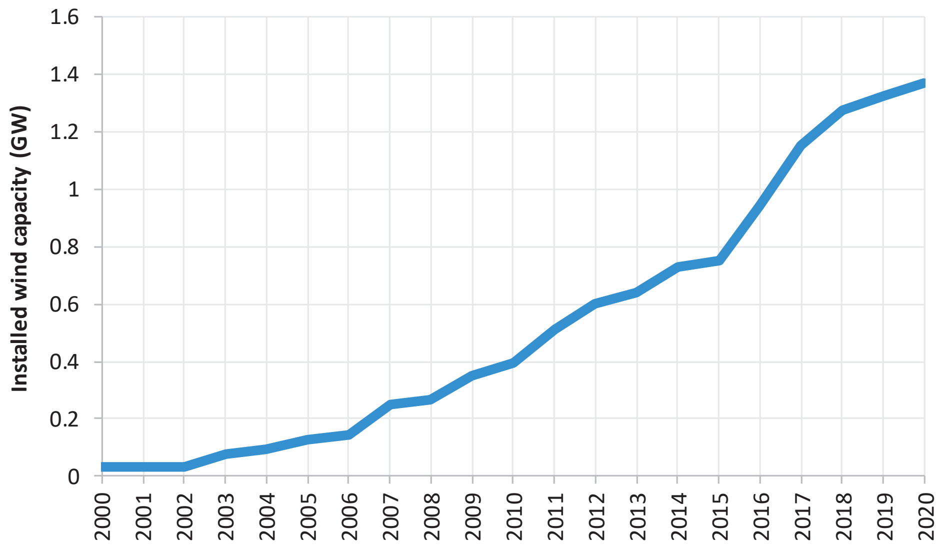
All monetary values in this report are presented in nominal GBP, unless otherwise stated

1 Overview of wind costs and benefits

1.1 Wind in Northern Ireland

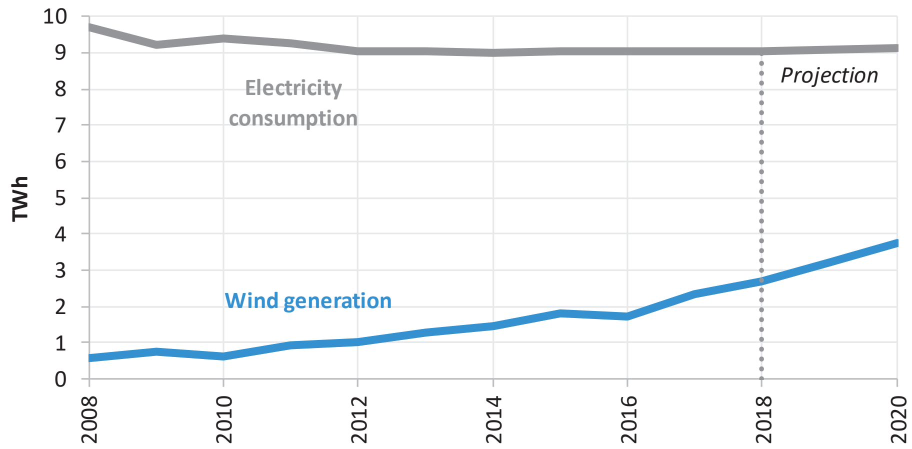
Over 20 years, wind generation has grown from very low levels to become a major energy source. From a starting point of near zero in 2000, installed wind capacity in Northern Ireland (NI) is projected to reach over 1.4 GW in 2020. To put this into context, the total dispatchable generation capacity in NI is around 2.3 GW[5]. In 2018 38.2% of all electricity came from renewable sources. Wind will contribute 3.8 TWh of electricity generation each year by 2020 – this is equivalent to around 42% of total electricity consumption. This has transformed the energy system and has resulted in both additional costs and benefits to the consumer, which this study seeks to quantify.

Figure 2 Northern Ireland installed wind capacity 2000-2020 (GW)



[5] See SONI Generation Adequacy Statement 2018-2027. This number excludes the Moyle interconnector. http://www.soni.ltd.uk/media/documents/Generation_Capacity_Statement_2018.pdf

Figure 3 Northern Ireland electricity demand and wind generation, 2008-2020 (TWh)



Note: This section introduces the wind benefits and costs we considered in this study. For a detailed calculation methodology of these costs and benefits, please see Section 4.

1.2 Wind benefits

This section lists the key financial benefits of wind for end consumers considered in this study. These benefits are quantified in Section 2.

- **Wholesale energy cost savings:** Wind farms require no fuel to run and therefore, once built, generate electricity at very low cost. As a result, wind generation displaces more expensive electricity sources such as gas or coal-fired power stations or electricity imports, reducing power prices on the wholesale market.[6] Government figures from the Department of Business, Energy and Industrial Strategy (BEIS) indicate that onshore wind will be the cheapest form of new generation by 2020.[7] Fuel costs are an important component of electricity bills, driving direct savings for consumers through lower electricity tariffs.[8]

[6] In the wholesale electricity market, generators compete in daily auctions to deliver electricity. The bids made by generators reflect to a large extent their short-run marginal cost of electricity generation, which consists largely of fuel, carbon and variable operating costs. In these auctions, generators with lower marginal costs will clear first, and the power price is set by the *marginal generator*, which is the generator with the highest marginal costs that is still needed to meet electricity demand. Wind generation has a marginal cost of close to zero and virtually always clears the auction, reducing the remaining volumes for fossil fuel generators, which results in the most expensive fossil plants not clearing the auction. As a result, less expensive plants are required to clear the market, leading to lower power prices.

[7] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

[8] For comparison, based on CRU's 2017 Electricity and Gas Retail Markets Annual Report, in 2017, fuel costs represented 43% of the total electricity bill for small commercial customers. (CRU does not publish the equivalent figure for retail customers).

- **Avoided non-compliance costs:** The EU has committed to achieving 16% of final energy consumption from renewable sources by 2020[9]. The UK's contribution to meeting this target is set out in its National Renewable Energy Action Plan (NREAP), which is legally binding. The UK's expected failure to reach its 15% target renewable energy consumption share will result in a progressive fine for each percentage point missed on the target. Given that wind generation helps to reach the target and avoid fines, this represents a saving to Northern Ireland taxpayers and consumers. We have conservatively included only one year of non-compliance costs in our analysis. However, if wind power had not previously been developed in Northern Ireland, it would likely take much longer than a single year to make up the shortfall and therefore the fines could occur over multiple years. The UK is currently in the process of leaving the European Union and the exact terms of the withdrawal are not yet known. Given the resulting uncertainty around the applicability of avoided non-compliance costs, we have also calculated the net consumer costs excluding this benefit for comparison.

1.3 Wind costs

This section lists the key costs of wind for end consumers considered in this study. These costs are quantified in Section 2.

- **Renewable support costs:** Northern Ireland wind is supported by the Northern Ireland Renewable Obligation (NIRO) scheme. This UK-wide renewable certificate scheme supports renewable generation, including wind, and closed to new generation in 2016. The cost of the scheme is initially incurred by energy suppliers, which are obliged to acquire a certain amount of RO certificates per MWh electricity supplied. Suppliers then pass this cost on to consumers. In Northern Ireland, the current supplier obligation stands at 0.185 ROC/MWh.

- **Constraint costs**: For stability reasons, the All-Island power system has to operate within certain operating limits or 'constraints'. For example, one constraint sets a limit on the level of generation from wind, solar, or imports across interconnectors at any one time. These generation sources are 'non-synchronous' and this is known as the System Non-Synchronous Penetration (SNSP) limit. Other constraints set a minimum safe level of generation for specific groups of power plants. If these constraints are at risk of being violated, the system operator needs to intervene to turn up or turn down power plants, which comes at a cost. The growth of wind generation has driven an increased need for these redispatch interventions, adding to costs.

- **DS3 costs:** Another set of tools that the system operator uses to manage the power system is called 'ancillary services'. The current ancillary services scheme in the All-Island market is known as 'DS3' which stands for 'Delivering a Secure Sustainable Electricity System'. Under DS3, electricity generators are paid to provide ancillary services[10]. The growth of wind generation is driving an increased need for DS3 services, the costs of which are recovered from end consumers.

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[9] Renewable Energy Directive 2009/28/EC

[10] One of the uses of DS3 services is to help manage some of the constraints on the power system, such as the SNSP limit. In that sense, DS3 services contribute to reducing constraint costs.

- **Network costs**: Wind farms require access to the electricity grid to export their power. Given that wind farms are often built in regions that have limited grid capacity, and given the fluctuating nature of wind in-feed, wind generation has resulted in a need to upgrade the electricity grid, resulting in additional costs.

2 Results and discussion

2.1 Overview

Our analysis indicates that the deployment of 1.4 GW of wind generation in Northern Ireland between 2000 and 2020 will result in a total net benefit to consumers of £0.1bn (£135 million to be exact). This cost is paid by all electricity consumers across the residential, commercial, agricultural and industrial consumers. To put this cost in context, this equates to a net benefit of about £4 per person per year [11].

This total net cost breaks down as follows:

- £0.6bn wholesale energy cost **savings**
- £0.2bn avoided EU non-compliance with 2020 target **savings**[12]
- £0.4bn renewable support **costs**
- £0.1bn DS3 **costs**
- £0.1bn network upgrade **costs**
- £0.1bn constraint **costs**

[11] The total cumulative benefit over 20 years of £135 million was divided by 20 and then divided by the population of Northern Ireland in 2017 (1,876,695) as per the latest census.
[12] This assumes that post-Brexit, the UK will still be bound to meeting its 2020 renewables targets and will be liable to pay a fine if it does not comply with these targets. See section 4.2.1 for more details.

Figure 4 Yearly costs and benefits of wind in Northern Ireland 2000-2020 (£m, nominal)

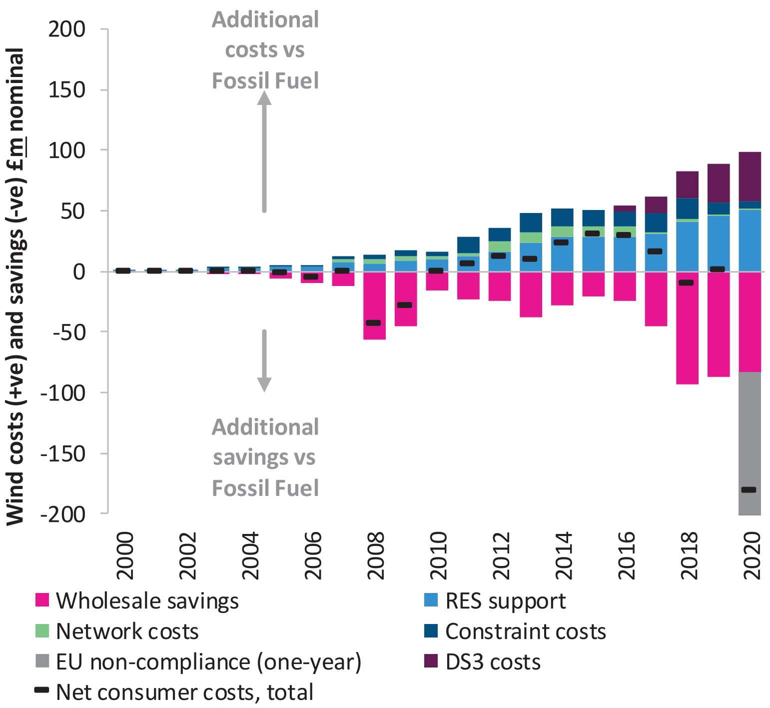
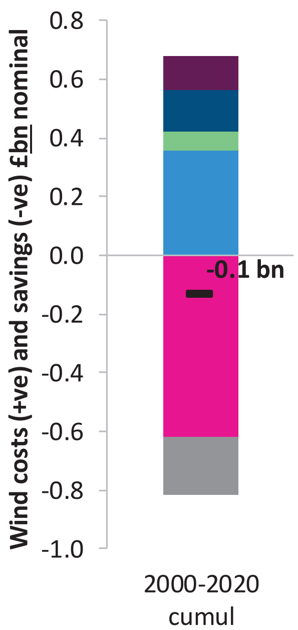


Figure 5 Cumulative, 2000-20 (£bn, nominal)

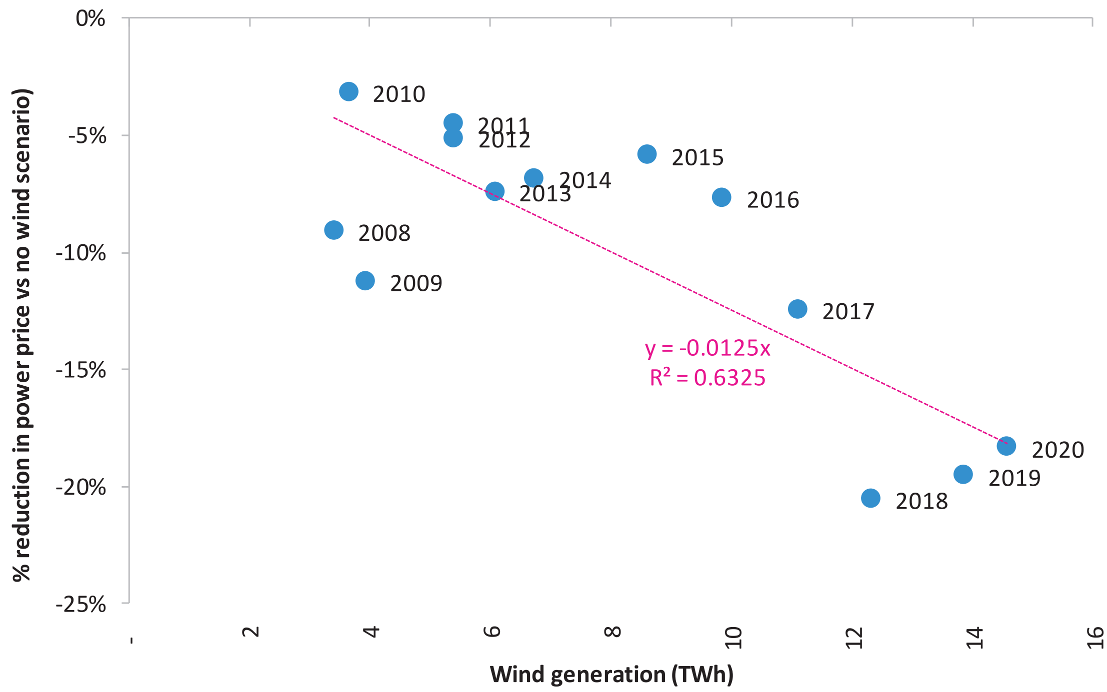


The net costs and benefits of wind have evolved over time (see Figure 4). In the early 2000s, low levels of wind generation result in limited costs and benefits. In 2008, power prices reach 64 £/MWh, partly as a result of high fuel prices. This increases the wholesale savings of wind, more than offsetting the support costs, driving a net benefit. As commodity prices fall, wholesale savings fall whereas support costs grow as the supplier renewables obligation gradually increases. By 2018, amid strong power prices, wholesale savings increase again, however are mirrored by an increase in DS3 and network costs, resulting in a net cost to close to zero. In 2020, the avoided EU non-compliance costs increases the total net benefit.

It is important to note that 2018-2020 is a projection as this study was carried out in 2018. There is some uncertainty within the results for the period 2018-2020 – like any projection, the exact degree of alignment with actual outturn is unknown. In particular, the UK is currently in the process of exiting the European Union, and the exact terms of its withdrawal are not yet known. In this context, it is currently uncertain whether or not the UK will still be liable to pay a fine to the EU if it does not meet its 2020 renewables target. If the fine is not payable, then we calculate an overall cost of wind in Northern Ireland of £61 million. This equates to about £1.60 per person per year.

Figure 6 shows the simulated impact of wind generation on the wholesale power price: actual power prices are significantly lower than power prices simulated under a 'no wind' scenario. The effect increases as wind generation grows – for example, we estimate that in 2018, wind helped to reduce power prices by over 20%.

Figure 6 Wind generation and wholesale price reduction vs 'no wind' scenario



3 Other wind benefits

3.1 Reduced exposure to volatile fuel prices

Wind generation results in less gas-fired generation. Over 2000-2020 we estimate that wind generation displaces a total of 4.3 mTOE (or 50 TWh) of natural gas. Wind farms, which produce electricity at a stable cost, reduce Northern Ireland customers' exposure to the price of gas. Overall, we estimate that wind generation reduces gas buying costs in Northern Ireland by about £0.8bn from 2000 to 2020.

The impact on coal is lower than that on gas, with wind displacing a total of 1.8 mTOE (or 21 TWh) between 2000 and 2020. Because of the lower cost of coal generation compared to gas, coal tends to be displaced by wind only once most gas plants have already stopped generating. We estimate that wind generation reduces combined coal and gas buying costs in Northern Ireland by about £1.0bn from 2000 to 2020 (see Figure 7).

3.2 Avoided carbon emissions

As wind has driven down gas and (to a lesser extent) coal consumption, carbon emissions have dropped too. We estimate that between 2000 and 2020, wind generation has reduced CO_2 emissions in Northern Ireland by a cumulative 9 million tonnes (see Figure 8). The total carbon emissions from energy supply in Northern Ireland in 2016 was 4.0 Mt, so a saving of 9 Mt is equivalent to over 2 years of total carbon emissions in the energy sector[13].

Figure 7 Northern Ireland cumulative fuel cost savings by wind, 2000-20 (bn £ nominal)

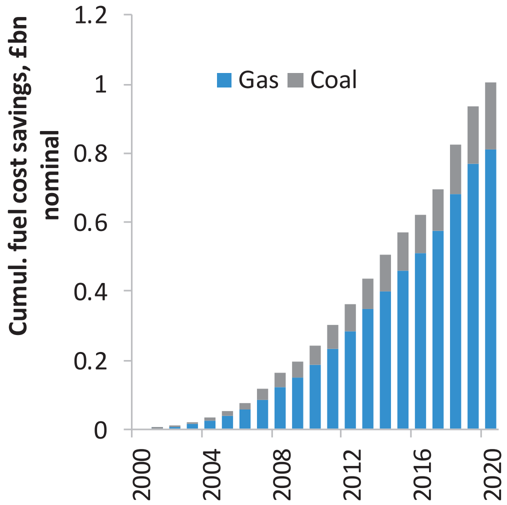
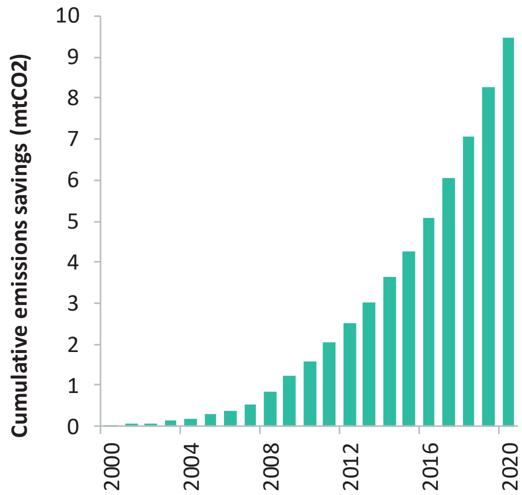


Figure 8 Northern Ireland cumulative emissions savings by wind, 2000-20 (mtCO2)



[13] Northern Ireland greenhouse gas inventory 1990-2016 statistical bulletin

4 Calculating the cost savings and additions due to wind power

This section describes each of the cost savings and additional costs in more detail than the overview provided in the previous section, particularly in relation to the methodology applied to quantify each one.

4.1 Cost savings due to wind power

The cost savings due to additional wind power in Northern Ireland include:

- reduction in wholesale electricity costs; and
- avoided future EU compliance costs (e.g. fines).

In this section we explain each of these cost savings, and our methodology for quantifying them.

4.1.1 Reduction in wholesale electricity costs

Wind farms, once constructed, are inexpensive to run as wind generation has a low marginal cost. Wind generation therefore displaces higher cost electricity sources such as gas plants, coal plants or imports. This dynamic means wind reduces power prices across the entire electricity market, which also lowers end costs for all consumers (a detailed description of this dynamic is in Appendix A).

We have analysed the impact of wind generation on SEM and I-SEM wholesale power prices in detail using our powerful in-house pan-European modelling platform.[14] This incorporates a power plant-level representation of the All-Island market, and simulates their operation in the market at hourly granularity.

As a first step, we set up our model in 'back-cast' mode to simulate and reproduce historical power prices from 2008-2018 YTD. This involves using actual outturn values for key inputs to the model such as gas, coal and carbon prices, power demand, installed capacity and wind generation. Once set up and run in this mode, our model very closely replicates actual historical power prices (see Figure 9).

As a second step, we assume wind generation to be zero and rerun the market model to simulate power prices in a 'no wind' counterfactual (see Figure 10). To maintain the same level of system security, we maintain a similar de-rated capacity margin by substituting wind for open cycle gas turbine (OCGT) plants. Under the I-SEM capacity market rules, wind receives a capacity credit of about 10% and OCGTs a capacity credit of about 92%. This means that 1 GW of wind is replaced by 109 MW (= 1 GW * (10% / 92%) of OCGTs. We calculate the savings as the difference in wholesale

[14] The SEM operated as an All-Island mandatory pool spot market for Northern Ireland and Ireland from 1 November 2007 to 30 September 2018. A new market design, the Integrated Single Electricity Market (I-SEM), went live on Monday 1 October 2018, having been delayed from 23 May 2018. This more closely integrates the Irish electricity spot market with the GB and continental markets, as well as replacing the previous administered mechanism for capacity payments with a new auction-based capacity market.

price (in €/MWh, then converted to £/MWh at the prevailing exchange rate) between the two runs, multiplied by the overall GWh electricity demand in Northern Ireland.

Figure 9 SEM historical and modelled SMP

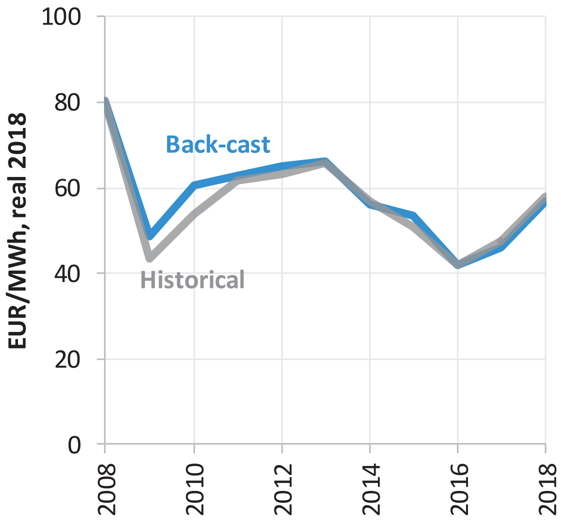
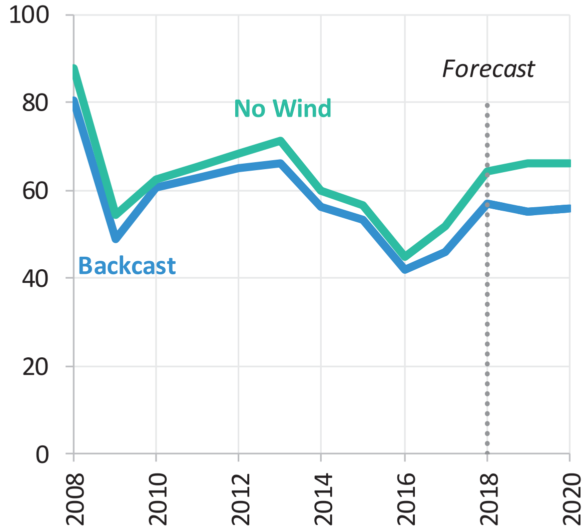


Figure 10 SEM back-cast and 'No Wind' SMP



For 2018 to 2020, we use our Baringa Reference Case assumptions[15] on capacity mix and the evolution of demand. For 2019 and 2020, we assume that commodity and carbon prices equal market forward prices for FY 2018. For the years 2000 to 2007, a lack of data availability prevents us from fundamentally modelling the wholesale price impact of wind. Instead, we have deduced a linear relationship between wind generation and power price impact from the 2008-17 back-cast and have used this to approximate the power price impact and wholesale savings of wind for the earlier period (see Figure 6).

Table 1 presents the installed wind capacity, wind generation and Northern Ireland electricity demand assumptions we have used in our modelling.

[15] The Baringa Reference Case represents Baringa's central view on the evolution of the SEM market. Under this scenario, Irish and EU Governments pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability.

Table 1 Northern Ireland wind capacity, generation and total electricity demand, 2000-20

Year	Wind capacity (GW)	Wind generation (TWh)	Electricity demand (TWh)
2000	0.03	0.1	8.5
2001	0.03	0.1	8.5
2002	0.03	0.1	8.5
2003	0.08	0.2	8.6
2004	0.09	0.2	8.8
2005	0.12	0.3	8.9
2006	0.14	0.3	9.4
2007	0.25	0.6	9.6
2008	0.27	0.6	9.7
2009	0.35	0.7	9.2
2010	0.39	0.6	9.4
2011	0.51	0.9	9.3
2012	0.60	1.0	9.0
2013	0.64	1.3	9.0
2014	0.73	1.5	9.0
2015	0.75	1.8	9.1
2016	0.94	1.7	9.1
2017	1.15	2.3	9.0
2018	1.28	2.7	9.1
2019	1.32	3.2	9.1
2020	1.37	3.8	9.2

4.1.2 Avoided EU compliance costs

The EU has committed to achieving 20% of final energy consumption from renewable sources by 2020[16]. The UK's contribution to meeting this target is set out in its National Renewable Energy Action Plan (NREAP), which is legally binding. We expect the UK to fail to reach its target of 15% renewable energy consumption, which will result in a progressive fine depending on by how much the target is missed. The investment in Northern Ireland wind farms from 2000-2020 will help the UK avoid these non-compliance costs.

We have not undertaken a detailed calculation of the avoided non-compliance cost for Northern Ireland specifically, and with the Brexit process ongoing, the non-compliance cost in case the UK does not meet its renewable target is uncertain. However, these costs have been estimated for the Republic of Ireland, and we have taken these as a guide for NI.

[16] Renewable Energy Directive 2009/28/EC

In a 2016 report[17], the Sustainable Energy Authority of Ireland (SEAI) estimates these compliance costs for Ireland to be between €65m and €130m per percentage shortfall on the overall binding target, of which we take the mid-point estimate of €97.5m. Given that wind is projected to represent 6.8% of overall energy consumption in Ireland, this translates into a total avoided compliance cost of €664m (97.5 * 6.8) as a result of wind generation, which equates in an equivalent avoided compliance cost of €59 per MWh of wind generation.[18]

We expect that any EU non-compliance cost would be calculated on the basis of total MWh renewable generation shortfall against the target and therefore apply this equivalent avoided cost of €59/MWh to the total expected wind generation for Northern Ireland in 2020 to estimate its avoided non-compliance cost as a result of wind generation. With projected 2020 Northern Ireland wind generation of 3.8 TWh, we estimate the total avoided compliance cost to be £196m (€222m) in 2020.

The exact methodology the EU will use to calculate non-compliance costs is still to be finalised. In our calculation, we have conservatively assumed that the compliance costs would be a one-off fine for 2020 only, rather than an annual payment until the target is met. However, we emphasise that it remains uncertain whether, post-Brexit, the UK will still be liable to pay a fine to the EU if it does not meet its 2020 renewables target.

4.2 Additional costs due to wind power

The additional costs due to wind power in Northern Ireland include:

- Renewable energy support
- Power plants accommodating the variability of wind power on the grid (i.e. constraint costs)
- Building additional electric grid (i.e. network costs)
- Adding more flexibility and controls to the grid (i.e. DS3 costs)

In this section we explain each of these costs, and our methodology for quantifying them.

4.2.1 Renewable support costs

Northern Ireland wind is supported by the NIRO. This forms part of a UK-wide renewable certificate scheme to support renewable generation, including wind. The cost of the scheme is initially carried by energy suppliers, as they are obliged to acquire a certain quantity of RO certificates per MWh electricity supplied. In Northern Ireland, the current supplier obligation stands at 0.185 ROC/MWh.

We have calculated the wind support costs for Northern Ireland customers as follows. We have multiplied the total required ROCs for Northern Ireland energy suppliers with the total ROC buyout price[19] to calculate the total renewables support cost carried by Northern Ireland energy customers. To calculate the support cost for Northern Ireland wind specifically, we multiplied the total support cost by the share ROCs received by Northern Ireland wind farms over all the ROCs received by all NI

[17] Sustainable Energy Authority of Ireland (SEAI), April 2016: 'Ireland's Energy Targets: Progress, Ambition and Impacts'
[18] This assumes 2020 wind electricity generation in ROI of 11 TWh
[19] Source: Ofgem annual reports on RO obligation

renewables, which varies from 96% in 2008 to 67% in 2018.[20] It is important to note that this share takes into account the ROC 'banding'[21] of 4 for small-scale onshore wind as well as the drop in NIRO support for large-scale onshore wind from 1 to 0.9 in 2013/14.

4.2.2 Power plants accommodating the variability of wind power on the grid (constraint costs)

The representation of the all-island market in our power market model closely replicates the way in which the market operates under the SEM and I-SEM structures. Generators are dispatched based on their short run marginal cost taking account of start fuel costs, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes. Two runs take place in the model:

- In the initial unconstrained run, no system constraints are in place and plants are dispatched on a merit-order basis. This model run simulates the wholesale electricity market price, which is set on an unconstrained basis.
- In the constrained run, we simulate the actual physical operation of power plants on the system. We have modelled two main system constraints: a minimum generation constraint in Ireland and Northern Ireland respectively, and a System Non-Synchronous Penetration (SNSP) constraint across the whole island[22]. The SNSP increases gradually from 50% in 2015 to 65% in 2018 and 75% by 2020.

We estimate the wind constraint costs (i.e. the costs resulting from the fact that the SEM power system is insufficiently flexible to absorb all wind generation) as follows: we run an unconstrained and constrained model for both the backcast and 'no wind' counterfactual scenario. In each case, we calculate the constraint cost by looking at the difference in generation costs between the unconstrained and constrained model runs. We then compare the 'backcast' and the 'no wind' scenarios in order to determine the change in constraint costs that can be attributed to wind. We have allocated the constraint costs between Ireland and Northern Ireland in line with the wind generation split.

4.2.3 Upgrading the electricity grid (network costs)

We have received information on network expenditure associated wind generation from Northern Ireland Electricity Networks (NIEN). These expenditures were funded through the general customer base (i.e. not incurred by wind generators). Costs are provided back to the RP4 price control period which commenced in 2007 and out to 2020 as part of the RP6 control period. NIEN does not expect

[20] Source: Ofgem renewables and CHP register (www.renewablesandchp.ofgem.gov.uk)
[21] The 'banding' defines the number of ROCs which an accredited generator receives per MWh of output.
[22] For stability reasons, the All-Island power system has to operate within certain operating limits or 'constraints'. For example, one constraint sets a limit on the level of generation from wind, solar, or imports across interconnectors at any one time. These generation sources are 'non-synchronous' and this is known as the Systen Non-Synchronous Penetration (SNSP) limit. Other constraints set a minimum safe level of generation for specific groups of power plants. If these constraints are at risk of being violated, the system operator needs to intervene to turn up or turn down power plants, which comes at a cost. The growth of wind generation has driven an increased need for these redispatch interventions, adding to costs.

any generator related reinforcement costs to be incurred prior to 2007. The costs exclude network reinforcement costs that were passed through to customers via connection charges.

Historic network reinforcement costs required to connect wind generation would be artificially supressed due to the inherent level of available capacity which would have been utilised before reinforcement was required. Therefore, the historic reinforcement costs may not reflect future costs for the connection of further generation to the network.

4.2.4 Adding more flexibility and controls to the grid (DS3 costs)

The DS3 (Delivering a Secure Sustainable Electricity System) programme was established by EirGrid and SONI to 'meet the challenges of operating the electricity system in a safe, secure and efficient manner while facilitating higher levels of renewable energy'. A key aim is to ensure that the SEM system can operate at higher System Non-Synchronous Penetration (SNSP) levels of up to 75%. With wind being the major factor behind an increase in non-synchronous generation, a large portion of the costs of this programme can be attributed to the growth of wind generation (the predominant renewable electricity source in across the island).

We have used the budget for DS3 services from 2015-2020 as set out by EirGrid and SONI, as shown in Table 2.[23] We have assumed that the budget for 2015 (€54m) reflects the cost of ancillary services excluding wind. This is because 2015 precedes the start of the effort to increase the SNSP level. We then assume that the increase in budget from €54m to €235m in 2020 is driven by the effort to increase the SNSP limit to 75% and therefore by wind. We have allocated the DS3 costs between Ireland and Northern Ireland by using the wind generation split.

Table 2 DS3 budget (all-island), 2015-2020

	Units	2015	2016	2017	2018	2019	2020
DS3 budget	€m	54	75	115	155	195	235

[23] EirGrid and SONI, July 2017: 'Consultation on DS3 System Services Enduring Tariffs', DS3 System Services Implementation Project

Appendix A Modelling methodology

Overview

Baringa has developed an in-house a Pan-EU power market model covering Ireland, Great Britain and most countries in Europe for the purpose of power market studies. The model sits within PLEXOS, a third-party commercial software product that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis and other purposes. PLEXOS is also used by the SEM Regulatory Authorities, including the CRU.

The Baringa Pan-EU model takes key inputs and scenario assumptions such as hourly demand profile, commodity prices, plant build and retirement and hourly wind and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries. The model engine carries out least cost optimisation to produce hourly dispatch for the generators and hourly prices for the markets taking full consideration of the operational constraints (ramp rates, start time, availability etc.).

The representation of Ireland in the model closely replicates the way in which the market operates under the I-SEM structure. Generators are dispatched based on their short run marginal cost, taking start fuel offtake, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes into account. Two runs take place in the model. In the unconstrained run, no system constraints are in place and plants are dispatched on a merit-order basis. In the constrained run, two system constraints are modelled: a minimum generation constraint in Ireland and Northern Ireland respectively and a System Non-Synchronous Penetration (SNSP) constraint across the whole island.

PLEXOS

PLEXOS introduction

PLEXOS is a highly advanced market modelling tool, incorporating a number of approaches to the modelling of interconnected markets, and a number of advanced pricing algorithms ranging from marginal cost pricing through to game-theory approaches. It is deployed worldwide by energy companies, investors and system operators. It has been used in the All-Island Modelling Project to support the development of the SEM, and by the Regulatory Authorities to estimate market power and determine the pricing of Directed Contracts[24] which ESB, with the largest generation portfolio, is required to sell.

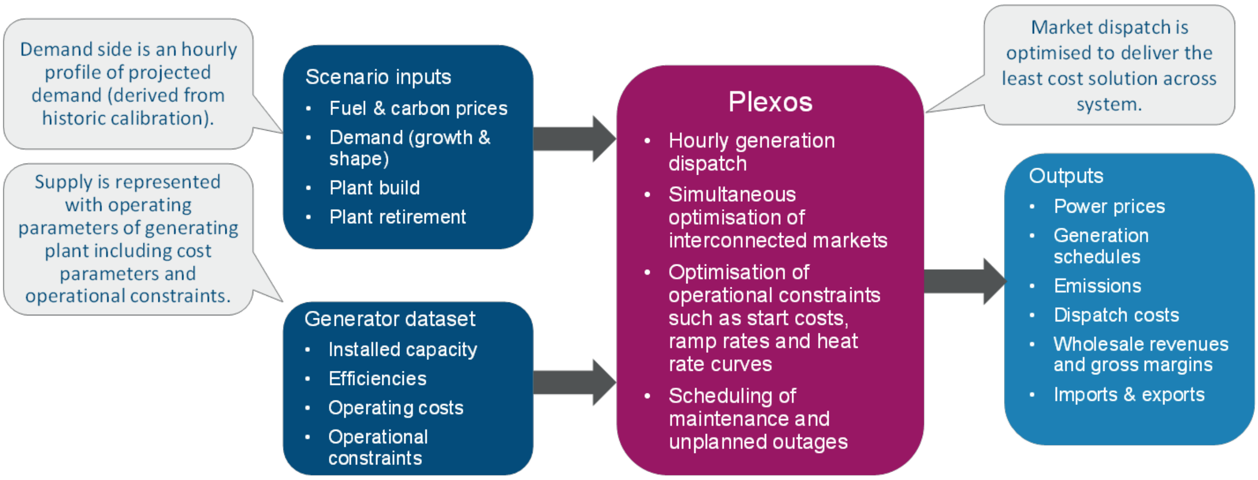
PLEXOS simulations are based on a mathematical programming formulation of power market dynamics. PLEXOS applies linear and mixed integer programming solution techniques to determine the dispatch and pricing outcomes, taking full account of short term dynamic constraints including ramp rates and min on/off times. This approach provides results that fully capture the complexity of power markets and allows the user to analyse fundamental issues such as nodal pricing, hydro

[24] Directed Contracts are financial contracts-for-difference (CfDs) which allow suppliers and generators to hedge against future power prices.

modelling, profit targeting and strategic behaviour. It is also conceptually similar to the way in which the market dispatch software works.

An overview of the model is shown in Figure 11.

Figure 11   PLEXOS Overview



All-Island configuration

Baringa has configured a model of the All-Island market from 2017 through to 2040 based on the RAs' validated dataset[25]. Some of the key modelling features are described below.

Demand

Demand is represented at hourly granularity. Hence, there are 8,760 settlement periods per year, with demand projected from actual historical hourly data to 2040, using both peak and energy demand growth forecasts. Demand is modelled on a station gate (sent out) basis.

Price formation

The model aims to dispatch plant in such a way that generation costs are minimised over each optimisation horizon (24 hours plus a 6 hour look-ahead; identical to SEM market dispatch software). In the Validated Dataset each generator has a multi-part heat rate curve. This is comprised of a no-load cost, and a number of incremental heat rates which apply over different tranches of the generator's capacity. The shadow price is calculated based on short-run marginal costs (SRMCs), and is set by the incremental heat rate of the marginal generator including the full pass through of the prevailing spot fuel and spot EUA (carbon) prices. This is consistent with the approach in the SEM Trading and Settlement Code (T&SC).

The calculation of the outturn prices for SEM includes a calculation of uplift, using an implementation of the algorithm as published in the T&SC. An uplift component is added in each period to ensure

[25] The RAs make available a public version of their SEM PLEXOS forecast model. This is independently updated and validated by independent consultants on a regular basis. The validated model is used by the RAs to fulfil several regulatory requirements, including the calculation of Directed Contract prices.

that each generator recovers its start-up and no-load costs (i.e. is 'made whole') over the period in which it operates. Hence, in each hour the model derives a marginal cost, an uplift payment and system marginal price (SMP).

Modelling of I-SEM

The new Integrated Single Electricity Market (I-SEM) arrangements began on 1 October 2018, and so for the final two years of our analysis, we have changed some aspects of our wholesale electricity market modelling approach in order to reflect the market design.

In accordance with the principle that the market will continue to be based on transparent centralised trading arrangements, least-cost dispatch of total system load and centralised unit commitment, we have assumed that the I-SEM energy market functions as a 'deregulated pool' with firm day-ahead pricing.

Under the simple or block-bidding formats in the I-SEM day-ahead market, generators bid either a simple price-quantity bid or potentially bid for variable levels of output over different periods. These bidding regimes differ from the previous SEM regime in that generators internalise technical uplift (start-up and running costs) in their bids at levels they themselves choose, as opposed to the previous ex-post algorithm calculation.

Recovery of generator start and no-load costs in the SEM was ensured via an uplift mechanism. In the SEM this uplift component often formed a significant portion of the power price, especially in certain hours. In I-SEM, generators have to internalise their start costs into bids into the EUPHEMIA day-ahead market coupling algorithm.

In line with the lack of bidding restrictions in the ex-ante markets under I-SEM, we assume that participant bids and offers in the day-ahead market are no longer restricted by a Bidding Code of Practice. This means that, under I-SEM, generators can bid above the price required to remunerate both their short run marginal cost and technical uplift during periods of system tightness. This additional uplift above generators short run marginal costs and technical uplift we describe as 'scarcity rent'. We have modelled 'scarcity rent' as a function of the capacity margin in each hour.

Plant constraints

All thermal plant on the system are modelled with annual maintenance rates and forced outage rates. The scheduling of maintenance is through a Monte Carlo approach to determine an optimal scheduling, whilst outage patterns are applied randomly. These parameters also feed through to the capacity payment modelling.

Plant dynamic constraints are also fully taken into account in the model. These are parameters that affect the dispatch of the plant and include minimum stable levels, minimum up and minimum down times, and maximum ramp rates.

Peat plant are assumed to be constrained to meet annual minimum fuel burn commitments, equivalent to an 80% load factor, with optimal economic dispatch where appropriate above this level. The wind plant are modelled by allocating installed capacity to one of twelve geographic regions in RoI, and one NI Wind region, each of which are assigned separate load factor profiles derived from historical data. These represent independent but correlated wind patterns at an hourly granularity. The resulting volatility can affect the dispatch of thermal plant.

Hydro modelling

The reservoir hydro units have a limited monthly energy profile, and the model will dispatch this energy according to prices within the month. The profile is kept constant for each river system over the scenario period.

Pumped storage plant will operate based on the day-night price differential and subject to the technical constraints of the plant (pumped load, pumping efficiency and head and tail storage capacity).

Gas capacity charges

Gas-fired generators in Ireland have the option of buying annual, monthly, or daily gas capacity. We assign assumptions on this for each gas-fired plant in the market, based on the RAs' validated PLEXOS model, and based on the load factors of plant in our modelling. We assume that plant buying annual gas capacity would reflect this as a fixed cost in formulating their offers to the I-SEM capacity auction for Reliability Options. Plant buying daily gas capacity are assumed to seek to recover their variable gas capacity costs in the energy market.

Interconnection

The SEM PLEXOS model released by the RAs contains a simplified representation of the GB market. We have used this as a starting point for modelling the SEM and then added a full representation of the GB market including fuel prices and assumptions on the evolution of the GB plant mix. The model simultaneously optimises across both markets in a single step. This ensures that the operation of each market is consistent and that the flows through the two interconnectors represent the most economically efficient solution.

Capacity payment modelling

SEM capacity payment mechanism

The SEM design included a separate Capacity Payment Mechanism (CPM). This was a price-based mechanism, designed to incentivise a level of capacity surplus sufficient to meet the security standards in ROI and NI. It provided generators with an additional revenue stream related to their levels of availability. The costs of the capacity mechanism were recovered from end consumers. We have used actual historical data on capacity payment levels to calculate the end consumer costs of the CPM both with and without wind generation.

I-SEM capacity market

Under the new I-SEM, from 1 October 2018, the CPM has been replaced with a new capacity market. This allocates a limited volume of Reliability Option (RO) contracts by competitive auctions. Capacity providers which are successful in the auction are paid the auction clearing price which is an annual €/kW payment for the contracted capacity. The costs of the I-SEM capacity market are recovered from end consumers.

We have modelled the I-SEM capacity market using our in-house capacity auction model, using the following assumptions:

- A de-rated peak capacity margin of 4% is assumed for security of supply.
- All generators in principle can offer capacity into the market:
  - existing generators estimate their earnings from the energy and ancillary services markets and then compute the differential between this and their fixed costs required to remain operational, and
  - new-build generators similarly estimate their earnings from energy and ancillary services and compute the differential between this and the sum of their fixed costs plus their annualised cost of capital.
- The clearing price for each year is set at the level at which the required 4% de-rated peak capacity margin is achieved.
- New-build generators receive the clearing price over a period of 10 years, to ensure stability for those making capital investment decisions.

Appendix B List of Acronyms

SEMO	Single Electricity Market Operator
SEM	Single Electricity Market
OCGT	Open cycle gas turbine
CCGT	Combined Cycle Gas Turbine
CRM	Capacity Remuneration Mechanism
TWh	Terawatt hour
GW,MW	Gigawatt, Megawatt
DS3	Delivering a Secure Sustainable Electricity System
NREAP	National Renewable Energy Action Plan
CER / CRU	Commission for Energy Regulation / Commission for Regulation of Utilities
SRMC	Short-Run Marginal Costs
T&SC	Trading and Settlement Code
SMP	System Marginal Price