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# Optimal Over Installation of Wind Generation Facilities

Dr. Celine McInerney (corresponding author)

Room 3.12 O'Rahilly Building,

Department of Accounting, Finance and Information Systems

University College Cork, Ireland

c.mcinerney@ucc.ie

Professor Derek W. Bunn

London Business School

Regent's Park, London NW1 4SA. UK

dbunn@london.edu

# Optimal Over Installation of Wind Generation Facilities

## Abstract:

This paper evaluates the economic benefits to over-installing turbines on capacity-constrained wind farm sites in order to capture more energy at low wind speeds. Although this implies curtailment at high wind speeds, we show that over installing generation facilities can increase returns to investors and reduce system costs. A detailed model-based analysis is developed using British data, with variations in the range of over installation, the renewable policy support systems (fixed feed-in tariffs or green certificate premia to wholesale energy prices) and the extent of replacement of fossil generation in the technology mix with wind. In the cases of premia to market prices, we use agent-based, computational learning and risk simulation to model market prices. Not only is over installation beneficial under fixed feed-in tariffs, but is more so under premia to market prices and increasingly so as wind replaces fossil generation.

Keywords: Capacity investment, wind power generation, electricity markets, power system economics, risk, agent-based simulation, investment appraisal.

# 1. Introduction

For industrial supply chains in general, it is often the case that production capacities are installed at different levels to their distribution channels. Usually, inventories play a key role in balancing these operations, but even with products than cannot be stored or services that cannot be delayed, and in network industries where production and distribution are integral parts of one system, this mismatch between production and distribution capacities commonly occurs for various reasons. For example, if a network infrastructure is difficult to adapt, it may be oversized to accommodate future growth in production. Alternatively, production facilities may be oversized if their output quantities are unreliable. In the particular case of investment in wind turbines, both of these reasons could apply. Whilst it might generally be expected that it would be more beneficial for wind farm developers to retain a future expansion option by securing a larger transmission connection agreement than is required from the outset, in this paper, we explore the opposite specification of over installing production capacity in relation to a transmission or contractual constraint. Using a model-based analysis, calibrated to British data, we analyse in detail the circumstances under which this over installation may be profitable.

With government imperatives to meet targets for renewable energy as well as carbon emission reductions, e.g., European Commission (2013), substantial expansion of transmission grids and interconnections are generally regarded as pre-requisite. To the extent that these are long-term and expensive infrastructure commitments, they have become one of the limiting factors in the development of wind resources (EnerNex, 2010; GE Energy, 2010; Mills et al, 2009). Thus, it is recognised that not only do the best sites for wind generation get developed first, it is often more convenient to prematurely re-power at existing locations than develop new sites (Jensen et al., 2002; Energy Wind Power, 2010; del Rio et al., 2011;

Mauritzen, 2014; Staffell and Green, 2014). Even where land is available, objections to wind farms can limit their development. Barclay (2012) observes that, of the total number of applications for onshore wind farms per year in the UK, on average up to 50% of these do not pass the planning process. Grid connections are often allocated on a queue system and, as specified by their “maximum export capacities” (MEC), wind farm developers will clearly seek to maximise use of their MECs, once acquired. Furthermore, where government subsidies are required to support the economic case for investment, these awards are increasingly being allocated through auctions in which bids stipulate a per MWh delivery price and a maximum (MW) output (DECC 2014a). Once awarded, developers may choose to over install, to the extent allowed, in order to increase output at low wind speeds, but curtail output in high wind conditions to remain within their contracted maximum. Evidently, from a public policy perspective, the efficient use of existing grid infrastructure through higher load factors should be encouraged.

Over installing a wind farm implies the construction of more turbine capacity at the site than the MEC could allow under high wind speeds. With high wind conditions, therefore, output will be curtailed and the generators will not be fulfilling their output potential. The intuition, however, is that most of the time wind speeds will be lower, and by having more turbines on the site, for a fixed MEC, average output will increase. It is possible therefore, to envisage that profit contributions may be higher through increasing the average capacity factor[1]of the wind farm (MEC load factor) at the site (even though the capacity factor of the individual turbines, or turbine load factor will be lower), despite the opportunity cost of curtailing above MEC. Furthermore, if wind generators are exposed to market prices, then as spot prices tend to be lower (or even negative) under high wind conditions (Hirth, 2013; Sensfuß et al, 2008; Munoz and Bunn, 2013), this opportunity loss of curtailed revenue would be reduced to a

[1] Here we interpret capacity factor in its conventional way as the power produced over a period of time expressed as a percentage of the maximum power that could have been produced, Boccard (2010).

possibly negligible amount. The attraction of over installing therefore depends not only on the investment costs and wind speed distributions, but also upon the type of subsidy regime (full, partial or no exposure to market prices) and the market structure itself (ownership and penetration of wind technology) to the extent that market concentration influences market prices. Furthermore, where the MEC is a binding constraint (and connection cables do come in "lumpy" sizes), over-installation can be the logical response. Nevertheless, over installing implies greater capital investment and more capital at risk. To be clear about the intuition, it is not being suggested that a higher NPV can be obtained by over-installing on a constrained site compared to an alternative project with the same capital commitment on a larger unconstrained site (if that were possible); rather that, given the site constraint, the NPV of the project can be improved by over-installation. The transmission owner and system operators' perspectives may also be favourable, since any increased load factor will also apply to the transmission assets and system operations.

The benefit of over installing turbines on a wind farms site is best understood in terms of energy output[2]. Table 1 shows the variation in energy output with over installation. We see in Table 1 the distinction between the individual turbine load factor and the MEC load factor: while over installing turbines in excess of the MEC reduces the load factor of each turbine, the overall MEC load factor of the wind farm is increased. We refer to capacity factor throughout the paper as the overall wind farm MEC load factor.

**Table 1:** Energy Output with Over Installation

| Optimisation with GE 2.5 MW/ 100 rotor @ 7 metres / second | | | | | |
|---|---|---|---|---|---|
| Level of Installation | 100% | 105% | 110% | 115% | 120% |
| Installed capacity (MW) | 100 | 105 | 110 | 115 | 120 |
| Capacity constrained turbine rating (MW) | 2.50 | 2.38 | 2.27 | 2.17 | 2.08 |

[2] Full details on assumptions are provided below in Section 1.1 Over installation with a Fixed-Price Feed-in Tariff

| | | | | | |
|---|---|---|---|---|---|
| Net energy per turbine (MWh) | 6,335 | 6,248 | 6,145 | 6,027 | 5,919 |
| Number of turbines | 40 | 42 | 44 | 46 | 48 |
| Total wind farm energy (MWh) | 253,419 | 262,424 | 270,378 | 277,243 | 284,107 |
| Unconstrained wind farm energy (MWh) | 253,419 | 266,090 | 278,761 | 291,431 | 304,102 |
| Increase in wind farm capacity factor | | 3.6% | 6.7% | 9.4% | 12.1% |
| Energy constraint | | 1.40% | 3.10% | 5.12% | 7.04% |

For a “normal” 100 MW wind farm a developer might choose to install 40 x 2.5MW turbines which would produce 253.4 GWh annually (40 turbines x 6.3GWh/ turbine). If he over installs the number of turbines on site by 10%, he would install 44 x 2.5MW turbines (for total 110MW installed) and while the maximum output of each turbine will be constrained or turned down to 2.27MW (100/44), the total wind farm output is increased by 6.67% to 270.4 GWh (44 x 6.1 GWh / turbine). Further details are provided in Appendix 1.

The potential economic benefit of over installation has been noticed by both the Irish and UK regulatory bodies. In 2014, the Irish Commission for Energy Regulation, (CER, 2014), decided to allow wind generators to over install by up to 20%, updating an earlier decision, CER (2011), whereby generators were permitted to over install by 5% of MEC for technical reasons (to compensate for losses). CER (2011) noted that 50% of transmission connected projects and 27% of distribution connected projects had over installed for technical reasons by averages of 2% and 1.8% respectively. Both MEGAVIND (2014) and DNG (2014) highlight the over installation of turbines in excess of MEC on offshore wind sites, a practice known as “overplanting” in that industry. The rationale for overplanting in the offshore context is related to dynamic line rating and reliability but nonetheless highlights industry practices of over installing. In the UK, the provision for 25% over installation was anticipated in the UK Contract for Difference (CFD) scheme which is supported by the Levy Control Framework, DECC (2014a). Over installing turbines can also lead to reduced transmission use of system charges which are levied based on the MEC, or Transmission Entry Capacity in the UK, National Grid (2015)[3]. In manufacturing processes, redundancy is often created to provide for outages and maintenance. Given turbine contract manufacturers typically guarantee 95% availability[4], over installation provides a buffer for production down time due to maintenance and faults. Staffell and Green (2014) show that wind turbine output declines with age at a rate similar to other rotating machinery and showed the UK fleet of wind turbines lost 1.6% +/ 0.2% of output annually between 2002 and 2012, so there is a natural depreciation of wind turbines over their useful economic life which over installing could mitigate.

A more subtle impact of over installing wind turbines is the reduction in correlation of individual wind farm wind output and system peak wind output. Under Feed in Tariffs, wind generators are indifferent to wholesale market prices and so are less likely to be concerned with this effect (assuming wind generation is not curtailed). However, if exposed to market prices, a generator is likely to see higher prices if it is generating when the system-wide wind is below maximum. If more wind is generated when wind is below its peak, in systems with least cost dispatch, this is likely to reduce prices for consumers.

In this paper we seek to clarify the economic, rather than technical, drivers for more substantial over installation, how they may depend upon the nature of the subsidy and the evolution of renewable penetration into the market, as well as evaluating the benefits of the increased MEC capacity factor to (1) enhance system reliability, (2) ease system balancing

[3] Mott McDonald (2010) estimates these at £10,000 /MW/pa of total annual operating costs of £34,203/MW for onshore wind.
[4]SEAI
http://www.seai.ie/Renewables/Wind_Energy/Wind_Farms/Wind_Farm_Development/Wind_farm_Contracts_and_Agreements/

challenges, (3) increase the return on existing grid infrastructure and (4) reduce the risk of outages. These system considerations invite the question of whether there should be further policy incentives for over installation.

In the context of previous research, analysis of the optimal sizing of wind farms has not explicitly appeared and indeed Sturge et al. (2014) observed that "*questions of energy yield are notably absent from the growing literature on planning for wind turbines*". This is despite an extensive literature of the investment case for wind (e.g. Venetsanos et al., 2002; Munoz et al., 2009; Lee, 2011; Munoz and Bunn, 2013) and whether generation investment should lead grid investment or the other way around (Boldt et al., 2012; Neuhoff et al., 2011; Schroder and Bracke, 2012; Van der Weijde and Hobbs, 2012) as well as a very extensive amount of engineering and environmental research on optimising turbine layouts (Chowdhury et al., 2012; Ekonomou et al., 2012; Gonzalez et al., 2010; Kusiak and Song, 2010; Maki et al., 2012; Rajper and Amin, 2012; Saavedra-Moreno et al., 2011, Serrano-Gonzalez et al., 2011). A number of authors have used real options to value wind farms, including Abadie and Chamorro (2012), Kumbaroglu et al. (2008) and Mendez et al. (2009). Madlener and Schumacher (2011) and Himpler and Madlener (2011) have examined the value of the option to repower an existing wind farm site, whilst Lee (2011) provides a comprehensive review of the literature for renewable energy investments and uses real options to determine the value of wind farm sites in Taiwan. Whilst it might be envisaged that, as with repowering, the option to over install generally remains open indefinitely, in practice it is difficult to over install the number of wind turbines on a site once the wind farm is built. There are a number of reasons for this: planning permission requires turbine locations to be specified and planning permission has a finite life, restrictive covenants from senior lenders can prohibit further borrowing and capital for expansion may be more expensive (Abel and Eberly, 1996).

We therefore formulate the decision to over install being made alongside the original investment and without the real option element associated with subsequent re-powering. In that respect, we underestimate the value of the asset, but provide a clearer analysis of over installation per se, without it being embedded in a repowering option. In the next section we look at the basic economic case for over installation under fixed feed-in-tariffs. Then we analyse the premium-to-market prices (green certificates) alternative. This requires a description of our market price formation model. Finally, we provide some indicative analysis of the system benefits that higher MEC capacity factors at wind farms could provide.

## 1.1 Over Installation with a Fixed-Price Feed-in Tariff

The incentive to over install is analysed using a discounted cash-flow (DCF) investment model for a notional 100 MW wind farm. Energy output is estimated using the power curve for a GE 2.5 MW turbine with 100 metre rotor sourced from www.wind-data.ch (a site commissioned by the Swiss Federal Office of Energy). We follow Seguro and Lambert (2000) in using the Weibull probability density function with parameters *k* for shape and *c* for scale. They suggest that if no information about the variability of the wind is available then a *k* value of 2 is often assumed and if the average wind speed is specified, then the scale factor (*c*) can be derived from this mean. We consider a base case feed-in tariff of £95/MWh, being representative of the level of UK onshore subsidy (DECC, 2013b) and an average wind speed of 7 metres / second. This average is derived from the 28% capacity factor used by Mott McDonald (2010) in its electricity cost update for DECC, the power curve of the GE turbine as mentioned above, and industry standard losses for wake / site topology. Staffell and Green (2014) find a UK average wind speed at existing wind farm sites of 7.5 m/s +/- 1.5 m/s but note actual power generated varies depending on turbine hub height. The power delivered to the grid (or capacity factor) varies according to several factors including the power curve of the turbine used, hub height, losses for wake / site topology and cabling and transformer losses on the wind farm site, CER (2014). DUKES (2005) suggest that the long term average annual capacity factor for UK onshore wind farms has ranged from 24% to 31% with an average of over 27%. More recent data from DUKES (2013) reports UK onshore wind capacity factors of 27.4% in 2009, 21.7% in 2010, 27.3% in 2011 and 26.2% in 2012.

As wind farms are typically financed using debt and equity, Mott McDonald (2010), our DCF model examines the free cash flows to equity (after bank interest, capital payments and tax) and discounts these by the post-tax cost of equity. This methodology is consistent with Stowe et al. (2007). The cost of equity used in this analysis is 9.6% DECC (2012c, p.11) and the post-tax rate is 9.3%. All revenues and operating costs are inflated at 2% per annum and the model focuses on real cash flows. The effects of working capital are ignored but in reality there is very little working capital required once a wind farm is built. Capital allowances which are available to wind farm developments in the UK are not explicitly modelled but an effective tax rate of 7.9% (which reflects the value of capital allowances) is used, as in KPMG (2013). Appendix 2 gives the full set of DCF assumptions.

Whilst the NPV of the wind farm, computed as the sum of the free cash flows (FCFs) in each year discounted by the cost of capital, gives the conventional economic value, we recognise that an incentive to invest will only occur if the debt service coverage ratios required by senior lenders can be maintained. The debt service coverage ratio is defined as the total cash flow available to service debt divided by the interest and capital repayments in a given period, usually one year, as in Moody's (2009). The higher the DSCR, the higher the margin of safety for lenders. If wind output is lower than forecast, revenues will be lower and the DSCR will decrease.

Fitch (2009, p. 5) outlines how banks and rating agencies approach wind assessment: a typical wind energy assessment for a green-field project involves modelling the local wind speed, duration and direction. This necessarily relies on local wind measurements which are usually only available for a short period of one to three years. These are therefore usually correlated to a long term reference through the use of an index or with data obtained from a nearby weather station. Site-specific factors are incorporated in the wind energy assessment. The result of the wind energy assessment is a prediction of the wind farm's long-term average production as well as various levels of production that can be exceeded with a corresponding degree of confidence, reported as a probability of exceedance associated with a certain time period. Whilst a P50 (median) estimate is usually specified as the long-term output level, all other production quantiles apart from the P50 are associated with a specific period: a 1-year P90 value refers to the annual output level that should be exceeded over any 1 year period with a 90% probability while the 10-year P90 value refers to the average annual output over a 10-year period, etc. The closer the P50 and P90 numbers are, the greater the proportion of senior debt a bank will provide (Economist, 2010; Fitch, 2009; Garrad Hassan, 2011). Garrad Hassan, who provide wind output audit / verification services to banks suggest lender models typically size debt for P50 output based on 1.4x DSCR and 1.2x DSCR for P90 wind output. Wind farm financings corroborate these numbers, (Borod, 2005; Euroweek, 2007; Project Finance and Infrastructure Finance, 2011). The DSCR is a function of the leverage of the project; the shorter the length of maturity and the lower the equity share, the more important is the DSCR restriction, World Bank/ Danida (2003). In practice, the debt for a single wind farm will often comprise a number of tranches and these will be effectively sculpted to maximise the debt component based on a minimum DSCR being maintained in each year, (DEWI, 2013; Wind Power Engineering, 2012; World Bank/ Danida, 2003).

As the revenue numbers in the model are based upon six years of historic wind data, we take a conservative P50 output measure from which a DSCR of 1.4x would be indicative of an investment threshold based on the approach of lenders (Project Finance and Infrastructure Finance, 2011). In the fixed price model we focus on a minimum DSCR. However, in the variable price model, we show an average DSCR as this allows us to capture the intra year revenue risk in the DSCR measure for each year in the 22 year wind farm life. In reality the only time the DSCRs are likely to be breached is in the first 5 years as this is when debt repayments are highest.  While lenders may prescribe both minimum and average DSCRs to be maintained over the life of the project, the average DSCR provides a good proxy for the financial health and bankability of the wind farm and is one of the most widely used debt metrics in project finance, Merna et al. (2010). While over-installation can increase the NPV, it would only make sense to do so as long a critical bank covenants such as the DSCR are not breached. Furthermore, it is the relative change in the DSCR with over installation that provides a representation of the financial viability and bankability of the project that is of general interest in this analysis.

## 1.2 Fixed-price FIT Model-based Results

Using the valuation model outlined above, the impact on NPV and DSCR of over installing turbines with fixed-price FITs is presented in Figure 1. There is a clear incentive to over install turbines and the optimum appears to be 8%. The minimum annual DSCR, evaluated over the life of the facility, declines steadily when turbines are over installed but from a high level, so minimum DSCR levels are not breached.  Sensitivity analysis with FITs of £100/MWh and £105/MWh, gave higher NPVs and DSCRs, but the same optima.

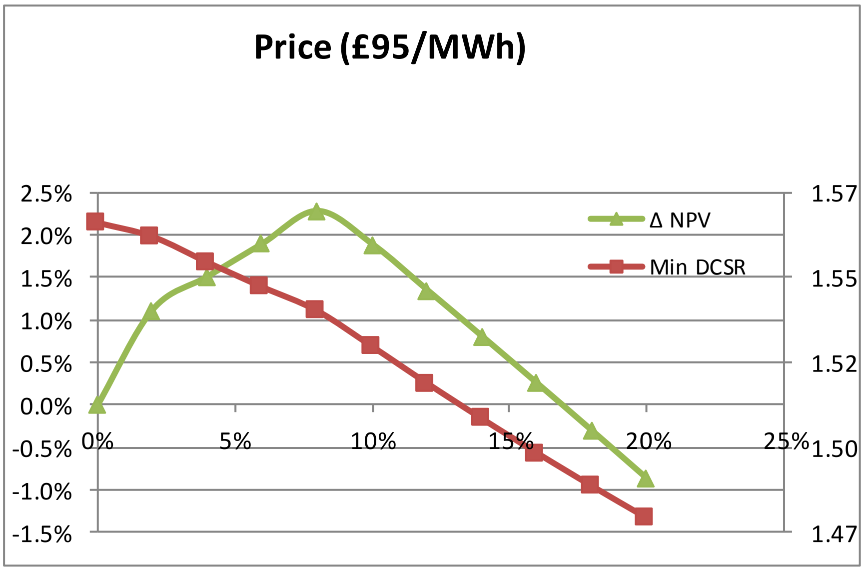


**Figure 1**: Over Installation with a Fixed-Price FIT

## 1.3 Sensitivity of NPV to Over-Installation with Fixed Price Model

Table 2 presents a sensitivity analysis using a range of prices and reflects the prices from DECC (2015) Contract for Difference (CFD) auction where prices for onshore wind were in the range of £79.23 to £82.50. The analysis shows that at lower prices there is much less incentive to over-install and indeed at prices of £80/MWh over-installing causes NPV to fall. This is because with low prices the additional capital cost of the over installation cannot be recovered.

**Table 2**: Price Sensitivity of NPV to Over-Installation of the Fixed Price Model

| ***Price in £/MWh*** | ***% Over Installation that Maximises NPV*** | ***↑ in NPV*** | ***Minimum DSCR (x)*** |
|---|---|---|---|
| £80 | 0% | Over-installing reduces NPV | 1.3 |
| £85 | 2% | 0.9% | 1.4 |
| £90 | 8% | 1.6% | 1.5 |
| £95 | 8% | 2.3% | 1.54 |
| £100 | 8% | 2.9% | 1.64 |
| £105 | 10% | 3.3% | 1.73 |
| £110 | 14% | 3.8% | 1.80 |

Sensitivity to the low and high capacity factors of 24% and 31% from DUKES (2005), (which implies average wind speeds of 6.4 metres/second and 7.3 metres /second) shows that with higher wind speeds, while the absolute NPV with 100% installation is higher, the incentive to over install is lower. This is because at a wind speed of 7 meters/second the wind farm is operating at full output 5.3% of the year, but with a higher average wind speed of 7.3 metres /second the wind farm is operating at maximum power 6.81% of the year so the impact of constraining off power is more significant at higher wind speeds. At a higher wind speed of 8 metres / second, the incentive to over install is lower as power is constrained off 10.7% of the year. CER (2014) confirm that the greatest incentive to over install is for medium wind speed sites. This is significant for progress with new investments as the best sites tend to get developed first, and as a consequence the relative value of over installing will increase as wind penetration increases and new sites are being developed.

## 2. Over Installation with Market Prices and Green Certificates

If wind investment is being supported with supplements to the market prices, either with fixed premia, or green certificates, even though market price risk will be a new element, the negative correlation of market prices and wind output may well work in favour of over installation and, furthermore, this negative correlation will become stronger as more wind replaces fossil fuels (Sensfuß, 2008; Munoz and Bunn, 2013). In order to investigate these issues, the exogenous fixed FIT prices in the previous model are replaced with a market sub model in which prices are endogenous and a function of wind output.

The market price formation model is specified as a conventional supply stack and demand model to derive market clearing prices at the intersection of demand and supply. It is formulated in substantial detail and calibrated to the GB market, as it was in 2012. This model allows for a probabilistic simulation of market prices on a half-hourly basis within a year so that a comparative static analysis of annual wind farm profitability can be used to examine the incentive to over install under a series of progressively increasing decarbonisation scenarios. A schematic representation of the modelling process is shown in Figure 2.

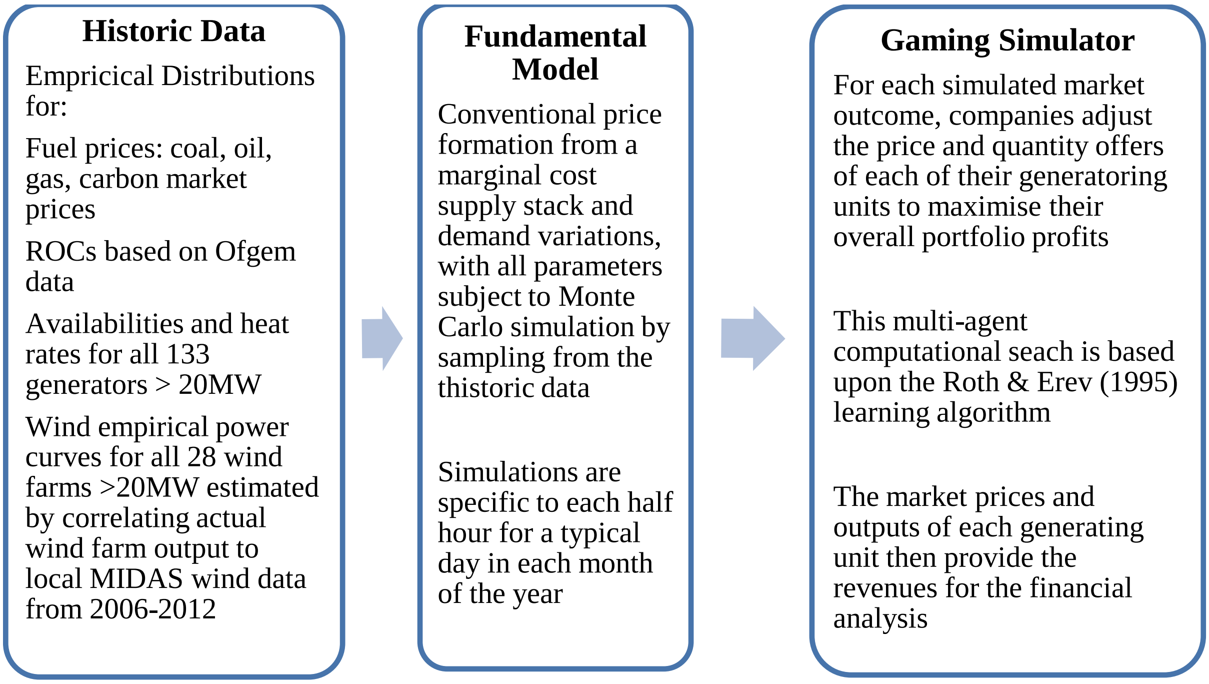


**Figure 2**: Market Modelling Sequence

The model is specified for half-hourly resolution and includes all 133 generating units with installed capacity in excess of 20 MW connected to the transmission grid, including all 28 wind farms (>20MW)[5], with their historic performance, geographical locations and local wind speed data. Empirical power curves for wind farms are generated by correlating actual wind farm output from hourly data for 2006 to 2012 to wind output from local weather stations[6]. This is a much more detailed approach than is often undertaken in similar models

[5] Smaller grid connected units were grouped into “others” category and embedded, distribution level generation was included on the demand side.

[6] Wind speeds for individual wind sites are based on historic wind speed data from the MIDAS surface database for the UK, UK Meteorological Office (2012). MIDAS Land and Marine Surface Stations Data (taken from the British Atmospheric Data Centre) http://badc.nerc.ac.uk/view/badc.nerc.ac.uk__ATOM__dataent_ukmo-midas.

and avoids estimation biases due to site specific effects. Wind generation connected at distribution level is treated on the demand side, along with other end-user behaviour. Price and generator output distributions are simulated using historic probability distributions for wind, demand, fuel prices and availabilities as well as their interactions. However, nuclear is always assumed to be at the bottom of the stack, although its marginal cost is higher than wind. This ensures nuclear output is not curtailed[7].

Furthermore, the analysis takes a company perspective. It includes generator ownership and models the effects of market concentration in moving price levels above marginal cost to those more reflective of an imperfectly competitive market. The model's Fundamental Simulator runs Monte Carlo price simulations of the marginal cost supply stack and demand, and then provides inputs into a Gaming Simulator which allows market players to individually optimize at the level of their portfolio of assets, for each simulation, the price and quantity offers for their generating units, according to the computational learning algorithm. The Gaming Simulator is designed to mimic the strategic decisions of major players to manage capacity availability as well as the generating unit mark-up decisions at each instance. As with many agent-based power market simulations, (Sensfuss et al, 2008), this process is done using the Roth & Erev (1995) computational learning algorithm. This is an iterative multi-agent search process based upon each agent maximising a profit function

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No adjustment is made for the difference in wind speed between the measurement height and the rotor height and this is a weakness in the analysis as Hirth (2013) and May (2015) note higher wind speeds are experienced at higher turbine heights. However, our analysis seeks to make general comparative conclusions and so the overall findings are not impacted.

[7] This may induce a price formation error in a stack price formation model depending upon how inflexible generators are treated within the market rules. The serial independence of simulations means that dynamic constraints such as ramp rates and start-up costs are not modelled explicitly but this is a common assumption (e.g. in modelling capacity adequacy by Ofgem, 2013). This approach may underestimate how low prices may go in periods with low demand and high wind output, when inflexible plant may offer discounted prices to remain in merit. However, for the purpose of comparative insights, we believe that our conclusions are robust to this modelling simplification.

through the reinforcement of successful strategies, the reversal of unsuccessful ones and persistent exploration of the strategy space. A probability distribution across capacity and mark-up choices is sequentially refined in this way for each agent with the "capacity gaming" stage preceding the "mark-up gaming." Each generating unit's mark-ups are independently derived for every simulation. The Base Simulator runs a Monte Carlo stochastic simulation and probability distributions are specific to each half-hour period. Each half-hourly period is independent, and so is each month (Full computational details are provided in Appendix 3). This serial independence in simulations means that dynamic constraints such as ramp rates and start-up costs are not explicitly specified, but this is a common assumption in long term modelling, and for example is used in the detailed medium term capacity assessment modelling by Ofgem (2013). On this basis, trading periods with low and negative prices underestimate how low prices might actually be if these dynamic inflexibilities were modelled explicitly.

Wind farm remuneration is based on the wholesale power market clearing price (the current APX market model) plus the renewable obligation credit (ROC). The model was initially calibrated to 2012 and substantial effort was given to precisely modelling location-specific wind farm generation and its portfolio implications. The basic model used in this analysis has also been presented in Bunn and Yusupov (2015). Under the system decarbonisation scenarios explored in Bunn and Yusupov (2015), the average price of £61.1/MWh projected by the model for 2015 was consistent with DECC (2012b) projections. Appendix 3 provides a more detailed description of the model and its calibration.

The technology mix is progressively decarbonised by replacing oil and then coal with wind. Under this decarbonisation sequence, new wind generation installation is assumed to be pro rata for the mix of onshore and offshore wind in 2011[8]. This methodology underestimates the scale of offshore development in the future but as this is a target year model it is a reasonable approach in this instance. A 17% equivalent firm capacity (EFC) Ofgem (2013, p.10) is used for wind to displace oil and coal in the technology mix. This is the amount of thermal generation that can be replaced by a particular capacity of wind generation while maintaining the same level of security of supply as measured by loss of load expectation (LOLE). It is the rate that the regulator used in the assessment of capacity adequacy Ofgem (2013). We assume a constant EFC under all decarbonisation scenarios but of course wind's contribution to firm capacity will decrease with increasing levels of wind penetration and this is a weakness in the model. The model is run from the 2 GW[9] of wind installed at the beginning of 2012 to 10.6 GW[10], 16.08 GW, 21.44 GW and 26.8 GW of wind installed. The model provides a distribution of annual revenues for each generating unit, which are then used as inputs for Monte Carlo simulation of NPV and DSCRs in the DCF model.

## 2.1 Over Installing with Market Prices and Green Certificates: Results

To understand the incentive to over install where wind farm owners are remunerated based on prices with green certificates (as opposed to under a FIT regime) two separate scenarios are modelled: (1) where only one 100 MW wind farm over installs, shown in Appendix 4 and (2) where all wind farms on the system over install, shown in Appendix 5.

[8] The ratio of onshore to offshore wind farms used in the model is 1.25 onshore to 1 offshore as only transmission-connected wind farms greater than 20 MW are included.
[9] The model only includes generators greater than 20 MW connected to the transmission network. Embedded, distribution level generation was included on the demand side. They are remunerated by the supply companies as they reduce demand for the supply companies.
[10] These particular sizes are driven by replacing coal units with wind in the system at the 17% equivalent firm capacity (EFC), as used by Ofgem (2013, p. 10).

Wind output data is generated based on historic data for wind speeds for individual wind sites from the MIDAS[11] surface database for the UK, UK Meteorological Office (2012). The weather station is chosen based on its proximity to each wind farm and the availability of full historic hourly wind data. Data for wind output is taken for seven separate wind farms which were in operation in 2011 and for which six years of clean historic wind data is available at the local weather station. Wind output generation for the wind farms is simulated based upon the wind dynamics of the associated weather stations. The wind farm power curves are empirically obtained by relating each wind farm's local weather station's wind speed to the wind farm's power output on an hourly level. The power curve characteristics of each wind farm include a cut-in speed, a full-capacity wind speed and a cut-off wind speed. Stochastic wind generation data is then produced for each of the seven wind sites based on wind profiles from the local weather station. Since wind farm wind speeds are correlated in the database, wind generation correlations are implicitly modelled through the simulated wind speeds and power curves. Demand is correlated to the wind output in the data base to account for wind-chill, following Dale et al. (2003) and Sinden (2007). Revenues for each wind farm are accumulated over all periods in the year at the market clearing price and output volumes as simulated for each period. The model thus simulates a series of statistical distributions of annual revenues under a number of different decarbonisation scenarios which are then used as inputs for the DCF investment model. Revenues are calculated based on simulations for each of the seven wind farm sites where 30 separate random simulations are run for each half hour in each year to give a total of 120,960 samples (7 sites over 12 months, each with a typical day of 48 half-hour periods and 30 Monte Carlo simulations). The final DCF calculations are sampled from the full set of simulations for computational efficiency as a consequence of the modular construction of a very large simulation model. The random

[11] MIDAS Land and Marine Surface Stations Data (taken from the British Atmospheric Data Centre) http://badc.nerc.ac.uk/view/badc.nerc.ac.uk__ATOM__dataent_ukmo-midas

sampling seeks to obtain unbiased and representative results, which should be achievable with 1000 draws. We agree that a stratified design for peaks and off-peaks, as well as maintaining the same sample for the different scenarios, would have improved efficiency. However, we still believe that the average results are unbiased and robust to this extra sampling variation.

## 2.2 Scenario (1) Variable Price Model with ROCs – Only One Wind farm over installs

This scenario explores the incentive to over install for a wind farm owner where he is the only generator on the system to do so. This will therefore have a negligible system price impact. Where only one wind farm over installs by, for example, 10%, revenue distributions are estimated as follows: a "virtual" 1.1 MW wind farm is located at each of seven weather stations chosen to be representative of the wind distribution across Britain. This is to avoid bias from selecting either a high or low wind speed site at one location. Each "virtual" 1.1 MW wind farm's output is capped at 1 MW. The "virtual" wind farms have a negligible impact on market prices (due to their size) and as such are price takers. So there are seven mini "virtual" wind farms in seven different locations. This methodology aims to replicate the average performance of a typical British wind farm and provides a generic revenue distribution, which is scaled up to represent a 100MW facility. Details are presented in Appendix 4 and are summarised in Table 3 below:

**Table 3**: Incentive to over install with Variable Price Model –One Wind Farm Over Installs

| Wind Installed (GW) | NPV with 0% over Installation 100MW wind farm (£m) | Turbine and MEC Capacity Factor with 0% over | NPV with 20% over Installation 100MW wind farm (£m) | Δ NPV (%) | MEC Capacity Factor with 20% over Installation[MC1] | Avg DSCR @ 20% over Installation (X) |
|---|---|---|---|---|---|---|

| | | Installation | | | | |
|---|---|---|---|---|---|---|
| 2 | 51.22 | 30.5% | 58.72 | +12.8% | 35.4% | 1.86 |
| 10.5 | 47.29 | 30.6% | 52.97 | +12.0% | 35.4% | 1.79 |
| 16.08 | 39.78 | 30.1% | 44.44 | +11.7% | 34.9% | 1.69 |
| 21.44 | 26.53 | 28.5% | 31.38 | +18.3% | 33.5% | 1.54 |
| 26.8 | 10.60 | 26.5% | 13.69 | +29.1% | 31.1% | 1.33 |

Looking at the Base case results for scenario 1, (full details are presented in Appendix 4), we observe a steadily increasing NPV with over installation and a comfortably acceptable DSCR. In the base case with just 2GW of wind installed the DSCR is 1.86x, and across the range of 0 to 20% over installation the DSCR is consistently above the 1.4x level which is likely to be required by senior lenders, except in the case of 26.8GW of wind installed where is falls to 1.33x[12]. This contrasts strongly with the fixed-price FIT pattern reported previously which reached a maximum around 8% for the £95 and £100 tariffs (the average price per MWh in scenario 1 is £97.40, which is halfway between these two variants). The conjecture that over installation will be even more attractive when the subsidy policy is a supplement to market prices, rather than a fixed tariff, is therefore confirmed in these simulations. We see the effective capacity factor increasing steadily from 30% to 35% as the over installing goes from 0 to 20%. The production facilities are becoming more profitable because greater use is made of the constrained factor (transmission capacity) and the unconstrained factor (turbine capacity) is receiving marginal revenues above its marginal cost. In these circumstances, accepting a lower turbine capacity factor is the efficient thing to do. However, we should acknowledge that while the absolute NPV has increased, in the case of over installation, investors will have put further capital at risk than they would in a wind farm that was not over installed.

[12] Recall a higher DSCR gives a greater margin of safety for lenders. Garrad Hassan (2011) who provide wind audit and verification services for lenders suggest lenders require a minimum DSCR of 1.2 to 1.4 x depending on the length of historic wind output available. As the revenue numbers in the model are based upon six years of historic wind data, we take a conservative P50 output measure which would imply a DSCR of 1.4x (Borod, 2005; Euroweek, 2007; Project Finance and Infrastructure Finance, 2011).

It would seem from this analysis that if a wind farm project has a significantly positive NPV after deducting all of the costs and using the correct cost of capital, there may be excessive rents in the system. While every effort was made to ensure the capital and operating costs and cost of capital are accurate, they are based on historic published sources and so it is not clear if these reflect the current market reality. Also, with respect to cost of capital, it is hard to estimate the risk premium required by investors particularly as decarbonisation increases prices volatility and investors will thereby demand higher returns. Nonetheless, we have to acknowledge the potential that rents exist and the attendant public policy issue this raises[13].

As decarbonisation progresses, from 2GW to 26.8GW, the first property to notice is that with no over installation the profitability of a new wind unit gradually decreases, both in terms of NPV and DSCR. This is consistent with results published elsewhere (e.g. Munoz and Bunn, 2013) and reflects the effect of increased penetration of wind lowering market price levels and increasing the downside risk. However, in all cases shown here, the investment criteria are met and remarkably again, in all cases for a given market structure and level of decarbonisation, the benefit of over installation increases steadily up the range to 20%. We can also see this in the capacity factors, which remain similar until we get to 21.44GW wind in the system. At this point, with no over installation, the capacity factor drops from 30.1% (with 16.08 GW wind) to 28.5%, as excess wind capacity become curtailed system wide at various times, but note that the benefit of 20% over installation is to bring this up to 33.5%. This 18% increment in capacity factor from 20% over installation is actually greater than the increments achieved in the lower 2GW, 10.05GW and 16.08GW wind penetration states.So as decarbonisation deepens through more wind, the marginal benefit of over installation increases.[MC2]

[13] The rent in the UK system is apparent when UK prices are compared to prices in the Republic of Ireland. For example, the price available to Irish wind generators greater than 5MW under the Renewable Energy Feed in Tariff was €69.58 in 2014 (DCENR, 2015) compared to prices proposed by DECC (2013b) of £95/ MWh.

Perhaps more remarkably, we can compare over installation with the alternative of building a new Greenfield facility with the same capacity as the over installation. We would expect a new Greenfield facility of say 120 MW (wind farm A) to have a higher NPV than a 100 MW wind farm over installed by 20% to 120 MW (wind farm B) because there would be no local curtailment, offset somewhat by savings on the set-up and connection. The NPV of the smaller but over installed (wind farm B) facility can therefore be taken as pro rata of the case with zero over installation in wind farm A[14]. For the Base case, the % increase in NPV with over installing is in all cases slightly less than the level of over installation, which means that without the offsetting set-up costs, 'normal' 120 MW wind farm A (if it could be developed conveniently) gives a higher NPV. However, looking at the situation with more wind in the system, e.g. 26.8GW, then the increase in NPV with over installation is substantially higher than the % over installation. This means that it is more profitable to over install than build a separate facility, even without the set-up benefits. The benefit of over installing under decarbonisation is that the wind farm will generate more wind output off-peak which will receive higher prices in a system where it is remunerated based on market prices. Moreover, in high wind conditions, with substantial wind generation on the system, low and sometimes negative prices will occur which, if the facilities are price takers, will adversely impact an extra turbine compared to an over installed site. For these reasons we see higher NPV from a 100MW wind farm over installed by 20% than from a new 120MW wind farm[15]. Furthermore, the reduced fixed costs of operating an over installed farm may also be

[14] In our DCF model, operating and maintenance (O&M) and land leasing costs are estimated on per MW installed, while insurance and rates and connection and use of system charges are based on MEC (as is industry practice). However, capital costs are based on the number of MW installed, so in the case of over installation, the increase in NPV may in fact be understated as a certain amount of grid connection and electrical costs would be fixed on the MEC.

[15] In practice it is likely that the larger site would chose to curtail at the high wind speeds because of detrimental negative prices. These negative prices are largely driven by increasing penetrations of offshore wind which at high levels of wind output can bid prices up to the value of two Renewable Obligation Credits (ROCs) to ensure they stay in merit. This creates negative prices below the subsidy level (1ROC) for onshore facilities and is thereby detrimental. The strategic option for the onshore facility to curtail output is not implicit in these comparisons. If it were, it would mean that there is no revenue difference for the higher installed (i.e. 120MW MEC) wind farm compared to the over installed (i.e. 100 MEC +20MW) constrained wind farm.

significant. Thus, at higher levels of decarbonisation, even though the profitability of wind investment declines, the relative value of over installation increases. This suggests investment in over installation is not likely to become stranded, *ceteris paribus*, as the market evolves to more wind generation in place of coal and gas.

## 2.3 Scenario (2) Variable Price Model with ROCs – All Wind farm Over Install

It is unlikely that all wind farms will be able to over install, but as a limiting case, the analysis is revealing. We notice that the results of over installing when there are just 2 GW and 10.5 GW of wind on the system are almost identical to the scenario 1 case. But in scenario 2, over installation starts to reduce NPV after 16.08GW decarbonisation. Although NPVs remain positive and capacity factors increase, the DSCRs become critical by 26.8GW and it is better not to over install. Evidently over capacity is having a detrimental effect in the extreme case of widespread over installation. As with all markets, overcapacity ultimately becomes unprofitable, but in this context, with renewable investment being driven by policy, it is likely that the capital costs and subsidy levels will be rather different, once the market has reached over 20GW installed wind. Either technological learning will have brought the capital costs down, and/or government subsidies will have increased to make an incremental wind investment as profitable as in the base case.  If we look at the base case of no over installation, with progressive decarbonisation, we see that with 2GW of wind installed on the system the NPV of a 100 MW wind farm is approximately £50m, dropping to £46m with 10.5GW wind installed, £39m with 16.08GW wind installed, £28m with 21.44GW wind installed and £11m with 26.8GW wind installed. While these is an incentive to over install up to 19.2 GW (16.08GW *120%) of wind on the system, there appears to be a wind saturation point somewhere between 19.2 and 21.44 GW of installed wind beyond which not only is the NPV of over installing negative but the NPV of investing in a regular (i.e. not over installed)

100 MW wind farm also diminishes. Full details of scenario 2 which considers the impact of all wind farms over installing are presented in Appendix 5. A summary is presented in Table 4 below.

**Table 4**: Incentive to over install with Variable Price Model –All Wind Farm Over Installs

| Wind Installed (GW) | NPV with 0% over Installation 100MW wind farm (£m) | Turbine and MEC Capacity Factor with 0% over Installation | NPV with 20% over Installation 100MW wind farm (£m) | Δ NPV (%) | MEC Capacity Factor with 20% over Installation | Avg DSCR @ 20% over Installation (X) |
|---|---|---|---|---|---|---|
| 2 | 50.77 | 30.3% | 58.56 | +13.3% | 35.4% | 1.86 |
| 10.5 | 46.21 | 30.4% | 52.23 | +13.0% | 35.4% | 1.79 |
| 16.08 | 39.25 | 30.1% | 41.00 | +4.5% | 34.9% | 1.65 |
| 21.44 | 28.11 | 28.8% | 21.47 | -23.6% | 32.4% | 1.42 |
| 26.8 | 10.70 | 26.5% | 1.99 | -81.85% | 29.4% | 1.19 |

# 3. System Benefits of Over Installation

As well as increasing the return to investors in wind generation assets, over installing turbines on wind farm sites offers several benefits for system operators. Over installing wind turbines ensures the more efficient use of existing grid infrastructure and can reduce or delay expensive grid reinforcements to facilitate higher wind penetration thus increasing the return on existing grid infrastructure assets. There is also an argument that due to over installing security of supply is improved which potentially reduces the risk of outages. Over installed wind can also provide system balancing and ancillary services as wind operating at less than 100% of maximum output can provide frequency and voltage control which become increasingly significant as the level of wind penetration increases.

## 3.1 Saving on Grid Investment through Increased Capacity Factors

There is a significant body of literature dedicated to whether generation investment should lead grid investment or the other way around (Boldt et al., 2012; Neuhoff et al., 2011;

Schroder and Bracke, 2012; Van der Weijde and Hobbs, 2012). Given the relative cost of generation compared to transmission and distribution assets, it may seem paradoxical to focus on how over installing can impact on grid investment. Nonetheless, the increase in capacity factors that is possible by over installing turbines on wind farm sites will evidently translate into the use of distribution and transmission facilities. If wind farm investors could be incentivised to over install turbines on their individual wind sites and maintain exports at the site's MEC, then there could be a significant reduction in grid investment which would increase consumer welfare. In a review of transmission integration cost studies for 40 US wind farms in the period 2001 to 2008, Mills et al. (2009, p. vii) find a median unit cost of transmission of $300/kW ($300,000/ MW), or roughly 15% of the current $2,000/kW cost of building the wind project. The All Ireland Grid Study (AIGS)[16], ESB International (2008) examines the costs associated with increased penetration of wind in Ireland and finds the cost of grid reinforcements / investment increases from €92 million with 2.2 GW of wind installed to €1,239 million with 6.9 GW installed or €244,042/MW installed, ESB International (2008, p. 14). In a study of German transmission expansion to facilitate integration of renewables, Boldt et al. (2012) estimate fixed HVAC costs for overhead lines of €150,000/MW, and variable HVAC overhead line costs of €400/MW/km and variable HVDC cable costs of €1500/MW/km. Based on a distance of 50 km[17], the estimate of total costs is €245,000/MW which is consistent with estimates from the US and Ireland. Obviously the level of grid investment / reinforcement is variable and depends on a number of factors including the length, type, congestion, capacity and terrain of the underlying transmission lines so these estimates provide an indication only of potential transmission expansion costs. By assuming an average cost of grid reinforcement of £200,000 per MW of installed power and an increase

[16] Commissioned by the Department of Communications, Energy and Natural Resources.
[17] This distance of 50km for Germany is somewhat arbitrary, in reality there are structural bottlenecks for transportation of wind energy in the North-South direction which are to be overcome by long HVDC lines of 400-800km.

in capacity factor of 10% for new wind farms, the UK could, for example, save about £300 million on grid investment in reaching its 2020 targets.

## 3.2 Reduction in Reserve Requirement Due to Additional Capacity

In many jurisdictions, capacity payments are in place to incentivise investment and maintain generation adequacy. In December 2014, National Grid (2014) announced successful applications in the UK's first Capacity Market auction will be paid £19.40 per kW for providing available capacity in winter 2018/19. Evidently, if wind is being subsidised under renewable incentives, it is unappealing to grant it additional capacity payments, and especially since it cannot commit to firm reserve on demand[18]. However, if over installation increases the capacity factor of existing plant, it does improve resource adequacy and reduces the need to procure further capacity in the auctions. Furthermore, the curtailed power that is due to over installation does not receive any remuneration from feed-in tariffs or ROCs. Thus, there is an argument that the expected curtailed power associated with over installation should receive some capacity credit, security of supply is improved. On this basis, we estimate that if all GB wind farms were over installed by 10%, an estimated payment of £1.30/MWh[19] could be paid to generators on over installed hours based on the system benefits of available capacity.

[18] In the UK wind does not receive capacity payments.

[19] This is based on and additional payment of £32,980 for over-installing 10 MW of wind on a 100 MW farm (Capacity payment of £19.40 per kW x wind equivalent firm capacity factor 17%). This is adjusted by the ratio of constrained to unconstrained output on 110MW compared to 100MW wind farm in MWh at 67% ((270,378-253,419)/ (278,761-253,419)) where 253,419 is the output (MWh) from a 'normal' 100MW wind farm, 278,761 is the output from a 110MW wind farm, and 270,378 is the output from an over installed 110 MW wind farm with a 100 MW MEC. The extra output would be valueless from a capacity point of view if it came when the station was constrained, and it is likely that times of capacity stress will be when the wind is low, and the *station would* not then be constrained. This is an over-simplification as the 17% reflects generation uniformly spread between 0% and 34%. This payment is then divided by the dispatchable additional MWh of energy generated 16,959 MWh (270,378-253,419) = £1.30 by over-installing by 10%. While it is not intuitive to remunerate capacity with a payment to energy if over installation increases resource adequacy and reduces the amount of capacity to be procured in future capacity auctions we consider this reasonable.

## 3.3 System Balancing and Ancillary Services

Whilst it is clear that the system operator cannot rely upon wind to increase output at short notice, the opposite is not the case. Wind turbines can be instructed to reduce power very quickly. In the GB market this is a valuable balancing service as there is generally a greater requirement for down regulation than up. This is because market participants appear to prefer to be slightly over contracted ("long") at "gate closure" when power exchanges close and the system operator commences the balancing process. Since balancing availability is generally only declared at gate closure, there is potential for participation, and more so if the wind farms are over installed. However, since the marginal cost of wind is so low, together with the energy subsidy, the system operator will generally take higher bids from other facilities most of the time.

Of more impact to wind generators in systems with a substantial amount of wind is the possibility of enforced curtailment of wind output (Denny et al., 2010; Smith, 2010). In many jurisdictions, SOs have capped the amount of total demand that can be served by wind since a synchronous power system relies on the generators having physical inertia to protect the system against disturbances, such as trips of lines or units, and wind turbines have little inertia. Rogers et al. (2010) revealed that in 2009 in the US, wind generation curtailment ranged from as low as 1 per cent in the Midwest Transmission System Operator's (MISO) control area to as high as 16 per cent and 10 per cent in Texas and Alberta, Canada respectively. The Irish SO, Eirgrid (2011) estimates that 4-10% of wind energy in 2020 will be curtailed to keep the total generation from wind below 50%. McGarrigle et al. (2013)

report similar results. Curtailment and its compensation costs may be minimised as the amount of compensation needing compensation will fall if generators self-curtail because they are exporting greater than their MEC. So while total curtailment is likely to increase, the amount needing compensation should fall.

Apart from energy balancing, one of the chief concerns for system operators with high levels of wind penetration is frequency and voltage control. Papalexoulos and Andrianesis (2012) highlight that while higher penetration of renewable generation will increase the need for faster ramping resources, there are no incentives for wind generators to provide these services, and this has implications for frequency and voltage control. In order for a generating unit to be used for primary frequency regulation, sufficient reserve capacity must be available. The suggested approach to address this issue is to shift the turbine from operating at its optimal power extraction condition to a reduced power level. Because of this generation margin, wind generators can participate in frequency support (Vidyanandan and Senroy, 2013). In some jurisdictions (for example Ireland), wind generators are paid a fixed availability payment per megawatt hour of so-called reactive power capability (€/Mvarh), which provides for voltage and frequency stability. A typical wind farm is usually specified to just meet the grid code requirements. For example in Ireland this is 0.33 of its active power in reactive power rating (this is set out in grid code compliance requirements)[20]. A specific reactive power chart could not be obtained from commercial wind turbine manufacturer but a generic P-Q curve is reported in Kayikci and Milanovic (2007) who show that the reactive power of a turbine can be increased if the turbine is operating at less than 100% active power. Using the P-Q curve from Kayikci and Milanovic (2007) we estimate, 1 MW of a wind turbine generator capacity can create 0.33 MVArh at 100% output and nearly 0.4 MVArh at 90% active power. On a 110 MW wind farm constrained to 100 MW, this

[20] See http://www.eirgrid.com/renewables/gridcodeforrenewables/

represents an extra 7.7 Mvarh capability which is worth £11.93[21]/MWh on the over installed capacity.

## 4. Conclusions

Our results indicate that by over installing turbines on a wind farm site, it is possible to increase the MEC capacity factor of the wind farm, which results in a higher NPV. This allows investors to exploit the investment trade-off where higher capital costs of over installation of turbines can be recovered because more wind is captured mostly at lower wind speeds when the output is more valuable. However, despite the increase in NPV, it should be observed that additional capital is at risk by over installing the wind farm sites. There are also potentially significant cost savings for electricity consumers through the system benefits of higher transmission utilisation, lower reserve procurements and some ancillary services.

In a GB example, under a fixed-price FIT scenario of £95/ MWh (which is the price proposed by DECC (2013b)), it is optimum to over install turbines by about 8% and this will result in an increase in project NPV of about 2.3%. Under fixed prices, for higher wind speed sites the incentive to over install is reduced as wind is constrained off more than for low wind speed sites so the additional cost of over installing turbines is not recovered through increased revenues. The opposite holds for low wind speed sites. This is an important policy insight because many of the high wind speed sites have already been commissioned and over installing is a way to increase the effective capacity factor on remaining low and average

[21] This is calculated based on the increase in reactive power capability between a wind farm operating at 90 (Mvarh= 0.4) and 100% (Mvarh=0.33) output (0.4 /0.33 -1 = 21.2% ) 21.2% x increase in reactive power on 110MW wind farm ((0.4-.033)*110 = 7.7 (Mvarh) x price /Mvarh reactive power £3 x 8,760 hours in year = £202,356 divided by total hours of energy produced on over installed 10MW (16,959) = £11.93. Reactive power is available on most wind turbines even if they are barely turning. Strictly speaking full reactive power is probably available between wind speeds above 4 metres per second and below 25 metres per second. Based on the power curve of the GE turbine used in the fixed price model reactive power would be available for 7,881 hours or 90% of the time. Also, GE have a new turbine WIND FREE that can produce reactive power even when the turbine is not turning. See: http://site.geenergy.com/prod_serv/products/renewable_energy/en/downloads/Solutions_for_Wind_Power_Performance%20-%20GEA14595B.pdf

wind speed sites. This may be particularly relevant for regions with high renewable targets and low capacity factors for wind.

Distinct from fixed price feed-in tariffs, in markets where subsidies to wind generators are supplements to the stochastic market prices, over installing turbines increases the NPV to investors even more so than with the fixed feed-in tariffs. This is because market prices tend to be lower at high wind speeds and so the opportunity cost of curtailed power is less. Additionally we found, that as decarbonisation progresses, other things being equal, the benefits of over installing increase. From a risk perspective, over installing is attractive because the additional output generated with the over installed turbines is much more valuable than the average price received per MWh of generation, since the extra output is generated under low wind conditions. Furthermore, over installing can reduce the high negative spikes in systems with high wind penetration, which would ultimately reduce the cost of capital for all generators. So, if over installing is beneficial, it would be even more so under green certificate and premium subsidy systems than under fixed price or capital subsidies.

All of this raises the question, not only whether profit maximising generators may choose to over install, or at least evaluate its option value, but also if policy incentives to over install turbines should be positively implemented. The potential policy support would need to be considered in terms of economic rents being earned in the sector but also in the context of increasing financial risk under deep decarbonisation scenarios. To some limited extent, policy makers could potentially increase the MEC capacity factor of wind, increase the return on transmission assets, increase the level of reserve, increase system stability, mitigate negative price spikes and at the same time create a return on investment that will be attractive for investors in renewable energy generation assets. Perhaps the Transmission System Operator, with responsibility for system stability and reserve could make a grid tariff payments for these services. Although over installing would only make a small contribution to these benefits, this option to over install is compelling given the scale of investment required to meet renewable energy targets and the attendant investment required into transmission and system operations.

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## Appendix 1: Wind Output Optimisation with Over Installation

| **Optimisation with GE 2.5 /100m rotor** | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Level of Installation** | **Base data** | **100.0%** | **102.0%** | **104.0%** | **106.0%** | **108.0%** | **110.0%** | **112.0%** | **114.0%** | **116.0%** | **118.0%** | **120.0%** |
| Installed capacity (MW) | 100 | 100 | 102 | 104 | 106 | 108 | 110 | 112 | 114 | 116 | 118 | 120 |
| Constrained Turbine rating (MW) | 2.5 | 2.50 | 2.45 | 2.40 | 2.36 | 2.31 | 2.27 | 2.23 | 2.19 | 2.16 | 2.12 | 2.08 |
| Net energy per turbine (MWh) | | 6,335 | 6,307 | 6,267 | 6,229 | 6,193 | 6,145 | 6,097 | 6,050 | 6,005 | 5,961 | 5,919 |
| no of turbines | | 40.00 | 40.80 | 41.60 | 42.40 | 43.20 | 44.00 | 44.80 | 45.60 | 46.40 | 47.20 | 48.00 |
| Turbine capacity factor (by individual turbine) | | 28.9% | 28.8% | 28.6% | 28.4% | 28.3% | 28.1% | 27.8% | 27.6% | 27.4% | 27.2% | 27.0% |
| Wind farm capacity based on MEC | | 28.9% | 29.4% | 29.8% | 30.2% | 30.5% | 30.9% | 31.2% | 31.5% | 31.8% | 32.1% | 32.4% |
| Increase in capacity factor for wind farm | | | 1.5% | 2.9% | 4.2% | 5.6% | 6.7% | 7.8% | 8.9% | 9.9% | 11.0% | 12.1% |
| Total windfarm energy (MWh) | | 253,419 | 257,321 | 260,723 | 264,125 | 267,527 | 270,378 | 273,124 | 275,870 | 278,615 | 281,361 | 284,107 |
| Unconstrained wind farm energy (MWh) | | 253,419 | 258,487 | 263,555 | 268,624 | 273,692 | 278,761 | 283,829 | 288,897 | 293,966 | 299,034 | 304,102 |
| Energy Constraint | | | 0.45% | 1.09% | 1.70% | 2.30% | 3.10% | 3.92% | 4.72% | 5.51% | 6.28% | 7.04% |

## Appendix 2: DCF Model Assumptions for Fixed Price FIT

**Capital and Operation and Maintenance (O&M) costs**

- Construction and O&M costs are taken from Mott McDonald (2010) and DECC (2012a). The costs are for a 100 MW wind farm. Commissioning is assumed to take place in 2020 with the decision to invest being made in 2013.
- Capital costs are £1,500/kW, DECC (2012a).
- Weighted average fixed and variable operating and maintenance costs over the life of the wind farm are given as £43,987/MW/year. These include turbine O&M, insurance and connection and use of system charges.
- Lease payments to land owners of 3% of gross revenues per annum are assumed.
- Pre-financial close development costs are assumed to be 8.6% of the engineer procure contract (EPC) prices per Mott McDonald (2010, p83).

**Technical data**

- Gross power output assumed is 100 MW.
- Average availability is 80% allowing for turbine availability, topology, wake, electricity losses on site, icing losses, blade degradation, etc. (in the fixed price model only).

**Key Timings**

- Plant operating life is assumed to be 22 years.
- Construction period is two years.
- Pre-development period including pre-licensing, licensing and public enquiry is 5 years.

**Residual Value**[22]

- Assumed to be 25% of initial cost.

**Wind Output**

- A Weibull distribution around an average wind speed of 7 metres /second is used (in fixed-price FIT model only. An empirical power curve is created in the market model based on actual wind sites).

**Financing and Cost of Capital Assumptions**

- Financing and cost of capital assumptions come from DECC (2011a, p18) which are the cost of capital "base case" assumptions for the weighted average cost of capital (WACC) using the Capital Asset Pricing Model (CAPM) for onshore wind assets and are as follows:
  - Pre-tax cost of debt 6.5%.
  - Capital allowances associated with wind farm developments in the UK are not explicitly modelled, but an effective tax rate of 7.9% is used as in KPMG (2013, p.16).
  - Gearing (70-75%) –70% is used.
  - Consistent with DECC (2012a) which is based on Arup (2010) and Oxera (2011), we use a pre-tax real cost of equity of 9.6%.

[22] *A residual value is included to reflect the value of a permitted site with a grid connection and the resale value of the turbines at the end of 22 years. This is based on industry practice, IWEA (2016).*

## Appendix 3: Price Risk Simulator with Computational Agent-based Learning

The model assumes that market structures as well as input distributions are specific to each half hour and includes month-specific fuel price distributions and correlations. The merit order is built as the stack of generators and interconnectors arranged in ascending order of submitted price where generators are dispatched based on lowest price. The annual analysis is the aggregation of 12 monthly simulations, based on simulating a typical day for each month in detail. For each day, probability distributions are specific to every half-hour "period." For example, an input wind speed distribution can apply to every day in January from 14:00 until 14:30, but no other period or month. Because of this assumption, the resolution of the simulation is set by the number of simulated "scenarios", each of which represents the potential outcome of a day within that month. Each period is independent and so is each month. A single iteration of a period within a scenario is referred to as an "instance". For each instance, the wholesale market model is solved as the intersection of demand with the full supply stack. A typical simulation experiment therefore includes 1 year of 12 months of 30 scenarios with 48 half-hour periods which totals 17,280 samples. Simulations are done in Python while input data is analysed using Python, PostgreSQL and Microsoft Excel.

A number of techniques are used to process data and fit distributions. Fuel distributions are fitted as log normal to data for the ICE's ARA coal futures, Brent futures and National Balancing Point (NPB) day-ahead markets. The EUA distribution for carbon prices is fitted as log normal to ICE's spot market from 2011. The ROC price distribution is fitted as log normal to Ofgem's data based on their average price level (£45) and volatility in 2011/12. The demand is comprised of one distribution fitted for business days and one for non-business days with the ratio of the two being proportional to the ratio of business to non-business days for each month. Generator capacity distributions are approximated with a 10-value discrete distribution of local modes / means because most generators favour specific output regimes. Each generator's cost is estimated using a combination of fuel price, EUA and ROC data, as well as the offers and bids submitted by generators to the balancing mechanism reporting archive[23] in the British Electricity Trading Transmission Arrangements (BETTA) market. Assuming a base cost obtained from DECC (2011b) and knowing the price of fuel, EUAs and ROCs, a fuel-cost-multiplier distributions were extracted for the bids and offers. Because a generator will seldom have an incentive to bid higher or offer lower than its marginal cost, the fuel-cost multiplier was extracted as lying between the former's expected maxima and the latter's expected minima. The input data and distributions for calibration were from 2006 to 2012. Intra-year fuel price distributions and correlations were fitted as log normal to data for ARA Coal futures, Brent Futures, EUA spot and BPD day-ahead markets. The ROC distribution was fitted as log normal to market data. Empirical wind farm power curves are obtained by calibrating each wind farm's local weather station's wind speed against the specific farm's power output on an hourly level. Day-ahead forecasting error is obtained from APX-ENDEX UK power prices. The model assumes that thermal generators that also own wind generation will engage in strategic withdrawals of wind to increase the price they receive on their thermal generation units. The model assumes the same power flows over interconnections to Great Britain as actually took place in 2011. This is a simplistic assumption but in the absence of a fully integrated European model we consider it to be reasonable.

[23] http://www.elexon.co.uk/wp-content/uploads/2012/11/bmra_sd_v18.0.pdf

# Appendix 4: Variable Model with ROCs - NPV and DSCR Impacts under Decarbonisation - Only One Wind Farm Over Installs

## Summary:

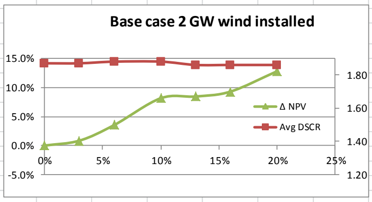
| Wind Installed (GW) | NPV with 0% over Sizing 100MW wind farm (£m) | NPV with 20% over Sizing 100MW wind farm (£m) | Δ NPV (%) | Wind Farm Capacity Factor with 0% Over Sizing % | Wind Farm Capacity Factor with 20% Over Sizing % | Δ Wind Farm Capacity Factor (%) | Avg DSCR @ 20% Over Sized (x) |
|---|---|---|---|---|---|---|---|
| 2.00 | 51.22 | 58.72 | 12.80% | 30.50% | 35.40% | 16.07% | 1.86 |
| 10.50 | 47.29 | 52.97 | 12.00% | 30.60% | 35.40% | 15.69% | 1.79 |
| 16.08 | 39.78 | 44.44 | 11.70% | 30.10% | 34.90% | 15.95% | 1.69 |
| 21.44 | 26.53 | 31.38 | 18.30% | 28.50% | 33.50% | 17.54% | 1.54 |
| 26.80 | 10.60 | 13.69 | 29.10% | 26.50% | 31.10% | 17.36% | 1.33 |

## Detailed:

*Individual windfarm over installs*

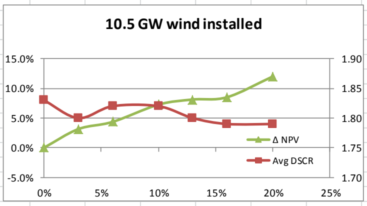
*Base case 2 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.870 | £51,215,223 | 0.0% | £97.34 | 30.5% | 266,850 |
| 3% | 1.870 | £51,652,256 | 0.8% | £97.18 | 31.1% | 272,616 |
| 6% | 1.880 | £53,091,364 | 3.5% | £97.44 | 31.8% | 278,909 |
| 10% | 1.880 | £55,754,399 | 8.1% | £97.31 | 33.1% | 289,878 |
| 13% | 1.860 | £55,935,642 | 8.4% | £96.96 | 33.7% | 294,898 |
| 16% | 1.860 | £56,457,563 | 9.3% | £97.11 | 34.3% | 300,843 |
| 20% | 1.860 | £58,719,793 | 12.8% | £97.39 | 35.4% | 309,891 |



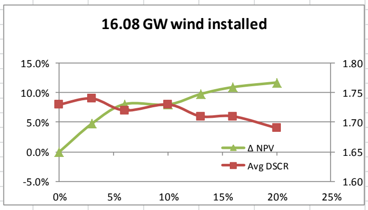

*10.5 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.830 | £47,293,561 | 0.0% | £94.52 | 30.6% | 268,029 |
| 3% | 1.800 | £48,775,637 | 3.1% | £94.34 | 31.0% | 271,181 |
| 6% | 1.820 | £49,352,836 | 4.4% | £94.68 | 32.0% | 280,533 |
| 10% | 1.820 | £50,725,581 | 7.3% | £94.64 | 33.0% | 289,327 |
| 13% | 1.800 | £51,134,581 | 8.1% | £94.01 | 33.8% | 295,832 |
| 16% | 1.790 | £51,317,533 | 8.5% | £94.42 | 34.3% | 300,476 |
| 20% | 1.790 | £52,972,648 | 12.0% | £94.40 | 35.4% | 309,701 |



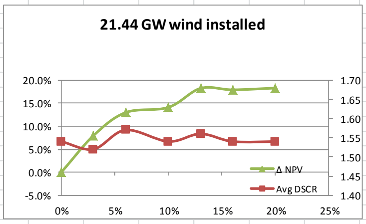

*16.08 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.730 | £39,781,455 | 0.0% | £91.44 | 30.1% | 263,579 |
| 3% | 1.740 | £41,681,173 | 4.8% | £91.33 | 31.1% | 272,172 |
| 6% | 1.720 | £42,984,399 | 8.1% | £91.21 | 31.6% | 276,574 |
| 10% | 1.730 | £42,955,819 | 8.0% | £91.50 | 32.8% | 287,566 |
| 13% | 1.710 | £43,665,679 | 9.8% | £91.57 | 33.2% | 291,237 |
| 16% | 1.710 | £44,132,946 | 10.9% | £91.19 | 34.0% | 298,172 |
| 20% | 1.690 | £44,441,541 | 11.7% | £91.16 | 34.9% | 305,359 |



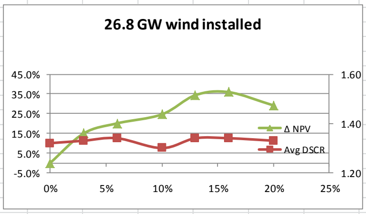

*21.44 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.540 | £26,534,755 | 0.0% | £87.73 | 28.5% | 249,948 |
| 3% | 1.520 | £28,645,273 | 8.0% | £87.29 | 29.1% | 255,271 |
| 6% | 1.570 | £29,973,142 | 13.0% | £87.77 | 30.4% | 266,395 |
| 10% | 1.540 | £30,271,618 | 14.1% | £87.51 | 31.0% | 271,669 |
| 13% | 1.560 | £31,368,477 | 18.2% | £87.95 | 32.0% | 280,276 |
| 16% | 1.540 | £31,282,631 | 17.9% | £87.35 | 32.6% | 285,915 |
| 20% | 1.540 | £31,383,481 | 18.3% | £87.51 | 33.5% | 293,602 |




*26.8 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.320 | £10,603,878 | 0.0% | £83.21 | 26.5% | 232,111 |
| 3% | 1.330 | £12,190,392 | 15.0% | £83.60 | 27.3% | 239,466 |
| 6% | 1.340 | £12,732,241 | 20.1% | £83.39 | 28.1% | 246,488 |
| 10% | 1.300 | £13,211,684 | 24.6% | £82.35 | 28.8% | 252,624 |
| 13% | 1.340 | £14,246,051 | 34.3% | £83.87 | 29.7% | 260,412 |
| 16% | 1.340 | £14,406,235 | 35.9% | £83.75 | 30.4% | 266,436 |
| 20% | 1.330 | £13,694,251 | 29.1% | £83.76 | 31.1% | 272,113 |



# Appendix 5: Variable Model with ROCs - NPV and DSCR Impacts under Decarbonisation - All Wind Farms Over Install

## Summary:

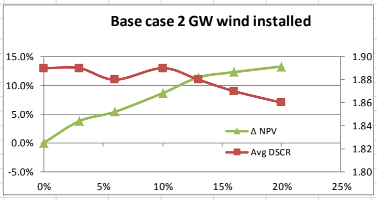
| Wind Installed (GW) | NPV with 0% over Sizing 100MW wind farm (£m) | NPV with 20% over Sizing 100MW wind farm (£m) | Δ NPV (%) | Wind Farm Capacity Factor with 0% Over Sizing % | Wind Farm Capacity Factor with 20% Over Sizing % | Δ Wind Farm Capacity Factor (%) | Avg DSCR @ 20% Over Sized (x) |
|---|---|---|---|---|---|---|---|
| 2.00 | 50.78 | 58.56 | 13.30% | 30.30% | 35.40% | 16.83% | 1.86 |
| 10.50 | 46.21 | 52.23 | 13.00% | 30.40% | 35.40% | 16.45% | 1.79 |
| 16.08 | 39.25 | 41.00 | 4.50% | 30.10% | 34.90% | 15.95% | 1.65 |
| 21.44 | 28.11 | 21.48 | -23.60% | 28.90% | 32.40% | 12.11% | 1.42 |
| 26.80 | 10.78 | 2.00 | -81.50% | 26.50% | 29.40% | 10.94% | 1.19 |

## Detailed:

*All wind farms overinstalled*

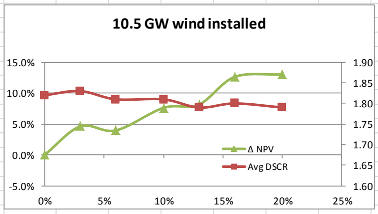
*Base case 2 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.89 | £50,776,774 | 0.0% | £97.44 | 30.3% | 265,854 |
| 3% | 1.89 | £52,780,105 | 3.8% | £97.44 | 31.3% | 273,789 |
| 6% | 1.88 | £53,684,049 | 5.4% | £97.44 | 32.0% | 280,026 |
| 10% | 1.89 | £55,583,126 | 8.6% | £97.39 | 33.0% | 289,328 |
| 13% | 1.88 | £57,296,321 | 11.4% | £97.46 | 33.9% | 296,587 |
| 16% | 1.87 | £57,904,107 | 12.3% | £97.37 | 34.5% | 302,185 |
| 20% | 1.86 | £58,560,081 | 13.3% | £97.33 | 35.4% | 309,708 |



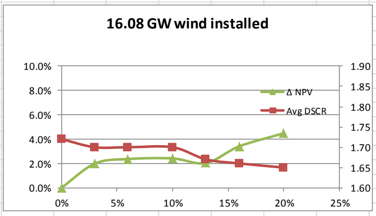

*10.5 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.82 | £46,212,679 | 0.0% | £94.61 | 30.4% | 265,878 |
| 3% | 1.83 | £48,349,209 | 4.6% | £94.35 | 31.4% | 275,049 |
| 6% | 1.81 | £48,049,135 | 4.0% | £94.62 | 31.8% | 278,468 |
| 10% | 1.81 | £49,734,284 | 7.6% | £94.47 | 32.9% | 288,112 |
| 13% | 1.79 | £49,989,438 | 8.2% | £94.13 | 33.6% | 294,343 |
| 16% | 1.80 | £52,049,141 | 12.6% | £94.20 | 34.5% | 302,428 |
| 20% | 1.79 | £52,237,264 | 13.0% | £93.83 | 35.4% | 310,281 |



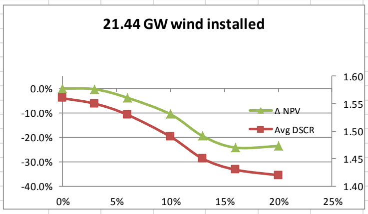

*16.08 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.72 | £39,248,195 | 0.0% | £90.94 | 30.1% | 263,579 |
| 3% | 1.70 | £40,026,410 | 2.0% | £91.00 | 31.1% | 272,172 |
| 6% | 1.70 | £40,176,951 | 2.4% | £90.70 | 31.6% | 276,574 |
| 10% | 1.70 | £40,194,780 | 2.4% | £90.84 | 32.8% | 287,566 |
| 13% | 1.67 | £40,045,842 | 2.0% | £90.37 | 33.2% | 291,237 |
| 16% | 1.66 | £40,586,297 | 3.4% | £90.01 | 34.0% | 298,172 |
| 20% | 1.65 | £41,006,919 | 4.5% | £89.53 | 34.9% | 305,359 |




*21.44 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.56 | £28,113,713 | 0.0% | £88.06 | 28.8% | 251,944 |
| 3% | 1.55 | £28,018,203 | -0.3% | £87.29 | 29.6% | 259,083 |
| 6% | 1.53 | £27,043,195 | -3.8% | £87.18 | 30.0% | 262,702 |
| 10% | 1.49 | £25,146,009 | -10.6% | £86.41 | 30.6% | 268,308 |
| 13% | 1.45 | £22,621,162 | -19.5% | £86.45 | 31.1% | 272,461 |
| 16% | 1.43 | £21,308,116 | -24.2% | £85.42 | 31.3% | 274,476 |
| 20% | 1.42 | £21,475,850 | -23.6% | £84.84 | 32.4% | 283,673 |




*26.8 GW wind installed*

| % Overinstallation | Avg DSCR | NPV (£) | Δ NPV | Mean Price £/MWh | Capacity Factor | MWh Produced |
|---|---|---|---|---|---|---|
| 0% | 1.31 | £10,775,276 | 0.0% | £83.35 | 26.5% | 232,057 |
| 3% | 1.30 | £9,927,041 | -7.9% | £82.96 | 27.0% | 236,834 |
| 6% | 1.30 | £9,834,648 | -8.7% | £82.53 | 27.8% | 243,294 |
| 10% | 1.25 | £6,343,609 | -41.1% | £82.19 | 28.2% | 247,365 |
| 13% | 1.24 | £5,826,418 | -45.9% | £81.48 | 28.7% | 251,112 |
| 16% | 1.24 | £6,097,179 | -43.4% | £82.63 | 28.9% | 253,547 |
| 20% | 1.19 | £1,996,986 | -81.5% | £81.00 | 29.4% | 257,688 |