Rules and mechanisms for integrating wind power in electricity markets

Alice Waltham

***Abstract* - Increasingly ambitious targets for the deployment of renewables have been set by policy makers and the technical capability to harness renewable resources has improved dramatically over the past years. IPA Energy + Water Economics with COWI A/S and SGA Energy recently carried out a study for the International Energy Agency Renewable Energy Technology Deployment cooperation (www.iea-retd.org). This report provided a comparison of rules and mechanisms for incorporating renewable energy production in Great Britain, Ireland, France, Germany, Netherlands, Italy, Denmark, Sweden, Finland, Norway, Ontario and Alberta. In this paper, we explore the ways to integrate wind power in electricity markets.**

***Index Terms*— balancing, Canada, Europe, feed-in tariff, green certificate, integration, risk, support scheme, trading, variability.**

I. Nomenclature

Ancillary services	Services provided to support the reliable operation of the transmission system and flexibility to cope with changes in generation or demand. The precise definition varies by jurisdiction, but it can include operating reserves, balancing power, fault ride-through capability, frequency and voltage control.
Bilateral	Trades or other contracts between two participants, for example a generator and supplier.
Capacity	Cf. Energy, Power. The maximum ability of a generating station to generate an amount of electricity in a given time. Measured in units of power (kW). The actual energy generated is dependant on the load factor.
Credit Cover	A requirement for cash or equivalent financial security to be provided as security against non-payment.
Day Ahead	The day prior to the day that is being traded for or balanced.
Energy	Cf. Power, Capacity. Formally defined as the amount of work. In the case of electrical energy this is measured in kWh.
Gate Closure	The last time at which energy can be traded before the markets are closed. Balancing trades may take place closer to real time on a separate balancing market.
Great Britain (GB)	England, Scotland and Wales (excludes Northern Ireland)
Gross pool	Electricity markets in which all energy is traded through a pool and settled by the central market operator.
Intraday	Within the day that is being traded for or balanced.
Ireland	The term Ireland refers to the Republic of Ireland, which excludes Northern Ireland. Within this document "the island of Ireland" or "all-island" includes both Eire and Northern Ireland.
Load Factor	Also may be known as a capacity factor. The ratio of the actual energy output of a power plant over a period of time and its energy output if it had operated a full capacity of that time period. For example, an onshore wind farm might have a load factor of 35%. This means that on average it generates at 35% of its capacity, although at any given time it may be generating anywhere between 0% and 100% of its total capacity.
Long	Cf. Short. Where a participant has more generation than is required to balance their demand (including losses where applicable)
Main Price	Cf. Reverse Price. The balancing price where a participant is out of balance in the same direction as the market, for example a participant that is "short" when the market is "short".
Merit Order	The order that a system operator will place generators in based on the costs to deliver a certain quantity of generation. Those generators that will allow the forecast demand to be met at the lowest costs (subject to system constraints) are described as being in the merit order and are despatched.

The original study on which this paper was based was commissioned and funded by the IEA Renewable Energy Technology Deployment (RETD).

A. C. Waltham is with IPA Energy + Water Economics, Edinburgh, Scotland, EH3 7HL United Kingdom (email: alice.waltham@ipaeconomics.com)

Net pool	Cf. Gross pool. Electricity markets where the majority of energy is traded and settled between participants through a variety of bilateral instruments, and the balance is traded and settled by the market operator.
Power	Cf. Energy, Capacity. Power is the ability to create energy in a given time.
Price Maker	Cf. Price Taker. In the context of an electricity pool, a price making generator will submit a number of bids/offers indicating how much electricity they would be prepared to despatch at a given price. The system operator will place the generators in order of cost to determine which plants will be despatched.
Price Taker	Cf. Price Maker. In the context of an electricity pool, a price taking generator will not submit a bid or will submit a bid at zero. This means it will always be despatched (subject to system constraints) and will receive the pool price. Price taking generators include variable generators with low marginal costs, such as wind.
Real Time	The actual time period that energy is being traded for or balanced.
Reverse Price	Cf. Main Price. The balancing price where a participant is out of balance in the opposite direction to the market, for example a participant that is "short" when the market is "long".
Short	Cf. Long. Where a participant has less generation than is required to balance their demand (including losses where applicable)
Supplier	Normally used to describe a retail electricity supplier that sells electricity to final consumers, this can include domestic, commercial and industrial consumers
United Kingdom (UK)	Includes England, Scotland, Wales and Northern Ireland
Vertical Integration	Vertical integration is the degree to which a firm owns its upstream suppliers and its downstream buyers. For example, within the electricity industry this can be used to describe the situation where a parent company owns both an electricity retail supplier and generator.

II. Introduction

There are a number of barriers for variable renewables in trying to integrate successfully in electricity markets. These can increase the costs of participation for renewables and ultimately increase the cost to consumers of renewable energy.

This paper is based on a study carried out by IPA Energy + Water Economics with COWI A/S and SGA Energy for the IEA RETD in 2008 [1]. In that study we researched mechanisms for integrating variable renewables into markets, cross border trading and networks. This paper focuses specifically on market mechanisms and the extent that they integrate wind and other variable renewables.

The research covers a number of jurisdictions. In Europe, these were Great Britain, the all-island market in Ireland, Italy, France, Germany and the Netherlands, as well as the Nordic Countries (Finland, Norway, Denmark and Sweden). In Canada, two provinces have been investigated: Alberta and Ontario. Each of these provides a very different market for variable renewable generation.

III. Challenges Integrating Variable Plant

Electricity markets have typically been designed around the requirements of large, controllable, centralised generators. Technical factors which up to now have prevented wind power from fully integrating into markets include:

1) Wind power can only be despatched down rather than up and can exhibit extreme ramp up and ramp down rates. This, combined with their variable and less predictable output, means that there can be a consequent requirement for additional ancillary services and can lead to greater exposure to short term markets and balancing prices. Balancing cost methodologies in so-called Net Pools may unduly impact variable generation, particularly if balancing costs are based on marginal rather than average costs.

2) Typical wind developments are smaller than conventional generation (although large wind developments are becoming more common). This means that the fixed costs of participating in complex markets can be particularly onerous for wind power, especially for independents; both in terms of trading and of reporting and regulation.

2) Wind projects tend to have lower load factors than conventional generation. This means that the costs linked to capacity rather than energy can impact disproportionately on wind schemes.

4) An additional market issue outside the scope of this report, is the higher cost of some renewable generation compared to conventional generation. In order to achieve significant levels of renewable deployment, some form of special treatment and subsidies is likely to continue to be required in many cases. However, the level of support required could potentially be reduced by removing barriers to variable generation that exist within markets.

IV. Two Approaches to Promoting Renewables

In designing markets, policy-makers have adopted a number of methods to incorporate variable renewables, such as wind. There are two broad approaches to promoting renewables deployment:

A. *Market Integration*

The first approach is to adapt existing market mechanisms to accommodate small but growing amounts of variable generation in a cost effective way without special treatment.

A number of different financial and fiscal measures have been adopted to encourage the deployment of low carbon technologies. For example, the European Union Emission Trading Scheme (EU ETS) disadvantages processes using fossil fuels and is one of the major tools for incentivising low carbon generation in the EU.

A full market integration approach may involve removing support and special treatment from renewables and allowing other mechanisms (those not directly targeting renewable growth) provide carbon savings at the lowest cost. The primary role of the energy markets is then be to ensure fair competition and to target the system costs appropriately, rather than to through special treatment and subsidies.

For this to work, market rules that impact on variable generation in comparison to conventional energy sources may need to be adapted.

B. Special Conditions

A second option is to accept that the full integration of variable renewables into the energy market is not the most pragmatic option and provide "special conditions" for such capacity.

Moving renewables outside of the market, or providing relief from certain market risks, recognises the technical constraints and environmental benefits of the technology while placing renewables at an advantage over other forms of generation. Such extra support can recognize the additional benefits of renewable energy such as support to rural economies and mitigation of environmental impacts.

This targeted support may allow for goals for renewables to be achieved more efficiently, the speed of renewable deployment to be managed and can provide critical support while newer technologies mature. It may therefore be the most appropriate form of renewable integration at low penetrations until a "critical mass" is established. However, as the renewables generation base grows, this may place a disproportionate burden on other market participants.

V. Degree of Integration

At present, electricity from wind and other renewable generators is integrated in electricity markets to varying extents. Support schemes, market arrangements and rules for despatch can either integrate or isolate variable renewables.

A. Support Schemes

A wide range of instruments are used by governments to support wind generation. These schemes differ in the extent to which they isolate wind power from market risk.

Table I shows the primary (i.e. most valuable) support mechanism for each of the jurisdictions reviewed. It also considers the degree of "market risk", meaning the exposure of the generator to the risks of operating within the market – for example volatility in the power price or renewable support scheme.

Of the countries studied, feed-in tariffs are the most common support mechanism. Most feed-in tariffs share some portion of the market risk with the generator. For example, in Denmark and the Netherlands the generator is paid a "top-up" to the market price for electricity. In contrast, in Ireland (Eire) the government publishes a maximum feed-in tariff level and the generator must negotiate the precise level of support for their scheme with a supplier.

The different designs of the support mechanisms involve different degrees of insulation from the market and therefore do not truly "integrate" renewables into the electricity markets. At one end of the scale full feed-in tariffs and competitive tender isolate renewables from the market entirely, whilst other countries seek to reduce but not eliminate the risk through investment aid and "top up" or market-linked feed-in tariffs. At the opposite end of the scale, green certificate systems, whilst providing an additional income stream, also introduce an additional element of market risk due to a potentially volatile market in the certificates.

TABLE I
PRIMARY SUPPORT MECHANISM FOR RENEWABLES

Jurisdiction	Primary Renewable Support Mechanism	Market Risk
UK[1]	Green Certificate	Yes
Ireland	Feed in tariff with market element	Reduced
France	Feed-in tariff plus Competitive Tender	No
Germany	Full feed in tariff	No
Netherlands	Feed in tariff with market element	Reduced
Italy	Green Certificate	Yes
Denmark	Feed in tariff with market element	Reduced
Sweden	Green Certificate	Yes
Finland	Tax exemption and Investment aid	Reduced
Norway	Feed in tariff with market element	Reduced
Ontario	Full feed in tariff	No
Alberta	None	Yes

B. Market Arrangements

The way in which wind generators can trade their output is determined by the market rules. The arrangements for the power they generate and the "renewable benefit" are identified separately in Table II for the countries we investigated.

In France, Germany and Ontario, renewable generation is effectively isolated from the general electricity market and purchased by a central agency. Conversely, in Great Britain, Alberta[2] and Sweden the generator trades both power and the renewable component on the open market. For comparison here we have considered this as being roughly equivalent to selling to a supplier or trader.

Across the different markets it can be seen that power is more commonly purchased by suppliers or traders, whereas the "renewable component" of the payment is typically

[1] Here we consider Northern Ireland with the rest of the UK (covered by the Renewables Obligation green certificates system) and take Ireland/Eire (covered by the feed in tariff, REFIT) separately.

[2] In Alberta, there is a central pool but most generators choose to have Net Settlement Instruction (NSI) Contracts with distributors or direct access customers.

managed by some form of central purchasing agency. The predominant trend is to enable the power and renewable energy component to be traded separately from each other. Only those countries with a feed-in tariff or tender process designed to cover the full cost of renewable generation oblige the power and renewable component to be traded together.

TABLE II
PRIMARY METHOD FOR RENEWABLE GENERATORS TO TRADE

Jurisdiction	Power	Renewable Component	Traded together?
GB	Suppliers/Traders	Suppliers/Traders	No
Island of Ireland	Suppliers/Traders	Suppliers/Traders	Yes
France	Central agency	Central agency	Yes
Germany[3]	Central agency	Central agency	Yes
Netherlands	Suppliers/Traders	Central agency	No
Italy	Suppliers/Traders	Suppliers/Traders	No
Denmark	Suppliers/Traders	Central agency	No
Sweden	Suppliers/Traders	Suppliers/Traders	No
Finland	Suppliers/Traders	N/A[4]	N/A
Norway	Suppliers/Traders	Central agency	No
Ontario	Central agency	Central agency	Yes
Alberta	Suppliers/Traders	Suppliers/Traders	No

C. *Rules for Despatch*

In all electricity markets it is necessary to make a decision about which plant will generate at a given time, depending on the plant availability, network availability and marginal cost of generating at each plant. These rules used for despatch have a significant impact on the deployment of variable renewables.

Table III shows where each country places the responsibility for deciding on despatch.

Depending on the market there is a split between whether the generator and the market participant with whom they have agreed to trade decide on despatch (in the table this is described as "counterparties") or a central system operator decides on despatch. The system operator can be the Transmission System Operator (in the case of Germany, Denmark and Italy) or the Market Operator (in the case of Alberta, Ireland and Ontario).

In all cases:

1) Where a central system operator is responsible for despatch, there are rules in place to prioritise the despatch of renewable generation. This can either be by allowing it to act as a price taker (Alberta, Ireland and Ontario) or by prioritising its despatch except where system security is compromised (Germany, Denmark and Italy).

2) Where counterparties agree despatch between them, there are no rules to prioritise renewable generation.

The result in both cases is that renewables with a low marginal cost (such as wind) is normally despatched. The implication seems to be that where a generator is free to negotiate a contract they can ensure that the conditions governing despatch are compatible with the variable nature of their generation.

In all cases, the despatch condition may be over-ruled if there are transmission constraints that prevent the energy from being delivered.

TABLE III
DESPATCH DECISIONS

	Who makes decision on despatch	Special rules to prioritise variable/renewable?	Normally despatched?
GB	Counterparties	No	Yes
Ireland	System Operator	Yes	Yes
France	Counterparties	No	Yes
Germany	System Operator	Yes	Yes
Netherlands	Counterparties	No	Yes
Italy	System Operator	Yes	Yes
Denmark	System Operator	Yes	Yes
Norway	Counterparties	No	Yes
Finland	Counterparties	No	Yes
Sweden	Counterparties	No	Yes
Ontario	System Operator	Yes	Yes
Alberta	System Operator	Yes	Yes

D. *Can wind integrate successfully?*

If there is to be a move away from centralised agencies purchasing power, it will be important to consider whether or not variable renewables are able to integrate successfully with existing market structures. In practice, in all systems the system operator must retain ultimate responsibility for maintaining the balance in the system in real-time. The question is how much of this responsibility can be carried out within the market and how much should be dealt with by the system operator alone.

In general, a system operator requires generators to notify them of their planned positions ahead of time. The nature of variable renewables means that output levels are less certain in advance than conventional generation, which makes accurate submissions to the system operator difficult. The final opportunity for notifying traded and physical positions, or "gate closure", is a key factor for variable renewable energy sources as it determines the ability of a project to manage its positions, both in terms of forecasting and trading.

One approach is to bring gate closure close to real time – and this is a general trend in most markets (Fig. 1).

For the most part, final notification of traded positions occurs within an hour of real time. Five of the jurisdictions have a greater lead time. However, in these cases there are

---

[3] In Germany there is not a "single central agency" who takes responsibility, but it is the regional grid operator in that area.

[4] In Finland the primary method of support is through investment aid rather than a redeemable value per MWh so the renewable component is not traded.

special rules surrounding the despatch of renewable generation.[5]

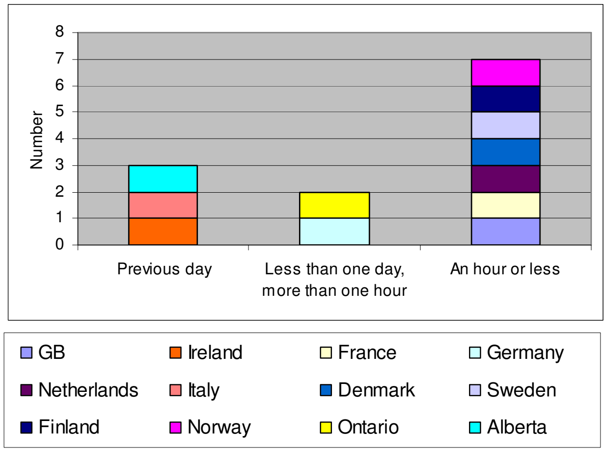

Fig. 1. Gate closure or notification.

The primary objective for having shorter gate closure is to put the onus for balancing on participants rather than the system operator. Generally, participants will be required to balance their portfolio up to the point of gate closure; after that point the system operator will balance the system up to real time.

One point of view would suggest that committing to shorter gate closures will help variable renewables, by allowing them to forecast their outputs as close to real time as possible. But, if a generator needs to balance their position they must purchase power to make up any shortfall, or sell it to reduce their excess – requiring a liquid market close to the time of delivery.

However, a significant proportion of markets have limited liquidity approaching real time, which limits the ability of participants to actively manage their positions towards gate closure. Fig. 2 shows our assessment of the proportion of electricity sold on the spot markets, including both the day-ahead and intra-day markets. This provides an indication of the liquidity of the spot market.

The greatest volume of electricity is traded on the spot market where a central market pool or day-ahead auction is either mandatory or highly utilised. The most extreme example of the central pool model is the new Single Electricity Market (SEM) in the island of Ireland, with a mandatory pool. Where there is not a strong central pool, trading tends to be predominately through bilateral trades.

A number of markets are characterised by a high degree of vertical integration with parent companies owning both electricity suppliers and generation assets. In some cases, a high degree of integration seems to limit trading on the spot market, such as in GB, France and the Netherlands. However, a higher degree of liquidity is seen in those countries where vertical integration is combined with extensive cross border trading and strong intraday or day-ahead auctions, such as in the Nordic countries, the Netherlands and Germany.

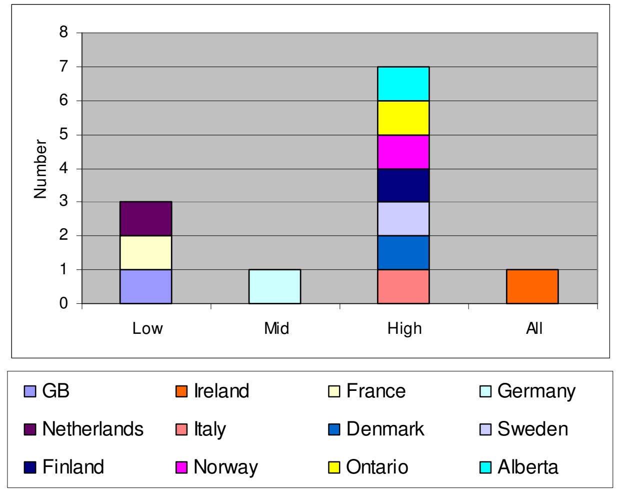

Fig. 2. Volume of electricity traded on the spot market (subjective assessment)

Where generators can choose to trade in a spot market individually, they may be restricted by other parameters. For example in Great Britain and the Netherlands the high costs and credit cover associated with a small renewable generator trading on the spot market mean that the generator is highly likely to opt for a long term bilateral contract with a larger supplier or trader instead. An alternative approach, used in the Nordic market, is to allow flexible terms for market participants. Here, they can choose whether to pay an annual fee plus a low price per MWh traded or alternatively they can pay a single higher per MWh fee, allowing flexibility for smaller participants.

In some cases the balance responsibility for wind energy falls on central agencies rather than the generator: in Alberta, Italy and Ireland all balancing is carried out on a whole grid basis by the system operator, in Germany, Denmark and France the TSO is obliged to purchase all renewable power and balance the renewables portfolio.

Providing the system operator purchases efficiently and costs are adequately targeted this need not result in a reduction in economic efficiency and may even improve economic despatch through greater purchasing power.

E. Wider market impacts

It is important to note that isolating renewables from the traded market does not necessarily isolate the market from the impact of renewable generation.

Wind power can significantly impact on energy flows to interconnected markets, for example between Germany and the Netherlands [1], or between Denmark and Germany, Norway and Sweden [2].

During normal operation, it is not clear if this impacts on the overall spot price, but at where there is an extreme of wind power, it can have an impact on the price of power in spot and pool markets. Very low spot prices can be observed at the same time as extremely high wind generation, and conversely high spot prices can be observed at the same time

[5] In Germany the TSOs are obliged to transmit and purchase all renewable generation. In Ireland, Italy Ontario and Alberta the operator prioritises variable generation if it chooses to act as a Price Taker in the market. This system suits variable generation with low marginal costs, such as wind, which will generally choose to run at any pool price.

as very low wind generation. This has been commented on in the Danish and German market [2].

Wind generation can also lead to an increased requirement for ancillary services, such as reserve power [3].

VI. Risk

The extent to which renewable generators are exposed to market risk varies significantly between countries. In this section we investigate the level of risk carried by projects in terms of exposure to market prices and balancing costs.

A. *Market Risk*

As seen earlier in Table I, there is no consistency in the level of market risk deemed appropriate for renewables projects. At one end of the scale is a complete isolation from the wider market as seen in the full feed-in tariff in Germany and Ontario and the feed in tariffs or tendering process in France. Other countries seek to reduce, but not eliminate the risk through investment aid and "top-up" feed-in tariffs. Conversely, in the UK, Italy, Alberta and Sweden, there is an additional market risk associated with the green certificate system. Whilst feed-in-tariff/competitive tendering schemes could be considered to be a political risk, particularly during planning and commissioning stages, projects in these environments are not exposed to the price risks, which are considered to be the greatest market risk factor.

Another important consideration for renewable generators may be political risks inherent in support schemes. In the Netherlands, the renewables industry objected strongly when feed in tariffs were suddenly set to zero because the Government felt they were on track to achieve targets. Tariffs were subsequently partially reinstated but for investors, political certainty and consistency may be a significant factor in an investment decisions.

Where renewable generation is protected from market price risk, for example via full feed in tariff schemes, this effectively segregates this generation from the rest of the market. Conversely, markets that have a certificate based trading scheme for renewables are also likely to have an increased exposure to price risk, which potentially gives increased price and political risk compared to other generation sources.

B. *Balancing Risk*

Within the countries investigated most systems split responsibility for balancing the system between counterparties and the system operator with the cut off occurring around gate closure. In some circumstances renewables are separated from this process and are balanced by the system operator.

Balancing charges are one potential mechanism to target the cost to the system of balancing the portfolio of generation. A number of the countries investigated insulate renewables from balancing costs (Fig. 3).

Variable renewables clearly do cause additional balancing costs (as they increase overall system uncertainty) and it can be seen as appropriate to expose them to similar balancing risks to conventional generation, although for variable generation balancing volumes will generally be proportionally larger.

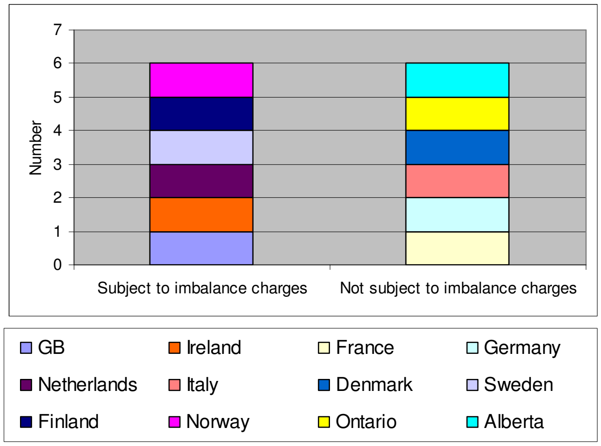

Fig. 3. Renewable generator meets (at least part of) balancing costs

In about half of the jurisdictions considered, renewable generators were exempted from imbalance charges:

1) In France, Germany and Denmark, the TSO purchases renewable generation and therefore the generator is completely isolated from the market, including imbalance charges.

2) In Italy, "non predictable" energy such as renewables does not participate in the balancing market, and do not need to meet imbalance costs. Effectively these charges are socialised.

3) In the Canadian markets, Ontario and Alberta, the market mechanisms do not include imbalance charges for any generators. Here imbalance costs from the generators are effectively socialised across demand customers.

In most market based mechanisms, "balance responsible participants" are required to balance their traded positions so that the amount of electricity they draw from the system (or sell) matches the amount of electricity they generate (or buy). If they are out of balance, they are penalised by the amount of their imbalance.

Most markets have dual imbalance charges that are different depending on whether a participant is "long" or "short" in the market (Fig. 4). This means that if a participant sells more electricity than they put on to the network they are "short" and pay a higher price than they would receive if they were "long" in the market and had put more electricity into the system than they required. Where imbalance charges are in force, different countries have different methods of calculating and allocating these. Normally, the charge to a participant is different depending on whether that participant is "long" or "short" in the market – in other words, whether they delivered more or less electricity than specified in the schedule. As a general rule when a participant is long he will receive a lower price for his electricity than he would have to pay if he were short. Where such a dual imbalance pricing regime is employed, the "main price" may be derived from energy balancing actions. The "reverse price" is generally either determined by reference to a power exchange or is based on the prices of the balancing actions in the reverse direction.

Many systems impose a charge based upon system operator balancing costs. This gives some degree of cost targeting. However, total system imbalance will often be different to the sum of individual imbalances, so this arrangement may over or under recover and as a result actual system operator costs are (typically) not distributed. Counterparties are then exposed to volatile imbalance prices – a problem which is particularly acute for variable generation that cannot always predict and sell its precise output.

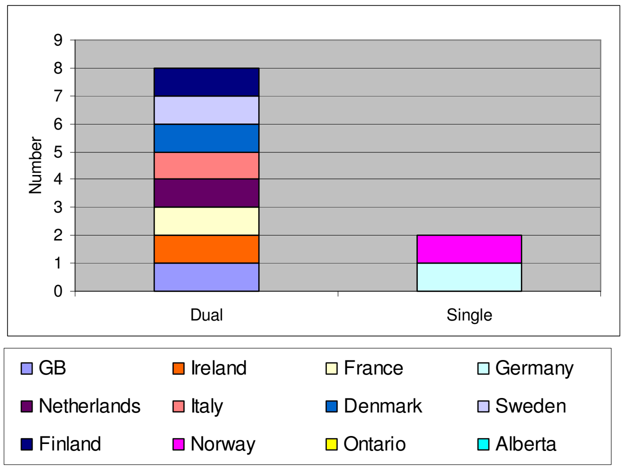

Fig. 4. Whether balance prices are different when participant is long or short?[6]

As Fig. 4 shows, only Germany and Norway have a single imbalance price that applies whether a participant is long or short.

Dual imbalance prices may have an undesirable side effect as they encourage balancing parties with wind as part of their portfolio to systematically under-notify their generation. This means they will only receive a lower buy price for the un-notified portion, but they are at less risk of being subject to the more penal (higher) prices to buy from the system operator.

Imbalance prices often do not strictly reflect cost. Imbalance charges can be used as an incentive for balancing parties to manage their position in a more secure way for the system. In such a system, imbalance prices calculated on a marginal basis will tend to over-recover when compared to expenditure on balancing actions. For example, in Sweden, this over recovery is retained by the TSO, whereas in Denmark, the Netherlands and France it is socialised or redistributed to parties. In GB, the entire imbalance charging receipts are redistributed to parties and the costs of balancing actions are socialised on an energy basis through Use of System charges. In the following table we show where the liabilities for imbalance reside for variable renewables in each of the countries.

As discussed previously, moving to a shorter gate closure/notification period will target balancing costs more on participants and place less responsibility on the system operator. This is not necessarily more efficient than the system operator undertaking balancing – depending upon how the costs are subsequently targeted. Moving to shorter gate closure will only incentivise economic balancing where there are short term liquid markets – which is not the case in many countries. However, where balancing is done at portfolio level, as is the case in most countries, companies can use their own plant to balance; this clearly puts independents and generators with more short term uncertainty at a relative disadvantage – since the markets may not provide them with efficient balancing options.

[6] Ontario and Alberta do not feature here as imbalance charges do not apply.

VII. Conclusions

Within electricity market mechanisms we identified the following features that had significant negative impact on renewable generation, both of which are linked to the variable nature of the output: volatile or penal balancing costs and barriers to trading close to real time.

In many markets, participants are incentivised to balance with penalties for being out of balance. This is more challenging for variable generation, which has limited (if any) control on its output. Different countries have different methods of calculating imbalance charges. The most common is a dual imbalance price system. This means that a participant that delivers more power than planned will receive a lower price for his electricity than he would pay if he delivered less power than planned. Imbalance charges when a participant is short tend not to reflect the cost of the actual imbalance caused by an individual participant. Instead, they reflect the "marginal" cost of the system as a whole (in other words, the cost of the most expensive generation despatched at the time).

A market that gives marginal imbalance signals to variable renewables will always place them at a disadvantage to more predictable generation sources.

To avoid these charges, participants have an option to balance through trading. In the markets there are essentially two aspects that assist variable renewables: allowing notification of expected generation relatively close to real time to enable generators to adjust their forecasted position and increased liquidity in shorter term intraday markets. Whilst, in a number of markets investigated, there could be considered to be relatively good liquidity up to and including the day ahead stage, post day-ahead relatively little trading occurs and there is limited market depth and liquidity.

To tackle these barriers, the jurisdictions studied have chosen a number of approaches to shield renewables from balancing risk, market risk or both.

Most jurisdictions considered have some form of support mechanism for renewables. The type of support mechanism determines the degree of insulation from market risk, with Germany and France choosing to isolate renewables completely from market and balancing risk using feed-in tariffs. Other feed in tariffs that provide a "top-up" or market link to their support reduce this risk but do not eliminate it. In contrast, the green certificate schemes used in the UK, Italy and Sweden, whilst providing additional revenue also add market risk.

Balancing risk is sometimes managed separately: Italy chooses to socialise the costs of balancing variable generation and in the two Canadian provinces (Alberta and Ontario) all balancing costs are socialised across demand customers.

Thinking back to the two market outlooks, if the key objective is to maximise renewable energy deployment then removing or reducing the market and balancing risk for variable renewable generation may be a way to reducing barriers to entry and also reducing the explicit cost of the support mechanism (although it is arguable that as such measures reduce the incentive to balance they may actually increase the overall cost of system operation). Feed in tariffs have been very successful in many countries [4] because they provide protection from the risks in the traded market or the balancing mechanism. It is notable that two markets with the most significant penetration of wind, Germany and Denmark, both provide high degrees of segregation from the market as generators are paid a fixed tariff and do not participate in either the traded market or the balancing mechanism.

However, excluding renewables from both market and balancing risk has the potential to cause a degree of distortion in the market, particularly as their level of market penetration increases.

If the aim is to move to maximise renewable integration on the same footing as conventional generation then responsibility for balancing actions and risks of operating in an electricity market should be felt by all generation sources, including renewables. In this case it is important that the costs faced by generators are correctly targeted and do not penalise variable generation unduly.

Allowing market participants to continue trading as close to real time as is practical can give renewable generators the opportunity to reduce their exposure to market imbalance costs. The systems of short gate closures and dual imbalances are designed to target costs at those that cause them. Whilst the theory behind this is sound, in practice it can lead to inefficiencies as there may not be sufficient liquidity in the markets for counterparties to manage positions close to real time and they may be penalised through targeting of marginal rather than average costs.

Longer gate closures lead to centralisation of balancing, which has to be managed efficiently by the system operator. System operator balancing costs could still be targeted (including reserve contracts) but could be on an average basis ensuring distribution of actual costs. This approach may well be a "better" system for independent variable renewables without actually favouring them whilst maintaining a cost targeting element.

There is tension between maximal integration and maximal deployment of variable renewable generation. Moving renewables outside of the market, or providing relief from certain market and balancing risks, recognizes the technical constraints and environmental benefits of the technology while placing renewables at an advantage over other forms of generation.

VIII. ACKNOWLEDGMENT

The author gratefully acknowledges the contributions of P. Bedson, G. Swales, M. Wagner, R. Carey, S. Velke, T. E. Pedersen, S. Graham, H. Chandler, P. Frankl, H. Holttinen and the IEA RETD for their work on the original version of this document.

IX. REFERENCES

[1] IPA Energy + Water Economics, COWI A/S and SGA Energy, "Innovative Electricity Markets to Incorporate Variable Production to IEA – Renewable Energy Technology Deployment" July 2008.

[2] Paul-Frederik Bach, "Wind Power and Spot Prices: German and Danish Experience 2006-2008, a Statistical Study for the Renewable Energy Foundation", 10 March 2009.

[3] The Netherlands Competition Authority - Office of Energy Regulation, "Market Monitor: Development of the Wholesale Electricity Market in 2006" , The Hague, December 2007

[4] European Commission, "The support of electricity from renewable energy sources", Brussels, 23.1.2008 (SEC(2008)57).

X. BIOGRAPHIES

Alice Waltham was born in London, on 12 March 1982. She graduated from the Imperial College London with a BSc (Hons) in Physics.

Alice Waltham has six years experience of the renewable energy industry and energy markets. She is a leading consultant in IPA Energy + Water Economics' Sustainable Energy and Climate Change team with Prior to joining IPA, Alice worked for Good Energy – a 100% renewable energy supplier in the UK – where she was responsible for all aspects of regulation.

She was a project manager of the international IEA Renewable Energy Technology Deployment (RETD) funded study identifying best practice for integrating variable generation sources into electricity networks/markets.

- Policy and Regulation: Alice is currently working on Renewable Energy Strategy in Bulgaria and the design of a Renewable Heat Incentive in the UK. In 2008 she successfully completed a project to produce the Rulebook for Renewable Energy Guarantees of Origin in Macedonia. Alice recently led a project for a private client investigating the feasibility of a ground source heat pump company. This has included consultation with key stakeholders and a review of existing legislation and regulation as well as future measures based on Government and EC statements.
- Wind: Alice played a central role in a project for three Regional Development Agencies examining the potential economic impact of offshore wind in Northern England in a number of investment scenarios. She has also worked on due diligence for offshore wind. In 2008, she contributed to a published study by IPA on the relative economics of windfarm projects, designed to help inform the UK Government's decision on whether to discount electricity transmission charges in the Scottish Islands.