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Understanding best practice regarding interruptible connections for wind generation: lessons from national and international experience

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Abstract: The aim of this study is to explore different practices for accelerating the integration of generating facilities to the electricity network using smart solutions. Case studies from Great Britain, Ireland and Northern Ireland and the Unites States were selected. The paper assesses and compares the different Principles of Access (POA) that have been implemented in these countries, such as Last-in First-out (LIFO), Pro Rata and Market-based. The social optimality of these approaches is also discussed. The paper also evaluates how the risk (regarding curtailment and investment) is allocated between parties (distributor network operators, generators and customers). Even though the cases are diverse, important findings and lessons have been identified which may assist UK distribution network operators to address the issue of increasing the connection of distributed generation while managing efficiently and economically energy exports from generators.

Keywords distributed generation, wind generation, non-firm, smart solutions

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EPRG WORKING PAPER

Understanding best practice regarding interruptible connections for wind generation: lessons from national and international experience

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Abstract

The aim of this study is to explore different practices for accelerating the integration of generating facilities to the electricity network using smart solutions. Case studies from Great Britain, Ireland and Northern Ireland and the Unites States were selected. The paper assesses and compares the different Principles of Access that have been implemented in these countries, such as Last-in First-out (LIFO), Pro Rata and Market-based. The social optimality of these approaches is also discussed. The paper also evaluates how the risk (regarding curtailment and investment) is allocated between parties (distributor network operators, generators and customers). Even though the cases are diverse, important findings and lessons have been identified which may assist UK distribution network operators to address the issue of increasing the connection of distributed generation while managing efficiently and economically energy exports from generators.

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1. Introduction

1.1 Background

The important support that renewable power has received during the last few years has contributed to the expansion of decentralised planning and dispatch of renewable energy facilities. In the UK different schemes[2] support the introduction of low carbon network technologies in order to deliver around 15% of the UK's energy demand from renewable sources by 2020 in the most cost effective way. The projected demand – from electricity, heat and transport - amounts to 234 TWh by 2020. Wind power plays an important role in this achievement and it is expected that a maximum of 90 TWh will be delivered by this technology (onshore and offshore) which represents an average of 38.5 % of the total projected renewable energy demand (DECC, 2011). Given that total renewable power production was around 40 TWh in 2012 (of which around half is from wind)[3], it is expected that there will be a significant increase in wind connections at the distribution level.

The connection of generation facilities to the distribution network is generally referred to as "distributed generation (DG)"[4]. The number of generators that are seeking to connect to the distribution network is increasing within different countries, but there are some limitations. In comparison with the transmission networks, distribution networks are passive systems (non-actively managed) with unidirectional power flow (from high voltage to low voltage). However, the provision of ancillary services[5] (from distributed generation) and the implementation of smart solutions may facilitate the integration of generators into the distribution network. In addition, the introduction of different incentives, such as Feed-in Tariff (FIT) and its different variants and quota obligations (QO), may lead to the saturation of the network. The challenge for the Distribution Network Operator (DNO) is to address this demand while finding the optimal use of the network.

1.2 The problem and an alternative solution

By connecting more generation to the distribution network, operations can be negatively affected in terms of voltage fluctuation and regulation, power factor correction, frequency variation and regulation and harmonics (Passey *et al.,* 2011), (Wojszczyk *et al.,* 2011). This requires an upgrade to the distribution network which, in many cases, can impact the economics of distributed generators. In contrast with the larger, centralised generators which do not incur such charges, distributed generators usually have to pay for this upgrade (Strachen and Dowlatabadi, 2002). In terms of wind generation, Georgilakis (2008) states that the impact on the system operating costs for integrating wind generation to the power system is very related to the level of wind penetration. The impact is very small at wind penetration levels of 5% however the impact remains moderate at penetration levels of 20%. Wind generation is dependent on the local conditions and is mainly characterised by its strong variation in time (intermittency) and its lack of predictability (due to weather

[2] Such as subsidies (Feed- in Tariff (FIT), Renewable Obligation (RO)), regimes (Connect and Manage) and other initiatives (Innovation Funding Incentive (IFI), Low Carbon Network Fund (LCNF), Distributed Generation (DG) incentives).
[3] See Chart 6.2 in DECC (2012).
[4] Also referred to as embedded generation, decentralised generation, dispersed generation or distributed energy resources (DER). DG technologies are categorised as renewable and non-renewable technologies.
[5] Refers to those operational services that support the transmission of energy from seller to purchaser while maintaining the system operational reliability.

unpredictability). According to Bollen and Hassan (2011), the distribution system is mainly concerned with actual variations, however in transmission systems both the actual variations and the predictability of these variations matters. An efficient integration of wind generation facilities to the electricity network will require an important upgrade of the network system services. The cost of this upgrade (which is directly related to the provision of ancillary services) can significantly be reduced when smart solutions are introduced.

A straightforward way of dealing with the impacts previously described is to curtail the level of wind generation behind an individual node on the distribution system. Such curtailment can be 'traditional' or 'smart'. 'Traditional' curtailment would shut off one or more wind turbines completely when the fixed tolerance levels are exceeded. This is a business as usual practice by which generators are controlled. Smart curtailment assesses exactly how much capacity is available at a given node in real time and allocates curtailment behind the node to meet the available capacity according to some allocation rule.

Smart curtailment is associated with the use of smart solutions which can be seen as a way to deal with the optimisation of network use whilst avoiding high network reinforcement costs which are currently paid by generators. The use of smart solutions helps the evolution of the traditional electricity networks by allowing the more efficient and cost-effective integration of generation facilities (such as wind power) to the transmission or distribution grids. Smart solutions contribute to electricity network efficiency by helping to manage and reduce the level of curtailment, especially in the integration of intermittent resources to the grid. Among these solutions are Dynamic Line Rating (DLR) and Active Network Management (ANM). A study performed by San Diego Gas and Electric shows that the capacity increased between 40% and 80% when transmission lines were monitored using DLR (DOE, 2012). Following Shell *et al.* (2011) it is the combination of both that makes a powerful option for managing energy exports from generators in the most effective manner. DLR allows the reduction of curtailment to the minimum strict levels and the increase of the available connection capacity for new power plants. For instance, results from a study performed by ELIA, the Belgian Transmission System Operator, showed that on average the available connection capacity increases more than 30%, but up to 100% when wind perpendicular to the line is more than 4 m/s[6]. Results from Michiorri *et al*. (2011) on SSEPD's ANM project in Orkney are also in agreement with this statement. The addition of DLR to the existing ANM solution showed a potential reduction of curtailment by 48% on average. Currently, the implementation of these solutions can be observed in a different number of initiatives including trials such as the Twenties Project (EU), Orkney Project (Scottish and Southern Energy Power Distribution, UK), Skegness Project (Western Power Distribution[7], UK), Transmission System Operators from Ireland (EirGrid) and Belgium (ELIA), inter alia. However, the implementation of these solutions is still in the initial stage. A survey conducted by the Department of Energy (DOE, 2009) in the US has shown that only 0.5% of the electric service providers were equipped with DLR systems, indicating the penetration and maturity of DLR as "nascent".

In summary, the deployment of smart solutions on the electricity networks will help to accommodate, facilitate and increase the connection of low carbon technologies. Because the implementation on smart solutions implies optimising network use and controlling output from

[6] These results refer to the implementation of DLR and ANM on the 70kV rural networks.
[7] Previously known as Central Networks.

generators, they require the creation of smart commercial arrangements. This involves a smart way to manage the amount and frequency of curtailment in order to provide system reliability, minimise social costs (i.e. negative prices that are incurred by end customers) and attract DG investment. The challenge is to identify arrangements that are (1) cost-effective for DNOs and generators, (2) economically efficient (making the best use of the network - reduce costs of given DG for consumers) and (3) socially efficient (maximising social welfare including carbon price and the social value of more connected renewables).

1.3 Our approach

This paper[8] explores and analyses different case studies of commercial arrangements that involve the allocation of curtailment, or so called Principle of Access (POA), in response to network constraints[9]. Thus, the aim of this paper is to select and explore a number of case studies, domestically and internationally, in which the practice of curtailment methods can be clearly identified in situations of network constraints. The case studies have been selected with the objective of understanding different alternatives to address the problem of network management and commercial implications of curtailing generation. The countries that are involved in this study are Ireland and Northern Ireland, the United States of America and Great Britain.

This paper constitutes an interesting piece of work and provides valuable insights to DNOs for promoting the connection of DG. This study explores interesting experiences under different regulatory and market contexts for a range of POA. In most of cases, the initiatives have recently been implemented and each required the revision of the most recent regulatory framework. This makes this paper one of the first to evaluate and compare new approaches for connecting DG.

The structure of the paper is as follows: Section two provides a brief explanation of the meaning of curtailment, the different types of curtailment allocation, risk allocation and social optimality. Section three explains the criteria for the selection of case studies. Section four discusses each case study. Section five summarises the findings related to the different practices. Section six sets the conclusions based on specific criteria related to Principle of Access, allocation of risks among the parties (curtailment risk and investment risk) and key lessons for DNOs.

2. Understanding curtailment

This section provides a brief introduction to curtailment in order to facilitate the discussion of the case studies in Section 4.

2.1 Definition

In this study the meaning of curtailment is associated with any limitation that prevents the generator to export its maximum capacity to the distribution or transmission network. There is no differentiation between curtailment and constraint (except for the Irish and Northern Ireland Case

[8] For further details about the project of which this paper is part see www.flexibleplugandplay.co.uk.

[9] The full version of this paper called "International Experience Report on Smart Commercial Arrangements" submitted to UK Power Networks in December 2012 can be found at: http://www.ukpowernetworks.co.uk/internet/en/innovation/learning-zone/

Study). The commercial rule for allocating constrained capacity supported by smart solutions such as ANM scheme has been characterised by Currie *et al.* (2011) as a "Principle of Access" (POA). Some of these allocation rules are described in section 2.2.

2.2 Allocation Rules

A set of rules for allocating wind generation is presented by ESB National Grid, the transmission system operator from Ireland, now EirGrid, ESB (2004) and Currie *et al.* (2011). Among the most relevant for this study are:

(1) Last In First Out (LIFO): Generators are given a specific order for being curtailed (based on a selected parameter such as the connection date). The last on the list (based on the ranking) is the first to be disconnected under a network constraint. One of the main advantages of LIFO is that there is no need for regulatory or technological change in order for it to be applied. However, from a technological point of view, this option does not necessarily incentivise nor does it support the connection of new and more efficient wind infrastructure. This is due to the fact that this will be removed first rather than older wind turbines, which may have already repaid their initial investment. LIFO also targets higher variance of returns on later projects.

(2) Pro Rata, equal percentage basis or shared percentage: Curtailment is equally allocated between all generators that contribute to the constraint. The amount of curtailment can be computed as a percentage of available capacity, installed capacity, or any other ratio. In contrast with LIFO, the Federal Energy Regulatory Commission (FERC) supports this kind of curtailment allocation for both firm and non-firm services. A recent consultation for managing curtailment in tie break situations conducted by the Single Electricity Market from Ireland and Northern Ireland (SEM, 2011); has demonstrated that electricity firms and organisations such as wind associations find this a much more suitable kind of allocation as compared to LIFO.

(3) Market-Based: Generators compete to be curtailed by offering a price based on market mechanisms. This approach is seen as the most optimal allocation rule. This is because it exploits the private information available to individual generators on their financial contracts and or the performance of their turbines. It also incentivises generator investment in flexibility and remote storage. However, this requires the development of a market for implementation which operates efficiently. This would require careful design given that there may be only a small number of sometimes financially unsophisticated generators behind a given node. The feasibility of this approach depends on the number of players (generators) and the respective transaction costs of setting up and responding to a market.

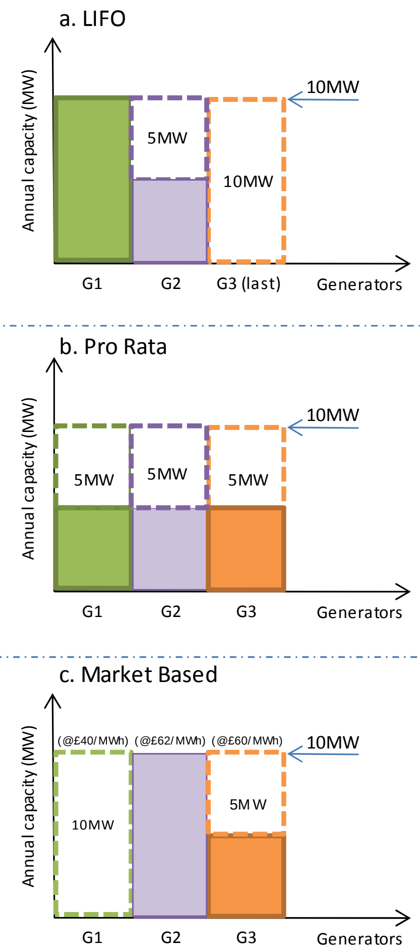
Currie *et al.* (2011) identify additional rules such as greatest carbon benefit, technical best and most convenient. However, the implementation of these rules is less likely than the first list provided due to the lack of precision in defining and measuring the respective parameters for ranking them (e.g. the carbon footprint per type of technology).

2.3 Risk Allocation among generators

The risk allocation of being curtailed will depend on the type of curtailment allocation to which a generator is subject. In a LIFO approach the risk is transferred to the marginal generator (the last generator is the first to be curtailed in case of constraints). Under a Pro Rata approach, generators are equally curtailed, regardless their order of connection. Thus, the risk is transferred equitably among generators. In a market-based approach, the risk is transferred to the generator that bids (for being curtailed) and whose offer is accepted. If market conditions are optimal, the selected generator to be curtailed is the one with the lowest bid price. Figure 1 illustrates the risk allocation among the three categories already described. For this illustrative example, it was assumed that there are a total of three generators with export capacity of 10MW each and that there was a need to curtail up to 15MW (maximum level of curtailment). G1 is the first generator to be connected and G3 the last.

Figure 1: Example of risk allocation

Allocation Rule	Notes
a. LIFO	G3 is the first generator to be curtailed up to 10MW then G2 up to 5MW. Maximum level of curtailment is 10MW + 5MW = 15 MW. G1 is not affected.
b. Pro Rata	G1, G2 and G3 are equally curtailed up to complete 15MW. Curtailed energy per generator is equal to: Maximum level of curtailment * Generator Capacity /(Total Capacity) = 15 * (10/30) = 5MW.
c. Market Based	G1, G2 and G3 bid for being curtailed. The selection is made on cost order: G1 first @£40/MWh (10MW), G3 second @£60/MWh (5MW). G2 is not selected because the maximum level of curtailment has already been allocated (10MW+5MW=15MW).



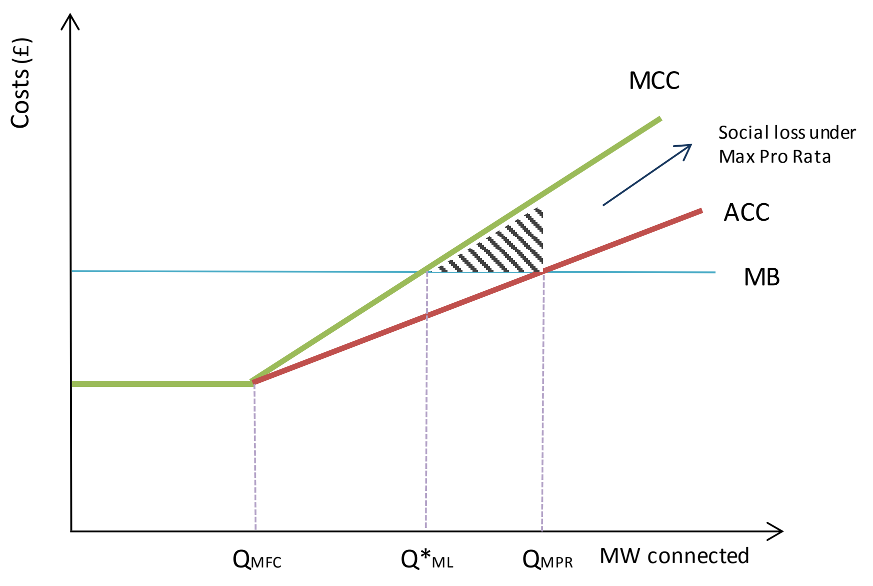
Own elaboration.

If the line capacity to export wind (which is a function of temperature and line availability) averages 30MW but is 15MW 10% of the time and 45MW 10% of the time, it is interesting to understand the behaviour of the different risk allocation scenarios. Under LIFO G3 is curtailed by 10MW 10% of the time, whereas under Pro Rata and Market-Based G3 is curtailed by 5MW 10% of the time. In this example, not only does LIFO increase the average cost of curtailment to the last in generator, it also increases its variance relative to the other approaches. This may additionally reduce the attractiveness of later individual projects to project financiers.

2.4 Social optimality: Marginal costs versus Average costs

A key question is what is the socially optimal approach to curtailment? LIFO is an approach where each generator is exposed to their marginal curtailment cost to the system. Pro Rata exposes each generator to the average cost of curtailment. If the marginal benefit to the system of each additional unit of capacity is constant, for example, if all wind generators behind a constraint had the same subsidy regime and the same technology, the marginal system benefits would include the value of the energy produced and the value of the subsidy net of production costs. For social optimality this marginal benefit should reflect all of the social benefits of additional wind capacity (i.e. the subsidy should reflect the environmental benefits). In this case it is straightforward to show that the social optimum occurs where Marginal connection cost (MCC) = Marginal benefit (MB). The marginal connection cost includes the rising curtailment cost. This is what happens under LIFO (ignoring risk), because the last-in generator faces this marginal cost. However, under Pro Rata each generator faces the average connection cost and sets this equal to marginal benefit (ignoring risk). This is not the social optimum because the last-in generator is actually imposing costs on the existing generators which they do not include in their own optimisation. Indeed setting ACC = MB would result in a social loss equal to the shaded area in Figure 2. This shows that each additional MW of wind generation beyond the point where MCC = MB actually produces an increasing incremental system cost above its system benefit.

Figure 2: Optimal connection (MW) with fixed constraint (ignoring risk)



Where **MCC** : Marginal connection cost, **ACC** : Average connection cost, **MB** : Marginal benefits, $\mathbf{Q_{MFC}}$: Max firm connection, $\mathbf{Q^*_{ML}}$: Max LIFO, $\mathbf{Q_{MPR}}$: Max Pro Rata. Own elaboration.

LIFO is therefore a better approach than Pro Rata if risk is ignored. However, private risk may not reflect the true social risk of connection (and private capital markets may be inherently risk averse) and hence it might be a good idea to reduce the riskiness of the marginal generator to reflect this.

A market-based approach is superior to both (again ignoring risk) because it gives a better signal of the true costs of curtailment. Market-based approaches however may have significant transaction costs (e.g. in calculating and assessing bids) associated with them and the benefits of a market approach need to be assessed against the costs of a market approach. Market-based approaches may also be subject to gaming if there are only a small number of bidders behind a constraint and compensation payments are related to the bids. Market-based approaches expose generators to the risk induced by the bids of other generators behind the same constraint. Given that these bids reflect the specific economic characteristics of individual generators, it may be less predictable than the overall level of the constraint.

The above discussion relates to the optimisation of capacity behind a fixed constraint. The social optimum becomes more difficult to discuss when investment to reduce the distribution constraint is possible. If enough wind is willing to connect in any location then increasing capacity is viable. If this is a medium term possibility then we need to worry about the extent to which principles of access impact on dynamic social efficiency. LIFO has the property of reducing the pressure to increase constraint capacity because constraint costs are targeted on a few generators and risk discourages connection up to the capacity limit. Pro Rata, by sharing constraint costs, makes it easier to get existing generators to contribute to increasing network capacity and encourages more generation in total. This may not be optimal in the short run but it could be optimal if it leads to more rapid wind generation roll out leading to self-financing increases to network capacity. Market-based approaches would seem to be better than LIFO in encouraging such dynamic efficiency, but suffer from risk allocation problems of their own.

Overall the different approaches have their own pluses and minuses in terms of social efficiency. Which is best depends on the relative importance of risk and dynamic versus static efficiency.

3. Case Study Selection Criteria

There are two criteria that have been taken into consideration for the selection of case studies. The first one is related to the level of maturity of the wind generation market (i.e. installed capacity) at the country-level. This level of maturity reflects, to some extent, the implementation of a mature regulatory framework that has promoted the deployment of renewable energy. The second one is related to the selection of experiences with some relevance to DNOs wishing to promote the connection of small scale onshore wind projects. In this context, the preference was given to those case studies that involve the use of smart solutions (such as ANM and DLR) and the practice of curtailment methods (firm and non-firm access). However, bearing in mind that the implementation of smart solutions is still at an initial stage, case studies with more passive arrangements such as the Renewable Auction Mechanism in the United States have also been included in this paper. The following table summarises the list of case studies covered.

Table 1: List of Case Studies

Country	Wind Figures		Case Study	Type of initiative
	Installed capacity (MW)	Share on electricity generation (%)		
Great Britain	7,952	4.4%	Orkney ANM	Project
			Connect and Manage	System Operator Regime
Ireland and Northern Ireland	1,998	11.4% (Ireland), 7.2% (Northern Ireland)	Wind curtailment in tie-break situations	System Operator Regime
United States [1/]	4,570	4.1%	Renewable Auction Mechanism	Programme

[1/] Regarding California.

Source: American Wind Energy Association (Wind energy facts: California), DECC (2012), EirGrid and SONI (2011). Own elaboration.

As indicated in table 1, the case studies covered fall into three categories: individual projects, a programme implemented by the regulator and a scheme run by the system operator. Two of the cases are drawn directly from transmission system experience precisely because the sort of constraint issues raised by distributed generation are already issues at the transmission level, and hence there are important lessons for DNOs when implementing programs from the operation of the transmission system.

4. Case Studies

4.1 Great Britain case studies

In this section, two case studies from Great Britain will be discussed: the Orkney Active Network Management (ANM) project and the Connect and Manage regime. The first one is concentrated on the use of smart solutions and innovative commercial arrangements for the connection of generation facilities to the DNO (Scottish and Southern Energy Power Distribution - SSEPD). The second one is an approach proposed by the Department of Energy and Climate Change (DECC) that promotes a faster connection of generation facilities to the transmission network, with firm access rights following the completion of local works (enabling) and planning. Both approaches seek to contribute to the achievement of the UK renewable targets by (1) increasing the available capacity of the DNO in a cost-effective way (using smart solutions) and by (2) increasing the rate of connection of renewable generation (with increased constraint costs).

4.1.1 Orkney ANM Project Case Study

The Project has been implemented in the Orkney Isles, in the North of Scotland and is the first smart grid in Britain. The distribution network in Orkney is connected to the Scottish mainland (Thurso grid substation) via the two 50 km 33kW submarine cable circuits with respective capacities of 20MVA and 30MVA. Before the implementation of smart solutions, two categories of connection were identified: Firm Generation (FG) and Non-Firm Generation (NFG). FG is the first group of generators already connected to the Orkney system that account for 26MW. NFG provided 20MW of further capacity which is based on both subsea circuits plus the minimum demand. Currently, FG and NFG capacity have been fully taken up by contracted generators. An innovate way to facilitate the connection of new generation was developed and implemented by SSEPD, along with the University of Strathclyde and Smarter Grid Solutions. ANM was the solution selected for making better use of the existing network and for releasing capacity and permitting the connection of new generators. This allowed the DNO to control the electricity output of generators in real time in order to match the available capacity. This new category was classed as New Non-Firm Generation (NNFG). This type of generation is actively managed based on both subsea circuits existing FG and NFG capacity and the maximum demand (31MW). Table 2 illustrates the way in which the maximum available capacity was computed for each of the categories (FG, NFG, NNFG-ANM) and the current connected capacity per category.

Table 2: Summary of Generation Connection Categories

FG			NFG			NNFG - ANM					
Generator	Type	IC (MW)	Generator	Type	IC (MW)	Generator	Type	IC (MW)	Generator	Type	IC (MW)
Flotta	gas turbine	10	Burgar Hill	wind	6	Holodykes	wind	0.9	Hatston	wind	0.9
Burgar Hill	wind	6	Sanday	wind	8	Burgar Hill	wind	2.3	Braefoot	wind	0.9
Stronsay	wind	3	Flotta	wind	2	Hammars Hill	wind	4.5	Rothiesholm	wind	0.9
Stromness	wave	7	St Mary's	wind	1	Ore Brae	wind	0.9	Other	wind	0.9
			Others		3	Mid Garth	wind	0.9			
Total	FG - full	26	Total	NFG - full	20	Total [1/]			NNFG		13.1
FG= (N-1)*circuit capacity + (local minimum demand)			NFG= N*circuit capacity + local minimum demand - FG			NNFG= N*circuit capacity + local maximum demand - FG - NFG					
FG= (2-1) *20 + 6 = 26 MW			NFG = 2*20 + 6 - 26 = 20 MW			NNFG = 2*20 + 31 - 26 - 20 = 25 MW					

Where N: number of circuits=2, circuit capacity=20 MW, minimum demand= 6 MW, maximum demand= 31 MW.
Source: DTI (2004), SSEPD (2010), SSEPD (2011), SSEPD (2012a), SSEPD (2012b), SGS (2012). Own elaboration.
[1/] Up to March 2012.

Currently, new generation connections to the Orkney network above 50kW are only available as NNFG. The commercial agreement for connecting NNFG involves ANM and a constraint policy, (SSEPD, 2012c, p. 14). An alternative would have been to reinforce the submarine cables to the mainland grid. This conventional solution would have involved the installation of an additional submarine cable to the Scottish mainland at a cost of £30 million. The ANM solution was implemented at a cost of £500k. This has allowed up to 25MW of new capacity to be contracted.

This case illustrates that one of the main advantages of using ANM is to avoid distribution upgrade costs (reinforcements) which are usually incurred by the developers and represent a significant cost. However, apart from the local connection costs, there are also other costs that are mainly associated with the implementation of the ANM solution, such as those related to the provision of ANM communication circuits between the developer site and DNO's central control at Scorradale. For instance, a new developer that asked for a 1MW NNFG connection could incur up to £400,000 (worst case)[10]. Thus, one developer that only asks for a 50KW connection would also incur similar costs to a developer requesting a 1MW connection, which represent significant costs for a small generator.

The previous finding is in line with the conclusions from Flexible Plug and Play's Stakeholder Engagement Report[11], in which some small developer generators describe the issue of curtailment

[10] In general these charges are applicable to any generator > 25 kW. The previous calculations are based on the response that the Orkney Renewable Energy Forum provided to National Grid in order to demonstrate the impact that high charging regimes for transmission would have on small projects such as those from Orkney Islands (National Grid, 2009).
[11] See: http://www.ukpowernetworks.co.uk/internet/en/innovation/documents/%20WS05.P0180.FPP.StakeholderEngagementReport1v051012.FINAL%20

as "too much trouble" for a 50kW project, mainly due to the additional communications and management overhead. It is noteworthy that in the case of the Orkney ANM project, an important number of LV small generators have not been subject to curtailment due to the infeasibility of installing specific communication equipment for controlling curtailment (they are too small to afford the associated costs). The aggregate capacity of these connections is becoming significant. In light of this, SSEDP has decided to apply a temporary solution by preventing the connection of small generators that are not subject to curtailment. They are evaluating low-cost solutions such as broadcasting for sending the curtailment signals instead of point to point dedicated communications (UK Power Networks, 2012, p. 27). In general, communications issues (that allow the output reduction of generators) have been one of the most important problems that the Orkney ANM project has to deal with. Communications failures were reported on BT rented private wires. Reliable communications (from NNFG site to ANM site) is the responsibility of the generator and are out of the ANM scope; however it may impact on the ANM system as it relies on real time information. (KEMA, 2012, pp. 13,15).

The Orkney ANM project has benefitted from the Innovation Funding Incentive (IFI), Registered Power Zones (RPZ) and DG incentives. Under IFI, the DNO is allowed to transfer the cost of eligible IFI projects to customers as follows: 80% in 2007/08, reducing in 5% steps to 70% in 2009/10 and 80% in 2010/11 until 2014/15. The RPZ can be seen as an extension of the DG incentive that was also introduced within DPCR4[12]. The DG incentive allows DNOs to recover the costs associated with the generation connection as follows: (1) 80% cost pass through and (2) an incentive per kW connected of £1.5/kW[13]. If innovation is added to this connection, DNO may have the chance to register this project as a RPZ. If this is the case, the DG incentive is increased for the first five years of operation by £3/kW. Table 3 illustrates the benefits that the DNO has received due to the capacity connected up to March 2012. A total of £ 13.1k has been awarded in the last period.

Table 3: Capacity connected, incentives and connection costs

Period	Capacity connected (MW)	Cumulative capacity connected (MW)	Incentives (DG+RPZ) £k	Number of generators	Connection costs (£k)	Ratio (£/kW)
First year (2009/10)	3.2	3.2	14.4	2	190	59.4
Second year (2010/11)	4.5	7.7	7.7	1	292	64.9
Third year (2011/12)	5.4	13.1	13.1	6	152	28.1

Source: DTI (2004), OFGEM (2009), SSEDP (2010), SSEDP (2011), SSEDP (2012a), SSEDP (2012b). Own elaboration.

In terms of the allocation of curtailment, the LIFO system was selected by the DNO for the trial and no other options were considered. Curtailment is organised in a hierarchical way based on the date of acceptance of the formal connection offer. This system has been supported by OFGEM as it is very straightforward and easy to understand. However, it can become complex when the number of interested parties increases. For this reason, SSEPD has set specific conditions for the queue of generation waiting to connect: proof of planning consent and a deposit paid as part of the commercial agreement (KEMA, 2012, p.12). Under the current commercial arrangement compensation to generators is not allowed and the maximum hours of curtailment will depend on

[12] In 2010 the RPZ scheme has been replaced by the Low Carbon Networks Fund.

[13] The DG incentive value has been reduced from £ 1.5/kW/yr (DPCR4) to £1.0/kW/yr (DPCR5) due to the change of the connection boundary (from shallow connection to shallowish connection). Other incentives or conditions remain the same. (OFGEM, 2009, p. 18).

the stack order of the generator, which is not known upfront (Meeus *et al.,* 2010, p. 12). This fact increases the risk allocated to the generators and decreases the risk on the DNO or consumers due to the absence of compensation.

Summary and Discussion

The Orkney ANM is a project that has benefited from different innovation incentive mechanisms. An interesting discussion exists around whether these incentives are good enough to encourage DNOs and generators to reinforce and to plan their network 'smartly'. In the case of the Orkney ANM project, the introduction of smart technologies has contributed to finding the right balance between parties.

It has been shown that smart solutions provide a cost-effective way for increasing the capacity under a non-firm access with adequate levels of curtailment under NNFG (ANM solution: £500k versus conventional reinforcement: £30million). A key challenge is how to optimally increase generation capacity behind a constraint versus carrying out traditional reinforcement. Further development is also a key issue for continuing with the deployment of financially viable projects. DLR and storage capacities are some of the potential options.

LIFO is the technique selected by the DNO for curtailment allocation. Under LIFO the position of the generator in the queue has a commercial value. In the case of network constraints the DNO has decided not to compensate generators. This means that the curtailment risk is fully transferred to generators. DNOs are free to find the best way to deal with curtailment issues and at the same time have to satisfy the demand for connections. In addition, generators are also responsible for some distribution upgrades. In the case of the Orkney ANM project, the costs of these upgrades have been replaced to some extent by the costs of the ANM solution, which represents an important saving for generators. However, as was indicated previously, small generators may be financially affected due to the high fixed costs that a solution like ANM requires (communications and control equipment). These costs can be mitigated if ANM fixed costs can be shared with other generators that are also connected at the same pinch point. Thus, only in a situation in which big savings are observed, would an ANM would be preferred instead of conventional reinforcement.

In terms of funding, the project has demonstrated commercial innovation. New non-firm wind generators have been able to get funding for their respective projects (bankable projects), notwithstanding the impact of potential constraints. Curtailment has been seen as something commercially acceptable.

4.1.2 Connect and Manage Case Study

A DECC (2009) consultation paper on improving grid access proposed a number of different approaches to transmission access. Subsequently, the Government selected Connect and Manage (CM) with socialised costs[14] as the most suitable option (DECC, 2010, p. 3). This approach commenced on 11 August 2010 and replaced the previous Invest and Connect regime (prior to May 2009) and the temporary Interim Connect and Manage (ICM) which promoted the connection of new generating facilities from May 2009 to August 2010. Under CM generators (embedded or

[14] Refers to the socialisation of all constraint costs including those that are not directly related to CM.

directly connected) are offered the opportunity to connect to the transmission network in advance of the completion of the wider transmission reinforcement works. Thus, one of the advantages of this approach is that the waiting time for connecting to the transmission network is significantly reduced. However, CM cannot be seen as an isolated initiative. This constitutes the continuation of specific improvements in the transmission sector in order to accelerate the integration of generating facilities. Other important improvements are those related to User Commitment, anticipatory investments approved by OFGEM and the application of new policies for managing the connection queue (UK Power Networks, 2012, Appendix 4).

Under CM, early connection required specific changes to be made to industry codes and licence modifications. An early connection implies that generators acquire full access rights on connection. CM with full access rights is seen as the default position for connecting generating facilities to the transmission network; however developers are allowed to discuss with the possibility of design variation options for accelerating their connection date through non-firm access (or second class access rights) with National Grid. The kind of work that is required for advancing connection is classed as "enabling works". Broadly speaking, enabling works are associated with the minimum reinforcement works that need to be done before a generator can be connected to the national transmission system or distribution system. Wider works, by contrast, are the other transmission works that are necessary to reinforce or extend the national electricity transmission system accordingly to the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). It is expected that enabling works do not exceed those works related to the Main Interconnected Transmission System (MITS) connection works[15].

Recent figures suggest that a total of 42 projects have been connected up to 30 April 2012, from which the category of small embedded generation has the largest number (36). The installed capacity associated with these connections is around 571MW where 346MW corresponds to transmission connected generation, 139MW to small embedded generation and 86MW to large embedded generation In terms of the advancement of connection, an average of 6.5 years and 11 years is observed for (1) transmission connected and large embedded generation that will connect via DNOs and (2) small embedded generation that will connect via the DNO based on the Statement of Works process (National Grid, 2012, pp. 4-5, 8).

Summary and Discussion

The implementation of Connect and Manage will accelerate the number of firm access rights to the grid which will contribute to meeting renewable electricity targets. Generators are encouraged to request a connection and to get it much quicker and more cheaply (in comparison with the invest and manage approach) due to the socialisation of constraint costs. Thus, under CM, generators acquire full access rights from the beginning and are subject to paying full Transmission Network Use of System (TNUoS) charges and the respective share of balancing costs via Balancing System Use of System (BSUoS). Enabling works (minor reinforcements) are generally incurred by connecting generator and wider works (major reinforcements) are shared between generators and demand more generally through TNUoS. However, the main concern of CM is that network congestion will also increase mainly for two reasons (1) due to the high number of generators connected with

[15] MITS substation refers to a transmission substation with more than 4 main system circuits connecting at that substation.

access rights and (2) due to the fact that the connection point is provided irrespective of the completion of the associated transmission development (this refers mainly to enabling works). As a consequence, a request for curtailment is essential. In this case, National Grid applies a kind of market-based approach as a method for allocating curtailment. This refers to the balancing mechanism which enables supply and demand to be balanced across the electricity transmission system and at the same time allows to resolve system constraints (system security) [16]. The system operator will try to find the most cost-effective offers for balancing the system taking into account diversity of supply in order to maintain system reliability. National Grid states that in general bids are accepted in cost order; however the acceptance of these bids is subject to dynamic limitations notified by the bidder and to specific geographical issues. For instance, due to the low competition between bidders behind individual constraints, it is not always possible to select cost-effective bidders[17]. Therefore, the system operator will generally try to manage bid and offer acceptances in price order, however timing and geographical issues may alter the actual acceptance from a simple price stack. In light of this, National Grid is obliged to pay very high prices to generators (such as wind farms) for them to accept curtailment. These payments do not necessarily reflect the subsidies that farms receive. Under specific circumstances, such as the event reported on April 5-6 2011 in Scotland, wind farms may receive up to 16 times the value of the subsidies which at the end of the day are transferred to customers (via BSUoS). During the April 5-6 event, a total of £890,000 in curtailment costs was paid to six wind farms[18]. In consideration of these facts, network operators are evaluating different options to manage surplus electricity production. Among these options are local storage but it would be an expensive solution.

It is also observed that CM contributes to mitigating stranding risk for consumers due to the two -stage mechanism (minor reinforcements followed by major reinforcements, if necessary) for integrating generating facilities to the transmission network. This two-stage approach contributes to making better investment decisions by National Grid. The way in which CM is designed gives, to some extent, more protection to customers that the previous approaches (IC and ICM) may not have done, as far as avoiding unnecessary anticipatory investment is concerned. Thus, even though is clear that the investment risks will be transferred to consumers (especially those related to wider reinforcements) there is a strong reason to believe that some of these costs may be mitigated by making better investment decisions in comparison with the previous programmes.

Finally, it is noteworthy that CM is something that cannot be currently implemented within distribution networks, due to the current regulation and operational differences between transmission and distribution networks.

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[16] The cost of this balance is recovered through BSUoS charges. The current allocation is as follows: 50% generators and 50% suppliers.

[17] Limited options are observed in North-West Scotland where constraints can only be resolved via hydro and wind units with an average of price taken between £-97/MWh and £-340/MWh. See the National Grid Operational Forum at http://www.nationalgrid.com/NR/rdonlyres/BDD8B04B-397E-4B08-8812-FB81F836411A/53333/Ops_Forum_12Ape2012_Final_Slide_Pack2.pdf

[18] See: http://www.ref.org.uk/publications/231-high-rewards-for-wind-farms-discarding-electricity-5th-6th-april-2011

4.2 Ireland and Northern Ireland Case Study

This case study introduces an interesting initiative regarding the curtailment mechanisms for wind generation in tie-break situations[19]. Since 2008, different considerations regarding the treatment of wind generation have been proposed by the Single Electricity Market (SEM) Committee from Republic of Ireland (ROI) and Northern Ireland (NI). This study will be focused on the last two proposals (SEM-12-028) and (SEM-12-090).

This case study is very instructive due to the introduction of different approaches to deal with curtailment and constraints, which are defined differently. This case study also suggests innovations in the way of compensating wind generators in curtailment situations. The recent proposal relates the degree of compensation (which has had to be gradually reduced regardless of the level of firmness) to the achievement of renewable targets.

4.2.1 The Single Electricity Market Wind Curtailment in tie-break situations

The increase in intermittent generation (especially wind) has deserved the attention of the SEM which, since 2008, has published a number of consultation papers that deal with issues regarding the treatment of wind generation. In August 2011 the SEM Committee published its final decision regarding “Scheduling and Dispatch”, SEM-11-062. This decision, among other related issues, set the priority dispatch hierarchy which favoured renewable generation, and suggested further consultation on the treatment of constraints and curtailment in tie-break situations. Tie-break situations refer to the case in which there is a requirement for the transmission system operator to turn-down wind generation after having exhausted other options based on the priority dispatch hierarchy. SEM has made a distinction between constraints and curtailment events. Constraints are network-specific and are related to the availability of the network. Curtailment is a system operation issue and it happens when wind generation exceeds the system demand. This study involves only the case of wind curtailment in tie-break situations. After much consideration and taking into account responses from key stakeholders, the SEM Committee published on 21 December 2011 a decision paper (SEM-11-105) in which, among other resolutions, decided to deal with curtailment issues in tie-break situations using a grandfathering approach with reference on Firm Access Quantity (FAQ) (SEM, 2011, p. 17).FAQ measures the level of firm financial access available in the network for a generator and are usually determined by the system operators. Firms are financially guaranteed exports to the network up to the limit of the allocated FAQ which varies from 0% to 100%. FAQ’s are annually re-assessed for all partially firm and non-firm generators (connecting to transmission or distribution system) that have valid connection offers or connection agreements. For instance, in ROI the types of firm access are: (1) fully-firm with a FAQ of 100% of their Maximum Exporting Capacity (MEC), (2) partially firm with a FAQ of between 0.1% and 99.9% of their MEC and (3) non-firm with a FAQ of 0% of their MEC[20]. The last category refers to those generators with temporary connections or those that have not been allocated FAQs.

[19] Section 4.2.1 defines tie-break situations.

[20] It is noteworthy that at the time of writing this paper, the concept of non-firm had not been introduced in Northern Ireland yet.

Different parties in the energy community submitted their comments to these proposals; many of them did not welcome the approach of grandfathering with reference on FAQ. As a result, after further analysis, SEM decided to withdraw its decision. A new discussion paper was published on 26 April 2012 (SEM-12-028) in which four options for dealing with the curtailment of wind energy in tie-break situations were proposed (SEM, 2012a). From the four options, only three of them considered compensation due to curtailment of firm wind generators. This compensation is made through the Dispatch Balancing Costs (DBC) which is ultimately paid by customers. DBC is computed by the difference between the generation dispatch as scheduled by the SEM and the actual dispatch as performed by the transmission system operators via their respective control centres (EirGrid, 2012, p. 10). The different options were as follows:

Table 4: Summary of Options

Options	Name	Description
Option 1	Grandfathering - LIFO	In which the stack order is based on FAQ. This means that firms with the lowest hierarchy of firmness (such as non-firm) are curtailed first. A firm with a FAQ=0% does not receive any compensation when the respective generator is turned down.
Option 2	Pro Rata	In which wind generators are turned down by an equal percentage irrespective of allocated FAQ. No compensation for non-firm generators.
Option 3	Temporary Pro Rata	A pro rata approach is used until the renewable target has been reached (40% all-island), after this a grandfathering approach is preferred. This means that all wind generators, independent of their respective FAQ, will be turned down on a pro-rata basis up until the meeting of the 40% target. After this, non-firm wind generators will be turned down first. In both cases, compensation is not received by non-firm generators.
Option 4	Pro rata with generators taking the risk	This option differs to the others because this does not consider any compensation at all. Wind generators are curtailed under a pro-rata basis but the risk of curtailment is born only by them. Customers are not directly affected because wind generators are not entitled to market compensation through DBC.

Source: SEM (2012a). Own elaboration.

Different responses from the industry and the public arose from this new consultation. A summary of some of the responses is given in the next paragraph.[21] Regarding Option 1, one of the main concerns was that non-firms projects would be unable to build due to their high exposure to curtailment risk (in 90% of cases wind farm connection offers in ROI are made under a non-firm basis). If this happens, the renewable targets would not be achieved and the system marginal price would increase. One respondent has shown that if Option 1 is adopted, and assuming an overall curtailment of 2% on all-island, non-firm generators (subject to Gate 1 and Gate 2)[22] would experience curtailment up to 9% and temporary connections would also suffer with curtailment up to 13%[23].

[21] The summary was made based on the consolidation of responses prepared by SEM in the last proposal for treatment of curtailment in tie-break situations (SEM, 2012b).

[22] The process for connecting renewable generators to the electricity network is based on the Group Processing Approach (GPA) in which instead of connecting one-by-one, generator applicants are processed together in geographic groups (Gates). Currently there are three gates: Gate 1, Gate 2 and Gate 3.

[23] Percentages are on energy basis. See report from Irish Wind Energy Association (IWEA, 2012).

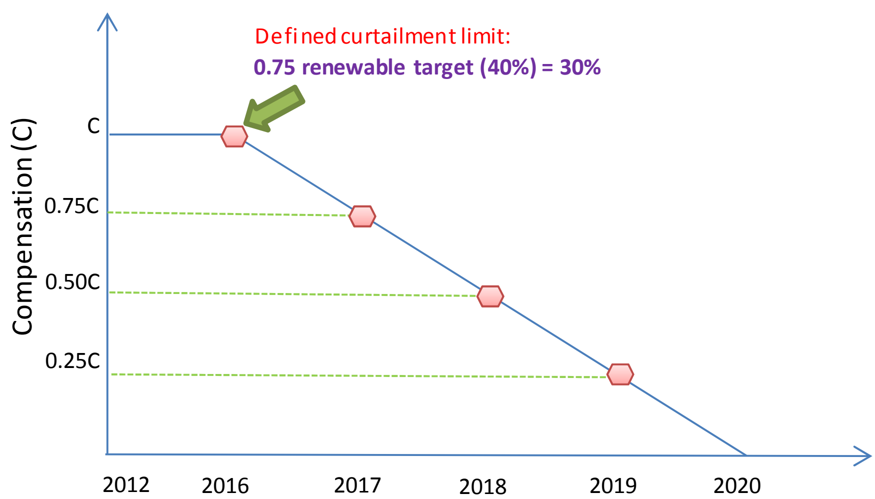
The majority of respondents were in favour of Option 2. However, some issues that were pointed out were the possibility of overbuild beyond the 2020 renewable targets due to the "uncapped curtailment" which may produce a negative impact on consumers due to inefficient grid roll-out. Other respondents supported this approach by arguing that under this option there is a natural protection that would provide the right balance between overbuild and targets. This natural protection refers to the renewable incentives such as REFIT in ROI and ROC and FIT in Northern Ireland which to some extent need to be in line with renewable targets. A modelling exercise conducted by EirGrid has shown that if Option 2 is implemented now, DBC would increase by €1.8 million and by €9 million in 2020.

Similar to Option 2, many respondents supported Option 3 however the main observation was that the link between grandfathering of curtailment and firm-access still remains. One respondent suggested that there is a strong possibility of not delivering the 2020 renewable targets due to the uncertainty at the changeover point (a delay would be observed because project would prefer to build after the delivery of firmness). Other respondents recommended a modified version of this approach. For instance, the Irish Wind Energy Association and Scottish and Southern Energy suggested a differentiated treatment between those projects that contribute directly to the renewable targets and those new projects that are built after the achievement of the targets.

Finally, regarding Option 4, no one supported this option. This is understandable because this option proposed the elimination of compensation, which could alter the wind generation revenues. Their position was supported by three main issues: unviable projects due to the removal of compensation, (2) a significant change to the SEM principles and (3) the threat of regulatory stability in the SEM (SEM, 2012b, p. 17).

In light of these responses, SEM has published a new proposal on 3 October 2012 (SEM-12-090): Pro Rata with defined curtailment limits. Under this approach the idea of indefinite compensation (even for firm generation) is not supported anymore after 2020. The following figure illustrates the proposal.

Figure 3: New Proposal for wind curtailment under tie-break situations



Source: SEM (2012b). Own elaboration.

SEM proposes to set the curtailment limit based on a renewable penetration threshold: set as the earlier of the confirmed achievement of 75% of the renewable target (40%) = 30% or the date of 1 January 1 2016. SEM suggests a gradual reduction of DBC compensation (*"sliding scale mechanism")* after the achievement of the renewable penetration target (this reduction would be 25% per year until no compensation is available) – 2020 at the latest. For illustrative purpose it was assumed that the date in which 75% of the renewable target is achieved is 1 January 2016.

In terms of the impact, the results from TSO modelling suggest that the estimated compensation payment savings would be around €13million, due to the non-payment of DBC for curtailment in 2020 (SEM, 2012b, p. 45). For this, it was assumed a curtailment level of 4% (638 GWh) with a System Non-Synchronous Penetration (SNSP) limit of 70%. SNSP is defined as the ratio of wind generation plus imports to load plus exports ($SNSP = (wind + imports)/(load + exports)$). Currently, it is feasible to securely operate the power system with up to 50% from non –synchronous generation sources (wind and HVDC imports) in all-island. EirGrid has estimated a maximum SNSP of 75% by 2020. Under the previous assumptions regarding curtailment and SNSP, the curtailment costs would be approximately €20 per MWh[24]. The TSO's report also shows that if this option is adopted now the expected curtailment level would be 2% across all wind generators. The report also indicates that if option 1 is adopted (grandfathering with reference to FAQ) a curtailment level up to 24% for non-firm would be experienced by 2020.

Summary and Discussion

With the new proposal SEM is trying to deal with the over-incentivisation of connection beyond the 40% renewables targets. In addition, SEM is trying to promote the connection of more efficient wind generation plants in which the level of compensation due to wind curtailment would not be decisive for the business case. The challenge is to reduce curtailment because this affects both the wind generators and customers. Curtailment cannot be avoided when high level of wind penetration is expected. Under the proposed new approach, generators will be curtailed Pro Rata and compensation will only be given to firms with a FAQ different from zero. In this situation the risk is partially transferred to generators due to the gradual reduction of compensation. This compensation will be progressively reduced up to the achievement of renewable targets (worst case 2020). In this circumstance the risk is shared with customers and generators or partially transferred to full firm or partially firm generators due to the gradual reduction of compensation. After the achievement of renewable targets, compensation will not be provided regardless of the firmness level. In this case, the risk is transferred from customers to all generators.

The allocation of different levels of firmness (FAQ) may contribute to a quick connection and the expansion of wind generation. This means that generators do not need full access rights (full firm) in order to have access to the market. However, depending on their respective FAQ, they will not enjoy the same rights as full firm generators (if FAQ=0% they are not compensated). A similar situation is observed in the Orkney ANM project but at distribution level, in which generators can choose a NNFG approach (non-firm but with ANM specifications), are subject to curtailment and are not compensated. This is in stark contrast to Connect and Manage at transmission level, in which

[24] In general, the impact of wind generators will depend on many factors such as installed capacity, capacity factor, availability, among others. For instance, a 10MW wind farm with a capacity factor (CF)=30%, availability 100% year, the estimated impact would be € 21k (0.3*10*0.04*8,640*20=€20,736).

generators have full access rights from the beginning, pay full TNUoS and are compensated through BSUoS. Both case studies show that the regulatory framework does not make any differentiation between constraints and curtailment.

4.3 The United States Case Study

California is one of the American states with the most experience implementing a RPS and FIT schemes for eligible renewable sources. There are different procurement methods for allocating these sources of energy. This section discusses an innovative procurement method proposed by the California Public Utility Commission (CPUC) in 2010: Renewable Auction Mechanism (RAM). RAM was launched as a way of encouraging the connection of small generators (up to 20MW) to the distribution and transmission grid in a cost-effective way. Three utilities use this method of procurement: Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E). These are vertically integrated utilities. This case study will analyse the general rules for the RAM programme and go on to concentrate on the specific rules that SCE[25] has proposed in its RAM Pro Forma Power Purchase Agreement (PPA) related to the second auction (RAM 2).

This case study has been chosen because it provides an interesting way to procure renewable energy through small generating facilities connected at the distribution and transmission level using a market-based approach. The RAM programme is an interesting attempt to combine generation and network costs in the allocation of subsidies and the choice of projects, as well as exhibiting novel curtailment risk transfer elements. In addition, the type of renewable products and the size of generators are in line with the renewable portfolio that certain UK DNOs are expecting to connect in the short term[26].

4.3.1 The Renewable Auction Mechanism (RAM) Programme

The RAM programme[27] is a market-based procurement mechanism that was adopted by CPUC on December 18, 2010 (Decision 10-12-048) in order to promote competition, lower costs to rate-payers, reduce transaction costs, incentivise the development of resources for promoting the use of the existing transmission and distribution network and to contribute to the RPS goals (CPUC 2010, p. 2). The RAM programme represents the proposals for expanding the existing FIT programme for generators up to 20MW, which still are considered small generators. Even though there are different renewable programs in California, it is expected that RAM programme will be the primary contracting tool for this market segment (up to 20MW).

Under this approach, CPUC ordered the three IOUs: SCE, PG&E and SDG&E to procure a total of 1,299MW of renewable energy in their respective service territories. CPUC RAM is a two-year programme. Four auctions over two years (two auctions per year, every six months) have to be held by the three investor-owned utilities[28]. The auctions are held simultaneously by the IOUs in order to

[25] SCE is the largest IOU in California. It serves around 4.9 million residential and business customers in 15 counties of Central, Coastal and Southern California. See: http://www.edison.com/files/SCE_PROFILE.pdf
[26] For example, our project partner, UK Power Networks in East Anglia.
[27] This programme replaces the former Renewable Standard Contract (RSC) Programme.
[28] The four auctions are classed as: RAM 1, RAM 2, RAM 3 and RAM 4.

maximise competition. IOUs allocate around 25% of their respective permitted capacity per auction. If this cannot be allocated or participants subsequently drop out, the capacity is added to the next auction. RAM 1, the first round of auctions, closed on November 15, 2011 in which CPUC approved 13 renewable DG contracts for 140MW in April 2012.

There are three types of products that generators can select: (1) firm (baseload) – such as biomass and geothermal, (2) non-firm peaking (peaking as-available) – such as solar and (3) non-firm non-peaking (non-peaking as-available) – such as wind, hydro. IOUs specify the amount of product for each auction. In terms of interconnection, generators require a physical interconnection to the utility transmission or distribution grid. They are required to demonstrate interconnection studies and/or agreements or to prove that the Fast Track Screens have been passed. Generators also have the option to bid their projects based on energy-only (EO) status or Full Capacity Deliverability Status (FCDS). The CAISO tariff applies for interconnection at the transmission level (typically at 115kV or higher) and the Wholesale Distribution Access Tariff (WDAT) applies for interconnection at the distribution level (typically below 66kV). An interesting requirement regarding interconnection is the availability of interconnection maps that IOUs make available to potential bidders that provide information regarding the availability of capacity at the substation and circuit level, and are updated once a month (CPUC 2010, pp. 70-71). These maps are free of charge and can be downloaded usually from the utility's website[29].

In terms of price, under RAM the generators are able to determine the product price. The price is adjusted based on the Time of Delivery (TOD) periods and the respective allocation factors. In the evaluation process IOUs select projects in order of least expensive first, up to the capacity limit per product. The transmission upgrade costs are also estimated by the utilities and added to the costs of the bids for elaborating the ranking. If a generator bids as FCDS, benefits from Resource Adequacy (RA) are also taken into account in the evaluation process. RA is seen as a capacity requirement. Thus, the rank is based on the levelised TOD adjusted product price plus transmission upgrade costs (under EO status or FCDS) less RA benefits (only if the product is bid as FCDS). The formula is as follows:

$$Total\ price = bid\ price\ (levelised) + ratepayer\ funded\ transmission\ upgrade\ costs - RA\ benefits$$

Where ratepayer funded transmission upgrade costs refer to those costs that are paid back to the generator over a five-year period through the Transmission Access Charge (TAC). Thus, transmission upgrade costs are not captured in the bid price.

The CPUC mandates to evaluate the proposals by an independent evaluator[30]. In the evaluation, RA benefits are received only by those generators with FCDS interconnection. Winners in the RAM auction receive the total price as per their bid (so it is a 'pay as bid' auction).In general the RAM pro forma is developed by each utility taking into consideration the general regulatory framework established by the CPUC for the RAM programme. The CPUC approves the PPA pro forma created by each utility. In this analysis, we are going to focus on the SCE RAM auction related to the most recent auction round (RAM 2). Table 5 summarises the main concepts of the PPA pro forma.

[29] See: http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm

[30] For instance for RAM 2, SCE and PG&E selected AccionPower and Charles Adkins of Ventyx Energy Software, Inc. as independent evaluators respectively.

Table 5: Summary RAM 2 Pro Forma – SCE

Concept	Description
Type of allocation	By auctions (up to 186MW,+/- 20MW)
Procurement products	Peaking as available (i.e. solar) - non-firm peaking : up to 166MW Non-peaking as available - non-firm peaking (i.e. wind) : up to 10MW Baseload (i.e. geothermal, biomass) - firm: up to 10MW Projects from 1MW to 20MW. If aggregated, minimum 0.5MW with a maximum of 5 MW (aggregated capacity)
Length of contract	Original term: 10, 15, 20 years Curtailed return term, either: 2 years after the completion of the original term or the day in which the Seller delivers to SCE twice the quantity of banked curtailed energy
Offers	Single or multiple Submitted to independent evaluator (Accion Power for RAM 2-SCE) Inside the three independent utilities service area (SCE, PG&E, SGP&E)
Interconnection/connection	Generation facilities can be connected to the transmission or the distribution network Probed generation facility's interconnection studies, Fast track or interconnection agreement Energy only (EO) or Full capacity deliverability status (FCDS) Direct assignment costs: incurred by the Seller, no reimbursement is applied Network upgrades: initially incurred by the Seller but then a repayment is made with interest over a 5 year period (after initial operation)
Product Price	Seller proposes the product price Price is not negotiable Prices are adjusted based on the Time of Delivery Periods (TOD) and Product Payment Allocation Factors (PPAF) There are four categories of TOD (on-peak, mid-peak, off-peak and super-off-peak) PPAF based on season (summer or winter) and TOD period. PPAF vary between 0.61 (super-off peak in winter) and 3.13 (on-peak in summer) Under curtailed return term, SCE pays to the seller 50% of the contracted price (product price)
Deposits	Development: For projects < 5MW: $20/kW For projects > 5MW: $60/$90/kW for intermittent and baseload respectively Performance: For projects < 5MW: $20/kW For projects > 5MW: 5% of expected total project revenues
Curtailment	Reliability (emergencies, order by CAISO) - no compensated Economic - compensated Use of curtailment cap (50 hours a year) MWh Pro rata approach
Compensation	Compensation is applied, excluding the case in which SCE is not awarded schedule under non-peak hours and (1) the price ahead is negative and (2) the curtailment cap does not exceed 50 hours per year

Source: CPUC (2010), SCE (2012c). Own elaboration.

SCE RAM 2 Auction

For the RAM 2 auction, SCE targeted the following distribution: peaking as available (166MW), non-peaking as available (10MW) and baseload (10MW), plus or minus 20MW (SCE, 2012b, Appendix B, p. 3). From this, it is clear the importance that SCE (an in general all the IOUs from California) gives to the solar PV technology, which is in agreement with their respective portfolio needs. At the present a total of 67MW (RAM 1) and 87MW (RAM 2) has been allocated (SCE, 2012a, p. 2), (SCE, 2012c, p. 3). The rest of capacity amounting to 569MW is expected to be allocated across RAM 3 and RAM 4[31].

Regarding the length of contract, the CPUC has established 3 options: 10, 15 and 20 years. However, this length may be affected by the quantity of energy curtailed (that exceeds a specific cap) during the contract term, which is classed as banked curtailed energy. This extra term is called curtailed return term, which is either the earlier of: (1) the day in which the delivery of the product is two times the quantity of the banked curtailment energy or (2) two more years after the last day of the original term. This condition has been set only by SCE. In terms of product price, SCE has established specific TOD and PPAF for the adjustment of price. These figures differ across IOUs. For instance, the minimum and the maximum factor values applied by SCE for RAM 2 auction are: 0.61 (super-off peak in winter), 3.13 (on-peak in summer) respectively. In RAM 2 auction, SCE applied the same PPAF to EO status and FCDS. In addition, under the curtailed return term SCE has set the product price as 50% of the contract price.

In terms of curtailment, only those related to economic reasons are compensated under specific conditions that depend on TOD (and their respective allocation factors) and the value of the day ahead price[32]. SCE has established a curtailment cap of 50 hours a year. This means that a generator with 10MW can be curtailed up to 500 MWh a year. This value was proposed by the utility and the CPUC approved it. Other IOUs such as PG&E have set a different curtailed cap equal to 100 hours a year, however the concept of curtailed banked energy is not applicable, thus the original contract is fixed.

Regarding curtailment allocation, generator output is reduced on a Pro Rata basis (according to their contract capacity to achieve the limitation) in certain situations, such as when lines are unavailable due to maintenance. For other cases SCE has not defined yet a specific method. SCE has indicated that they are currently working on a method to calculate and transmit a "real time" limitation setpoint to each generator affected (especially in situations where a limitation is going to continue for an extended time). The setpoints would be computed according to the contract capacity but would be adjusted in real time taking into consideration the measured output of the generators in order to maximise the output as close to the allowed quantity as possible. This approach will help to minimise the loss of generation and to maximise the utilisation of the grid capacity.

From Table 6 it is noteworthy that when the CAISO awards a schedule to SCE, the utility has the right but not the obligation to order the generator (or seller) to curtail the output. If the order is made, SCE has to compensate the generator regardless of the curtailment cap.

[31] RAM 3 auction closed on 21 December 21 2012 and RAM 4 will close on 31 May 2013. The capacity targeted for RAM3 is 230MW (SCE, 2012d, p. 3)

[32] There are two kinds of curtailment: reliability and economic curtailment. Only economic curtailment is compensated.

Table 6: Curtailment Scenarios

Item	Concept	Condition	Curtailment [C]	Compensation	Price	Notes
Case 1: CAISO awards a schedule to SCE						
A	SCE has the right (but not the obligation) to order (OSGC Order) the curtailment of the delivery of energy (from Seller) when there is an excess of the schedule awarded (OSGC Quantity)		No cap	Yes	Product Price adjusted by PPAF	Other additional compensation (If applicable) are those related to Federal Production Tax Credits
Case 2: CAISO does not award a schedule to SCE and the Seller's Actual availability report sets that the generating facility would have been able to deliver						
B	Non-on-peak hours	If day ahead price is >=0	No cap	Yes	Product Price adjusted by PPAF	The Curtailed Product will not be included in the Banked Curtailed Energy
		If day ahead price is < 0	If [C] < 50 hours	No		Compensation is not applicable because the amount of curtailment does not exceed the curtailment cap (50 hours a year)
			If [C] > 50 hours	Yes	Product Price adjusted by PPAF (applied only to Curtailed Product in excess of the cap)	The Curtailed Product (in excess of the cap) will be included in the Banked Curtailed Energy
C	On-peak hours	If day ahead price is >=0	No cap	Yes	Product Price adjusted by PPAF	The Curtailed Product will not be included in the Banked Curtailed Energy
		If day ahead price is < 0	No cap	Yes	Product Price adjusted by PPAF	The Curtailed Product will be included in the Banked Curtailed Energy

OSGC Order: Over-Schedule Generation Curtailment Order, OSGC Quantity: Over-Schedule Generation Curtailment Quantity, PPAF: Product Payment Allocation Factor.
Source: SCE (2012b). Own elaboration.

Compensation is based on product price (adjusted based on PPAF) as offered by the generator. When CAISO does not award a schedule to SCE, the curtailment cap is not applied for on-peak hours regardless of the value of the day ahead price. The curtailment cap is only applied for non-peak hours and when the day ahead price is lower than zero. In this case, compensation only applies when the curtailed energy exceeds 50 hours. Under this scenario the curtailed energy (in excess of the cap) is included in the banked curtailed energy.

Summary and discussion

The RAM programme has been designed to incentivise the rapid expansion of small generators in a cost-effective way (market- based). In terms of curtailment, there is not a rule that defines the risk sharing among the main parties. SCE is working on a new method for managing the generator output based on the identification of a real time limitation setpoint for each generator. It was observed that in the case of SCE, the curtailment risk is, to some extent, transferred to the generators in specific scenarios. Due to the fact that utilities bear the market price risk (utilities pay generators a fixed price and then sell energy to the market at the market price), they would prefer to curtail generators when the market price is too low and at the same time would try to minimize compensation. The study also indicates that curtailment allocation is on a Pro Rata basis but only for maintenance purposes.

It is noted that selecting the best bidders depends not only on the price and RA, but also on the transmission upgrade costs. Transmission upgrade costs are the only ones that are not included in the bid price because these are socialised across all CAISO consumers. The transmission upgrade costs are reimbursed to the generators over a five year period through the Transmission Access Charge. Thus, generators that require distribution upgrades (based on their respective interconnection studies) for interconnecting the generating facility to the distribution system pay all the respective connection upgrade costs and have to include these in the bid price. Therefore, if a transmission upgrade is required, the investment risk is transferred to all customers; conversely, if a distribution upgrade is needed, the investment risk is transferred to the generator.

Finally, the provision of relevant information to generators such as the status of the DNO's network is essential. Interactive maps (Google Earth) - with relevant information in terms of capacity, voltage, constraint areas, among others - provided free of charge by SCE and other IOUs - constitutes an important tool to generators for making better decisions in the selection of connection points.

5. Findings

This section summarises the main findings from the four case studies. It can be seen from our analysis that the cases may seem different given their respective regulatory and market contexts; however they share significant similarities with each other in regards to what problems they are attempting to address. Table 7 summarises the key characteristics of each case study and organises the summary in four components: general information, connections and cost figures, curtailment and investment.

Table 7: Summary of Case Studies

Concept	Orkney ANM	Connect and Manage	Wind Curtailment in tie-break situations from SEM	RAM - SCE
General Information				
Type of initiative	DG Project.	System operator regime for all generators.	System operator regime only for wind generators.	DG Programme.
Access right	Only NNFG (non-firm with ANM specifications) is available.	Firm access (since the beginning).	Depending on technical conditions, access vary from non-firm to full firm access (FAQ from 0% to 100%).	Firm access.
Project allocation	First come first served under specific terms and conditions.	First come first served under specific terms and conditions.	First come first served under specific terms and conditions.	By auctions based on the PPA contract, two auctions per year.
Project size	There is no rule but generally generators < 10MW.	Variable (from small embedded generators to transmission connected generation).	Variable.	From 1 MW to 20MW (RAM1, RAM2). From 3 MW to 20MW (RAM 3, RAM 4). Aggregated generators up to 5MW.
Length of contract	Indefinite.	Variable with lifetime rights to the network. However, for wind farms is limited to 25 years.	N/A.	10, 15 or 20 years.
Contract operation date [1/]	Variable but expected to be reduced using ANM.	Variable and after minimum reinforcement costs (enabling works). Average: 4.4 years (08/2011-04/2012).	Variable depending on network conditions.	No more than 2 years after CPUC approval with 6 month extension for regulatory delays.
Type of technology	Renewables.	All technologies (renewables and non renewables).	Only wind generators.	Eligible renewables.
Availability of interactive network maps/tables providing available capacity, areas of constraints, location of circuits, etc.	SSEPD provides a list of substations with relevant information regarding capacity, voltage and areas of constraints.	N/A.	N/A.	Yes, free of charge (Google Earth application). This facility is compulsory across the IOUs.

Table 7: Summary of Case Studies *(continued)*

Concept	Orkney ANM	Connect and Manage	Wind Curtailment in tie-break situations from SEM	RAM - SCE
Curtailment				
Difference between constraints and curtailment	No.	No.	Yes. Curtailment (system issue) and constraints (network capacity issue). SEM has provided a rule set for making the distinction.	No.
Principle of access [3/]	LIFO.	Market-based mechanism.	Curtailment (proposal): Pro Rata with defined curtailment limit.	Pro Rata (maintenance). Other situations: there is no specific method.
Compensation	No compensation at all.	Generators are always compensated in the existence of network constraints (excluding those with specific bilateral contracts).	Depends on the FAQ allocated. If FAQ=100% (full compensation), if FAQ=0% (no compensation), if 0%<FAQ,100% payment is made proportionally to the allocated FAQ. The last case is only applicable in ROI.	Only applicable to economic curtailment. Use of curtailment cap (50 hours per year) when CAISO does not award a schedule to SCE (on non-on-peak hours and ahead price is negative). See Table 6 for details.
Curtailment Risks	Transferred to generators.	Socialisation of all constraint costs through BSUoS. Transferred to consumers (50%) and generators (50%).	Two stages of risk allocation: (1) Transferred to customers (through DBC) up to the achievement of renewable targets (2020 worst case) with gradual reduction of compensation due to curtailment. (2) Transferred to generators (after 2020), no compensation at all (regardless of access rights) after 2020.	The only scenario in which risks are partially transferred to the generator is when CAISO does not award a schedule to SCE (on non-on-peak hours and day ahead price is negative). In the rest of cases generators are always fully compensated (product price).
Investment				
Investment Risks	Transmission upgrades: not applicable. Distribution upgrades: Transferred to generators.	Transmission upgrades: Transferred to National Grid users through TUoS. Distribution upgrades: not applicable except for embedded generators.	Transmission upgrades: Transferred to the SOs users. Distribution upgrades: not applicable.	Transmission upgrades: Transferred to CAISO users through TAC. Distribution upgrades: Transferred to generators.

1/ In Connect and Manage the 4.4 year average refers to new transmission connected and large embedded generation for the period 01/08/11 to 20/04/12.

2/ Regarding Connect and Manage figures refer only to those projects that have already been connected. For instance, there is a total of 107 projects (transmission connected and large embedded generation) with signed agreements (total capacity: 29,762 MW).

3/ SCE is evaluating a new method for managing curtailment based on the identification of real time limitation setpoint to each affected generator.

Own elaboration.

6. Conclusions

6.1 Principle of Access

Three kinds of POA have been identified across the cases studies: LIFO, Pro Rata and Market-Based. The analyses of these case studies are examples of actual implementation of these POA. They are each different from the general situation in the GB distribution market, where only firm access is offered and curtailment due to a distribution network constraint is not an issue.

LIFO, Pro Rata and market-based each have pros and cons. All of these options represent different alternatives of how the DNOs could address the need for connection of more wind to the existing distribution system. LIFO makes economically efficient use of the available capacity in the short run, however it transfers increasing risk to the last in generator connected, and it may also compromise dynamic efficiency by making it more difficult to get agreement to increase network capacity when this becomes socially valuable. The Pro Rata approach has the advantage of reducing risk to the marginal generator, but this comes at the cost of potentially connecting too much generation behind a constraint. Setting the right capacity limit is crucial yet difficult as it needs to consider both short run and dynamic efficiency. Finally, market-based approaches – such as CM - have the advantage of allowing generators to optimally turn down their wind farms according to their costs of doing so. This has the dual advantage of encouraging generator investment in flexibility and of creating the opportunity to have system operator incentives to reduce curtailment. The problem with market-based approaches is deciding who pays the generators for curtailment – this is usually a combination of the system operator and the customer. In this scenario, risk is being transferred which requires a mechanism to absorb this risk transfer via the regulatory settlement. Additional problems are those related to the lack of competition, high transaction costs that may affect small generators and the administrative burden for a DNO to set up bidding mechanism.

6.2 Allocation of risks among the parties

6.2.1 Curtailment risks

Curtailment can impact the financial viability of the generation projects. However, this impact can be mitigated if compensation is given in exchange for the respective reduction of the generation output. From the cases studies it has been observed that usually, system operators transfer the risk of transmission connected generation being curtailed to the customers. However, for distribution connected generation, the rules are less homogeneous. SCE and SSEPD have set different approaches. The first one does allow compensation and the second does not.

6.2.2 Investment risks

The connection of generating facilities to the distribution or transmission network can be subject to network upgrades (or reinforcements). From the cases studies, it can be observed that the risk of these investments is generally transferred to the generators when an upgrade to the distribution network is required. On the other hand, when the transmission network the investment risk is transferred to the users. Thus, regulation allows the socialisation of transmission upgrades but not the socialisation of distribution upgrades.

6.3 Key lessons relevant to Distribution Networks Operators

Wind turbines embedded in the distribution network are one of the most cost effective renewable energy technologies. Hence the desirability of understanding the best commercial arrangements to facilitate the timely connection of distributed wind generation. Based on the analysis of the four cases studies we identify some key lessons:

- **Smart solutions versus conventional reinforcement :**

  One challenge is to determine the way to optimally increase generation capacity behind a constraint without making incremental network reinforcement. There is an equilibrium condition in which the option of reinforcement represents the most economically viable way to increase capacity. It is clear that current approach followed by most DNOs does not find the appropriate equilibrium point where more distributed generation is connected before triggering network reinforcement.

- **Compensation versus no compensation:**

  It is important to find the best arrangement to minimise curtailment in order to reduce the possibility of paying compensation to generators. Distribution network reinforcements could be an option (depending on the associated costs and the number of generators that seek for connection) for mitigating the risk of curtailment. This will attract the interest of generators. However, some degree of curtailment risk mitigation for the generator would seem to be reasonable.

- **Publishing interconnection/connection maps as a way for encouraging connections to less congested points:**

  DNOs in general - should consider seriously providing more transparency on the status of the network. They can take advantage of this facility as a tool to provide not only valuable information for generators for the selection of the most convenient connection points, but also for accelerating the evaluation process conducted by the DNOs.

- **Stakeholder engagement matters:**

  Stakeholder engagement has been a key point that contributed to the projects' respective successes. There is a clear evidence of stakeholder engagement especially in the Orkney ANM project implemented by SSEPD and the RAM programme implemented by SCE. A main point, especially in the Orkney ANM project, has been to provide certainty and confidence to generators when talking about non-firm access to the grid. Thus, DNOs should try to promote stakeholder engagement by encouraging active participation of key parties in the development and implementation of DG projects.

- **An Auction mechanism an alternative way for procurement renewables with focus on small generators (up to 20MW) in which price and connection costs are bid:**

  The RAM scheme implemented by the CPUC is an interesting option to procure capacity with focus on small generators. This initiative encourages the early implementation of those projects with the lowest network upgrade costs, which has a positive impact on consumers due the lower transmission access charges. Thus, a regional auction mechanism for procurement of small scale renewables can be seen as a potential option for DNOs to accelerate the connection of the most cost-efficient projects. The government may be encouraged to implement such a scheme to be run by local DNOs. The capacity to be allocated per auction can be determined based on the specific renewables targets that have been set in the UK. However, this option may add more complexity to the energy procurement process in terms of implementation when there is not enough demand. There is further analysis to be done to understand how that could be implemented in the UK context.

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