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Abstract

This paper presents work by the International Energy Agency's Task 26 'Cost of Wind Energy' on technological and cost trends in land-based wind energy in six participating countries (Denmark, Germany, Ireland, Norway, Sweden, US) and the EU between 2008 and 2016. Results indicate that there is a general trend towards larger, taller machines with lower specific powers resulting in higher capacity factors, despite small falls in new site wind resources in most countries, while wind project capital costs and project finance costs also fell. This resulted in an average levelized cost of energy fall of 33% for new projects to 48€ /MWh at the end of the study period. Analysis of the components of levelized cost change indicated that changes in specific power, financing cost and capital cost accounted for 45%, 25% and 17% respectively of the estimated reduction. It is therefore important that

*The views expressed are purely those of the authors and may not in any circumstances be regarded as stating an official position of the European Commission.

trends in technological factors such as specific power are considered when assessing wind energy learning rates, rather than just capital costs, which has been the primary focus heretofore. While LCOEs have fallen, the value of wind energy has fallen proportionately more, meaning grid parity appears no closer than at the beginning of the study. Policymakers must therefore consider both the cost and value of wind energy, and understand the volatility of this gap when designing land-based wind energy policy measures.

1 Introduction

The decarbonization of electricity generation is a key international policy objective in reducing global greenhouse gas (GHG) emissions. A variety of renewable technologies, such as wind and solar, are currently competing with conventional fossil-fuelled thermal plant to serve new and existing system demand. In 2017, net global renewable electricity capacity additions were 178GW, accounting for more than two thirds of all new capacity (IEA, 2018). Globally, renewables are expected to account for 30% of installed power generation capacity by 2022 (IEA, 2017a). In recent years electricity production using wind energy has been among the fastest growing forms of renewable generation around the world (IEA, 2017a), while global average annual wind capacity additions are projected to be in the region of 50GW/annum over the period 2017-2040 (IEA, 2017b). The European Union (EU) has set a binding renewable energy target for 2030 of at least 32% (European Commission, 2018), much of which is likely to be delivered by wind. Similarly, China may increase its 2030 renewable energy generation target from 20% to 35% by 2030, with wind expected to play an important role (Bloomberg, 2018a).

As wind becomes an increasingly important and competitive source of energy generation in many electricity markets, it is crucial that governments, the wind industry and the wind research community are able to discuss the costs of wind energy on the basis of a sound methodology. Without transparent, robust and credible information on their costs, organizations without a clear understanding of wind systems are left to determine and publicize their costs, possibly in error. This problem is exacerbated by the diversity of wind technologies, asset management practices and variations in international project development cost assumptions. Growing wind capacities are affecting wholesale electricity prices in many countries and are resulting in changes in the value of wind energy itself. These changing costs and benefits are affecting the economic performance of new wind projects. While this paper primarily focuses on international cost developments, it also investigates concurrent changes in the value of wind energy and its implications for the industry.

Wind power deployment has been supported by energy policies and by cost reductions (Wiser *et al.* 2011). The degree of future deployment will be affected by similar dynamics, requiring careful assessments of cost-reduction opportunities (*inter alia* IPCC 2014; Zhang *et al.* 2016). Evaluating the possibilities for further cost reductions, meanwhile, requires a clear understanding of the past and current cost of wind energy as well as drivers for those costs and the relationship between the cost and value of wind energy.

The International Energy Agency's Task 26 'Cost of Wind Energy' comprises government, research, industry and academic experts from nine countries as well as the European Commission, and has been established to help fill this informational gap.[1] The primary objective of the Task is to provide information on the cost of wind energy in order to understand past, present and anticipate future trends using consistent, transparent methodologies. This will facilitate comparisons between wind technologies and other generation options within the broader electricity sector.

The aim of this paper is to communicate some of the recent work undertaken by the Task in estimating the cost of land-based wind energy in participating countries.[2] It details the various data sources used in the different jurisdictions, the methodologies employed and some of the important results obtained, notably:

- land-based wind technology, cost, performance and financing trends in participating countries from 2008-2016;
- land-based wind production cost trends in each country, using the metric levelized cost of energy (LCOE);
- factors contributing to LCOE changes in each country over the period; and

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[2]Work by the Task on offshore wind technology can be found on the Task 26 website (https://community.ieawind.org/task26/home) results section.

- how the gap between LCOE and the market price for electricity has changed over the period.

A variety of approaches have been used to assess wind energy costs. Learning curves have been used to understand past cost trends and as a tool to forecast future possibilities (Lindman and Söderholm 2012; Rubin *et al.* 2015); more recently Tu et al. (2019) use this method to investigate the future grid parity of wind energy in China. They have been criticized for, in most cases, focusing primarily on capital costs (Ferioli *et al.* 2009; Rubin *et al.* 2015) and ignoring other means of reducing generation costs (one notable recent exception is Williams *et al.* 2017), and for simplifying the many causal mechanisms that lead to cost reduction (Ferioli *et al.* 2009; Ye and Rubin 2012; Samadi 2018). In part due to methodological variations, estimated historical learning rates for land-based wind span an enormous range, from a 33% cost decline with each doubling of cumulative production to a cost increase of 11% for each doubling (Lindman and Söderholm 2012; Rubin *et al.* 2015). Engineering assessments can provide a technology-rich complement to learning analyses (Mukora *et al.* 2009). They typically entail detailed modelling of specific technology advancements and often consider both cost and performance, providing insights into trends in the total production costs of wind energy (Fingersh *et al.* 2006; Sieros *et al.* 2010). But they also require complex design and cost models, and sometimes emphasize incremental advances. Finally, some studies have used expert knowledge to gain insight into the possible magnitude of future cost reductions (Wiser *et al.* 2016; Wüstemeyer *et al.* 2015). When well designed, expert elicitation has been shown to provide valuable insights, but it is impossible to eliminate the possibility of motivational or cognitive biases when surveying experts.

Our cross-country analysis contributes to the above literature, and to related literatures that have tracked the historical levelized cost of land-based wind energy (IRENA 2018; BNEF 2015) and/or assessed the impact of turbine scaling on wind energy potential, costs, and value (Burt *et al.* 2017; Rinne at al. 2018; Hirth and Muller 2016; Dalla Riva 2017). Our core focus is on assessing historical trends in wind technology advancement, cost, performance, and financing in order to develop an overall picture of the 'all-in' generation costs of wind energy across a number of countries, and to explore how those costs have varied over time, the drivers for the observed cost reductions, and trends in achieving 'grid parity.' Our results can inform policy and planning decisions related to wind and improve the representation of wind in energy-sector models by establishing a well-referenced historical and recent baseline for a diverse set of countries. The work presents a unique detailed analysis of internationally-comparable wind project data which provides new insights into land-based wind project technology, cost and financing trends, and describes the components contributing to production cost and market value changes over the 2008-16 period.

The remainder of this paper is structured as follows. Section 2 details the approach used in estimating the levelized cost of energy. Section 3 gives an overview of the various international sources of the technical, cost and financial data used. Section 4 describes the methodology used for comparing LCOEs both temporally and between participating countries, how the components of LCOE change over time were identified, and how the value of wind energy was estimated in order to contextualize LCOEs. Section 5 presents the results of our analysis, while Section 6 provides some concluding remarks.

2 Levelized Cost of Energy for Wind

The levelized cost of energy can be thought of as the time-weighted 'average' cost of producing one unit of energy from a generator taking account of all life cycle costs (such as those for construction, fuel, maintenance and decommissioning) discounted at the opportunity cost of capital (or 'discount rate'). It sums all such costs and apportions them equally to each unit of energy produced by the energy investment over its lifespan. Both future costs and energy outputs are discounted at a financial discount rate which is appropriate to the investment, considering its risk profile and debt:equity ratio (gearing). The LCOE can be thought of as the revenue (or energy tariff) required for each unit of energy produced to give a net present value (NPV) of zero over a project's lifespan.[3]

LCOEs normally represent the average or typical cost of new generating investment in a particular market. Individual projects are higher and lower than this average. It is used widely in the electricity generation sector to track progress in reducing the cost of individual technologies and to assess the sensitivity of production costs to various input parameters (e.g. IRENA 2018; Partridge 2018); a review of available unit energy cost metrics by Aldersey-Williams and Rubert (2019) concludes that LCOE is the industry-preferred choice. It also serves as an input to comparisons of the economic competitiveness of different forms of electricity generation

[3] By definition we use the real WACC as a proxy for the time value of money, which may or may not be accurate but is nonetheless standard practice.

such as fossil fuelled power stations (coal, gas and oil), nuclear power and more recently renewables such as wind and solar. At the same time, it is important to recognize that LCOE is imperfect as a measure of economic competitiveness, and so is not used as the sole decision-variable when comparing alternative sources of electricity supply. This is because generation sources are not homogenous, but instead have varying technical and economic characteristics and so deliver different grid services (Eser *et al.*, 2016; Borenstein 2012). Moreover, the external costs of different power generation technologies are not captured by LCOE, thus distorting the benefits of some technologies, notably those with high emissions such as coal-fired plant. The LCOE of a resource must be paired with an assessment of its 'value' to the electricity system to assess its economic competitiveness (Edenhofer *et al.* 2013; Winkler *et al.*, 2016) — we present a simple comparison of this type for land-based wind in section 5.4 of this paper.

The simplest estimate of LCOE considers all real cash outflows without accounting for the cash effects of tax, interest or depreciation. Here, the discounted costs incurred over the lifespan of the project (right hand side of Equation 1) are balanced by notional discounted benefits; the latter are represented by the product of the discounted energy output over the same period and the LCOE (right hand side). This equality is based on the fact that LCOE represents the unit value of energy which gives a net present value of zero; that is where the sum of discounted costs equal the discounted benefits.

$$\sum_{n=0}^{N} LCOE \times E_n \times (1+r_n)^{-n} = \sum_{n=0}^{N} (C_n + OM_n + D_n)(1+r_n)^{-n} \qquad (1)$$

where: $LCOE$ is the levelized cost of energy (€/MWh); E_n is the energy produced in year n (MWh); r_n is the real discount rate in year n; N is the economic life of the project (years); C_n is project capital expenditure in year n (€); OM_n is project operation and maintenance expenditure in year n (€); D_n is project decommissioning cost in year n (€).

The weighted average cost of capital ($WACC$) is the average rate a company pays to finance its assets. It represents the opportunity cost of the project to the company. In our analysis we use standard practice and let WACC equal the discount rate (r_n). For a simple company financed by debt and equity only, and where interest payments are tax-deductible (which is the case for participating countries), WACC is given by:

$$WACC = \frac{Dt}{Dt + Eq} \times i(1 - T) + \frac{Eq}{Dt + Eq} \times e \tag{2}$$

where Dt is the amount of project debt funding; Eq is the amount of equity funding; i is the interest rate on debt; e is the return on equity; and T is the corporate tax rate.

WACC may be either real or nominal, depending on whether real or nominal costs of debt and equity are used. For ease of calculation, we employ real (i.e. unaffected by inflation) cash flows in all cases. For this reason, a real WACC is used for discounting in all cases unless otherwise specified. While WACC may not be constant over the lifespan of a project in-as-much as refinancing occurs after construction, we are estimating the present value of costs using a lifetime average WACC figure.

We make a number of assumptions. First, we assume the capital cost, C_0, which represents the total investment necessary to achieve commercial wind project operation, including any interest payments during the construction period, is incurred immediately preceding full project operation (i.e. in 'year zero'); this is conventional practice. We assume that the energy output (E_n), operating and maintenance costs (OM_n) and $WACC$ (r_n) are the same for each year n, or have been previously levelized over the economic life of the project (N). It is also assumed that there is no degradation in asset performance over its lifespan. We take the view that the end-of-life scrap value of the asset balances decommissioning costs (D_n); any error in this assumption is small given the relatively small contribution of decommissioning costs to life cycle costs and because it is incurred at the end of the project and is thus heavily discounted. Taking these assumptions and solving for $LCOE$, Equation 1 becomes:

$$LCOE = \frac{C_0 + OM \times \sum_{n=1}^{N}(1 + r)^{-n}}{E \times \sum_{n=1}^{N}(1 + r)^{-n}} \tag{3}$$

In order to avoid the need for multi-annual cash flow calculations, we levelise the one-off, up-front capital expenditure over the project lifespan, while taking account of the time value of money. To do this, we use the Capital Recovery Factor (CRF) ratio which, when multiplied by the capital cost (C_0) gives a constant annual cash flow, discounted to the base year; it equals the capital cost when summed over the project lifespan and is given by:

$$CRF = \frac{1}{\sum_{n=1}^{N}(1+r)^{-n}} \tag{4}$$

Substituting CRF into Equation 3 we get:

$$LCOE = \frac{CRF \times C_0 + OM}{E} \tag{5}$$

However, this expression does not allow for the cash effects of depreciation. Depreciation involves writing off an annual tax-deductible proportion of the capital investment (C_0) over a specified period. Again, to simplify calculations, these proportions can be discounted and summed to give the present value of all future depreciation effects:

$$PVD = \sum_{m=1}^{M} \frac{Dp_m}{(1+r_{nom})^m} \tag{6}$$

where: PVD is the sum of the present values of all annual depreciation rates; M is the depreciation period (years); Dp_m is the fraction of capital depreciated in each year m; r_{nom} is the nominal $WACC$.

We assume that projects face the prevailing tax rates and follow the tax depreciation rules for each country. We do not, however, include any explicit tax credits for wind in the LCOE calculation. By deducting depreciation allowances at the corporate tax rate (T) from all costs and (energy-related) revenues, and by also including PVD (Equation 6), Equation 5 becomes:

$$LCOE = \frac{(\frac{1-T\times PVD}{1-T})CRF \times C_0 + OM}{E} \tag{7}$$

This is the expression for LCOE which is used for all calculations in this paper.

3 Data Sources

Given the size of the wind energy markets in the participating countries and the resources available to the Task members, it was generally not possible to gather primary survey data. Participants therefore relied on a variety of secondary sources, both public and private. Due to differences in the legal, regulatory and national data gathering environments in the participating countries, the quality and quantity of these sources varied. Data acquisition methods for LCOE estimation therefore varied from country to country depending on the availability and format of these data sources. The Task members, however, strove to make data as compatible as possible.

The equations in Section 2 above identify the main variables and, therefore, data required to calculate LCOE. These include:

- *capital expenditure* (C_0, in €) invested in the wind project;
- *economic lifespan* (N, in years) of a typical wind project;
- *operational expenditure* (OM in €/annum): the annual operating and maintenance expenditure (maintenance, management, land rental, insurances, etc.) used in each year of the project (assumed to be fixed or levelized over the project lifespan);
- *annual wind project energy output* (E, in MWh/annum);
- *financial parameters* such as corporate income tax and depreciation rates (T and Dp respectively);
- *nominal and real WACCs* based on the nominal costs of debt and equity, and representative debt:equity ratios in each country; these are converted to real values using expected forward-looking inflation rates (2% for all countries); and
- *World Bank GDP and currency exchange rate values* were used to convert nominal prices in different years to real prices in the base study year (2017), with the exception of the EU which used Eurostat deflators.

Table 1 summarizes the sources of data for the most important variables for each of the participating countries: capital expenditure (CapEx); operational expenditure (OpEx); annual wind project energy output (Energy Output); and weighted cost of capital (WACC). A number of data sources and assumptions which are common to all countries are not included in the table. For example, the economic lifespan was assumed to be 20 years for all countries. While there is growing evidence that wind project lifespans exceed this duration, it remains a common assumption among the policy and research community, as well as within the wind industry. Taxation and capital depreciation rules were obtained from the relevant national tax authorities in all cases.

Country	CapEx	OpEx	Energy Output	WACC
DE	Industry surveys, conducted by Deutsche WindGuard with the German Mechanical Engineering Industry Association (VDMA).	Industry surveys, conducted by Deutsche WindGuard with the German Mechanical Engineering Industry Association (VDMA).	Federal Network Agency (Bundesnetzagentur). Production data 2016 by German TSOs. Betreiber-Datenbasis: Index Version 2017	Surveys and interviews with experts from financial institutions.
DK	Project-level data publicly available under the Koberetsordning (Share Purchase Right) regulation. Shallow grid connection cost included (up to coupling point). Loss-of-value compensation costs as well as eventual purchase of old turbines costs are included.	Project-level data publicly available under the Koberetsordning (Share Purchase Right) regulation. O&M data was available only from 2013 to 2016.	Project-level wind energy output data from the Core Data Registry (Stamdataregister), Danish Energy Agency. Wind index data from Vindstat.dk, EMD International (2017).	Data for 2008–2012 from a previous IEA Wind TCP Task 26 report (Schwabe *et al.* 2011) has been integrated with interviews with developers and banks active in the land-based wind sector in Denmark to assess values up to 2016
IE	Obtained from filed company account balance sheet data from the Comapny Registrations Office (cro.ie) portal.	Obtained from filed company account profit and loss data from the Company Registrations Office (cro.ie) portal. Should be treated with caution due to small sample size and possibly contaminated secondary data. Verified with industry sources.	Metered data obtained from Single Electricity Market Operator (SEMO) market data for 2016 and corrected using wind index based on 30 year synoptic weather station data.	Nominal cost of debt data obtained from selected filed company accounts of wind companies. CAPM model used to estimated return on equity using company and market data.
NO	CapEx data reported directly to Norges vassdrags- og energidirektorat (NVE) by wind plant owners immediately following commissioning.	O&M estimates based on reported data (Erapp II database) for a small wind project sample over several years and NORWEA industry survey.	Metered hourly production from TSO Statnett for all wind plants. Data corrected with wind plant-level wind indices produced for NVE by Kjeller Vindteknikk.	Based on average 10-year government bond rates and a 3% risk premium.

Country	CapEx	OpEx	Energy Output	WACC
SE	Investment costs obtained from a Swedish Energy Agency survey of annual financial reports for selected wind projects (undertaken by Sweco).	Average annual fixed O&M costs obtained from a Swedish Energy Agency survey of annual financial reports for selected wind projects (undertaken by Sweco).	Pre 2015 data from Swedish Energy Agency Electricity Certificate Registry metered generation data; 2015 onwards based on estimations of full load hours in applications for electricity certificates.	Based on wind industry and financing interviews (Feb 2018).
US	U.S. Department of Energy's Wind Technologies Market Report (Wiser and Bolinger 2017), which obtains wind project cost data from Energy Information Administration (EIA), Federal Energy Regulatory Authority (FERC), and a wide variety of industry sources.	Industry survey conducted by Lawrence Berkeley National Laboratory, as well as a range of other industry sources including Wiser and Bolinger (2017).	U.S. Department of Energy's Wind Technologies Market Report (Wiser and Bolinger 2017), which obtains wind project performance data primarily from EIA and FERC.	Based on historical data on the cost of debt from, in part, Bloomberg New Energy Finance as well as Lawrence Berkeley National Laboratory estimates of the cost of equity and the debt-equity ratio under the scenario in which the federal Production Tax Credit (PTC) is not available. Because LCOE values reported here exclude the value of the PTC, the WACC is estimated accordingly.
EU	Bloomberg New Energy Finance project database (2018b) and a number of research notes were used (Grace 2014, 2015; Hostert 2016a, 2016b, 2017).	Obtained at industry events (e.g. EWEA conferences); figures from secondary sources were validated with industry interviews and surveys.	JRC Wind Energy Database (2018) and Eurostat wind energy production data (Eurostat 2018a, 2018b)	Industry sources gathered mainly at two workshops: Wind Risk Management and Mitigation Forum (London, 2015) and the IEA-, EC-, RVOand TKI-sponsored workshop "Reducing risk and risk perception in the financing of offshore wind energy". Utrecht, NL, 2016.

Table 1: Summary of the sources of data in each of the participating countries.

Most capital expenditure data for the study were obtained from project-level national government sources. In Denmark, for example, developers must provide capital cost information at the project planning stage to the government in accordance with the Koberetsordning ('Share Purchase Right') regulation. Norwegian wind farm licenses require all wind farm owners to report capital cost information to NVE after commissioning. In Ireland statutory financial statements (for all companies) were used to obtain wind project investments for approximately 80% of all wind projects. Sweden also gathered investment data from annual financial reports for a representative sample of wind projects. In the US capital cost data are available from government agencies such as the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC); these were supplemented by information from industry sources, with data ultimately collected for roughly 90% of all wind projects. Germany, however, relied on industry surveys for their capital cost data.

In all countries official primary sources of operational cost data were either very limited or absent. Denmark was the exception, with OpEx data collected by government agencies under the same Koberetsordning regulation as for investment costs above; however these data only cover the 2013-16 period. Both Ireland and Sweden estimated OpEx costs from official, filed financial accounts data for wind project companies. However, due to data quality issues these sources often required that OpEx data be separated from other data using expert judgement and so this may have resulted in some inaccuracies. Ireland obtained operating costs from profit and loss (P&L) accounts contained in statutory financial statements (as for CapEx above); however, these only accounted for approximately 10% of companies although results were cross-checked with industry contacts. Most countries therefore relied primarily on data gathered directly from industry contacts and sample sizes were typically small. Germany, for example, relied on direct industry surveys for operational cost data. Norway used a small sample of official data supplemented with the findings of a wind industry association (NORWEA) survey. The EU used secondary data sources which were then validated with industry experts. In the US only small amounts operational cost data are available from government agencies (Wiser and Bolinger 2017), so those data were again supplemented with industry interviews. Given the foregoing, it is important to stress that there is considerable uncertainty attached to OpEx data for most countries. This is not ideal given that OpEx can account for 20-25% of life cycle costs (IRENA, 2018). In all cases, the OpEx data obtained were representative of average annual costs levelised over the project lifespan.

High quality energy output data were available from official sources in all countries. Typically, transmissions system operators (TSOs), market operators, government departments or energy regulators gather metered data at the individual wind project level for market participation purposes. For example, German data were obtained from the country's TSOs (Tennet, Amprion, 50Hertz and Transnet BW) and the Federal Network Agency (Bundesnetzagentur). In Ireland half-hourly energy data are available from the Single Electricity Market Operator for all wind projects; these were summed to provide annual figures. Swedish figures were predominantly metered data from the Swedish Energy Agency. In Denmark, the Danish Energy Agency (DEA) provides data on annual energy output at a turbine level in the Core data registry. In the US over 90% of energy outputs were available at an individual wind project level from the EIA and FERC. The energy output data were normalized to average wind years in each country to better compare resulting LCOEs. Given limitations in data availability, we do not fully consider the possibility of performance degradation as projects age; however, given the limited temporal span of our analysis and recent research on performance degradation (Olauson *et al.*, 2017), we do not believe this creates substantial error.

Data on project financing (costs of debt and equity) and capital structure were difficult to obtain due to their commercial sensitivity and there is therefore significant uncertainty regarding the figures obtained. In almost all instances these data were obtained through interviews with developers and/or financial institutions, or through secondary sources of industry data. In general, large companies with an excellent knowledge of key wind industry sub-sectors were targetted for these secondary data sources. These included, for example: energy investment and generation companies with large wind portfolios; financing institutions specialising in energy and wind; and the operation and maintenance divisions of large turbine manufacturers. In Denmark, a series of interviews with banks and land-based wind developers was conducted; Germany and Sweden also used this method. The US relied primarily on secondary sources of industry data. A similar approach was adopted in Norway where typical debt and equity data were acquired from several financial institutions, but this information was supplemented by data from NORWEA. Ireland used a different approach whereby statutory audited accounts including profit and loss (P&L) data were used to identify the cost of debt and gearing for a small sample of wind project companies; these were verified with financial institutions. The cost of equity was estimated using the capital asset pricing model (CAPM).

In addition to gathering the data required to estimate LCOEs, data which might help explain the underlying reasons for changes in LCOE over time and differences between regions were also obtained. These included:

- *wind project size*, describing the total installed nameplate capacity in MW for each project included in the study;
- *turbine nameplate rating capacities* for each project describing the maximum power output in MW;
- *rotor diameters* in metres for the turbines used in each project;
- *hub heights* in meters;
- *average wind resource* available at the wind project site in m/s at a representative hub height based on national wind mapping tools;
- *specific power*, which is the ratio of capacity to swept area (W/m^2) (lower specific power typically improves turbine capacity factors for a site); and
- *IEC class* describing the suitability of the turbine for different site wind resources (IEC class I, II and III are designed for use with high, medium and low site wind resources respectively).

These data were obtained from a variety of sources in the participating countries. For example, in Ireland turbine data were largely obtained from independent wind market reports, the Irish Wind Energy Association and statutory planning applications. In Denmark, all wind project turbine characteristics are publicly available in the Core Data Registry (Stamdataregister), maintained by the Danish Energy Agency. In Sweden the main souces of project data were the electricity certificate system registry, (hosted by the Swedish Energy Agency) and a wind project database ('Vindbrukskollen' administered by County Administrative Board of Västra Götaland). In the United States, technical data on wind projects and turbines are collected by the American Wind Energy Association, EIA, Lawrence Berkeley National Laboratory, and others, and are summarized in Wiser and Bolinger (2017). In Germany turbine characteristics are available from the Federal Network Agency.

Wind speed data were obtained from two main sources: national spatial wind resource datasets; or site-specific measurements. Ireland, Germany, Sweden and the US use the former source whereby wind farm grid coordinates are used to access interpolated data based on long-term synoptic meteorological data. In Germany, wind atlas data were interpreted and

Country	Period	Turb. Cap.	Diam.	Hub Ht.	Wind Speed	Cap. Fact.	CapEx	OpEx	WACC
DE	2008-10	97%	97%	97%	100%†	96%	n.a.*	n.a.*	I
	2014-16	100%	100%	100%	100%†	99%	n.a.*	n.a.*	I
DK	2008-10	94%	94%	94%	93%	86%	n.a.‡	0%	I
	2014-16	97%	97%	97%	91%	95%	90%	90%	I
IE	2008-10	100%	100%	100%	100%†	86%	85%	∼10	∼10%
	2014-16	100%	100%	100%	100%†	100%	78%	∼10	∼10%
NO	2008-10	100%	100%	100%	100%	100%	100%	I	I
	2014-16	100%	100%	100%	100%	100%	100%	I	I
SE	2008-10	99%	94%	94%	96%†	98%	32%	∼10%	I
	2014-16	101%	91%	91%	91%†	104%	73%	∼20%	I
US	2008-10	100%	100%	100%	100%†	92%	90%	I	I
	2014-16	100%	100%	100%	99%†	99%	96%	I	I
EU	2008-10	93%	93%	46%	I	I	I	I	I
	2014-16	100%	100%	8%	I	I	I	I	I

Notes: 'I' denotes where industry- rather than project-level data were gathered; †based on national wind resource datasets rather than site measurements; *based on a variety of surveys, for further details see <https://community.ieawind.org/task26/dataviewer>; ‡exact coverage unavailable.

Table 2: Summary of national wind project sample sizes for key technology, performance and financing variables expressed as a percentage of installed capacity.

adjusted using expert knowledge and IEC class information. Denmark and Norway use wind speeds measured on the wind project sites.

In all countries, sample sizes (see Table 2) equal to or approaching the population were obtained for turbine capacity, rotor diameter, hub height, wind speeds and capacity factors. Sample sizes were slightly lower for CapEx and much more limited for OpEx and WACC, which relied heavily on industry sources. For the EU, large samples of data were only available for turbine capacity and diameter.

For the whole of the EU those specifications were only available for name plate capacity and rotor diameter, around half the hub heights and marginally less for other elements. The table illustrates that the greatest data uncertainties relate to OpEx and WACC inputs.

4 Methodology

A summary flowchart of the methodology used is presented in Figure **??**. National participants gathered the most compatible available data at the level of the wind project for the variables described in Section 3 above for the period 2008 to 2016. This period was chosen for the study since little data were available before this for many of the countries involved; and delays in national data collation meant that post-2016 data were largely unavailable at the time of writing. Power output data were collected for the most recent study year only (2016) and these were corrected to reflect long-term average outputs (this is discussed in more detail later in this section). All cost data were converted to Euro in the year they were incurred and then inflated to a common 2016 base year[4].

Once the data were collected and normalized, mean annual values were calculated for each country. CapEx and OpEx were weighted by installed capacity. Capacity factors were generation-weighted in a similar way. The resulting parameters thus represent mean or 'typical' project characteristics for each study year. In reality, parameter values vary significantly from project to project in each country and result in a wide range of LCOEs. However, we estimate 'typical' LCOEs which can be used for comparative analysis, both between countries and over time. We do this by estimating LCOE from averages of the input parameters, rather than estimating LCOE for each project, and then averaging those estimates; we use the former approach over the latter approach due to data availability issues in several participating countries that preclude conducting the analysis for each wind project.

Equation 7 was used to estimate annual LCOEs for each country using the resulting mean vales. This assumes that input parameters (e.g. energy production, WACC, OpEx) for each of the study years (2008-16) remained constant over the 20-year LCOE assessment period. Two different LCOEs were calculated for each participating country for each of the sample years. These are:

- $LCOE_{nat}$ which uses the country-specific tax and depreciation rules which apply in each year (see Table 3); and
- $LCOE_{std}$ which applies 'standard' (or internationally representative) tax, depreciation and WACC rates to all countries (these are taken as the average values of participating countries, excluding the EU to prevent double counting).

$LCOE_{nat}$ results give the truest estimation of the levelized costs of energy in a country since it considers all the country-specific inputs including technology performance (e.g. capacity factors), costs (e.g. CapEx, OpEx

[4]US$ results can be found on the IEA Task 26 website <community.ieawind.org/task26>

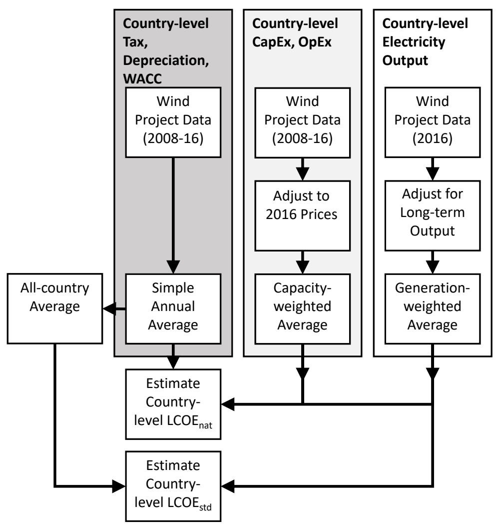


Figure 1: Flow diagram overview of the methodological approach used.

Country	2008	2009	2010	2011	2012	2013	2014	2015	2016
DE	29.5 (16-25*)	29.4 (16-25*)	29.4 (16-25*)	29.4 (16)	29.5 (16)	29.6 (16)	29.6 (16)	29.7 (16)	29.7 (16)
DK	25.0 (5)	25.0 (5)	25.0 (5)	25.0 (5)	25.0 (5)	25.0 (8)	24.0 (8)	23.0 (8)	22.0 (8)
IE	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)	12.5 (20)
NO	28.0 (20)	28.0 (20)	28.0 (20)	28.0 (20)	28.0 (20)	28.0 (20)	28.0 (20)	27.0 (20)	25.0 (5)
SE	26.0 (20)	26.0 (20)	26.0 (20)	26.0 (20)	26.0 (20)	22.0 (20)	22.0 (20)	22.0 (20)	22.0 (20)
US	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)	40.0 (5†)
EU‡	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)	20.0 (20)

Notes: *different durations applied to project components: turbines (16 yrs), cabling and grid connection (20-25 yrs) and infrastructure (19 yrs); †using the Modified Accelerated Cost-Recovery System (MACRS). Sources: relevant national tax offices, ‡except EU which are indicative values.

Table 3: Corporate income tax rates and, in parenthesis, depreciation periods for each of the participating countries.

and taxation) and financial structure (e.g. the typical costs of debt and equity, gearing and depreciation rules). $LCOE_{std}$ standardises the effects of financial structure, tax and depreciation across all countries so that the effects of national differences in technology performance and industry costs can be compared. The two measures help to establish whether wind energy is cheaper in some countries due to lower financing costs and more competitive financial rules or because of better wind site quality, more appropriate turbine characteristics or lower industry costs. In order to calculate $LCOE_{std}$, all-country average values of tax, depreciation (straight line) and WACC were used for the 2008-10 and 2014-16 periods as shown in Table 4.

2016 electricity production data were used when estimating the LCOE for each year in each country to give the most up-to-date comparative cost of wind energy production in each case. Here, wind project production data for the 2016 calendar year are used for all projects installed between 2008 and 2016. However, because the wind resource for 2016 might not be representative of the long-term average for a country or region, the corresponding wind energy output data obtained for each project may either be an over- or under-estimate, thus resulting in unrepresentative LCOEs. The representa-

Parameter	2008-10	2014-16
Tax Rate (%)	26.8	25.6
Depreciation Period (yrs)	15.1	14.8
WACC (nominal) (%)	6.6	5.4
WACC (real) (%)	4.5	3.3

Table 4: Corporate tax rate, depreciation period and WACC values used to caluclate $LCOE_{std}$ based on average values for all participating countries.

tiveness of 2016 data was therefore assessed and corrected for each country. Regional wind energy indices were estimated as the ratio of the 2016 average wind resource to an average calculated over a representative number of years (typically based on synoptic wind data). This period varied between countries: 1993-2012 was used in Denmark; 2007-2016 in Sweden; and in Ireland a 30-year average was used. The resulting ratios were used to scale energy output data for each wind project.

In order to simplify presentation and help identify trends, results are averaged over two three-year intervals, one each at the beginning (2008-10 inclusive) and end (2014-16) of the study period. Three-year periods are used in order to remove the effects of unusually high or low values which are present in single year statistics for some countries. The full set of annual time-series data are available for viewing and download for all countries on the Task 26 website[5]. The main analysis then proceeded as described below.

- The main technological, financing and cost trends for each country, and differences between countries were identified by comparing average values for the two three-year periods 2008-10 and 2014-16.

- $LCOE_{nat}$ and $LCOE_{std}$ were estimated for each country for the two periods (2008-10 and 2014-16) using the corrected wind energy outputs from Equation 7 and the data from Table 3 and Table 4 respectively.

- The contributions of changes in performance, cost and financing to changes in national LCOEs were analysed. This involved comparing average $LCOE_{nat}$ in the periods 2008-10 and 2014-16. The LCOE for 2008-10 was calculated in the usual way for each country according to Equation 7 using average 2008-10 cost and financing parameters and the wind index-corrected energy output for 2016. The value of each of the 2008-10 variables was then substituted in turn with that for

[5] <https://community.ieawind.org/task26/dataviewer>

2014-16 and its corresponding effect on the 2008-10 LCOE estimated. The effect of each single variable change was then scaled to the total difference between the 2008-10 and 2010-16 LCOEs to estimate the contribution of each to the change over the study period.

– The extent to which life cycle wind energy production costs (as measured by LCOE) are approaching the wholesale market value of electricity was then assessed in each country. Wind production-weighted wholesale prices (also referred to as the 'market value of wind power') were calculated for each trading period and averaged for each year (see Equation 8). These were then compared to national average LCOEs for each year of the study period.

$$MV = \frac{\sum_{t1}^{t2} P_t \times E_t}{\sum_{t1}^{t2} E_t} \tag{8}$$

where: MV is the market value of wind; $t1$ and $t2$ are the start and end times of the sampling period; P_t is the wholesale electricity price for time period t; and E_t is the quantity of wind energy delivered to the market in time period t.

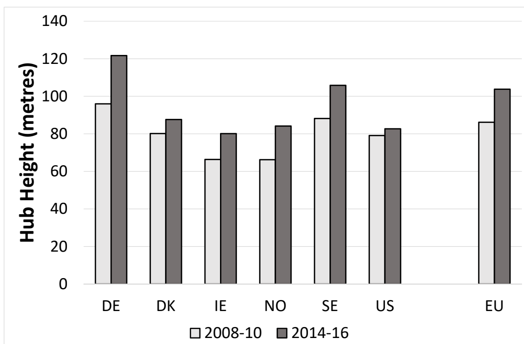
5 Results and Discussion

Results of the technology, cost, performance and financing trend analysis are first presented. Changes in both measures of LCOE - national and standard - are then discussed for each country. The components of national LCOE changes between the two time periods are then described. Finally, $LCOE_{nat}$ results are presented alongside wholesale electricity prices. Results are presented over the two averaging periods: 2008-10 and 2014-16.

5.1 Technology, Cost, Performance and Financing Trends

Figures 2(a)-(d) summarise key technology trends over the study period and show the average hub heights, turbine nameplate capacity, rotor diameter and specific power for each country for the periods 2008-10 and 2014-16.

It can be seen that there is a trend towards larger and taller turbines. Hub heights increased from approximately 65-95m to 80-120m over the periods, with an average increase in the region of 20%. In general this has been simply driven by the availability of taller machines capable of accessing higher wind resources. The highest turbines were observed in Germany



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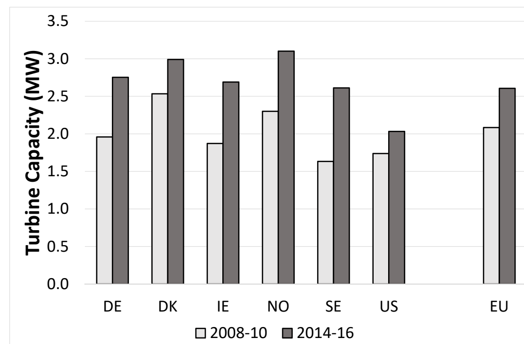

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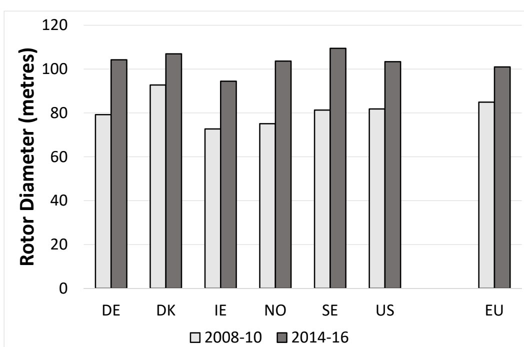

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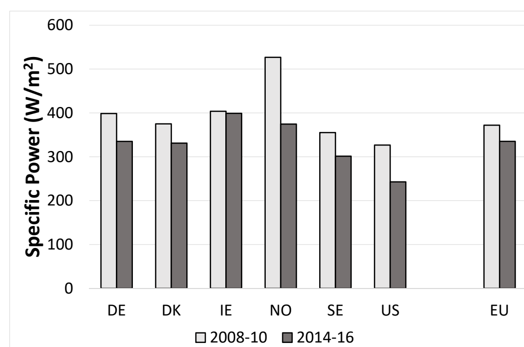


(d)

Figure 2: Technology trends in participating countries (capacity-weighted averages) shown for the periods 2008-2010 and 2014-16: (a) hub height; (b) turbine nameplate capacity; (c) rotor diameter (d) turbine specific power. (Notes: 2009, 2010 NO data unavailable for (a)-(c); 2016 EU data unavailable for (a)).

where a lack of easily-accessible high wind-resource sites has resulted in the development of complex, forested terrain with lower wind speeds and higher turbulence; these require turbines with taller towers to maximise economic returns. Growth was lowest in Denmark and the US at approximately 9% and 5% respectively. In Denmark, tip height restrictions have limited height increases. In the US the focus over this period was on increasing rotor size and thereby reducing specific power; some additional regulatory complexity also hindered the move towards higher hub heights.

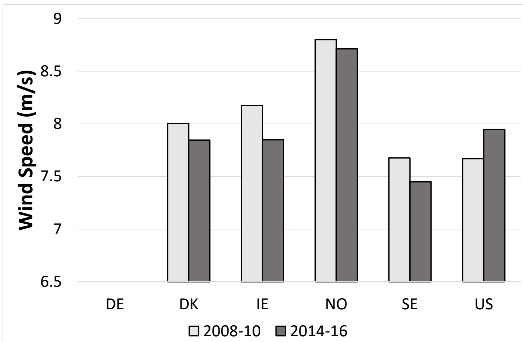
Turbine nameplate capacities have also increased in all countries. In the 2008-10 period turbines were typically in the 1.5-2.5MW range in all countries; by 2014-16 average values were roughly 2.5-3.0MW in all countries excepting the US, where growth was more muted. Average rotor diameter also grew in all countries, from 70-90m in the 2008-10 period to over 100m in 2014-16 (with the exception of Ireland, where diameters grew to approximately 95m). The resultant growth in rotor swept area was relatively greater than that for nameplate capacity and, therefore, resulted in a decline in specific power in all countries, as can be seen in Figure 2(d). All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites; they were intended to maximize energy capture in areas where the wind resource is modest, and where large rotor machines would not be placed under excessive physical stress due to high or turbulent winds. However, as wind technology has developed these machines are now being deployed on sites with stronger and more turblent winds. In the 2008-10 period, average specific power typically ranged from 350-450W/m^2, although Norway was in excess of 500W/m^2. The averages for the 2014-16 period decreased to 250-400W/m^2, with the lowest values observed in the US and the highest in Ireland and Norway. Average wind speeds in Norway and Ireland are higher than other countries (see below), which suggests higher specific power turbines may be more appropriate in these countries.

Figures 3(a) and (b) summarise the average wind speeds and capacity factors for the periods 2008-10 and 2014-16. While countries provided wind speeds at between 75 and 110m, these were adjusted to 100m above ground level using the power law to allow better comparison. It can be seen that Ireland and Norway have the highest average wind speeds and there has been very little change over the two periods for all countries. Average speeds on newer sites in Denmark, Ireland, Norway and Sweden were marginally (2-

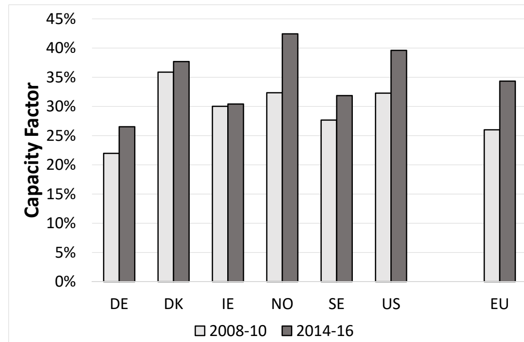
4%) lower than for the 2008-10 period, with those in the US increasing by approximately 4%. The reasons for these changes are complex and include both climatological and country-specific aspects. For example, between 2010 and 2017 it is estimated that global wind energy has increased by 17% (Zeng *et al.*, 2019). The development of the transmission network is one reason for the improvement in the available wind resource quality in the US.

Capacity factors increased for all countries, albeit only marginally for Ireland. In general, capacity factors increased from the 22-36% to 27-42% ranges between the periods. Average capacity factors in Germany, Norway and the US increased by 21%, 31% and 23% respectively, with Sweden registering a 15% increase. Because there is a slight decline in the quality of the wind resource in which projects are being located in all countries (expect the US), these increases appear to be explained by higher hub heights and lower specific powers. Given the fact that the US registered among the highest increases in capacity factor but only a small increase in hub height, changes in specific power may in large measure explain the improvements in capacity factors, although increases in wind speeds also contributed to a smaller extent. The observed higher capacity factors are important since they reduce LCOEs. Higher capacity factors can (when achieved through turbine designs that shift generation from higher to lower wind speed periods) also result in lower balancing costs and an increased wholesale market value for wind, as highlighted in Hirth and Muller (2016) and Dalla Riva *et al.* (2017).

Figures 4(a), (b) and (c) present the average trends in capital costs, project financing, and operational expenditure in the participating countries. Capital costs have fallen by a combined all-country average of 10% between the periods. Almost all countries recorded falls from a range of approximately 1,100-2,100€/MW to 1,200-1,600€/MW. Very small decreases were observed for Germany and Ireland (1-3%) with larger falls for Denmark and Sweden (16-21%). Average US capital costs were high in the 2008-10 period but have fallen most significantly (27%) and are now in line with other countries. Norway registered a 23% increase but costs here remain below the all-country average nonetheless. This increase may be more reflective of low 2008-10 prices resulting from strategic bidding or more accessible sites than of high prices in the latter period. In general, however, cost decreases can be explained by technology learning, economies of scale (e.g. larger machines and wind projects) and changes in market conditions. The reasons for cost stagnation in Ireland and Germany are unclear. In Germany increases in hub heights required to access suitable wind speeds has been a factor limiting CapEx reductions, although these have contributed to reductions



(a)



(b)

Figure 3: Site trends in participating countries (weighted averages) (a) wind speeds adjusted to 100m elevation; (b) capacity factors. (Notes: no DE data available for (a); no EU data available for (a); 2009, 2010 NO data unavailable for (a) and (b).)

in LCOE (see next section). In Ireland, stagnant costs might be due to a significant loss of construction sector capacity following a deep recession in 2008-10 and subsequent strong economic growth resulting in high construction inflation; this may have offset any falls in turbine prices over the period. It is not possible to determine the extent to which individual CapEx components (e.g. turbines, site works, grid connections) contribute to these cost reductions due to data constraints. The effects of CapEx component changes on LCOE could not be investigated for the same reason (see inter alia Stehly et al. (2017) and IRENA (2018) for a more detailed analysis of recent changes in wind porject capital costs). Other studies have found that period-averaged global wind turbine costs have fallen by 26% (in real US$ prices) between 2008-10 and 2014-16 (Bloomberg, 2019). We find a 10% average decrease in the all-country wind project costs, suggesting that non-turbine costs have increased. If true, this may be due to higher land costs, greater site access difficulties, more substantial civil costs for larger units or additional grid-connection and reinforcement requirements as the easiest-to-develop sites are used.

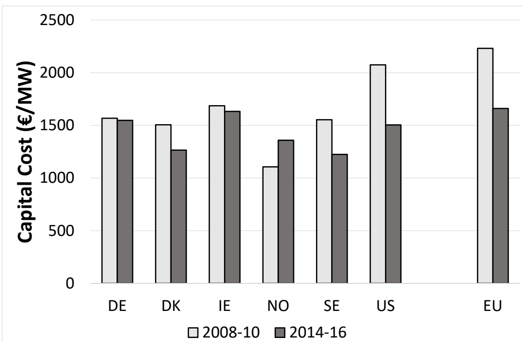
Operational cost ranges (see Figure 4(c)) were approximately 45-60 and 40-50€ /kW-yr over the 2008-10 and 2014-16 periods respectively for all countries. EU figures, however, are much lower but focus on direct turbine maintenance contracts and ignore other operation and maintenance charges such as land lease payments, insurance costs and owner costs; therefore, they may not be directly comparable to other OpEx statistics reported here. As mentioned above, OpEx data are limited for most countries so any observed trends should be treated with caution. Results indicate a moderate decrease (8-18%) over the period for all countries with the exception of Sweden which recorded the greatest reduction of 29%.

The period-average real, after-tax WACCs have fallen for all countries from the 2.9-5.6% range to 1.2-4.6%. Germany, Denmark, Norway and Sweden all recorded falls of 40-60% between the two averaging periods, with falls of approximately 15% in Ireland and the US. Decreases in the risk-free cost of debt over the period has had a significant impact on lower WACCs in all countries. For example, the period-averaged LIBOR has fallen from 1.09% (2008-10) to 0.29% (2014-16). Furthermore, since the mid-2000s wind power has come to be seen as a more mature technology with a proven track record and thus new projects attract lower risk premiums, thus reducing the cost of debt and, consequently, WACC.

5.2 Levelized Cost of Energy Trends

As discussed in Section 4, two LCOEs are estimated using 'standard' tax and depreciation ($\mathrm{LCOE_{std}}$) and 'national' tax and depreciation rates ($\mathrm{LCOE_{nat}}$). Figure 5 shows the results for both of these measures for the participating countries. In the 2008-10 period, values of $\mathrm{LCOE_{nat}}$ ranged from 45-89€/MWh, falling to 34-68€/MWh 2014-16. Denmark recorded the lowest national generation costs for both periods. The 2014-16 values for Ireland (68€/MWh) and Germany (57€/MWh) are higher than the other countries which cluster in the 34-49€/MWh range. It is evident that values decreased in all countries, with average decreases between the 2008-10 and 2014-16 periods of approximately 25-45% for all countries except Ireland, which recorded a fall of only 10% due to small declines in capital costs and WACC, as well as little change in capacity factors. In all other countries the combination of lower financing costs, increased capacity factors and falls in capital and operational costs resulted in the significant LCOE reductions observed.

Figure 5 also shows the $\mathrm{LCOE_{std}}$ results which indicate the relative differences in siting, performance and cost characteristics among countries, since financing, tax and depreciation differences are eliminated. Overall $\mathrm{LCOE_{std}}$ trends are similar to $\mathrm{LCOE_{nat}}$, with significant falls observed. Germany and Ireland record the highest 2014-16 values (both 62€/MWh) due to a combination of relatively higher capital costs with lower capacity fac-



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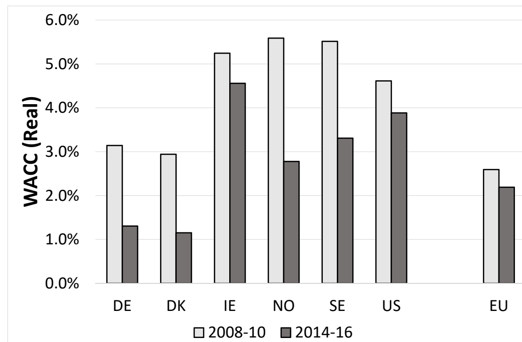

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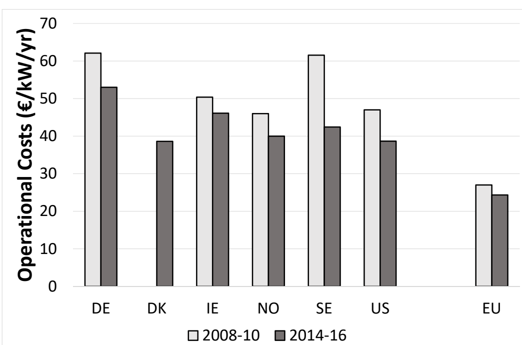


(c)

Figure 4: Cost and financing trends in participating countries (weighted averages) (a) unit capital cost (CapEx); (b) after-tax real weighted average cost of capital (WACC); and (c) unit operational cost (OpEx). (Notes: 2009, 2014 DE data, 2009, 2010 DK and 2009, 2010 NO data unavailable for (a). 2009, 2010 NO data unavailable for (b); 2009 DE, 2008-10 DK data and 2009, 2010 NO data unavailable for (c))

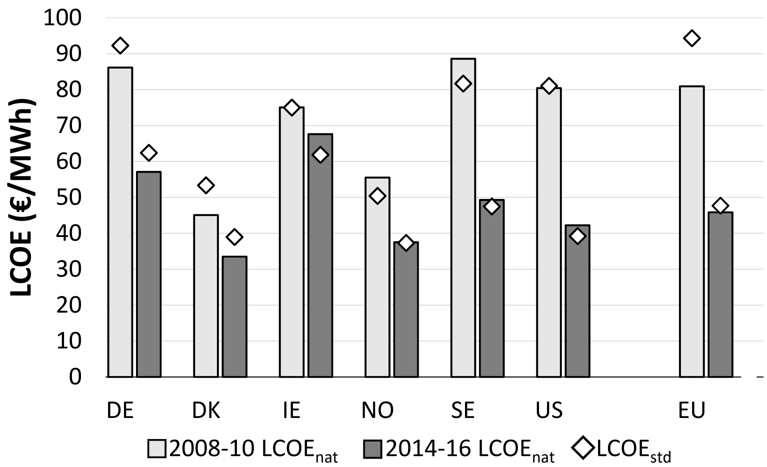


Figure 5: Levelized costs of energy results: 2008-10 and 2014-16 average $\mathrm{LCOE_{nat}}$ and $\mathrm{LCOE_{std}}$

tors. Conversely Denmark, Norway and the US have the lowest values (37-39€ /MWh); these countries have the highest capacity factors and lowest operating costs as well as relatively low capital costs. Country-specific financing, taxes and depreciation are relatively more costly in Ireland, Sweden and the US in the 2014-16 period, thus leading to relatively higher $\mathrm{LCOE_{nat}}$ than in other countries.

5.3 Components of LCOE Change

The factors contributing to the falls in $\mathrm{LCOE_{nat}}$ reported above are illustrated for each country in Figure 6. Overall, increased capacity factors (resulting in greater energy outputs) have had the greatest effect on reducing LCOEs, contributing to reductions in the region of 12-20€ /MWh except in Ireland and Denmark where much smaller contributions of 1 and 3€ /MWh were estimated respectively. The key driver of increased capacity factors appears to be the trend towards lower specific power machines. This is illustrated by the significant increase in capacity factors in the US where hub heights remained largely unchanged but specific power declined. In other countries, the combination of falling specific power and higher hub heights combined to increase capacity factors.

Falls in project investment costs (CapEx) have contributed significantly to lower LCOEs in Sweden, the US and the EU, with falls between 12 and 13€/MWh attributable to this factor; this is consistent with the significant CapEx reductions recorded in these countries (see Section 5.1). In Denmark, however, CapEx changes resulted in a smaller LCOE reduction (4.3€/MWh) and this parameter had virtually no impact in either Germany or Ireland. In contrast to other countries, the higher capital costs increased the Norwegian LCOE by almost 7€/MWh over the periods. Falling costs of finance, as measured by WACC, have resulted in $\mathrm{LCOE}_{\mathrm{nat}}$ reductions in all countries. This has had varying impacts, with reductions of as much as 8-9€/MWh in Germany, Norway and Sweden, but smaller decreases were observed in the US, Germany, Ireland (2.4-4.5€/MWh) and the EU (1.4€/MWh).

Operational costs resulted in a 7€/MWh fall in Sweden's LCOE, but had smaller effects elsewhere. Changes in corporate tax and depreciation rules had minor effects on LCOEs in Norway and Sweden resulting in reductions of 2 and 1€/MWh respectively, but had no observable effects in other countries.

5.4 LCOE and Market Value of Wind Energy

In this section we compare LCOE estimates to the market value of wind. This value can be thought of as the amount of revenue wind plants in each country would have earned if they had sold their power to the local wholesale power market and received no other policy or financial incentives. It should be noted that LCOEs are estimated over a 20-year project lifespan, whereas the market values of wind energy are for individual years. As such, comparisons should be handled with care.

An important policy consideration is whether the LCOE of wind has fallen to the price it can earn in wholesale electricity markets; LCOEs at or below this value would not need the types of direct supports which have traditionally been used to promote the technology. Figure 7 (a) shows $\mathrm{LCOE}_{\mathrm{nat}}$ for 2008-10 and 2014-16 as well as the market value of wind energy for both periods. It is evident that the falls in the cost of wind energy have been accompanied by falls in the market value of the electricity produced by wind projects. Whereas the overall average value of wind energy has fallen by 43% between the periods, LCOE has fallen by a lesser proportion (33%), thus indicating the 'grid parity' gap has widened. A number of factors ex-

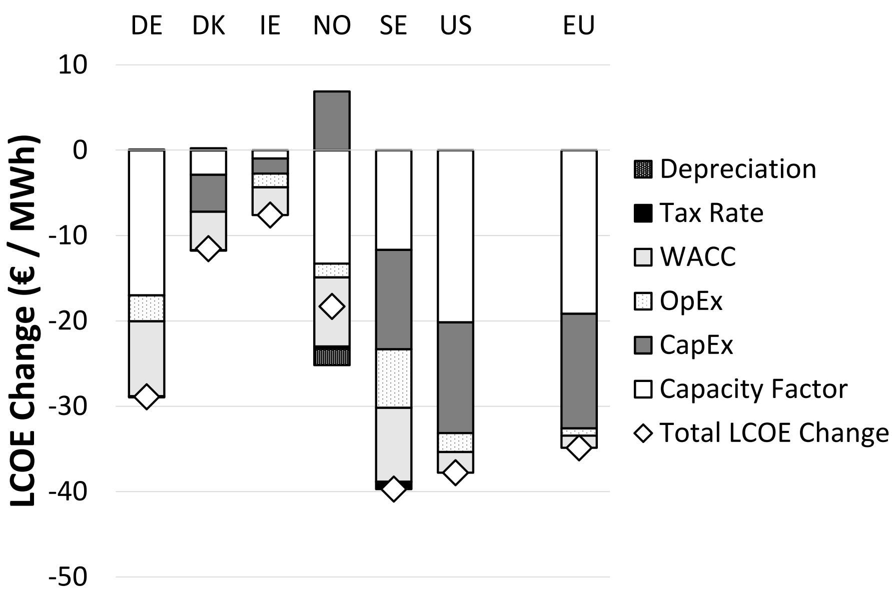


Figure 6: Contribution of input variables to changes in average national LCOEs for 2008-10 and 2014-16.

plain the reduction in wholesale electricity prices in the countries analysed, including: the significant decrease in the prices of fossil fuels over the period which has resulted in lower generation costs; and the increase in variable renewable energy production, which has a near-zero marginal cost and shifts the generation merit order so that wholesale electricity spot prices fall, especially at times when wind production is high (Wiser *et al.* 2017; Hirth 2018).

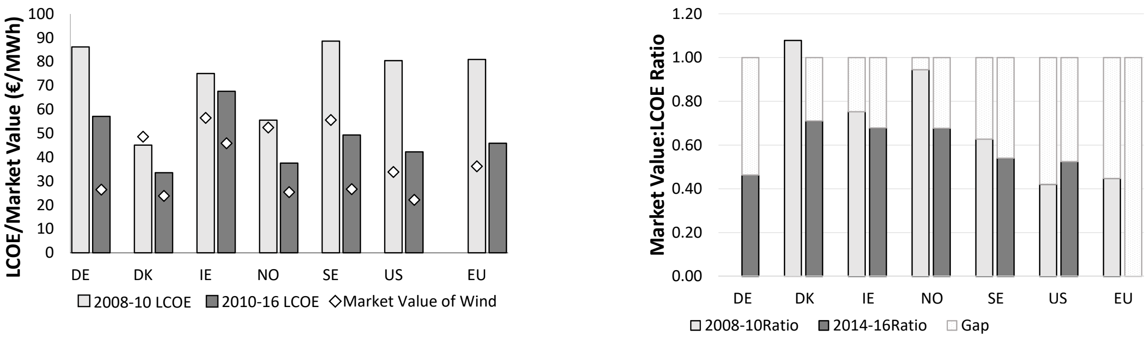
The market value of wind energy has decreased by approximately 50% for DK, NO and SE. Falls of 34% and 19% were recorded for the US and IE respectively. Data are unavailable for DE and the EU.

It is noteworthy that market values greater than LCOE were observed in Denmark in the 2008-10 period but that by 2014-16 this situation had reversed. This highlights the ongoing importance of understanding and forecasting the relative 'grid parity' gap between wind energy costs and wholesale electricity prices and how policy responses must consider the dynamic nature of this relationship. For example, the sudden removal of policy supports when electricity prices are relatively high may quickly result in the loss of investment incentives when they fall. While it is difficult for policymakers to forecast the market value of wind, there are expectations for a medium term increase of wholesale price in Europe possibly leading to grid parity in the medium term in many counties (Dalla Riva *et al.*, 2017).

Figure 7 (b) shows the ratio of the market value of wind to $\mathrm{LCOE}_{\mathrm{nat}}$ in both the 2008-10 and 2014-16 periods and indicates whether the 'grid parity' gap is increasing or decreasing in each country. It can be seen that ratios have fallen for all countries excepting the US, with the greatest falls observed in DK and NO (no comparative DE or EU data available). The 2008-10 ratio in DK was greater than 1 (1.08), but this fell to 0.71 in 2014-16 indicating that market value of wind fell more rapidly than LCOE. The US is unique in that the fall in LCOE has been proportionately greater than the fall in the value of wind energy, resulting in an increase in the ratio from 0.42 to 0.52. Small decreases were recorded in both IE and SE. By 2014-16 ratios for DE, SE and the US were in the range 0.46-0.54, while for DK, IE and NO they lay between 0.68 and 0.71.

6 Conclusions

This paper presents the findings of recent work undertaken by the International Energy Agency's Task 26 'Cost of Wind Energy' in relation to technological and cost trends in land-based wind energy in six participating



(a) (b)

Figure 7: LCOE and electricity prices: (a) LCOEs and the wholesale market value of wind energy 2008-10 and 2014-16 for participating countries; (b) ratios of wholesale value:LCOE of wind energy for both years. (Notes: market value of wind energy 2008-10 and 2014-16 unavailable for DE and EU respectively.

countries and the EU. Results indicate that there is a general trend towards larger, taller machines with lower specific powers resulting in higher capacity factors. Between the 2008-10 and 2014-16 periods, average hub heights, diameters and name plate capacities for all countries have grown by approximately 20% to 94m, 30% to 104m and 35% to 2.7MW respectively. The relatively greater increase in swept area than name place capacity resulted in a 10% decrease in specific power to 335W/m^2 and a consequent 14% increase in capacity factor to 34%.

Despite an increase in global wind speeds over the period, almost all countries recorded a small reduction in average wind speeds for new sites (2-4%), suggesting that high-quality wind resource sites are still available for development; the US saw a 4% increase. The use of lower specific power machines has meant that new project capacity factors have continued to increase despite these small decreases in site wind speeds.

Wind project capital costs have fallen for all countries by an average of 10% to 1,422€ /MW between the two averaging periods. Given the reported 26% fall in international wind turbine (as opposed to project) costs (Bloomberg, 2019), it appears that non-turbine development costs have increased in many countries. Reductions in the international cost of debt and the maturing of wind energy technology has meant that project finance costs fell significantly in many countries: approximately halving in Denmark, Germany and Norway; and falling by 10-15% in other countries.

These increases in capacity factors, falling capital costs and lower financing costs, in concert with trends in operating costs, taxation, and depreciation resulted in an overall fall of 33% in average levelized costs of energy for new land-based wind projects over the study period, which by 2014-16 averaged 48€ /MWh. However, large variations in national values were observed: in 2014-16 Denmark recorded the lowest levelized costs (national) at 34€ /MWh due to a combination of a good average capacity factor, relatively low capital costs and a very low weighted cost of capital; Ireland recorded the highest value of 68€ /MWh for the opposite reasons. The comparison of 'standard' and 'national' levelized costs shows that higher-than-average costs of national taxes, depreciation and costs of capital resulted in relatively higher 20014-16 values in Ireland in particular and, to a lesser extent, in Sweden and the US. In contrast, lower-than-average finance, tax and depreciation costs in Denmark and Germany helped to lower their production costs relative to other countries over the same period. These effects were largely explained by variations in national weighted average costs of capital rather than by taxes and depreciation.

An analysis of the components of levelized cost of energy change found that increases in capacity factors and decreases in weighted average costs of capital and capital costs had the biggest impact on lower levelized costs, accounting for 45%, 25% and 17% respectively of the decrease in the all-country average between the two periods. Operating cost reductions accounted for almost all of the remainder of the fall, but this particular result should be treated with caution due to significant data uncertainty. It is interesting to note that capital expenditure falls rank third in order of importance to the observed falls in levelized costs. Historically, however, wind-related technology learning literature has tended to focus on capital cost trends, although this only partly explains changes in the cost of wind energy production. Therefore, while larger turbines and the associated economies of scale will play an important future role in reducing wind energy costs, the impact of technological advances to enhance energy production should not be underestimated.

While levelized costs of energy have fallen in all countries, the value of wind energy has fallen proportionately more, meaning grid parity is possibly further away than previously thought. To what extent this fall in value is caused by low fossil fuel prices or the very low marginal cost of wind on the market is not known. It is therefore difficult to predict whether these prices will increase to close the 'grid parity' gap for land-based wind energy. Policymakers must therefore consider both the cost and value of wind energy, and understand the volatility of this gap when assessing competitiveness and designing policy measures to incentivise investment in wind projects.

Renewable energy technologies such as wind which require evidence-based policy supports need consistent, accurate and readily available data which can be used for national policymaking and international benchmarking. A wide variety of national data sources were used in this study, and while much of this was of high quality and internationally comparable, some areas were identified which require improvement. In particular, the quality and representativeness of operating cost data was a concern given its importance to life cycle costs. Similarly, there was uncertainty regarding the cost of finance (particularly the cost of equity) and financial structure; weighted average cost of capital has a significant impact on the levelized cost of energy. There was very little data on the break down of capital costs which hindered understanding of the where costs changes were occurring in the supply chain. Improving data quality requires up-front planning at a national level. In many respects Denmark is a good model for other countries. Here there is public access to a wide range of high-quality wind project data as a result of the Koberetsordning regulation which links project policy supports to data sharing.

In addition to improving data access and quality, several other extensions of this work hold merit. First, our analysis has focused on a narrow subset of countries for which data are collected though an International Energy Agency collaboration, but this analysis could usefully be expanded to a broader set of major wind energy markets globally. Second, our assessment has focused on land-based wind power, but as offshore wind power expands, it will be valuable to conduct similar assessments that disentangle cost drivers.

Finally, our analysis has focused on 2008-2016, but future work would usefully extend the time frame both back and forward in time, in part to inform future cost projections. The cost of land-based wind is not expected to remain stagnant; instead, additional technological advancements and cost reductions are anticipated (e.g., Wiser et al. 2016, NREL 2018). Moreover, given trends in the value of wind energy presented earlier, further cost reductions may be necessary if wind is to become a primary source of global electricity supply. While we do not project future costs in this paper, an assessment of historical costs and the applications of learning curves is one means of doing so, and the work presented here provides useful guidance in this regard. In particular, and as discussed previously, learning curves for wind have, with few exceptions, focused on extrapolating the capital cost of wind into the future. And yet, as shown in this paper, there are multiple means of reducing the levelized cost of wind energy — not only through capital cost improvements, but also through increased performance, lower operating costs, and improved financing. Any analysis that considers only capital cost improvements and that ignores other cost-reduction pathways is therefore likely to understate the potential for further cost reductions.

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