Title	Wind as a price-maker and ancillary services provider in competitive electricity markets
Authors(s)	Troy, Niamh, Twohig, Sonya
Publication date	2010-07
Publication information	Troy, Niamh, and Sonya Twohig. "Wind as a Price-Maker and Ancillary Services Provider in Competitive Electricity Markets." IEEE, 2010.
Conference details	IEEE Power and Energy Society (PES) 2010 General Meeting, July 25-29 2010, Minneapolis, Minnesota
Publisher	IEEE
Item record/more information	http://hdl.handle.net/10197/3241
Publisher's statement	Personal use of this material is permitted. Permission from IEEE must be obtained for all other uses, in any current or future media, including reprinting/republishing this material for advertising or promotional purposes, creating new collective works, for resale or redistribution to servers or lists, or reuse of any copyrighted component of this work in other works.
Publisher's version (DOI)	10.1109/PES.2010.5590007

Wind as a Price-maker and Ancillary Services Provider in Competitive Electricity Markets

Niamh Troy, *Student Member, IEEE,* Sonya Twohig, *Member, IEEE,*

Abstract—**Electricity markets are currently evolving to accommodate large scale penetration of wind generation. In this research, potential changes to the classification and role of wind generators in the Single Electricity Market (SEM), the market for Northern Ireland and the Republic of Ireland, are examined. The effect of wind generators opting to become price-making and the potential for wind generators to provide positive spinning reserve is investigated. By submitting bids for available generation, price-making wind generators can increase their revenues from the market and influence the average electricity price. Results also show reduced emissions and systems costs arise in allowing wind to provide spinning reserve.**

Index Terms—**Wind Power Generation, Power System Modeling, Market Prices**

I. INTRODUCTION

WInd generation represents a feasible option to reduce carbon emissions, improve security of supply and decrease dependence on already limited supplies of fossil fuels in the power generation sector. As such, in 2008 more wind was installed in Europe than any other power generating technology [1]. In countries such as Germany, Denmark, Spain and Ireland wind generation plays a significant role in meeting energy needs and in satisfying EU renewable energy targets [2]. The SEM (Single Electricity Market) at present incorporates 1160 MW of wind, providing 12% of the annual electricity demand [3]. This is estimated to rise to between 5000 MW and 6000 MW installed capacity in order to meet the Government target of 40% of the electricity demand from renewables by 2020 [3]. This is among the most ambitious of national targets and for a small islanded power system that is weakly interconnected, it represents enormous technical challenges. Nonetheless wind penetrations contributing up to 45% of system demand have been recorded by EirGrid, the Irish Transmission System Operator (TSO) this year [4].

Since late 2008, the SEM has seen a considerable reduction in electricity demand as a result of economic recession, with decreases of the order of 6% for many months in 2009 when compared with same in the previous year [5]. Projected demand in 2020 is now about 20% less than predicted previously. This has led to a large capacity margin and greater levels of competition between generators, with traditionally base-loaded thermal plants now being two-shifted and mid-merit units operating as peakers. In spite of this downturn, wind connections to the system are continuing due to the government support mechanism remaining unchanged. Nearly 4000 MW of new wind plant has been approved for connection with an additional 4600 MW in the application queue, more than is required to meet 2020 targets [6].

Research activities to date have concentrated on the technical challenges associated with operating a power system with a large wind power penetration such as frequency and voltage control, maintaining adequate operating reserve levels and transmission system upgrades. More recently, the impact significant wind generation can have on electricity markets has been investigated. In this research, scenarios where wind generators actively bid into the market is examined for the SEM market design of Northern Ireland and the Republic of Ireland. The potential role for wind generators to provide positive spinning reserve is also investigated.

II. THE SEM AND MARKET EVOLUTION

In SEM all dispatchable generators are classified as predictable or variable depending on the predictability of their short term availability. In addition a generator can be classified as autonomous if the generating unit is not controllable by the TSO. Autonomous units, or self-dispatching units, do not participate in the market and their available generation is simply netted from demand at all times. Predictable and variable units have a further sub-classification as either price-making or price-taking. Price-making units, such as conventional power plants, submit monotonically increasing bids to the market for their generation, whereas price-taking units, such as wind units, simply submit a profile of intended output and their bid price is automatically set to zero. As such, price-taking units play no role in setting the electricity price.

Under EU law, all wind units are given priority dispatch, meaning they will always be run at their maximum available output unless doing so would threaten system security [7]. Units with priority dispatch status, that are fully dispatchable in SEM can choose to register as price-makers or price-takers, but to date all wind units in SEM have chosen to register as price-takers. Opting to become a price-maker implies priority dispatch is forgone and the wind unit owner is actively managing its own running in the market schedule.

The depression of electricity prices resulting from large scale wind integration has been shown extensively [8]–[11].

N. Troy (niamh.troy@ucd.ie) is with the Electricity Research Centre, University College Dublin, Ireland, which is supported by Airtricity, Bord Gais, Bord na Mona, Cylon Controls, the Commission for Energy Regulation, EirGrid, Electricity Supply Board (ESB) International, ESB Networks, ESB Power Generation, Siemens, SWS Group and Viridian. Her research is funded by a Charles Parsons Energy Research Award from the Department of Communications, Energy and Natural Resources administered by Science Foundation Ireland. S. Twohig (sonya.twohig@eirgrid.com) is Manager of Grid Revenue and Metering at EirGrid, the Irish Transmission System Operator. This work was conducted at EirGrid.
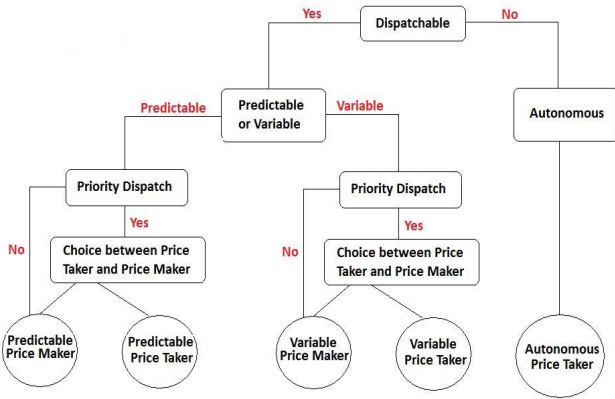
Fig. 1. Classification of Generating Units in SEM

Periods of very high wind can result in prices of zero or even negative prices, which will adversely affect revenues earned by all types of generators. This can have serious consequences on a power system as new investment is not attracted which can lead to capacity shortfalls in the long term. A possible development in the wind industry is the formation of consortiums of small wind generators, seeking to actively participate in the market and have greater control over their dispatch, rather than simply 'take' the market price. Thus in the future it is possible some wind generators may opt to become price-makers. As wind is set to make up a considerable portion of future portfolios, such a development could have a significant impact on electricity prices. In addition, as the controlability of wind farms improves, opportunities for them to provide positive spinning reserve to the system may arise.

III. Wind as an Ancillary Services Provider

To ensure system stability and reliability, EirGrid, as TSO can chose to dispatch down wind for the following reasons: (i) to maintain a minimum number of online units which are needed to provide system inertia, (ii) to maintain sufficient spinning reserve on the system in order to deal with frequency excursions and (iii) to maintain sufficient ramping capability to deal with changes in demand. As the wind penetration on the system increases, it is likely the incidence of wind curtailment will occur more frequently. During these hours when wind must be curtailed for security reasons, there is an opportunity to reduce the demand for spinning reserve on the system by the amount of wind curtailed. As the predictability of wind power outputs is high in short time frames, it is reasonable to assume that, provided the wind generators have proven controlability to receive dispatch instructions, dispatched down wind generators are capable of providing positive spinning reserve to the system. This may have potential benefits for the system overall as the requirement on thermal units to provide spinning reserve to the system is reduced, thus allowing them to operate at higher outputs and therefore higher efficiencies.

In order to use wind to provide reserve for the system, it must be dispatchable by the TSO. A specific grid code for wind generators was set out by EirGrid, outlining requirements for fault ride through, frequency control and voltage control capabilities of wind farms as well as specifications for the communications and control functionality. Presently approximately 50% of installed wind is compliant with this grid code and so is capable of being dispatched down. However, the Reserve Constrained Unit Commitment (RCUC) software used by the TSO to dispatch generators currently does not utilize curtailed wind in meeting the demand for spinning reserve in any optimization period. If this functionality were introduced, such that wind was capable of contributing to the demand for spinning reserve, it is likely wind would be dispatched down in other periods also (not for system security reasons), when it could meet spinning reserve requirements at a lower cost than thermal units alone could.

IV. Modeling Tool

The model used in this study was the Wilmar Planning Tool, a stochastic unit commitment and economic dispatch model. Wilmar was originally developed to model wind integration in the Nordic systems and was then adapted to the Irish System for the purpose of the All Island Grid Study [12].

The main functionality of the Wilmar Planning Tool is in the Scheduling Model and the Scenario Tree Tool. The Scenario Tree Tool contains the stochastic element of the model and generates scenario trees with branches of varying probability, containing hourly wind, load and reserve data, to feed into the unit commitment algorithm. The source load data, wind power production data, wind speed data and data for the historical accuracy of the wind forecasting tools currently used in the All Island power system was provided by the system operators, EirGrid and SONI. Monte Carlo techniques are employed to convert the historical wind and load time series into scenario time series for 2020. The model can also be run deterministically whereby each scenario tree generated has only one branch with a probability of one.

The Scheduling Model minimizes the expected cost of the system over the optimization period covering all scenarios generated by the scenario tree tool and subject to the generating units' operational constraints, such as minimum down times (the minimum time a unit must remain offline following shut-down), synchronization times (time taken to come online), minimum operating times (minimum time a unit must spend online once synchronized) and ramp rates, in addition to system constraints such as minimum number of units online and reserve constraints. The cost function contains fuel, carbon and start-up costs. The Scheduling Model produces a year-long dispatch with hourly time resolution for each individual generating unit on the test system so that their specific operation can be examined.

In Wilmar reserve is categorized as spinning or replacement. Spinning reserve, which is needed in short time scales (less than five minutes), is supplied only by synchronized units. The system should have enough spinning reserve to cover an outage of the largest online unit occurring at the same time as a fast decrease in wind power production. Positive spinning reserve is provided by increased production from online units, pumped storage or wind (as described in Section V-B), whilst negative spinning reserve is provided by decreased production

from online units or by pumped storage when in pumping mode. The demand for replacement reserve, which is reserve with an activation time greater than 5 minutes, is determined by the total forecast error which is defined according to the hourly distribution of wind power and load forecast errors and the possibilities of forced outages. A forced outage time series for each unit is also generated by the scenario tree tool using a Semi-Markov process based on given data of forced outage rates, mean time to repair and scheduled outages is produced. Any unit that is offline and can come online in under one hour can provide replacement reserve.

Rolling planning is also employed to re-optimize the system as new wind and load information becomes available. Starting at noon the system is scheduled over 36 hours until the end of the next day. The model steps forward with a three hour time step with new forecasts used in each step. The Generic Algebraic Modeling System (GAMS) was used to solve the unit commitment problem using the mixed integer feature of the Cplex solver. For all the simulations in this study the model was run with a duality gap of 0.01%.

In SEM electricity prices (system marginal price) are determined by the marginal cost of the most expensive generator required to meet the demand for every half-hour period in an ex-post, unconstrained market schedule. As the market schedule is determined ex-post, realised values of wind and load are used. Thus, in this study, the Wilmar model was run deterministically, with no constraints for reserve or minimum number of online units, to act as proxy market tool and provide a snapshot of what the pricing schedule for SEM in 2020 will be. However, to simulate the actual production schedules of generators the model was run stochastically with reserve constraints and a constraint to maintain a minimum number of thermal units online at all times. Therefore, for each scenario investigated a deterministic unconstrained run, to obtain the price profile for the year and a stochastic constrained run, to obtain the production schedules for the wind and thermal generators on the system were carried out.

A. Test System

The All Island Grid Study examined the feasability of various renewable portfolios that may exist in 2020. The test system used in this study is based on the Portfolio 5 test system that was defined in the All Island Grid Study which contained 6000 MW of wind power. In the original Grid Study this 6000 MW of installed wind provided 34% of the electricity demand. However, to account for economic downturn, the system demand for 2020 was revised downwards from 54 TWh to 43 TWh, increasing the wind energy penetration to 43%. The portfolio is shown in detail in Table I and the fuel prices are shown in Table II. The system peak was 7.7 GW and minimum demand was 2.8 GW. A carbon price of €30/tonne was assumed.

The power exchange capacity to Great Britain is assumed to be 1000 MW. A simplified British system is modeled where similar unit types are aggregated into large blocks and wind energy provides approximately 12% of electricity demand. Wind and load is assumed to be perfectly forecast in Great

TABLE I
INSTALLED CAPACITY (MW) BY GENERATION TYPE

Generation Type	Installed Capacity MW
Coal	1324
Base-load Gas	3953
CHP	166
Peat	343
Mid-Merit Gas	1155
Gasoil	388
Pumped Storage	292
Base Renewables	306
Hydro	216
Tidal	72
Wind Power	6000

Britain. Flows on the interconnector to Britain are optimized such that the total costs of both systems are minimized and these can be altered intra-day.

TABLE II
FUEL PRICES (€/GJ) BY FUEL TYPE

Fuel	Fuel Price
Coal - Republic of Ireland	1.75
Coal - Northern Ireland	2.11
Base-load Gas	5.91
Mid-merit Gas	6.12
Peat	3.71
Gasoil - Republic of Ireland	9.64
Gasoil - Northern Ireland	8.33
Base Renewables	0

V. RESULTS

A. Impact of Price-Making Wind

A number of scenarios were investigated in this study. Firstly, to investigate the impact that price-making wind will have on the market as a whole, a portion of the total wind on the system was assumed to be price-making and given a marginal cost to represent a bid price. Out of the total 6000 MW wind, 2000 MW was assumed to be price-making and bids ranging from €60/MWh to -€60/MWh were investigated. As there is currently no price-making wind in SEM, a business-as-usual scenario where all the wind was price-taking (i.e. bids €0/MWh) was also carried out for comparison. In the scenarios with price-making wind, the bids (or variable costs) submitted by these wind generators were constant for all periods throughout the year. In reality however, the bidding profile submitted by the wind farm owner would more than likely be varying from one trading period to the next. These bidding scenarios examined here are intended to illustrate the ability of a wind farm owner to manage the commitment of its units in the market schedule and examine the impact on the market overall.

Figure 2 shows the average electricity spot price and standard deviation of spot price over the year for each of the price-making wind scenarios examined and for the business-as-usual
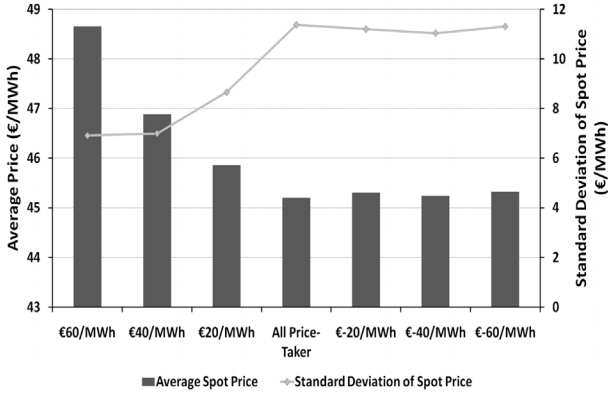
Fig. 2. Average and Standard Deviation of Spot Price for each scenario over the year

Fig. 3. Percentage of Price-making Wind Dispatched and Revenues Earned by Price-making Wind (and Price-taking Wind for reference)

case with all price-taking wind. The scenarios in which price-making wind was given a positive bid resulted in a higher average spot price over the year relative to the case with all price-taking wind. The average spot price over the year was approximately equal for both the scenarios in which price-making wind bidded negatively and the scenario with all price-taking wind. The scenarios where the price-making wind bids negatively show little difference relative to each other as the minimum price in the model was €0/MWh. As the model is minimizing costs on both the All Island Irish system and the interconnected British system, if prices drop to €0/MWh on either system due to large wind penetrations, power will be transferred across the interconnector to meet demand in the neighboring country. Therefore the model never pays to export excess wind power from one system to the other, as might sometimes be the case in reality, hence the system price never falls below €0/MWh.

Examination of the standard deviation of the spot price shows an inverse relationship between the average price and standard deviation across the price-making scenarios examined, with lower prices correlated with a higher standard deviation. When the price-making wind units bid negatively, the spot price is significantly depressed during periods of high wind penetration and so when the wind penetration drops-off the price increases again, thus leading to the high standard deviations seen in Figure 2, indicating price spikiness. As price-making wind generators bid higher prices, the spot price is on average higher but the standard deviation is lowered as the price difference between hours of low and high wind penetration is less.

Figure 3 shows the revenue earned per MW by price-making wind across each of the price-making wind scenarios and the revenue per MW earned by the price-taking wind in the business-as-usual scenario with all price-taking wind. Figure 3 also shows the percentage of the available price-making wind that is actually dispatched in the stochastic, constrained dispatch schedule. It can be seen that the revenue earned by wind is greater for each of the negative bidding scenarios investigated and also the €20/MWh scenario compared to the case when all wind is price-taking. Revenues for price-making wind peak in the €20/MWh scenario. The €60/MWh
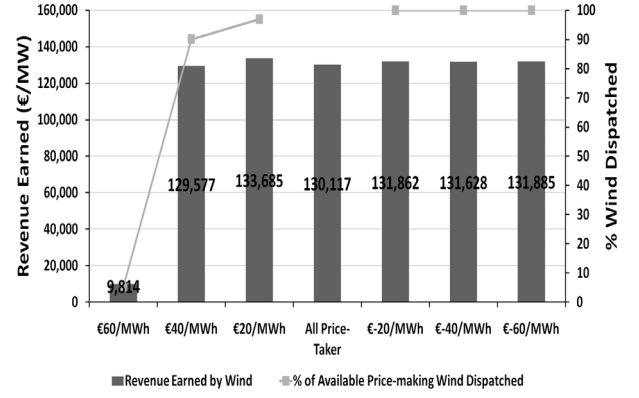
and €40/MWh scenarios show reduced revenue for the price-making wind unit because despite increased electricity prices on average, the price-making wind is more frequently out of merit and therefore not dispatched. In the scenario where wind bidded €60/MWh only 5% of this price-making wind is actually dispatched in the stochastic dispatch schedule.

Figure 4 illustrates the disparity between the market (ex-post) unconstrained schedule and the stochastic constrained schedule representing the actual dispatch of generation. The total amount of generation, summed over all generators in the year, that was actually dispatched but was not in merit in the market schedule (Dispatch Schedule > Market Schedule) is shown for each scenario as well as the total amount of generation summed over all generators in the year that was scheduled in the market schedule but was not actually dispatched (Market Schedule > Dispatch Schedule). In SEM these differences correspond to constraint payments which are paid or received by the TSO to the generators who have been redispatched from the market schedule. Generators that are not in merit in the market schedule but are called on to operate in reality receive:

$$
\begin{aligned}
&(SMP * MSQ) + ((ADQ - MSQ) * Bid\ Cost) \\
&\Rightarrow (SMP * 0) + (Positive\ Constraint\ Payment)
\end{aligned}
\tag{1}
$$

where SMP is the system marginal price, MSQ is the market schedule quantity and ADQ is the actual dispatch quantity. Here the generator receives a constraint payment, but this only covers the cost of production. In SEM, all wind is included in the market schedule as it's bid price is set to €0/MWh, but in actuality it may not always be dispatched because of system security reasons. Therefore, other generators could be constrained on but they will not receive the market price for their production as these units were not in merit in the market schedule. These units receive their incurred costs as constraint payments, hence there is no resultant profit from generating in these periods.

On the other hand generators that are in merit in the market schedule but are dispatched down to a reduced quantity
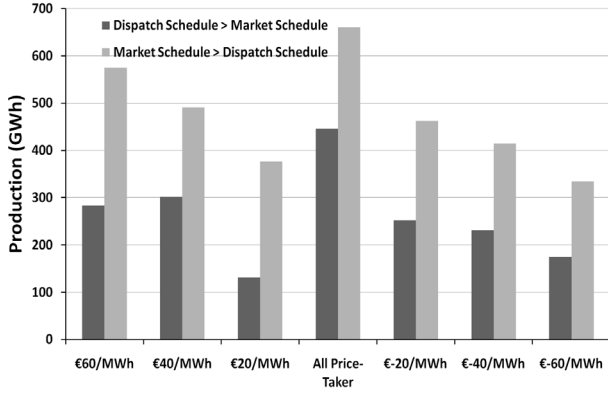
Fig. 4. Comparison of misalignment between Market Schedule and Actual Dispatch across scenarios

receive:

$$(SMP * MSQ) - ((ADQ - MSQ) * Bid\ Cost)$$
$$\Rightarrow (SMP * MSQ) + (Negative\ Constraint\ Payment)$$
(2)

In this case a negative constraint payment is added to the energy payments. Because the market schedule is reserve unconstrained, generators can be scheduled in the market schedule at full output but actually dispatched to a lesser output in order to provide reserve.

As seen in Figure 4, the disparity between the market schedule and the actual dispatch for generators is greatly reduced for each of the price-making wind scenarios relative the scenario where all wind is price-taking. Thus the effect of introducing price-making wind is to reduce the variation between the market and dispatch schedules, thereby the amount of constraint payments paid to or by the TSO is reduced.

B. Wind as an Ancillary Services Provider

This section examines the system benefits of allowing wind to provide positive spinning reserves during periods when it is curtailed for system security reasons and also of dispatching down wind to meet spinning reserve requirements when this is cost optimal. In the Wilmar model, wind is curtailed to provide positive spinning reserves for the following reasons: (i) to maintain the power balance, (ii) to maintain a minimum number of thermal units online, (iii) if it is more cost optimal to keep conventional units running rather than shut them down and incur their start-up costs at a later time and (iv) if it is more cost optimal to provide spinning reserves from wind. If wind is curtailed for the first three reasons, the amount curtailed is netted from the demand for spinning reserve in that hour. The model was run allowing wind to be curtailed for these reasons and any wind curtailment was used to meet the spinning reserve requirement. Then the model was run allowing wind to be curtailed for the first three reasons only, but not to provide spinning reserve and any curtailed wind was not used to meet the spinning reserve requirement. This is more representative of current arrangements where wind would not be curtailed to provide spinning reserve. (All wind is assumed to be price-taking in these scenarios.)

The scenario where wind can be curtailed to provide spinning reserve showed only 0.54% of wind energy curtailment over the year, compared with 0.37% curtailment for the scenario where wind can not provide spinning reserve. As seen from Table III, this corresponded to a difference of over 31 GWh of wind curtailment, just for spinning reserve reasons. The amount of curtailment is higher when wind can be curtailed to provide spinning reserve, but overall the amount of curtailment in both scenarios is small. By allowing wind to contribute to the demand for spinning reserve at appropriate times, thermal units that would otherwise provide this reserve can operate at increased outputs and therefore higher efficiency. This results in CO_2 savings and an overall reduction in system costs as fuel is saved. These results are summarized in Table III. Although the levels of curtailment shown here are small, in reality however, when transmission constraints are taken into consideration, the level of wind curtailment would likely be significantly higher. Indeed experience from SEM during 2009 would indicate this to be the case, particularly on windy nights. Therefore, even greater system benefits than indicated here could be observed by including the functionality to allow wind contribute to spinning reserve requirements in system scheduling software.

TABLE III
SYSTEM IMPACTS OF WIND PROVIDING SPINNING RESERVE

		Can Provide Reserve	Can not Provide Reserve
Wind Curtailment	%	0.54	0.37
	MWh	99284.53	68028.64
CO_2	Mtons	12.608	12.618
System Costs	M€	1070.402	1070.761

From the wind generators perspective, registering as a reserve provider has significant benefits. By providing spinning reserve to the system wind can receive additional payments for ancillary services. In SEM, generators that are included in the reserve unconstrained market schedule will receive the system marginal price for their production, as per the market schedule, and as price-taking wind has a marginal cost of €0/MWh, it will always be included in the market schedule. If wind (or any other generator) is dispatched down in the actual dispatch schedule, it will be paid as per Equation 2. However, as the bid cost is set to €0/MWh for price-takers, its earnings will not be reduced by the curtailment event, but in fact increased overall when ancillary services payments are taken into consideration. Therefore, both wind generators and the system overall benefit from allowing wind generators to provide spinning reserve.

VI. DISCUSSION

Wind generators in SEM at present benefit from support mechanisms (renewable obligation certificates in Northern Ireland and feed-in tariffs in the Republic of Ireland). As the technology matures and the wind industry becomes increasingly competitive however, it is reasonable to assume that special support mechanisms for wind generators may be phased out. Alternatively this may arise if systems reach a

point where no further wind developments can be connected. Although conventional generators in a power system with large levels of wind power will suffer from reduced electricity prices on average, wind suffers from an additional effect that anytime it generates it lowers the price that it will receive. This is known as wind revenue cannibalization. This could result in wind generators opting to become price-makers in an effort to influence the electricity price rather than simply 'take' the price.

Both positive and negative bids are examined in this study to represent two possible evolutions of the market. Positive bids could arise if the Commission for Energy Regulation (CER) decided to abandon the renewable support mechanism and allow wind farms receive a minimum payment from the market rather than pay for an explicit support. Negative bidding on the other hand could ensure that the wind unit is scheduled in the market so as to guarantee payment for an external support mechanism, if this support mechanism is dependent on the output of the wind unit.

Both bidding strategies would also be plausible scenarios in the event that the CER develop a policy that non-firm price-taking units cannot be given priority dispatch ahead of all firm units in the market. In this scenario only price-taking units which had firm access would be given priority dispatch status. If non-firm price-taking units could not be guaranteed to be scheduled in the market then there would be a strong incentive to opt to become a price maker.

However, SEM is a regulated market and generators must adhere to bidding principles which state that generators must bid their short-run marginal cost. Keeping in line with these bidding principles, price making wind would bid a price of €0/MWh. In other electricity markets, generators are free to bid strategically. However, if price-making wind units could justify to the energy regulator the need to bid prices other than the short-run marginal cost, the various price-making scenarios investigated here could be feasible.

VII. Conclusions

This work examines the system impacts of price-making wind. The price-making wind scenarios investigated in this paper showed that wind can improve its revenues and potentially manage its dispatch by bidding into the market. This is shown to influence the average price for electricity and also the spikiness of the price, with negative bids from price-making wind leading to more spiky prices. All of the price-making wind scenarios investigated result in closer alignment between the market schedule and the actual dispatch of all generators on the system. This is beneficial as in-merit generators are paid appropriately and constraint payments are reduced.

It was also shown in this work, that by allowing wind to contribute to the demand for spinning reserve when either it is curtailed for system security reasons or when it is more cost optimal to provide reserve from wind rather than thermal plant, there are benefits for both the system overall and the wind generator. The reduced requirement for thermal plant to provide reserve allows them to operate at increased outputs and thereby increased efficiency thus reducing CO_2 emissions

and overall system costs, whilst wind generators also benefit from ancillary services payments.

References

[1] European Wind Energy Association, *Winning with European Wind*, Brussels: EWEA, June 2009.

[2] H. Holttinen, P. Meibom, A. Orths, B. Lange, M. O'Malley, J. Olav Tande, A. Estanqueiro, E. Gomez, L. Soder, G. Strbac, J. Smith, F. van Hulle "Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration", *Proceedings of the 8th International Workshop on LargeScale Integration of Wind Power into Power Systems*, October 2009, Bremen, Germany.

[3] EirGrid, *Generation Adequacy Report 2008 - 2015*, Dublin: EirGrid, December 2008.

[4] EirGrid,"EirGrid Monthly Electricity Statistics Update November 2009", 2009. [Online]. Available: http://www.eirgird.com/operations/systemperformancedata/electricitystatistics/ [Accessed: Nov. 24, 2009].

[5] EirGrid,"Electricity Statistics", 2009. [Online]. Available: http://www.eirgird.com/operations/systemperformancedata/electricitystatistics/ [Accessed: Nov. 24, 2009].

[6] Commission for Energy Regulation (CER),"Criteria for Gate 3 Renewable Generator Offers and Related Matters, ", December 2008. [Online]. Available: http://www.cer.ie/ [Accessed: Nov. 24, 2009].

[7] Eur-lex,"Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001", 2001. [Online]. Available: http://www.eur-lex.europa.eu/ [Accessed: Nov. 25, 2009].

[8] F. Sensfuss, M. Ragwitz, M. Genoese, "The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany ", *Energy Policy*, Vol. 36, Issue 8, pp 3086-3094, August 2008.

[9] C. Obersteiner, M. Saguan, H. Auer, C. Hiroux, "On The Relation Between Wind Power Generation, Electricity Prices And The Market Value Of Wind Power", *Proceedings of the 31st IAEE International Conference* , 2008, Istanbul, Turkey.

[10] R. Green, N. Vasilakos, "Unit Market behaviour with large amounts of intermittent generation", *Energy Policy*, to be published.

[11] T. Jonsson, P. Pinson, H. Madsen, "Day-Ahead Electricity Prices in Denmark: The Impact of Wind Power Forecasts", *Proceedings of EWEC 2009* , March 2009, Marseille, France.

[12] All Island Renewable Grid Study - Workstream 2B, "Wind Variability Management Studies," *http://www.dcmnr.gov.ie*, 2008.

Niamh Troy received the B.Sc. degree in Applied Physics from the University of Limerick, Ireland. She is currently conducting research for the Ph.D. degree at the Electricity Research Centre in the University College Dublin, Ireland.

Sonya Twohig Sonya received primary and masters honours degrees in Physics from University College Cork in 1997. After her studies she worked in oil industry for four years with Schlumberger. In 2001 Sonya undertook a MBA in Smurfit Business School (UCD) which included research into the design of effective electricity trading arrangements in Ireland. Since 2002, Sonya has been employed by EirGrid Plc. as Grid Revenue and Metering Manager. In 2009, Sonya Twohig completed a MEngSc. thesis entitled 'Evolution of Market Design in a Power System with High Wind Penetration'.