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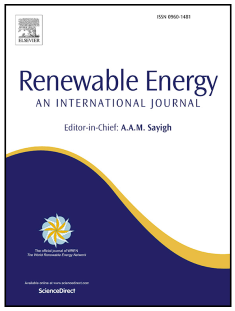

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Modelling the Impact of Wind Generation on Electricity Market Prices in Ireland: An Econometric versus Unit Commitment Approach

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Abstract

The aim of this research is to assess the impact of wind generation on electricity market prices using two different approaches: an econometric regression model and a unit commitment model (the latter being a methodological approach favoured by the engineering discipline). Overall, the findings of this paper indicate that wind generation reduces the marginal price on the case study electricity system, a result which is consistent across both methodological approaches. The level of savings is non-trivial and in the order of 4 - 5.4% of total dispatch cost. It is also found that the relationship between wind and prices is linear. The majority of literature in this area uses either an econometric or a unit commitment approach but not both, thus this paper allows for the isolation of the impact of modelling approach on the results. It finds that the results from both methods are comparable and the choice of modelling approach influences the results by just 1.4%. Thus, depending on the type of analysis required, an ex-post econometric model may be preferred by policy makers to an ex-post unit commitment model given the significant reduction in data requirements and computational time involved.

JEL Classification: Q41, Q42, C51, D44

Keywords: Renewable Resources, Marginal Pricing, Wind, Merit Order, Unit Commitment

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1 Introduction

Climate change concerns coupled with security of supply considerations have resulted in increasing global interest in the design of sustainable electricity systems to bring about emissions savings and fuel security while minimising cost. Of the low-carbon technologies currently available for electricity production, wind generation is one of the most commercially attractive and, as a result, has gained a significant market share internationally. In the ten years from 2003 to 2013, global wind installations grew from 39 GW to 318 GW, an eight-fold increase, and by 2013 wind generation represented more than 2.5% of global electricity production (GWEC, 2013). In Europe in 2013, installed wind penetrations reached 117 GW, meeting 8% of EU electricity consumption (EWEA, 2014).

This growth has resulted in a greater focus on the impacts of wind on the operation of electricity systems, in particular the need for greater flexibility due to increases in volatility (Ambec and Crampes, 2012; NERC, 2009). This requirement for flexibility can be seen through the increase in trading on the intraday electricity markets in continental Europe, in part due to an increase in volatility from renewables (Weber, 2010).

Dale *et al.* (2004); NREL (2011, 2013) and others establish that as the level

and Electricity Markets Authority. This work was conducted in part while Eleanor Denny was a visiting scholar at the Harvard Environmental Economics Programme, Harvard University, Cambridge, MA 40215, USA. This work was conducted in part while Amy O'Mahoney was at Trinity College Dublin and was funded by Teagasc under the Walsh Fellowship Programme Grant number 2008013 and the Electricity Research Centre (ERC).

of wind generation increases in an electricity market, extra balancing costs are incurred in the form of additional reserve and frequency response. They indicate that as wind farms tend to be located in rural and often remote areas, wind generation can also have a significant effect on transmission reinforcement costs.

Research and experience to date has also shown that adding wind to an electricity system results in integration costs relating to investment and operational costs associated with the non-wind generating units (Holttinen *et al.*, 2011). In particular, wind generation has been shown to result in increased cycling of existing units, in other words, an increase in the number of start-ups and ramping, and increased operation at part load for existing units (Denny and O'Malley, 2009; Troy *et al.*, 2010), although this cost is found to be small relative to the overall cost savings of including renewables in the generation mix (NREL, 2013).

The benefits associated with wind generation include a reduction in fossil fuel consumption for electricity generation, local and global environmental benefits, diversity of supply, reduced exposure to international fuel price fluctuations, and the meeting of national and international policy targets (Holttinen *et al.*, 2011).

In addition, in recent years there has been a growing literature on the benefits of renewable generation in terms of its impact on wholesale electricity prices. Würzburg *et al.* (2013) provide a comprehensive overview of the existing studies in this area illustrating that the vast majority of research suggests that increases in renewable generation result in reductions in wholesale electricity prices. Würzburg *et al.* (2013) broadly classify the research in this area into two categories: empirical studies (using real past data, primarily employing econometric techniques) and simulation based studies (using real (past) and hypothetical data).

Given the growing availability of ex-post data from power systems with large levels of installed renewable generation, empirical studies investigating the impact of renewables on wholesale prices are increasing in prominance. Würzburg *et al.* (2013) summarises the results from nine empirical studies on six different power systems which indicate a reduction in wholesale prices in the range of €1.33 to €9.90 per MWh for each additional GWh of renewable energy produced. While this range may appear large, it is sensitive to the size of the underlying system and reduces to €0.06 - €1.34 per MWh per additional percentage of renewable generation relative to total installed capacity.

Within the empirical studies, there exists significant hetereogeneity in methodological approaches ranging from autoregressive techniques (Robinson, 2000; Ziel *et al.*, 2015; Woo *et al.*, 2011), to univariate (Gil *et al.*, 2012) and multivariate (Nicholson *et al.*, 2010; Woo *et al.*, 2011; Gelabert *et al.*, 2011) regression analyses. As such, Würzburg *et al.* (2013) warn that given the wide range of power systems considered and variables and techniques used, comparisons between studies (even those using the same general methods), should be conducted with caution.

Prior to the availability of ex-post data, simulation models, such as unit commitment models, were the standard approach to quantifying impacts on power system operation and costs. These models are the preferred approach of the engineering discipline and are typically complex and approach a detailed representativeness of the underlying physical system, however, they require significant knowledge of the characteristics of the specific system and model tool and can be computationally complex (often take many hours to converge). As they are simulation models, they also have limitations with respect to the accurate portrayal of the AC network and the steady state and transient stability issues that come with realistic operations. Würzburg *et al.* (2013) summarise the results from eleven simulation based studies and report wholesale price reductions in the range of €0.24 to €3.99 per MWh per additional GWh of renewable energy (or €0.02 - €2.05/MWh per additional percentage of renewable generation).

As highlighted above, the measured impacts of renewables on wholesale prices vary widely and it is unclear to what extent these variation are driven by differences in the underlying power systems or differences in the modelling approaches (and variables included). In this paper, the authors utilise both an empirical (econometric) and a simulation approach to examine the impact of wind generation on wholesale prices. Both models examine the same underlying power system over the same period of time and utilise the same set of assumptions and as such isolate the impact of the methodological choice on the results. To the authors' knowledge, this paper thus represents the first paper to compare empirical and simulation methods in the examination of the impact of wind generation on wholesale prices. As such, if the results of both models are consistent, this can be considered a compelling result.

There are many physical constraints on an electricity system, such as transmission constraints, unit capacity restrictions, reserve requirements, ramping restrictions, shut-down and start-up times of conventional units to name but a few, which may prevent the full effect of wind generation savings from being realised in reality. Unit commitment simulation models can account for some of these physical constraints and for this reason may be preferred to empirical econometric models. This is the issue at the centre of this paper - do econometric models and unit commitment models produce comparable results despite the fact that the former cannot explicitly account for the multitude of physical constraints on the underlying system?

The results of this paper are likely to be of significant interest to economic policy makers who may find the data requirements of unit commitment models overly onerous for use in evaluations such as cost benefit studies. If the results of both approaches are comparable, it suggests that policy makers could use simple econometric models (such as those presented in this paper) for analyses rather than more complex unit commitment models.

This study will not attempt to estimate the costs incurred as a result of wind integration, or the level of wind subsidisation required/paid, but will focus instead on the quantification of the impact of wind on wholesale prices. The paper considers wind generation on the electricity system in terms of its 'merit order effect' on supply and demand. This premise assumes that benefits from wind generation are realised by displacing conventional generation in meeting demand and that there is a distribution of marginal costs for each unit in the merit order stack. This will be tested through the work.

The remainder of this paper is structured as follows: Section 2 explains the merit order effect; Section 3 introduces the Irish electricity market as the case system; Section 4 details the two methodologies considered and data used; and the results, discussion and conclusion are presented in Sections 5, 6 and 7 respectively.

2 Merit Order Effect

We assume that electricity is a homogenous good, to which suppliers are indifferent between generators, as there is no product differentiation [2] . The market is capacity constrained; with each generator limited in their supply by the

[2] This is not necessarily the case in markets with certain renewables schemes such as ROC in the UK, which is designed to incentivise renewable generation into the electricity generation market by placing an obligation on all UK suppliers of electricity to source an increasing proportion of their electricity from renewable sources (Ofgem, 2011). However, for the purposes of the theoretical model, this homogenous assumption is justified.

maximum output they are capable of producing. As a result, we can describe the generation of electricity as a Cournot oligopoly model with linear inverse demand, where generators are able to choose their level of supply but not the price which they receive for the electricity that they generate. The price of electricity, P is therefore determined by market demand, Q, times a variable component b, which corresponds to the marginal cost of electricity, and a constant, or fixed cost component, a. Thus, the price can be defined as:

$$P = a - bQ \tag{1}$$

Generators still have market power, as each firm's output decision affects the price of electricity, and their rival's output level.

As a firm begins to generate a portion of its electricity portfolio output through wind generation, it can now supply electricity at a lower average marginal cost (MC) than previously (since wind has a MC $= 0$). The firm will benefit from this change in costs in two ways; firstly due to the fact that the quantities of electricity produced from competing firms are strategic substitutes i.e. as wind output increases, rival generators will produce less as demand is held constant; and secondly, since the Cournot-Nash outcome of a firm depends on the costs of its rival.

Industry output will remain constant as the shift is taking place between firms only, and demand is in no way affected by this change in supply. Consumer prices are typically fixed in the short run, and therefore they are not affected by changes in the marginal cost of generating electricity and thus demand remains constant as prices shift. Increasing penetrations of responsive demand may increase the price elasticity of short run demand however, as yet, installed levels of responsive demand are not considered sufficiently high to impact on total demand in any hour. Over the longer term, changes in wholesale prices may have an impact on demand and usage behaviour (Pouris, 1987), however, this is considered to be outside the scope of this paper.

Theoretically both firms could continue to increase the proportion of wind in their portfolio up to 100%, which would result in the same proportion of electricity being produced, but at a MC = 0. This however is not feasible in practice as it does not consider the fixed cost element of a generator's portfolio. Also, the proportion of overall system costs using this method would become less instructive as other costs (e.g. balancing) would be incurred through other cost mechanisms (e.g. bilateral contracts, ancillary services markets).

Wind generation affects the intersection of the merit order (supply curve) with the demand curve; Figure 1 demonstrates that it essentially shifts the supply curve for generation to the right as more generating capacity comes online, thereby reducing the system marginal price (SMP).

Wind generation is generally consumed prior to other forms of generation due

Fig. 1. Sample Merit Order Effect

Note: SMP is system marginal price. Figure 1 illustrates the merit order effect over a short period of time (typically one hour) with perfectly inelastic demand. It is likely that demand would be more elastic with increasing penetrations of demand side response measures and over longer time horizons.

to its zero marginal cost and the fact that it has priority dispatch, meaning that electricity produced by wind in Europe must be given priority access to the grid by the transmission system operator unless system security dictates that it must be constrained (European Commission, 2001) [3] .

This is known as the Merit Order Effect (MOE), which arises from the fact that, all else equal, adding wind power to the system should replace higher marginal cost plant on the system, and this in turn is likely to lower wholesale electricity prices (Felder, 2011; Cludius *et al.*, 2014) [4] . Depending on the amount of wind available, the level of demand and the conventional generation cost profile in a given time period, this price reduction may vary significantly from hour to hour.

[3] It should be noted that depending on the connection agreement, not all wind generation is covered by priority dispatch however, for the purposes of this study, it is realistic to assume that wind generation bids at a marginal cost of zero and will be consumed prior to other forms of generation in Ireland (subject to system security constraints.) In the US, dispatch also depends on the locational marginal price at the node and not the total system marginal cost.

[4] Assuming a non-uniform distribution of costs among the units in the range of demand. If wind displaces one unit but the next unit has similar costs, then the impact on prices may be negligible.

3 Irish Electricity System

The Irish electricity system (covering both the Republic and Northern Ireland) is an ideal test case for identifying the merit order effect of wind generation as it is a small, isolated system with limited interconnection to other systems. The time period studied in this paper is the year 2009 and in that year only one interconnector was operational with a capacity of 500 MW (representing approximately 6% of installed capacity in 2009) [5].

Growth in installed wind capacity in Ireland has been relatively rapid from a level of 182MW in 2002 to approximately 1,533MW at the end of 2009. This figure has continued to grow since 2009 with 2,647MW installed by the end of 2014, representing over 21% of total installed capacity in 2014 (Eirgrid, 2014). The year 2009 is the chosen year for analysis in this study as wind generation made a significantly high contribution to electricity consumption (allowing for a comprehensive ex-post analysis), combined with a single interconnector and readily available data from the market and system operators.

Table 1 shows the installed capacity of renewables in 2009 was 8% with the percentage of gross electricity consumption met by renewables at 14.1%. While this is the overall level of demand met by renewables in 2009, there were instances where renewables made a much greater contribution to instantaneous

[5] A second 500MW interconnector to the UK has subsequently been commissioned and commenced operations in 2012.

demand. For example, in 2009, there were numerous occasions when renewables met over 40% of Ireland's instantaneous electricity demand (usually during windy nights when demand was low) (SEAI, 2010a). Thus, although installed capacity of renewables may appear relatively modest at 8%, the contribution of renewables to the electricity system is considerably higher.

In terms of conventional generation mix, Ireland has a heavy reliance on natural gas for electricity generation, as seen in Table 1, followed by coal-fired generation. Ireland also has an indigenous peat resource which is currently used to generate electricity at three power stations. The Irish government supports the use of peat for electricity generation through a Public Service Obligation levy on all electricity bills and it has a 'must-run' status within the Irish electricity system. This implies that regardless of its marginal cost, it is always dispatched to generate electricity when available. The justification for this support is for security of supply reasons (to reduce Ireland's dependence on imported fuels) and to support jobs in rural areas (O'Mahoney *et al.*, 2013).

Table 1: Ireland's electricity supply in 2009

The Irish electricity market is known as the Single Electricity Market (SEM) and is a gross pool electricity market (with a separate capacity mechanism) that covers the Republic of Ireland and Northern Ireland. Generators bid energy and price pairs 24 hours ahead and are dispatched on a least cost basis (subject to technical constraints). Generator bids are based on the spot price of their fuel on international fuel markets, the spot price of carbon and the efficiency of their generating station (CER, 2014). The system marginal price (as illustrated in Figure 1) in a given period is set at the marginal cost of the most expensive unit required to meet demand in the same period and is paid to all dispatched units, regardless of their bid.

Table 1 illustrates the average marginal costs across all power stations in each category. After renewables and peat generation, the conventional generators on the power system are dispatched to meet demand according to their marginal cost bids, thus as wind penetrations grow, the most expensive conventional units become displaced. In Ireland it can be seen that the most expensive units are the small number of oil generators followed by gas and coal. Conventional generation will tend to be displaced by wind generation in this order (subject to technical constraints).

Payments to generators in the Irish Single Electricity Market come in three different forms: Energy payments; Capacity payments; and Constraint payments [6]. Energy payments are comprised of the marginal price in the gross pool market (as illustrated by the SMP in Figure 1) and an uplift payment. The uplift component is paid if a generators start-up and no-load costs are not

[6] Ancillary service payments are paid/levied outside the Single Electricity Market by the Transmission System Operators. Subsidies are potentially a fourth payment stream to renewable generators, but are not considered part of the Single Electricity Market payment mechanism and are thus not considered in this paper.

covered by any infra-marginal rent it receives. The uplift component represents approximately 25% of the average Energy Payment (CER, 2011).

Capacity Payments reward available capacity and Constraint Payments compensate generators who were underutilised compared to their dispatch schedule e.g. as a result of transmission congestion. Capacity payments and constraint payments represent approximately 20% and 6% of total payments made to generators respectively (CER, 2014).

For the purposes of this paper, the focus will be on the portion of the energy payment determined by the marginal price in the gross pool market. This payment represents approximately 75% of energy related payments and 55% of the total payments made to generators and is referred to in the market documentation as the shadow price of energy. It should be noted that this price is not a shadow price in the economic sense i.e. it is not the value of the Lagrange multiplier at the optimal solution. However, the Irish market documentation refers to the shadow price (essentially SMP in Figure 1) so for consistency we will continue to use this terminology here (CER, 2011).

It should be noted that the results of this study are relevant for the year 2009 only and the market structure assumed in this paper could change significantly with the introduction of the integrated single European market (I-SEM, 2014). Thus, the results presented here are limited to the Irish market in 2009 and inference of the results beyond this scope should be done with caution.

4 Methods

This article uses two different methods to examine the impact of wind generation on the marginal wholesale electricity price (the shadow price) in the Irish electricity market. The first model is a multivariate time series regression model using historical data. The second model is a unit commitment simulation model utilising the same historical data. Both methodological approaches are discussed in this section.

4.1 Regression Model

In this study we generate a time series multiple regression model using Irish hourly data for 2009 from the Single Electricity Market (SEM). It is expected for the Irish system that the most accurate predictors of the shadow price in any hour would be the fuel input prices of gas, coal, oil and carbon from the day prior to bidding (when bids must be made), and the demand in that hour. The merit order effect implies that wind generation will reduce the amount of conventional generation required to meet demand and thereby reduce the price, thus, wind generation is also hypothesised to have an impact on the shadow price.

The basic inverse supply function to be estimated is expressed in equation 2:

$$\begin{aligned} ShadowPrice_t = \alpha + \beta_1 NetDemand_t + \beta_2 NetDemand_t^2 \\ - \beta_3 Wind_t - \beta_4 Wind_t^2 \\ + \beta_5 Gas_{t-24} + \beta_6 Coal_{t-24} + \beta_7 Oil_{t-24} \\ + \beta_8 Carbon_{t-24} X_t + \beta_9 D + \epsilon_t \end{aligned} \tag{2}$$

$NetDemand$ refers to total system demand at time t less demand that is met through peat output, hydro generation and electricity imports since none of these units bid into the Irish electricity market in 2009. $NetDemand$ is measured on an hourly basis and represents the total hourly demand which must be met by supply from the conventional units (except peat) and wind generation. $NetDemand^2$ is also included to allow a non-linear relationship between price and demand.

$Wind_t$ is the total wind output at time t. We expect wind to have a negative sign as our hypothesis is that wind will reduce the price of electricity at any given time. We include a square term in order to allow the relationship between the price and wind to be non-linear.

The bidding rules of the Irish electricity market require units to submit market bids into the gross pool auction based on the spot price of fuel and carbon, and their individual marginal heat rate i.e. their fuel consumption and carbon cost per MWh. Thus, *Gas, Coal, Oil* and *Carbon* relate to the daily spot prices of these fuels on the global spot exchange markets and reflect the spot prices used in generator bids. In practice, these fuel prices are bid into the market on a day-ahead basis, and therefore are lagged by 24 periods.

Controls are included for hour of the day, day of the week, month and public holidays (represented by D in equation 2), as all of these have an effect on the demand for electricity, the availability of wind for generation, and the scheduled maintenance of conventional plant, which additionally has an effect on the fuel mix (Thomas *et al.*, 2011).

Given the potential multicollinearity issues of including both $NetDemand$ and $NetDemand^2$, and $Wind_t$ with its square term, the model presented in equation 2 is also estimated with data for $NetDemand$ and $Wind$ centred around their mean. This is shown in equation 3 below where $NetDemandCentered$ and $WindCentered_t$ refer to variables which are centred around their mean values.

$$\begin{aligned} ShadowPrice_t = \alpha &+ \beta_1 NetDemandCentred_t + \beta_2 NetDemandCentred_t^2 \\ &- \beta_3 WindCentred_t - \beta_4 WindCentred_t^2 \\ &+ \beta_5 Gas_{t-24} + \beta_6 Coal_{t-24} + \beta_7 Oil_{t-24} \\ &+ \beta_8 Carbon_{t-24} X_t + \beta_9 D + \epsilon_t \end{aligned} \tag{3}$$

The shadow price of electricity is set at the marginal cost of the most expensive generator required to meet demand in a given period, and each MWh generated receives the same shadow price. Thus, a reduction in this price due to wind, reduces the price paid to each generator for each unit of electricity that they produce. This allows us to calculate the total saving for every hour of each day which is attributable to wind. We can calculate the total savings from wind based on this average value by multiplying the coefficient for $Wind_t$ by the actual wind output per hour and the demand per hour, as shown in equation 4.

$$TotalSavings = \sum_{t=1}^{8736} (-0.0034 * Wind_t * NetDemand_t) \tag{4}$$

This paper also examines the impact of wind generation on prices during different hours of the day using hourly interactions. The hourly interaction model to be estimated is presented in equation 5, where $Hour$ is a matrix of dummy variables representing each hour of the day. The model is estimated without an intercept in equation 5 to allow each of the interaction terms to be estimated (Cludius *et al.*, 2014). $WindCentred_t$ is also dropped due to perfect collinearity with the full matrix of interaction terms.

$$\begin{aligned} ShadowPrice_t = {} & \beta_1 NetDemandCentred_t + \beta_2 NetDemandCentred_t^2 \\ & - \beta_3 WindCentred_t^2 - \beta_4 (WindCentred_t * Hour) \\ & + \beta_5 Gas_{t-24} + \beta_6 Coal_{t-24} + \beta_7 Oil_{t-24} \\ & + \beta_8 Carbon_{t-24} X_t + \beta_9 D + \epsilon_t \end{aligned} \tag{5}$$

In order to quantify hourly price reduction benefit of wind, the hourly coefficient for the interaction term $WindCentred_t * Hour$ (β_4 from equation 5) is multiplied by the historical wind output and system demand for each hour of 2009, as shown in equation 6 below.

$$TotalHourlySavings = \sum_{t=1}^{8736} (\beta_{4t} * Wind_t)\,(NetDemand_t) \tag{6}$$

It should be noted that the regression models are aggregate models which do not explicitly include individual generator data or physical system characteristics. The simulation model, which is described in the following section, is a much more detailed model and includes individual generation unit characteristics and system requirements (such as reserve constraints).

4.2 The Unit Commitment Simulation Model

The second method of evaluating the impact of wind generation on electricity prices is conducted using a simulation model of the Irish electricity system for the same period in 2009. This simulation model runs on the Plexos electricity modelling software platform (Energy Exemplar, 2013a) and is similarly configured to the model used by the Irish regulatory authorities for this period. The model handles both the unit commitment, which determines the commitment schedule of units (Kiviluoma *et al.*, 2012), and the economic dispatch, which relates to the dispatch levels of those units (Baldick, 1995). It also replicates the energy pricing formulation used in the Irish wholesale electricity market and estimates the shadow prices which are of interest to this study.

Equation 7 describes the cost function which is minimised in the unit commitment simulation model for all i generating units on the Irish system for every hour t :

$$\begin{aligned} min \Bigg(& \sum_{i=1}^{N} Start\, costs_i + \sum_{i=1}^{N} No\, loadcosts_i \\ & + \sum_{i=1}^{N} Marginal\, Cost_{i,t} * Output_{i,t} + \sum_{i=1}^{N} Reserve\, Cost_{i,t} \Bigg) \\ & \text{subject to} : \sum_{i=1}^{N} Generation_i, t = \sum_{i=1}^{N} Demand_i, t \end{aligned} \tag{7}$$

Generators are assumed to have montonically non-decreasing piecewise linear bids for energy and reserve and the constraints included are load balance, reserve capacity requirement, and maximum and minimum rated capacities. Other costs and constraints include no load costs, start up and shut down costs, carbon costs, and constraints such as minimum generation, start up constraints, and maximum and minimum ramping up and down times. Generator availability schedules are also included. The full mathematical details of all the constraints are available in Energy Exemplar (2013b).

Unit commitment and economic dispatch is carried out using a rounded relaxation optimisation process using the Xpress suite (Fair Isaac Corporation, 2013). Using piece-wise linear heat rates and generator characteristics, generating plants are represented individually in the Irish market. A lumped generator model of the Great Britain market is included, as well as 500 MW of interconnection to the Irish system which was the case in 2009. Wind and hydro generation were modelled as price taker units within this simulation model as they are in practice.

In order to compare the results of the econometric and unit commitment models, they are both run with identical input data for net demand, wind output, fuel and carbon prices, however the simulation model also captures generator level data and system constraints which are not included in the regression model.

It is thus obvious that the simulation model provides much more detail about the operation of the Irish electricity system which cannot be captured using time series econometrics. While the unit commitment model falls short of a true system representation, it does capture the significant majority of the operation costs. This rigour requires significant data input and knowledge of the underlying system which can be logistically time consuming to gather and compute. The regression model requires significantly less data, computation time and knowledge of the underlying system, however, the key research question is whether the two different methodologies provide similar results.

4.3 Data

Table 2 provides summary statistics for each of the variables included within this study on an hourly basis. Data for the shadow price is taken from the market operator's website, which provides data on a half hourly basis since the inception of the Single Electricity Market in 2007 (SEM, 2013). Hourly data is generated by averaging half-hourly observations.

Table 2: Summary Statistics

Net demand is calculated as total system demand minus the output of the peat stations, hydro units and interconnector flows, the data for which were obtained from the transmission system operator's website and the market operators website (Eirgrid, 2013; SEM, 2013).

Wind data is published on the Eirgrid website for the Republic of Ireland, and data for Northern Ireland was provided by the system operator in Northern Ireland (Eirgrid, 2013; SONI, 2010). Fuel and carbon prices were taken from daily global exchanges, and converted into euro using historical exchange rates.

The data presented in Table 2 is included in both the econometric and unit commitment models for consistency.

5 Results & Discussion

5.1 Regression Model Results

Table 3 presents the results of the main drivers of the shadow price using a number of different specifications of the regression model presented in Equation 2. Serial correlation was found, thus estimations are made using Generalised Least Squares - Prais Winston techniques with robust standard errors.

Table 3: Basic Regression Model Results

Examining model specifications 1a and 1b first, it can be seen that net demand has a positive significant effect on the price. This is expected since an increase in net demand causes a movement up the merit curve to more expensive generating units, causing the price to increase. For example, from model

1b, a 100MW increase in net demand causes a €1.42/MWh increase in the price. Irish demand can be seen to be highly cyclical and predictable, as are the prices over time. This is illustrated in Figure 2, which presents Demand and Price in the first business week of January 2009.

Fig. 2. Load & Shadow Price for first business week in January 2009

Note: Demand data sourced from the Transmission System Operator's website (Eirgrid, 2013). Price data sourced from the Market Operator's website (SEM, 2013).

It can be seen from Model 1c and 1d that although the square of net demand is statistically significant, it has a coefficient of close to zero (actual coefficient is 0.00000198) and is thus not considered economically significant. Thus, we can deduce that there is an virtually linear relationship between prices and demand for 2009.

Models 1b and 1c show that the coefficient on *Wind* is negative and statistically significant at the 99% level. This implies that increases in wind generation reduce the system marginal price - a finding consistent with the merit order hypothesis and the majority of literature in this field (Würzburg *et al.*, 2013). The squared output of wind is found to be significant in Model 1d, however, it has a coefficient of zero (actual coefficient -0.000000105) and therefore is not of economic consequence. Thus, we see a linear relationship between wind and prices.

Gas and oil prices are seen to be consistent and statistically significantly positive across Models 1a to 1d. This is to be expected as the marginal units on the Irish system are gas and oil fired and are thus most likely to be the price setters. As coal serves as a baseload fuel it is rarely the marginal unit and thus does not tend to directly affect the shadow price of electricity. This is evident in the small and insignificant coefficient for coal prices.

Model 1e provides the full specification of the basic model from equation 2, however, it can be seen that this model appears to be unstable with an unexpected negative coefficient on net demand (implying that an increase in demand reduces price). This is not the case in reality, as seen from Figure 2, and is expected to result from multicollinearity between $Netdemand$ and $Wind$ with their squared terms. As such, Equation 3 presents a model with centred data to deal with this multicollinearity issue and the results of this model are presented in Table 4.

Table 4: Centred Regression Model Results

The result from models 2a and 2b are consistent and variables present the expected coefficients. It appears that centring the data has dealt with the multicollinearity issue and model 2b is considered a better representation than that presented in model specification 1e previously. It can be seen $NetDemandcentred^2$ and $Windcentred^2$ have coefficients of zero, again confirming their linear relationship with price[7].

The coefficient for wind generation is consistent across both models, -0.0030 and -0.0034 for models 2a and 2b respectively. Looking at the Akaike and Bayesian information criteria we see that of these two model specifications, the most appropriate model (the one with the smallest AIC/BIC values) is model 2b. The results of this model find that an increase of 1 GWh of wind on the Irish system led, on average over the course of 2009, to a fall in the shadow price of €3.40/MWh. This is closely aligned to the results of other empirical studies examining the impact of wind generation on wholesale prices. For example, Würzburg *et al.* (2013) summarise the results from empirical studies in seven different countries and show that the average impact of wind generation on wholesale prices is €3.81/MWh for each additional GWh of wind.

In isolation, the impact of wind may not seem to be a significant amount, particularly given that the mean Shadow Price is €36.22, however, this saving represents the *average* impact per MWh of wind generation on the *average* shadow price. Using equation 4 it is found that the total savings from wind generation (using the average saving per MWh) are €44.36 million, which represents a saving of 3.76% on the total annual dispatch cost.

It may be the case that the savings from wind vary throughout the day and

[7] Higher order powers of $NetDemand$ and $Wind$ were also tested and were found to also have coefficients of zero.

provide greater reductions at times of higher prices. Thus, Table 5 presents the savings from wind generation on an hourly basis found by estimating equation 5. Coefficients for the interaction term $Wind*Hour$ are presented horizontally for ease of presentation.

Table 5: Hourly Results

It can be seen from Table 5 that the value of wind generation changes throughout the day based on the different marginal units that are displaced throughout the day. For example, it can be seen that, on average, wind has a maximum benefit at 6pm when prices tend to be among their highest.

Since wind reduces the demand for generation with higher marginal costs, its value depends on the demand at the time and the cost of the units it displaces relative to the new marginal unit. Given the range of savings when examined on an hourly basis, it may be the case that the hourly coefficient provides a truer indication of shadow price savings rather than the overall average coefficient. While the overall average reduction is €3.40 per GWh of wind, the value of a reduction in electricity price at peak hours is much more beneficial to consumers than a reduction during the night. Thus, when analysing the overall benefit of wind generation on price reduction we can use these hourly coefficients rather than the overall average of €0.0034/MWh.

Estimating equation 6 finds that the value of wind to the market dispatch resulted in savings of €46.99 million in 2009 which represents a saving of 4% over the total market dispatch cost. In other words, the hourly econometric model suggests that the total market dispatch costs would have been 4% higher in 2009 in the absence of wind. This value, which was calculated using the hourly coefficients, is slightly higher than the value of wind found using the average savings (of €0.0034/MWh) as savings during the peak hours of 6 and 7pm would have a higher benefit than savings during the night.

5.2 Simulation Results

The unit commitment model was run using the Irish Commission for Energy Regulation's Validated Backcast Model for 2009, which uses actual plant availability and forced and scheduled outage rates for 2009 in order for it to mimic the true operation of the system (CER, 2010; Energy Exemplar, 2013a). In this paper we also include historical time series values of wind output, demand, fuel and carbon prices which are identical to those used in the regression model. The unit commitment model simulates the operation of the Irish system on an hourly basis and provides the hourly shadow price as an output.

This model was run twice, first assuming zero wind, and then a second time including the wind output time series for 2009. Table 6 presents the simulation summary statistics for the shadow price under the 'without wind' and 'with wind' scenarios.

Table 6: Summary Statistics from the Unit Commitment Model

These simulated results are relatively close to the true historical values of the shadow price, with a slightly lower average price, however, they have a much lower standard deviation, than found historically (see Table 2). In reality the shadow price is impacted when the system is under stress, for example, when there are large errors in demand or wind forecasts, or if there are unforeseen faults or constraints on the system. The simulation model assumes perfect forecasts for demand and wind, and cannot take these other unforeseen events into account, and as such is likely to underestimate the magnitude and range of the shadow price. The total annual cost of dispatch for the system as simulated by the unit commitment model with wind is €1,045 million, which is 11.5% below the actual cost of €1,180 million in 2009.

Notwithstanding the fact that the unit commitment model underestimates the shadow price and its standard deviation, the simulated values of the shadow price with and without wind are consistent with one another. Thus, we can compare the differences in prices across the two simulations to determine the relative impact of wind on prices.

As can be seen from Table 6, wind generation is seen to reduce the average shadow price in the unit commitment model. Examining the simulation results more closely we can determine the average savings from each MWh of wind for each hour of the day. This is illustrated in Figure 3.

Fig. 3. Average hourly savings per MWh of wind from the unit commitment model

Note: Wind savings are plotted on the primary y-axis and average shadow prices from the unit commitment model without wind are plotted on the secondary y-axis. Wind savings are in €/MWh per MWh of wind energy produced.

As seen in the econometric model, the unit commitment model finds greater savings attributable to wind during the day when prices are higher compared to at night. In fact, both models find maximum benefits during the peak hour of 6pm. While the general pattern is comparable with the econometric model, the unit commitment model finds greater savings on average particularly in the early morning and late evening hours (of 10pm to 8am).

The overall savings attributable to wind in the unit commitment model are calculated according to the following formula:

$$\Sigma Savings_t = \Sigma(Pricewithoutwind_t - Pricewithwind_t) * (Demand_t) \quad (8)$$

Overall, the simulation model finds that wind generation results in an average saving of €0.0045/MWh per MWh of wind generation. This is approximately 25% higher than that estimated by the econometric model which found an average saving of €0.0034/MWh. Overall, the unit commitment model estimates an annual dispatch saving of €59.5 million, which represents a saving of 5.38% compared to the total simulated dispatch cost (€1,045 million). As shown previously, the econometric model showed a dispatch saving of €46.99 million from wind, which represented 4% of actual total dispatch costs (of €1,180 million). Thus, we see a difference of just €12.6 million, or 1.4%, between the two methods.

This difference in results between the two methodologies could be accounted for through the impact of uncertainty of demand, wind and generation outages between the econometric and unit commitment models. It may be the case that the value of perfect demand and wind forecasts relative to what was available in 2009 could be of the order of this €12.6 million per annum but it is likely there are other factors to also consider, thus further research would be required before this conclusion could be made.

In summary, both the econometric and the unit commitment model find that wind results in a cost saving to the Irish electricity market in 2009. They find that the level of this saving is non-trivial and results in a market dispatch saving of between 4 - 5.4%. Given that both models provide similar results using very different methods, the results can be considered compelling and a more reliable representation of reality than if just one method was utilised.

6 Discussion

The results above demonstrate the marginal price savings as a results of wind using two very different methodologies. Both methodologies show a reduction in the marginal price as a result of wind generation with findings in line with the existing literature in the field. The econometric model finds savings in the order of €3.40/MWh for each additional GWh of wind, compared to the unit commitment model which finds savings of €4.54/MWh.

The key contribution of this work was to not only examine the impact of wind, and the nature of that impact, on the price but to also compare two methodological approaches, namely an econometric and a unit commitment approach. The results in this paper indicate that the two methodologies are highly comparable and lead to a difference in savings of just 1.4%. However, it should be noted that both methods have their strengths and weaknesses and may not be perfect substitutes depending on the analysis required.

The econometric model is a much simpler approach and may be favoured by policy makers due to relatively small data requirements. For example, in this paper, the only data required were time series data of the price, demand, wind and fuel prices. No information was required on the exact nature of the generating units nor technicalities like reserve and unit constraints. As such, depending on the type of analysis required, an econometric approach will result in significant computational and data savings compared to a unit commitment approach.

However, the main drawback of the econometric approach is that it is an ex-post analysis and as such it requires a significant level of wind generation to be already present on the system. As such, it may be a useful tool for policymakers who are considering the impacts of increasing penetrations of wind from already moderate levels, however, it is unlikely to provide much insight when penetration levels are low or non-existant. In these cases, a simulation model, such as a unit commitment model is likely to be preferable. Although, it should be noted that an econometric approach may be of value to policymakers in systems with low levels of installed capacity in circumstances where renewables contribute significantly to instantaneous consumption. For example, in this study, renewables met over 40% of demand during certain hours despite an installed capacity of just 8%.

Given its sophistication, the unit commitment model is likely to continue to be the gold standard model in terms of power system planning and design, however, despite some of its limitations, the econometric model is still considered useful for policymakers in a number of respects. Firstly, the econometric analysis can be completed very quickly and provide indicative measurements for officials who are often trying to meet tight budgetary cycles and may not have the time, or the in-house expertise, to run the sophisticated unit commitment models. Secondly, the econometric model is likely to be easier to explain/interpret than the unit commitment model for use in educating non-experts in the field (be they policy makers or the general public). For example, the econometric model may be easier to explain and be more convincing for a Minister for Finance/Treasury than the simulated unit commitment model.

Thirdly, the transparency of the econometric model represents a significant advantage for policy makers compared to the black-box nature of a unit commitment model. Greater transparency often leads to improved stakeholder buy-in and increases the potential for engaged and educated debate. Fourthly, the relatively small amount of data required means that the econometric model would be a much more cost effective method of analysis than using a unit commitment model. This would be particularly important in a decentralised system where it is often the case that the local government controls the budget. The ability of local governments to handle and assess information from unit commitment models may be limited and could require costly and time consuming consultants. In this regard, the econometric model is likely to be a significantly more cost-effective way to determine the impact of renewables on the electricity prices for the local community without the need to employ complex unit commitment tools and potentially costly consultants.

Neither the econometric model nor the unit commitment model in this paper took account of load and wind forecast errors (due to a lack of data availability), however, it is likely that these factors impacted on the lower variability in the prices simulated by the unit commitment model. As such, it is possible that the estimates of the savings due to wind in this paper are slightly overestimated, especially if times of high wind forecast error are correlated with times of high wind output. However, load forecast errors are also omitted in this work and it may be the case that these two errors combined have a lower impact than each individually, although further research is required in this area. The impact of errors may also be influenced by the manner in which the power system is operated and the extent to which the market relies on wind power forecasts in determining dispatch schedules. This is considered beyond the scope of this paper but is an area of interest for further research.

Strategic behaviour by generators, which may influence prices, is also not considered in either approach. While this is not considered to be an issue in the shadow price component of the Irish electricity market, it may be an issue in other payments to generators in Ireland and in other markets (DiCosmo and Malaguzzi Valeri, 2014; Robinson and Baniak, 2002).

The results presented in this paper illustrate that the value of wind generation varies throughout the day depending on both the wind output and the demand at any given time. Ireland is fortunate to have a rich wind resource, the output of which is more closely aligned with demand patterns than may be experienced in other systems. Ireland does not have a large air conditioning demand, thus electricity demand peaks during the winter months which corresponds with when wind output is also likely to be highest. Additionally, wind output in Ireland tends to be higher during the day rather than at night which also corresponds with demand, although there is significant variation on a day to day basis. As such, the impact of wind generation may be seen to be greater in Ireland than in other countries. Notwithstanding this, the wind and demand regime should not overly influence a comparison of the econometric and unit commitment models and either approach can be considered appropriate for an ex-post analysis.

As wind penetrations increase in an electricity system it is likely that the underlying system will evolve to allow for greater flexibility, for example by increasing interconnection, storage, flexible generation, demand response etc. This can be seen in Ireland where, by the end of 2015, installed wind penetrations reached 3084 MW, representing 24% of electricity demand for 2015, which was facilitated in part by a new 500MW HVDC interconnector to Great Britain to reduce the isolation of the Irish system. As the econometric model is an ex-post model, it has the capacity to capture actual changes in the underlying system. In other words, were this study to be undertaken for 2015, the actual flows on the new interconnector could be accounted for implicitly by deducting them from *NetDemand* in the model specified in equation (2) or by explicitly including the flows as an additional explanatory variable in equation (2). In fact, the flexibility of the econometric model in this manner may make it more adaptable than a unit commitment model in terms of modifying the participants in the market. However, it should be noted that the more isolated the system, the easier it will be to confidently model the impacts of wind generation (in respect of both the econometric and unit commitment models).

The results in this paper are based on ex-post data for the year 2009. Given the different installed capacities and wind output profile, as well as demand, fuel and carbon prices in other years, these numerical results are considered to hold for the year 2009 only and extrapolation to other years or for other systems should be done with extreme caution. This paper found that the two methodologies of econometric modelling and unit commitment simulation were comparable, however, the numeric results are specific to the underlying system of study in 2009 (a system which may change with the introduction of the single integrated European market). It is likely that policy makers in other jurisdictions with gross pool markets will gain greater value from the econometric model compared to jurisdictions with alternative market designs and it is advised that further study be undertaken to evaluate the results in the context of the single integrated European market as well as for other market structures.

7 Conclusions and Policy Implications

In this paper we compare two methods for assessing the impact of wind on system prices. We hypothesise that an ex-post econometric model should produce similar results to a unit commitment model while being much more efficient in terms of data requirements and computation time. Results indicate that both models result in costs savings as a result of wind generation on the Irish system. The econometric model indicates an average saving to the system marginal price of €3.40/MWh per GWh of wind output, while the unit commitment model indicates a saving of €4.54/GWh. This difference of approximately 25% in the estimated saving per MWh of wind between the two models is non-trivial and is likely due to the fact that the simulation model assumes perfect forecasts for demand and wind. The simulation model cannot take unforeseen events into account and therefore under-estimates the total costs of running the system. This results in the likely over estimation of the savings attributable to wind generation in the simulation model. It is possible that a more sophisticated unit commitment model, which accounts for forecast errors, would produce results more closely aligned to the econometric model, thus further work is recommended in the area of simulation model development.

Both models show that the value of wind varies throughout the day and reaches its maximum benefit during the peak hour of 6pm. Over the course of the year 2009 the models indicate that wind generation resulted in a market dispatch saving of between 4 - 5.4% depending on the methodological approach. Thus, the impact of the methodological approach on results is of the order of 1.4%. Given the comparability of the results from both approaches, it is concluded that depending on the type of analysis required, an ex-post econometric model may be preferable to an ex-post unit commitment model given the significant reduction in data requirements and computational time involved.

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Table 1
Ireland's electricity supply in 2009

Fuel Type	Percentage of installed capacity	Percentage of electricity consumption	Average Marginal Cost €/MWh
Natural Gas	57	57	42.57
Coal	18	14	36.22
Peat	12	9	*51.63*
Renewables	8	14.1	0
Oil	4	3	129.33

Note: Data on installed capacity and share of electricity consumption is for 2009 and is sourced from SEAI (2010b). Marginal costs are nominal and are based on average disclosed daily generator bids from 2009 sourced from SEM (2013). Marginal costs are based on fuel prices, carbon prices and average unit efficiencies. Marginal cost data is provided for the peat-fired stations for reference purposes only as they have must-run status in the Irish electricity market and in reality are dispatched regardless of marginal price.

Table 2
Summary Statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
Shadow price (€/MWh)	8736	36.22	14.63	4.12	243.34
Net demand (MWh)	8736	3522	726	1743	6114
Wind (MWh)	8736	423	257	11.27	1183
Gas (€)	8736	34.59	13.29	15.51	77.09
Coal (€)	8736	51.18	5.44	44.12	65.04
Oil (€)	8736	44.35	6.86	28.16	53.74
Carbon (€)	8736	13.36	1.54	8.2	15.9

Note: Observations for shadow price and net demand were not available for all hours on 1st January 2009, thus the time series commences on 2nd January and continues until 31st December 2009 inclusive. The number of observations reflects these 364 days with 24 observations per day. In reality, the Irish Single Electricity Market is settled four days ex-post, thus the shadow price used here is the 4 day ex-post price and represents the actual price paid to generators (SEM, 2013).

Table 3
Basic Regression Model Results

Variables	Model 1a	Model 1b	Model 1c	Model 1d	Model 1e
NetDemand	0.0146***	0.0142***			-0.0149***
	(0.0007)	(0.0007)			(0.0030)
$NetD^2$			0.0000***	0.0000***	0.0000***
			(0.0000)	(0.0000)	(0.0000)
Wind		-0.0030***	-0.0029***		-0.0053***
		(0.0005)	(0.0005)		(0.0018)
$Wind^2$				-0.0000***	0.0000
				(0.0000)	(0.0000)
Gas_{t-24}	0.390***	0.401***	0.382***	0.378***	0.380***
	(0.0338)	(0.0340)	(0.033)	(0.0327)	(0.0327)
$Coal_{t-24}$	0.158	0.163	0.153	0.151	0.129
	(0.129)	(0.127)	(0.124)	(0.124)	(0.124)
Oil_{t-24}	0.441***	0.488***	0.474***	0.469***	0.427***
	(0.0738)	(0.074)	(0.0710)	(0.071)	(0.070)
$Carbon_{t-24}$	0.840***	0.828***	0.710***	0.714***	0.553***
	(0.189)	(0.187)	(0.1178)	(0.178)	(0.174)
Constant	-59.13***	-59.08***	-31.34***	-31.55***	2.188
	(9.484)	(9.365)	(8.831)	(8.878)	(10.56)
Rho	0.301	0.295	0.286	0.287	0.294
Durbin Watson stat	2.05	2.04	2.04	2.05	2.06
R-squared	0.587	0.593	0.611	0.610	0.611
AIC	60068	60029	59727	59734	59629
BIC	60401	60369	60067	60074	59983
Observations	8736	8736	8736	8736	8736

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 4
Centred Regression Model Results

Variables	Model 2a	Model 2b
NetDemandcentred	0.0142***	0.0119***
	(0.0001)	(0.0004)
NetDemandcentred^2		0.0000***
		(0.0000)
Windcentred	-0.0030***	-0.0034***
	(0.0005)	(0.0006)
Windcentred^2		0.0000
		(0.0000)
Gas_{t-24}	0.401***	0.380***
	(0.033)	(0.033)
Coal_{t-24}	0.163	0.129
	(0.127)	(0.124)
Oil_{t-24}	0.488***	0.427***
	(0.074)	(0.070)
Carbon_{t-24}	0.828***	0.553***
	(0.187)	(0.174)
Constant	-10.28	-4.926
	(9.06)	(8.821)
Rho	0.295	0.294
Durbin Watson statistic	2.05	2.06
R-squared	0.593	0.611
AIC	60030	55963
BIC	60370	59984
Observations	8736	8736

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 5
Hourly Results

VARIABLES	Interaction Model				
NetDemandcentred	0.0120***				
	(0.0004)				
NetDemandcentred^2	0.0000***				
	(0.0000)				
Windcentred^2	0.0000				
	0.0000				
Gas$_{t-24}$	0.379***				
	(0.0325)				
Coal$_{t-24}$	0.0691				
	(0.05)				
Oil$_{t-24}$	0.408***				
	(0.064)				
Carbon$_{t-24}$	0.506***				
	0.159				
Wind*00:00	0.0001	Wind*08:00	-0.0047***	Wind*16:00	-0.0063 ***
	0.0007		(0.0010)		(0.0011)
Wind*01:00	-0.0002	Wind*09:00	-0.0047***	Wind*17:00	-0.0015
	(0.0005)		(0.0014)		(0.0049)
Wind*02:00	-0.0008	Wind*10:00	-0.0047***	Wind*18:00	-0.0101***
	(0.0006)		(0.0016)		(0.0039)
Wind*03:00	-0.0015***	Wind*11:00	-0.0041***	Wind*19:00	-0.0052
	(0.0006)		(0.0010)		(0.00315)
Wind*04:00	-0.0016***	Wind*12:00	-0.0032***	Wind*20:00	-0.0037**
	(0.0006)		(0.0009)		(0.0016)
Wind*05:00	-0.0011**	Wind*13:00	-0.0043***	Wind*21:00	-0.0037**
	(0.0005)		(0.0009)		(0.00016)
Wind*06:00	-0.0009	Wind*14:00	-0.0049***	Wind*22:00	-0.0031***
	(0.0006)		(0.0010)		(0.0008)
Wind*07:00	-0.0030***	Wind*15:00	-0.0047***	Wind*23:00	-0.0016*
	(0.0009)		(0.0009)		(0.0008)
R-squared	0.933				
Rho	0.294				
DW statistic	2.06				
Observations	8,736				

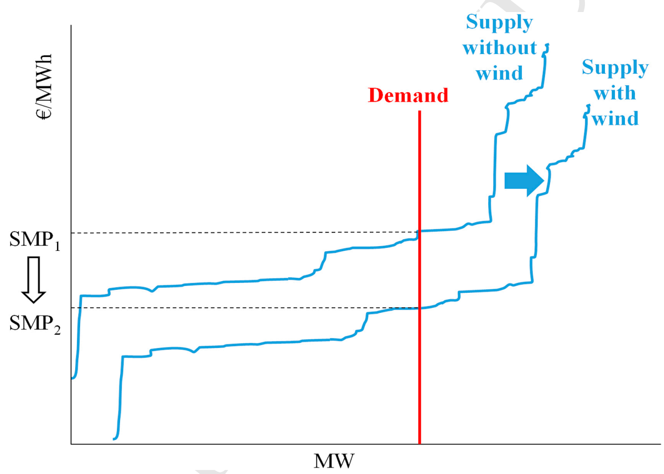
Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

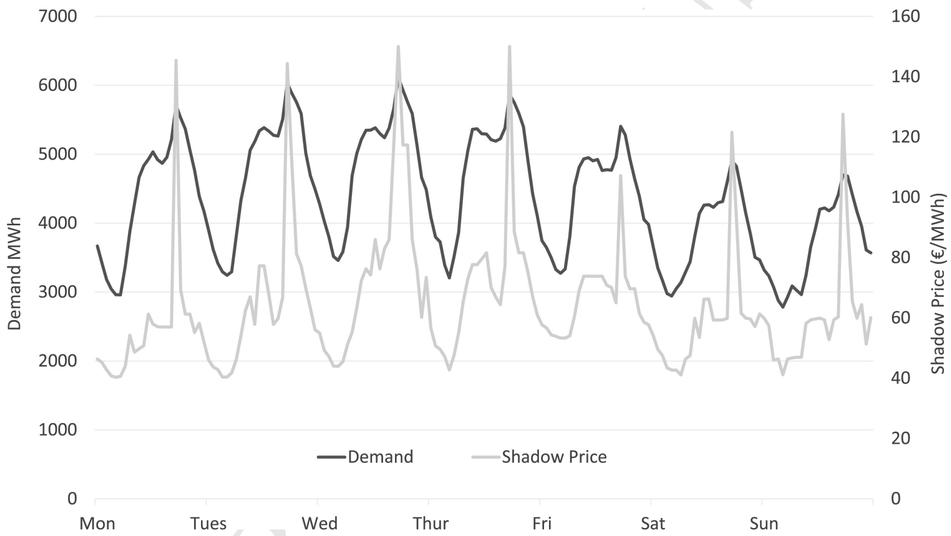
Table 6
Summary Statistics from the Unit Commitment Model

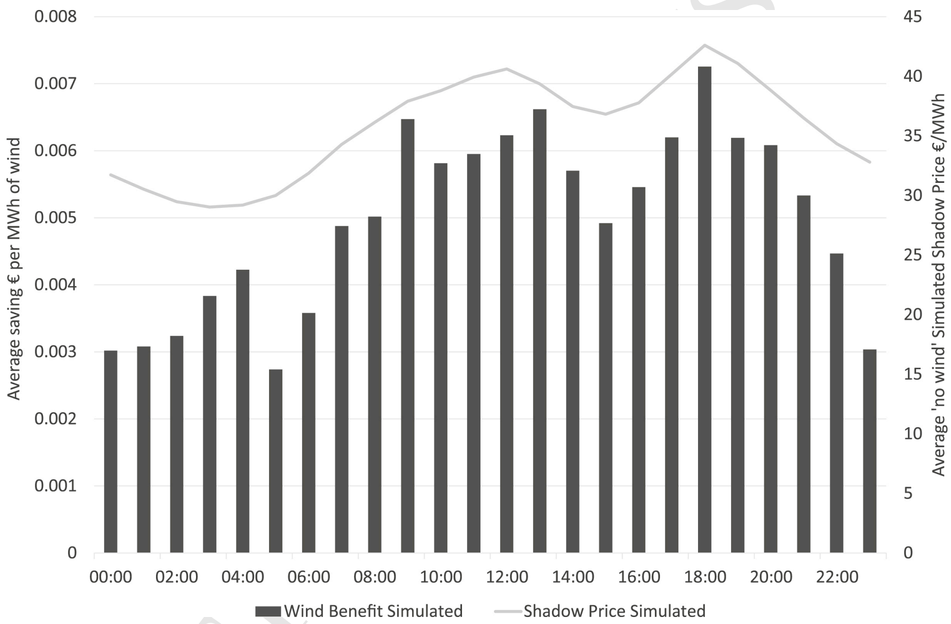
Variable	Mean	Std. Dev.	Min	Max
Shadow price without wind	35.57	6.47	15.28	69.02
Shadow price with wind	33.65	5.70	15.28	65.44

List of Figures

ACCEPTED MANUSCRIPT


€/MWh
Supply without wind
Supply with wind
Demand
SMP1
SMP2
MW


7000
6000
5000
4000
3000
2000
1000
0
Demand MWh
160
140
120
100
80
60
40
20
0
Shadow Price (€/MWh)
Demand
Shadow Price
Mon
Tues
Wed
Thur
Fri
Sat
Sun



0.008
0.007
0.006
0.005
0.004
0.003
0.002
0.001
0
Average saving € per MWh of wind
45
40
35
30
25
20
15
10
5
0
Average 'no wind' Simulated Shadow Price €/MWh
00:00
02:00
04:00
06:00
08:00
10:00
12:00
14:00
16:00
18:00
20:00
22:00
Wind Benefit Simulated
Shadow Price Simulated

Highlights:

- Impact of wind on electricity prices using economics and engineering methods
- Paper isolates the impact of modelling approach on the results
- The findings of both the economic and engineering approaches are comparable
- Wind provides power system savings of the order of 4 – 5.4% of total dispatch cost