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Ultra High Wind Energy Penetration in an Isolated Market

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Abstract— **This paper addresses the market design implications of implementing ultra high (up to 42%) wind energy penetration in an isolated market. High wind penetration is becoming an increasing feature of many markets and the impact to such markets will need to be analyzed. In this paper, the Single Electricity Market (SEM) market design is analyzed in the context of increasing wind penetration and given the results of the recently published All Island Grid Study which indicated that ultra high wind capacity could be accommodated subject to certain key assumptions.**

Index Terms— **power systems, wind energy, market design, capacity and ancillary services.**

I. Introduction

Wind energy is a growing source of energy supply in many markets. The design of such markets will need to be assessed in terms of the impact wind energy has to the market schedules and price signals. This paper seeks to address the market design implications of ultra high wind penetration using the example of the Single Electricity Market (SEM) design in Ireland and in the context of the recently published All Island Grid study on renewable penetration for 2020.

The SEM has been established between Ireland and Northern Ireland on 1st November 2007 [1] integrating two previous markets designs into one common trading platform for wholesale electricity across the island. With current installed wind capacities across the island accounting for >900 MW and this figure is set to increase to in >4000 MW by 2020 significant challenges exist both technically and economically [2]. It is the intent of this paper to put forward recommendations as to the evolution of the SEM market design in accommodating ultra high wind penetration.

The All Island Grid study concentrated on producing feasible scenarios for wind penetration. The All Island Grid study was commissioned by the energy departments of Ireland and Northern Ireland and its objective was to develop a vision for high renewable energy penetration by the year 2020. Six generation portfolios were devised of differing levels of renewable energy [3]. Wind energy was the predominant renewable resource in each portfolio and this will be the focus of this paper. In terms of wind penetration, portfolio 1 included 2,000 MW, portfolios 2, 3 and 4 contained 4,000 MW, portfolio 5 contained 6,000MW while portfolio 6 assumed 8,000 MW while assuming a maximum load of 9,600 MW. Each portfolio has a different underlying plant mix.

The rest of this paper describes firstly the SEM in terms of the key market design features and their impacts on both conventional and wind generation. Following this some key results of the All Island Grid Study are presented with an overview of what the study concluded regarding cost/benefit analysis. Finally the market design implications for ultra high wind energy are then explored with conclusions made using the SEM as a case study.

II. Single Electricity Market

A. Overview

This section provides a high-level overview of the key features of the SEM which was introduced to replace the bilateral contract markets in Ireland and Northern Ireland [1]. Under the SEM, the sale and purchase of electricity is conducted on a gross basis, with all generators/suppliers receiving/paying the same price for the electricity sold into/bought via the pool. The key features of this design are:

- mandatory gross Pool with single clearing price;
- day-ahead complex bidding;
- ex-post System Marginal Price (SMP) pricing (which excludes transmission, reserve and other constraints), with a single island-wide price for each Trading Period;
- central dispatch with constraints payments;
- separate Capacity Payments Mechanism; and
- locational transmission losses.

B. Pricing

All Generator Units receive and all Supplier Units pay the same energy component of price in a Trading Period for electricity; the SMP. The SMP is determined via the Market Scheduling and Pricing (MSP) Software, which is run by the Market Operator. The MSP Software calculates the SMP in each Trading Period to reflect the cost of the marginal MW required to meet demand in a Trading Period within the context of an unconstrained schedule – this is the Shadow Price component; and recover operating costs associated with

Start Up Costs and No Load Costs – this is the Uplift component. The resultant formula for the derivation of SMP in a Trading Period is:

- SMP = Shadow Price + Uplift

The SMP is bounded by a Market Price Cap and a Market Price Floor, which are set by the Regulatory Authorities.

C. Dispatch

In principle it is a reasonable expectation that the cheapest generation will be scheduled to run first, whilst respecting the technical capabilities of the Generator Units. However, while the MSP Software produces a market schedule on the assumption of an unconstrained system, ignoring the impact of, for example, transmission constraints, voltage and reserve requirements, the system operators must dispatch Generator Units taking system constraints and reserve requirements into account (and must also consider real-time issues on the system such as unplanned outages). Therefore, the actual dispatch schedule followed is likely to deviate from the market schedule produced by the MSP Software. Constraints payments are made to generators who have been dispatched away from the Market Schedule.

D. Capacity Mechanism

While SMP pricing ensures that SMP reflects the value of energy, the Capacity Payments Mechanism attaches a value to the provision of capacity within the market. The Capacity Payments Mechanism is intended to strike a balance between providing the highest capacity prices at periods of highest loss-of-load probability or tightest margin in order to value the provision of capacity appropriately, and providing a stable set of investment signals. Under the Capacity Payments Mechanism (CPM), Capacity Payments are made in respect of Generator Units based on a measure of their availability, and hence the provision of capacity. Capacity Payments are funded by Capacity Charges, which are levied in respect of Supplier Units based upon their electricity consumption. [1]

III. All Island Grid Study

A. Overview

The All Island Grid study was divided into a number of work streams which included: Portfolio Assessment, Resource Assessment, Generation Variability / Dispatch, Network Analysis and Cost-Benefit Study.

The Portfolio Assessment provided a high level assessment of suitable generation portfolios of the All-Island system in 2020 and is the focus of all other studies. The Resource Assessment study determined the location and quantity of varying levels of renewable resources across the island. It assessed where the most feasible locations would be for each Renewable Energy (RE) [4]. The Generation Dispatch study assessed the impact of RE levels for all portfolios in terms of their impact to both spinning and replacement reserve. It also assessed the reliability of each of the portfolios on system operation [5]. The Network study was divided into two halves; a security constrained analysis which determined lines which were overloaded for each of the portfolios and an AC power flow analysis which showed the effect of each portfolio on reactive power and voltage control [6].

The final study was a cost benefit analysis that assessed the impact on key stakeholders and highlighted market impacts. The methodology employed is cost based extracted from real market designs the conclusions of which are summarized in [7].

B. Key Assumptions

Each work stream addressed the year 2020 only, which assumed a data set or time-series for the All Island system with total load of 54 TWh, minimum load of 3,500MW and maximum load of 9,600MW. All data was modeled to reflect the forecasted conditions for this year.

The principle of system marginal cost pricing was used for pricing electricity and reserves. The dispatch was calculated with a resolution of one hour an hourly time period was used to calculate the system marginal cost.

In terms of plant mix a number of existing units were decommissioned while 1,000 MW of interconnection with Great Britain was assumed. It was assumed that 10% of the interconnector capacity would be held back for spinning reserve with the rest being used for import/export. It remains to be seen, in practice, whether the interconnectors would be dispatched accordingly by the relevant system operators.

The Resource study assumed that the environmental planning system in both Ireland and Northern Ireland would be supportive of large amounts of wind energy which would be spread across the island.

A key assumption with regard to wind energy feasibility was the assumption that wind capacity will actually be connected to the Grid.

C. Study Results

The key results of the study were summarized in work stream 4 and focused on the most feasible scenarios that could be accommodated, the total costs to society and the impact to stakeholders.

In terms of RE penetration, up to 42% RE can be feasibly accommodated on the All Island Power system. Wind is the cheapest RE resource across all portfolios and it displaces more expensive conventional generation in the merit order curve. It was found that the generation mix affects the marginal price in each portfolio as illustrated in Figure 1. For example, portfolio 4 contains new coal plants with relatively low marginal generation costs, thus prices tend to be low while, portfolio 3 has a high share of OCGT with high fuel costs which creates a higher marginal price.

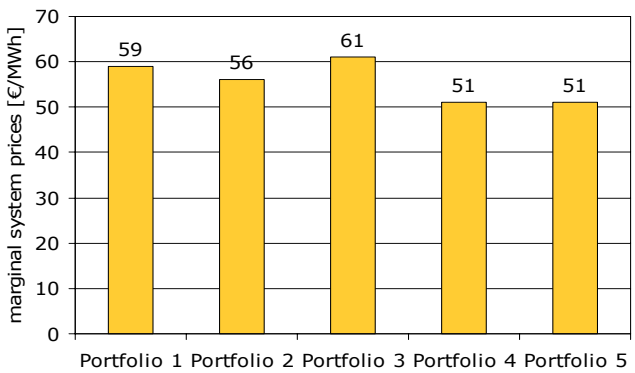

Figure 1: Average "price" levels in the different portfolios [7].

The study showed that the total cost to end users varies by at most 7% between the highest cost and lowest cost portfolios where the costs to society were taken as additional to the investment costs of existing conventional generators and existing and base case transmission asset costs. Thus the presented results indicate that the difference in cost between the highest cost and the lowest cost portfolios are low, given the assumptions made in the study.

In terms of the impact on conventional generation it was found that at higher proportions of renewable capacity installed less conventional capacity is required to run and thus the operational cost decreases. The difference of operating cost between the portfolio with the highest cost (portfolio 1) and the lowest cost (portfolio 5) is about 30 % or €740 million. Because of their relatively low fuel costs, the capacity factor of existing coal and peat plants is relatively high and thus act as base-load units in all portfolios. New conventional combined cycle plant is utilised more than existing gas plant and is evidenced by a higher capacity factors and a reduction in the marginal price.

In all portfolios wind energy remains the dominant RE technology and in the context of cost basis one that requires the least support. In portfolio 1, more than two TWh of renewable energy can be provided from wind projects that do not require support payments but can refinance their costs from electricity market revenues under the cost based market assumptions included in the study. In portfolio 5, support is required for the production of almost 23 TWh of renewable energy.

As is currently the case, it was shown that the fuels utilised by the All Island Power System, for the most part, have to be imported. However the study does show that the total amount of imported fuels declines with increasing shares of renewable generation by as much as 23% between portfolio 1 and portfolio 5.

Portfolio 1 represented the base case for carbon emission. At higher proportions of renewable capacity installed, less carbon is emitted. Portfolio 4, with the new coal plant utilised, has the highest emissions. Compared to portfolio 1, 25 % of the total carbon dioxide emissions from the electricity sector can be avoided by incorporating the renewable generation of portfolio 5.

IV. Market Implications

A. *Introduction*

Given that wind energy is becoming a significant resource in many markets the design of these markets will need to evolve to ensure that appropriate price signals are given to both conventional and renewable generation. The interplay between the market schedule and the dispatch schedule will also need to be investigated in terms of the need to redispatch plant for system security reasons. This section assess how the SEM market may evolve leading up to 2020 thereby assisting in the promotion of the 'right' portfolio of plant to accommodate ultra high wind energy.

B. *Conventional Generation*

The All Island Grid Study highlighted that the role played by conventional generation would change dramatically by 2020 becoming less relied upon for electricity production and increasingly used to ensure generation adequacy and system security. However, one question needs to be asked given the outcomes for the 2020 study: Will the SEM design promote the most efficient plant portfolio with ultra high wind capacity i.e. up to 6,000 MW? Clearly the SEM was designed to reward the most efficient plant. However given increasing wind penetration this may result in lower system marginal prices. Capacity payments coupled with ancillary service payments will be required to ensure that there is sufficient base load and peaking conventional plant.

With increasing wind energy the conventional plant mix need to become more balanced in terms of base load and peaking. The CPM has the potential to promote investment in peaking plant such as Open Cycle Gas Turbines (OCGT) and Aero Derivative Gas Turbines (ADGT) over the next 5-10 years. However, as the capacity payments mechanism is divided into variable and fixed payments a clear availability signal to generators may not be evident for all capacity periods. In particular, the way in which the variable element of the CPM operates in conjunction with the revenue pots can lead to uncertainty over how much those responding to availability signals will be paid. This uncertainty may lead to a deficit of generation at peak periods which may cause market prices reaching VoLL (Value of lost load). The CPM should thus be weighted in favour of fixed payments to generators.

Given the future reliance on conventional generation for system security and generation adequacy, increased focus needs to be given to development of an ancillary services market. This point was also affirmed in the All Island Grid Study. Currently the SEM procures ancillary services by contract only and is managed separately by the system operators in Ireland and Northern Ireland. This type of design will be limited in terms of price signals and transparency regarding plant efficiency when dispatched for reserve. Ancillary services will need to be designed to ensure that a

balanced mix of conventional plant is made available. Market based products tailored to ensuring a specific plant mix is available for a particular trading period could be designed. These products could be released on a rolling basis by the system operators and as needed based on forecast system demand. For longer term reserve requirements contracts of up to 5 years could be awarded to the most efficient plant.

In terms of dispatching conventional generation it was found that with increasing levels of wind energy the scheduling of conventional generation was reduced. However policies in relation to minimum levels of conventional generation running on the system will determine how the system is dispatched in practice. Internationally it is recognized that the limit to capacity for wind penetration is of the order of 15-30% without causing significant power system security issues [8]. For SEM the potential to curtail wind units for system security reasons may result in a significant difference between the Market Schedule and the Dispatch. This may introduce significant constraints payments for the system operators and potentially restrict the dispatch of renewable generation.

C. Wind Generation

To deliver significant investment in wind would require a definite revenue stream for wind energy on the same level playing fields as conventional plant. The SEM distinguishes between price making wind and non-price making wind generators. Like other price-makers, wind is designed to be treated similarly i.e. will be scheduled in the market if the price it bids is below the marginal price. It is also subject to central dispatch and receives capacity payments based upon availability figures declared in real time to the control centre.

With ultra high levels of wind energy the probability of constraining or curtailing wind becomes more likely. However the present the policy of wind curtailment is not fully developed. Currently, wind generators who are scheduled in the market may be constrained down and thus will be seeking compensation payments. This policy may need to be revisited especially given the possibility of curtailment will be even greater with higher levels of wind penetration.

The evolution of the SEM will also depend on the principles of the 'Gate Processing System' for wind connections in Ireland as this system will have a significant effect on the wind penetration levels which can be accommodated [9]. There have been two Gates to date. Gate 1 was finalised in December 2004 and processed applications equating to 373 MW of renewable capacity. The principles and criteria for Gate 2 were finalised in June 2006 and this could potentially see a further 1300 MW of renewable generation capacity connected to the system.

Both Ireland and Northern Ireland currently provide support mechanisms for wind energy. In Ireland there is the REFIT (Renewable Energy Feed-In Tariff) program while in Northern Ireland there is the ROC (Renewable Obligation Certificate) scheme. These schemes including the previous Alternative Energy Requirement (AER) program in Ireland has proven successful in ensuring that investors are guaranteed a fixed revenue stream from wind farms [9]. Given the implication to the All Island Power System of wind farms situated in areas of low transmission capacity it would be worthwhile considering how locational signals can be incorporated into such mechanisms. Currently the siting of wind farms is chosen by the developer/investor with limited consideration as to the capacity of the All Island Power System to accommodate the additional capacity. There might also benefit to developing single support mechanism across the island as part of the SEM which would harmonize existing mechanisms and deliver a single approach to RE penetration.

D. Grid Design and Operation

Regardless of what level of wind penetration is feasible, substantial reinforcement of the existing transmission networks will be required in all portfolios except for portfolio 1. This is a substantial planning challenge and the typically long lead times require an immediate policy response if the study year 2020 is accepted as target date.

More actions have to be taken in order to support the portfolios with increased renewable energy shares and to facilitate the respective transition processes. Sufficient investment in and appropriate operation of the generation plant relies on adequate framework conditions and underlying policies. Despite the snapshot character of the study, the results indicated a number of key issues relevant during this transition.

The market design needs to reflect the ability of the transmission systems to accommodate large scale wind. A complete rethink may be required in terms of how the power system is planned and connection offers made given that installed wind energy currently stands at 800 MW. The key areas of focus for the system operators will be in determining which areas to build transmission lines where firm connection offers are made. Policies need to be reviewed to address how best the system operators can plan for ultra high wind penetration [10].

V. Conclusions

The All Island Grid Study has been described, as well as the context of a recently launched Single Electricity Market for Ireland and Northern Ireland. Market design implications for ultra high wind energy penetration were examined with the following conclusions:

- SEM is designed to promote the most efficient plant portfolio/plant mix. However it has not been specifically designed to promote a plant mix that includes high wind capacity.
- To deliver the most appropriate plant mix with ultra high wind penetration would require specific tailoring of the design. The most effective means by which to achieve this may be to redesign the capacity payments

mechanism and assess for each type of plant what would be an appropriate payment stream.

- To ensure there is sufficient adequacy and system security a market for ancillary services would need to be explored as ultra high wind penetration will require tailoring ancillary services to deliver reliability and system security given ultra high wind penetration.

ACKNOWLEDGMENT

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