Offshore transmission for wind: comparing the economic benefits of different offshore network configurations

T. Houghton[*a], K.R.W. Bell[b], M Doquet[c]

[a] *Curtin University Graduate School of Business,*

78 Murray Street, Perth, WA6000, Australia

[b] *Department of Electronic & Electrical Engineering, University of Strathclyde*

Royal College Building, 204 George Street, Glasgow G1 1XW, United Kingdom

[c] *RTE, R & D Division, 9 rue de la porte de Buc, 78005 Versailles, France*

Abstract

It has been argued that increasing transmission network capacity is vital to ensuring the full utilisation of renewables in Europe. The significant wind generation capacity proposed for the North Sea combined with high penetrations of other intermittent renewables across Europe has raised interest in different approaches to connecting offshore wind that might increase also interconnectivity between regions in a cost effective way. These analyses to assess a number of putative North Sea networks confirm that greater interconnection capacity between regions increases the utilisation of offshore wind energy, reducing curtailed wind energy by up to 9TWh in 2030 based on 61GW of installed capacity, and facilitating a reduction in annual generation costs of more than €0.5bn. However, at 2013 fuel and carbon prices, such additional network capacity allows cheaper high carbon generation to displace more expensive lower carbon plant, increasing coal generation by as much as 24TWh and thereby increasing CO_2 emissions. The results are sensitive to the generation "merit

* Corresponding author at the Curtin University Graduate School of Business, 78 Murray Street, Perth, WA6000, Australia Tel: +61 (0)8 9266 3236 Fax: +61 (0)8 9266 3368 Email: thomas.houghton@curtin.edu.au

order" and a sufficiently high price would yield up to a 28% decrease in emissions depending on the network case. It is inferred that carbon pricing may impact not only generation investment but also the benefits associated with network development.

Highlights

- Alternative HVDC transmission network structures across the North Sea are compared
- A coordinated, multi-terminal grid is shown to be superior relative to radial connections in the 2030 scenario
- Increasing transmission capacity might lead to increased CO_2 emissions depending on the generation merit order
- Carbon price is potentially a powerful driver of benefits from network development
- The costs and benefits of a multi-terminal HVDC grid are likely to be highly sensitive to the future cost of DC circuit breakers

Keywords: renewable energy, carbon emissions, carbon pricing, electricity transmission, offshore wind energy, cost benefit analysis

1 Introduction

Driven by policies supporting the development of renewable electricity generation, it has been forecast that between 2013 and 2030 as much as 200GW of offshore wind generation will be installed in Northern Europe, while a further 200GW of onshore wind capacity is planned continent-wide (Moccia et al 2011). This is set against a backdrop of the planned closure of up to 55GW of nuclear plant (World Nuclear Association, 2013). If these changes occur, they will have profound implications for the European electricity transmission system as the centres of production shift and the characteristics of the generation fleet change. As a consequence, upgrades to grid capacity, whether offshore or onshore, have often been described as essential to facilitating renewable energy (European Parliament, 2012) and, hence, to reducing carbon emissions associated with production and use of electrical energy. Moreover, new transmission capacity, it is argued, would ensure security of supply and optimal use of generation assets across Europe. However, expanding transmission capacity is costly and environmental concerns mean that the number and routing of new transmission lines must take account of the need to maximise utilisation and minimise environmental impact. These principles hold both onshore and offshore, where the demand to install both more interconnection capacity between regions and to connect offshore wind farms to shore would see a proliferation of cables on the seabed and of cable landings at, often sensitive, coastal locations.

Until now, most offshore wind farms have been located close to shore and each has been connected directly to a substation within the onshore grid via high voltage alternating current (HVAC) transmission cables. As generation assets are shifted farther offshore, high voltage direct current (HVDC) connections, which become more economically attractive over longer distances (Crown Estate, 2008), are expected to displace HVAC technology. The intermittency of wind generation means that the capacity of these radial transmission cables for connection of generation is not fully utilised 100% of the time and, given the growing interest in new interconnection capacity between regions of Europe (Fichaux and Wilkes, 2009), attention is being devoted to exploring whether interconnections and connections of offshore wind farms can be combined. This principle is illustrated in Figure 1 which shows the radial approach, the addition of interconnectors and the combined (multi-terminal) topology.

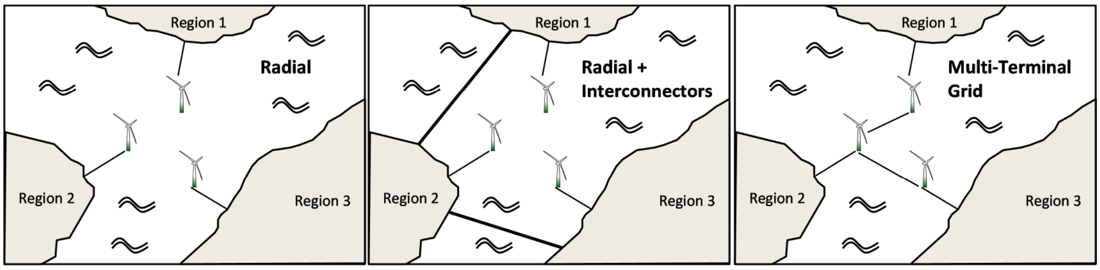

Figure 1 Stylised offshore network configurations

It is postulated that a coordinated development of offshore network capacity might increase the utilisation of offshore network branches, improving the viability of offshore transmission investments, and, by virtue of providing multiple paths to shore, facilitate more reliable market access for the offshore generation and mitigate wind curtailment (Fichaux and Wilkes, 2009; North Seas Countries Grid Initiative, 2010; De Decker and Kreutzkamp, 2011; Irish and Scottish Links on Energy, 2012). The concept is embodied in the European Coordinator's Second Report in which G.W. Adamowitsch (2009) is quoted as saying, "...an integrated European approach [to networks] is needed for releasing the full offshore potential."

While the logic of the argument is clear, the benefits of a coordinated approach to the electricity system in Europe as a whole have not yet been fully explored, and this provides the main context for the analysis described in the current paper. The work, carried out under the auspices of the TWENTIES project (Twenties Project, 2013), seeks to compare different network structures according to a number of performance metrics including CO_2 emissions, fossil fuel generation and available energy not utilised or curtailed energy. The comparison enables incremental operational and investment costs to be examined.

The model applies the principles of least cost generation dispatch, meaning the results are sensitive to the so-called "merit order" and in consequence the robustness of the results is examined with different generation 'stacks'. Changes to the merit order could result from multiple exogenous market factors but given its central role in policy-making, carbon price is taken as the instrument by which the cost of fossil fuelled generation is varied in this analysis.

Section 2 of this paper describes the model, approach and network configurations together with other input data. In Section 3, the results of the analysis are discussed and the implications explored. Finally in Section 4, a number of conclusions are drawn and suggested areas for future work advanced.

2 Approach and Methodology

2.1 TWENTIES modelling approach and the use of ANTARES

The TWENTIES project was established in 2010 by 26 partner organisations from 11 European countries to answer fundamental questions regarding the European transmission network. The purpose of the work described here was largely to address the question, "What should the transmission system operators (TSOs) implement to allow for offshore wind development?", and to identify the economic drivers for the coordinated development of interconnected offshore HVDC networks in the 2030 time horizon. The studies were designed to compare coordinated and non-coordinated network designs according to a number of key operational performance measures and provide a cost benefit analysis of a coordinated approach.

As observed in Section 1, it is widely expected that greater transmission interconnection capacity would offer operational cost reductions through the more effective use of low marginal cost / low carbon generation, such as wind power. Moreover, it is expected that a co-ordinated design for the offshore grid would reduce the total investment cost associated with linking wind farms to shore and interconnecting regions. The work described in this paper aimed to test these hypotheses through a high-level analysis of the impact on the European power system of proposed North Sea grid structures linking hubs that aggregate wind farms in development areas. This higher level perspective is in contrast to other studies (Fichaux and Wilkes, 2009; North Seas Countries Grid Initiative, 2010; De Decker and Kreutzkamp, 2011) which have tended to focus on coordinated grid development at the wind farm level. The key features of the simulator, ANTARES (Antares, 2015), are described in Section 2.5. It allows the explicit modelling of hourly time series over multiple years describing numerous possible futures through *sequential* Monte Carlo simulation. This permits realistic patterns of flows to be generated and examined and the links that are most highly constrained to be identified, vital to gaining a full understanding of the constraints inherent in the different proposed structures. The following are unique features of ANTARES:

- the ability to model available generation stochastically taking into account forced or planned thermal outages (without optimization of the maintenance scheduling) and variations in wind speed, solar power and water inflow;

- respect of realistic, physical inter-temporal constraints arising from minimum generation levels as well as, minimum on and off times the respect in inter-area power transfer limits; and
- the dispatch of generation in the most economic way to meet demand (subject to the maintenance of adequate reserve) making effective use of hydro power.

2.2 Definition of network structures

2.2.1 Guiding principles

A four-step approach was applied to developing the network configurations and subsequent analysis.

1. Develop a simplified model of the European power system with a single node per country[1], with network branches between nodes representing actual or proposed power flow paths, allowing different cases to be straightforwardly set up with different sets of net transfer capacities (NTCs) on branches. The entire European network[2] was included, allowing the relationships between countries immediately surrounding the northern European offshore regions and those "deeper" into Europe to be represented (see Figure 2);
2. Establish a plausible set of generating assets associated with each node (both onshore and offshore) together with an annual load profile describing both the level of demand and the diurnal, weekly and seasonal variations;
3. Define a set of offshore "nodes" in areas where it has been proposed future wind farms will be built;

[1] Note that Denmark is modelled as two nodes since it sits across two synchronous areas while GB is also divided in two reflecting the significant publicly acknowledged constraint across the border between Scotland and England.
[2] All the EU 27 countries plus Norway, Switzerland, Albania, Bosnia, Macedonia and Serbia

4. Postulate possible offshore network configurations that are adequate for the proposed offshore wind generation and replicate the generic set of topologies in Figure 1.

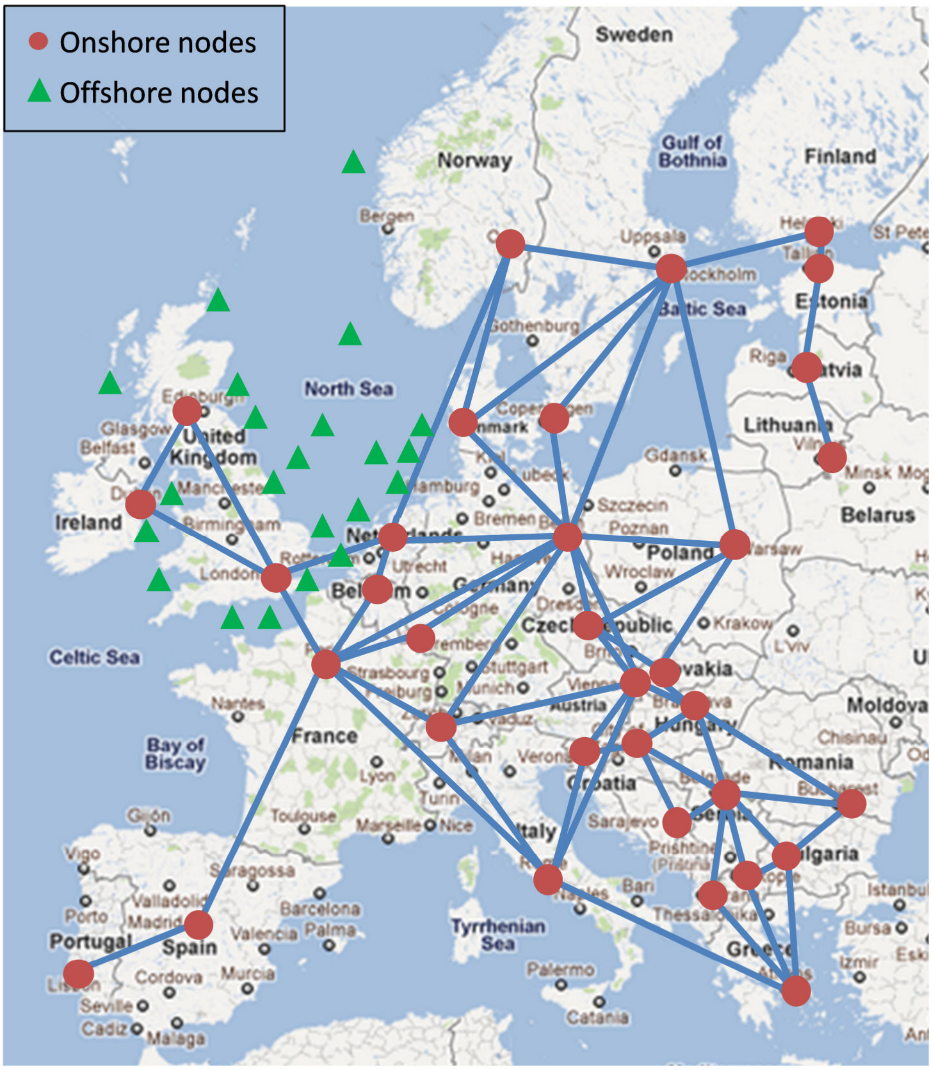

Figure 2 Onshore network representation and offshore development locations

2.2.2 Detailed design considerations

The primary objective of the study was to examine the performance and relative costs and benefits of a “dual-use”, multi-terminal, interconnected offshore network (roughly shaped as an “H” and thus referred to as the H-grid) when compared with network arrangements that bring offshore wind directly to shore in a radial pattern (Radial). An additional scheme where point-to-point interconnector capacity between regions is added to the Radial configuration was also considered (Radial +

IC), drawing on published plans regarding investment in transmission capacity between the three broad regions, Continental Europe, Scandinavia and the British Isles (Figure 3). Since, in the Radial case, cables are dimensioned according to the wind farm hub capacity and may be relatively under-utilised given the intermittent nature of wind generation, the coordinated approach combines both the radial connections and the interconnector pathways into a single network with the capacities of new offshore branches being established through an iterative process (Figure 4).

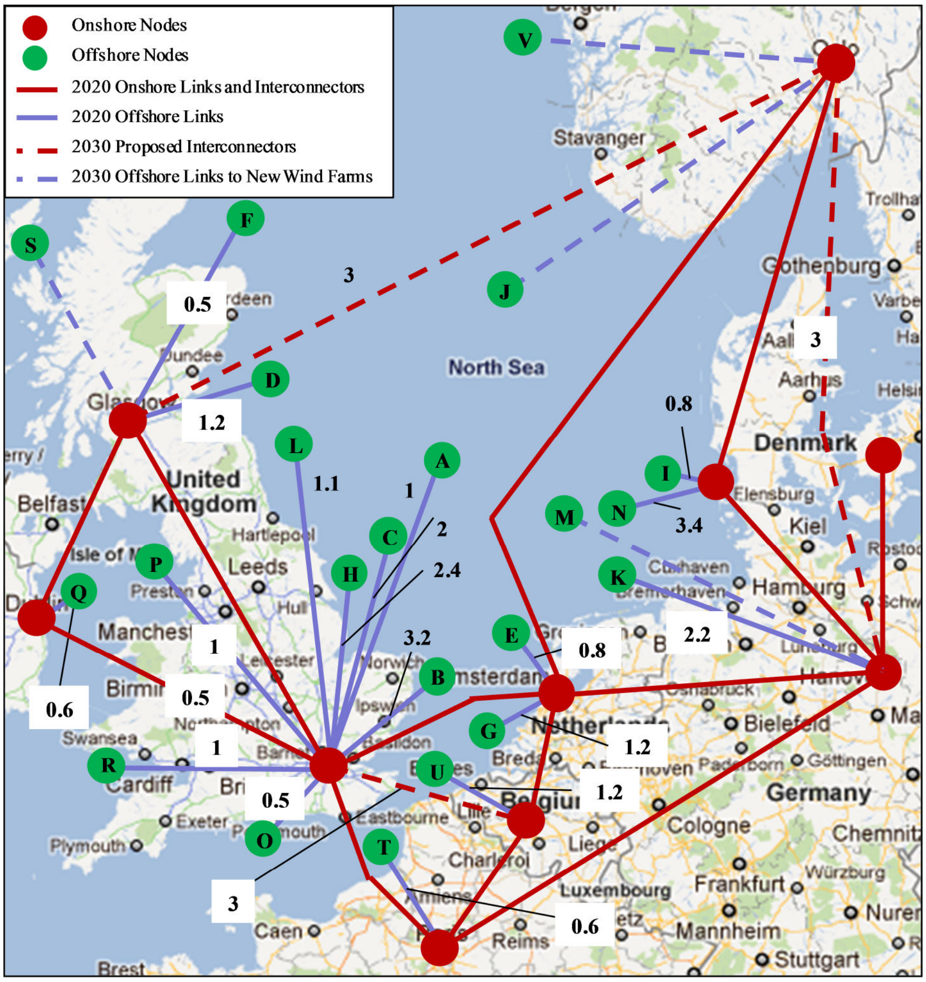

Figure 3 Radial offshore network configuration

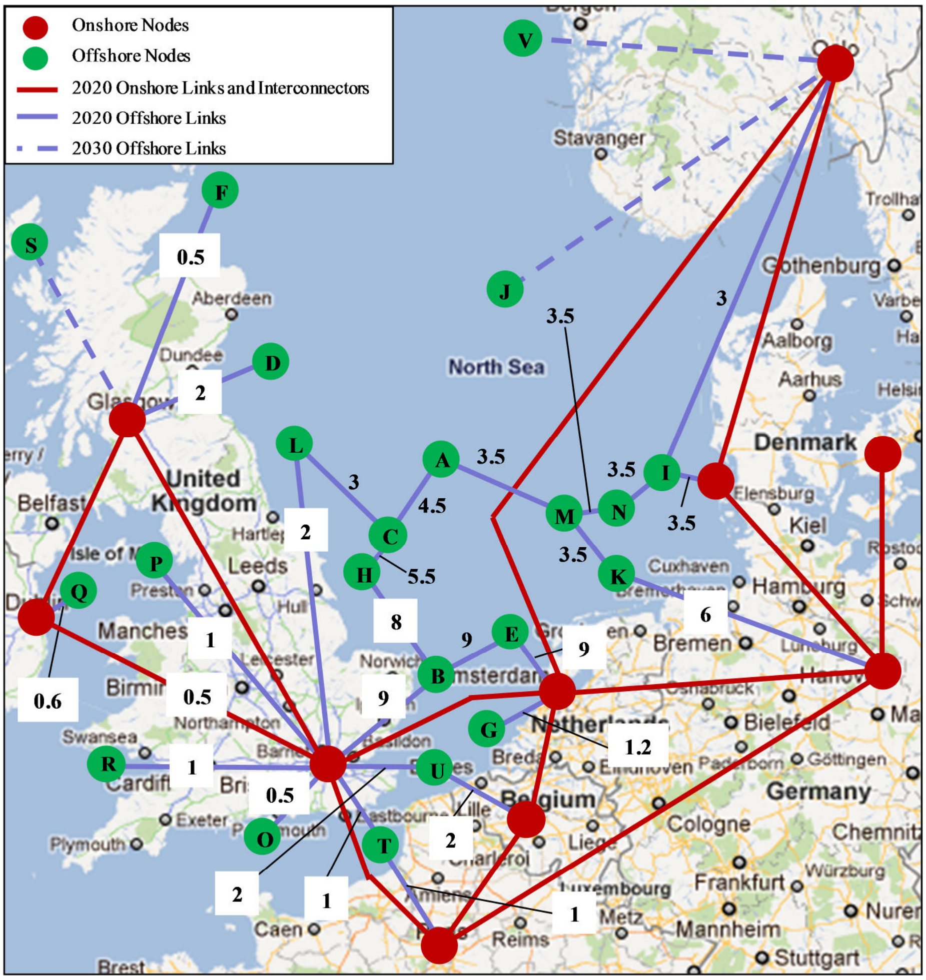

Figure 4 Multi-terminal offshore 'H-grid' configuration

In order that the carbon and fuel costs savings associated with new offshore wind can be appreciated, a reference case was developed in which no new offshore wind or offshore transmission assets are constructed, (No Wind case).

The capacities of the onshore network connections are defined according to the ENTSO-E[3] Net Transfer Capacities (NTC) values (ENTSO-E, 2010). Additional inter-regional connections are envisaged from GB North to Norway, GB South to Belgium and Germany to Norway, each of a putative 3GW, selected to reflect the capacity of current source (or line commutated) converter (CSC) based links currently being developed (e.g. the Western HVDC link in Great Britain which has

[3] European Network of Transmission System Operators of Electricity

cables rated at 600kV[4]) and expected further developments of the capacities of cables used with CSC or of voltage source converters (VSC) and associated cables which to date offer link capacities of 1.4GW[5] with two links readily operable in parallel . The offshore wind farms are connected directly back to their country of origin or, in some cases, the nearest shore. The purpose of the study was not to optimise the H-grid – a complex task that would require consideration of a multitude of factors including cable routing and consents risks associated with shore locations and any reinforcements required within the onshore systems for different connection options – either in terms of configuration or capacities but to offer a credible rule-based design. The design objective was to ensure all the offshore wind farms within the grid connect to at least two shores and at the same time replicate the additional point-to-point routes between regions envisaged in the Radial + IC configuration. The initial capacities in the H-grid are postulated in order to allow sufficient capacity to bring all the wind to shore plus an additional allowance on each branch to enable some exchange between regions even when wind farms are operating at 100% output. The network capacities were then refined through a simple heuristic. An optimal design should strike a balance between the cost of additional network capacity and the value of the additional power transfers that are facilitated. In consequence, wind power might, from time to time, be restricted for power system operational reasons, e.g. the scheduling of reserve.

2.2.3 Transmission system protection and control

It is assumed that long, cable-based transmission networks will be built using HVDC technology and it is further assumed that a multi-terminal HVDC network will be both operationally feasible and afford cost savings relative to an offshore network

[4] Details of the link can be found at http://www.westernhvdclink.co.uk/
[5] See, for example, http://nsninterconnector.com/about/what-is-nsn-link/

comprised of two-terminal HVDC links built around AC offshore hubs (Bell et al, 2010; Bell et al, 2014). Different network structures may have different control and protection requirements and this issue has largely been ignored to date in the literature to assess the benefits of DC grids. The widespread expectation among TSOs that HVDC grids should make use of DC circuit breakers (DCCB) to isolate short circuit faults (Tang and Boon-Tek, 2002) relies on the notion that if DCCB are not used, faults on the DC side may result in the loss from service of the entire DC grid. The operational implications of this are significant, since the loss of many gigawatts of wind energy through a single contingency would breach the generally accepted principles for reserve requirements. By contrast, in radial designs the loss through a fault on the DC side would be limited to a single wind farm cluster, a more manageable event from a TSO perspective. It is worth noting that other work-arounds may be feasible and these are discussed elsewhere in, for example, (Irish and Scottish Links on Energy, 2012; Bell et al, 2014) but transmission system operators may favour the deployment of a DCCB at least at the ends of branches that are not directly connected to converters. At the time of writing, no high voltage DCCBs are available commercially and current cost estimates are very high compared to HVAC protection and the sensitivity of the results to the cost of DC breakers has been tested.

2.2.4 Offshore network investment costs

Table 1 provides the average capital costs for each network element based on the cost ranges provided by ENTSO-E (Offshore Transmission Technology Report, 2011), with the exception of the DCCB where the “current” cost is estimated based on the cost of an analogous technology, i.e. a modified converter station.

Table 1 Assumed capital costs for network elements (number units in 2030)

System Element	Average Cost (€m)	Number in Radial	Number in Radial+IC	Number in H-grid
VSC Converters		82	82	88
800MW	85			
1250MW	135			
2000MW	170			
3000MW CSC Converter	213	0	6	0
Offshore platform	70	73	73	73
HVDC 1000MW 500kV Cable per km	0.72	7,677	11,383	15,598
Implied total cable cost (€m)		5,527	8,195	11,231
DC 1000MW Circuit Breaker		0	0	30
Base	40			
Optimistic target	3			
Realistic target	15			

Three possible cost scenarios for the DCCB are considered as follows:

- Base Cost: 25 – 30% of the average cost of a VSC converter of equivalent rating;
- Realistic Target: 10% of the average cost of a VSC converter consistent with costs presented in Jovcic et al (2011); and
- Optimistic Target: reflecting the current costs of AC CB and assuming a technological breakthrough.

All radial connections from new, distant offshore wind farms or connections within the H-grid are assumed to be based on VSC technology offering a high degree of flexibility in terms of power flow control (VSC Transmission Tutorial, 2011). The point-to-point connections in the Radial+IC configuration are assumed to be built around the more established and less costly CSC technology, reflecting the presence of strong systems at each end. The capital costs of the offshore portions of the network configurations vary according to the length and capacity of the network branches, the number of onshore and offshore converter stations and the number of DCCB in the system.

2.3 Generation and demand input parameters

ANTARES applies a sequential Monte Carlo approach in order to cope adequately with uncertainties relating to wind forecast errors, planned and unplanned outages of thermal plant, the use of hydro generation to smooth out price variability consequential to interactions between the level of demand and availability of power from sources with very low marginal costs, such as wind.

The characteristics of demand variation by country are established based on data from ENTSO-E (2013) and future time series generated based on an assumption of demand growth (REALISEGRID, 2013). The relationships between the demand and weather time series, which depend, among other things, on the nature of heating and cooling demand in a particular country and the season, are not modelled explicitly although the inter-temporal and spatial relationships are captured in the historic data used to generate the Monte Carlo time series.

The installed generation capacities and demands by region and by target year are shown in Table 2, based on data from industry sources (Zervos and Kjaer 2008; Power Statistics, 2010; Global Market Outlook for Photovoltaics 2013-2017, 2010). There is a category of generation, such as energy from waste and some combined heat and power plant, which is non-dispatchable and since much of this to date has been “invisible” to the TSO it is treated non-stochastically in the model.

Table 2 Installed capacity by generation type in 2030

All in GW unless otherwise stated	Continental Europe	British Isles	Scandinavia	**Total**
Coal	101.2	29.8	9.6	140.6
Lignite	52.5	0.3	1.2	54.0
Gas (CCGT and OCGT)	119.0	30.9	44.8	194.7
Other Dispatchable fossil fuelled	86.3	7.9	11.4	105.6
Nuclear	72.1	1.2	3.9	77.2
Other Non-dispatchable Generation	19.8	2.2	8.0	30.0
Hydro	98.0	1.7	60.4	160.1
Pumped storage	39.9	3.1	9.1	52.1
Onshore wind	166.0	18.0	9.3	193.3
Offshore wind	20.1	39.5	1.7	61.3
Solar	160.2	5.4	0.0	165.6
All generation	935.1	140.0	119.4	1234.5
Peak demand	*489.1*	*76.1*	*95.7*	
Annual consumption (TWh) incl. Pumping load	*3,020.7*	*430.4*	*535.9*	*3,987.0*

Note: The load is defined according to (ENTSO-E, 2013) on a country by country basis.

Fossil fuel generation is assumed to remain at the same level across each generation type as in 2011 implying that plant closed in the period to 2030 is replaced with like-for-like plant. Nuclear plant closures were established according to information available at World Nuclear Association (2013) while plant openings include only those plants currently under construction.

Table 3 presents total generation costs per MWh of electrical output for different levels of CO_2 price with the base case level being derived from the REALISEGRID (2013) reports. These are based on data for generation costs excluding any CO_2 price from the Digest of UK Energy Statistics (2010) and reflect one particular estimate of the current short-run marginal costs of generation which are used as the basis for dispatching, as discussed by Greenblatt et al (2007). In light of the fact that considerable uncertainty attaches to these costs, no attempt has been made to predict future energy prices for the cost-benefit analysis.

Table 3 Generation costs as a function of carbon price

Prices in € / MWh	Carbon Emissions t / MWh	Cost excl. CO_2	Cost incl. CO_2 at €10 / t	Cost incl. CO_2 at €20 / t	Cost incl. CO_2 at €60 / t	Cost incl. CO_2 at €85 / t
Nuclear	0.0	7.0	7.0	7.0	7.0	7.0
Lignite	1.1	15.0	26.5	38.0	83.9	112.7
Coal / Coal CHP	0.9	27.0	36.2	45.3	81.9	104.8
Gas CCGT / CHP	0.4	40.0	44.1	48.1	64.3	74.4
Gas OCGT	0.6	61.5	67.7	73.8	98.4	113.8
Oil / Oil CHP	0.6	121.0	127.3	133.6	158.8	174.6

The short run marginal cost of coal generation begins to exceed the cost of gas at a CO_2 price of around €26 / t while lignite remains cheaper than coal until the price of carbon reaches €52 / t, the point at which a complete reversal of the merit order occurs. In order for the pumped storage plant (PSP) to be used to its fullest extent, a sufficient differential (given by the inverse of the assumed efficiency) must exist between the peak- and the off-peak- locational marginal prices calculated at the PSP sites. This occurs at a carbon price of €83 / t leading to the application of a €85 / t CO_2 price for the reverse merit order case.

2.4 Other considerations

The study was not designed to consider the full investment costs associated with offshore wind development and only the comparative network investment and generation operational costs are taken into account. That is, capital and operating costs regarding the wind generating fleet are not assessed. The discount rate applied to arrive at the levelised costs was 10% and the lifetime 20 years. The values reflect the expected lifetime of offshore wind farms and the relative riskiness of offshore network investments.

In addition to the short-run marginal costs of generation, there are less tangible contributions to the cost of generation. The first is attached to the curtailed energy that cannot be used by consumers, either because they do not need it or because there is a grid congestion that prevents this energy from reaching them. The second component is related to the value brought by the grid to the whole power system when it acts as a partial substitute for generation investments. Simulations provide useful figures for both aspects through the expectation of residual unsupplied energy volumes. To be incorporated in the cost-benefits analysis, these quantities need to be given reference values, the choice of which is often controversial. In the framework of this study, it will be further shown that a parametric approach allows conclusions to be drawn that remain robust for a very wide range of assumptions.

2.5 The ANTARES tool

The study reported here has used the ANTARES analysis tool (Doquet et al, 2008; Doquet et al 2011) developed by the French system operator, RTE[6], which has also been used in production of the European 'Ten Year Network Development Plan' (TYNDP) on behalf of ENTSO-E (Ten Year Network Development Plan, 2012). ANTARES is a sequential Monte-Carlo based simulation tool designed to model the dispatch of thermal, hydro and intermittent generation with hourly time resolution, taking into account transmission constraints and demand variations. Generation and demand are described stochastically, reflecting both the auto correlation and spatial correlation functions associated with each variable and these are used to develop a least cost dispatch of generation (both hydro and thermal) for each hour of the year. The simulator was initially developed to assess generation adequacy but has subsequently been modified to address the economic effects of different system developments.

[6] Réseau de Transport d'Électricité

ANTARES makes use of detailed hourly wind speed, demand and key generator parameters such as capacity, forced outage rates and operating cost. However, in order that credible hourly time series of dispatches can be produced, it also makes use of generator minimum on and off times as well as principal hydro characteristics such as typical monthly water inflows within a unit commitment process based on heuristics and defined operating reserve requirements that broadly represent how generation would actually be dispatched. Reserve requirements are defined at the level of an "ANTARES macro-node", the size of which may vary from a single substation to a whole region (in this case, a single country or offshore wind generation area).

A particular feature of the ANTARES model is that it incorporates built-in generators of time-series of various kinds, including wind speeds and / or wind power, defined by suitable sets of parameters. The common principle of the modules dedicated to these variable power time-series is that the values they generate are hourly samples of twelve stationary stochastic processes (one for each month) characterized by:

- A marginal law (e.g., a Weibull law in the case of wind speed, defined by two parameters, shape k and scale λ);
- An autocorrelation parameter θ , modelling the relationship between distant values in time as an exponential decay; and
- An overall spatial correlation matrix between the stationary processes.

The method used to generate values meeting the first two commitments is based on the use of stochastic differential equations that define the processes mentioned above as diffusion processes embedding ad hoc parameters (Bibby, Skovgaard and Sorensen, 2005). For modelling the total wind power output at the scale of a whole country, it was proposed by Doquet (2007) to use, for the marginal law of the process, Beta distributions characterized by parameters α, β.

The equation relevant for an X_t diffusion process auto-correlated through an exponential decay of parameter θ and having for marginal law a Beta distribution $(\alpha, \beta\ )$ is as follows; in this expression, B_t denotes a standard Brownian motion:

$$\boldsymbol{dX_t = \theta\left(\frac{\alpha}{\alpha+\beta} - X_t\right)dt + \left(\frac{2\,\theta\,X_t\,(1-X_t)}{\alpha+\beta}\right)^{1/2} dB_t}$$

For modelling wind speeds following Weibull distributions of shape k and scale λ , the following formulas are used, in which Γ and $\Gamma(\ ;\ )$ denote respectively the standard and (upper) incomplete Euler's Gamma functions:

$$\boldsymbol{Speed = \lambda\,X_t \quad ; \quad \mu = \Gamma\left(1 + \frac{1}{k}\right)}$$

$$\boldsymbol{dX_t = \theta\,(\mu - X_t)dt + \left[\frac{2\,\theta}{k}\,X_t^{\,(1-k)}\,e^{(Xt^k)}\left[\mu\left(1 - e^{(-Xt^k)}\right) - \Gamma\left(Xt^k\,;(1+\frac{1}{k})\right)\right]\right]^{1/2} dB_t}$$

In modelling flows of power across a network, it is essential to respect correlations between generators at different locations. In the course of the practical generation of values through a Euler discretization, the spatial correlations, are taken into account by enforcing, for each hour, a particular correlation matrix applied to the Brownian motions attached to each diffusion process. These hourly matrices are chosen so as to make the final values of the sampled processes fit best the target correlation matrix.

- Since physical processes such as wind speeds are known not to be actually stationary (it is unlikely that, in a given location, the statistical distribution of speeds at 3 PM is exactly the same as at 3 AM), the modelling for time-series includes also, for each month, an average daily modulation curve (24 values). These factors are used to modulate the stationary values generated beforehand and thereby make them more realistic.

- At this stage, the generated values may or may not (depending on their nature) need to be processed through a final “wind-to-power” conversion module. In the case of wind speeds, this is where curves that cut-off low and high speeds come into play; due to smoothing effects depending on the size of the fleets pulled together in the same simulation node, this adjustable curve can be very different from a typical single-machine power conversion curve (Tradewind, 2009). An example of the power curve applied to the offshore wind farms is shown in Figure 5.

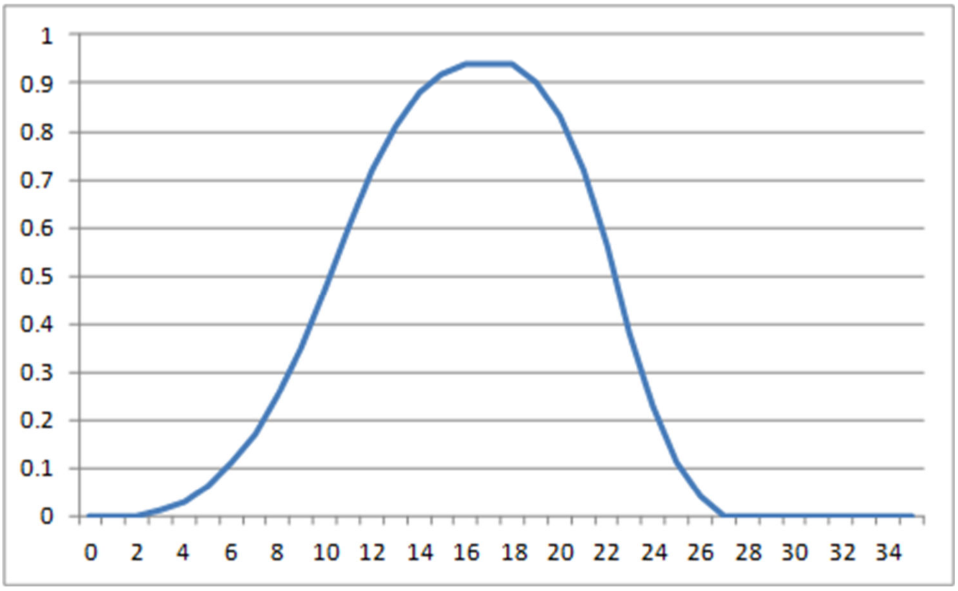

Figure 5 Characteristic lowland wind farm power curve

In the framework of this study, different sources were used for the parameters listed above regarding wind speeds and wind power levels.

For off-shore wind sites, where relatively little generation exists as yet, raw wind speeds were modelled and subsequently converted into power. In each location, the parameters of the Weibull processes came from analysis of the relevant outputs (100m-high) of a meteorological simulation model from Meteo France. The analysis of these data indicated that the shape parameters of the Weibull distributions to use, depending on their geographical location and on the month of the year, should lie in the range 1.9 to 2.5 with an average value of 2.2. Summer months favoured lower coefficients, whereas in winter steadier speeds (higher coefficients) were found. These figures, while slightly lower, are consistent with the findings of Archer and Jacobson (2003). Likewise, significant seasonal and geographical variations were observed for scale parameters, with a range of 7.5 to 14 and an average of 11.

As expected, spatial correlation decreased with distance: For instance, for two sites both located at 55° North but separated by 5° in Eastern longitude a 60 % correlation was identified, while 13° farther Eastward in the Baltic Sea, the correlation dropped to 20 %.

Regarding on-shore nodes, their very large size and the fact that significant generation fleets already exist made it admissible to model wind power directly and not wind speeds. As a consequence, Beta-type stochastic processes were used; their parameters came from analysis of publicly available wind power historical time-series for the different countries.

Finally, the spatial correlation matrix incorporated three kinds of terms:

- Off-shore-to-off-shore terms which were given by the correlations between the original wind speed time-series used to identify the Weibull process parameters;

- On-shore-to-on-shore terms which were given by the correlations between the historical wind power time-series used to identify the Beta process parameters; and
- Off-shore-to-on-shore terms which were given by the correlations between off-shore wind speed time-series and on-shore wind speed time-series available for some locations.

It may be noted that, aside from this operating mode based on the most prominent statistical parameters characterizing the time-series to emulate, the ANTARES model is also able to use directly sets of ready-made time-series deemed to fit all theoretically desirable properties, provided that such databases are available. Beyond first-order statistical properties, the best solution of all would be to have access to time-series that fully reproduce all of the higher details of correlations through space and time). Such a database including all desired types of time-series across all Europe was not available at the time of the study and as a consequence, the ANTARES built-in time-series generators were used.

In the economic dispatch of available generation, fossil fuel plants are selected according to the "merit order", with plant being scheduled on a least marginal cost basis subject to operational constraints such as a local plant's dynamic constraints as well as wide-area grid constraints. The market is assumed to be "perfect" from every standpoint, which allows the problem to be formulated in classical terms. The economic problem can therefore be set out for each Monte-Carlo year of the sample as minimizing the overall generation cost throughout the year, while respecting:

(a) Minimum and maximum power output of every available plant;

(b) Minimum and maximum on and off duration of thermal plants;

(c) Monthly totals of available hydro energy;

(d) Maximum interconnection capacities between areas; and

(e) Binding constraints relating to interconnection capacities

From a practical standpoint, the simulator does not try to address the problem of the annual optimization of the operation of the whole system as a single but very large problem. More realistically and efficiently, once hydro credits have been broken down from the yearly scale to the monthly scale, and then from the monthly scale to the weekly scale, the rationale is to analyze one “Monte-Carlo year” from the beginning to its end by a succession of weekly independent optimization problems: as a result the large annual problem is converted into a set of 52 smaller ones.

Pumped storage power plants, and other kinds of special devices, can be modelled by introducing into the system various virtual elements (dummy collecting nodes, dummy outlet nodes, etc.) connected to the actual system for which power exchanges are restricted by “binding constraints” that permit the efficiency rate of the facility to be represented. As a result, the economic behaviour of the PSP can be modelled as realistically as possible, its operation being dependent on the price variations between peak- and off-peak hours.

Reflecting all these uncertainties and interactions requires the simulation of a large number of years of operation in a sequential Monte-Carlo approach, typically thousands of them if a loss of load probability is to be estimated with any degree of confidence, although the type of economic analysis made here can be conducted with fewer trials (up to a few hundred). Even so, this is computationally intensive even for the relatively simplified network presented here. With roughly 1200 different power stations or wind farms and 56 zones or putative offshore hub locations represented as single nodes with interconnections between them based on NTCs, a sequential simulation of each hour of operation in hundreds of different years requires significant computation time on a typical office PC and yields a huge amount of information requiring analysis.

3 Results and Discussion

Simulations were carried out for all the principal network configurations in 2020 and 2030, with only the latter presented here for the sake of clarity. Output parameters were compared, sensitivity to merit order examined and cost benefit analyses carried out.

3.1 Comparison of output metrics

For each of the network configurations, the primary output metrics considered were: annual CO_2 emissions (mt); the annual energy production from different types of thermal and renewable generation (TWh); available but unused zero marginal cost energy or curtailed energy, i.e. available energy that, based on relative marginal prices in a given period, would normally be used but, for technical reasons, cannot be (TWh); and unsupplied energy, i.e. demand for energy by consumers that could not be served (TWh).

Summary results for the 2030 are presented in Table 4 for the network cases described in Section 2.2 and for a carbon price of €21 / t; the values are the expected values across all Monte Carlo simulation years. The absolute values for the No Wind case are shown in column 1 of Table 4, providing a benchmark case in which no offshore wind generation or associated grid is developed, while columns 2 to 4 show the *changes* in each of the measures relative to the No Wind case. It can be seen in column 4, for example, that generation from nuclear, fossil fuels, hydro and renewables increases by 5.7TWh, exactly balancing the change in net PSP load (down 0.7TWh) and unsupplied energy (down by 6.4TWh).

Table 4 Comparative 2030 results for carbon price of €21 / t (base case merit order)

All TWh except CO_2 in millions of tonnes	Absolute No Wind	Relative to No Wind Case Radial	Radial+IC	H-grid
Load	3987.1	0.0	0.0	0.0
Unsupplied energy	9.7	-4.3	-6.1	-6.4
Net pumped storage load	-13.5	0.4	-0.7	-0.7
Effective net load	3990.9	4.7	5.4	5.7
Coal	894.3	-56.8	-35.3	-33.1
Lignite	336.8	-2.0	-0.3	0.1
Gas	704.2	-106.9	-130.8	-141.0
Other dispatchable fossil fuelled generation	27.2	-4.7	-5.7	-6.2
Nuclear	556.7	-1.0	0.4	0.7
Other non-dispatchable generation	233.5	233.5	233.5	233.5
Hydro	654.5	0.0	0.0	0.0
Wind	341.6	176.1	177.1	185.2
Solar	242.0	242.0	242.0	242.0
Total renewable generation (hydro, wind, solar)	1238.1	176.1	177.1	185.2
Total generation	3990.9	4.7	5.4	5.7
Net curtailed energy	10.2	13.8	12.8	4.7
CO_2 emissions	1506.8	-101.0	-89.8	-91.9

The new offshore wind capacity has the effect of increasing total wind generation from 342TWh (if no new offshore wind is present) to 518TWh in the Radial case, leading to a CO_2 emissions saving of 101mt. Wind production now exceeds both nuclear and lignite, contributing 13%, while hydro provides 16% of production and solar 6%. Curtailed energy reaches 24TWh and while this cannot all be identified as curtailed wind energy, it may be assumed that a large part of it is wind, at least overnight and during winter. At noon and in summer, a significant share of the spillage could have to be imposed on solar producers. Note that, since a large part of the generating fleet is still made up of thermal plants, spilled renewable energy can, in some instances, be interpreted as green energy making way for thermal power that cannot easily be scheduled off because of minimum power stability constraints.

The fact the H-grid reduces spilled energy by a large amount can be interpreted as a side-effect of its being able to foster exchanges between the main interconnected areas more efficiently than the other structures. This curtailed energy represents 1% of total wind production while unsupplied energy, at 5TWh, is ~0.1% of total demand.

Column 3 shows the effect of adding 3GW of additional point-to-point capacity, giving rise to an increase in usable wind production of 1TWh, while in the H-grid case (column 4) the increase in wind production is significantly greater at 9TWh. The net effect of adding offshore wind is to reduce CO_2 emissions intensity by between 0.38mt / TWh and 0.35mt / TWh according to the network case. This supports the case for a coordinated grid although it should be noted that it is difficult to fully assess the equivalence of the configurations from a capacity perspective. While the extra interconnection capacity in the Radial + IC and H-grid cases does facilitate an increase in the utilisation of low carbon generation, with the generation merit order assumed to be as it is in 2013, the simulations also show an *increase* in CO_2 emissions in these cases relative to the Radial case amounting to around 11mt. This non-intuitive result stems from the increased utilisation of cheaper coal and lignite in place of more expensive, but lower carbon, gas.

3.2 Effects of merit order reversal

It might plausibly be argued that the increasing carbon emissions evident when more interconnection capacity is added can be obviated by a change in the merit order of fossil fuelled generation. In the absence of market driven changes to the prices of gas, coal and lignite, this could be effected through an appropriate CO_2 price. The reverse merit order results are shown in Table 5 in terms of differences from the results for the “forward” merit order case.

Table 5 Summary 2030 results for carbon price of €85 / t (reverse merit order): change relative to base case

All TWh except CO_2 in millions of tonnes	No Wind	Radial	Radial + IC3	H-grid
Lignite	-265.7	-271.4	-277.0	-278.5
Coal	-278.8	-321.2	-355.5	-362.8
Gas	539.7	587.7	627.8	637.3
Other dispatchable fossil fuelled generation	0.0	0.0	0.0	0.0
Nuclear	0.3	0.1	0.1	0.2
Other non-dispatchable generation	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0
Wind	0.3	1.2	1.1	0.4
Solar	0.0	0.0	0.0	0.0
Total renewable generation (hydro, wind, solar	0.3	1.2	1.1	0.4
Net pumped storage production	4.2	3.6	3.5	3.4
Unsupplied energy	0.0	0.0	0.0	0.0
Net curtailed energy	-0.3	-1.2	-1.1	-0.4
CO_2 emissions	-336.6	-363.2	-385.2	-390.0

The effect of the change in carbon price is dramatic, with coal and lignite production down by 321TWh and 271TWh respectively and gas production up by 588TWh to compensate. The consequence of this is to significantly reduce carbon emissions, relative to the €21/t case, with the reduction ranging from 363mt in the Radial case to 390mt in the H-grid case. The relative shift increases as the configuration moves from Radial to Radial+IC to H-grid; for example, coal is down by 321TWh in the Radial case, 356TWh in the Radial+IC case and 363TWh in the H-grid case. The emissions intensity decreases to 0.26mt / TWh in the H-Grid case, indicative of relatively greater access to lower carbon generation that appropriately configured interconnection capacity affords.

3.3 Cost-Benefit Analysis

In order to examine the economic benefits of one network structure relative to another, the levelised annual cost of each network configuration is compared and in turn compared with annual operating costs of generation. This does not constitute an investment appraisal of the H-grid itself that should take account of the remuneration that would be available to the transmission network developer but rather examines whether the additional costs (if any) that are incurred are justified by a reduction in the cost of generation and volumes of CO_2. The results are shown in Table 6.

Table 6 Estimated annualised costs and benefits in 2030 for €21 / t carbon price

€m	Relative to Radial Case		
	Radial + IC	**H-grid (Low)**	**H-grid (High)**
Capital Cost Difference	463	773	2401
Operational Cost Difference	-223	-668	-668
Net Benefit	-240	-105	-1,733

The first row of Table 6 shows the comparison of the resulting levelised annual cost of each of the interconnected configurations against the cost of the Radial case. The relative increase in capital cost of the Radial + IC case is €463m while the H-grid is heavily dependent on the approach taken to system protection; in the H-Grid (Low) case, where no DCCBs are included, the network would show annualised capital costs relative to Radial of €773m, whereas in the H-Grid (High) case, annual costs of €2,401m are imputed. Table 7 show the sensitivity of the comparison to the capital cost of the DC breakers.

Table 7 Sensitivity of H-Grid benefit to DC breaker cost at €21 / t carbon price

€m	Realistic Case (€15m)	Optimistic case (€3m)
Capital Cost Difference Incl. DC Breakers	1,661	1,306
Net Benefit Incl. DC Breakers	-993	-638

The operational cost difference shown in Table 6 includes only actual expenses (fuel costs, O&M costs, etc.) and does not include the other components (or externalities) mentioned in 2.4, i.e. curtailment cost or unsupplied energy value. Each of the configurations with extra offshore wind capacity brings operational cost savings with respect to the Radial case, as would be anticipated, ranging from €223m per annum for Radial + IC case to €668m for the H-Grid.

Although none of the configurations with additional inter-regional capacity shows a net benefit over the Radial case when no cost is imputed against curtailed energy, given policy makers' ambitions for utilisation of renewable energy and the priority system access typically granted to them, an opportunity cost associated with curtailment of renewables might also be quantified, a view supported by De Jonghe et al (2011) and Xu and Zhuan (2013). If costed at the level of lost income to renewables operators, including that not received from renewables financial support mechanisms, this cost can reach very high values. One approach to quantifying this cost would be to apply an average price paid to wind farms by the TSO for reducing load which, based on empirical data from Britain, is of the order of €100 per MWh (Carnwath, 2011). Similarly a value should be attributed to unsupplied energy and while the cost of this is contested in the literature, figures for the value of lost load range between €15,000/MWh (REALISEGRID, 2013) and €60,000/MWh (the Secure Project) with Karuki and Allan (1996) falling between in their "by energy" analysis. These very high values, however, often refer to "unpredictable" unsupplied energy, such as that which can affect a load disconnected from the power system as the consequence of short-circuits or other incidents on the grid. An alternative approach, more suited to larger and more predictable conditions, such as a shortfall of generating power to face all the peak demand a few years ahead, regardless of the grid conditions, would be to apply the marginal operating cost plus annualised capital cost of typical peaking on-shore plants. This would lead to figures in the range of a few hundred of Euros per MWh (Lazard, 2014).

Figure 6 presents an overall parametric comparison between Radial, Radial+IC and H-Grid (Low) as the cost attributed to spilled and unsupplied energy is varied. It seems clear from this analysis that, unless both spilled energy and unsupplied energy are valued using very low prices, the H-grid structure is preferable to the other two.

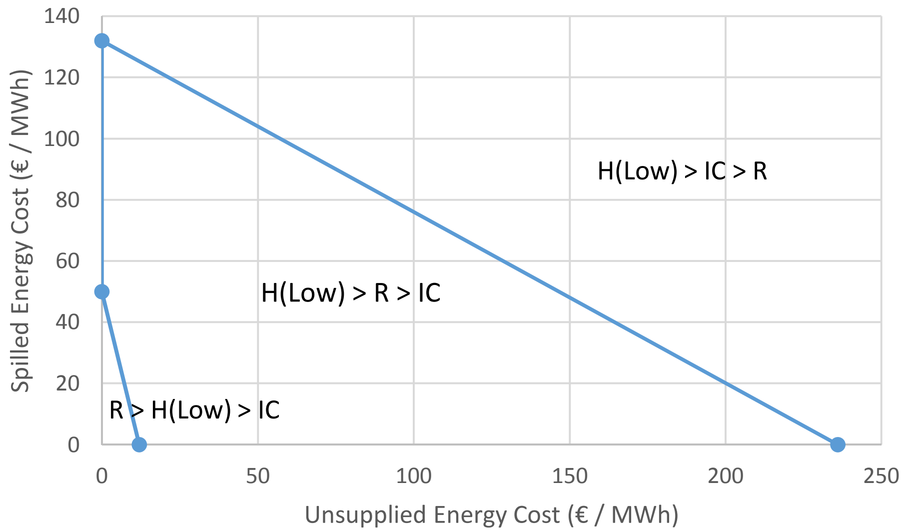

Fig 6 Relative merit of network configurations as a function of cost of spilled and unsupplied energy at a carbon price of €21 / ton

(Note: $x > y$ indicates that configuration x is preferred to configuration y)

4 Conclusions

The work described in this paper had the aims of investigating the benefits of integrating new offshore wind energy and of testing the widely held belief that the utilisation of renewable energy will be increased by an increase in transmission capacity in Europe with resulting benefits in terms of CO_2 emissions. More specifically, it has tested the expectation that system benefits are to be gained by increasing network capacity offshore in a coordinated way as offshore wind generation capacity is increased. In general, network capacity connecting different areas may be expected to offer a number of significant benefits, e.g. to permit local surpluses of wind power to be used more widely, to allow reserve power to be held remote from a particular area (minimising the total reserve holding) and to increase the utilisation of renewable energy. However, the precise level of benefit of new offshore power transfer capacity is uncertain and, even for a particular background of installed generation capacity, varies significantly due, in particular, to the variation of weather from year to year and uncertainty in prices of conventional fuels.

The results show that a coordinated, offshore, multi-terminal HVDC grid in an H-grid configuration, designed to facilitate both bringing wind power to shore and the exchange of power between regions, could provide system operational benefits relative to simple radial connection of the offshore generation. These benefits include reduction in use of high cost generation, reduced wind generation curtailment and, depending on the merit order of fossil fuelled generation, lower CO_2 emissions.

While increased inter-regional interconnectivity facilitates increased utilisation of wind, with 2013 patterns of fuel prices, it would also allow the wider utilisation of lignite and coal production and hence increased carbon emissions unless the price of carbon is sufficient to cause a reversal of the merit order such that gas-fired combined cycle gas turbine generation is favoured over lignite and coal. This suggests that incentivising investment in renewable generation and network capacity may not, depending on relative fuel prices, be sufficient to bring about a decrease in carbon emissions associated with electrical energy. Moreover, analysis of the flows – for reasons of brevity, not reported here – highlighted the importance of being able to model the complexities associated with system operation, such as the efficient utilisation of pumped storage plant.

Given the assumptions used in this study, when operational cost savings (in terms of fuel costs for generators) are compared with relative investment costs (levelised on an annual basis), the H-grid design examined in this study does not provide significant benefit compared with simple radial connection of new offshore wind generation and the relative merit of different network configurations is affected by the value applied to curtailed energy reflecting the improved performance of the H-Grid in particular in bringing offshore wind ashore. Similarly, the value applied to energy demand not served would have a considerable impact on the results. The results are also sensitive to structural issues such as (1) the approach taken to protection and control and, (2) the capital costs of DC circuit breakers.

4.1 Future work

Through advanced modelling of the European power system, the work to date has provided insight into the value that additional offshore network capacity can bring and the parameters by which its contribution can be measured. These include an examination of the capital cost of network elements and the change in the dispatch of generation of different types, which has allowed key identifying features to be understood. However, in order to further examine the relative merits of the H-grid approach further work will seek to optimise the design through more thorough analysis of network utilisation and to quantify the benefits to wind farm operators of having multiple paths to shore. In addition, work is planned to investigate alternative network configurations that do not require DC breakers.

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