Alternative Trading Arrangements for Intermittent Renewable Power: A Centralised Renewables Market and other concepts

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1 Summary and Introduction

1.1 Purpose of the report

One of the issues identified by Ofgem's Project Discovery was that imbalance prices may not rise sufficiently at times of high demand to elicit extra supply or demand response.[1] A proposed solution is to sharpen the price signals, by making imbalance prices closer to the marginal cost of balancing actions. However, Project Discovery also recognised that such a move could reduce incentives to invest in intermittent sources of renewable energy – mainly wind, but perhaps also solar and wave. The output of such renewable sources is inherently difficult to forecast and they are therefore more exposed to imbalance charges.

It also seems likely that imbalance prices will become more volatile over time, as the levels of intermittent generation increase and more balancing actions are required to match supply and demand. At present, GB has an installed wind capacity of around 5 GW, of which over 90% corresponds to licensed (>=10 MW) wind farms who have to provide real-time data to the transmission system operator, National Grid Electricity Transmission (NGET). This is a relatively small capacity and, to date, balancing of wind power has not been a major issue. However, NGET forecasts that wind capacity will reach 16 GW by 2015/16, and that essentially all of this increase will be in large, transmission-connected wind farms. Accordingly the issue of balancing wind power and integrating wind power into the market will become a more pressing issue over the next few years.

One possible solution to reduce imbalance risk for intermittent renewable generators would be to organise a Centralised Renewables Market (CRM). The CRM, which Project Discovery described at a high level, would allow for pooling of imbalance risk, among other things. Ofgem have commissioned The Brattle Group to examine the costs and the benefits of various options for the design and governance of a CRM. Among other things, the CRM should:

- promote long-term investment in renewables,
- retain incentives on players to balance the system in the short term, and
- be compatible with the current GB arrangements.

We have reviewed the experience with managing the output and sale of sales of intermittent renewable energy (IRE) in several countries that have a high capacity of wind power. We conclude that while there are interesting lessons to be learnt, the countries examined are still developing their policies for managing intermittent generation. International experience highlights the importance of giving incentives for accurate forecasting of wind power, and the risks associated with selling wind power in a single trading session.

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[1] Ofgem Consultation, Project Discovery – Options for delivering secure and sustainable energy supplies Ref: 16/10. 3 February 2010.

1.2 **Conclusions**

On the basis of the analysis presented in the remainder of the report, we have reached the following conclusions:

- The CRM should be a *service*, rather than a *market*. An agent – which we call the Centralised Intermittent Renewables Aggregator, or "CIRA", would reduce imbalance exposure by aggregating IRE power and selling it using existing market mechanisms and products.
- The CIRA would offer services only to IRE generators, as it is these generators that face the greatest forecasting difficulties and imbalance risk. Within this category, we expect that initially only wind power would make use of the CIRA's services. (When, or if, other forms of IRE power such as solar and wave power reached a critical mass, then these forms of power could also be aggregated by the CIRA.) Accordingly, in this report we focus only on wind power, while acknowledging that the same types of measures could be applied to other forms of IRE generation.
- To ensure that there was a liquid market for IRE power, it might be helpful to alter the Renewables Obligation (RO) so that RO certificates were linked to purchases from the CIRA.
- To avoid undue volatility in the prices achieved for intermittent generation, maximise the probability that all available intermittent output is sold and reduce the impact on other market participants, sales of IRE should take place over a variety of timescales from day-ahead down to close to real time.
- The rules under which the CIRA operates should not be too prescriptive, rather it should be given discretion as to how it organises sales of IRE. To ensure that the interests of the CIRA are aligned with those of participating generators, the CIRA should be subject to an incentives maximise the revenues earned by intermittent generators and minimise their imbalance exposure. How these incentives would be imposed will depend on whether the CIRA is funded solely by participating generators or not. However, there should also be safeguards to ensure that the imbalance exposure of other market participants is not significantly increased. There must be some degree of predictability about how, and when, sales of IRE will take place.
- The CIRA should be given responsibility for making intermittent generation forecasts and for submitting contract notifications (where IRE sales are not made via exchanges) and physical notifications. On the other hand, it probably makes sense to allow CIRA participants to decide whether or not the CIRA should submit Balancing Mechanism bids and offers on their behalf.
- Procedures for allocating the CIRA's costs and revenues to participating generators should be subject to consultation and approval by Ofgem.
- There seems to be no particular reason why the transmission system operator should automatically be given the role of the CIRA, Instead, the CIRA role should by chosen by competitive tender.

- The charges that the CIRA can levy on participants should be regulated in some form, perhaps by making these charges part of the criteria to award the CIRA role. Similarly, the tender process could also play a role in setting the incentive schemes.

- IRE generators should face the same imbalance prices as all other market participants. Appling reduced imbalance charges to IRE generators would reduce incentives to balance, which would be inefficient. Rather than addressing the *price* of imbalances, the benefits of aggregation should reduce the *quantity* of imbalances for intermittent generators, and hence mean that the barrier to entry potential provided by imbalance costs will be reduced.

- Our analysis suggests that there could be a significant benefit from aggregating the output of IRE generators. However, if the CIRA concept is to be pursued further, Ofgem should quantify the benefits of the CIRA relative to the status quo, and test the reaction of the main potential participants to the concept.

- If Ofgem identifies significant quantitative benefits to use of a CIRA, but potential participants seem reluctant to use such a service without good reason, then Ofgem could consider making use of the CIRA's services compulsory. If participation is made compulsory, the extent of the compulsion should be limited (in time or the volume of generation involved or both), and measures should be put in place to ensure that participating generators will be no worse off than if they had not been forced to use the CIRA's services. This could be justified if Ofgem felt that establishing a CIRA could reduce barriers to entry in intermittent generation.

- The potential benefits of a CIRA service include:

    - Reduced overall imbalances charges for renewable generators. Errors in wind power forecasts for different wind farms would offset one another, especially if the wind farms are physically far apart, since the forecasting errors will only be weakly correlated;

    - Wind forecasts should be more accurate, if all or most wind power generators contribute to the development of a single wind forecasting model, and the CIRA has effective incentives to improve its wind forecasting accuracy;

    - Possible increases in security of supply, if NGET is able to make or access more accurate forecasts of wind power, and real-time data is available to NGET from unlicensed wind farms which would not normally be available absent the CIRA service.

- The costs of the CIRA service include:

    - Tendering for the CIRA role;

    - Set-up costs for the CIRA, including development of a wind forecasting model and trading system to manage wind power;

    - Ongoing costs including those relating to adding new participants to the trading systems and forecasting model.

- The benefits of using an aggregator/agent for managing wind power are proportional both to the capacity of installed wind and the geographic dispersion of wind power. According to the Seven Year Statement by 2015/16 there will be about 15 GW of wind power installed in GB. By that time, offshore wind farms should help geographic dispersion because they will generally be far away from the bulk of onshore wind. Hence it seems that the benefits of using a CIRA should become apparent by around 2015. We also note that it could be advantageous to begin the process of setting up the CIRA at least one or two years before it is strictly required so as to give time for learning and experience.

1.3 **Overview of the report**

We begin with a short description of the current trading arrangements for wind powered generators, so as to make clear the issues that alternative trading arrangements would address. By way of background, and to see if there are any lessons to be learnt, we describe how intermittent generators are treated in the three European countries with the highest proportions of wind power: Spain, Germany and Denmark. We then go on to set the scene for our discussion of the key issues surrounding alternative trading arrangements for IRE power by describing in more detail the objectives these trading arrangements should meet. We also describe the "straw man" CRM concept included in Project Discovery, which provides the starting point for our discussions, and the interactions between trading arrangements for IRE power and security of supply. We also note that it would be possible to encourage renewables investment via some form of capacity mechanism rather than an energy trading mechanism.

The next five sections of the report deal with various key design issues, on which we base the conclusions presented above. These are:

- When CRM power should be traded;
- Imbalance exposure for CRM participants;
- The role of the CIRA, and how it should be chosen and funded;
- Performance incentives for the CIRA; and
- Whether the arrangements should be voluntary or mandatory and the consequences of this decision for de minimis participation levels.

The final section considers the links between alternative trading arrangements for IRE and security of supply.

2 Current Trading Arrangements for Intermittent Generators

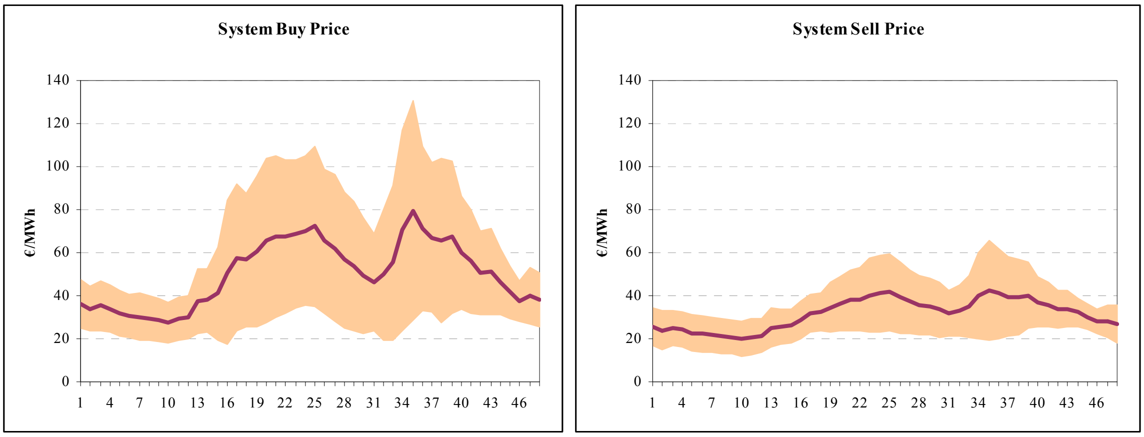
The current trading arrangements for intermittent generators depend on whether or not they are licensed. Note that it is possible to be a licensed 'embedded' generator connected at the distribution level, but all unlicensed generators are embedded. The distinction between licensed and unlicensed generators depends only on their size – power plants with a capacity greater than 10 MW have to be licensed.

In energy trading terms, licensed intermittent generators are treated like any other generator - specifically, they are required to be signatories to all the relevant industry codes, most notably the Balancing and Settlement Code (BSC). This means that, in addition to selling their output, they are responsible for notifying their contracts and final physical notifications (FPNs) to the Transmission System Operator (TSO) and paying imbalance charges on the difference between their contracted and metered volumes. They can, if they choose, make use of the services of an aggregator, who, as the name suggests, bundles together the output from a variety of power plants and, for a fee, makes the various necessary notifications on their behalf. The advantage of using an aggregator is that it can result in lower imbalance exposure for each of the individual generators because their imbalances net out.

Unlicensed generators are not required to be signatories to the BSC (although they can choose to do so). Typically they sell their output to a supplier who has customers within the relevant distribution network. Their output serves to reduce the metered demand of the supplier and, hence, the level of transmission network and balancing services use of system charges (TNUoS and BSUoS) that the supplier has to pay. Both the generator and supplier also benefit from avoiding the scaling carried out to account for transmission losses. On the other hand, if the output of the distributed generator is hard to predict, the supplier purchasing its power may be exposed to increased imbalance charges. This will be reflected in the price that the supplier is willing to pay the generator.

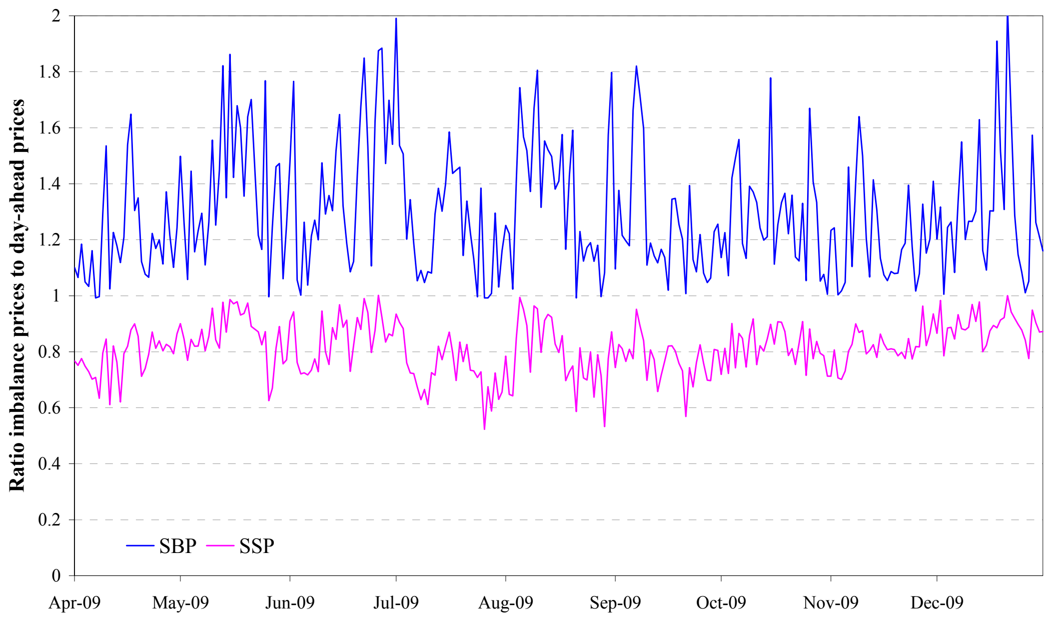
Figure 1 shows average imbalance prices by time of day over the past year (from the middle of March 2009 to the middle of March 2010) and also provides an indication of their volatility. The lines correspond to the average imbalance price in each half-hour whilst the coloured areas represent one standard deviation around the average. Market participants who are short i.e. have metered volumes lower than their contracted volumes, have to pay the system buy price (SBP) whilst market participants who are long are paid the system sell price (SSP). As the figure illustrates, there is often a significant difference between the two prices and the SBPs also exhibit a high volatility. As we noted in the introduction, these imbalance prices could become both more volatile and higher if the capacity of wind power on the system increases, and if balancing prices move closer to the marginal cost of balancing actions.

Figure 1: Average GB imbalance prices by time of day



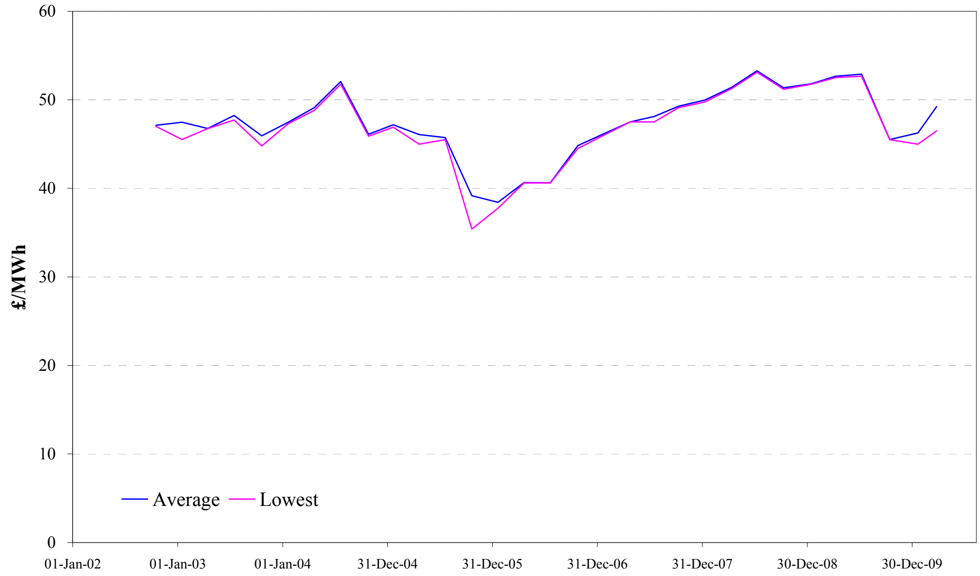
Not only are GB imbalance prices relatively volatile but they are also vary significantly from spot i.e. day-ahead prices, as shown in Figure 2 below. Over the course of the past 12 months, SBPs have on average been nearly 30% higher than day-ahead prices and SSPs over 20% lower.

Figure 2: Relationship between imbalance prices and spot prices in GB



From April 2010, small unlicensed generators (those <5 MW) will be protected fully from the market and simply receive a Feed-In Tariff (FIT). All other licensed and unlicensed renewable generators receive subsidies (ROCs and LECs – see Appendix I for more details) that can substantially increase their revenues or, in the case of small (<5 MW) generators remove their exposure to wholesale prices entirely. For example, Figure 3 shows the ROC prices achieved in e-ROC auctions since January 2002. For almost all this period, the subsidy achieved by renewable generators has exceeded 40 £/MWh.

Figure 3: ROC auction prices[2]



3 Trading Arrangements for Wind Power in other Member States

Before analysing the main issues associated with trading arrangements for IRE generation in GB, we have investigated the arrangements for selling wind power in several other Member States. We look at Spain, Denmark and Germany, since these countries have the highest levels of wind capacity relative to demand in the EU. In 2009 Germany and Spain had the highest wind capacities in the EU by a significant margin. The objective is to inform the debate about how the GB trading arrangements could best be organised by drawing on the experiences of countries that are further advanced in installing wind power.

3.1 Spain

Wind capacity in Spain has grown rapidly over the last decade, from less than 1 GW in 1996 to over 17 GW in 2009. The installed capacity should reach 20 GW by 2010 and is expected to exceed 40 GW by 2020. In 2009 wind production accounted for about 70% of renewable production in Spain (excluding conventional hydro) and met about 14% of overall Spanish electricity demand, including more than 54% of demand during one night in December 2009.

The Spanish electricity market arrangements are similar to GB, in that there is a mix of bilateral trading and trading via an organised exchange. Use of the power exchange is not compulsory, but counter-parties to bilateral contracts must inform the market operator (OMEL) and the system operator (REE) of the contracts and delivery periods, so that they can be accounted for in managing reserves and constraints. We also note that the volumes traded via the exchange in Spain are much larger than in GB – they typically account for around 70% of all trades.

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[2] See http://www.nfpa.co.uk/auctionprices.html for more details.

Since 2004, wind producers in Spain have had the option to choose between receiving the regulated "feed-in tariff" and receiving the market price plus a premium ("the market tariff"). Under the feed-in tariff the generators receive a fixed price for their output and thereby face no price risk. Prior to 2004, all wind producers received a fixed feed-in tariff. Wind generators can switch between the feed-in tariff and the market tariff once a year. The vast majority of wind generators have now chosen to receive the market tariff. In 2009 and so far for 2010, more than 95% of wind production was sold at the market tariff.

In 2007, a cap-and-floor system was added to the market tariff by making the premium variable. When wholesale prices are low, the premium provides a floor to the total remuneration – rising as prices fall. However, it decreases to zero as the market price rises. Thus when wholesale prices are high, the wind generators still receive the market price but no premium. The cap is therefore not a limit on the total remuneration received by the wind generators but instead a limit on the size of the premium.

The logic behind the cap-and-floor scheme is to limit the level of price uncertainty for renewable producers while leaving some exposure to market signals, as well as reducing the overall system costs of subsidising renewable power. The premium was theoretically calculated so that expected average income for wind producers under the market tariff was slightly greater than for wind producers at the feed-in tariff.

Wind generators that opt for the market tariff have had responsibility for forecasting their output since 2004. Prior to this time, distribution companies were responsible for forecasting output. Since 2005, wind generators that choose the feed-in tariff have also been responsible for forecasting.[3]

Imbalances are measured as the difference between scheduled and actual generation and imbalance charges are only applied to deviations that add to the total system imbalance. Imbalance prices are zero for deviations that help alleviate the system imbalance. (Note, however, that this system has led to concerns that it reduces the incentive to provide accurate forecasts,) Wind generators opting for the market tariff have been exposed to full imbalance costs since 2004.

Between 2004 and the start of 2007, wind producers that received the feed-in tariff were subject to imbalance charges only if their installed capacity exceeded 10 MW and they were out of balance by more than 20%. For any imbalance volumes in excess of the 20% tolerance band, the generators paid 10 % of the "yearly average electricity tariff". Thus, these imbalance penalties were smaller than the real costs of balancing. By way of comparison, average forecasting errors are around 20% at the day-ahead stage and fall to 8-10% for forecasts produced around 6 hours before real time.

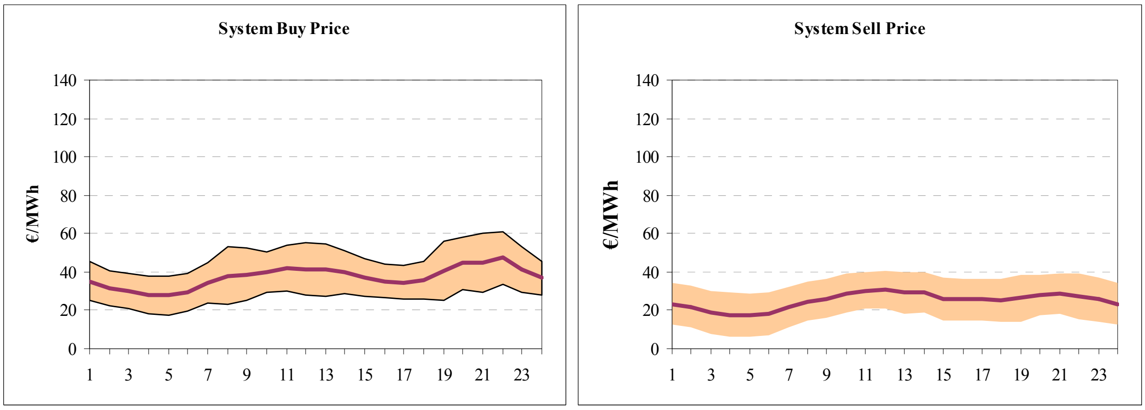
In 2007, following positive experiences with individual wind farm forecasting (or forecasts by aggregators on their behalf, see below), the tolerance band was abolished. Since 2007 almost all

[3] This prediction had to be done for each one of the twenty four scheduling hourly intervals of the electricity production market in each day (and giving at least thirty hours advance notice of that day).

wind producers have had to forecast their production and become fully responsible for the imbalance costs calculated in the same way as for any other generators.[4]

However, as Figure 4 shows imbalance price[5]s are generally lower and less volatile than in the GB market. The lower volatility is likely to be due to the large volume of hydro capacity on the Spanish system, which can respond almost instantaneously to imbalances and so reduces the need for more costly balancing actions from thermal plants. Moreover, as Figure 5 shows, over the last 12 months imbalance prices have generally been closer to day-ahead prices than in GB. Not that the spikes in the ratios that occur from December 2009 correspond to periods where day-ahead prices are zero but imbalance prices are not.[6] Accordingly, exposure to imbalance is less of an issue in Spain than it is in GB.

Figure 4: Average imbalance prices in Spain by time of day, April 2009 to March 2010

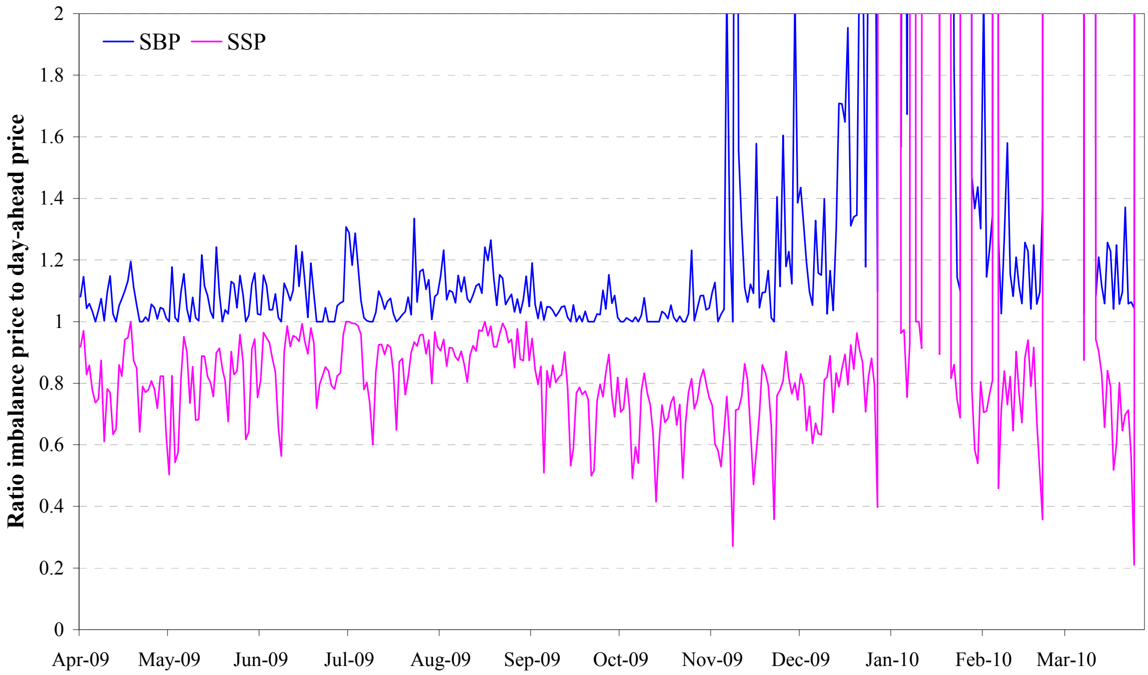


[4] The following facilities selling their power under the feed-in-tariff regime are exempted from deviation penalties: (a) facilities not obliged to have time-metered equipment; and (b) facilities represented by a utility (distribution company) when the deviation from the forecast figure is lower than 5 percent.

[5] In addition to these imbalance prices, intermittent generators also make payments for secondary and tertiary reserve which are sometimes included in imbalance costs.

[6] In the period from 28 December 2009 to 27 March 2010, there have been 226 periods with zero prices, including two days where prices where zero for over half the day.

Figure 5: Relationship between imbalance prices and spot prices in Spain



All wind farms can access the market through an intermediary agent. Such agents can aggregate the output of several wind generators, thereby helping them reduce their imbalance exposure. There are currently three large aggregators specialising in wind power, who each account for around 20% of the wind capacity.[7] Consequently, at this stage there would be substantial opposition to the introduction of any mandatory centralised IRE trading arrangements.

With the significant increase in wind penetration in Spain, the Spanish system operator showed increasing concerns regarding security of supply and reliability. Following these concerns, the Spanish system operator decided to set up a national control centre for renewable technologies (the CECRE) to improve the monitoring and control of renewable generation, including wind production, in real time. The 2007 Royal Decree requires wind facilities bigger than 10 MW to be connected to CECRE through regional dispatch centres. CECRE and the dispatch centres play the role of an intermediary between the wind producers and the system operator, transmitting real time information from wind farms to the system operator. With this information, the system operator can give orders to curtail wind power for security of supply reasons that have to be obeyed by wind producers.

3.2 Denmark

Denmark now has an installed capacity of 3.5 GW, 0.6 GW of which is off-shore and, in 2008, wind production was equal to 19% of total demand. Energinet, the transmission system operator in Denmark, has reported that oversupply of wind power is a problem for around 100 hours each year.

[7] There is a fourth large aggregator, but this is owned by Iberdrola, who is prohibited from aggregating output from wind farms that it does not own.

Energinet expects the frequency of oversupply to increase by three to five times unless means to deal with the oversupply are implemented.[8]

Denmark is part of the ‘NordPool’ system, in which its day-ahead market (Elspot) and other markets are coupled with the electricity markets of Norway, Sweden, Denmark and Finland. Because of transmission constraints and geography, Denmark is split into a West and an East price zone.[9] While most electricity is bought and sold via NordPool, it is also possible for generators to carry out bilateral trades.

Danish wind generators either receive the market price plus a fixed subsidy, the market price plus a subsidy subject to a cap, or a fixed total remuneration (effectively the market price plus a variable subsidy which together equal a fixed amount). Which tariff applies to a wind farm depends primarily on when the wind turbine was connected to the grid and whether the turbine is on-shore or off-shore. Older plants receive fixed total tariffs while more recent additions to the grid receive a fixed subsidy. Caps apply to the sum of the market price plus subsidy if the wind turbine was added prior to 2005 or the plant is utility-owned and was connected after 2000. The most recent subsidies are set out in Denmark’s 2009 Promotion of Renewable Energy Act. The subsidies typically apply for a fixed length of time (e.g. 20 years) or a fixed level of output (e.g. first 22,000 hours at full capacity).

For onshore wind, the subsidy for plant recently connected to the grid (since 21 Feb 2008) is 0.25 DKK/kWh (approximately 32 €/MWh) for the first 22,000 hours at full capacity.[10] For the two off-shore wind farms, Horns Rev 2 and Rødsand 2, the subsidies result in a fixed total tariff of 0.518 DKK/kWh and 0.629 DKK/kWh (65 €/MWh and 81 €/MWh). These subsidies apply up to an output of 10 TWh for a maximum of 20 years after connection to the grid. The total tariffs were set during the tender process for the off-shore plant. An additional subsidy also exists for wind turbines characterised as “ailing”.

There was a plan to use RE certificates instead of the financial subsidies. However, establishment of the RE certificate market has been postponed indefinitely and the financial subsidies remain. Scrapping certificates are used as an incentive to replace old plant. If a wind turbine is replacing an older turbine, the new turbine receives a scrapping certificate that allows it to receive an additional subsidy. The majority of wind turbines built since 1999 have been built under this repowering program.

Wind farms have now become responsible for selling their own output and for their own balancing (although they can contract the responsibility out to a “balancing responsible party”). One exception is where a purchase obligation still exists. Purchase obligations apply to wind turbines connected to the grid before 2003 and household turbines of 25 kW or less.[11] Energinet is obliged to purchase the output from these plants at regulated prices. It estimates their output on a

[8] Energinet document ”The Danish Wind Case: Fast Facts”, June 2009.

[9] DK West has around a 40% higher level of interconnection to other markets than DK East.

[10] This does not apply to utility-owned plants or plants under purchase-obligations.

[11] Utility-financed turbines are not included in this category.

day-ahead basis and submits offers to the NordPool Elspot market for this output. Energinet then pays the selling price plus subsidy to the generators. Purchase obligations need to be enforced by producers in order for them to come into effect.

Energinet is also responsible for balancing for wind turbines operating under purchase obligations. The balancing costs along with other subsidies paid to wind generators are recovered through the PSO. Wind turbines under a purchase obligation are also exempt from paying the grid tariff that applies to generators. Around 1/3 of wind capacity in Denmark is currently under a purchase obligation.

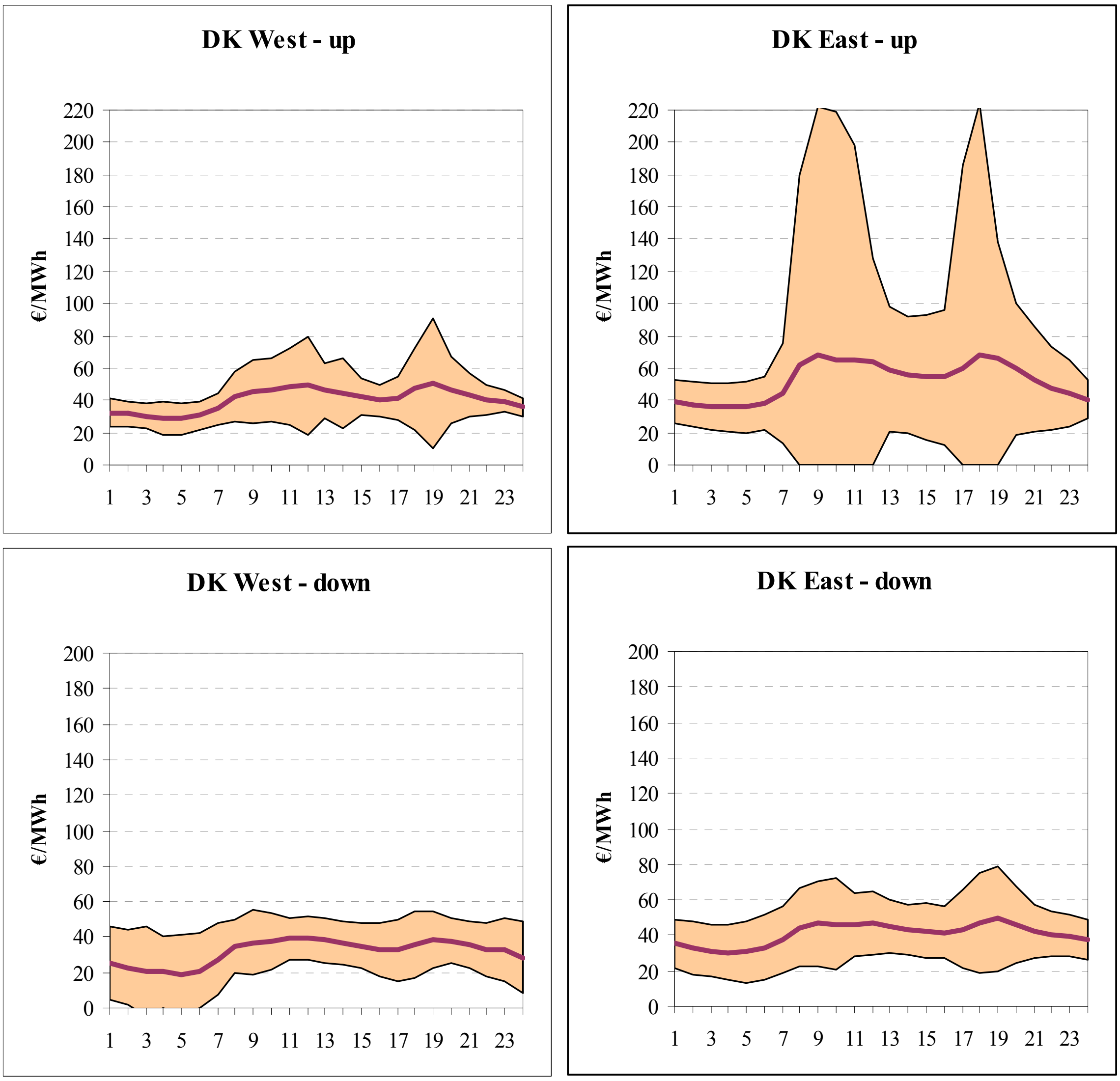
Purchase obligations end after ten years or when the plant's output has exceeded its purchase obligation quota, whichever occurs later. After 2012 all purchase obligations of ten years or more will end regardless of whether their quotas have been met. If a purchase obligation has recently ended, the wind generator can choose between selling their own output and balancing themselves or handing over the responsibility to Energinet.

Wind generators receive a refund on their balancing costs. The rebate is equal to 23 DKK/MWh (3 €/MWh). We have compared the rebate to the hourly upward and downward balancing prices for a recent days and the rebate appears to be equal to around 5-10% of the balancing prices.

Under the Renewable Energy Act, Energinet has the right to instruct off-shore wind farms to implement downward regulation. The Act also sets out the rules for calculating lost output and lost earnings resulting from downward regulation instructions and the wind farms are compensated according to these rules. Energinet can restrict output from off-shore wind farms for several reasons including critical surplus generation (surplus production that cannot be exported).

We present in Figure 6 data on the average size and variability of imbalance prices in Denmark over the past year. Most of Denmark's wind capacity is in the DK West region (about two-thirds at the end of 2008), which has much lower and more stable imbalance prices. As noted above, DK West has a much higher level of interconnection to surrounding markets than DK East. It is probably this fact that accounts for the difference in imbalance prices between DK West and DK East. The additional interconnector capacity may help deal with the intermittent nature of wind, as it is easier to send excess power to other regions or buy-in power to make up unexpected shortfalls. Note also that most of the volatility in DK East upward regulation prices has occurred in the period December 2009 to February 2010, when imbalance prices have been as high as 1400 €/MWh. Conversely, however, imbalance prices in DK East have on average been closer to day-ahead prices (approximately +/-10%) than DK West imbalance prices (approximately +/-20%) although in both regions these average figures mask the fact that there have been a number of very much larger "spikes", see Appendix II. It is also important to remember that many of the wind farms exposed to imbalance prices are owned by the two dominant utilities, DONG and Vattenfall, who can use the remainder of their generation portfolio to minimise their overall imbalance exposure.

Figure 6: Level and volatility of Imbalance Prices in Denmark



3.3 Germany[12]

Wind is already a very significant resource in Germany – it will have about 29 GW of installed wind capacity in 2010, producing about 65 TWh of energy or 12% of demand. Some forecasts expect German wind capacity to increase to over 50 GW by 2020.[13]

The German electricity market design is similar to GB. There is a mix of bilateral trading and trading on a power exchange, the European Energy Exchange or EEX. However, the volumes traded on the EEX are higher than the volumes currently traded on day-ahead exchanges in GB.

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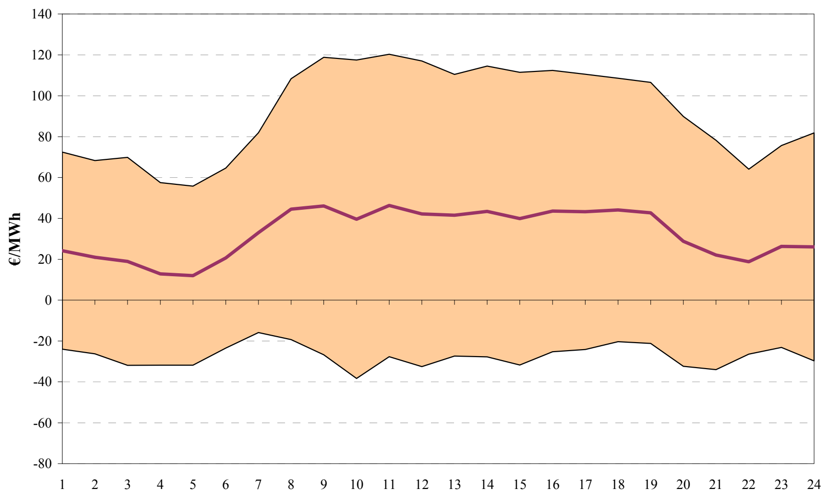
[12] The description of the German regulatory regime is based on information supplied by Amprion, one of Germany's four TSOs.

[13] The German Wind Energy Association estimates potential for 55 GW of wind by 2020. See http://www.wind-energie.de .

Wind power in Germany is paid a FIT, which involves an initial, higher tariff for between 5 and 20 years. The tariff then falls to a lower 'basic tariff' depending on how local wind conditions compare to a so called 'reference yield'. Wind installations on very good sites receive the initial tariff for five years, while for turbines on less windy sites will receive the higher initial FIT for longer.[14]

Since most wind farms in Germany are connected at the distribution level, the Distribution System Operator (DSO) to which the wind farm is connected is responsible for paying the FIT. If the wind farm is connected at the transmission level then the TSO [15] will pay the wind farm the FIT. However, even in the case of distributed generation, it is the relevant TSO that is responsible for selling the wind power on the market. The difference between the FIT and the market price is socialised. Under the FIT scheme, wind farms are not responsible for making nominations and are not exposed to imbalance charges, illustrated in Figure 7. German imbalance prices (which are the same for buying and selling to and from the system) are not particularly high on average but are much more volatile that imbalance prices in Spain and Denmark-west. Imbalance prices also show a fairly constant and high volatility across all hours, including off-peak hours. Figure 7 indicates that insulating wind power from these imbalance prices represents a significant subsidy to wind power.

Figure 7: Level and volatility of Imbalance Prices in Denmark, March 2009 to February 2010 inclusive



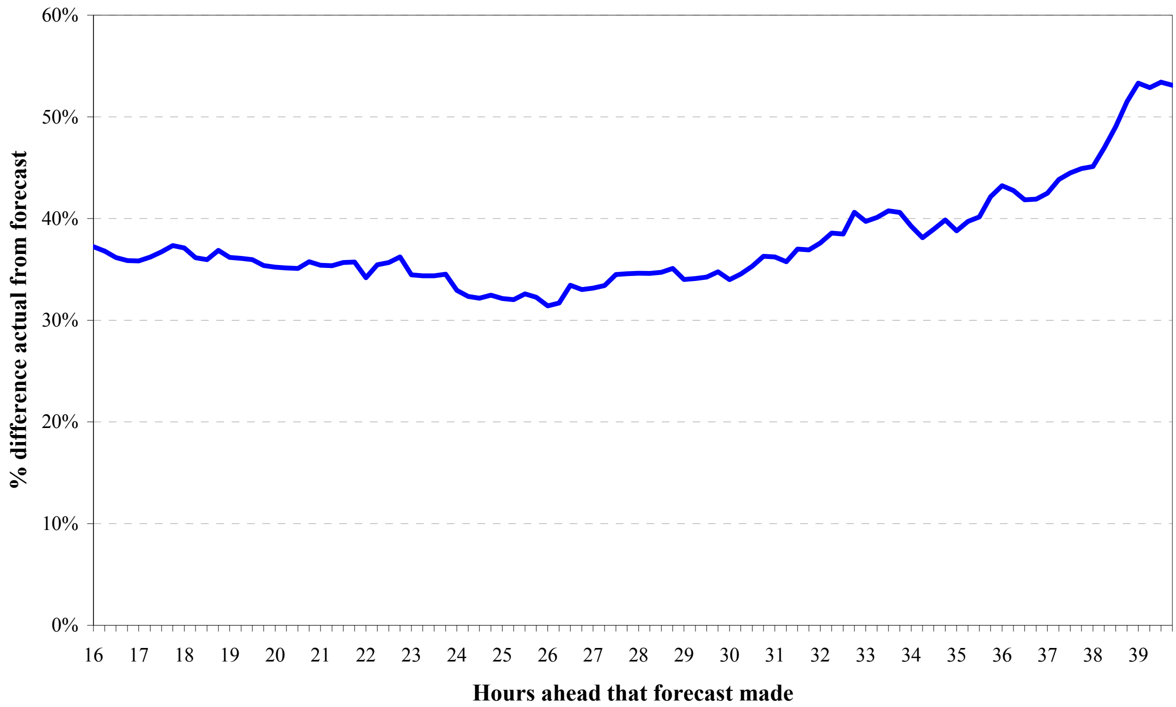
To manage the sale of wind power, at 08:00 on the day before delivery (D-1) the TSOs make a forecast of the available wind output. The TSOs are then obliged by law to sell the entire amount on the day-ahead market. We understand that the reason for selling the entire amount on the day-ahead market is because this is felt to be more transparent, and that the TSOs do not want to get involved in more sophisticated trading strategies as this is felt to be outside of their core business. However, as Figure 8 shows, selling all the wind power day-ahead results in considerable discrepancies

[14] As of January 2009 the initial tariff for onshore wind was €92/MWh, and the basic tariff was €50.2/MWh.

[15] Germany has four separate TSOs.

between the output sold and that actually produced – particularly for the back end of the next day, which can be up to 40 hours distant from the forecasting time.

Figure 8: Historic wind forecasting errors in Germany



As a result of this approach, individual wind farms have no incentive to respond to price signals, for example by reducing their output at times of low prices. Other market participants have also complained that selling the entire wind power volume on the day-ahead market leads to prices that are more volatile than necessary and has led to negative prices on numerous occasions. The wind farms themselves are indifferent to market prices because their income is derived from the FIT but they might still have an incentive to adjust their output, were this possible, if they were part of a wider portfolio of plants.

On the day of delivery the TSOs make updated forecasts of wind production, and adjust their positions by trading power in the intraday market. For example, a TSO might have forecast and sold 70 GWh of wind power day-ahead but, on the day, a revised forecast might predict only 60 GWh of wind. The TSO would then buy 10 GWh on the day-ahead market to make up for the shortfall. The final imbalance costs are socialised. We understand that there are no incentive schemes in place to encourage the TSOs to make more accurate forecasts and reduce imbalance costs, but that apparently a 'moderate' incentive scheme may be under development.

In principle, the German Renewable Energy Act (EEG), which came into effect in January 2009, allows for a second way of despatching renewable energy, including wind power, into the market. This second scheme is more similar to the Spanish system – wind farm operators sell their power directly into the market, and they receive the market price plus a 'top up' subsidy. Under this scheme wind farms are responsible for making their own forecasts and paying imbalances charges, in the same way as other non-renewable generators. Wind generators can switch between the FIT regime and the market-plus-top-up regime on a monthly basis. However, we understand that as the

German government has not decided the level of the bonus hardly any operators have elected to use the bonus system, and nearly all wind power is produced under the FIT scheme.

In terms of system management, the TSOs are allowed to curtail wind power if system security is endangered. While wind farms are responsible for providing real-time data on their production, it is the DSO's responsibility to relay the signals to the relevant TSO's control room. This task is complicated by the high number of small wind farms in Germany, and so in reality the TSOs do not have oversight over all the wind power being produced at any time.

As we describe above, the four German TSOs are responsible by law for managing the FIT and selling wind power. The German energy regulator (the *Bundesnetzagentur* or BNA) will monitor the success of these arrangements for the next two years (until the end of 2011), at which point it will make proposals for further developments to the German government. One possible outcome is that an institution other than the TSOs takes over the management of the FIT.

We note that the current system neither capitalises on the opportunities presented by having four separate TSOs, nor does it achieve economies of scale. For example, as each of the four TSOs make their own forecasts, there could be an opportunity for competitive benchmarking to reduce forecasting errors, but this has not so far been taken up. On the other hand having four separate TSOs forecasting wind power seems to lose an opportunity for economies of scale by having a single wind forecasting body.

3.4 Lessons from International Experience

From our review of international experience we conclude that none of the countries can be used as a template for GB trading arrangements, since either the structural differences are too large to make comparisons meaningful e.g. Spain with its hydro resource, or the arrangements are in a state of flux e.g. Germany. However, we can draw some important lessons from international experience:

- The management of wind power has become a major issue in all three of the markets studied. While it may seem that GB does not need special trading arrangements for wind power today, the experience of Spain, Germany and Denmark suggest that within five years GB could need similar arrangements.
- All three markets provide a preview of the increased price volatility that GB can expect with increased levels of wind power. For example, the average and peak level of wind power as a percentage of demand in Spain is very similar to what we expect for GB between 2015 and 2020 (discussed in more detail below). Between the 1 January 2010 and the 27 March 2010 the Spanish power exchange reported zero prices for 210 hours, or about 10% of the time (and sometimes for extended portions of a day). In addition, on 1 January 2010 the TSO was forced to constrain off 4 GW of wind power, as high wind coincided with low demand on the New Year holiday. These examples illustrate that it is important to consider the debate regarding alternative trading arrangements for wind in the context of a GB market with much higher levels of wind capacity and price volatility than we see today.
- The complaints in Germany about selling all wind power in a single block suggest that it would be better to spread out sales of wind power, and that any trading arrangements

should account for the limited ability of the market to absorb potentially large quantities of wind power at a single point in time.

- It is important that the party making the forecasts bears some of the imbalance charges that result from forecasting errors. In Spain, it seems that the move to expose wind power to full imbalance charges has resulted in increased demand for wind power forecasting services and that this had led to improvements in accuracy, with the CECRE and market participant forecasts showing good agreement.. In contrast, it seems that Germany lacks incentives to improve forecasting accuracy, because the cost of forecasting errors are socialised.

4 Overview of the issues

4.1 Objectives

In considering how trading arrangements for IRE should be organized, we have made the following assumptions regarding the objectives that it is intended to deliver. As we understand it, the primary objective is to reduce any barriers to investment in IRE that may exist as a result of the current trading arrangements. The following are potential barriers which should be addressed:

- *Unduly high imbalance exposure*: due to the difficulty of accurately forecasting their output, it is harder for intermittent generators to balance their contract positions to their metered volumes than it is for other types of generator.
- *Lack of a liquid market*: there is currently no centralized trading point for renewable energy so generators have to go out and contract their output bilaterally with suppliers. This can lead to substantial transaction costs, especially for smaller, independent generators.
- *High operating costs*: in order to try and reduce their imbalance exposure, intermittent generators need access to sophisticated forecasting services, which can be expensive. In addition, the costs of maintaining full time trading functions (necessary because of the intermittent nature of their output) can also be a burden for smaller licensed generators.

Thus, the design of alternative trading arrangements should deliver benefits in all these areas without unduly distorting the market. In particular, they should not significantly increase the imbalance exposure of other market participants.

4.2 Starting point

Ofgem's Project Discovery document provided a "straw man" on how a CRM market could work in GB. We have taken this as a starting point – but only in terms of the type of market (energy not capacity) that is envisaged and the benefits that it is intended it should deliver. The main features of the straw man CRM outlined in Project Discover are as follows:

- At some point prior to gate closure, say 4 hours out, the SO completes a forecast of IRE output (mainly wind) across the country.
- A position is deemed for each intermittent renewables plant at this point (in lieu of a Final Physical Notification).

- The SO then sells out this deemed renewables volume through a within-day auction with buyers submitting bids. (Other sellers could submit offers and demand side response could also be offered.)
- The auction will clear, generating a single market price.
- Following each auction the SO then has control of the variable renewables fleet – it would have the option of constraining back output (subject to rules governing priority dispatch for renewables) if this was the most cost effective way of providing reserve/managing transmission constraints. The SO would be incentivised (as currently) to minimise balancing costs.
- The SO would continue to use the balancing mechanism and other balancing services contracts to provide the flexibility required to balance the system, taking into account the variable generation position.
- The auction clearing price is the price paid to all variable renewables output based on their metered (not deemed) output.
- The renewable generator pays Grid a balancing fee (which could be fixed or vary depending on market conditions).
- Renewables plant would receive ROCs and LECs based on metered output as currently.
- They would receive compensation from the SO for lost output and ROCs/LECs where they have been constrained off. These costs could either by channelled into BSUoS and smeared or factored into the balancing fees charged to variable renewables plant.
- The centralised renewables market could be optional, although some of the potential efficiency benefits for the SO could then be lost.

4.3 An alternative approach to encouraging investment

In accordance with the agreed scope of work for this project, our report focuses on trading arrangements that encourage renewables investment by providing enhanced opportunities for trading and for reducing imbalance exposure. However, we consider it worth noting in passing that an alternative approach to encouraging investment in renewables would be to introduce some form of a "renewables capacity adequacy market" (RCAM) along the lines of the resource adequacy markets in place in many US markets. Under an RCAM, suppliers would be required to demonstrate that they had signed contracts with renewable generators to cover a specified percentage of their load for, say, 2-3 years into the future. This would provide revenue stability to intermittent generators, because the payments would depend not on their output but on their capacity and would be fixed for several years in advance.

4.4 Is there a need for a separate market?

The CRM straw man assumes that IRE generation should be traded through a market separate from the normal wholesale arrangements. We do not believe that such a radical step is necessary to deliver the benefits envisaged to result from a CRM. Instead, we are strongly of the view that organised support for IRE generators should be provided (to the extent that it is needed) via a centralised aggregation *service*, in which an aggregator or agent aggregates IRE power and sells it via existing trading platforms. Consequently, in the remainder of the report, we do not refer to the CRM, but rather to the role of a Centralised Intermittent Renewables Aggregator or CIRA. This would create a situation not so very different from that in Spain, where many wind farms make use of the services of an aggregator, except that the idea is that there would only be a single centralised aggregator.

There is clearly a further debate to be had regarding whether there is a need for any form of centrally organized support. For example, as noted above, the current trading arrangements already provide for the use of aggregation services, although these have not developed to the extent that might have been expected. We suspect that this has not happened to date because a) levels of installed wind capacity have been relatively modest and b) much of the wind capacity is owned by parties with other non-intermittent generation, and these parties can balance their own wind power relatively easily. There are arguments both for and against the introduction of a centralized aggregation service[16] but, for the purposes of this report, we have simply concentrated on how such a service could be organized most effectively.

5 When to sell intermittent power

The CRM, as described in Project Discovery, proposes that output from intermittent generators will be sold in the intra-day market, perhaps 4 hours before real time. The logic is that the closer to delivery the sales occur, the more accurate the output forecasts will become. This reduces the risk of imbalances. However, there is a trade-off here between a) reducing imbalances and b) selling power in a market that is sufficiently liquid to absorb it. For example, a wind farm could make a very accurate forecast 1 hour ahead of gate closure – but the market could not absorb all GB wind power so close to delivery, especially in the future as the capacity of wind power increases.

In order to reach a judgement on how this trade-off should be made, we first analyse how wind forecasting accuracy improves closer to delivery. We then examine how much power is currently sold intra-day, the volume of wind-power that would be available in future and how this might vary from day-to-day. In the discussion below, we concentrate upon wind output forecasting because over the medium term it is wind farms that will provide the main source of intermittent output.

5.1 Forecasting wind power output

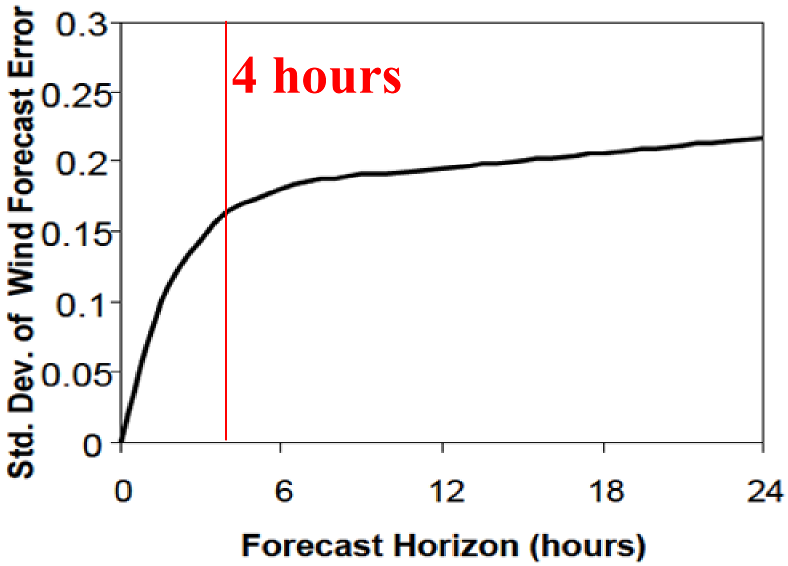
Figure 9 reproduces a figure from a study of the North American Electric Reliability Corporation (NERC), which illustrates the standard deviation of the wind forecast error as a function of the forecast horizon.[17] What is notable is that the forecasting accuracy only starts to

[16] These arguments mostly resolve around whether competition in aggregation provides a better service than an appropriately incentivised centralised aggregator, not just in terms of forecasting services but also in other service aspects such as differing risk-reward trade-offs.

[17] NERC, Accommodating High Levels of Variable Generation, Fig. 4.1, p64. The NERC report cites the original source for the data in the figure as Doherty, R. and O'Malley, M.J., "Establishing the role that wind generation may have in future generation portfolios," IEEE Transactions on Power Systems, Vol. 21, pp. 1415 – 1422, 2006.

improve significantly when the forecast horizon is less than about 4 hours. Moving from a 24 hour forecast horizon to a 6 hour horizon only reduces the standard deviation of the error from about 0.22 to 0.18. Moving to a 2 hour forecast horizon almost halves the standard deviation to about 0.12. Accordingly, the gain in forecasting accuracy from moving to an intraday market seems relatively modest, unless power is sold very close to delivery.

Figure 9: Forecast error as a function of time horizon



However, we recognise that the data in Figure 9 is based on the US market – in reality wind forecasting accuracy will be different in GB, and, indeed, will be different from season to season and even for different times of day. Accordingly we have also looked at some GB data to check if the findings of the NERC report also broadly apply to the GB market.

A 2007 study found that in GB the standard deviations of 9.3% and 1.4% for forecasting accuracy over a four hour and a half-hour forecast horizon respectively.[18] This confirms that, as in the US, there is a large improvement in GB wind forecasting accuracy when the horizon is reduced from about 4 hours. However, the paper did not compare the accuracy of a forecast made with a 24 hour horizon to one of a 4 hour horizon.

One way to get a sense of the improvement in wind forecasting accuracy between a 24 hour ahead and a 4 hour ahead forecast is to look at how much wind-power output changes over this period. This is known as persistence forecasting – where the forecast output for a future hour is simply the output in the current hour. We have analysed estimated hourly wind-power data for onshore Scotland[19] and calculated the error in the persistence forecast for different forecasting

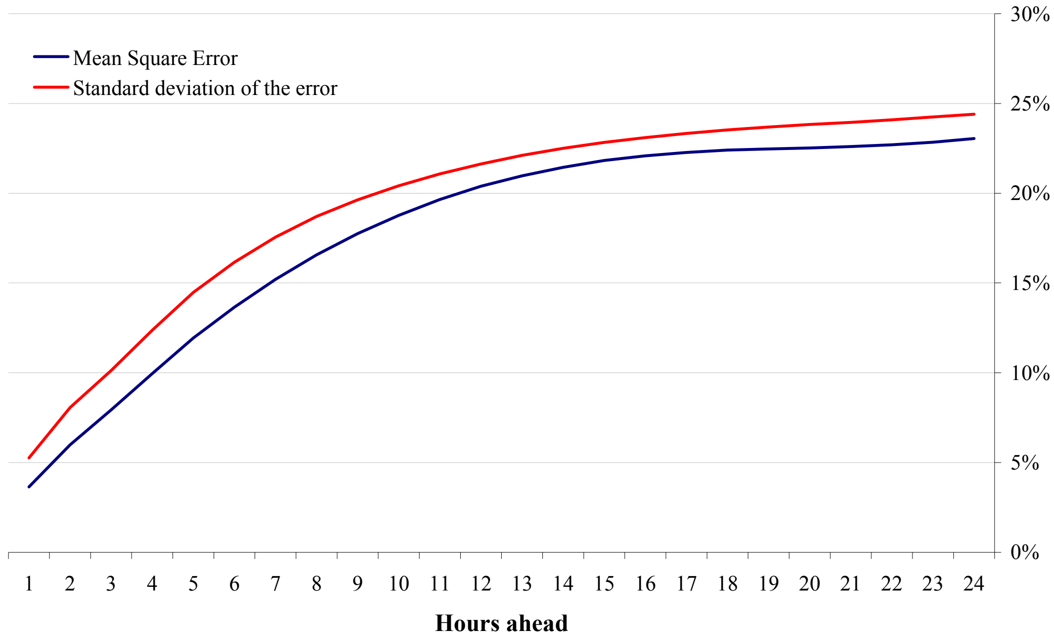
[18] Goran Strbac, Anser Shakoor, Mary Black, Danny Pudjianto, Thomas Bopp, Impact of wind generation on the operation and development of the UK electricity systems, *Electric Power Systems Research*, Volume 77, Issue 9, Distributed Generation, July 2007, Pages 1214-1227.

[19] Specifically the data was for Lossiemouth in Scotland but it has been "processed" to provide data typical of a cluster of wind farms within a 200km radius of Lossiemouth,

horizons.[20] For example, for a 24 hour horizon, we forecast the wind power load-factor for hour t using the actual wind power output in hour t-24. We then calculated the difference between the forecast load-factor and the actual load-factor. After repeating this calculation for all the periods in our dataset (approximately 24,000), we took the standard deviation of this time series. We repeated this exercise for forecast horizons down to one hour. Figure 10 illustrates the results. As we expected, the standard deviation of the error reduces for shorter forecast horizons, though not as dramatically as the NERC data suggests it should. This is probably because the NERC data is based on something more sophisticated than a persistence forecast – more sophisticated forecasts will perform much better than a persistence forecast at horizons of 4-6 hours or greater.

Nevertheless, the simple persistence forecast confirms the NERC findings – the reduction in the standard deviation of the forecast load-factor error from moving to a 24 hour forecast to a 9 hour forecast is about 20%. Moving to a 2 hour reduces the error by about 65%.

Figure 10: Errors of a persistence forecast of wind load factor as a function of the forecast horizon



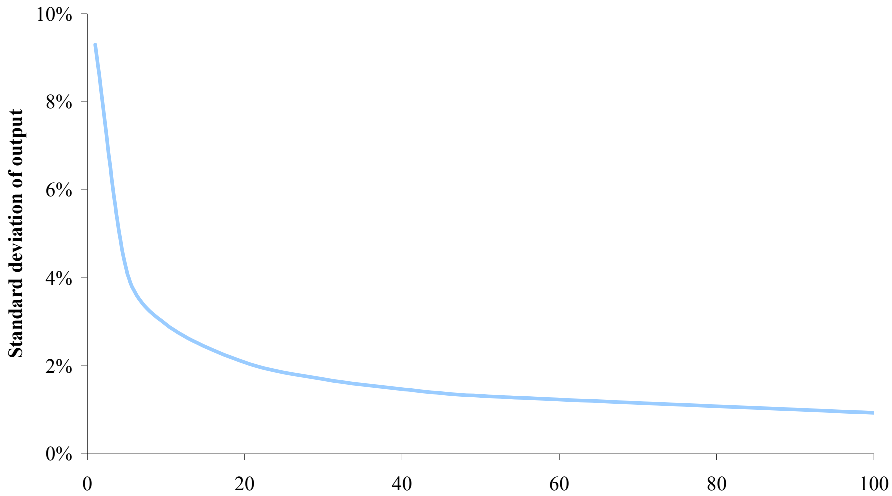
We also note that wind forecasting techniques have improved considerably in recent years, and should improve again in future as computing power and the incentives to provide accurate wind forecasts increases. Accordingly the accuracy of wind power forecasting is a dynamic situation.

Of course, all the analysis presented so far looks at the forecasting accuracy for a single wind-farm. One of the advantages that a CIRA would bring is that a forecast for wind output across GB as a whole should be more accurate than the forecast for a single wind farm. The extent of the improvement will depend on the degree of correlation between the output of individual wind farms: the less correlated they are, the greater will be the reduction in the standard deviation. By way of

[20] We use wind data from January 2007 to October 2009 inclusive, so about 24,000 hours of wind-power data. We have converted the wind speed data to wind power for a typical turbine. We then adjust the estimated output to simulate a more dispersed group of wind turbines.

illustration of this point, Figure 11 shows the reduction in the standard deviation of a 4 hour ahead forecast from combining together different numbers of entirely uncorrelated wind farms of the same size. Starting from a value of 9.3% for one wind farm, the standard deviation drops down to 2% by the time that 20 wind farms are included in the forecast.[21]

Figure 11: Improvement in forecast accuracy as a function of independent wind farm numbers



This analysis suggests two things. First, that relatively low levels of forecasting accuracy might be achievable some time in advance, at least at an aggregate GB level. Second, that the extent to which this is true will depend on the degree of correlation between wind farm outputs across GB. As Figure 12 shows, by 2016/17 there should be some significant geographical dispersion of GB wind farms brought about by the commissioning of off-shore wind. Nonetheless, the vast majority of on-shore wind farms will continue to be located in Scotland and, in particular, in Zone 1. Studies of the correlations between wind power output and distance, summarised in Figure 13, suggest that the output of wind farms in Scotland and the south, east and west of England and Wales would have a correlation of about 0.2. This reduction in correlation with distance could be usefully exploited, if geographically dispersed wind farms were aggregated together.

[21] However, we acknowledge that while this 'portfolio' effect would reduce imbalance costs, NGET would still require location specific forecasts so as to manage system constraints.

Figure 12: Likely dispersion of GB wind farms in 2015/16[22]

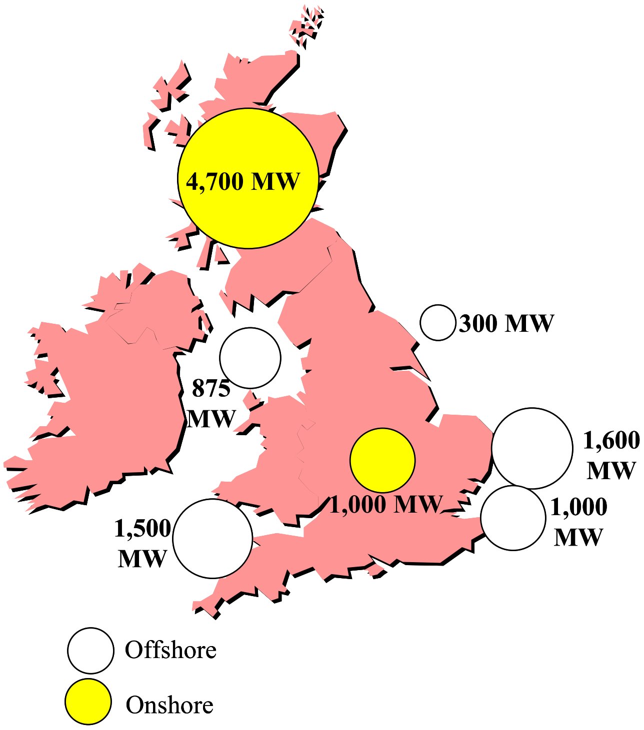
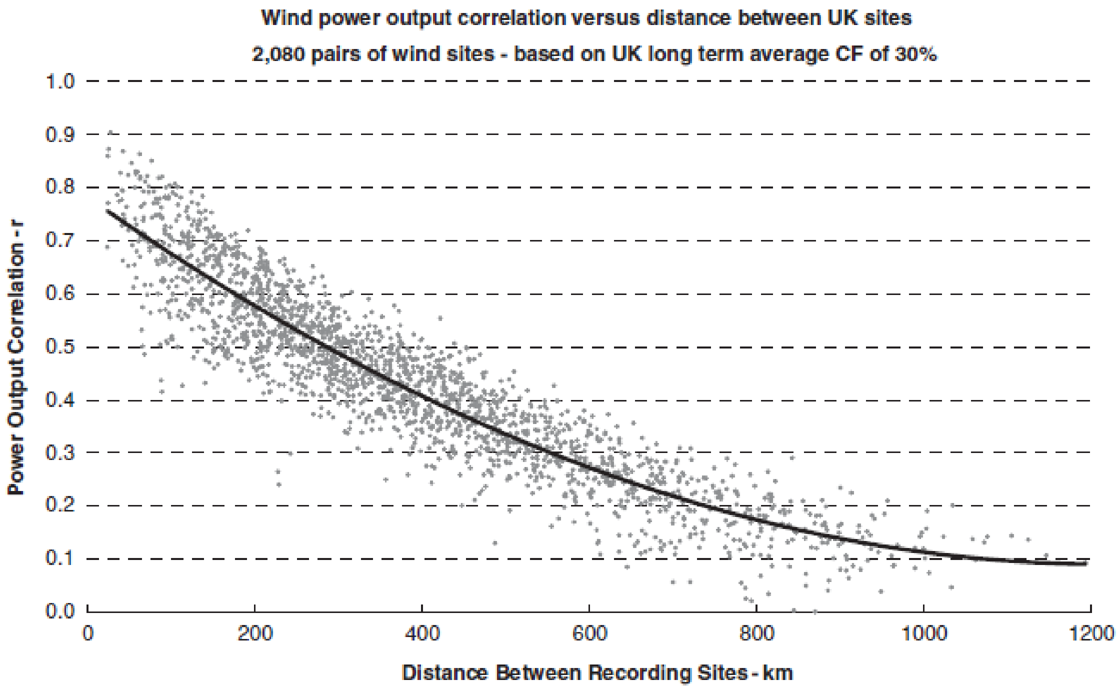


Figure 13: UK wind speed correlation by distance between recording sites[23]



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[22] Source: NGET 2009 Seven Year Statement

[23] Sinden, G., 'Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand', Energy Policy, 2005, Fig. 5. p.7.

5.2 Trading volumes intra-day

We see at least two issues related to selling wind-power an intra-day market. First, would there be sufficient demand to absorb the volume of wind-energy offered? Second, how would the market cope with the uncertainty of how much energy might be offered intra-day? Under the CRM as outlined in Section 4, suppliers would need to make a decision about how much power to buy at the day-ahead stage, based on an expectation of how much wind power will be available intra-day. This decision could be complicated if there is significant uncertainty about how much wind power will be available.

Selling the majority of wind powered generation in an intra-day market could represent a very large increase in the volumes traded so close to delivery, if the capacity of wind powered generation increases as many expect. For example, Ofgem estimated that in 2008 total 'prompt' APX traded Power UK volumes were about 3% of total generated output.[24] Elexon also examine volumes of trades (the Market Index Volume or MIV) to set imbalance prices. The MIV only includes trades which are made 20 hours or less before gate closure. In 2009 Elexon estimated the average MIV was 525 MWh per half-hour, giving a total 2009 MIV of about 9 TWh, or a little less than 3% of national demand. Of this volume, Elexon estimate that about 70% is traded within 4 hours of gate closure.[25] Accordingly, we estimate that only about 2% of GB demand is currently traded within 4 hours of gate closure – which is roughly the time horizon at which wind forecasting accuracy starts increasing significantly. Note that only about half this volume relates to half-hourly products – the remainder relates to products which are delivered over periods of up to 4 hours. As wind power would be most likely sold via half-hourly products (since longer term products would increase the risk of imbalance) we conclude that only about 1% of GB power is currently sold in the way that the Project Discovery CRM proposal imagines for wind power.

In contrast, one scenario for 2020 forecasts about 30 GW of onshore and offshore wind, which would generate 98 TWh of energy a year.[26] Total demand in this scenario is about 410 TWh, so that wind power would contribute 24% of total electricity supply. Based on these assumptions and typical hourly wind capacity factors deduced from our Scottish wind speed dataset, we have estimated the percentage of demand that might be met by wind output in 2020 and, in Figure 14, display this as a wind coverage duration curve. The figure shows that up to 50% of demand might be met by wind output on the basis of average wind capacity factors and this means that in high wind situations the percentage might be much higher.

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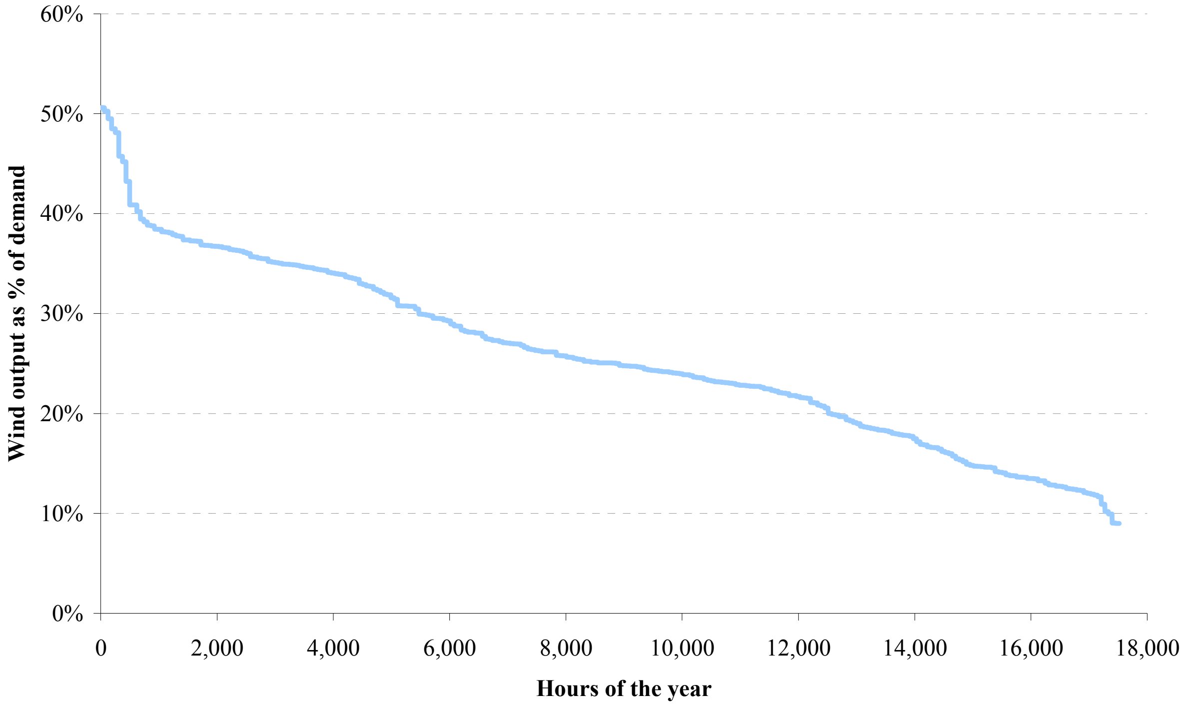
[24] Ofgem Discussion Paper, Liquidity in the GB wholesale energy markets, Ref: 62/09, 8 June 2009, p.75.

[25] The MIV data is from the Elexon Data Review for the Market Index Definition Statement, 25 August 2009, Table 2 and Graph 4.

[26] National Grid, Operating the Electricity Transmission Networks in 2020, June 2009, 'Gone Green' scenario.

Figure 14: Possible coverage of demand by wind output in 2020



Requiring other market participants to wait until close to real time to purchase this level of output would very significantly increase their imbalance exposure. This is because the number of alternative sources of additional generation that would be available so close to gate closure, if wind output turned out to be lower than market participants expected, might be quite limited. For example, there would probably not be time to start-up and synchronise many conventional power plants.

A less extreme, and nearer term, scenario is contained in NGET's Seven Year Statement (SYS) which forecasts that wind capacity will reach 16 GW by 2015/16. Assuming a 30 % load factor,[27] this wind capacity would result in a generation of about 42 TWh, or 13% of 2015/16 demand. Selling about 13% of demand about 4 hours ahead of delivery represents a very large increase in the current volume of power sold at this stage. There would also be a high degree of uncertainly in the volume of wind power available day-ahead. Using Figure 9 as guide, we could suppose that the wind forecast day-ahead was 1 standard deviation above or below the mean. This means that, at the day-ahead stage, we would forecast that wind-energy available the next day could be anywhere between 92 GWh and 138 GWh, a very wide range of possible outcomes.

5.3 Possible trading schemes

On the basis of the previous analysis we conclude that attempting to sell all intermittent output around 4 hours ahead of real time may not be an optimal solution because (a) there would still be significant uncertainty regarding actual output (b) the volumes that would need to be sold might be

[27] According to National Grid the current average load factor for GB wind is 30%. This will likely increase by 2015/16, because more wind capacity will be located offshore with a high load factor. Accordingly, our estimate of wind power production is conservative.

too large to be readily accommodated by the market and (c) other market participants could face significantly increased imbalance exposure. In addition, we have some concerns that relying solely on rolling half-hourly sales would impose high transaction costs on smaller participants.[28]

We recommend, therefore, that intermittent renewable power should be sold over a number of different timescales. There are at least two different types of trading scheme that could be used:

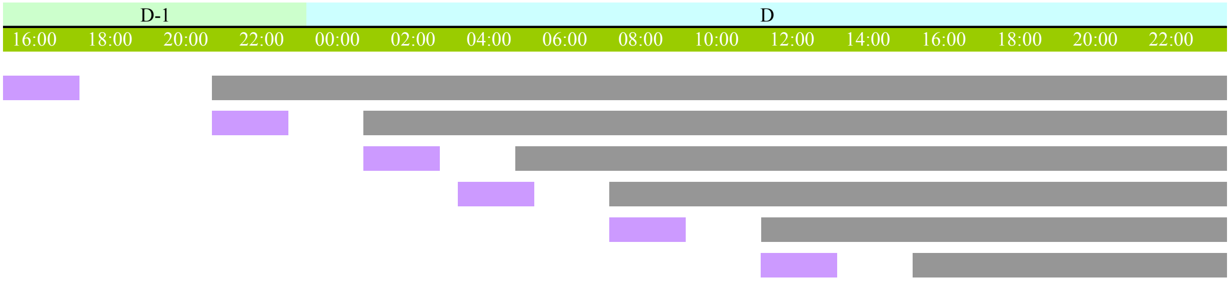
- *Day-ahead plus close to real time sales*: an initial volume of output would be sold in a day-ahead auction and these sales would then be fine-tuned by rolling sales of half-hourly products close to real time.
- *Spanish type intra-day markets*: a limited series of intraday markets starting in the afternoon of the previous day and covering increasingly short periods of time.

Under the first option, the idea is that a forecast of the likely level of output would be made at the day-ahead stage, together with an estimate of the uncertainty surrounding that forecast. A level of intermittent power would be offered to the market for each period of the following day that reflected the level of power that could be delivered with, say, 90% confidence. Subsequently, additional volumes would be offered to the market on a rolling basis as the forecast improved. For example, suppose that, day-ahead, the 90% confidence level of intermittent output for the period 17:00 to 17:30 was forecast to be 11,500 MWh at the day-ahead stage. This volume would be offered to the market day-ahead. Four hours before delivery, the accuracy of the forecast will have improved, and the central forecast itself may also have changed. Suppose that 4 hours ahead of delivery (so at 13:00) the 90% confidence level is now 11,600 MWh. An additional 100 MWh would be offered to the market for sale between 17:00 to 17:30. The additional sales could either take place once at a specified time before gate closure (four hours in this example) or they could be made whenever there was a significant change in the confidence level *and* the uncertainty of the forecast.

The alternative proposal is similar but would involve specifically organised sessions. In Spain, there are a series of six intra-day market sessions, as shown in Figure 15. The first session is open from 16:00 to 17:45 on the previous day and is used to fine tune market participants' positions from 21:00 on that day to the end of the next day – a period of 28 hours. The last session is open from 12:00 to 12:45 on the day in question and can be used to fine tune positions from 16:00 to 24:00 (9 hours) – although, of course, the first intra-day session for the next day provides a final chance to fine tune positions from 21:00 to 24:00 (3 hours).

[28] Strictly, this might not be necessary since RO certificates can be traded separately from the underlying power. However, as we discuss below, it might be desirable to link RO certificates to purchases from the CIRA.

Figure 15: Timetable of Spanish intra-day markets



Whilst the precise timetable used in the Spanish market might not be suitable for the CRM, a modified version would provide a means of reducing the volumes that had to be sold at any one time and allowing market participants to purchase at least some of their renewable power requirements at the day-ahead stage.

Of the two methods, we favour the first one because it could be implemented without the need to introduce new trading arrangements and, consequently, is consistent with our recommendation on how support for IRE should be delivered. For example, the day-ahead sales could be made on either or both of the two daily auctions (APX or N2EX) and, similarly the sales close to real time could be made on an intra-day market.[29] Such an approach should reduce costs and alleviate some of the concerns raised by respondents to the Project Discovery consultation.[30]

Another way of ensuring that there was a liquid market for IRE would be to change the RO such that the RO certificates (ROCs) associated with generators participating in the CIRA were linked to CIRA purchases. At present, ROCs can be traded separately from the underlying power and this gives suppliers considerable market power which can be perceived as a barrier to entry by independent renewable generators.

Based on international experience, especially in Germany, it would be best if the CIRA had some discretion over when to make sales of intermittent power. Providing that the CIRA is subject to appropriate incentives (which we discuss below), a flexible approach should ensure that the wholesale revenues earned by intermittent generators are maximised.

On the other hand, we accept that the interests of other market participants need to be considered. Allowing the CIRA complete flexibility over how intermittent generation is sold would mean that suppliers would never be sure when and where wind power was going to appear on the market. This could substantially increase not only their transaction costs and imbalance exposure but also those of other generators. We suggest, therefore, that the CIRA has to abide by an agreed set of principles when it comes to determining when IRE power is offered to the market but that these principles should not be too prescriptive. For example the CIRA could be required to state the principles it will use to decide when and how much power to sell. It could also be required to publish its wind power forecast in advance and to update this forecast as delivery approaches. In this way, the position of all market participants should be protected.

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[29] For example APX manages a spot market in which various power products are traded intra-day.

[30] One of the main criticisms seemed to be that it would not be a good idea to create a separate market for wind.

6 Imbalance charges

Project Discovery suggested that intermittent generators should not be subject to normal imbalance charges but rather should be subject to a "fixed or variable balancing charge". This suggestion seems somewhat at odds with the statement made in a recent consultation on regulation and wind power by the Council of European Energy Regulators (CEER) which stated that "*balancing arrangements should provide the same incentives for wind generation as for other types of generation*".[31] Moreover, we are concerned that a balancing charge that is not cost-reflective – which, by definition, a fixed charge could not be – would not provide appropriate incentives to improve forecasting skills and the controllability of wind output and hence make the integration of large volumes of intermittent output more problematic.

Instead we consider that participating generators should be subject to normal imbalance charges but only to the extent that the combined output of all the IRE handled by the CIRA was out of balance. As we discussed in Section 5.1, the effect of combining the output of many wind farms, particularly if they are geographically dispersed, should be to improve the accuracy with which their output can be forecast. Accordingly, aggregating the output of wind farms should result in lower – perhaps significantly lower – imbalance charges for any individual wind farm than would be the case if it were to face imbalance charges on its own account.

We acknowledge, however, that the benefits of aggregation might be relatively modest to begin with because, at present, most wind farms are concentrated in Scotland. Hence, currently wind generation is likely to be more highly correlated than when more offshore wind farms are up and running. There is not time within the scope of this project to investigate how much of a problem this is likely to be but it is a piece of analysis that we recommend should be undertaken. If it appears likely that the CIRA would not deliver significant reductions in terms of imbalance exposure initially then it may be necessary to consider whether some additional transitional relief should be put in place, or the introduction of the CIRA should be delayed until there is clear evidence that sufficient wind power will come online soon. Ideally, any additional relief should be delivered via the RO so as to avoid distorting the market but we recognise that this may not be feasible. An alternative would be to introduce a tolerance band within which imbalance charges would not be payable. However, if a tolerance band were to be introduced, then we believe that it should be applied consistently to all generation sources. For example, it could be applied only to generators below a certain size.

7 The Centralised Intermittent Renewables Aggregator

Project Discovery assumed that the TSO, NGET, would be responsible for organising the CRM. However, this is not the only possibility and NGET, in its response to Project Discovery, expressed reservations about undertaking the role. Accordingly, we discuss who might undertake the role of the CIRA later in this section. However, we think it is appropriate to begin by describing

[31] Page 20, "Regulatory aspects of the integration of wind generation in European electricity markets", Ref: C09-SDE-14-02a, 10 December 2009.

the functions that the CIRA would have to undertake as this provides a useful context for considering who would be in a position to be the CIRA.

7.1 Functions of the CIRA

The tasks that the CIRA would need to undertake would include some or all of the following:

- Produce forecasts of the output of the intermittent generators making use of the service;
- Organise the sale of the forecast output;
- Submit balancing and settlement data on behalf of the intermittent generators;
- Arrange the distribution of revenues (from the sale of energy in both the traded market and the BM) and costs (from the purchase of energy and imbalances).

7.1.1. Forecasting responsibility

In theory, producing output forecasts for each wind farm on a centralised basis[32] is not an essential part of the role because individual wind farms could produce their own forecasts. However, we believe that it would be preferable for the CIRA to undertake this role for at least two reasons. First, it will avoid unnecessary duplication of effort thus reducing costs. It would not seem efficient, even if it were practical, for each wind farm to developing a state-of-the-art forecasting service.

Second, it makes allocating revenues and costs more straightforward. For example, Table 1 illustrates a situation where the output of 3 wind farms is being aggregated. Their total forecast output for a period is 215 MWh but they actually produce 210 MWh and hence they are short 5 MWh. How should this imbalance exposure be allocated? One method might simply be to pro-rata it according to the absolute size of their forecast inaccuracies: Farm A would be allocated 1 MWh and Farms B and C would each be allocated 2 MWh. This provides the right signals to improve forecasting accuracy. However, if each farm had produced its own forecast then Farm B might argue that such an allocation was “unfair” because its forecast inaccuracy had reduced the potential exposure of the other two farms. There could also be problems in periods where there is a large difference between the SBP and SSP. In the example, Farm B is long by 10 MWh, but ends up paying for a share of a short position. If the price which the wind farms had to pay for making up their short power was very high, Farm B might object to being exposed to this financial cost when its forecast meant that it was actually long.

[32] If the CIRA is responsible for forecasting output, it will have to do so for individual wind farms – at least for those that are BSC participants since they will have to submit data on intended production levels for their own wind farms.

Table 1: Example of aggregation issues

Farm	Forecast	Actual	Difference
A	100	95	-5
B	60	70	10
B	55	45	-10
Total	215	210	-5

7.1.2. Selling the power

In the previous section, we have discussed *when* CRM power should be sold but there are two other important considerations:

- H*ow* the power should be sold; and
- What *incentives* should be provided to sell the power efficiently?

The question of how the power should be sold is particularly relevant given the criticisms that have been levelled at the German approach of selling wind power at a single block i.e. for a single price at a single point in time. One possibility would be to allow participating generators to specify the minimum price at which they were prepared to sell their power – assuming that they could control their output. (Note also that spreading out the time over which the power is sold should also reduce the possibility of this being a problem.)

We deal with the second issue mostly in section 8 below. However, if participating generators are allowed to set minimum prices this must increase the possibility that not all the volumes offered for sale will necessarily be bought. This strongly suggests that the CRM arrangements should not be too prescriptive – the CIRA should have some flexibility in how the power is sold, subject to some form of incentive to maximise revenues for participating generators. Clearly, if power was not sold at the day-ahead stage, it should continue to be offered in the intra-day market. As a last resort, it could form the basis of offers in the Balancing Mechanism. Assuming that wind farms, at least to a large extent, will produce power whenever they can in order to receive ROCs/LECs, it may be more economic for them to offer their power for sale in the Balancing Mechanism rather than simply accept the SSP for their excess power or risk being constrained down.[33] By submitting offers that the TSO is likely to accept (and bids which it is unlikely to accept), given its incentives to minimise balancing costs, they would have some control over the price they receive for their power, which they would not if they simply accept SSP.

7.1.3. Submitting balancing and settlement data

The data that BSC participants have to submit includes initial physical notifications (IPNs), final physical notifications (FPNs), bids and offers to the Balancing Mechanism (BM) and contract

[33] To the extent that this is likely, given the requirement to provide priority dispatch to renewables.

volumes.[34] Would it be more efficient for the CIRA to make all these submissions on behalf of participating generators?

As far as contract volumes are concerned, we consider that there is little doubt that the least efficient outcome would be for the wind farms to make the notifications. If the sales are made via an organised exchange, then we would expect the exchange to make the notifications – just as it would for any other transactions on its platform. For any other sales, then the CIRA would seem to be best placed to make the notifications – particularly because sales may not correspond to output from a single generator.

If the CIRA is responsible for forecasting output and organising the sale of participating generators' power, it will have all the data necessary to make the submissions of IPNs and FPNs. Consequently, it seems likely that there would be efficiency savings to be made from requiring the CIRA to make the submissions. This is particularly the case as otherwise there would be the potential for submissions made by individual wind farms to be inconsistent with the actions taken by the CIRA, which might require quite complex rules to resolve. Of course, if the CIRA is responsible for submitting FPNs it will need to have access to real time data on the output of the wind farm to make sure that its forecasts are as accurate as possible at gate closure.

When it comes to the submissions of bids and offers, the situation is less clear cut. On the one hand, individual wind farms are in the best position to assess any actions that they can provide and the prices at which they are prepared to offer them. On the other hand, they will have to rely upon the CIRA to inform them whether any of their forecast output has not been sold.

Different generators may have different views on which approach they prefer: for example intermittent generators owned by the Big 6 might well prefer to take responsibility for their own submissions so that they can make decisions based on their entire generating portfolio. Smaller, independent intermittent generators might prefer the CIRA to take responsibility for their submissions. One possibility would be to allow participating generators to choose whether or not the CIRA makes submissions of balancing and settlement data on their behalf.

7.1.4. Allocating revenues and costs

This is a key role for the CIRA. There will clearly be a need for well-defined, transparent procedures for allocating revenues from the sale of power (both in the traded market and the Balancing Mechanism) and costs (primarily imbalance costs but also, potentially, the costs of purchasing power in the traded market to make up for reductions in forecasts of output).

Given that the CIRA will be acting for intermittent generators as a whole, we recommend that the allocation procedures should be subject to consultation and approval by Ofgem, via a procedure similar to that used, for example, for National Grid Gas's Incremental Entry Capacity Release Methodology.

[34] We assume that licensed renewable generators would have to make submissions in the normal way, even if the cash-out prices to which they are exposed is different to the normal cash-out prices.

7.2 **Who should undertake the role?**

The Project Discovery consultation proposed that the TSO, NGET, would run the CRM. However, in its response to the consultation, NGET expressed a distinct reluctance to undertake the role, primarily because it is concerned that its involvement could lead to accusations of "biased operation".

We do not think that there are compelling reasons why the TSO should undertake the role of CIRA. This is because, as discussed in Section 10 below, the interest of the TSO in predicting the output from intermittent generators as part of its role in ensuring security of supply is largely a separate consideration to ensuring that the output of intermittent generators is sold as efficiently as possible. We also consider that it is possible that NGET might face conflicting objectives if it were to undertake the role. This is because that the way in which it forecast and sold intermittent power could have significant consequences for the volume and cost of balancing actions that it had to undertake. Indeed, the only reason that we can see for suggesting that the TSO should undertake the role of CIRA is that it will have to produce a detailed forecast of intermittent output (at least down to a regional level and, for larger wind farms, down to an individual farm basis) for system management purposes anyway. Consequently, there would potentially be economies if the same forecast were used to determine how much intermittent generation is available for sale.

Nonetheless, we consider that, on balance, it would be preferable for some entity other than NGET to undertake this role. Ofgem could, for example, go out to competitive tender to find an entity willing to take on the role. Under this approach, the CIRA role could be for a fixed term, providing an additional incentive to carry out the role effectively in order to maximize the chance of being reappointed. It would clearly be important to exclude generating companies from providing the service because of the enhanced information they would necessarily gain regarding intermittent generation levels, both over longer forecasting timescales and close to real time. (Just as the incumbents in Spain are not allowed to aggregate independent wind farms with their own wind output.)

If the TSO were satisfied that the forecasts produced by the CIRA were better than its own forecasts, the TSO could simply use the CIRA forecasts for system management. This would avoid any duplication of effort in having the TSO and the CIRA both produce intermittent generation forecasts. We recognize, however, that it might take some time for the TSO to develop confidence in the CIRA's forecasts, so that there might be some duplication of effort initially. Alternatively, the CIRA could choose to contract out its forecasting requirements to the TSO – although we think that this is an unlikely outcome since forecasting intermittent output would be one of the CIRA's core business activities.

7.3 **Funding the CIRA**

Typically, companies acting as commercial aggregators charge a fee to the generators making use of their service. This can be a fixed fee but can also be a percentage of the power that they sell and/or the savings that they make. For example, it is possible to calculate what imbalance charges a generator would have faced if it had acted on its own and compare these to the imbalance charges allocated to it by the aggregator and then to charge a percentage of the difference.

In the case of the CIRA, the situation is somewhat different. This is because there would only be one CIRA so there would be no competitive pressures determining the level of charges it could levy on participating generators. Of course, if the charges were too high and use of the CIRA's services was voluntary, intermittent generators could choose not to make use of the CIRA. However, such an outcome would rather undermine the whole purpose of setting up the CIRA. Consequently, we believe that the fees that the CIRA could charge should be regulated by Ofgem. For example, as outlined in the preceding sub-section, we recommend that Ofgem should go out to tender for the CIRA, with potential aggregators bidding to offer the lowest fees, either in absolute terms or as percentage margins on revenues and imbalance savings.

We can also see a case for Ofgem guaranteeing a minimum revenue to the CIRA, especially for the first few years whilst the capacity of wind power is still building up, particularly if the market is voluntary. Such a guarantee would help kick-start the market, and overcome any reluctance to tender by potential bidders because of concerns that they would not be able to cover their fixed costs

A further question concerns whether the costs of the CIRA should be met only by participating generators or more broadly. The participating generators will be the participants who benefit most directly from the CIRA's services. However, it could be argued that suppliers with RO obligations would also benefit to the extent that it encouraged investment in renewable generation and thus helped them to meet their obligations. Furthermore, there might be benefits to suppliers in being able to meet their obligations via the CIRA rather than having to make arrangements with individual generators. Consequently, there might be an argument for splitting the costs of the CIRA between participating generators and suppliers with RO obligations.

The decision on which participants should contribute to funding the CIRA has implications for the form of the charges that the CIRA can levy and how it should be incentivised. We discuss these issues in more detail Section 8.1 below and simply note that in either event some equitable method for allocating costs will be required. Our initial view is that cost allocation based on metered volumes might be appropriate irrespective of which participants are funding the CIRA. The rationale for this is that they provide a proxy of the benefits from the CRM accruing both to intermittent generators (their revenues will scale with metered volumes) and suppliers (their RO obligations scale with metered volumes).

We do not have a strong view as to which approach is better and, at least to some extent, consider that the decision will be determined on the basis of what is more likely to be acceptable to the market as a whole (and politically). We note, however, that if the number of participating generators is small and they have to cover all the costs of the CIRA, then the level of charges might be sufficiently high to act as a barrier to investment, In other words, it might we worth considering whether a broader charging base is needed for an initial period.

8 Incentives

As we have already made clear, we recommend that the CIRA should have flexibility over how it chooses to sell the forecast output of participating generators. We therefore consider that it is crucial that the CIRA is appropriately incentivised to (a) maximise wholesale revenues for intermittent generators and (b) minimise their imbalance exposure. We discuss how this might be achieved in Section 8.1 below.

Looking further into the future, we wonder whether there may not also need to consider whether the way in which the RO applies to suppliers may need to be changed. As we discuss in Section 8.2, RO obligations currently only apply at an annual level and this might lead to perverse incentives when it comes to purchasing power from the CIRA.

8.1 Incentives on the CIRA

The extent to which explicit incentives need to be introduced for the CIRA will depend on the way in which it was funded.

For example, if the costs of the CIRA were recovered only from participating generators then it would be possible to directly incentivise it through the charging structure. It could, for example, be required to levy charges on participating generators that are based partly on a percentage of the revenues earned by intermittent generators and partly on a percentage of their reduced imbalance costs then this would directly provide appropriate incentives.

A potential problem with such an approach is that it would not guarantee that the CIRA could recover its costs (or at least some minimum percentage of them) and might, therefore, make the role an unattractive one. However, this problem could be overcome in a number of ways. For example, in addition to the margin charges outlined above, participating generators might have to pay a flat fee for signing up to the CIRA's services. Alternatively, the level of the margin payments could vary over time so that any shortfalls in one year could be made up over subsequent years in a similar fashion to the way in which revenue shortfalls under price controls can be recovered in subsequent years.

If it were to be decided that the CIRA needed to be funded from a broader range of market participants then a different funding mechanism would be required. Essentially some form of price control with incentives would need to be put in place. This would determine the overall level of revenues that the CIRA was allowed to earn and these could then be spread over the relevant market participants. There seems no obvious reason why the incentives incorporated into a price control could not mimic the effect of margin payments unless this was considered unduly complicated. It would, for example, be perfectly possible to base an imbalance incentive on the savings achieved by aggregation. Providing an incentive to maximize revenues is less straightforward but one possibility would be to base it on the difference between the revenues actually achieved and a target level of revenues, with the target being set by multiplying the metered volumes of participating generators by either a pre-agreed price (based on the forward curve) or the Market Index Price.[35]

[35] A potential problem with using the Market Index Price is that it could be affected by the actions of the CIRA. On the other hand, it would provide a good indication of prevailing price conditions.

8.2 Is there a need for incentives on suppliers?

The RO obligation only applies at annual level so that, in effect, suppliers are free to choose when during the year they contract for renewable energy. At present, this is not a significant issue because suppliers generally contract to purchase the entire output of a renewable generator together with the associated RO or LE certificates.[36] However, if a CIRA role is created, we assume that the intention is that the certificates will be linked to purchases from the CIRA. If this is the case, a point might be reached where suppliers have some flexibility as to when they choose to meet their obligations. This could arise even if on average there was a match between RO obligations and renewable output but conditions were particularly windy one year.

If this were to be the case, then it would be cheaper for suppliers to concentrate on purchasing renewables power at times when wind output is high, since the abundance of wind will likely push the wholesale price of power down. While the CIRA would have incentives to try and manage power sales in a way which avoids depressing the wholesale price, at times this might be unavoidable – for example, where a period of high wind output coincides with low demand. Having met their obligations, demand for renewable energy might be low toward the end of the year with the result that power prices are lower. This would increase the volatility of revenues earned by intermittent generators, which might have unfortunate cash flow and, hence, debt service implications. This problem could be mitigated by altering the RO/LEC arrangements so as to require suppliers to bid for a minimum volume in each trading period. We do not think that such a change is likely to be required in the short term but it is, perhaps, something that should be noted for consideration over the medium term.

9 Voluntary or mandatory participation and de minimis considerations

A de minimis level is only an issue if use of the CIRA's services is compulsory. Consequently, the main issue is whether there is any justification for making the use of the CIRA service mandatory.

The Project Discovery consultation suggested that TSO efficiency gains might be lost if the CRM was voluntary but, as we discuss below in Section 10, we consider that the issue of efficiently providing security of supply is largely separate from the trading arrangements for IRE. A more pertinent concern seems to be whether the advantages of using the CIRA's services would be sufficient to attract widespread participation. If this were not the case, then the intended diversity benefits of aggregating wind power would be lost. In other words, there is something of a "chicken and egg" situation: the aggregation of wind power will only provide benefits if it is widely supported, but in order to gain support it needs to demonstrate that it provides benefits.

We are reluctant to recommend that use of the CIRA's services should be mandatory, partly because it represents a significant intervention in the market and partly because we think it could create resistance to the whole concept of alternative trading arrangements for IRE generation. We

[36] Of course, it is also possible for generators to sell their ROCs separately from their output but for the purposes of the discussion we ignore this possibility.

think that before Ofgem takes any decision regarding mandatory or voluntary participation, it should undertake a quantitative study to provide evidence of the likely benefits that use of a CIRA-type service should provide. Assuming that the quantitative study indicated substantial positive benefits to using a CIRA, Ofgem could canvas opinion amongst IRE generators to see whether they would be willing to sign up to use the services of an aggregating agent. Ofgem should also make it clear what kind of incentives the CIRA would have to carry out its duties efficiently.

If the CIRA appeared likely to yield significant benefits but market participants appeared reluctant to use the services of a CIRA, without offering any compelling reasons why, Ofgem could make it compulsory to use the CIRA's services. The underlying concern is that the larger generators – who find it easier to manage their own imbalance risk from their wind power plants – might be reluctant to see the creation of a CIRA if this makes entry by smaller players easier. These kinds of objections would not be a valid reason to refuse to use the CIRA's services. On the other hand, Ofgem should be open to objections from market parties if they highlight valid reasons why the benefits of a CIRA may have been overestimated or the costs underestimated.

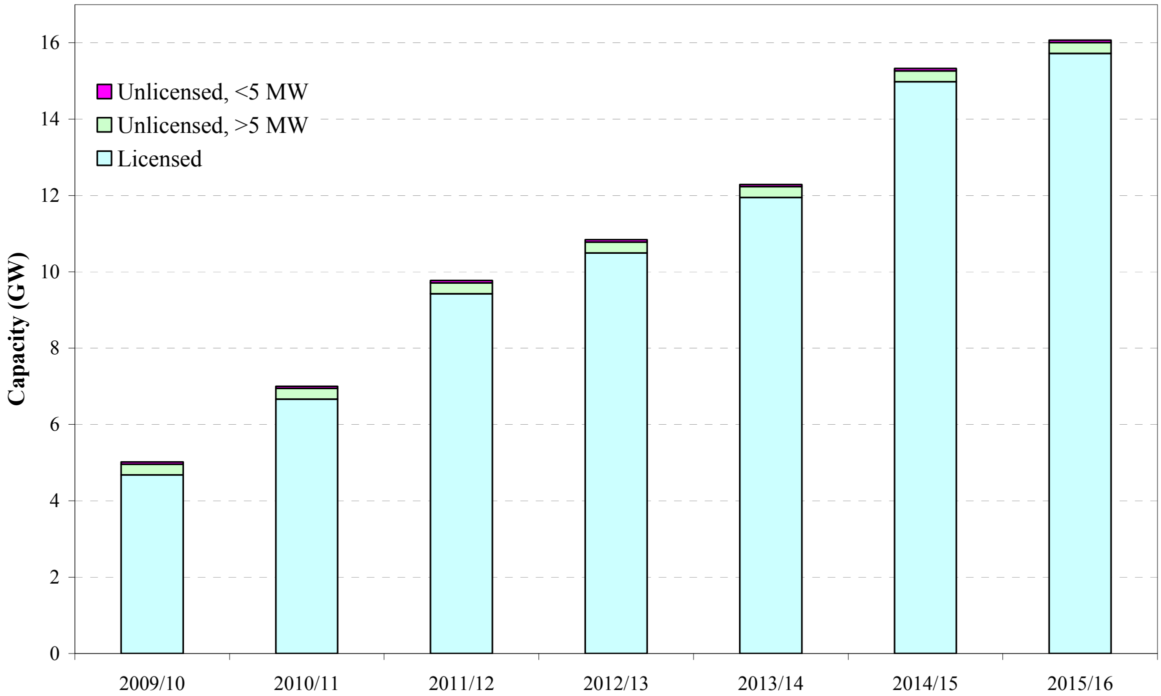
If Ofgem considers that some degree of compulsory use of the CIRA's services is necessary, then the obligation might only be applied to some fixed percentage of a generator's IRE output. Participation could also only be compulsory for a predefined period or until the volumes of power handled by the CIRA reached some predefined level. After this time participants could choose not to use the CIRA's services – but hopefully the CIRA would have demonstrated its value and participants would want to continue using the service voluntarily.

If some degree of compulsion is considered necessary, the most obvious way of achieving this would be to impose the obligation on licensed generators by adding another condition to their licenses. The time, or volume, limits on compulsory participation could also be managed through the license condition.

We also consider that if use of the CIRA's services was mandatory then it would be reasonable to set a floor on the revenues that participating generators receive to protect participating generators from poor performance by the CIRA, and to lower resistance to using the CIRA's services. For example, the floor might be expressed as a guarantee that generators would achieve a certain percentage of the Market Index Price, appropriately weighted

As Figure 16 demonstrates, it is anticipated that there will be a dramatic increase in wind capacity over the next few years and almost all of this additional capacity will come via large-scale (off-shore) licensed wind farms. Consequently, once over an initial phase, and providing that the CIRA delivers the benefits envisaged, it should be possible to withdraw the obligation to participate in the market. Indeed, if the CIRA does not deliver benefits, then there would seem to be little point in persisting with it. However, the objective is that the quantitative study of CIRA benefits would be sufficiently detailed that there should be a high level of confidence that the use of a CIRA would deliver net benefits.

Figure 16: Anticipated growth in wind capacity[37]



Whilst it may be necessary to oblige licensed renewable generators to use the CIRA's services, it would clearly not be possible or sensible to required unlicensed generators to participate. However, unlicensed generators could elect to use the CIRA's services. Whether or not it makes sense for such an unlicensed generator to use the CIRA's services will depend on at least three factors. First, the extent to which the price they are being paid currently is discounted below wholesale levels (see the discussion in Section 2 for an explanation of why they are likely to receive a discounted price). Second, the extent to which any additional revenues might be offset by exposure to imbalance prices. Third, how much it would cost to install the metering and communications equipment required of BSC participants, and the costs of using the CIRA service. We suspect, but do not have the data to confirm it, that it is only likely to be generators that fall just below the 10 MW licensing limit that are likely to benefit from using the CIRA service.

10 Implications for security of supply

We consider that there is an important distinction to be made between what benefits alternative trading arrangements – such as the use of a CIRA – can reasonably be expected to deliver to existing and potential intermittent generators and what benefits it might deliver in terms of security of supply. Our view is that there are likely to be few security of supply benefits from alternative trading arrangements for wind power.

Security of supply will only be threatened by an increase in intermittent generation if its output is poorly forecast by the TSO and this leads to difficulties in matching supply and demand in real

[37] Source: NGET 2009 Seven Year Statement.

time. There is no obligation on the TSO to rely upon output forecasts produced by individual intermittent generators and, indeed, the timescales over which the two sets of forecasts need to be made may be different. For example, the TSO may need to take a view many hours in advance of a trading period (and possibly at the day-ahead stage) whether or not it needs to increase the levels of reserve available to it by issuing instructions to a conventional plant to start warming up so that it will be synchronized with the grid in time to provide power if necessary. An intermittent generator, by contrast, may only need to produce a forecast in time to trade fairly close to real-time on the intra-day market.

Alternative trading arrangements could however improve security of supply in two ways:

1. Using a CIRA could result in improved wind-power forecasting techniques, these improved forecasts could be made available to the TSO, which could then sue them to plan reserve requirements.
2. There might be a better understanding of the likely pattern and level of larger (>5 MW) embedded generation. This potential benefit could materialize if generators with capacities in the range 5-10 MW choose to use the CIRA's services.

However, we think that security of supply benefits are a secondary benefit of using a CIRA. The main benefit is reduced imbalance costs and hence increased incentives to reduce invest in wind power.

Appendix I : Renewable support mechanisms in GB

Currently, both licensed and unlicensed renewable generators have an additional revenue source through the sale of Renewable Obligations Certificates (ROCs).[38] ROCs have been in place since 2002 as a means to encourage investment in renewable generation. ROCs are issued to renewable generators that have been accredited for this purpose by Ofgem. The number of ROCs that a particular generator receives depends on the amount of eligible electricity it generates as well as other factors such as the technology used and its location. Only generation that is sold to customers within the UK by a licensed supplier is eligible for ROCs.

Generators can then sell their ROCs to suppliers either directly or indirectly. Under the Renewables Obligation, suppliers are required to provide evidence to Ofgem that a certain amount of the electricity they sell comes from renewable sources. This evidence can be submitted in the form of enough ROCs to cover their obligation. Suppliers' obligations in this regard have been steadily increasing. In 2010-2011, suppliers are required to present 11.1 ROCs per 100 MWh supplied in England and Wales. This requirement will increase to 20 ROCs per 100 MWh by 2020. A similar requirement also exists for suppliers in Northern Ireland. Instead of purchasing ROCs, suppliers can choose to meet part, or all, of their renewables obligation by paying into a fund. Any profit from the fund is then distributed pro-rata among the suppliers who presented ROCs.

The number of ROCs issued to each generator depends on the technology of the generator, the capacity, the location of the plant and the amount of time it has had its RO accreditation. We show, in Table 2, the ROCs that will be issued to a sample of different types of plant in 2010-2011. The ROCs provided to further types of eligible plant can be found in the source document.

[38] For simplicity, we do not describe the previous support mechanism – the Non-Fossil Fuel Obligation or NFFO – despite the fact that this still applies to some generators. In any event, the level of subsidies under the NFFO tends to be higher than under the RO.

Table 2: Sample of ROCs Issued to Generators for 2010-2011

	Number of ROCs received per MWh generated	Number of MWh for 1 ROC
Landfill gas	0.25	4
Sewage gas	0.5	2
Onshore wind/hydroelectric	1	1
Offshore wind	1.5	0.67
Wave/tidal/photovolatic/anaerobic digestion	2	0.5

Source:
Taken from Ofgen Guidance Document "Renewables Oligation: Guidance for Generators", April 2010, p. 40. Please see table in original report for full list of technologies.

Renewable levy exempt certificates (LECs) can be used by suppliers to claim exemption against the Climate Change Levy which is charged on the non-domestic supply of electricity. LECs are electronic certificates that are issued to accredited generators for each MWh of renewable energy output. LECs are used to identify the renewable energy from accredited generators and therefore cannot be traded separately from the electricity. This is different to ROCs which can be traded separately to the renewable electricity.

From 1 April 2010, certain generators with a capacity of <5 MW will be entitled to receive a feed-in tariff.[39] The relevant generators are wind, hydro, photovoltaic, anaerobic digestion and CHP. In the case of CHP, the feed-in tariffs will only apply for plants with capacity of less than 2 MW. The feed-in tariffs have been developed to encourage take-up of small scale, low-carbon generation. These plants can now choose between receiving ROCs or the feed-in tariffs.

Whereas the value of ROCs varies, feed-in tariffs are set at a fixed price. Feed-in payments will be made by licensed suppliers serving 50,000 or more domestic customers. These suppliers will become known as Mandatory Feed-In-Tariff (FIT) Licensees. Through their license, these Licensees will be obliged to make payments to any of their own customers that have relevant generation and request the feed-in tariff. If requested, the Licensees will also be obliged to make payments to customers of other suppliers that are not Mandatory Feed-In-Tariff (FIT) Licensees. Licensed electricity licensees that do not have sufficient customers to automatically become a Mandatory FIT Licensee can opt to become a Voluntary FIT Licensee.

There will be two components to the feed-in tariffs: a generation payment and an export payment. The generation payment will be a fixed payment per kWh that applies to the amount produced by the generator. The export payment will be made for the output that is exported to the open market. The export payment can be either at the FIT export tariff rate currently set at 3p/kWh or can be negotiated.

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[39] This description is based on the Ofgem consultation document “Feed-in Tariff: Guidance for Licensed Electricity Suppliers”, 24 March 2010.

Appendix II Imbalance prices in Denmark as a percentage of day-ahead prices

Figure 17: DK West

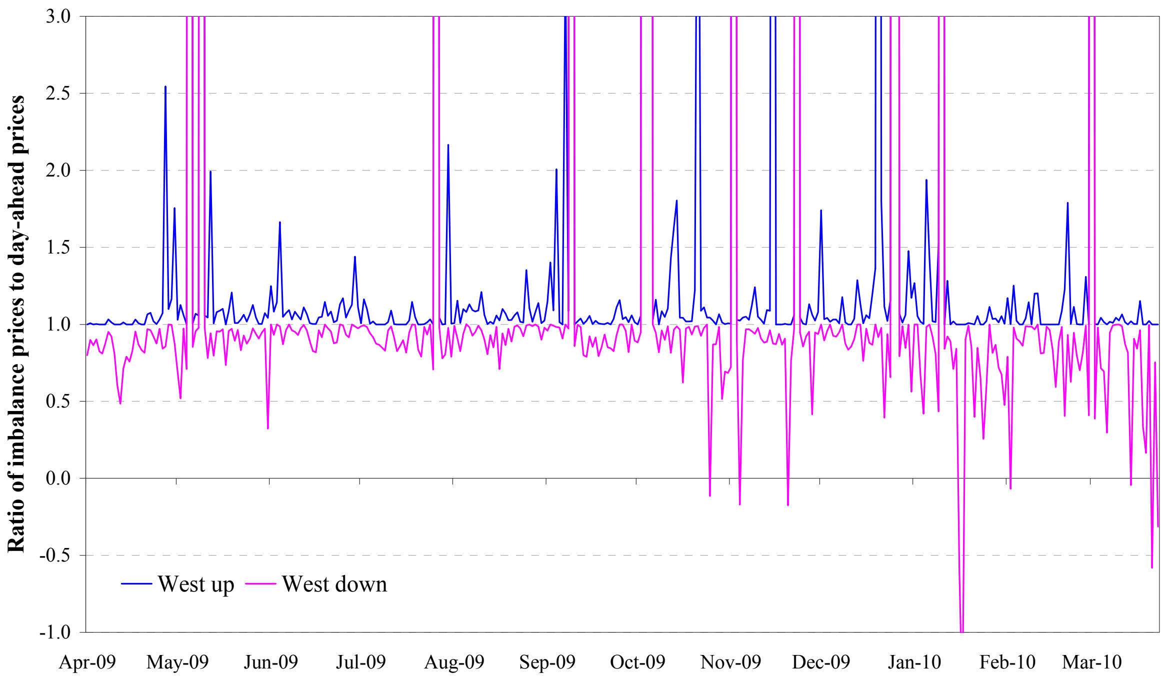

Figure 18: DK East