Experience of the use of smarter connection arrangements for distributed wind generation facilities

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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 the United Kingdom, 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 Power Networks to address the issue of increasing the connection of distributed generation while managing efficiently and economically energy exports from generators in the context of the Flexible Plug and Play Low Carbon Networks trial.

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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. The connection of generation facilities to the distribution network is generally referred to as "distributed generation (DG)"[2]. There is no agreement in the definition and boundaries of distributed generation. It can vary across countries and regions as a result of differences in the operating voltage in which the connection is established and in the size of installed capacity[3]. 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)[4]. However, the provision of ancillary services (from distributed generation) and the implementation of smart solutions may facilitate the integration of generators into the distribution network. The increase of DG is directly related to the renewable energy targets that have been set in order to guarantee security of supply without dependency on fossil fuels, to reduce the greenhouse emissions and to increase diversity of technologies. In order to meet these targets, regional and national regulation subsidy schemes have been maintained or introduced in various forms[5]. Feed-in Tariff (FIT) and its different variants[6] and quota obligations (QO) are the most widely adopted forms of incentives. FIT are price-based mechanisms while QO are volume-based mechanisms. Some examples regarding the QO are the Renewable Obligation (RO) in the UK and the Renewable Portfolio Standard (RPS) in US. Currently both approaches tend to be technology–specific. Banding is introduced under which QO are allocated per MWh of electricity based on the kind of renewable technology[7]. Other incentive mechanisms include investment subsidies, tax credits, green electricity tariffs and donation projects (EWEA, 2005). In general, all these incentives 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.

[2] 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.

[3] Generally in Europe the distribution grid can be categorised into high voltage distribution grid (60-110 kV), medium voltage distribution grid (10-60 kV) and low voltage distribution grid (230/400 V). The transmission segment operates typically at voltage levels higher than 110 kV. The majority of distributed generators are connected to the distribution grid; Cu (2006). In the US, a similar categorisation is observed. In the UK, the high voltage transmission system operates at typical voltages of 132kV, 275kV and 400kV. For further details see Section 4.1.1.

[4] Section 1.2 provides further details related to the differences between transmission and distribution networks.

[5] Targets vary across countries and sometimes even by states (US). For instance, the European Union under the 2009 Directive on renewable energy has set specific targets for EU-27 by 2020. Norway (67.5%), Sweden (49%) and Finland (38%) are those with the highest targets of renewable energy share (as percentage of gross final energy consumption). Source: Eurostat. In the US under the Renewable Portfolio Standards, several states have also set renewable energy targets by 2020.

[6] Fixed FIT, Premium FIT and contract for difference FIT. For further discussion see EWEA (2005).

[7] Banding (a range of values) is introduced in order to distinguish the different levels of support that renewable generators receive based on the type of technology. Banding is required as a result of the differences that exist across technologies such as those related to planning, implementation costs and level of maturity of technology. For further details related to the bands applicable in the UK see Section 4.1.2.

1.2 The problem and an alternative solution

As a result of their low short run marginal costs (zero fuel costs), wind generation has played an important role in the expansion of renewable energy. However, transmission operators and ultimately distribution operators have to deal with specific issues in order to integrate these generators efficiently to the electricity network. In contrast with the transmission networks, distribution networks are characterised as being passive: once built there is limited intervention. Distribution networks require a lower level of monitoring, control and supervision in comparison with the transmission network. They need to satisfy a demand that is already known and does not need to make any kind of energy balancing exercise such as that required by the transmission firms. Thus, transmission networks require operating more actively, with automatic and manual interventions (Bollen and Hassan, 2011, p. 371). The distribution network was not initially designed to accommodate generation. In contrast with the transmission networks which were designed to accommodate generation and to transport electricity to load centres in a semi-active or active way (with the integration of power electronics)[8]; distribution networks were designed to transport electricity from loading centres to end customers (unidirectional power flow) in a passive way.
Thus, by connecting more generation to the distribution network, operation 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)[9]. 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). Results from a survey conducted among European Union Member States shows that the contribution of distributed generation to the provision of ancillary services is very low and is limited to reactive power control and energy balancing (Cossent *et al*., 2009).

Georgilakis (2008) states that the impact on the system operating costs for integrating wind generators 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 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. The costs of variability and predictability have been analysed in the US. It can be observed that when installed capacity of wind is less than 5%, the cost due to uncertainty is negligible. However, for a penetration level of around 23%, the costs per household would not exceed tens of dollars per year. This result is in line with Georgilakis' (2008) findings. Corbus *et al.* (2009) evaluate the operational impact of large amounts of wind on the Eastern Interconnection in the US. The study demonstrates that wind integration costs are driven mainly by the costs of additional reserves due to variability of wind rather than uncertainty; which means that the mechanism for scheduling reserves impacts the cost of integration.

[8] See: http://www.iea.lth.se/publications/Theses/LTH-IEA-1050.pdf.
[9] Improvement in energy loss is usually seen as a positive impact of DG due to the short distance between the generation site and the end customer equipment. This statement is valid for low DG penetration levels. Following Mendez *et al*. (2006), at high DG penetration levels a reversion of power flow can be originated when the output exceeds the demand. This would produce an increase in energy loss due to wind power.

From the previous discussion, it is noticed that an efficient integration of 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[10] the level of wind generation behind an individual node[11] 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)[12] and Active Network Management (ANM)[13]. 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)[14]. Results from Michiorri *et al*. (2011) on SSE'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)[15], Orkney Project

[10] Curtailment is related to the reduction (total or partial) of the generator output. For further details regarding curtailment see Section 2.

[11] A node refers to a point in the network at which two or more elements are interconnected. See: http://ocw.mit.edu/courses/electrical-engineering-and-computer-science/6-061-introduction-to-electric-power-systems-spring-2011/readings/MIT6_061S11_ch1.pdf

[12] In contrast with the standard practices applied by the system operators in which thermal limits are established under seasonal worst-case assumptions (static limits), DLR allows the measurement of changing environmental conditions and updates the system models accordingly, allowing increases in the transmission capacity limits beyond what would otherwise be the case under conventional (conservative) fixed limits. The main determinant of a line's thermal limit is the average conductor temperature, which can be computed mainly by two sensors: one that measures line tension and the other that measures air temperature. DLR is very convenient in the integration of wind generators to the transmission line, especially in strongest wind conditions. This is when DLR can importantly improve the transmission capacity (MIT, 2011, p. 46).

[13] ANM allows the use of the dynamic capacity in a secure and controllable way and facilitates the non-firm or interruptible generator connections. For further details see Currie *et al.* (2011).

[14] These results refer to the implementation of DLR and ANM on the 70 kV rural networks.

[15] Twenties is a wind power project composed of 26 partners including transmission system operators, generation firms, manufacturers and research organisations in the electricity sector. A total of eleven countries (ten European member state

(UK), Skegness Project (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 in the US has shown that only 0.5% of the electric service providers were equipped with DLR systems (DOE, 2009), 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 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). Hence, such smart commercial arrangements are the ways in which the financial flows arising from more dynamic curtailment are allocated – as such they incorporate a physical curtailment rule and an associated financial payment rule. The way curtailment is allocated will influence the distribution of risks among parties (DNOs, generators and customers). Thus, rules regarding curtailment matter. Rules related to the transmission system operators are clearer and more transparent (curtailment language is much more common with respect to transmission than with respect to distribution). The lack of clear and transparent rules means that DNOs have to determine their financial and economic approach to the dispatching of renewable energy (such as wind) bearing in mind their own regulatory incentives and market rules, and hence their approach may not be in the best interests of society. We discuss this further in Section 2.

1.3 Flexible Plug and Play Project

In light of these facts, this report forms part of the Flexible Plug and Play Low Carbon Networks (FPP)[16] project led by UK Power Networks. The aim of the project is to trial innovative and cost-efficient technical and commercial solutions to integrate distributed generation to the electricity distribution network. In addition, Flexible Plug and Play also seeks to develop novel non-firm commercial arrangements with wind generators to support their rapid connection to the network. This will be accomplished by offering more cost effective alternative connections in a quicker manner. However, the implications of non-firm connections should consider the allocation of risks among parties (UK Power Networks, generators and customers).

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and one associated country) are involved in this initiative. The total budget is around €56.8 million with €31.8 million as EU contribution. For further details see: http://www.twenties-project.eu/node/1

[16] The project has a total costs of £9.2 million from which £ 6.8 million has been awarded by OFGEM under the Low Carbon Network Project, £ 2 million contribution from UK Power Networks and £ 1 million from the project partners (Cable&Wireless, Alston Grid, Silver Spring Networks, Smarter Grid Solutions, GL Garrad Hassan, Imperial College London, Institution of Engineering and Technology, Fundamentals, Converteam and University of Cambridge). The project is being deployed in an area of around 700km^2 in Cambridgeshire. The duration of the project is 2 years (from January 2012 to December 2014). The project is composed of eight Workstreams with specific tasks allocated to the project partners (UK Power Networks, 2012a). For additional details see: http://www.ukpowernetworks.co.uk/internet/en/innovation/fpp/

1.4 This report and its objectives

The Electricity Policy Research Group (EPRG) from University of Cambridge is the project partner responsible for exploring and analysing different case studies of commercial arrangements that involve the allocation of curtailment, or so called Principle of Access,[17] in response to network constraints. Case studies have been selected as the research method which in comparison with other methods will allow a comprehensive understanding of the key issues associated with the different options of commercial arrangements. Thus, the aim of this report is to explore a select number of case studies, domestically and internationally, in which the practice of curtailment methods can be clearly identified in response to network constraints. The countries that are part of this study are Ireland, the United States of America and the United Kingdom[18]. The case studies refer to renewable projects, programmes or to any other initiatives that have been implemented or recently proposed. This report will assess each case study based on (1) the commercial and regulatory framework governing the allocation of curtailment costs between network operators, network owners, generators and customers and (2) the interaction between curtailment costs and network investment decisions (i.e. anticipatory investment, system operator incentives). A general analysis of the regulatory framework and the form of curtailment applied is also discussed for each case study. The case studies have been selected with reference to their relevance to the UK Power Networks objective of understanding different alternatives to address the problem of network management and commercial implications of curtailing generation. This report does not limit the analysis to those that have implemented smart solutions or those with curtailment methods at the distribution level. Case studies that involve more passive arrangements or curtailment methods at the transmission level have also been included in the analysis. These case studies can give valuable insights regarding the different options for allocating curtailment under network constraints.

The structure of the report is as follows: Section two provides a brief explanation of the meaning of curtailment, categories, the different types of curtailment allocation, risk allocation, social optimality and the way curtailment impacts different parties. Section three explains the criteria for the selection of case studies and the way the analysis is structured. Section four discusses each case study based on the selection of specific criteria such as form of curtailment, regulatory environment, allocation of risk among the main parties and the relationship between curtailment and investment decisions. Section five identifies the findings and lessons learned 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 UK Power Networks; in addition it outlines next steps.

[17] Following Currie *et al.* (2011), Principle of Access refers to the set of commercial rules for allocating constrained capacity using smart solutions such as Active Network Management (ANM).
[18] Section 3 explains the selection criteria.

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

The term curtailment is generally associated with the partial or full reduction of the generator output in a situation with network constraints. 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). A number of different principles of access can be identified, such as 'last in first out' (LIFO) where the generator connected last behind a constraint would be the first to be curtailed in the event of a capacity constraint. It is noteworthy that these rules are separate from the allocation of risk among the parties in the sense that rules of physical curtailment can be financially hedged, so that their financial and overall economic implications are different, e.g. where a DNO operated LIFO to physically manage its constraints but offered full insurance against financial losses to constrained generators. Different POAs , as discussed below, have different overall economic and social efficiencies associated with them. Curtailment is described by the Single Electricity Market from Ireland and Northern Ireland (SEM, 2012a, p. 4) as "*the term (that) applies to situations whereby generation is dispatched down from a level at which it would otherwise wish to run, typically for a reason other than a transmission constraint*". It states that curtailment of wind generation happens when there is excess of wind generation available to meet system demand; thus, curtailment is a system operation issue and should not be related to network capacity. On the other hand, constraints are a different type of event which is linked to the availability of the network. However curtailment and constraints raise similar technical and financial issues.

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 Study).

2.2 Categories

There is no common way of categorising curtailment. Following ICF (2012), curtailment can be classified as either voluntary or involuntary. The former classification consists of (1) reliability based curtailment (in which renewable generation is curtailed in order to preserve system reliability and to relieve overloads in the system) and (2) environmental curtailment (in which renewable generators or others are curtailed in order to allow the use of specific resource– such as free federal hydropower)[19]. The reliability based curtailment is one of the most popular among transmission system operators and DNOs. The latter classification occurs when a) there is more supply than demand – energy surplus) or when b) renewable generation is curtailed in lieu of turning off other generating facilities such as coal or nuclear for economic reasons. Involuntary curtailment is less likely to be accepted across the European Union Member States because, based on the 2009

[19] This is a very specific case applied to Pacific Northwest System Operator in the US.

Renewable Directive; renewable generation has priority access over conventional sources of generation.

In terms of wind curtailment, the National Renewable Energy Laboratory (NREL, 2009b, pp. 1-2) has identified the following categories of curtailment such as: (1) curtailment as a condition of generator interconnection: when generators accept to be curtailed if there is a requirement due to transmission constraints or specific system conditions, (2) contractual curtailment: typically those agreed in power purchase agreements between utilities and wind generators, (3) bid-based curtailment: such as that applied in the New York Independent System Operator (NYISO) in which wind generators are allowed to bid price that includes their willingness to curtail operations, (4) based on the type of wind technology: applied by the Electric Reliability Council of Texas (ERCOT) in which a distinction is made between wind farms with rapid response (RRWR) and those wind farms with slow responses (SRWF); for instance RRWF are allowed to operate above the daily limit but SRWFs are not and (5) based on reserves: applied in Bonneville Power Administration (BPA) in which a curtailment situation is considered if 90% of the BPA's balancing reserves have been utilised.

2.3 Allocation Rules

Different ways for allocating curtailment have been proposed. 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)[20]. The last on the list (based on the ranking) is the first to be disconnected under a network constraint. The LIFO mechanism has been applied in both the Orkney and Skegness projects in UK which is discussed in Section 4.1.3. 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, Currie *et al.* (2011). 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. Nor is LIFO seen to be fair. In the United States of America, for instance, the Federal Energy Regulatory Commission (FERC) requires that curtailment (applied by transmission providers) be made on a "non-discriminatory basis" for firm and non-firm, and LIFO is not allowed[21]. 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. FERC supports this kind of curtailment allocation for both firm and non-firm services. A recent consultation for managing curtailment in tie break situations[22] conducted by the Single

[20] A different approach of curtailment allocation is discussed in Jupe *et al.* (2010), in which the curtailment of the generators is technically ranked by the magnitude of Power Flow Sensitive Factor (PFSF).
[21] See Order 888, FERC Stats. & Regs. ¶ 31,036, 31,749 (1996); Order 888-A, FERC Stats. & Regs. ¶ 31,048, 30,180 (1997).
[22] Section 4.2.3 defines tie-break situations.

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. Based on the current UK rules regarding curtailment and compensation mechanisms, Scottish and Southern Energy (SSE) has shown that under a Pro Rata approach the costs regarding energy production and curtailment compensation will be €113m lower in 2020 than under LIFO (SSE, 2012, p. 6).

(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 (i.e. the carbon footprint per type of technology). These other rules do not need to be considered because they are hypothetical principles of access that lack a theoretical underpinning in economic efficiency and are, to our knowledge, not in use or under consideration in any jurisdiction.

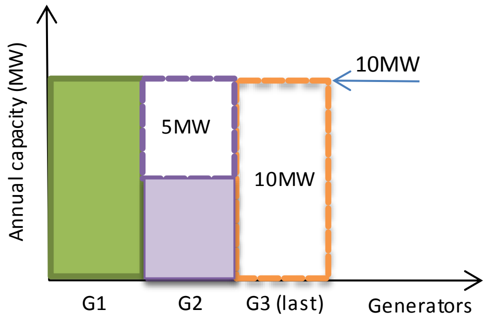
2.4 Risk Allocation among generators

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. The following figure 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 15 MW (maximum level of curtailment). G1 was the first generator to be connected and G3 the last.

Figure 1: Example of risk allocation

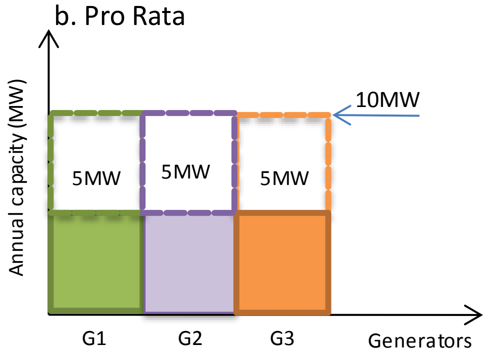
Allocation Rule	Notes

a. LIFO



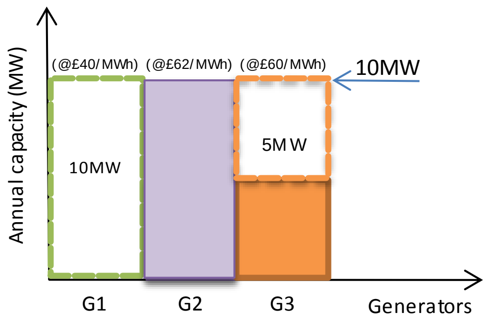
G3 is the first generator to be curtailed up to 10MW then G2 up to 5MW. Maximum level of curtailment is 10MW + 5MW = 15 MW. G1 is not affected.

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).

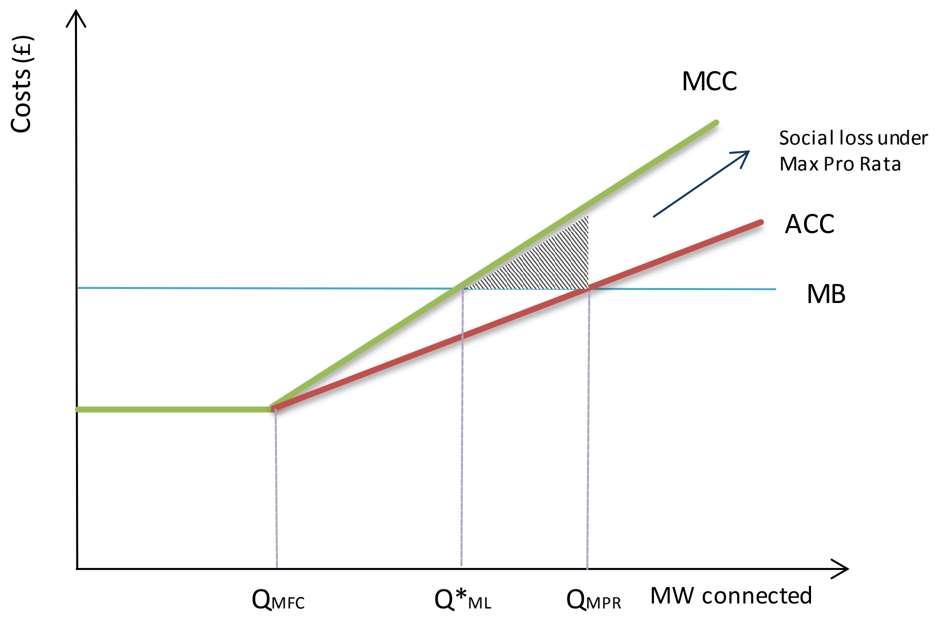
Own elaboration.

If the line capacity to export wind (which is a function of temperature and line availability) averages 30 MW but is 15 MW 10% of the time and 45 MW 10% of the time, it is interesting to understand the behaviour of the different risk allocation scenarios. Under LIFO G3 is curtailed by 10 MW 10% of the time, whereas under Pro Rata and Market- Based G3 is curtailed by 5 MW 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.

2.5 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 connectio cost, **MB**: Marginal benefits, **Q_{MFC}**: Max firm connection, **Q^*_{ML}**: Max LIFO, **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. LIFO makes sense if all the generators are assumed to be the same. However, LIFO may not accurately reflect the order of curtailment costs. For example the older generators may be less reliable and require more maintenance and hence it may be cheaper to switch them off during constraint periods (especially during very windy days). 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.

2.6 Impact

High levels of curtailment can have a significant impact on generators' revenues. A study conducted by the National Renewable Energy Laboratory (NREL) indicated that at 5% or more curtailment revenues and Debt Service Coverage Ratios (DSCRs) of wind generators deteriorate[23]. Regulation therefore plays an important role in the impact of curtailment. In some cases, when compensation or other benefits are allowed, the economic losses can be mitigated. For instance, in the case of Ireland, discussed in section 4.2, wind generators with non-firm connections are not compensated, however those with firm connection are eligible to receive market price compensation in the form of constraints payments (SEM, 2011). A situation could arise where generators prefer to pay grid

[23] See: http://www.renewableenergyworld.com/rea/news/article/2012/03/impact-of-curtailment-on-wind-economics

operators (to avoid curtailment) in order to take advantage of benefits such as Production Tax Credits (PTC) and Renewable Energy Certificates (REC). Finally, the impact of curtailment can also be transferred to end customers when the costs of curtailment are socialised. Thus, customers have to incur in those costs.

3. Case Study Selection Criteria and Structure

3.1 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 UK Power Networks. 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 report. The following table summarises the list of case studies covered.

Table 1: List of Case Studies

Country	Wind Figures [1/]		Case Study	Type of initiative
	Installed capacity (MW)	Share on electricity generation (%)		
United Kingdom	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 [2/]	4,570	4.1%	Renewable Auction Mechanism	Programme

[1/] For further details see Sections: 4.1.1 (United Kindgdom), 4.2.1 (Ireland and Northern Ireland), 4.3.1 (United States)

[2/] Regarding California

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

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.

3.2 Structure of the Case Studies

Each case study discusses four main topics which capture the relevant information that is needed to evaluate the respective experience. However, due to the heterogeneity of the cases studies, further concepts have also been analysed in order to take advantage of the additional potential lessons learned.

Firstly, it is important to understand the regulatory environment in which the different renewable projects, programmes or other related initiatives are implemented. Thus, a revision of subsidy mechanisms (such as Feed-in Tariffs, quota obligations, or renewable tenders) has been conducted to have a better approach to the interaction between specific compensation mechanisms. In addition, we discuss the electricity market structure with the aim of understanding the way in which distributed wind generators facilities fit in it. We have also revised the curtailment rules applied to the specific transmission operators.

Secondly, bearing in mind that the aim of this report is to explore innovative commercial arrangements under network constraints, it is important to understand the meaning of curtailment under the context of each case study. As previously mentioned in Section 2, this will allow us to make proper comparisons among the different experiences.

Thirdly, the risk allocation and order of curtailment is also a key point for understanding the distribution of risks among network operators, generators and customers. In this section, the commercial interface between network owners or operators and generators in terms of the order of curtailment will be explored when applicable.

Fourthly, the relationship between curtailment cost and network reinforcement will be assessed. In this section, we want to analyse the link between increased curtailment of generation and the decision to invest in the network. The priority that is given to reinforcement and investment costs for maximising social welfare and minimising risks will be analysed. This is important to understand the dynamic interaction between curtailment now and future investment in reducing curtailment, as part of long term efficiency.

4. Case Studies

4.1 United Kingdom Case Study

In this section, two case studies from the UK 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). Taking into consideration the different incentives that generators, distribution network operators and transmission operators have for promoting the connection of renewables in the electricity network, it is worth describing the main support mechanisms. To put these cases in context, a short description of the UK electricity market is given.

4.1.1 Electricity Market

The electricity market in the United Kingdom is composed of four sectors: generation, transmission, distribution and supply. Generation and supply are opened to competition and transmission and distribution are regulated markets. In England, Wales and Scotland, six major energy firms[24] dominate the supply electricity market with a participation of 99% in the domestic supply and 67% in the wholesale market (DECC, 2010a, p. 11). A total of 14 firms (DNOs) run the regional distribution networks: 12 in England and Wales and 2 in Scotland[25]. Six different groups own the 14 DNOs. National Grid Electricity Transmission (NGET) is the System Operator. The transmission grid consists of approximately 25,000 circuit kilometres of high voltage overhead lines and operates at typical voltages of 132kV (only in Scotland and offshore), 275kV and 400kV. The regional distribution networks is composed of around 800,000 circuit kilometres of overhead lines and overground cables and operates in the following voltages: 11kV, 33kV, 66kV and 132kV[26]. Price controls for regulating the 14 DNOs and the 3 transmission firms[27] are set through five-year periods by the Office of the Gas and Electricity Market (OFGEM). The current price control runs from 1 April 2010 to 31 March 2015 for distribution (DPCR5) and from 1 April 2007 to 31 March 2013 for transmission (TPCR4)[28].

The Energy Trends Publication from DECC (DECC, 2012c) indicates that a total of 84.4 TWh of renewable generation was reported as connected in the second quarter of 2012. This represents a

[24] Scottish Power, Centrica, RWE Npower, E.ON, SSE and EDF.
[25] In addition four independent network operators run smaller networks.
[26] See: http://www.decc.gov.uk/en/content/cms/meeting_energy/network/network.aspx
[27] NGET for England, Scottish Power Transmission Ltd (SPTL) for southern Scotland and Scottish Hydro-Electric Transmission Ltd (SHETL) for northern Scotland.
[28] This period reflects the one year "adapted roll-over" of the current price control for the period from 1 April 2012 to 31 March 2013 that has been authorised by OFGEM. See section 4.1.4 for further details.

reduction of 0.5% in comparison with the earlier year. The share of electricity generation is as follows: coal (36.1%), gas (29.8%), nuclear (21.9%), renewables (9.6%), oil (0.9%) and other (1.6%). In relation to the share of renewables, bioenergy[29] has the highest share of generation (38%), followed by onshore wind (26%), offshore wind (20%) and hydro (17%). In addition, the DECC Publication also shows that the UK's electricity renewable capacity was around 14.2 GW. Onshore wind had the highest share (38%), followed by bioenergy (23%) and offshore wind (18%).

4.1.2 Support Mechanisms for Renewables, Distributed Generation and Distribution Network Operators

In this section, three support mechanisms associated with wind generation are discussed: Renewable Obligation (RO), Feed-in Tariff (FIT) and the new Contract for Difference Feed-in Tariff (CfD FIT). In addition, mechanisms for promoting distributed generation are also described. Since 2002, the RO is the main mechanism that has been used in the UK (from 2005 in Northern Ireland). OFGEM administers the RO and DECC is responsible for setting the level of the obligation. Under this mechanism, a quota obligation is imposed on electricity suppliers regarding the share of electricity from renewable generation they deliver to consumers. Renewable Obligation Certificates (ROC) - tradable green certificates - are issued to qualified electricity generators[30]. Initially, one ROC was allocated for one MWh of renewable production, but in April 2009 banding was introduced[31]. Electricity suppliers purchase these certificates from electricity generators in order to meet their obligation. If electricity suppliers are not able to meet their obligation, they should make a buy-out payment to cover the number of pending ROCs[32]. The RO replaced the previous Non Fossil Fuel Obligation (NFFO) which was based on a bidding mechanism[33].

In July 2011, the Electricity Market Reform White Paper was introduced. The reform package involves four key elements, including the introduction of new long-term contracts for low carbon electricity generation[34]. CfD FIT was the mechanism selected for low carbon electricity generation. Under this mechanism, generators receive a top-up payment when the market price (reference price) is below the strike price (a pre-agreed level). By contrast, if the market price is above the strike price, generators have to pay back the difference. Thus, when electricity prices are higher than the agreed tariff, generators have to return money to consumers. CfD FIT will be introduced in 2014

[29] Composed of: landfill gas, sewage gas, biodegradable municipal solid waste, plan biomass, animal biomass, anaerobic digestion and co-firing (generation only); (DECC, 2012c, p. 44).

[30] There are two types of mechanisms for determining the quota systems: tendering systems and tradable green certificate systems.

[31] The allocation of one ROC by one MWh is not valid anymore. There is a differentiation based on the type of generation technology. Four bands were adopted in 2009: (1) technologies in the established band (0.25 ROCs/MWh), technologies in the reference band (1 ROCs/MWh), technologies in the post-demonstration band (1.5 ROCs/MWh) and technologies in the emerging technologies band (2 ROCs/MWh). For instance for onshore wind and offshore wind the allocated figures are 1 and 1.5 ROCs/MWh respectively. See: http://chp.decc.gov.uk/cms/roc-banding/

[32] For instance for the period 2012-2013 the buy-out price has been set in £40.71 and the ROC per MWh of electricity supply are 0.158 (England, Wales and Scotland) and 0.081 in Northern Ireland (OFGEM, 2012, p. 2).

[33] The NFFO mechanism had significant drawbacks such as: (1) delays in building a project, (2) the absence of penalties when generators failed to install the agreed capacity, (3) unrealistically low offers and hence unprofitable bids and (4) the selection of site without considering the local environmental impact (EWEA, 2005, p. 33).

[34] The three additional key elements are: (1) the establishment of capacity mechanism - a decision for selecting the capacity market mechanism was made in the December 2011 Technical Update from DECC, (2) the setting of the emissions performance standard (EPS) at 450g CO_2/kWh and (3) the legislation of a carbon price floor.

and until March 2017 the generators will have the chance to select between RO and CfD FIT schemes. RO will close to new accreditations after March 31 2017 and the RO lifetime will not be extended beyond 2037 (DECC, 2011b, p. 124).

The cost-effectiveness of the CfD FIT mechanism was measured by DECC as follows: (1) reduction of cost of capital in comparison with business as usual - overall saving of £2.5 billion over the period up to 2030, (2) reduction in the overall cost of support to customers and (3) lower consumer bills – by 2030 under CfD FIT reduction of increase in bill levels would be around 6% and under Premium FIT between 1 and 5% only (DECC, 2011b, pp. 41-43).[35]

FIT was introduced in April 2010 and is applicable to small-scale generators (less than 5MW) which received a guarantee payment from an electricity supplier (for the electricity they generate and use) and for the electricity they export to the grid (in case of surplus)[36].

Originally there were two mechanisms which promote distributed generation and innovation by DNOs: Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ)[37]. Both of these mechanisms were introduced and funded by OFGEM. IFI and RPZ were introduced in 2005 within the Distribution Price Control Review (DPCR4) in addition to the Distributed Generation Incentive. Further details and description of these two initiatives are given in the Orkney ANM project, which benefitted from these.

4.1.3 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. Each circuit is composed on three overland sections with a total of 10 km and two subsea cable crossings with of 40 km (DTI, 2004, p. 5). Before the implementation of smart solutions, two categories of connection were identified: Firm Generation (FG) and Non-Firm Generation (NFG). FG is the conventional “fit and forget” generation. This is the first group of generators already connected to the Orkney system that account for 26 MW. The capacity limit is based on N-1 subsea cable circuit capacity plus the minimum demand (6 MW). NFG provided 20 MW of further capacity which is based on both subsea circuits plus the minimum demand. Inter-tripping arrangements for disconnecting NFG are utilised in the event of loss of either subsea cable circuit from Orkney to the UK mainland if the power output exceeded the capacity of 20 MW (Currie *et al.*, 2007). Currently, FG and NFG capacity have been fully taken up by contracted generators and amount to 47 MW. 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

[35] These figures and their interpretation was strongly criticised by Platchkov *et al.* (2011) and in Pollitt (2012).

[36] A reducing FIT mechanism for solar and non-PV technologies has been proposed. From October 2012 solar PV feed-in-tariffs will be revised on quarterly basis by OFGEM based on the rate of deployment per kind of band (baseline degression of 3.5% every three months), (DECC, 2012a, p. 5). For non-PV technologies (wind, hydro and AD installations only), the degression mechanism will become effective from April 2014 and will occur on an annual basis (baseline degression of 5% each year) with a possibility of an additional degression if the deployment significantly exceeds expectations during the first 6 months of the year (DECC, 2012b, p. 9).

[37] IFI has been extended up to the end of the present price control review. In 2010 the RPZ scheme has been replaced by the Low Carbon Networks Fund.

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 (31 MW). The following table 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) FG= (2-1) *20 + 6 = 26 MW			NFG= N*circuit capacity + local minimum demand - FG NFG = 2*20 + 6 - 26 = 20 MW			NNFG= N*circuit capacity + local maximum demand - FG - NFG 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.

It is noteworthy that the maximum economically viable capacity under NNFG-ANM initially was 15MW. This amount was computed by Scottish and Southern Energy Power Distribution (SSEPD). Further studies show that the maximum capacity is around 25MW (Currie *et al.,* 2006) [38].

Currently, new generation connections to the Orkney network above 50kW are only available as NNFG. As explained before, this is the only option because FG and NFG are fully allocated. This means that the commercial agreement for connecting NNFG involves ANM and a constraint policy, (SSEPD, 2012c, p. 14). An alternative would be 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 NNFG connection would have incurred the following costs: (1) Pro Rata central control system – proportioned on a generation output basis [£5,000/MW], (2) site specific monitor points usually shared by the number of generators that are connected to the pinch point [£214,500], (3) full site specific local control SCADA [£35,750], (4) others such as utility bills and local connection charges. It can therefore be surmised that the only costs linked to capacity

[38] Results from Currie *et al.* (2006) suggest that under specific assumptions in terms of total capital costs (£ 920,000), discount rate (10%), revenue for combined energy sale and ROC's (@ £40/MWh and @ £60/MWh) the incremental annual output is reduced from 3,400 MWh to 2,300 MWh (@ £40/MWh) and to 1,533 (@ £60/MWh). These figures provide an indicative of the economic limit on generation development.

are those related the central control system, the rest of the costs are fixed. If the worst case scenario (in which there is only one generator on the pinch point) were to occur, a 1MW developer could incur the following costs: £214,000 + £5,000 + £37,750 + other charges (telephone, local connection charges) = £ 400,000 (worst case)[39]. Thus, one developer that only asks for a 50KW connection would also incur similar costs to a developer requesting a 1 MW connection, which represent significant costs for a small generator[40].

The previous finding is in line with the conclusions from Flexible Plug and Play's Stakeholder Engagement Report[41], in which some small developer generators describe the issue of curtailment 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, 2012b, 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)[42].

As previously mentioned, the Orkney ANM project has benefitted from the IFI, RPZ and DG incentives. The aim of the IFI is to encourage research and development in DNOs' activities. Under this initiative, 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 aim of RPZ was to encourage DNOs to develop and implement innovative and cost-efficient ways for connecting generation to their networks. The RPZ can be seen as an extension of the DG incentive that was also introduced within DPCR4. 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[43]. 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

[39] 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).

[40] At it was mentioned before, new NNFG are available for generators with 50kW or higher.

[41] See: http://www.ukpowernetworks.co.uk/internet/en/innovation/documents/%20WS05.P0180.FPP.StakeholderEngagementReport1v051012.FINAL%20

[42] For instance, based on the generator experience it was reported that one day of lost production covers the costs of a new radio link investment. Average curtailment has been between 1% and 2% mainly during low demand periods such as summer night time (KEMA, 2012, p. 15).

[43] 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: such as O&M allowance (£ 1.00/kW/yr), network access rebate to be paid to generators at high voltage or above (£0.002/kW/hour), high cost project threshold (for those projects that require reinforcement costs in excess of £200/kW), among others (OFGEM, 2009, p. 18).

of operation by £3/kW[44]. Table 3 illustrates the benefits that the DNO has received due to the capacity connected up to March 2012. The cumulative capacity connected was around 13.1MW and taking into consideration the DG incentives of £1.5/kW/yr (period 2009/10) and £1.0/kW/yr (period 2010/11 onwards) and the RPZ incentive of £3/kW/yr (period 2009/10), a total of £ 13.1k has been awarded in the last period. The table also shows the incurred connection costs per year. The lowest ratio (£28.1/kW) is observed in the last period[45].

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)

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 at the end of the day will depend on 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 (this will depend on the kind of arrangement that distributor operators can voluntarily propose). Currently in the UK, compensation for curtailment at distribution level is not regulated and hence cannot be passed back to customers, as opposed to the arrangements at the transmission level where curtailment costs can be recovered through the Balancing Mechanism (BM) via Balancing Services Use of System (BSUoS) charges.

Summary and Discussion

Specific incentives have encouraged the implementation of smart solutions that contribute to the expansion of distributed generation. The Orkney ANM is a project that has benefited from different incentive mechanisms such as IFI, RPZ and distribution generation incentives. An interesting discussion exists around whether these incentives are good enough to encourage DNOs and generators to reinforce and to plan their network 'smartly'. It is important to find the right balance between the allocation of risks between the main parties (generators, DNOs and consumers). In the case of the Orkney ANM project, the introduction of smart technologies has contributed to find the right balance between parties.

[44] For further details regarding IFI and RPZ projects see: http://www.ofgem.gov.uk/Networks/Techn/NetwrkSupp/Innovat/ifi/Pages/ifi.aspx

[45] Among the reasons that can support the low unit costs in comparison with the unit connection costs for the previous periods, could be the size of generators (these are small generators, around 0.9 MW) and the possibility of sharing connection facilities, which reduces connection costs per generator.

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). The project has demonstrated that the initial contracted capacity under new non-firm generation increased from 15MW to 25MW. A key challenge is how to optimally increase generation capacity behind a constraint versus carrying out traditional reinforcement. There is an equilibrium condition in which the option of reinforcement represents the most economically viable way for increasing capacity. As a complement to this, further development[46] 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 this sense, a deposit is required for ensuring commitment to the project's development. One of the main advantages of this method is its simplicity. However, if the number of generators increases, the picture gets more complex because the maximum hours of curtailment will always depend on the stack order of the generator, which is not known upfront. 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. In the UK, 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[47]). 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. The project has also shown that stakeholder involvement matters. An early involvement with the main stakeholders (especially with developers) was a key factor for the project success. In addition the distributed generation forum convened by OFGEM is also a way to capture the main concerns of generators regarding their experience of getting connected.

[46] Including but not limited to smart solutions.

[47] Among other options is the use of different technologies, such as broadcasting, where point to point connections are avoided due the high associated costs. In general, communication systems for connecting NNFG sites with ANM sites have been one of the main concerns.

4.1.4 Connect and Manage Case Study

A DECC (2009, p. 9) consultation paper on improving grid access proposed a number of different approaches to transmission access[48]. Subsequently, the Government selected Connect and Manage (CM) with socialised costs[49] as the most suitable option (DECC, 2010b, p. 3). This approach commenced on 11 August 2010 and replaced the previous Invest and Connect regime (prior to May 2009)[50] and the temporary Interim Connect and Manage (ICM) which promoted the connection of new generating facilities from May 2009 to August 2010[51]. Under CM generators (embedded or directly connected) are offered the opportunity to connect to the transmission network in advance of the completion of the wider transmission reinforcement works[52]. 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, 2012b, 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. Changes were mainly made to the Connection and Use of System Code (CUSC), the System Operator Transmission Owner Code (STC) and Standard Licence Condition (SLC). In addition, derogations from the planning criteria of National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) have been proposed in order to allow the connection of new generation in advance of the completion of the wider works. The kind of work that is required for advancing connection is classed as “enabling works”. The criteria for identifying enabling works can be found at the new Section 13 of CUSC. These criteria are based on those criteria cited in the NETS SQSS Chapter 2 (Design of Generation Connection), which are also the same criteria used for ICM. Regarding wider works, these are mainly associated with those works

[48] The potential options were: Connect and Manage (socialised) – preferred option, (2) Connect and Manage (hybrid) and (3) Connect and Manage (shared cost and commitment). The second and third options are more complex options and take longer to implement. Government supports a narrow intervention that is able to delivery security of supply and to help meet its renewable targets on time.

[49] Refers to the socialisation of all constraint costs including those that are not directly related to CM. Government sees this approach as the most transparent and workable solution. This principle has been set in the transmission licence. Constraint costs can arise for a combination of reasons. A list of reasons is provided in DECC (2010b, pp. 11-12)

[50] Under this regime the completion of all transmission reinforcement works was required prior to the connection.

[51] Under CM the following changes were introduced: (1) the period of user commitment for connected generators increases from one year to two years, (2) derogations against the NETS SQSS are managed by the transmission owner instead of OFGEM and are subject to final approval by the system operator and (3) the implementation of an enduring solution which replaces the interim one (ICM).

[52] The offers also include those generators with signed Invest and Connect (Pre ICM) agreements. There is no need for them to transition but they can ask for a transition to CM if required. Further information regarding the impact for customers with different contractual arrangements (such as signed agreements, unsigned offers, existing applications and new applications) can be found at: http://www.nationalgrid.com/NR/rdonlyres/8E46984C-422F-4DF9-A1EB-B79EA584A5A6/42455/Implementation_of_TAR_letter30710.pdf

that required to meet NETS SQSS Chapter 4 (Design of the Main Interconnected Transmission System).

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 NETS SQSS. In general, the boundary between enabling works and wider works varies depending on the specific circumstances of the project, thus each case needs to be evaluated by National Grid or by the respective transmission licensee in Scotland. It is expected that enabling works do not exceed those works related to the Main Interconnected Transmission System (MITS) connection works[53]. Enabling works only can go deeper into the system in exceptional circumstances.

In order to deal with network constraints and the connection of new generation, grid investments have been taken into account within the present transmission price control period (TPCR4)[54]. For instance, for the period 2011/2012, OFGEM authorised the following funding: £78 million of pre-construction funding and £ 241 million of construction funding regarding projects that planned to start their construction before 1 April 2011. In addition to this, the transmission owners identified further potential investments by the end of 2011/2012 that amounted to £764 million (DECC, 2010b, p. 7).

Recent figures suggest that an important number of generators (categorised as transmission connected generation, large embedded generation and small embedded generation)[55] under CM have connected to the transmission or distribution systems (embedded generation). 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 346 MW corresponds to transmission connected generation. In addition, the number of new signed agreements between 1 August 2011 and 30 April 2012 regarding transmission connected generation and large embedded generation is around 35 where installed capacity, connection year and advancement of connection (years) vary from 5.7MW to 350MW, from 2011 to 2020 and from 1 year to 12 years respectively. In terms of the advancement of connection, an

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[53] MITS substation refers to a transmission substation with more than 4 main system circuits connecting at that substation. National Grid has the obligation to publish (within the Seven Year Statement) a map of the National Electricity Transmission system identifying the relevant MITS substations. See: http://www.nationalgrid.com/uk/Electricity/SYS/current/. Examples of MITS substations, MITS connection works and scenarios in which reinforcements can be classed as enabling works for one generator and wider works for another; can be found in National Grid (2011a, pp. 5,7).

[54] It is noteworthy that the current transmission price controls (TPCR4) expired on 31 March 2012, however OFGEM has authorised a one year "adapted roll-over" of the current price control for the period from 1 April 2012 to 31 March 2013. This provides enough time for adapting the next price control (TPCR5) to the conclusions of the RPI-X@20 project and other developments in the transmission sector.

[55] The CM allows the connection of distributed generation (or embedded generation) to the transmission or distribution system. Under CM distributed generation refers to those generators that are large enough to have or are considered to have a significant impact on the transmission system. Among these are: (1) distributed generation that directly seeks for a connection to National Grid, (2) medium size distributed generation with a registered capacity of 50MW or more but less than 100MW in NGET's area, (3) small size distributed generation where the DNO considers that the connection may have an important impact on the transmission system; and have to request for a Statement of Works (SOW) to National Grid, (DECC, 2010b, pp. 33-34). Based on the Grid Code, small size distributed generators are defined as those with a capacity less than 50MW (in NGTE's area), less than 30MW (in SPTL's area) and less than 10MW (in SHETL's area). See NGET (2012, p. 39), Section: Glossary and Definitions.

average of 6.5 years and 11 years is observed for (1) transmission connected and large embedded generation that will connect via DNO and (2) small embedded generation that will connect via the DNO based on the SOW progress (National Grid, 2012, pp. 4-5, 8).

Summary and Discussion

From the previous paragraphs, it is clear that the implementation of CM 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 TNUoS charges and the respective share of balancing costs via 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 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[56]. 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[57]. Therefore, the system operator will generally try to manage bid and offer[58] 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 (such as ROCs, a FIT, and Levy Exemption Certificates). 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)[59]. During the April 5-6

[56] It 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). The cost of this balance including the operation of the BM is spread across all the market participants and recovery through BSUoS charges. The current allocation is as follows: 50% generators and 50% suppliers. Generators are not required to participate in the BM and nor are they subject to any restriction of the prices they may offer. Generators that do not participate in the BM can have a bilateral contract with National Grid for procuring balancing services. The costs associated with these actions are also transferred to transmission users via BSUoS.

[57] 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

[58] Bid refers to the price in £ per MWh that generators are willing to pay for reducing their output. A negative price means that National Grid would have to pay the generator to reduce their output. Offer refers to the price in £ per MWh that the generator would be paid by National Grid in order to increase their output subject to the offer acceptance (National Grid, 2011b, p. 4)

[59] The rate pay per MWh was as follows: (1) Whitelee wind farm: £180 (total: £308k), Farr wind farm: £800 (total: £265k), Hadayard Hill wind farm: £140 (total £140k), Black Law wind farm: £180 (total: 130k), Millennium wind farm: £300 (total:

event, a total of £890,000 in curtailment costs was paid to six wind farms. 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.

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[60]. 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). In order to have a better understanding of the case study, a brief approach regarding the electricity market and renewable incentive mechanisms in ROI is given.

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 Electricity Market

The Single Electricity Market Operator (SEMO) is in charge of the wholesale electricity market for ROI and NI. The SEMO is a cross-border operator and it is the first of its kind in the world as it combines two separate jurisdictional electricity markets (and subsidy mechanisms for renewables). SEM is regulated by the SEM Committee (SEMC) and is composed of the Commission for Energy Regulator (CER), the Northern Ireland Authority for Utility Regulation (NIAUR) and an independent member. The SEM went live in November 2007.

£33k) and Beinn Tharsuin wind farm: £180 (total: £11.5k). See: http://www.ref.org.uk/publications/231-high-rewards-for-wind-farms-discarding-electricity-5th-6th-april-2011

[60] Section 4.2.3 defines tie-break situations.

The NI electricity market was fully opened to competition in November 2007. SONI is the independent transmission system operator from NI with around 2,000 circuit kilometres of 110 kV and 275 kV of lines with a maximum demand of circa 1,850MW. Northern Ireland Electricity (NIE) is the distribution system operator (DSO) and the Transmission assets owner (TO). The current price control runs from 1st October 2012 to 30 September 2017 and it is referred to as RP5. This price control is applied to NIE T&D, as a monopoly provider.

In the Republic of Ireland, generation is a competitive market and transmission and distribution are regulated markets. The CER has proposed a progressive deregulation of the retail market which covers the whole associated markets[61]. After a very extensive consultation process with key stakeholders from the electricity market from ROI and Northern Ireland, the proposal for the total deregulation (end of price regulation) was published in 2010 through the Roadmap to Deregulation, CER (2010a)[62]. CER proposed the removal of retail price control (of a specific group of customers) when a set of four criteria has been met[63]. These criteria involved: number of independent suppliers, market share of independent suppliers, market share of incumbents and the switching rate and rebranding of ESB (incumbent) [64]. The EirGrid, a state-owned company, is the grid operator and operates around 6,500 km of high voltage wires. ESB Network is the owner of the transmission system which is regulated by CER. The distribution network is operated by ESB Networks Ltd., with around 165,000 km of lines and with typical operation voltages at 38 kV, 20 kV and 10 kV (CER, 2010b, p.1). The generation market is operated by ESB Power Generation and by independent power generators. There are two key drivers of the price of electricity: the cost of generation and the cost of maintaining/reinforcing networks. In terms of generation, around 80% of the electricity generation in ROI comes from fossil fuels. Regarding networks, an important issue is the dispersed population which increases network costs (more lines per customer)[65]. Price controls are reset every 5 years. The current price control (Price Review 3 or PR3) runs from 2011 to 2015.

It is important to note that in terms of wind generation installed capacity; all-island figures show an important increase during the last decade. It has grown from 182MW in 2002 to 1,998MW in 2010, with similar percentage increase in both Ireland and Northern Ireland. The distribution of wind generation installed capacity between Ireland and Northern Ireland by 2010 was around 80% and 20% respectively. It is estimated that in order to meet the 40% all-island renewables target, Ireland would need between 3,500MW and 4,000MW and Northern Ireland around 1,300MW of total wind installed capacity by 2020 respectively. In relation to the share of electricity produced by wind, this has also grown importantly, especially in Ireland. From 2005 to 2010 it has increased from 4.1% to 11.4% in Ireland and from 3.4% to 7.2% in Northern Ireland[66] (EirGrid and SONI, 2011b, pp. 35-39).

[61] There are four relevant separate markets: (1) large energy users - LEU, (2) medium-size business including public lighting - MSB, (3) small business – SM and (4) domestic. There are eight active supply licence holders in ROI.

[62] Decision Paper titled: Review of the Regulatory Framework for the Retail Electricity Market: Roadmap to Deregulation.

[63] Since 1st October 2010 the market for all business customers has been deregulated. In the domestic market, no price control has been applied since April 2011.

[64] Following CER, switching is an important indicator for measuring competition. Figures indicate that between March 2009 to February 2010, the percentage of switching for the second of subsequent time was as follows: 81% for LEU, 49% for MSB and 43% for SM (CER, 2010a, pp. 29-30).

[65] Regarding population density: 60 persons/sqkm (Ireland) and 244 persons/sqkm (Britain). In terms of distribution lines: 84 m/customer (Ireland) and 49 m /customer (average 75 other countries), (CER, 2010c, p. 3).

[66] 2010 is considered a poor wind year. For instance, 2009 figures indicate a share of 8.7%.

4.2.2 Support mechanism for renewables in ROI

In ROI the primary price support mechanism for renewables is the Renewable Energy Feed-in-Tariff (REFIT). Under this scheme suppliers receive a guaranteed price (minimum floor price) for renewable energy with an additional payment of 15% of the reference price over a 15 year period. In contrast to other similar schemes, REFIT payments are made to the supplier which then pays the renewable generator based on the Power Purchase Agreement (PPA) contract they signed. This price should not exceed the REFIT reference price regarding the specific technology category[67]. REFIT 2 is the current scheme promoting the implementation of 4,000 MW of new renewable electricity capacity. Among the main conditions are that plants: (1) must be new, (2) cannot be operated nor under construction on 1 January 2010 and (3) must be operational by end 2015.

The support mechanism for renewables applied in NI can be found in Section 4.1.2 of this document, which discusses the main mechanisms used in the UK.

4.2.3 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, such as priority dispatch, wind curtailment, access rights (firmness), inter alia. 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[68] and suggested further consultation on the treatment of constraints and curtailment in tie-break situations. SEM makes 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. For the management of constraints under tie-break situations specific groups (differentiated geographically) and categories have been proposed. Into each group there are different categories based on the level of firmness: fully-firm, partially firm and non-firm. This study involves only the case of wind 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[69]. 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

[67] The REFIT 2 reference prices are as follows: €66.35 MWh (onshore wind above 5MW), €68.68 MWh (onshore wind equal or less than 5MW), €83.81 MWh (hydro equal to or less than 5MW) and €81.49 (biomass landfill gas) (DCEN, 2012, p. 10).

[68] The order in which the different generation units should be dispatched down is as follows: (1) re-dispatch of conventional generation and system operator counter trading on the interconnector after Gate closure, (2) peat stations, (3) hybrid plant, (4) high efficiency CHP/biomass/Hydro, (5) wind, (6) interconnector and (7) generation that dispatch down for safety reasons (i.e. flooding). Regarding (5) wind, there are 3 levels: (a) wind farms which should be controllable but do not provide this (until 2013), (b) wind farms which are controllable, (c) wind farms which are exempted or are not expected to be controllable. This hierarchy does not apply in those situations in which it compromises the secure operation of electricity system. The SEMC suggested that economic factors would be taken into account in the order of dispatch but only in exceptional situations, however this position should not threaten the delivery of renewable targets (SEMC, 2011, pp. 16-17).

[69] As it can be seen from the previous footnote, the priority dispatch hierarchy reflects the importance of renewable targets and new technology, which is in agreement with the Renewable Energy Directive (Article 16). The hierarchy disregards the concept of firmness and only refers to dispatching (not re-scheduling or de-committing plant).

with curtailment issues in a tie-break situations using a grandfathering approach with reference on Firm Access Quantity (FAQ) (SEM, 2011, p. 17)[70].

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%. 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[71]. The last category refers to those generators with temporary connections or those that have not been allocated FAQs[72]. SEM has established that parties would be given firm capacity (fully-firm access) after the completion of the Associated Transmission Reinforcements (ATRs). A non-firm basis access is given after the completion of the Site Related Connection Equipment and safety associated ATRs (Short Circuit Driven Deep Reinforcement Works). In this circumstance, an applicant may be partially firm if the ATRs associated with only a portion of its capacity are complete (EirGrid, 2012a, p. 2).

FAQ is determined using the called Incremental Transfer Capability (ITC) Programme. This measures the quantity of extra electricity that the transmission system is able to transmit from the generator (under test) to the electricity customers. The availability of generation capacity is identified and allocated to the generators on a date-order basis. The available firm capacity is computed for each generator based on three study seasons: maximum electricity demand in summer, maximum electricity demand in winter and minimum electricity demand in summer. For each study, different dispatch scenarios are analysed. The ITC programme finds the point at which a thermal overload on the transmission system is produced. The available firm capacity for a specific scenario is determined by the generator output at the point of thermal overload. The available firm capacity for the year is determined by the worst case available capacity for each season and dispatch scenario. 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.

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[73]. 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-

[70] In addition to this decision, SEM also decided to modify the constraint categories outlined in SEM-11-063. The adoption of a grandfathering approach based on the level of firmness (FAQ) for the treatment of constraints in tie break situations (post application of dispatch principles) remained the same. This means that generators with lower FAQ will be dispatched down before those with a higher FAQ. The SEM also established that within each category, all generators will be dispatched down in the respective constraint category on a Pro-Rata basis (SEM, 2011, p. 16).

[71] It is noteworthy that in the case of Northern Ireland, the concept of non-firm has not been introduced yet. A consultation paper has been published in order to determine the methodology for computing the FAQ for generators connecting to the transmission or distribution systems. A threshold (total MEC of 5MW or more at connection point) for computing FAQs is proposed for those generators that want to connect to the distribution system (SONI, 2011, p. 21).

[72] In ROI the status of the existing connected projects is approximated as follows: (1) 921 MW (firm access), (2) 98 MW (partially firm), 133 MW (non-firm, Gate 2&1), 85 MW (temporary connection). In addition, there are also 374 MW allocated to older generators that are not expected to be controllable due to the project size and derogations (IWEA, 2012, p. 21).

[73] Ninety three submissions were received by SEM. The majority of respondents had a direct financial interest in the wind farm industry. Among the respondents were system operators, wind farms from the island, IWEA, consultancy firms, generation firms, manufacturing wind turbines firms, among others (SEM, 2012b, p. 7)

break situations were proposed (SEM, 2012a). SEM invited the energy community to support their position by providing factual data and impact analysis based on five specific issues: (1) impact on the consumers and Dispatch Balancing Costs - DBC, (2) facilitation of Ireland and Northern Ireland 2020 renewable targets, (3) efficiency of the entry signal, (4) stable investments environment and (5) consistency of treatment for constraints and curtailment. From the four options, only three of them considered compensation due to curtailment of firm wind generators. This compensation is made through the DBC which are 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. These costs are ultimately borne by consumers (EirGrid, 2012b, 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.[74]

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)[75] would experience curtailment up to 9% and temporary connections would also suffer with curtailment up to 13%[76].

[74] 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).

[75] 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) by EirGrid and ESB Networks. Each Gate is divided into specific groups and within these there are subgroups. A

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 2020 this would increase by €9 million.

Similar to Option 2, many respondents support 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 SSE 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.

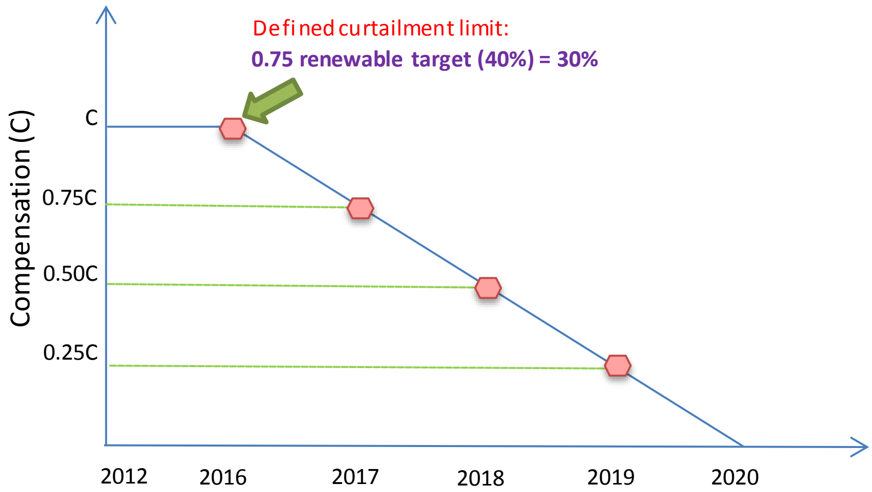
Finally, regarding Option 4, no one supported this option. This is understandable because this option proposed the elimination of compensation, which could alter the wind generation revenues. Their position was supported by three main issues: unviable projects due to the removal of compensation, (2) 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 recently published a new proposal (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. 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 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. The following figure illustrates this approach. For illustrative purpose it was assumed that the date in which 75% of the renewable target is achieved is January 1, 2016.

group is composed on those applicants that share common transmission deep reinforcements. A sub-group is composed of those applicants that share shallow transmission or distribution connection works (CER, 2008, p. 41). This allows the optimisation of electricity network investments. Currently there are three gates. Gate 1 (launched in 2004) and Gate 2 (launched in 2006) which have allowed the connection of around 1,700 MW by mid-2010. Gate 3 is the last group and allowed around 150 new renewable generators (mainly wind farms) with combined capacity of circa 4,000 MW (80% onshore, 20% offshore). Conventional generation is also allowed in Gate 3 with a total capacity of 1,350 MW (this includes a 350MW interconnector to the UK) (CER, 2010d, pp. 2-3). Connection offers under Gate 3 were issued from December 2009 to July 2011. In terms of order of offers, areas which are less technically complex would be offered first by the system operator. However when possible, the system operator will issue offers to applicants based on the earliest application date (CER, 2008, p. 8).

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

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



Source: SEM (2012b). Own elaboration.

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.[77] Under the previous assumptions regarding curtailment and SNSP, the curtailment costs would be approximately €20 per MWh[78]. 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, Pro Rata with a defined curtailment limit, SEM is trying to deal with the over-incentivisation of connection beyond the 40% renewables targets which may eventually have a direct impact on consumers due to the socialisation of compensation through DBS. 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. However, it is noteworthy that over-incentivisation can be mitigated by the removal of renewable subsidies such as REFIT 2. This support mechanism cannot exceed 15 years and may not extend beyond 31/12/2030

[77] For a comprehensive study regarding the calculation of the operational boundaries of the SNSP for 2020 see EirGrid and SONI (2010).

[78] In general, the impact of wind generators will depend on many factors such as installed capacity, capacity factor, and 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)

(DCEN, 2012, p. 4). On the one hand, SEM wants to protect consumers from full compensation to generators for curtailment events, even when the renewable targets have been achieved. On the other hand, SEM wants to promote the connection of more wind generators giving them the right incentives in order to achieve the renewable targets. 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. An interesting initiative that could help to minimise the level of curtailment is the DS3 Programme: 'Delivering a Secure, Sustainable Electricity System' which is lead by SONI and EirGrid. The programme aims to ensure security of supply on the island through the creation of a changing plant portfolio to assist in the achievement of the 2020 renewable targets as set in the Renewable Directive 2009/28/EC and detailed in legislation by minimising curtailment of renewable generation[79].

This case study also indicates that the categorisation of the event (curtailment event or constraint event) is decisive for market compensation under a tie break situation. Curtailment refers to a system problem in which the only solution is to turn down some wind generation. It happens when there is an excess of wind generation on the whole system. Constraint is linked to the availability of the network and is a local issue. For instance under the 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 situation 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. Under a constraint event, non-firm generation will be constrained before partially firm generation and partially firm generation will be constrained before fully-firm generation. Under this scenario, non-firm generators will suffer the most (they are the first to be constrained) and compensation to firms with FAQ different from zero will continue to be given to generators. In this situation, risks remains transferred onto customers. From the previous explanation, the challenge for SEM is to make a clear distinction between these two concepts, constraints and curtailment[80].

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

[79] It has three main working areas which are related to the system performance (identification of system portfolio capability and performance that is required for securing the power system), system policies (development of suitable policies for assuring the system security in terms of voltage and frequency all-island power system) and system tools (design, development and implementation of system tools for managing the complexity of the operation and for providing decision support tools. For further details see EirGrid and SONI (2011a).

[80] The SEM has proposed an operational rule set which provides that (1) if the security issue could only be resolved by reducing the output of one or a small group wind farms, we are facing a constraint event; (2) if the security issue could be resolved by reducing the output of any all of the wind farms, we are facing a curtailment event. In both cases it is assumed that the control centre had control over every wind farm on the Island of Ireland. See Annex from SEC (2012b).

generators have full access rights from the beginning, pay full TNUoS and are compensated through BSUoS. Both UK case studies show that the regulatory framework does not make any differentiation between constraints and curtailment. Table 8 from Section 5 makes a comparison across the four case studies that are part of this paper.

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[81] has proposed in its RAM Pro Forma Power Purchase Agreement (PPA). In addition, a discussion of the case study is also provided based on specific criteria such as the form of curtailment applied in this context, the risk allocation and order of curtailment and the relationship between curtailment cost and network reinforcement. A brief description of the electricity market structure and support mechanism for renewables in the United States is provided first.

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. In addition, the type of renewable products and the size of generators are in line with the renewable portfolio that UK Power Networks is expecting to connect in the short term.

4.3.1 Electricity Market Structure in California

Similar to the rest of the American states, in California the electricity industry has traditionally been dominated by the consolidation of vertically integrated utilities. Some of them have been granted monopolies with exclusive service territories and with specific obligations for providing and expanding the service. There are two kinds of utilities: Private or Investor-Owned Utility (IOUs) which are regulated by the state public utility commission (PUC) or by the Federal Energy Regulatory Commission (FERC) and (2) the public utilities (such as electric cooperatives and municipal electric companies) that are locally regulated by specific electric boards. There are three major IOUs in California (SCE, PG&E and SDG&E) which serve around two-thirds of the total electricity demand in this state[82]. The CPUC is responsible for regulating the electric and natural gas market, among other

[81] 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. It generates around 43% (5,574 MW) of the electricity it provides to its customers. The owned generation portfolio is as follows: 37% (natural gas), 19% (nuclear), 18% eligible renewables (such as solar, wind, small hydro, biomass and geothermal), 7% (coal) and 6% (large hydroelectric). See: http://www.edison.com/files/SCE_PROFILE.pdf

[82] The other IOU is Southern California Gas Company.

public utilities in California[83]. This sets and designs the retail rates of IOUs and also is responsible for the achievement of renewable targets through the procurement by the IOUs of power from renewable sources in order to meet the state's RPS. The California Independent System Operator (CAISO) is the independent system operator from California and regulates IOUs operating in the ISO balancing authority area[84]. CAISO is regulated by the FERC and does not own the grid. FERC basically regulates the transmission of electric energy and the sales of electric energy at wholesale in interstate commerce by public utilities[85].

Regarding electricity generation, around 200.4 TWh was generated in 2011, of which natural gas, nuclear and hydroelectric are the generation resources with the highest share, 45%, 21% and 18% respectively[86]. The share of wind is around 4% and equivalent to the provision of power to 1.2 million homes[87]. California is ranked second nationally, after Texas, in terms of installed wind capacity with a total of 4,570 MW online capacity, 1,023 MW under construction and 6,739 wind projects in queue by October 2012. Installed wind capacity in California represents around 9% of the total installed wind capacity in the United States. However in 2002 the share of installed wind capacity was around 39%[88].

4.3.2 Support Mechanism for Renewables

RPS is the most common market-based mechanism in the United States which promotes the increase of eligible renewable energy resources to the total energy procurement. RPS put in place an obligation to the electricity supply firm to produce a particular quota of their electricity from renewable energy sources. Generators earn renewable energy certificates for every unit of electricity which can be sold to the electricity supply firms (similar to the RO in the UK). RPS is a state-level policy and can be either mandatory or voluntary. The procurement method is usually under annual competitive solicitations (a request for offers). RPS is mainly applied to IOUs and electric service providers. States have set different renewable targets based on the electricity market characteristics and the potential of renewable sources. RPS rules vary across states with regard to the minimum requirement for renewable energy, implementation timing, the eligible technologies and resources[89]. Twenty nine states, Washington DC and two territories have adopted RPS. Eight states and two territories have adopted voluntary renewable portfolio goals. Several states have set renewable energy targets by 2020. Some of the states with the highest targets are California (33%),

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[83] In addition to the privately-owned electric and natural gas firms, the CPUC regulates telecommunications, water, railroad, rail transit and passenger transportation firms.

[84] In the United States there are two types of TSO: Independent System Operators (ISOs) which operate in a single state and Regional Transmission Organisations (RTO) which operate in several states (cross border). California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), New York ISO (NYISO) are in the first group. In the second group are Southwest Power Pool (SPP), Midwest ISO (MISO), PJM Interconnection (PJM) and ISO New England (ISO-NE). See Electricity Market Overview: RTO map from FERC. See: https://www.ferc.gov/market-oversight/mkt-electric/overview/2012/10-2012-elec-ovr-archive.pdf

[85] See Parts II and III of the Federal Power Act (FPA). Under this Act, public utility is defined as "any person who owns or operates facilities subject to the jurisdiction of the Commission".

[86] See California electricity statistics & data from the California Energy Commission: http://energyalmanac.ca.gov/electricity/

[87] See Wind energy facts from California: http://www.awea.org/learnabout/publications/factsheets/upload/3Q-12-California.pdf

[88] See Maps of current installed wind power capacity in the United States from U.S. Department of Energy: http://www.windpoweringamerica.gov/wind_installed_capacity.asp

[89] See: http://www.epa.gov/chp/state-policy/renewable_fs.html

Colorado (30%), Connecticut (27%), Minnesota (30%), New Mexico (20%) and Kansas (20%), DSIRE (2012). In California CPUC and the California Energy Commission (CEC) are responsible for implementing California's 33% RPS programme[90]. Since the RPS implementation in California, 2,871 MW of new renewable capacity has achieved commercial operation. In 2011 SCE, PG&E and SDG&E served 21.1%, 20.1% and 20.8% respectively, of their retail sales with RPS eligible renewable energy (CPUC, 2012c, p. 3).

In addition to the setting of the RPS, there are other mechanisms such as FIT that also play an important role in the achievement of renewable targets. FIT has shown an important increase in its implementation especially for solar PV technology in small and medium size projects. FIT is seen as a complement to the RPS. Different kinds of FIT have been implemented across states[91]. In California, CPUC implemented the FIT Programme on February 14, 2008 and authorised the purchase up to 480MW of renewable generating capacity from projects smaller than 1.5MW. The main objective of the programme was to promote the development of small scale renewable distributed generation by the sale of power to the IOUs using a standard contract and avoiding time-consuming contract negotiations. California was the first one to adopt a FIT scheme based on avoided cost[92]. Under the FIT scheme there is around 170 MW under contract. A recent instrument is RAM, launched in 2010 by the CPUC which was designed to encourage the implementation of small renewable generating facilities using a market-based approach. This case study focuses on RAM and the details regarding this programme are given in the next section. Other initiatives in California for promoting distributed generation are those such as the California Solar Initiative, Self-Generation Incentive Programme, Combined Heat and Power Tariff and utility solar programs[93].

It is noteworthy that different procurement strategies have been adopted for the achievement of the renewable targets. Some of them seek cost-effective projects such as those based on competitive solicitations and auctions. However, these strategies can be negatively affected if the number of bidders is not appropriate. High transaction costs associated with competitive

[90] In California the RPS programme was established in 2002 under Senate Bill 1078, modified in 2006 under Senate Bill 107. The initial target was a 20% RPS by 2020 then it changed to a 33% RPS by 2020 (Senate Bill 2 of the First Extraordinary Session (SB 2 (1x)) (Simitian) (Stats. 2011, ch. 1).

[91] Among there are: (1) FIT payments based on levelised RE project costs – this is the most popular type of FIT used worldwide, based on the levelised costs of renewable generation plus a target rate of return (e.g. Gainesville, Florida; (2) FIT payments based on utility avoided costs -FIT payments based on either utilities avoided costs in real time (based on a locational marginal pricing – LMP- formula) or based on long-run fossil price projections (e.g. California, Central Vermont Public Service Corporation in Vermont, Xcel in Wisconsin); and (3) Fixed-price incentives – based on a fixed price without taking into consideration avoided costs or RE generation costs (e.g. We Energies solar buy-back in Washington), (NREL, 2009a, p .2). Among other states that have implemented FIT legislation or that have recently proposed it are Oregon, Hawaii, Maine, Indiana and Ohio (NARUC, 2010, p. 1).

[92] The initial price (US$ 0.096 /kWh, effective in 2010) was based on avoided costs which were computed taking into consideration the Market Price Referent (MPR) which referred to a natural gas-fired electric plant; this means that MRP reflected a fossil fuel price. The price did not represent a high enough incentive for renewable generation and as a result only 17MW were allocated in 2010 under FIT scheme. On May 24, 2012, under Decision 12-05-035 a new price mechanism was implemented which created the new renewable market adjusting tariff (Re-MAT) which complies with the federal and state law. This new methodology allows the FIT price to adjust in real time based on market response. The Re-MAT is composed of two elements: the starting price and the adjustment mechanism. The starting price is computed based on the weighted average contract price of SCE, PG&E and SDG&E' highest price executed contract that results from the RAM 1 auction held in November 2011. This price was adopted for the three types of products: baseload, peaking as-available and non-peaking as available and represents a single and statewide FIT starting price. This price was set in US$ 89.23/MWh. The second component consists on a two month price adjustment mechanism that allows the increase or decrease of each product price every two months based on the market response (CPUC, 2012b, pp. 43-44). In addition, the Decision 12-05-035 also increased the maximum allowed capacity to 3MW.

[93] See: http://www.cpuc.ca.gov/PUC/energy/DistGen/

solicitations and the time incurred for negotiating the bid price can also discourage the participation of small projects in the auction[94]. Other strategies, such as FIT, provides transparency of the process (the price is known in advance) and has been designed to attract the participation of small projects. The procurement under this approach is first-come first-served[95]. However the price does not necessarily suit the different renewable technologies (i.e. the market reference price in California applied for FIT was initially associated with a fossil price). Bilateral contracts are another option and have been used in regulated and competitive markets, however the lack of competition among developers (because comparison is not possible between different market players) results in less accurate pricing (NREL, 2011, p. 14). The RAM programme is an example of how to promote the expansion of small renewable generating facilities in a cost-effective way at the distribution company level.

4.3.3 The Renewable Auction Mechanism (RAM) Programme

General Description

The RAM programme[96] 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) [97]. The RAM programme represents the proposals for expanding the existing FIT programme for generators up to 20MW, which still are considered small generators[98]. 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) (CPUC, 2010, pp. 2-3).

Under this approach, CPUC ordered the three IOUs: SCE, PG&E and SDG&E to procure a total of 1,299 MW of renewable energy[99] in their respective service territories[100]. 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. The auctions are held simultaneously by the IOUs in order to 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. RAM 2 closed on May 31 2012 and the results

[94] For instance, for RPS annual solicitations (applied by IOUs or electric service providers) the bid price is subject to negotiations and can take few years before the contract is concluded.
[95] An example of this is the California Renewable Energy Small Tariff (CREST) Programme with projects up to 1.5MW.
[96] This programme replaces the former Renewable Standard Contract Programme (RSC).
[97] Among other mechanisms (mandatory or voluntary) adopted by SCE are: the California Renewable Energy Small Tariff (CREST) Programme, the Combined Heat and Power (CHP) Programme and the Solar Photovoltaic Programme (SPVP-IPP).
[98] The minimum contract size is 1MW, however projects with a capacity equal or higher than 500kW can be aggregated up to 5MW.
[99] The initial amount was 1,000MW but was expanded to 1,299MW. The additional capacity (299MW) is composed of 74MW for SDG&E (Decision 12-02-002) and 225MW for SCE (Decision 12-02-035). The current distribution is as follows: SCE (723.4MW), PG&E (420.9MW) and SDG&E (154.5MW). This distribution is based on the regulated utilities share of total system state-wide peak (similar to the one adopted by the CPUC for the FIT programme). Only eligible renewable resource (ERR) can participate in the RAM. This meets the criteria set in Public Utilities Code Section 399.12, Public Resources Code Section 25741 and the California Energy Commissions Renewable Portfolio Standard (RPS) Eligibility Guidebooks.
[100] The RAM programme allows a generator to bid into a specific auction (i.e. SCE) and to be allocated in either PG&E or SDG&E's service territory. Existing and generating facilities are eligible.

will be published soon. The contract operation date is within 24 months of CPUC approval with a 6 month extension for regulatory delays[101].

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 (CPUC, 2010, p. 102). IOUs specify the amount of product for each auction[102]. In addition, generators have the option of selling their electricity under two different approaches: (1) full buy/sell or (2) excess sales. In the first case, generators sell 100% of their electricity to the utility; in the second case generators only sell their excess output to the utility after first offsetting their local load (CPUC, 2010, p. 47).

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)[103]. 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[104].

In terms of price, under RAM the generators are able to determine the product price[105]. The price is adjusted based on the Time of Delivery (TOD) periods and the respective allocation factors[106]. 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[107]. If a generator bids as FCDS, benefits from Resource Adequacy

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[101] Initially the deadline for commencement of commercial operation was 18 months. It was extended to 24 months by Resolution E-4489 from the CPUC. With this change, the number of eligible bids increased by 40% (CPUC, 2012b, p. 8).

[102] IOUs determine upfront the type of product for procurement based on their respective portfolio needs (CPUC, 2010, p. 35).

[103] Initially, this option was not allowed in the RAM 1 auction and producers were not required to attain FCDS if there was a cost to producers; however producers were required to apply for a deliverability study. Resolution E-4489 from the CPUC created the option for generator to bid as either EO status or with FCDS. If the producer bids under EO status, it is not compulsory to apply for deliverability study (CPUC, 2012a, p. 8).

[104] For instance, SCE uses the Google Earth application and provides information regarding the location of distribution circuits, substations, sub transmission systems and areas of transmission constraints. In addition, information regarding voltage levels, available capacity and current and queued DG interconnections amounts is also provided. For instance, at distribution layer, preferred (in green colour, high load density areas with low DG penetration levels, less than 2MW) and non-preferred (in red colour, low load density areas with high DG penetration levels) distribution circuits are also indicated. This information helps potential generators to make their best decision with respect to connection. Usually projects less than 10MW are connected to the SCE's distribution system.
See: http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm

[105] The price should take into account subsidies, tax credits, cost incurred by participant, the adjustments of the offered price with the respective TOD factors.

[106] Depending on IOUs TOD may refer to on-peak, mid-peak, off-peak, super-off-peak periods, super peak, shoulder, night, among others; which are associated with summer and winter periods. The allocation factors also vary across IOUs.

[107] For EO status transmission costs refer to reliability network upgrade (RNU) costs. For FCDS transmission costs refer to RNU and deliverability network upgrade (DNU) costs.

(RA) are also taken into account in the evaluation process[108]. Thus, the rank is based on the levelised TOD adjusted product price[109] plus transmission upgrade costs (under EO status or FCDS) less RA benefits (only if the product is bid as FCDS)[110]. The formula is as follows:

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

Where ratepayer funded transmission upgrade costs[111] refer to those costs that are paid back to the generator over a five-year period through the Transmission Access Charge. Thus, transmission upgrade costs (either those related to EO or FCDS) are not captured in the bid price.

The CPUC mandates to evaluate the proposals by an independent evaluator[112]. In the evaluation, RA benefits are received only by those generators with FCDS interconnection. Generators with EO status do not receive RA benefits in the evaluation. RA is seen as a capacity requirement. Winners in the RAM auction receive the total price as per their bid (so it is a 'pay as bid' auction).

Obligations regarding metering, communication, telemetry and meteorological stations are also set in the PPA contract. For instance, for intermittent technologies, generators are required to install and maintain at least one meteorological station per site (generating facility) in order to report data to the CAISO and the existing SCE weather station data collection system. For wind generators, historical data regarding the generating facility's wind speeds and other relevant meteorological variables are required[113].

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 PPA pro forma can be downloaded from the IOUs web sites. The CPUC approves the PPA pro forma created by each utility. The PPA pro forma across the three IOUs are very similar. 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.

[108] The RA programme was implemented in 2004 by CPUC. RA contributes to the safe and reliable operation of the grid and provides incentives to the deployment of new resources required for reliability in the future. Under FCDS delivery network upgrades are allocated in interconnection studies and can qualify as RA. Under the CPUC and CAISO rules only those projects that connect as FCDS are eligible to offer and provide RA. Generators have to indicate the date in which they would achieve FCDS. Generators are allowed to submit multiple offers for the same generating facility (with separate offers) for EO status and FCDS. Both are subject to curtailment in emergency circumstances.

[109] Levelised price refers to the average price of energy over the contract term taking into account the expected generation, TOD, product price (MWh), payment escalation factor, equipment degradation factor and a discount rate. The discount rate used for computed levelised product price differs across IOUs. For instance, the discount rate approved by CPUPC for the RAM 2 auction was 10% (SCE) and 7.6% (PG&E). Sources: (CPUC, 2012a, p. 21), (PGE, 2012, p. 7).

[110] RA benefits are computed by each IOU. Benefits are calculated based on the IOUs forecast of net capacity value and peak capacity contribution factor. The capacity contribution factor is technology and location specific. The Qualifying Capacity Methodology Manual describes the methodology for determining the amount of RA that the generating facility would provide in the IOUs evaluation (SCE, 2012b, Appendix B, p. 9).

[111] Those costs resulting from the most recent interconnection study submitted by the generator along with its offer.

[112] The independent evaluator is responsible for assessing the integrity and competitiveness of each RAM auction. The utility submits the independent evaluator's report along with the advice letter to the CPUC asking for the approval of contracts resulting from the respective RAM auction (CPUC, 2010, p. 95). IOUs select their respective independent evaluators. For instance for RAM 2, SCE and PG&E selected AccionPower and Charles Adkins of Ventyx Energy Software, Inc. as independent evaluators respectively.

[113] Meteorological station specifications regarding SCE can be found at Exhibit P-1 from the PPA pro forma.

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 5MW (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, SDG&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 (2012b). Own eleboration.

SCE allocated a total of 67MW in RAM 1[114]. The rest of capacity amounting to 512.4MW is expected to be allocated across RAM 2, RAM 3 and RAM 4[115]. For the RAM 2 auction, SCE has established 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. The following table shows the results from the first auction (RAM 1).

Table 6: RAM 1 Results

Product	Capacity - Proposal (MW)	Number of offers 1/	Number of signed contracts	Capacity allocated (MW)	Installed capacity (MW)			Estimated annual energy (GWh)			Contract term (years)
					Min.	Max.	Average	Min.	Max.	Average	Average
Peaking as available	55	91	7	67	2	20	9.6	5	49	23.6	20
Non-peaking as available	5	1	0	0							
Baseload	5	0	0	0							
Total	65	92	7	67	2	20	9.6	5.0	49.0	23.6	20

1/ Total capacity amounting to 1,260.46 MW. The share of offers was as follows: 91 projects (solar photovoltaic) and 1 project (small hydro facility).

Source: SCE (2012a), SCE (2012b)

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[116]. 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. In general, 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. SCE is planning to use specific PPAF for EO status and FCDS in RAM 3. 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[117]. 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. SCE have indicated that this value was proposed by the utility and that 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. In terms of 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

[114] The contract capacity varies from 2MW to 20MW and was 100% allocated to seven solar PV generators. Initially a total of nine projects were shortlisted, amounting a total of 76.95 MW; however two of them elected not to sign a contract with SCE (SCE, 2012a, pp. 6-8)

[115] RAM 2 auction closed on May 31, 2012; the RAM 3 is planned for December 21, 2012 and RAM 4 for May 31, 2013.

[116] Banked Curtailed Energy refers to the cumulative curtailed product that exceeds the curtailment cap (for the whole contract period) for which SCE paid a compensation (equals to Product Price) the next monthly payment.

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

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 7 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.

Table 7: 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)

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 from 1MW to 20MW in a cost-effective way (market- based)[118]. Even though the existence of the RAM pro forma with general rules given by the CPUC, IOUs have had the flexibility to propose different ways to deal with specific issues such as those mainly related to curtailment, compensation, allocation factors and discount rates for adjusting the product prices. This flexibility allows generators to know in advance the specific rules and to select their preferred IOUs for making their bids. For instance in terms of curtailment, there is not a rule that defines the risk sharing among the main parties. It varies depending on the terms and conditions of the PPA. It was observed that in the case of SCE, the risk is, to some extent, transferred to the generators in those scenarios in which the curtailment cap of 50 hours per year is applied. This happens only when CAISO does not award a schedule (to the utility) on non-peak hours and when the day ahead price is negative. In the rest of the cases, generators are compensated regardless of the curtailment cap. 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. It is important to note that in this context, compensation is provided except for situations that may affect the reliability of the system (such as those resulting from an emergency, any order/directive from CAISO). Under this particular situation, curtailment is usually called reliability curtailment; in other cases it is called economic curtailment. The study also indicates that curtailment allocation is on a Pro Rata basis but only for maintenance purposes. This means that the risk of being curtailed is equally distributed among generators. It is expected that this risk will be equally spread across the utilities' owned-generating facilities. 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.

Another interesting point from this case study is the choice that IOUs give to generators to interconnect under EO status or FCDS. On the one hand, those projects with EO status may contribute to a quicker expansion of the utility renewable generation portfolio. On the other hand, the selection of FCDS implies higher product prices for the project that may affect the ranking of generators; however, the benefits that these projects receive for the RA may partially offset other costs. The inclusion of RA in the evaluation of bids reflects the value that capacity has for utilities.

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. This means that transmission upgrade costs are paid not only by the customers from the utility that made the investment decision, but also by customers from the rest of utilities (including municipal utilities). 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.

[118] This range is in agreement with the size of wind generators that are expected to be connected to the UK Power Networks network.

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.

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.

Table 8 from Section 5 summarises and compares the four case studies that are part of this paper.

5. Findings and Lessons Learned

This section summarises the main findings and lessons learned 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 and with Flexible Plug and Play in regards to what problems they are attempting to address. Table 8 summarises the key characteristics of each case study and organises the summary in four components: general information, connections and cost figures, curtailment and investment.

Different types of initiatives have been compared: such as projects (Orkney ANM), programmes (RAM) and system operators' regimes (CM and Wind curtailment in tie-break situations). In terms of access rights, some of these cases are more flexible such as that proposed by SEM, where depending of technical conditions generators can be classified as partially firm, in addition to the conventional categories of firm and non-firm access. In the case of Orkney ANM project there is only one option (NNFG) which is in line with ANM specifications. In this scenario the use of smart solutions has allowed the expansion of the economic curtailment boundary from 15MW to 25MW, but new challenges arose for determining the extent to which the contracted capacity continues increasing. Thus, further development is a key issue; DLR and increased storage capacity are some of the potential options to cope with this further development.

The method of energy procurement also differs between cases. The RAM is the only one of these case studies where a market-based approach has been used in order to select the most efficient projects. The RAM also promotes the early implementation of those projects with the lowest network upgrade costs because lower connection cost projects are more likely to win in auction, which has a positive impact on rate-payers (lower transmission access charges). The programme also allocates value to capacity due to the benefits of RA and this is used in calculating the ranking of projects. In terms of project size, the Orkney ANM and the RAM are those which incentivise the deployment of small distributed generators. Concerning contractual issues, the length of contract has been fixed in the RAM, where in comparison with the rest of initiatives, generators can only choose among three pre-determined periods (5, 10 or 20 years). However in the Orkney ANM project the length of contract is indefinite. A similar situation is observed in CM, however for wind farms the term is limited to 25 years.

Table 8: 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, 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.
Connection and cost figures				
Generating facilities/projects/wind farms [2/]	9 generators (connected up to 03/2012).	42 projects (connected up to 04/2012).	N/A	7 projects (only solar PV).
Installed capacity	13.1 MW , @ 1.5 MW/ generator.	571 MW, @ 13.6 MW/project .	1,998 (MW), 80% (Ireland), 20% (Northern Ireland).	67MW, @ 9.6 MW/generator.
Connection costs	Around £634k, @ 70.4k / generator, @ 48.4k / MW.	N/A	N/A	N/A
Constraint costs	N/A	£4.2 million (04/2011-04/2012), @ £7,400/MW.	N/A	N/A
Reinforcement costs	Estimated at £ 30 million, but avoided due to the implementation of the ANM scheme.	N/A	N/A	N/A
Advancement (years)	Time to build a new subsea cable circuit.	6.5 years for transmission connected and large embedded generation. 11 years for small embedded generation.	N/A	N/A

Table 8: 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 7 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.

The RAM also incentivises a prompt operation date for connecting DG which cannot be greater than two years after the CPUC approval. In the Orkney ANM project, the waiting time for connecting generators under NNFG has been reduced due to the use of smart technologies which avoided important reinforcement works. The four case studies encourage the connection of renewable generators but only CM incentivises the connection of non-renewable generators as well. The system operator regime from Ireland and Northern Ireland focuses on wind generators. 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 - are provided free of charge by SCE and other IOUs from California (SDG&E, PG&E). Regarding the Orkney ANM project, SSEPD has published a table that lists the substations with similar information. Thus, utilities encourage connection at less congested points in their networks by publishing the available room for new capacity.

In terms of connected capacity and connection costs, under CM a total of 42 projects have been connected since the beginning of the regime, with an average capacity of 13.6MW per project. CM has proven to be a good alternative for connecting embedded generators: which have contributed to around 40% (up to April 2012) of the total installed capacity in the system. Figures from RAM 1 and the Orkney ANM project are less ambitious, with a total of 7 projects and 9 generators connected, which have an average installed capacity per project/generator of 9.6 MW and 1.5 MW respectively. As a result of the two-stage approach (minor reinforcements followed by major reinforcements), CM has been successful in reducing long waiting queues because it accelerates the connection of generators to the transmission grid; however this also results in higher constraint costs which amounted to around £4.2 million with an average of £7,400/MW. In Orkney, it has been demonstrated that ANM is a financially viable solution which would save around £30 million in reinforcement costs, with an average of £3.3 million per generator and £2.3 million/MW (based on the current number of generators already connected) The two-stage approach in CM has also permitted to advance the connection of generators (transmission connected and large embedded generation; and small embedded generation) by around 6.5 and 11 years respectively.

The definition of curtailment across the studies is associated with a reduction of the generation output under specific conditions. However in Ireland and Northern Ireland, c*onstraint and curtailment* have different meanings and implications in terms of compensation and dispatch. Constraint refers to a system issue while curtailment refers to a network capacity issue. Both concepts are economically equivalent for our purposes. It is worth noting that in the Orkney ANM project curtailment is seen as something commercially acceptable, even given the large impact on the marginal generator. Different Principles of Access have been identified: LIFO in the Orkney ANM project, market-based in CM and Pro Rata in wind curtailment under tie-break situations and in the RAM programme (but only for maintenance purposes).

One of the main advantages of LIFO is its simplicity, however if the number of interested parties increases it becomes more complex. In CM curtailment allocation is based on a market-based response; however this could increase the cost to consumers. Under specific circumstances, such as the low competition between bidders behind individual constraints, National Grid does not necessarily select the most cost-effective offers for balancing the system. In the case of Ireland and Northern Ireland, Pro Rata with compensation paid beyond pre-defined limits has been recently proposed by SEM. Under this new approach, there is a clear tendency to eliminate unlimited compensation to wind generators for curtailment reasons once renewable targets have been achieved. The idea is to select the most cost-efficient wind projects in which the level of compensation due to wind curtailment is not decisive for the business case. It is important to mention that SCE is currently evaluating a new method for managing energy exports from generators by calculating and transmitting a real time limitation set-point to each generator affected (especially in situations where a limit will continue for an extended period time).

The allocation of curtailment risks across the case studies also differs. In the Orkney ANM project, no compensation is given for curtailment and therefore the risk is transferred to generators.. In CM compensation is always given and constraint costs are socialised through BSUoS. Thus the risk is transferred to consumers and to generators. Under the SEM new proposal, there are two-stages of risk allocation related to the achievement of renewable targets. In the first one, the risk is transferred to customers through DBC and in the second one the risk is transferred to the generators because no compensation is offered. In the RAM a curtailment cap is applied only in those situations where CAISO does not award a schedule to SCE (on non-on-peak hours and day ahead price is negative). Thus, in this situation, some curtailment risk transfers away from generators onto the purchasing utility with incentive to manage curtailment risk efficiently (i.e. try to avoid curtailment).

Finally, in relation to investment and reinforcement upgrades, the cost allocation is also dissimilar across case studies. For instance, in the Orkney ANM project and the RAM programme, the costs of distribution upgrades (reinforcements) are transferred to the generators. In terms of the system operator regimes, the transmission upgrade costs are always transferred to the network users such as generators and customers. It is important to mention that the two-stage approach implemented by CM has contributed to the reduction of stranded transmission assets by encouraging connections. This allows for better decisions to be made on network investments, thus customers are more protected.

6. Conclusions

6.1 Principle of Access (POA)

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 current situation in the GB distribution market, where only firm access is offered and curtailment due to a distribution network constraint is not an issue.

The LIFO mechanism (with reference to the date of connection offer acceptance) was selected by the DNO (SSEPD) for expanding the capacity of the existing connections beyond that which is possible under firm access. One of the main advantages of this approach has been its simplicity which facilitated the understanding of its operation, the technical implementation and the elaboration of contractual terms. However, an increase in the number of generators makes the picture more complex. Under this approach, the position of the generator in the queue has a commercial value: the lower the position the more risk to be curtailed, thus LIFO imposes increasing risk on successive generators. Regarding its economic properties, LIFO is good in terms of average incentive but poor in terms of risk transfer if prices paid for wind generation accurately reflect social value of generation. LIFO has the disadvantage that the value of building out constraint focussed on newer generators and hence more difficult to get a vote to lift a constraint passed. This effectively raises the transaction costs of getting agreement to build out a constraint, even when this would be socially beneficial.

The Pro Rata approach has been recently proposed by SEM (Ireland and Northern Ireland) and is being applied by SCE (United States) in specific conditions like network maintenance. In addition, FERC agrees that curtailment of both firm and non-firm connections must be made on a non-discriminatory basis and supports the Pro Rata approach for this purpose. SEM has proposed the use of a Pro Rata approach (with defined curtailment limits) after the removal of the previous decision of using a grandfathering mechanism (with reference on firmness) for wind curtailment in tie-break situations. Fairness and risk reduction and its ability to increase wind capacity seem to be the key argument in its favour. Pro Rata also has a dynamic advantage of making it easier to vote to lift a constraint. However, as discussed in Section 2.5, one of the disadvantages is that marginal generation is being cross-subsidised by not being exposed to the curtailment costs it imposes on all generators behind the constraint. This could mean that too much generation connects behind a constraint relative to the social optimum.

A market-based approach has been identified under the CM regime. From an economic point of view, the market-based approach is the preferred option because it would give rise to a socially optimal allocation rule (in the absence of risk and transactions costs). In this case, in an ideal scenario (perfect competition) the system operator will accept bids in cost order. But this is not always the case. For instance, National Grid states that the acceptance of these bids is subject to dynamic limitations and also to specific geographical issues. It is not always possible to select cost-effective bidders due to the low competition between bidders behind individual constraints. The low diversity of generation sources in specific locations makes this scenario more complicated such as the case of North-West Scotland where constraints can only be resolved via hydro and wind units. In addition to this, the size of generators also matters under a market-based approach. Transaction cost for small generators may be an issue.

In summary, 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 (i.e. such as that managed by SEC by an independent evaluator).

6.2 Allocation of risks among the parties

Two kinds of risk have been identified: curtailment risks and investment 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 can transfer the risk of transmission connected generation being curtailed to the customers. However for distribution connected generation, the rules are less homogeneous. For instance, in the case of CM, all the constraint costs are socialised through the BSUoS (shared between generators and suppliers). In the case of Ireland and Northern Ireland, compensations due to constraints or curtailment are socialised through the DBC (levied only on suppliers) and compensation is only given to fully firm and partially firm generators. Thus, there is some attempt to offer a degree of financial insurance via the FAQ. However, the new proposal regarding wind curtailment in tie-break situations indicates that compensation would be removed (regardless of the level of firmness) after the achievement of renewable targets. Concerning the distribution firms, SSEPD and SCE have set different approaches. SSEPD has decided not to compensate the NNFG-ANM. Thus in this situation, the risk is totally transferred to the generators. On the other hand, SCE has established a curtailment cap that is only applicable when CAISO does not award a schedule to SCE and, at the same time, when the day ahead price is negative. This makes sense because SCE bears the market price risks, then SCE would prefer to curtail generators when the market price is too low and would try to minimise compensation. Thus, the risk is transferred to generators when the curtailed energy does not exceed the cap (50 hours per year), and is partially transferred to generators when the curtailed energy exceeds the cap (partially because generators are compensated for the difference that exceeded the cap, thus the first 50 hours of energy curtailed are not compensated).

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.* In the case of the Orkney ANM project, the respective reinforcement costs at distribution level that amounted to £30 million were avoided due to the implementation smart solutions such as ANM with a total cost of £500k. Otherwise, based on the current number of generators already connected under NNFG-ANM, the incurred cost per generator would have been around £3.3 million. Thus, especially for small DG there are not enough incentives due to the high reinforcement costs that generators would face. A similar situation is noticed in SCE when distribution upgrade costs have to be fully funded by generators and in contrast to transmission upgrade costs, these costs are supposed to be taken into account in the calculation of the bid price. Transmission upgrade costs in California are reimbursed to the generators over a five year period through the Transmission Access Charge. At the transmission level, under the CM regime in the UK, reinforcement costs (such as those related to wider works) are shared between generators and demand through TNSUoS charge. However, the way in which CM is designed (minor reinforcements followed by wider reinforcements) contributes to better investment decision making and therefore provides more protection to customers in comparison with the previous approaches such as IC and ICM. Therefore, CM promotes the reduction of stranding risks for consumers. A similar approach is also noted in Ireland and Northern Ireland at transmission level, in which reinforcement costs are socialised through the TUoS charge.

6.3 Key lessons relevant to UK Power Networks

This project has arisen as a result of the UK government's policy of connecting more renewables to the grid and the desire to meet the UK's 2020 renewable target. 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.

UK Power Networks is in a trial period to implement smart technologies through FPP. There is a requirement to figure out the optimal way to make use of them under business as usual. UK Power Networks is a low risk firm and consequently has to think of creative solutions. Based on the analysis of the four cases studies we identify some key lessons for them. These are as follows:

- **Smart solutions versus conventional reinforcement:**

  Smart solutions are seen as an option to avoid or defer high reinforcement costs and also to operate a more cost-effective network. The decision of any of these options will depend on the respective associated costs. Usually, the risk of being curtailed tends to be higher when a smart solution is adopted than when reinforcement is made. In addition, the cost of reinforcement will depend on the number of generators that are seeking connection and the order in which the Network Operator decides to curtail them. *Thus, a key challenge for UK Power Networks is to determine the way to optimally increase generation capacity behind a constraint versus the option of making the incremental reinforcement. There is an equilibrium condition in which the option of reinforcement represents the most economically viable way to increase capacity.*

- **Compensation versus no compensation:**

  Two different approaches applied by distribution firms have been analysed. One does not allow compensation at all (SSEPD) and the other (SCE) imposes a condition on compensation (with a curtailment cap of 50 hours per year) only when the system operator does not award a schedule to the distribution firm on non-peak hours and with the existence of negative prices. In the rest of cases, SCE allows compensation. Regarding system operators, National Grid, EirGRid and SONI; the compensation is always given through the specific charge for balancing the system, BSUoS (in UK) and DBC (in Ireland and Northern Ireland). In the case of UK, at the moment there is no ability to do this in distribution. The advantages of setting a scheme in which the DNOs could compensate generators over a certain level of curtailment are that it would encourage connection and introduce dynamic benefits in terms of packing more generation in behind existing constraints. *Thus, a key challenge for UK Power Networks is to find the best arrangement to minimise curtailment in order to reduce the possibility of compensation. 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. In this situation, UK Power Networks requires a mechanism to be able to fund the compensation payments and be compensated for the risk arising from its curtailment estimates.*

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

  The publication of interconnection/connection maps by the different IOUs has allowed generators to make better decisions in the selection of connection points. This tool provides information regarding the availability of capacity at substation and circuit level, and also the location of distribution circuits, substations, sub transmission systems and areas of transmission constraints. For example, SCE provides this information in maps that are continuously updated. Maps are free of charge and the application is Google Earth. *Thus, UK Power Networks - and 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. The existence of Forums organised by regulators such as OFGEM (in order to capture the main concerns of generators regarding their experience in getting connected) and also those organising by the respective IOUs (in order to understand the main concerns of bidders regarding the procurement process and evaluation of offers, use of specific tools such as interconnection maps, among others); has been also very helpful. *Thus, UK Power Networks should try to promote stakeholder engagement by encouraging active participation of key parties in the development and implementation of the Flexible Plug and Play trial.*

- **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. Results from the first auction conducted by SCE, which serves around 4.9 million customers in California, indicate that the offer capacity (around 67MW) was fully allocated to 7 projects. This demonstrates to some extent the success of the first auction (RAM 1). In addition, 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. In addition, this mechanism also promotes the implementation of projects that can be online no later than 24 months after the CPUC approval. This condition allows for the selection of the most cost-efficient projects as well as those that can be implemented quickly. *Thus, a regional auction mechanism for procurement of small scale renewables can be seen as a potential option for UK Power Networks to accelerate the connection of the most cost-efficient projects. 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.

6.4 Next steps

There are two strands of learning from the future arising from 6.3. The first is around what UK Power Networks should do under the present regime to connect more wind generation. The second is around what might done to change the regulatory environment in GB to facilitate more wind generation connecting to the distribution network.

Going forward with the Flexible Plug and Play project, as well as understanding how to implement non-firm connections to allow the use of smart network technologies, UK Power Networks is currently in the position to implement a LIFO or Pro Rata approach to new DG connections. To allow a more strategic approach from developers and provide transparency on the network status, it is important for UK Power Networks, as well as other DNOs to provide more information on where to connect and how much capacity might be available at a given point in time. A key learning from many of these case studies is that customer engagement plays a key role in making these initiatives successful. Therefore, UK Power Networks will have to focus on customer engagement to understand their concerns on the issues and their willingness to participate in any decision made. Finally, it will have to look carefully at whether it will be able to underwrite some of the risk associated with non-firm connections. This could be providing certainty to generators by limiting the capacity connected or in return for higher payments.

On the other hand, UK Power Networks' ability to undertake a market-based approach is limited by its ability to absorb the risk of non-payment under a CM regime. The current regulatory environment limits the scope for risk transfer away from wind generators, even if this was socially optimal. The RAM scheme in California clearly indicates the benefits of an integrated local approach of connecting subsidised small-scale renewable, however, there is further analysis to be done to understand how that could be implemented in the UK context. The government may be encouraged to implement such a scheme to be run by local DNOs.

Finally, we believe that the selection of the four case studies has given valuable insights to UK Power Networks for promoting the connection of DG. Additional case studies may shed further light on the issue. However, 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.

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Appendix: Acronyms

Acronym	Definition
ANM	Active Network Management
BM	Balancing Mechanism
BPA	Bonneville Power Administration
BSUoS	Balancing Services Use of System
CCA	Community Choice Aggregators
CER	Commission for Energy Regulator
CfD FIT	Contract for Difference Feed-in Tariff
CHP	Combined Heat and Power
CM	Connect and Manage
CPUC	California Public Utility Commission
CREST	California Renewable Energy Small Tariff
CUSC	Connection and Use of System Code
DBC	Dispatch Balancing Costs
DECC	Department of Energy and Climate Change
DLR	Dynamic Line Rating
DNO	Distribution Network Operator
DNU	Deliverability Network Upgrade
DOE	Department of Energy
DTI	Department of Trade and Industry
EO	Energy-Only
ERCOT	Electric Reliability Council of Texas
ERR	Eligible Renewable Resource
ESP	Energy Service Provides
EWEA	European Wind Energy Association
FAQ	Firm Access Quantity
FCDS	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
FG	Firm Generation
FIT	Feed-in Tariff
FPA	Federal Power Act
FPP	Flexible Plug and Play
ICM	Interim Connect and Manage
IFI	Innovation Funding Incentive
IOU	Investor-Owned Utility
ISO	Independent System Operator
ISO-NE	Independent System Operator-New England (ISO-NE)
ITC	Incremental Transfer Capability
IWEA	Irish Wind Energy Association
LIFO	Last-in First-out
LSU	Load Serving Utilities
MEC	Maximum Exporting Capacity
MISO	Midwest Independent System Operator
MITS	Main Interconnected Transmission System

Appendix: Acronyms *(continued)*

Acronym	Definition
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards
NFFO	Non Fossil Fuel Obligation
NFG	Non-Firm Generation
NIAUR	Northern Ireland Authority for Utility Regulation
NNFG	New Non-Firm Generation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PG&E	Pacific Gas and Electric
PNM Interconnector	Pennsylvania New Jersey Maryland Interconnection
POA	Principle of Access
PPA	Power Purchase Agreement
PPAF	Product Payment Allocation Factors
PTC	Production Tax Credits
PUC	Public Utility Commission
RA	Resource Adequacy
REC	Renewable Energy Certificates
REFIT	Renewable Energy Feed-in-Tariff
RNU	Reliability Network Upgrade
RO	Renewable Obligation
ROC	Renewable Obligation Certificates
RPS	Renewable Portfolio Standard
RPZ	Registered Power Zones
RTO	Regional Transmission Organisations
SCE	Southern California Edison
SCP	Standard Contract Program
SDG&E	San Diego Gas and Electric
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SHEPD	Scottish Hydro Electric Power Distribution plc
SHETL	Scottish Hydro-Electric Transmission Ltd
SLC	Standard Licence Condition
SNSP	System Non-Synchronous Penetration
SONI	System Operators from Northern Ireland
SPP	Southwest Power Pool
SPTL	Scottish Power Transmission Ltd
SPVP	Solar Photovoltaic Program
SSE	Scottish and Southern Energy plc
SSEPD	Scottish and Southern Energy Power Distribution
STC	System Operator Transmission Owner Code
TNUoS	Transmission Network Use of System
TOD	Time of Delivery
WDAT	Wholesale Distribution Access Tariff