Single Electricity Market

Principles of Dispatch and the Design of the Market Schedule in the Trading & Settlement Code

A Consultation Paper

8 July 2009

SEM-09-073

Summary

In February 2008, the Regulatory Authorities ("the RAs") published a discussion paper, "Wind Generation in the SEM: Policy for Large-Scale, Intermittent Non-Diverse Generation", setting out a variety of matters that the SEM Committee considered necessary to address in the context of increasing penetration of intermittent generation, notably wind, and in anticipation of the All Island Grid Study.

Respondents to the discussion paper raised a number of issues. A general view was that the Single Electricity Market (SEM) is not robust against high levels of wind generation and that the fixed costs of some plant that will be required by the system will not be covered. Another was that the capacity payment mechanism presently over-rewards wind generation and that wind generation would reduce the infra-marginal rents for thermal generators needed for back-up. Also, there was considerable criticism of the concept of "curtailment", whereby the output of generators could be reduced without compensation, with some respondents suggesting that it would likely penalise wind generators for the inflexibility of other generators. There were calls too for debate on the respective treatments of generators having firm and non-firm access. This paper considers only the dispatch processes and associated aspects of the Trading & Settlement Code ("TSC").

Within this document, in considering what changes might be appropriate in the context of a high and rapidly increasing penetration of renewable generation, the fundamental purposes of dispatch and the "unconstrained" or "market schedule", a key component of the TSC, are examined. It is suggested that, in order to make most efficient use of existing resources, the purpose of dispatch is purely to minimise the short-term cost of production. It is further explained that the purpose of the market schedule is to allocate infra-marginal rents to generators. In the absence of these rents, generators would have the incentive to build only the best new entrant peaking generating unit (the "BNE Peaker").

It is suggested that it is important that infra-marginal rents are allocated to generating units that are useful to the system in meeting demand. It is noted that the TSC currently over allocates infra-marginal rents behind export constraints. Three options for change are presented. It is also proposed also that "Deemed Firm Access", whereby FAQ or MEC is allocated in advance of the completion of necessary transmission system infrastructure reinforcements, should not be introduced. More generally it is suggested that it is important to emphasise the principle that the market schedule should not deviate significantly from

providing infra-marginal rents to the portfolio of generation required to meet actual customer demand.

It is also explained that the concept of “curtailment” can be described in terms of how the market schedule is constructed and that, whilst it is important to understand the circumstances in which generators are and are not compensated for not running, a separate concept or definition of “curtailment” is not required.

The paper also identifies that as the number of Variable Price-Takers increases, it will become more and more frequent that not all of them can be run at particular times in so-called “Excessive Generation Events”. Furthermore, the potential costs of dispatching other plant in order to accommodate additional output from priority dispatch plant are likely to become significant. Clarity is needed over the dispatch of such generators. Options are presented, ranging from dispatching such plant with no regard for the costs incurred, through to prioritising dispatch on the basis of short-term avoidable costs of production.

A number of other more detailed issues are also discussed, and proposals put forward. Depending upon which of the options for treatment of priority dispatch is chosen, it is proposed to set SMP to the effective bid price of the marginal price-taking generator rather than PFLOOR in the event that the quantity of price-taking generation exceeds demand and that the quantity of generation paid PFLOOR in such circumstances should not exceed demand.

Furthermore, it is proposed that if any of the options for allocating infra-marginal rents behind export constraints are adopted, the option should also apply to Variable Price Takers and also that where tie-break rules are required, de-loading should be instructed by the TSOs on a pro-rata basis. The proposals relating to hybrid plant vary depending which of the options on priority dispatch is chosen, but in principle it is proposed that where possible any relevant solution is applied proportionately to such plant. The importance of the RAs’ existing proposals to review the incentive arrangements applying to the TSOs and asset owners and the review of the Capacity Payment mechanism is highlighted in the context of the discussions as is the importance of ensuring that the TSOs and asset owners continue to make available information relating to changes to scheduling and dispatch of generation in light of increasing levels of renewables and whether there are any associated technical limitations on the quantity of certain types of plant that can be accommodated as well as how such technical issues may be resolved.

The proposals put forward are supported in a number of cases by the results of a programme of modelling the impact of renewables on the system up to 2025.

Contents

1. Introduction

In February 2008, the Regulatory Authorities ("the RAs"), comprising the Commission for Energy Regulation ("the CER") and the Northern Ireland Authority for Utility Regulation ("NIAUR") published a discussion document [1] (the "February 2008 discussion document"), in order to promote discussion over key issues caused by increasing levels of wind generation on the island of Ireland and the potential solution to those issues in the context of the SEM and in anticipation of developments arising from the All-Island Grid Study which, at the time, had recently been published. The document set out a variety of matters that the SEM Committee considered it necessary to address in the context of increasing wind penetration with a focus on dispatch and pricing. The RAs stated that they considered that changes to existing rules and procedures arising from the process would be proportionate and limited to those which were necessary and appropriate and that in reaching decisions on the matters being consulted upon, acting within their legal remit the RAs would be guided by their legal duties and functions and a number of "guiding principles".

Twenty six responses were received[2]. In September 2008, the RAs published an initial response to these comments and set out the next steps[3] (the "September Paper"). The RAs undertook to publish a further consultation paper on this issue, which would cover a range of inter-related issues associated with scheduling and dispatch and the Trading and Settlement Code (TSC).

In January 2009, the RAs invited interested parties to engage in bilateral discussions on these issues. A number of meetings were held with interested parties, including EirGrid and SONI as the Transmission System Operators ("TSOs").

This consultation paper takes forward certain issues raised in both the February 2008 discussion document and in the bilateral meetings with interested parties, and puts forward for consideration proposals for changes to the TSC, dispatch processes and connection matters that may be appropriate in light of the substantial quantity of renewable, notably wind, and conventional generation in the connection queue process and the anticipated

1 "Wind Generation in the SEM: Policy for Large-Scale, Intermittent Non-Diverse Generation", SEM/08/002, 11th February 2008. http://www.allislandproject.org/en/generation.aspx?article=9de651c9-9e5c-4330-9b60-e1829d547e49&mode=author

2 The "guiding principles" and main issues raised are identified in Section 2.3 below. Non-confidential responses can be viewed at http://www.allislandproject.org/en/generation.aspx?article=5bb9b3bb-d35f-43aa-ad50-d2f0d18cc436. A more detailed summary and response to the issues raised is included in Appendix 4.

3 Wind Generation in the SEM: Policy for Large Scale, Intermittent, Non-Diverse Generation. Initial response to comments and next steps. SEM-08-127, 28th September 2008. http://www.allislandproject.org/en/generation.aspx?article=5bb9b3bb-d35f-43aa-ad50-d2f0d18cc436.

substantial quantity of new/upgraded network. It focuses particularly upon generation dispatch and on the design of the “unconstrained schedule”. The RAs are consulting separately on reviews of the capacity payment mechanism and ancillary services and upon proposals for SO incentivisation.

The structure of the paper is as follows: Section 2 gives background, including legal considerations and other consultations and studies; Section 3 examines the fundamental purpose of dispatch and the trading arrangements and explains how this informs the assessment of the current arrangements and possible options for change; Section 4 explains what the principles developed in Section 3 mean in the context of a number of current SEM issues, such as curtailment, etc.; Section 5 summarises the proposals and concludes; and Section 6 details the proposed next steps. Appendix 1 describes aspects of the current arrangements for wind generation and for firm and non-firm generation; Appendices 2 and 3 describe modelling analysis which quantifies a number of the effects being considered; Appendix 4 includes more detail of the responses to the February 2008 discussion document; whilst Appendix 5 gives an assessment of proposals and options against the criteria set out in the February 2008 discussion document.

Comments on any of the issues raised in this document should be returned, in electronic format, by 1700hrs on September 18th to info@allislandproject.org.

2. Background

2.1. SEM Arrangements

The SEM, the all-island arrangements for the trading of wholesale electricity, went live on the 1st November 2007. The all-island arrangements include the following key features:

- a gross mandatory pool incorporating a new energy pricing mechanism;
- a capacity payment mechanism; and
- harmonised all-island arrangements for ancillary services .

The introduction of the SEM was underpinned by new legislation[4] in both Ireland and Northern Ireland which included provision for joint regulation of the wholesale electricity market arrangements through the SEM Committee. Numerous papers describing the high-level design and subsequent design decisions, as well as initial versions of the Trading & Settlement Code ("TSC"), can be found on the AIP website. The current version of the Trading and Settlement Code can be found on the website of the Single Electricity Market Operator (SEMO)[5].

2.2. Legal Background

The duties of the Commission for Energy Regulation (CER), of the Northern Ireland Authority for Utility Regulation (NIAUR) and of the SEM Committee in relation to SEM matters are set out in the SEM-related legislation in Ireland and Northern Ireland. In the case of Ireland, this is the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007[6], and in Northern Ireland, the 2007 Electricity Order[7]. The SEM Committee, as constituted in Ireland and in Northern Ireland, has identical duties in relation to SEM matters which principally include the protection of consumers in both Ireland and Northern Ireland wherever appropriate by promoting effective competition. In each case, when carrying out their functions, the RAs must also have regard to, *inter alia,* security of supply, the effect on the environment in Ireland and Northern Ireland and the need, where appropriate, to promote

4 Electricity Regulation (Amendment) (Single Electricity Market Act) 2007, The Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 SI No. 913(N.I.7).

5 See: http://www.allislandproject.org/en/high-level-design-consultation.aspx?article=f87b8dba-3fd8-48cb-9562-6a9e278a1830 for SEM high-level design and http://www.allislandmarket.com/MarketRules for a copy of the latest Trading and Settlement Code.

6 Electricity Regulation (Amendment) (Single Electricity Market) Act 2007. http://www.oireachtas.ie/documents/bills28/acts/2007/a507.pdf.

7 The Electricity (Single Wholesale Market) (Northern Ireland) Order 2007. http://www.opsi.gov.uk/si/si2007/uksi_20070913_en_1.

the use of energy from renewable sources. In addition to the above provisions, it is noted that the SEM legislation provides[8] that the CER, NIAUR and the SEM Committee shall '*have regard to the objective that the performance of any of their respective functions in relation to the Single Electricity Market should, to the extent that the person exercising the function believes is practical in the circumstances, be transparent, accountable, proportionate, consistent and targeted only at cases where action is needed*'.

In carrying out the relevant duties pertaining to renewables, as set out in SEM legislation and referred to above, the RAs are cognisant of the EU Directive pertaining to renewables. [9] The aim is to achieve an EU-wide 20% share of the final consumption of energy from renewable sources by 2020, including a 10% share of energy from renewable sources in transport energy consumption. The national targets for the overall share of renewables in the final consumption of energy by 2020 are 16% for Ireland and 15% for Great Britain.

It is noted that, in Ireland, Section 6 of the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007 amends Section 9 of the Electricity Regulation Act 1999 and in doing so provides that, where the SEM is in operation, subsections (3), (4) and (5) of that Section shall not apply in relation to an SEM matter. These subsections pertained to various matters to which the Commission must have regard and certain duties, including that to require that the System Operator gives priority to generating stations using renewable, sustainable or alternative sources when selecting generating stations. In Northern Ireland, there is no specific legislative provision regarding provision of priority dispatch for renewables.

Whilst, as is described above, in carrying out their functions, the SEM Committee must have regard to, *inter alia,* the effect on the environment in Ireland and Northern Ireland and the need, where appropriate, to promote the use of energy from renewable sources, support mechanisms and targets for renewables are essentially a matter for Government and not the direct responsibility of the SEM Committee or the RAs.

2.3. Previous Consultations

The February 2008 discussion document was published in order to promote discussion of the key issues that may arise from the increasing penetration of intermittent generation, notably wind, on the island of Ireland in the context of the SEM design, the publication of the

8 The Electricity (Single Wholesale Market) (Northern Ireland) Order 2007, Article 9(7)(a) and Section 9BD of the Electricity Regulation Act 1999 as amended by the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007.

9 Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

All Island Grid Study and the potential for increasing congestion for a period on both the transmission and distribution systems on the island.

The February 2008 discussion document suggested that wind generation poses substantial new challenges for the operation and management of the electrical system for a number of reasons: wind generation usually connects to the transmission or distribution system in electrically remote locations; the scale of new wind entry is potentially very significant; wind and wind generation is difficult to forecast precisely; and wind generation has a number of technical characteristics which differ from that of conventional generating plant. Some respondents also expressed a general view that the SEM is not robust against high levels of wind generation and that the fixed costs of some conventional plant that will be required by the system will not be covered. More specifically, some comments related to the capacity mechanism and argued that the capacity payment mechanism presently over-rewards wind generation, whilst others argued that wind generation would reduce the infra-marginal rents for thermal generators that will be needed for back-up. Other comments suggested that the level of future wind was being restricted by the lack of flexibility of other generation and that future market mechanisms would need to provide more rewards for flexibility, whereas presently generators could profit from a lack of such flexibility. Also, there was considerable criticism of the concept of “curtailment”, where this is interpreted as generators being constrained down without compensation, with some respondents arguing that it would be likely to penalise wind generators for the inflexibility of other generators. Many respondents commented on the treatment of generators with “firm” and “non-firm” access and raised issues over how firmness should be treated in both dispatch and in circumstances when generating plant was constrained off.

The February 2008 discussion document stated that in reaching decisions regarding the matters consulted upon, the RAs, acting within their legal remit, would be guided by their legal duties and functions and by the following principles:

- Equity
- Cost minimisation
- Value reflective pricing
- Competitiveness
- Transparency
- Security of supply

An assessment against these principles of the options put forward in this paper is included in Appendix 5.

In September 2008, the RAs published an initial response paper[3] in which they committed to various pieces of additional work in order to progress a range of issues associated with the treatment of renewable generation in the SEM. They also identified other work streams which were addressing relevant matters and which were already underway. In relation to Ancillary Services, including compliance with Grid Code requirements, the RAs noted that the TSOs had commenced a review on an all-island basis. Following the publication of a SEM Committee decision paper on harmonised all-island arrangements for Ancillary Services in January 2009[10], the TSOs are now inviting comments on the implementation of the RAs' decision[11]. The TSOs' review is continuing in light of the conclusions of this consultation process. Insofar as TSO incentives were concerned, the RAs considered that it was most appropriate to pursue further work following the setting of policy in relation to dispatch issues, i.e. also in light of the conclusions of this consultation process.

A more extensive summary of the main points raised in response to the February 2008 discussion document and the RAs' response is included as Appendix 4.

2.4. Renewables Targets

Directive 2001/77/EC8, adopted by the European Parliament and the Council of the European Union in September 2001, set out national indicative targets for electricity produced from renewable energy sources by 2010. In April 2009, the EU Council of Ministers adopted a directive setting a common EU framework for the promotion of energy from renewable sources. This Directive replaces 2001/77/EC and sets out binding targets for Member States with the aim of achieving an overall 20% share of energy from renewable sources by 2020. The specific national targets for the share of the gross final consumption of energy from renewable sources are 16% and 15% for Ireland and the United Kingdom, respectively.

The UK currently has an electricity target of 10% from renewable generation and, for Northern Ireland, the Department of Enterprise Trade and Investment's Strategic Energy Framework, published in June 2004, contains a target for the proportion of electricity that is generated from indigenous renewable sources by 2012 of 12%, of which at least 1.8% should be from non-wind renewable sources. The Renewables Obligation Order (Northern

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10 Harmonised All-Island Implementation Arrangements for Ancillary Services and Other Payments and Charges. SEM Committee, 30th January 2009. SEM-09-003. http://www.allislandproject.org/en/transmission.aspx?article=78f3993b-363f-4b8b-9e1c-15deca01ec12.

11 Additional information may be found at: http://www.eirgrid.com/EirgridPortal/DesktopDefault.aspx?tabid=Ancillary%20Services;

Ireland) 2007 contains a target of 6.3% of total energy supplies, i.e. not just electricity production, to come from renewable sources by 2012. In November 2008, DETI published a scoping paper on the Northern Ireland Strategic Energy Framework[12]. This restates DETI's June 2004 target of 12% renewable energy from indigenous sources by 2012, with at least 1.8% from non-wind resources. It also states that actions to progress beyond the 2012 target will form part of the new energy framework.

The Irish Government's White Paper on Energy sets out the Irish Government's energy policy framework for the period 2007-2020[13]. This sets a target of 33% of electricity consumption from renewable sources by 2020 and states that an all-island target for renewable energy will be set with Northern Ireland Authorities in 2007, informed by the All-Island Grid Study discussed below. Furthermore, the Irish Government has agreed to increase this target to 40% by 2020[14].

Whilst, as noted in Section 2.2, the RAs are not specifically tasked to deliver these targets, it is appropriate that the design of the SEM should continue to operate effectively and allow such targets to be achieved economically and efficiently, and with continued security of supply.

2.5. The All Island Grid Study

In July of 2005, the Governments of Ireland and Northern Ireland jointly issued a preliminary consultation paper (the "July 2005 paper") on an all-island '2020 Vision' for renewable energy.[15] The paper sought views on the development of a joint strategy for the provision of renewable energy sourced electricity within the All-island Energy Market leading up to 2020 and beyond, so that consumers, North and South, could continue to benefit from access to sustainable energy supplies provided at a competitive cost. Within the context of the All-island Energy Market Development Framework agreed by Ministers in November 2004 and the undertaking to develop a Single Electricity Market, views were sought on how the electricity infrastructure on the island might best develop to allow the maximum penetration of renewable energy.

12 Northern Ireland Strategic Energy Framework. Pre-consultation Scoping Paper. November 2008 DETI http://www.detini.gov.uk/cgi-bin/downutildoc?id=2306.

13 Government White Paper: Delivering a Sustainable Energy Future for Ireland. The Energy Policy Framework 2007-2020, Department of Communications, Marine and Natural Resources, March 2006.

14 Minister Gormley T.D. Outlines Carbon Budget. 15/10/08. http://www.environ.ie/en/Environment/News/MainBody,18676,en.htm.

15 All Island Energy Market Sustainability in Energy Supplies: A "2020 Vision" for Renewable Energy. DETI and DCMNR, July 2005. http://www.dcenr.gov.ie/NR/rdonlyres/271DDB5C-0EE3-4A89-A752-688B42527140/0/2020VisionforREfinal.pdf.

The July 2005 paper identified that further information was required on: the resource potential for different renewable technologies on the island of Ireland in 2020; the extent to which partially dispatchable and non-dispatchable generation could be accommodated; network development options; and the economic implications of the policy options outlined within the paper.

A working group was established to specify and oversee the completion of studies that would provide more detailed information on the above issues. The working group recommended an "All Island Grid Study" comprising four work-streams. The All Island Grid Study examined the impact and feasibility of a number of different generation portfolios with increasing renewables penetration. Its results were published in January 2008[16], and the key conclusions were as follows:

- the results indicated that the differences in cost between the highest cost and lowest cost portfolio are low (7%), given the assumptions made and the costs included in the Study;
- all but the high coal based portfolio led to significant reductions of CO2 emissions compared to Portfolio 1 (the portfolio with the least renewables);
- all but the high coal-based portfolio led to reductions on the dependency of the all-island system on fuel and electricity imports;
- the limitations of the study may overstate the technical feasibility of the portfolios analysed and could impact on the costs and benefits resulting. Further work is required to understand the extent of such impact;
- timely development of the transmission networks, requiring means to address the planning challenge, is a precondition for the implementation of the portfolios considered;
- market mechanisms must facilitate the installation of complementary i.e. flexible dispatchable plant, so as to maintain adequate levels of system security.

A number of areas of required further work were also identified which included:

- modelling the behaviour of the system accommodating high portions of renewable generation;

16 Final Report on the All Island Grid Study. Published on DCENR's website at: http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Electricity+Grid+Study.htm.

- carrying out detailed network planning studies assessing the challenges associated with the development of the transmission system and generator connections; and
- evaluating the portfolios under the conditions of real markets in order to specify the conditions under which sufficient returns will be available for existing and new conventional and renewable generation.

2.6. Previous Modelling of the Impact of Wind on the SEM

In January 2009, the RAs published the results of a modelling study[17] examining the impact of high levels of wind penetration on the SEM in 2020. The results of the study suggested that the increasing penetration of wind generation in the market will have noticeable effects on the unconstrained market. The key results were that:

- in most modelling scenarios, irrespective of the level of fuel and carbon prices, the increasing penetration of wind would be accompanied by significantly lower wholesale market prices;
- the economic benefits of increasing wind penetration are sensitive to carbon and fuel prices;
- the picture on incentives for generators to enter and exit the market were mixed and dependent upon the generation portfolio modelled;
- a mixed portfolio of plant, i.e. CCGTs, OCGTs and wind, has a greater positive impact on CO2 emissions than OCGTs and wind only; and
- the SEM design is potentially robust to significant increases in the amount of wind generation on the system, though the marginal nature of the incentives on new generation to enter the market is of concern, which suggests that the design will need to be kept under close review in years to come.

This study looked at the outcomes of the energy and capacity market only and did not look at the effect of increased wind penetration on constraint or other costs (and associated generator revenue streams) of operating the system.

In December 2008, EirGrid and SONI committed to engaging consultants to undertake technical studies in respect of the operation and management of the all island system with

17 Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market (SEM). A Modelling Study by the Regulatory Authorities. January 2009. SEM-09-002. http://www.allislandproject.org/en/modelling-group-minutes-presentations.aspx?article=7e445962-3abe-4224-90a4-82adc6038b91.

increasing levels of wind penetration[18]. EirGrid and SONI noted that the All Island Grid study had already been performed and this indicated that a renewable target of 42 % by 2020 may be technically feasible. They also noted that a number of important caveats remained and stated that they wished to use this benchmarking All Island Grid study as a platform to better understand the remaining caveats

2.7. Grid 25 Study

In March 2007, the Minister for Communications, Marine and Natural Resources published an Energy White Paper "Delivering a Sustainable Energy Future for Ireland"[19]. This paper stated that "*... through EirGrid's Development Strategy (2007-2025) and in light of the All-Island Grid Study, the necessary action to ensure the electricity transmission and distribution networks can accommodate, in an optimally economic and technical way, our targets for renewable generation for the island to 2020 and beyond would be ensured*".

In October 2008, EirGrid published its "Strategy for the Development of Ireland's Electricity Grid for a Sustainable and Competitive Future"[20], referred to as "GRID 25". This document puts forward a strategy for delivering an investment of €4 billion in essential infrastructure in the period to 2025, doubling the capacity of the bulk transmission system in Ireland and intended to facilitate the necessary increase in renewable generation and to meet the demands of the electricity consumer.

It is understood that in Northern Ireland, a similar grid development strategy is also being developed.

2.8. Connection Policies and Processes

In Ireland, since 2004, all renewable generation seeking to connect to the transmission or distribution system has been subject to a group processing methodology. The group processing approach allows connection applications to be processed in a coordinated and by implication more efficient manner.

Renewable applications processed under the group processing approach have been processed in 'gates'. To date there have been three such gates: Gate 1 and Gate 2 led to

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18 All Island TSO Facilitation of Renewables Studies. 10th December 2008. http://www.tendersdirect.co.uk/Ourservice/TenderView.aspx?ID=2307515.

19 Delivering a Sustainable Energy Future for Ireland. DCENR, March 2007. http://www.dcenr.gov.ie/NR/rdonlyres/54C78A1E-4E96-4E28-A77A-3226220DF2FC/27356/EnergyWhitePaper12March2007.pdf.

20 GRID25. Strategy for the Development of Ireland's electricity Grid for a Sustainable and Competitive Future. Eirgrid October 2008. http://www.eirgrid.com/EirgridPortal/uploads/Announcements/EirGrid%20GRID25.pdf.

offers issued to 1700MW of renewable generation while Gate 3 will result in around 4000MW receiving offers from December 2009. The Gate 3 decision[21] was published by the CER on December 16th 2008 and sets out the process and timelines that the TSOs will follow in making connection offers. The paper also includes the list of applicants that are included in the gate. If all projects were to be constructed and connected, the offers to be made in Gate 3 would be sufficient to achieve the Irish government's 2020 target of 40% renewables.

Central to the connection offer process is the ability of the transmission network to take the output of the generation planned. The CER approved an application date order methodology for selecting projects for an offer in Gate 3, with their scheduled firm connection dates determined through EirGrid's Incremental Transfer Capacity Programme (ITC). This in turn is based on the GDS's transmission upgrade strategy. The GDS will provide network assumptions between 2010 and 2025 that EirGrid will then use within its Incremental Transmission Capacity Programme (ITC). The ITC, which is based on the application of an (N-1) security standard, is the programme by which generators will be provided with their detailed offers. These offers will include a firm transmission capacity profile for 2010-2025 for each generator.

Under Gate 3, the allocation of "firm transmission capacity" at each node will be rationed in any given year from 2010 through to 2025, if necessary, on an application date-order basis. To be included with the offers, or shortly thereafter, is a view from the TSO of the likely incidence of constraining off until deep works are complete.

In Northern Ireland, the use of a gate process has not been adopted. All connection applications are processed by the TSO or distribution system operator (as relevant) and new entrants are required to wait until the infrastructure developments required to support their connection application are complete to obtain fully firm access, although it is understood that options for offering non-firm connections are being considered. It is also understood that in the case of some distribution connections, it may be that upgrading the network to allow exports of embedded generation under all outage scenarios may not be economically efficient, principally because the historic development of the distribution network has been aimed at distribution of power to customers rather than the accommodation of substantial quantities of generation. As a consequence, it is understood that in some instances, distribution connected generation is being offered access whereby the permissible export capability of the generation is restricted under certain system conditions (e.g. outages etc.).

21 Criteria for Gate 3 Renewable Generator Offers and Related Matters. Direction to the Transmission System Operators. 16th December 2008. CER/08/260. http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=fb726a75-7365-4dfb-9e16-ff5c5d2d363a.

3. Principles of the Single Electricity Market Design

3.1. Introduction

This Section describes the principles underpinning the design of the SEM in doing so it describes the function of the market schedule and dispatch.

3.2. Dispatch and the Market Schedule

A desirable characteristic of the SEM, as with most other electricity markets, is that it should be efficient, i.e. that the demand for electricity by consumers should be met at least cost of production. This objective must be met subject to a number of operational requirements, such as maintaining a defined reliability of supply, which may result in particular generation not being used.

It is desirable that the efficiency objective is met over both the short and long run. This implies that not only should the cost of production be minimised given the portfolio of generation that is available at any given time but that the overall portfolio of generation will be that which gives a lower cost of production than any other portfolio[22]. In other words, it is desirable both that the portfolio of generation provided by the generators is used efficiently by the TSOs and that the portfolio of generation (i.e. the mix of peaking, mid-merit and baseload plant) provided by generators is efficient also. The short-term objective, of minimising the cost of production given the existing portfolio of generation, is achieved through minimising costs in generation dispatch, whilst the long run objective, of ensuring the best portfolio of plant is provided, is achieved by market arrangements that provide incentives for generators to invest in the most appropriate mix of generating plant by giving the appropriate signals for market entry and exit.

3.3. Dispatch

The objective of generation dispatch should thus simply be to achieve short-run efficiency by minimising the cost of production of meeting customer demand, given the generation portfolio that has been made available to the system operator and taking account of the need for system safety, reliability and security, i.e. ensuring that the limitations of the transmission system are not exceeded, that frequency is maintained and that the system can withstand defined transmission or generation faults without more than a specified loss of load.

22 Renewables support mechanisms will change the portfolio that generators are incentivised to provide. Nevertheless, the market arrangements should seek to give the least cost generation portfolio given this external effect.

Were dispatch not to be at least cost, and it was proposed to generate using an expensive generator in preference to a cheaper one then, subject to system constraints, the generators would, if possible, want to enter into an arrangement whereby the cheaper generating unit would generate in lieu of the more expensive one, thus fulfilling the more expensive generator's commitments but at lower cost. In effect, the generators would choose to be dispatched on a least cost basis and would, if possible, trade between themselves so as to achieve this result. However, it is widely recognised that in practical electricity systems such bilateral transactions would be difficult to arrange over potentially very short timescales and more so given the technical considerations associated with the safe and stable running of the transmission system. Hence, in most systems, including the SEM, one or more central system operators have the task of delivering the most efficient achievable outcome directly, without the need for bilateral trades between generators.

Similarly, dispatch decisions taken by the system operator should ignore any concept of 'firmness' or 'non-firmness' of transmission access. This is because, for example, where a new “non-firm” generator that is cheaper than an existing “firm” generator connects to the transmission or distribution system, cost will always be minimised by generating from the cheaper unit in preference to the more expensive existing unit, irrespective of the nature of any access rights.

This principle of minimising the cost of production irrespective of any access rights is currently reflected in the way in which generators are dispatched in the SEM by the TSOs today.

3.4. Role of a Market Schedule

An electricity market could be designed to compensate generators at only their bid price for actual generation. If bid prices reflect short-run avoidable costs, generators will be indifferent between generating and not generating. However generators under this scenario would never recover their fixed costs and hence would exit the market. Alternatively, if all of the fixed costs were sunk, existing generators might not exit but potential new entrants would choose not to enter.

An additional capacity payment paid to enough generators to meet total customer demand (plus a margin for security) and based on the fixed costs of a 'Best New Entrant Peaker' (“BNE Peaker”) would ensure that enough generators could recover their operating costs plus the fixed costs of a BNE Peaker. However, there would be no incentive for generators to invest in plant which had higher fixed costs but lower avoidable costs than the BNE

Peaker, as such generators would be paid only the lower fixed costs of the BNE Peaker and the lower bid price for their actual generation. Under this arrangement, only a BNE Peaker would be able to recover its costs – all other plant types would lose money – and hence only BNE Peakers would enter the market.

This problem may be avoided by paying certain generators, not at the avoidable cost of production, but at a system marginal price or SMP. Whilst there are a number of variants, a common design which follows this approach, and of which the SEM is an example is that payments to generators are given by:

$$GP = MSQ.SMP + (DQ - MSQ).BP \qquad (1)$$

where:
- GP = payments to generators;
- SMP = system marginal price;
- BP = bid price;
- DQ = dispatch quantity; and
- MSQ = market schedule quantity,

This is sometimes interpreted as meaning that generators are paid at SMP for their output in the "market schedule" (often referred to as the "unconstrained schedule") and at bid price for the deviations between their market schedule quantity and the output to which they are dispatched by the TSOs.

Rearranging this equation gives,

$$GP = (SMP - BP).MSQ + BP.DQ \qquad (2)$$

The last term, BP.DQ, is merely the cost of production which, as is described in the previous Section, the TSO is seeking to minimise when it dispatches the system. The first term is the difference between SMP and BP - the "infra-marginal rent" - for generators scheduled in the market schedule. These infra-marginal rents provide the incentive to build plant other than a BNE Peaker. This is because if the aggregate lifetime infra-marginal rents outweigh the additional cost of capacity then it will be profitable for a generator to build generating units with a cost of production lower than that of the BNE Peaker. As the baseload market becomes saturated, and more and more baseload units compete for the infra-marginal rents, so the scope for those infra-marginal rents to outweigh the additional capacity costs will reduce and it will become more profitable to invest in load-following generation which will have a relatively lower capital cost but a higher cost of production[23]. Infra-marginal rents therefore give incentives to build a mix of baseload, mid-merit and peaking plant that will result in a minimum cost of production which is lower than would be the case with a generation portfolio consisting of only BNE Peakers. This will minimise the cost of production, not just over the short-term, but in the long run also.

However, for this long run minimisation to be effective, it is vital that infra-marginal rents are allocated to generation that can actually contribute to minimising the short-run cost of production, i.e. to generation that will get dispatched. The generation to which infra-marginal rents are allocated is determined by the market schedule, and thus it is important that the market schedule is constructed to reflect the mix of plant routinely required to satisfy the demand of customers at least cost[24]. To this end, the design of the market schedule used in the SEM reflects a number of real-world constraints, including:

- generator dynamics - without modelling the dynamic characteristics of generating plant, i.e. ramping rates, minimum stable generation, etc., the market schedule would tend to allocate infra-marginal rents to low cost but inflexible generators, ignoring their inability to follow variations in customers' demand; and
- transmission capacity - broadly-speaking, generators are precluded from participating in the market schedule until the transmission system deep infrastructure reinforcements necessary to accommodate their output are complete. However, as is discussed in Section 4.2 currently in circumstances where generators with non-firm access are dispatched above their FAQ, they are permitted access to the market schedule at a level equal to their dispatch quantity.

In either case, the consequence of failing to model these 'real-world' operational limitations would be that there would be plant included within the market schedule that was technically unable to run, because of the real-world system limitations. As a result of being included in the market schedule, this plant would receive infra-marginal rents, giving it the incentive to enter (or not to exit) the market, even though it did not make a significant contribution to

23 There are, in fact, two effects operating here: first, with an inability of baseload to follow load, generation with better dynamics will be able to earn infra-marginal rents despite having a higher cost of production than baseload generators; second, because of the lower load factor of load-following plant, it is going to tend to shift the trade-off between capital costs and cost of production in favour of lower capital costs and higher operating costs.

24 It could be argued thus that infra-marginal rents should be allocated only to those generators that are actually dispatched. However, there are reasons why, to a limited extent, this may not be desirable: first, it would be inappropriate for the system marginal price to be inflated by expensive generation that has to be dispatched behind localised import constraints; and, secondly, actual dispatch may be influenced by effects such as transitory variations in transmission capacity or dispatch errors. Hence the use of some form of “schedule” to determine prices and quantities which excludes these effects may be desirable.

meeting customers' demand. However, by including in the design of the market schedule the requirement for transmission system deep infrastructure reinforcements to be completed, the incentive to construct generation ahead of the transmission system's ability to accommodate its output is reduced, whilst including generator dynamics in the design of the market schedule provides an incentive for load-following plant to enter the market.

In the SEM, the incentive on generators to wait until sufficient transmission infrastructure reinforcement is available is diluted by permitting generators with non-firm access to be available in the market schedule above their Firm Access Quantity (FAQ) if they are dispatched above this level by the TSO. Whilst this may, in some ways, be considered a desirable feature of the SEM, because it permits new entrants to compete for dispatch and infra-marginal rents from an earlier stage, as discussed further in Section 4.2, if both the non-firm new entrant and a firm existing generator behind an export constraint are scheduled in the market schedule, generators located on the import side of the constraint, which are required to run in practice, are excluded from the market schedule and consequently do not have access to infra-marginal rents and are therefore incentivised to deliver only BNE Peakers[25]. Consequently the market design currently does not give appropriate signals for generators to deliver an efficient portfolio of plant on the import side of the constraint.

In the extreme, the failure to model these real-world constraints (where material) would result in a portfolio of plant receiving infra-marginal rents but persistently being constrained-off, whilst customers' demand was being met by BNE peakers. In practice these effects take place at the margin but, nevertheless, the potential long-term effects of the misallocation of infra-marginal rents, with the inability of all plant in the efficient portfolio to cover its costs, are likely to be significant. As is discussed further in Section 4.2.2 below, modelling analysis suggests that, unless changes are made to existing SEM arrangements, by 2020, the misallocation of infra-marginal rents would result in the incentive on those generators actually required to meet demand to deliver an efficient portfolio of plant being diluted by €277m/year.

From the above, it follows that the market schedule should include generating plant that is of value in meeting actual demand.

25 This is discussed further in Box 2, Section 4.4

4. Options for SEM Changes

4.1. Introduction

Section 3 established two basic principles of an efficient energy market i.e.:

i) real-time dispatch should have the objective of minimising production cost, (taking into account system security considerations); and

ii) infra-marginal rents, required to give investment incentives for generators to construct an efficient generation mix, should be allocated to generating plant that is useful in meeting customer demand, in order that an efficient mix of usable plant is delivered.

Both of these principles, as is discussed further in this section, are substantially encapsulated within the existing SEM arrangements.

However, given the large number of applications for connection to the transmission and distribution networks in Ireland and Northern Ireland, it is anticipated that a substantial number of new generators will seek to participate in the SEM in the intermediate future. These generators include a large number of renewables, particularly wind-powered generators, as well as conventional plant. The effects of this influx of new entrants are likely to include:

(i) a very substantial capital infrastructure programme in both Ireland and Northern Ireland such that the transmission and distribution networks can be appropriately reinforced to accommodate the new generation plant;

(ii) there is likely to be a large number of generators connecting to the system before the necessary infrastructure is complete, and hence operating with “non-firm” access[26];

(iii) a large increase in the number of intermittent generators participating in the SEM, which have different technical characteristics to the existing generation portfolio, implying that requirements of the system, such as inertia and fault level in-feed, which have always been met by conventional generating plant may become a factor in system operation; and

26 Please refer to section 2.8 above. In some cases, generators access rights may be limited through setting firm access quantities (FAQs) below the maximum export capability (MEC) of the generator until deep infrastructure works are completed. In other cases, where planning standards would otherwise require substantial infrastructure reinforcement, rights may be restricted by limiting FAQs under particular system conditions, e.g. when certain circuit outages are required etc., including by the use of so-called “special protection schemes”.

(iv) uncertainty over the way in which the TSOs will change the schedule and dispatch processes as the generation portfolio increasingly includes a large proportion of intermittent generation, e.g. whether or not additional reserves will be required or whether the TSOs will improve forecasting techniques or adopt more probabilistic methodologies in dispatch decisions, all of which may affect both the overall amount of intermittent generation that can be used to meet customer demand, as well as the nature of the other generation required in the portfolio.

Thus, whilst the construction of the market schedule in the SEM currently corresponds well with the generation that is required in dispatch to meet customer demand, it is important that the arrangements are reviewed in the context of increasing levels of non-firm and intermittent generation. It is possible for example that unless changes are made to the existing SEM arrangements, there may be an increasing divergence between the generating plant actually used to meet demand in dispatch by the TSOs and the generating plant that is allocated infra-marginal rents in the market schedule and consequently that the wrong investment signals emanate from the market. This is discussed further in Section 4.2 below.

In this context, this section goes on to review:

- the construction of the market schedule;
- curtailment;
- technical constraints;
- allocation of access rights;
- deemed firm access;
- dispatch principles;
- priority dispatch;
- hybrid plant;
- treatment of variable price takers;
- the determination of SMP when demand is met by price takers;
- the quantity of generation paid PFLOOR;
- tie-breaks in dispatch;
- system operator and asset owner incentives; and
- the capacity payment mechanism and ancillary services.

4.2. Construction of the market schedule

4.2.1. Introduction

As discussed in Section 3.4, the effect of allocating infra-marginal rents to generators at times when they are not used in dispatch is that some generators that are required in actual dispatch do not receive these rents. This section considers the issues and implications arising in the SEM within this context.

4.2.2. Issues and Proposals

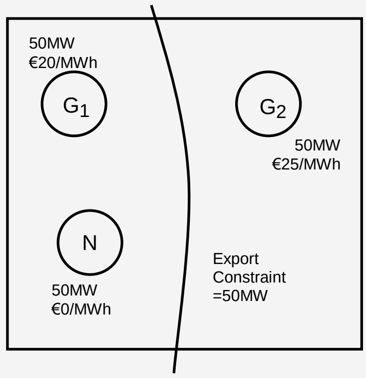
An example from the current SEM design which could lead to the misallocation of infra-marginal rents has been briefly discussed in Section 3.4. Generators with non-firm or partially firm access are currently included in the construction of the market schedule above their Firm Access Quantity (FAQ) level, if they are dispatched above their FAQ by the TSO. Because other plant with firm access may be co-located behind an export constraint with non-firm generators, in total, infra-marginal rents may be over allocated to plant that is behind an "export constraint" compared to that which can be accommodated in actual dispatch. This is illustrated further in Box 1 below.

The concept of "export constraints" in this context is important to understand and one which is used in subsequent sections of this paper. Generators which connect to the transmission system ahead of the transmission reinforcements necessary to afford their firm access are connecting behind "export constraints". These "export constraints" are not transitory constraints due to transmission faults or outages but are due to a lack of infrastructure capacity which will exist until the transmission reinforcements are complete.

Box 1 – Current SEM Arrangements

Consider a simple system with three generating units G_1, G_2 and N. All three generators have an availability of 50MW. G_1 and G_2 are incumbent generators with fully firm access, having bid prices of €20/MWh and €25/MWh respectively. N is a new entrant having a bid price of €0/MWh but its access is totally non-firm (FAQ = 0MW). System demand is 100MW, so that two of the three generators are sufficient to meet demand. However, due to the transmission constraint, the TSO is unable to dispatch the two cheapest generators, G_1 and N, and G_2 must run always if system demand is to be met.

Current TSC arrangements include non-firm generation in the market schedule (providing it is in merit) at the maximum of its Firm Access Quantity (FAQ) or Dispatch Quantity (DQ). The market schedule thus comprises G_1 and N, and hence all 100MW of generation behind the export constraint receives infra-marginal rents. G_2 is constrained-on and hence receives only its bid price. Thus, any G_2 other than a BNE Peaker will lose money.



	Current TSC
DQ	N and G_2
MSQ	N and G_1

As is described in Section 5.4 of Appendix 2, market schedule modelling studies were undertaken where the total output of generators behind export constraints was limited to the level of the export constraints. The market schedule was therefore required to schedule alternative generation on the import-side of these constraints in order to meet demand. In studies for 2020, the infra-marginal rents paid to generators on the import side of the constraints increased by €277m compared to infra-marginal rents under existing arrangements. This implies that if the existing arrangements are retained, in 2020, the incentive on those generators actually required to meet demand (i.e. those on the import side of the constraints) to deliver an efficient portfolio of plant would be diluted by €277m.

Further analysis of the 2020 modelling study, as is shown in Appendix 2, Section 5.6 and 5.7, highlights the impact that this will have on the ability of plant, other than BNE Peakers, to receive enough revenues to cover their fixed costs.

As a consequence, unless additional payments or alternative arrangements are introduced that incentivise other plant types, only BNE Peakers will be expected to receive enough revenues to cover their fixed costs even though this will not necessarily represent the most efficient long run generation portfolio.

A further concern raised by respondents to the February 2008 discussion document was that additional flexible plant would be required to support the operation of the system with materially increased levels of wind generation, and that this plant was not being adequately rewarded in the SEM. This comment also reflects[27] one of the key conclusions of the All Island Grid Study, which stated, "*Market mechanisms must facilitate the installation of complementary, i.e. flexibly dispatchable plant, so as to maintain adequate levels of system security*". If additional flexible plant is required and the need is not reflected in the market schedule such that it does not receive infra-marginal rents, then it is likely that other means of providing additional remuneration to such plant, for example through increased capacity payments or ancillary services payments for reserve will be required.

It should also be noted that a further consequence of including generation in the market schedule which cannot actually be dispatched is, not only that some plant needed to meet actual demand fails to receive infra-marginal rents, but also that SMP, and hence the infra-marginal rents paid to all generating plant, is depressed. This is seen in the simple example illustrated in Box 1, where SMP is set by G1 at €20/MWh. Whilst a lower SMP may appear to be beneficial to customers, at least in the short-term, lowering of the infra-marginal rents will shift the balance of new entry towards "low capital high operating cost" plant and away from "high capital low operating cost" plant. Thus, if SMP is suppressed to below the economic level, costs to customers are likely to be increased over the longer-term.

At the same time as failing to provide the correct investment incentives for plant that is required, the allocation of infra-marginal rents to plant which cannot actually be dispatched, will provide incentives for generators - both renewable and conventional - to invest in plant that is not, or not yet, capable of being accommodated by the transmission system. From a customer standpoint, payments would be being made to generating plant which could not be used to meet demand. From an environmental standpoint, providing infra-marginal rents to renewable generators that cannot be dispatched will not help to meet emissions targets, as these targets require that renewable generation is dispatched, not merely that the capacity is constructed and included in the market schedule. Hence, both in order to ensure ongoing efficiency for consumers as well as to ensure that the SEM provides appropriate signals for the right renewable and conventional plant, it is important to maintain a good correlation between the market schedule and actual dispatch.

27 See Section **Error! Reference source not found.** above.

The risks posed to generators by the uncertainties of future system requirements[28] could, if desired, be underwritten by the electricity consumer. This could be effected by insuring new entrant generators against these uncertainties by providing certainty of future revenues. For instance, it would be possible to commit to constructing future market schedules that disregard the system's potential requirement for system inertia and/or fault level in-feed. To do so might well be a self-fulfilling prophecy, as generators would not have the incentive to construct plant that resolved such technical limitations should they arise.

As the SEM operates now, generators have to consider carefully the future demand profile of the system and weigh up the relative requirements for baseload vis-à-vis mid-merit or peaking generation, doing so taking into account the possible entry and exit decisions of competitors. They are incentivised to do so because they know that the profile of demand will be reflected in the design of the market schedule. Similarly, making it clear that, where material issues arise which could give rise to a material divergence between the market schedule and actual dispatch, appropriate changes will be made to the market schedule, will ensure that generators consider carefully these other requirements of the system also.

In light of this, it is proposed that the RAs commit to monitoring the relationship between actual dispatch and the construction of the market schedule and that where material deviations between the two emerge, or where it becomes apparent that they are likely to emerge in the future, steps are taken to rectify the divergence. This means that the RAs will commit to ensuring that infra-marginal rents are, in general, paid to generating plant that is of use in actual dispatch and not to plant that cannot be run for material technical or system reasons.

Proposal: It is proposed that the RAs should seek to ensure that the construction of the market schedule is such that infra-marginal rents are allocated to generating units that are of value to the real-time operation of the system, and where deemed appropriate to make the necessary changes.

This does not mean that the RAs would make changes to the market schedule in all circumstances where differences arise between the construction of the market schedule and actual dispatch. Instead the RAs would need to take into account the materiality of any deviation and the costs of any reforms to correct the deviation. Nevertheless, it is intended that the consequences of this proposed approach will be that, when making decisions, the

28 Including, for example, uncertainties over what new infrastructure will be built and when, what technical constraints there will be, if any, on the total quantity of renewable generation that can be dispatched at any given time, etc.

emphasis of investors should be on the fundamental technical requirements and economics of the system and not on the market rules as they are, or are expected to be, at any given time. It is also intended that whilst, currently there may be many uncertainties associated with the future impact of large quantities of renewable generation, the adoption of such a policy will provide a degree of certainty to existing and future market participants as to how the SEM arrangements will be managed in light of technical or system limitations that actually materialise.

Given the existing uncertainties associated with what generating plant will be needed in the future and how it will be dispatched, it is not possible to provide a definitive list of areas of possible change at this point in time. Nevertheless, a number of potential candidate changes are already emerging. These and a number of other proposals for change to the existing TSC are discussed later.

4.3. Curtailment

A number of definitions have been suggested for "curtailment". Nevertheless the general usage of the term suggests that the term 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, and generally without compensation.

There has been much comment about there being wind-specific reasons for curtailment, and in response that these wind-specific reasons may be discriminatory. In this context, technical requirements, which are discussed in Section 4.4 below, such as fault level in-feed and system inertia, have been cited as being new requirements which apply only to wind generation. However, the need for adequate levels of fault level in-feed and system inertia would already affect the choice of generation which could be accommodated by the system, were it not for the fact that the characteristics of previous generation technologies has resulted in more fault level in-feed and system inertia being available than the system requires. Hence, in the past it has not been necessary even to consider whether such factors should be modelled in dispatch or in the market schedule. The different characteristics of new generation technologies, most obviously wind generation, means that these factors could, in future, become primary factors in defining how the TSO dispatches the system, and consequently the issue of whether these should be modelled in the market schedule arises.

The issue of "curtailment" therefore is simply one of whether or not the relevant generator is included in the market schedule. If it is, then when dispatched down, it will receive compensation (i.e. it will receive its infra-marginal rent). If it is not, then it will not receive compensation. In other words, if a generator's output is "curtailed" but the generator is still included in the market schedule, then the generator may be considered to have been "curtailed" with compensation, whereas if the generator's output is "curtailed" and the generator is not included in the market schedule, then the generator may be considered to have been "curtailed" without compensation.

Whilst it is important to understand the circumstances in which plant that is dispatched down does and does not receive compensation, in light of the above discussion, it is suggested that there is no need for a separate concept or definition of "curtailment", and that instead, it simply forms part of the wider question of how the market schedule should be constructed.

4.4. Technical constraints

4.4.1. Introduction

The connection of large quantities of wind generation will mean that the technical characteristics of plant connected to the transmission and distribution networks differs from that of previously connected plant. A number of concerns have been raised, and are the subject of ongoing analysis by the TSOs. These include whether dispatch will have to take account of the need to:

(a) ensure the adequate fault level in-feeds to allow the continuing effective operation of transmission protection; and

(b) maintain adequate levels of system inertia to maintain stability in the presence of system disturbances.

Currently these are not primary considerations in dispatch and therefore not modelled in the market schedule. In future, it is possible that these issues will be critical factors in the dispatch of the power system and the failure to model such matters in the market schedule may lead to a material divergence between actual dispatch and the allocation of infra-marginal rents in the market schedule. It may be appropriate at that point to consider correcting this divergence.

4.4.2. Options and Proposals

One option would be to model these technical constraints in the market schedule explicitly. The market schedule would then determine the least cost solution, subject to the various dynamic constraints, to meeting not only system demand for MW but also the system's requirements, for example, for fault level in-feeds and system inertia. In order to achieve this, generators would need to submit additional parameters describing, say, the inertia that the generator contributes to the system. When the inertia requirement was tight, generators providing more inertia might be included in preference to generators providing less whilst, at other times, inertia would not significantly affect the mix of plant in the market schedule. Generators omitted thus from the market schedule might be considered to have been "curtailed" in the same way that under the existing arrangements cheap generators may be excluded from the market schedule if their dynamic capabilities mean that they cannot be scheduled to meet demand. Nevertheless, if there is some such reason why any particular mix of plant could not in practice be used to meet customers' demand then long-run efficiency and the best interests of customers will not be served by constructing a market schedule and allocating infra-marginal rents to that mix of plant.

Alternatively, it is possible that these technical requirements can be reflected in the market schedule more simply by the imposition of Grid Code requirements. Many technical requirements are already dealt with in this manner. For example, the system requires generating plant with the capability to operate at a range of power factors so that adequate system voltages can be maintained under a wide range of conditions. By imposing and enforcing a Grid Code requirement, generators without this capability are excluded both from real dispatch and also from the market schedule. The downside of the Grid Code requirement approach is that all generators are compelled to provide the capability even though the system may function perfectly well if it is provided only by some. This implies an inefficient oversupply of the capability, and can lead to difficult decisions where generators seek a derogation from the Grid Code requirement. Nevertheless, where the cost of providing the capability is relatively low, the inefficiency of requiring provision by all will be small. If it proves necessary to make changes to deal with the issues of, for example, fault levels and system inertia that may arise with increasing levels of wind generation, the solution adopted will need to take into account the cost of providing the required services as well as the practicalities of its implementation.

Proposal: The TSOs and asset owners should continue to make available information relating to:

(a) their understanding of what changes to the scheduling and dispatch of generation are being contemplated in light of the increasing level of renewable generation on the system, including where there may be technical limitations on the quantity of certain types of plant that can be accommodated on the system; and

(b) their view of how technical issues (for example system inertia, fault levels etc.) will be resolved.

4.4.3. Other Technical Issues

A related matter is the extent to which existing generators comply with the existing provisions of the Grid Code. A number of concerns have been raised over whether the failure of existing plant to comply with Grid Code technical requirements (either through non-compliance or derogation) means that under certain circumstances non-compliant plant will be displacing other generation in both actual dispatch and in the market schedule. For example, generators that exceed the maximum limit on Minimum Stable Generation may be run at their declared value rather than the lower level required by the Grid Code, thus excluding output from other generators. It has been suggested that the market schedule should be constructed assuming that all generators are Grid Code compliant. Whilst this could remove or reduce any additional profits that may otherwise accrue from Grid Code non-compliance and whilst efforts should be made to encourage and enforce Grid Code compliance, it would be not be efficient to pay infra-marginal rents to generators on the basis of a market schedule which assumed perfect Grid Code compliance rather than a schedule which reflects the actual level of non-compliance. This is, again, because it would reduce the quantity of infra-marginal rents paid to plant actually used to meet demand.

It is therefore proposed that the TSOs should continue with their current initiative to enforce Grid Code obligations on existing and new generating plant, which may include determining and recouping any gains the generator may make from not being Grid Code compliant. Whether these gains are recouped through the TSC or by separate means is for consideration. The TSOs should also keep the Grid Code under review in order to determine whether any additional obligations need to be placed on generating units in order to ensure that future generation portfolios continue to support the satisfactory operation of the system.

Proposal: In relation to the Grid Code;

(a) the current initiative from the TSOs to place additional emphasis on enforcing existing Grid Code obligations on incumbent and new generating units should continue; and

(b) the TSOs should also keep the Grid Code under review in order to ensure that future generation portfolios continue to support the satisfactory operation of the system.

4.5. Allocation of Access Rights

4.5.1. Introduction

Existing SEM processes limit the Firm Access Quantity (FAQ) allocated to generators until such time as the deep infrastructure works required to accommodate their output have been completed. As a consequence, the level of constraints on the system is generally relatively low. Exceptions to this may arise where:

- generators are granted firm access prior to the completion of the works and constraints arise as a result of the need to take construction outages;
- outturn generation and demand patterns are not as were envisaged in planning studies; and
- where regions of the transmission system are not reinforced to the level required by the planning standards, such as the quantity of transmission connecting Northern Ireland and Ireland.

Nevertheless, as discussed in Section 4.2 above, under existing SEM rules, the market schedule allocates infra-marginal rents behind export constraints simultaneously both to generation with non-firm access which is dispatched above FAQ and to other generation with firm access which is in merit on a system-wide basis but which is more expensive than (and hence displaced in actual dispatch by) the non-firm generation. In these circumstances, although the quantity of firm access (in the form of Maximum Export Capacities (MECs) and FAQs) corresponds broadly to the capability of the transmission system, infra-marginal rents are potentially allocated to more generation than the transmission system can support across the export constraint. This provides incentives that encourage investment in generation ahead of the capability of the transmission system to support it. As will be the case with technical constraints, it also means that other generation, on the opposite side of the export constraint, will have to be constrained-on and will not appear in the market schedule, and hence will not receive infra-marginal rents despite being required to meet system demand. Box 2 illustrates further.

Moreover, this allocation of infra-marginal rents is susceptible to gaming. For instance, existing Price-Taking generation with firm access could elect to become Price-Making, submit a low bid price, and be constrained-off by new non-firm generation being dispatched in its place. For any given MW capability for an export constraint, the same MW quantity of additional generation could be connected in advance of the reinforcement of the transmission system, with that extra quantity of generation *and* the constrained-off generation all receiving infra-marginal rents.

4.5.2. Analysis of Options

Options, all of which share the common characteristic of permitting infra-marginal rents to be allocated only to the amount of generation that the transmission system can accommodate, are described below. It is noted that all options presented are high level in nature and require further consideration in relation to implementation requirements.

Option 1: the market schedule allocates infra-marginal rents to the correct quantity of generation behind each export constraint by modelling export constraints in the market schedule. Just as now generators must compete for infra-marginal rents on a system-wide basis, generators will have to compete for infra-marginal rents behind export constraints.

Note that as described in Section 4.2.2, these “export constraints” are not transitory constraints due to transmission faults or outages but are due to a lack of infrastructure capacity which will exist until the transmission reinforcements are complete. Instead, the export constraints would be calculated on the same basis as are FAQs currently, with the value of the export constraint calculated with reference to planning standards[29]. This would remove the risk of system operator dispatch errors and other transitory changes in transmission system capability to exactly the same extent as under the current arrangement; and

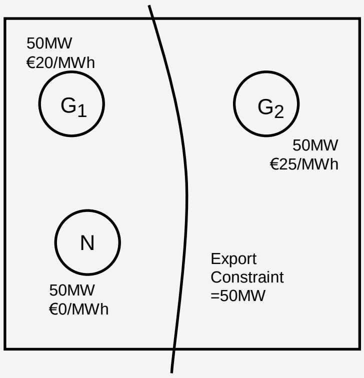
Option 2: the market schedule allocates infra-marginal rents only to generators having firm access quantities. New, non-firm entrants are constrained-on, receiving only bid price, until transmission system reinforcements are completed and they in turn are allocated firm access. Partially firm new entrants will receive infra-marginal rents for output up to FAQ and bid price for output above FAQ. The lack of infra-marginal rents for new entrants will diminish incentives to connect new plant before the transmission system infrastructure is capable of accommodating the additional output.

29 In many circumstances, the value of the export constraint could be expected thus to equal to the sum of the FAQs that would be normally allocated behind such a constraint. However, where there are two or more generators which, across the scenarios that the planning process requires the TSOs to consider, do no run simultaneously, the planning process may allow those generators to 'share' the constraint. In this case the sum of the FAQs may be higher than the capability of the export constraint.

Either of these options addresses the potential misallocation of infra-marginal rents on the import side of any constraint and the associated distortion of incentives. Under Option 1 generators compete for infra-marginal rents whereas Option 2 respects the incumbency of first-comers, as do the current arrangements. Thus, whilst generators are always at risk of being displaced from the merit order (and hence at risk of losing infra-marginal rents) on a system-wide basis, Option 2 removes the risk posed by export constraints arising as a result of the connection of non-firm new entrants. Under Option 2 there is no incentive for new entry ahead of transmission or distribution system reinforcement, since constrained-on plant other than the BNE Peaker cannot cover its costs. As a consequence, under Option 2 there may be more pressure from new entrant generators on the transmission and distribution companies to complete reinforcements in a timely manner. Conversely, Option 1 allows new entrants to enter if they can out-compete existing generators. In this case, pressure to complete the transmission and distribution infrastructure is likely to come from displaced existing generators. Arguably new entrants may be the more effective lobby, as the option of not entering provides a bargaining position that existing generators, whose costs are sunk, do not have.

Box 2

Consider a simple system with three generating units G_1, G_2 and N. All three generators have an availability of 50MW. G_1 and G_2 are incumbent generators with fully firm access, having bid prices of €20/MWh and €25/MWh respectively. N is a new entrant having a bid price of €0/MWh but its access is totally non-firm (FAQ = 0MW). System demand is 100MW, so that two of the three generators are sufficient to meet demand. However, due to the transmission constraint, the TSO is unable to dispatch the two cheapest generators, G_1 and N, and G_2 must run always if system demand is to be met.



Current TSC arrangements include non-firm generation in the market schedule (providing it is in merit) at the maximum of its Firm Access Quantity (FAQ) or Dispatch Quantity (DQ). The market schedule thus comprises G_1 and N, and hence all 100MW of generation behind the export constraint receives infra-marginal rents. G_2 is constrained-on and hence receives only its bid price. Thus, any G_2 other than a BNE Peaker will lose money.

Under both Option 1 and Option 2, the total of MSQ allocated behind the export constraint is limited to 50MW, being the capability of the transmission constraint. Under Option 1, N is allowed to compete with G_1 for allocation of MSQ behind the export constraint. In this option, N is not only dispatched (as a result of its lower bid price) but is included also in the market schedule in preference to G_1. Under Option 2, the market schedule includes G_1, on the basis that it has firm access whereas N does not. The non-firm new entrant is excluded from the market schedule but is constrained-on by the TSO due to its bid price being lower than G_1.

	Current TSC	**Option 1**	**Option 2**
DQ	N and G_2	N and G_2	N and G_2
MSQ	N and G_1	N and G_2	G_1 and G_2

Whilst the current TSC arrangements provide incentives for more generation behind the export constraint than the transmission system can support, Option 1 and Option 2 both allocate infra-marginal rents to the appropriate quantity of generation. Under Option 2, the rent accrues to G_1 as the incumbent and exclusion from the market schedule diminishes the incentive for N to connect until the transmission system is reinforced. Under Option 1, N can compete immediately, albeit G_1 and N are vulnerable to further new entry.

Option 1 applies the same competitive dynamic behind export constraints that currently applies on a system-wide basis. Arguably, Option 1 thus provides incentives for efficiency. On the other hand, a new entrant will also be aware that it, too, can be subsequently out-competed by further new entry, which may lessen the incentive to enter unless prices are higher although, in practice[30], it is hard to envisage that potential new entrants would fail to enter and make use of the availability of increased transmission capacity.

Finally, Option 2, operating on a 'first-come-first-served' basis, creates an incentive on potential generators to apply for connection early in order to secure their place in the queue. Hence the mechanism for allocating access rights may itself contribute to creating a queue of applicants, which necessitates the current "gate" process. Under Option 2, it is likely that generators, recognising that access rights are more valuable to lower cost generators, will want to trade access rights. This has been seen in other similar situations, such as in Great Britain where proposals to permit existing generators to trade their access rights with new entrants have been considered. Thus a variant of Option 2 is to facilitate access rights trading that, if undertaken efficiently, would result in the same allocation of infra-marginal rents as Option 1. A second variant would be to determine the efficient allocation of access rights centrally (as in Option 1) rather than through bilateral trading, but to also to determine the levels of compensation that should be expected in an efficient market. This has the effect of achieving the same efficient allocation behind the export constraint as Option 1 whilst recognising rights of incumbents relative to Option 2. A particular example of this would be where a generator failed to make use of its access rights as a result, say, of being unavailable or of being out-of-merit. Under such circumstances, there would, under Option 2, be an under-allocation of infra-marginal rents behind the export constraint, tending to lead to less investment in generation than the export constraint can support. Hence a further option, which is a modification to Option 2 provides for the reallocation of infra-marginal rents as follows:

Option 3: the market schedule allocates infra-marginal rents first to generators having firm access. In the event this allocation leaves spare capacity on any "export constraint" and there is in-merit non-firm generation behind that boundary, this generation is then included in the market schedule also, up to the limit of the export constraint[31].

This option thus requires a three-stage process for calculating the market schedule:

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30 And, theoretically, any increase in risk will be fully diversifiable, and hence will not require a higher rate of return.

31 As in Option 2, the export constraints of *all* transmission boundaries must be respected. This is of particular relevance where constraints are "nested".

(i) calculate the least cost market schedule using only plant with firm access, i.e. plant which is fully-firm or partially firm plant up to the level of its FAQs;

(ii) for each export constraint, calculate the spare capacity, being the capability of the export constraint less the sum of quantities allocated to firm generators behind that constraint in Step (i);

(iii) re-calculate the least cost market schedule using firm generation (as in Step (i)) and also non-firm generation up to the spare capacity of the relevant export constraint as calculated in Step (ii). Note that, to keep the same quantity of scheduled plant, the inclusion of non-firm generation in the market schedule in Step (iii) would be at the expense of the firm generator that was marginal in Step (i)[32].

4.5.3. Modelling

Detailed modelling of the SEM has been conducted to support and inform the options considered above. The modelling methodology, approach, assumptions and results are discussed in detail in Appendices 2 and 3, however key findings and results are described below. The following schedules were modelled:

CS — A constrained schedule including modelling of thermal ratings, group transmission constraints and reserve requirements. This is intended to model the actual dispatch that will be undertaken by the TSOs;

MS FAQ PM — A market schedule (i.e. without transmission constraints or reserve) with the availability of price makers capped at the maximum of their estimated FAQ and their constrained schedule output. This is intended to model the existing TSC rules;

MS FAQ all — As above, but with the cap on FAQs described above applying to both price-making plant and price-taking plant. This is intended to model the impact of changing the TSC rules to cap the availability of price-takers to FAQ in the

32 In the event that there was more than one non-firm generator behind an export constraint and one or more of these had partially firm access, it is possible that the re-calculation of the market schedule might result in the firm output of generators with partially firm access is re-allocated to the non-firm units. In this case, the methodology described above would not fully implement option 3 as described. If option 3 is favoured following the responses to this consultation further work to identify how it may be implemented in detail would need to be progressed . It is noted that all options presented require such further consideration of detailed implementation issues.

market schedule in circumstances when they are dispatched below their availability, as discussed in section 4.10;

MS FAQ Cap As MS FAQ all, but with the availability of non-firm plant capped at FAQ (rather than the maximum of FAQ and the constrained output). This is intended to model the impact of Option 2 i.e. changing the market rules to limit access to the market schedule to FAQ even where plant operates above this level in actual dispatch.

Under each of the schedules, as well as the observations on infra marginal results discussed above, the following impact on SMP, wind constraints etc were noted:

SMP

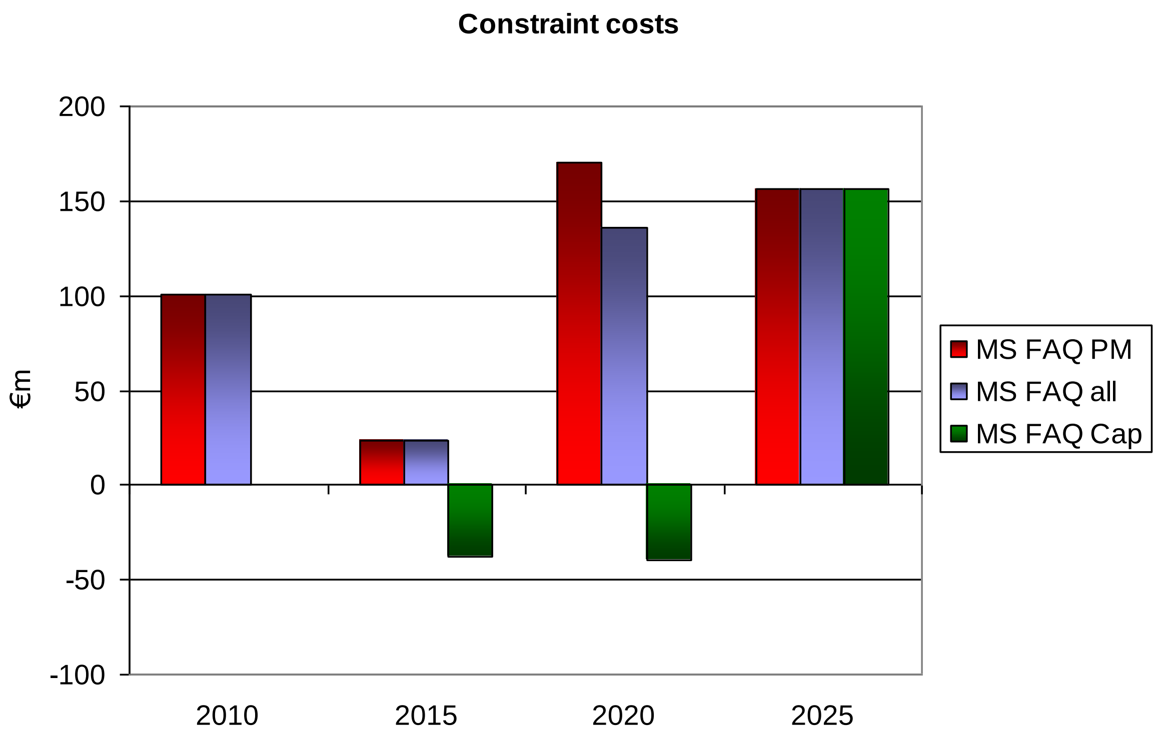
The table below shows the time weighted average SMP for the three market schedules run in the spot years 2010, 2015, 2020 and 2025.

€/MWh	**2010**	**2015**	**2020**	**2025**
MS FAQ all	46.13	49.74	62.04	73.74
MS FAQ PM	46.15	49.74	61.73	73.74
MS FAQ Cap (Option 2)		50.08	69.51	73.74

As might be expected, with the additional restrictions placed on access to the market schedule by the MS FAQ CAP (Option 2), the time weighted value of SMP is increased, particularly in 2020 when the greatest amount of non-firm generation has been modelled on the system. Although Option 1 has not been modelled it may be that more low cost non-firm generation would be included in the market schedule than under Option 2 and that the time weighted average SMP would be consequently be lower than that of Option 2, but still higher than that for either MS FAQ all or MS FAQ PM options.

Constraint Costs –

The chart below shows the constraint costs estimated in each of the three market schedules run in the spot years 2010, 2015, 2020 and 2025. Constraint costs are determined as the difference in production cost between the constrained schedule and the relevant market schedule.



In the case of the MS FAQ CAP (Option 2) model, constraint costs are negative, reflecting the fact that in actual dispatch, cheaper generation behind the constraint is dispatched by the TSOs, whilst in the market schedule it is limited to the level of its FAQ. This results in dispatch costs being lower than the market schedule costs and therefore constraint costs being negative. Although Option 1 has not been modelled it may be that the constraint costs arising from that option would be "less" negative than under Option 2. This is because the market schedule in Option 1 would be a closer reflection of actual dispatch than Option 2 and hence have a lower constraint cost.

4.5.4. Summary and Proposal

In summary therefore, all options would limit the aggregate level of access to the market schedule for generators behind export constraints, and thus ensure that generators on the other side of the constraint (i.e. those actually needed to meet demand at the times when the constraint applies) do have access to infra-marginal rents. Behind the export constraint, Option 2 would continue to allocate access rights similarly to today, although until the necessary transmission and distribution infrastructure were completed, new entrants would expect only non-firm or partially-firm access and participation in the market schedule would be limited to their Firm Access Quantity (FAQ). This would respect the existing concept of firm and non-firm access rights but would continue to provide incentives for generators to apply early for connections in order to secure access rights as early as possible under the first-come-first served arrangements. Option 3 would be similar, except that non-firm generators would be granted access to the market schedule but only when firm generators within the export constraint did not use their firm access rights. Under Option 1, the same quantity of firm access would be allocated as in Option 2. However, instead of being 'hypothecated' to particular generators, these rights would be allocated through competition amongst the relevant generators.

In terms of the criteria proposed in the February 2008 discussion document, all options are equitable going forward as all generators will be aware of the relative position of future incumbents and future new entrants. As between new entrants and existing generators, whether any option is more equitable than any other depends on whether or not existing generators are regarded as having entrenched rights to the future use of the transmission system. Ostensibly Option 1 will provide the greatest incentives to invest in efficient generation, minimising costs and promoting competitiveness, although this assumes that this incentive will not be outweighed by higher compensation for greater risk.

Proposal: The RAs would welcome views on how access to the market schedule for plant situated behind export constraints should be limited and on the options described in this Section 4.5. Respondents are also invited to propose alternative options to those presented in the above section.

4.6. Deemed Firm Access

4.6.1. Introduction

In response to the February 2008 discussion document, two respondents raised the issue of deemed firm dates. This issue was raised in response to the document's discussion of compensation for non-firm constraints and in light of the extensive connection application queue. This section considers, in the context of the principles established in Section 3, whether deemed firm dates should be introduced within the SEM.

4.6.2. Options and Proposal

As discussed in Sections 3 and 4.2, the current SEM design has the potential to over allocate infra-marginal rents to generators behind export constraints, where those generators are low-cost non-firm generators that are dispatched and more expensive but in-merit firm generators. As discussed this will potentially lead to incentives to over-invest in generation behind those export constraints as well as suppressing efficient investment elsewhere on the system. “Deemed Firm Access” will have a similar effect.

Deemed Firm Access, whereby FAQ or MEC is allocated in advance of the completion of necessary transmission system infrastructure reinforcements, will lead to incentives to invest in generation ahead of the capability of the transmission system to support it. Leading to an over-allocation of infra-marginal rents to generation behind export constraints and consequently an under-allocation of infra-marginal rents to plant not behind the export constraint and actually required to meet customers' demand. This, as discussed previously, will shift the balance of new entry towards low capital high operating cost plant and away from high capital low operating cost plant, increasing costs to customers over the longer-term. On this basis and consistent with the principles established in Section 3, the RAs propose that Deemed Firm Access should not be introduced to the SEM.

Proposal: The RAs propose that “Deemed Firm Access”, whereby FAQ or MEC is allocated in advance of the completion of necessary transmission system infrastructure reinforcements, should not be introduced to the SEM.

4.7. Dispatch Principles

As discussed in Section 3.3, to maximise operational efficiency in the short-term, the objective of dispatch should be simply to achieve short-run efficiency by minimising the cost of production of meeting customer demand, taking account of the need for system security given the generation portfolio available to the TSOs.

As discussed previously, were dispatch not to be at least cost, and it was proposed to generate using an expensive generator in preference to a cheaper one then, subject to system constraints, the generators would, if possible, want to make a side-deal whereby the cheaper generating unit would generate in lieu of the more expensive one, thus fulfilling the more expensive generator's commitments but at lower cost. In effect, the generators would choose to be dispatched on a least cost basis and would, if possible, trade between themselves so as to achieve this result.

Similarly, dispatch decisions taken by the system operator should ignore any concept of 'firmness' or 'non-firmness' of transmission access. This is because where a new “non-firm” generator that is cheaper than an existing “firm” generator connects to the transmission or distribution system, cost will always be minimised by generating from the cheaper unit in preference to the more expensive incumbent, irrespective of the nature of any access rights.

This principle, consistent with the licence obligations of the TSOs, of minimising the cost of production irrespective of access rights is currently reflected in the way in which generators are dispatched in the SEM by the TSOs today.

Proposal: Given that it would represent the most efficient short-term use of available resources, and is consistent with existing dispatch processes, the RAs propose that the TSOs should continue to dispatch the system to minimise production cost of generation, taking into account system security requirements and, as now, disregarding any concept of firmness in the dispatch process.

4.8. Priority Dispatch

4.8.1. Introduction

Priority dispatch is the practice whereby renewable or other generators such as peat are dispatched in preference to other generators. It is established in both the old and new RES and other directives, and was specifically enshrined in legislation in Ireland prior to the implementation of the SEM. It has been practiced by the system operators in both Ireland and Northern Ireland and is facilitated by the Trading and Settlement Code in that renewable and certain other generators are allowed to register as variable price takers which means that they are scheduled in dispatch ahead of price makers (they are actually netted off demand). To date no conflicts have arisen as a result of this practice. The renewable generation involved has been mainly wind which has a low (close to zero) short run marginal cost and so would in all likelihood have been scheduled ahead of more expensive conventional plant. Also, the volumes involved have been relatively low so, apart from a small number of 'curtailment' events, the system operators have easily accommodated the amounts of wind generation available.

However with the prospect of much higher levels of wind generation a number of issues arise. The main one is determining the extent of priority that should be given to renewable and other generators who are afforded priority dispatch status in law. Generally, because of the low short-run marginal cost, it is economic to dispatch wind ahead of other forms of generation. However there will be instances when the system operator may, for example, need to choose between reducing the output from wind generators or dispatching off a conventional generator and incurring high start up costs. This would mean that to give a high priority to keeping the wind running could incur considerable cost for the consumer. Also, the modelling shows that in some scenarios the total carbon emissions resulting from high levels of wind would be increased. Alternatively, the renewable plant in question may have a relatively high short-run marginal cost. It is also noted that there are provisions in EU legislation for the provision of priority dispatch to generators other than renewable generators, namely those using indigenous primary energy fuel sources, those producing combined heat and power. In these cases, this provision is at the discretion of the Member State.[33] It is noted that, in Ireland, this discretion has been exercised in relation to generation from peat[34].. In any event the system operator may need to choose between reducing output from a unit having priority dispatch at a cost lower than that incurred by altering the dispatch of a non-priority dispatch plant.

The provisions for priority dispatch, insofar as it relates to renewable generation, going forward are set out in the new RES Directive. However there are a number of possible interpretations of how this requirement might translate and apply in the SEM, and these can broadly be narrowed down to two main possible interpretations:

Absolute priority

Under this interpretation, it is arguable that the requirement for member states to give priority in dispatching generation from renewable sources is absolute. It derives from article 16 (2) (c) of the new RES Directive and has as its only exceptions safety and security of supply. This is equivalent to attributing a price of minus infinity to renewables and would imply that, for example,

- there is no need for the renewable generation to have a prior purchaser – the system operator should just dispatch it anyway so long as safety and security aren't compromised
- the system operator may not take merit order into account when dispatching renewables, even if they are expensive e.g. biomass
- the system operator would take any action to run a renewable generator or prevent dispatching it down i.e. run the system in such a way as to maximise the amount of wind run including cycling conventional plant up/down on/off, even if this meant, for example, incurring large start up costs, and
- if this interpretation is taken as being equivalent to attributing an effective price of minus infinity to wind then one might also argue that the obligation extends to building huge

[33] Ref: Directive 2003/54/EC, New Internal Market Directive repealing Directive 2003/54/EC, 2007/0915 PE-CONS 3648/09 12th June 2009

[34] Ref: Statutory Instrument No. 217 of 2002 Electricity Regulation Act 1999 (Public Service Obligations) Order 2002

amounts of transmission system and investing heavily in static equipment to provide the necessary reactive compensation, inertia, etc.

The implications of the absolute interpretation of priority dispatch are explored further in Option 1 below.

Qualified Priority

Under this interpretation of the Directive, it is arguable that priority should be given to generation from renewable sources but not absolute priority; a qualified priority. There are two main reasons why this approach may be appropriate.

The first is that the established legal principle of proportionality may be taken into account. This can be summarised as meaning that the measures adopted must be appropriate, necessary in order to achieve a legitimate objective, and that where a choice exists between a number of appropriate measures the least onerous should be adopted and the disadvantages caused must not be disproportionate to the aims pursued.

The second reason why Article 16 (2) (c) might be interpreted as not requiring absolute priority to be given to generation from renewable sources would be the assumption that it was not intended to be read in isolation but along with the rest of the Directive and recitals and taking into account Member States' other duties. This would mean that statements elsewhere in the directive and recitals about the renewable generation requiring to have a buyer, the TSO not being obliged to purchase, no particular price being guaranteed and system operation being a valid factor to take into account (as well as safety and security) should all be read along with Article 16 (2) (c) delivering a general requirement to give *reasonable* priority in dispatching generation from renewable sources.

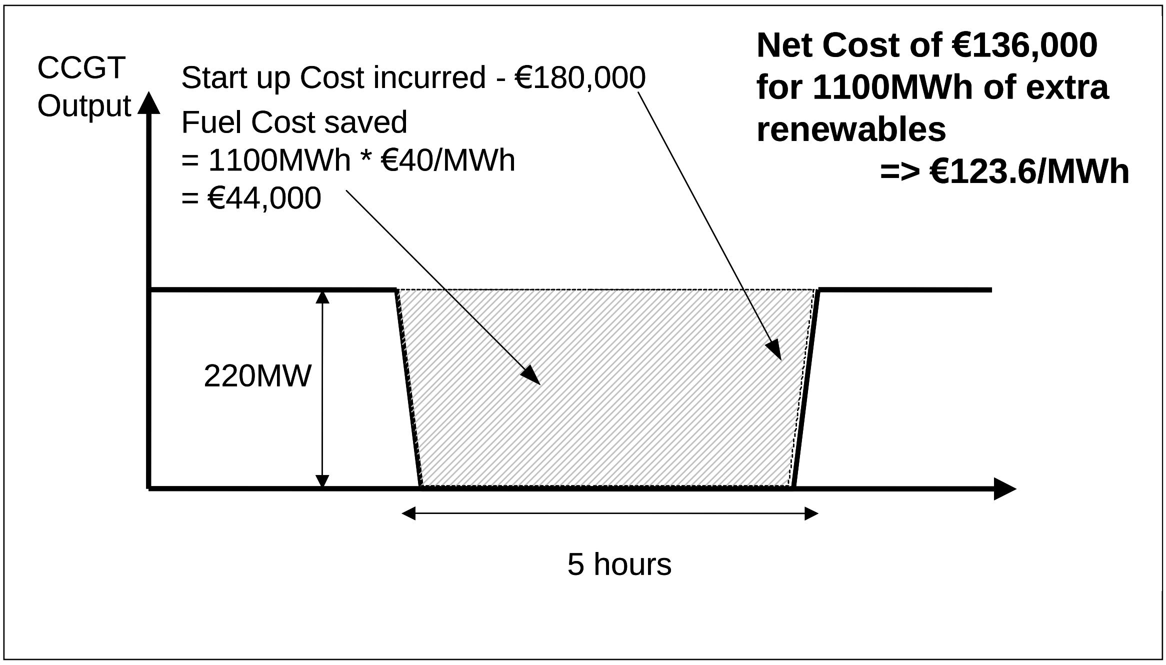
An important concept here is that of there being a purchaser for the output of renewables. Under current market arrangements renewables are treated as price takers and so the need for a purchaser or purchase decision has not arisen before. However there is an argument that the system operator, in making the dispatch decision, is implicitly making a purchase decision i.e. the dispatched MWs will attract bid price. In short, it is arguable that the intent of the Directive is not that the requirement to ensure that the system operators give priority in dispatching generation from renewable sources, would have a significantly different outcome in a market such as the SEM as compared to an alternative market design; e.g. a bilateral market.

In the event that the right to priority dispatch is a qualified right, there are a number of ways that this ‘qualified priority’ could be objectified. The first is through a series of secondary considerations for the SO to take into account e.g. dispatch wind unless it will increase the carbon emissions, or dispatch wind unless start up costs of greater than €X are incurred etc.. Alternatively, it could be achieved by attributing an effective price greater than minus infinity to renewables. This effective price would be used in dispatch scheduling decisions and in calculating whether to incur start up or other costs to keep wind running.

It is reasonable to assume that the system operators would require objective rules that their systems (e.g. RCUC) can apply automatically so that the dispatch engineer is not required to make complex value judgements in real time which might be disputed later.

The following section considers a range of prices, or methodologies for setting prices, that could be attributed to renewables. Option 1 deals with the situation where priority dispatch is considered an absolute right. Alternatives for implementing qualified priority are explored in options 2(a) to 2(d).

In reviewing these options and their application, a relevant consideration is the whether a distinction is to be drawn between the priority to be applied when making a decision to place a generating unit in the dispatch schedule as distinct from subsequently dispatching that unit away from that level of output in real time. In other words, the question of what timeline the priority dispatch provision refers to in the context of dispatch decisions; does it apply to the decision to schedule a plant for dispatch and/or the decision to move a plant already scheduled for dispatch in real time? In that context, the time period over which the options should work and how that can be facilitated is noted. Also, consideration should be given to how non renewable plant afforded priority dispatch at the discretion of a Member State should be treated relative to renewables afforded such priority under Directive 2009/28/EC. Finally, the question of the need to require plant afforded priority dispatch to register as Price Makers, as opposed to as Price Takers under the Trading and Settlement Code under these options is raised.



4.8.2. *Option (1): Dispatching Irrespective of Cost*

Absolute priority, as discussed above, would mean that the SOs would dispatch such priority dispatch generators (or allow them to run) irrespective of cost and dispatching them in preference to all other plant unless technical or security constraints make this impossible.

A tangible effect of dispatching in this manner would be, for example, that, a CCGT would be de-committed overnight and resynchronised for the morning demand pick-up, thereby incurring a start-up cost, irrespective of the cost of the start-up, in order to accommodate additional output from priority dispatch generation. The cost of this CCGT "two-shifting" would appear in Imperfection Charges which are levied on Suppliers, and it is possible to calculate an implicit cost per MWh. For example, a generating unit with a start-up cost of €180,000, a minimum stable generation (MINGEN) of 220MW and a Bid Price of €40/MWh being de-committed for a period of 5 hours, would imply a cost per additional MWh of priority generation of €123.60[35]. (See diagram below.) This cost would be in addition to any explicit support received by the priority generation outside the market arrangements.

If such costs are to be incurred in redispatching other plant in order to accommodate generation which is afforded priority dispatch, where such plant elected to submit bid prices and be treated as a Price Maker, it would be consistent also to dispatch such generation simply out of merit. In the above example, a cost of €123.60/MWh is incurred in dispatching

35 CCGT output saved and additional wind output accommodated = 5h x 220MW = 1100MWh. Additional cost incurred = €180,000 - €40/MWh*1100MWh = €136,000. Hence the cost per additional MWh of wind generation is €136,000/1100MWh = €123.6/MWh.

priority dispatch generation which is Price-Taking. If this price were considered worth paying to dispatch an additional MWh of Price-Taking priority dispatch generation then it would be rational also to dispatch a Price-Making priority generator with a bid price of €123.60/MWh, irrespective of SMP.

In deciding whether priority dispatch should simply mean dispatching a generating unit out-of-merit (even when system reasons do not require it), it is informative to consider the possible interpretation of priority dispatch in the context of a bilateral market[36]. In a bilateral market, generators are responsible for finding their own customers for their energy, and priority dispatch could not imply anything more than that efforts are made to not frustrate these bilateral trades. So it is only in a gross pool that the issue of scheduling and dispatching plant out-of-merit (other than for system reasons) can even arise. This highlights the fact that the ability to implement this form of priority dispatch is dependent upon the specific trading arrangements adopted. Under a bilateral contract market with self-dispatch for all generators, the concept of certain generators being given priority dispatch would be equivalent to requiring suppliers to enter into bilateral contracts with such generators irrespective of the price offered.

If Price-Taking priority dispatch generation is to be dispatched whenever system security permits, it would be equivalent to treating such plant as if it had a price of minus infinity in the dispatch process. Another consideration that should be taken into account if priority dispatch plant is to be dispatched with an effective price of minus infinity would be how its treatment should be tracked through into operational planning and investment planning timescales. For consistency, in principle if a priority dispatch unit is to be dispatched with an effective price of minus infinity, all possible steps in operational planning and investment planning timescales should be taken in order to ensure that the output of priority plant can be accommodated in real-time dispatch. In investment planning timescales, this would require the construction of an unlimited number of transmission circuits to guard against all possible fault outages, and in operational planning, taking all possible steps - for example purchasing ancillary services and planning post fault actions - to ensure that the exports from priority stations can be accommodated. It may be the case that such an approach would not be considered a proportional implementation of the concept of priority dispatch.[37]

36 Although the two fundamental market designs, namely gross pool versus bilateral market plus 'residual' pool are ostensibly very different, the overall economic effect should be the same, at least to a first order.

37 See later in Section 4.6.6.

4.8.3. Option 2(a): Dispatching purely on economic merit

Taking the above example and imagining that the system were dispatched on a strictly least cost basis then preferring to incur the €136,000 net cost of de-committing and resynchronising the CCGT in order to schedule an additional 1100MWh of priority generation, although actually levied through Imperfection Charges which are levied on Suppliers, would imply an effective bid price in dispatch for the priority generation of *minus* €123.60/MWh, i.e. the additional MWh of priority generation would be scheduled unless a saving of more than €123.60 could be made by not doing so.

Under such circumstances, if demand on the system were increased by 1100MWh, then the costs of meeting demand in total would in fact reduce, because it would no longer be necessary to incur the start-up cost of the CCGT. Because an increase in demand would result in a reduction in costs, it follows also that during these periods, the system marginal price should be negative, reflecting the fact that, were an additional 1100 MWh of demand to be taken over these periods, the €136,000 decommitment and resynchronising cost would not be incurred. Furthermore, with the correct system marginal price, priority generators should, if they were able, make the same decision of whether or not to run that the system operator would take scheduling in strict economic merit. Hence, with a higher system marginal price, the priority dispatch generators would choose to run whereas, with a lower or negative system marginal price, the priority dispatch generators might prefer not to run, whereas it might still be economic for the CCGT to choose to run through.

This means that priority dispatch generators only wish to run other than in strict economic merit order if the prices in the market in which they are operating are not truly reflective of marginal costs at any given point in time, i.e. priority dispatch would only be desirable if prices in the market were not determined on a truly cost reflective basis.

4.8.4. Option (2b) Priority dispatch in tie-break situations only

Where plant is dispatched in economic merit order a concept of priority dispatch could still be used to resolve “tie-break” situations, i.e. situations in which it was necessary for the system operator to choose between two units, one with priority dispatch status and one without. In circumstances which there were no relative economic or technical differences between the two units, the concept of priority dispatch could require the system operator to choose the generator with priority dispatch. This approach is likely to arise only very rarely (if at all) in practice as the likelihood of there being absolutely no such differentiating features is low.

In practice, tie-breaks are more likely to occur between generators both having priority dispatch status. In these cases, clearly priority dispatch status does not help the TSOs to choose between them.

4.8.5. Option (2c): Dispatching taking into account subsidies

If prices in the market were to be determined on a truly cost-reflective basis, where a priority dispatch generator[38] receives external subsidies, that generator would wish to be dispatched on an economic basis taking the external subsidy into account. The generator would continue to make an operating profit from generating so long as the price it received for doing so was greater than its avoidable costs of production less any external subsidy which, for plant with a low operating cost in the first place, such as wind, will typically be negative.

Under this option, there is an argument that dispatch would double count the costs of carbon emissions, first because the opportunity costs of carbon emissions are reflected in the bid prices of fossil fuel plant and second because the bid prices for dispatch of renewable generation would reflect the subsidies that they receive[39]. Nevertheless, under existing arrangements, renewable generators do receive external subsidies, for example through ROCs and generators emitting CO_2 are required to hold emissions permits. The inclusion of both the opportunity costs of carbon emissions and renewables subsidies in bid prices would therefore reflect the true marginal, avoidable costs faced by generators and would, for example, ensure that the dispatch solution would reflect that which the generators would prefer in a perfectly competitive market, given the external subsidies and carbon tax. It is noted also that, for instances where renewable generators elect to be Variable Price Makers, the current value of PFLOOR is set at "*a level sufficiently below zero to allow renewable generators to bid the opportunity cost of their ROCs and CHP plant at the opportunity cost of using their heat boilers*"[40]. It is noted that under this option, the fact that different support scheme exist on the island will result in a 'hierarchy' of priority based on the nature of the support scheme and the level of support afforded. This will apply in the context of different support schemes in Ireland and Northern Ireland and in the context of differing schemes within a jurisdiction. Also, different levels of support within a given scheme will also impact.

38 Or, indeed, any generator.

39 To the extent that the subsidies are intended to deliver CO2 emissions reductions.

40 "A Review of the Effectiveness of PCAP & PFLOOR. A Consultation Paper.", SEM-09-065, 17 June 2009, http://www.allislandproject.org/en/trading-settlement-code-consultation.aspx?article=e1cf127c-f359-4f0e-ba12-df16ad4ac158.

4.8.6. Option (2d): Dispatching at some other effective price

Priority dispatch could alternatively be taken to imply some other arbitrary price to be used in dispatch decisions, say, minus €1,000/MWh or minus VOLL. VOLL may be considered an appropriate price to adopt because, in principle, consumers would elect not to take demand rather than pay above this price for electricity even if it were generated from a renewable generator. Whilst such a rule would provide a clear basis for dispatch as discussed in Option 2(a), its adoption would only be in the interests of the priority dispatch generator if prices in the market were not set to reflect true avoidable costs.

The costs in 2020 of treating priority dispatch plant as having a high negative price, rather than a price of zero or minus external subsidies, are estimated to be €85m for SEM or €42m when also taking into account GB production costs[41].

4.8.7. Modelling

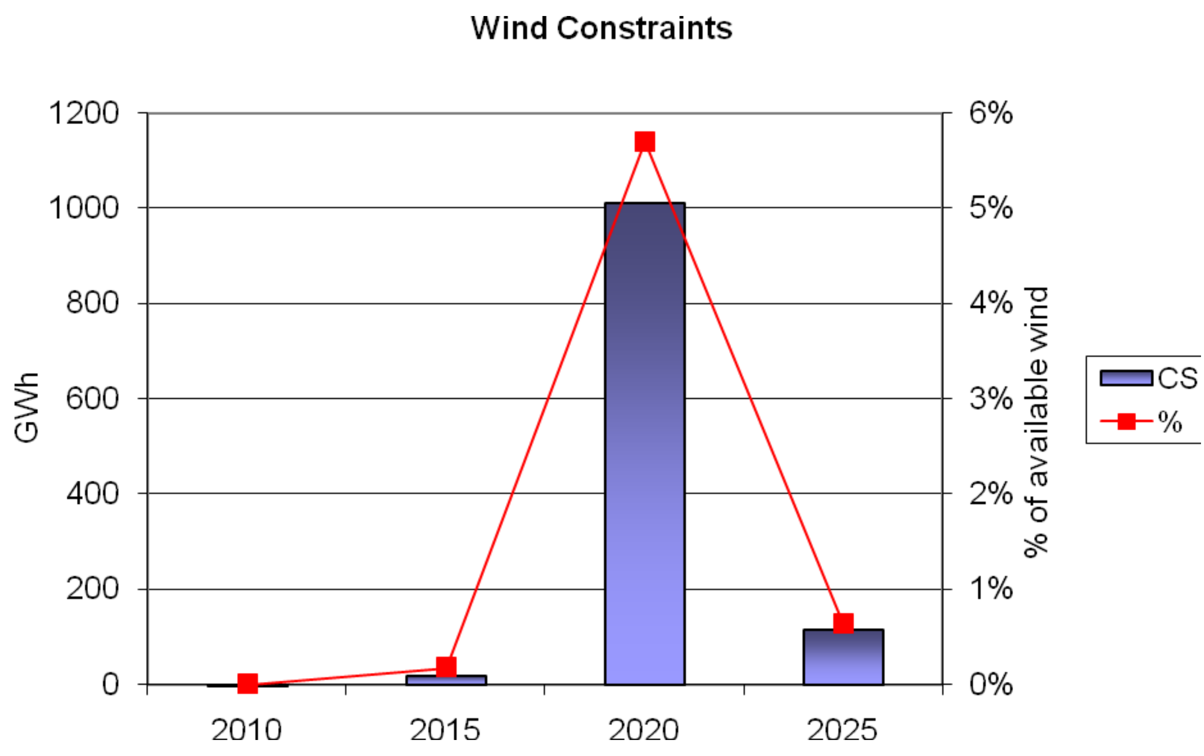
Detailed modelling of the SEM has been conducted to support and inform the options considered above. The modelling methodology, approach, assumptions and results are discussed in detail in Appendices 2 and 3, however key findings and results pertinent to the above discussion on priority dispatch are described below.

A constrained schedule including modelling of thermal ratings, group transmission constraints and reserve requirements which is intended to model the actual dispatch that will be undertaken by the TSOs was utilised.

Two constrained schedules were run where wind generation was modelled with the following effective prices, one of "zero" (although a nominal variable operating cost of 0.4€/MWh was assumed within PLEXOS) and the other of "-1000€/MWh".

By comparing the scheduled wind output in each run to the assumed wind availability profile, a view can be formed on the likelihood of constraining wind output. Results from the fully constrained schedule for the "zero" price scenario (see graph below) indicate that wind constraints represents around 0.2% of available wind energy in 2015, rising to 5.7% in 2020 and then falling to 0.6% in 2025 following extensive grid reinforcements.

41 See figure 21 in Appendix 2.



The results imply that grid constraints and reserve requirements could lead to a shortfall against 2020 renewables targets in actual dispatch if wind is priced at zero cost (and assuming as is the case here that grid reinforcements lag behind wind plant commissioning by some five years).

To consider a world in which priority dispatch is operated at “any cost”, a sensitivity was conducted modelling wind with an extreme negative offer price (minus 1000 €/MWh). Constraining of wind output was observed to be lower (4.9%) in 2020 in this sensitivity, although overall SEM generation costs were higher, reflecting increased two-shifting and start-up costs.

Total SEM production costs in the constrained schedule for 2020 were €85m higher in the sensitivity with negative wind bid prices. However, production costs in GB actually fall, as a result of a change in interconnector exports and/or imports. If this benefit were to accrue to the SEM, i.e. through additional revenue for exports or reduced costs for imports, the differential would fall to €42m. Although specific modelling of effective priority dispatch prices between zero and -1000€/MWh has not been undertaken, it may be reasonable to assume that if the price of priority dispatch plant is between these values, the additional SEM costs would be less than €85m in 2020 (or €42m overall if GB costs are also taken into account).

The Regulatory Authorities welcome comments from interested parties on the options for priority dispatch, as presented in this Section 4.8. Specifically the RAs seek comments on:

(a) The case for affording absolute priority or qualified priority to plant having priority dispatch;

(b) In the event that qualified priority were to apply, the relative merits of the alternatives posed for the purpose of attaching an effective price or other objective measure for use by the SOs when making dispatch decisions taking account of the proportionality principle;

(c) Whether a distinction is to be drawn between the priority to be applied when making a decision to place a generating unit in the dispatch schedule as distinct from subsequently dispatching that unit away from that level of output in real time;

(d) The extent to which non-renewable plant (e.g. peat) who are afforded priority dispatch present particular issues which might require that they are treated in an alternative way to renewable generators.

4.9. Hybrid plant

Depending upon which of the options for treatment of generating units with priority dispatch set out in Section 4.8 is adopted, it may be possible to simply extend the option also to cover hybrid generating units – i.e. to generating units which have a proportion of their output which is classed as renewable as follows:

i) If priority dispatch Option 2(a) were adopted, hybrid plant would be dispatched purely on an economic basis in line with all other plant;

ii) If Option 2(b) were adopted, in tie break situations, with all other factors being equal, plant with the highest proportion of renewable output would be dispatched first;

iii) If Option 2(c) were adopted, hybrid plant would be permitted to reflect its proportionate renewable subsidies in its bid prices and would then be dispatched on a merit order basis reflecting the appropriate level of subsidy.

The treatment of hybrid plant would be more complex if Option 1 were adopted and again, the RAs would welcome views on how hybrid plant should be treated in such circumstances as part of the response to this consultation.

Proposal: The RAs propose that the rules applying to hybrid plant should depend upon which of the options for treatment of priority dispatch plant are eventually chosen. The RAs welcome views on how the principles of priority dispatch should be extended to hybrid plant as part of the response to this consultation.

4.10. Treatment of Variable Price-Takers

As was acknowledged in the February 2008 discussion document, the detailed rules of the T&SC result in any generation which is classed as a Variable Price Taker being afforded firm access, and hence infra-marginal rents, irrespective of whether the transmission system deep infrastructure reinforcements needed to accommodate the associated output have been completed and any MEC or FAQ awarded under the generator's connection agreement.

This is because in circumstances when a Variable Price Taker (VPT) is dispatched down, its Market Schedule Quantity (MSQ) is currently determined as the maximum of its actual output and its availability[42]. Given that this availability may exceed both the FAQ and the level at which it has been possible to dispatch the generator, the effect is thus to provide incentives to invest in excess generation ahead of the capability of the transmission and distribution system to accommodate its output. In this case, however, the treatment of VPTs differs from that of Price Makers in that the market schedule will allocate infra-marginal rents to more generation than there is demand[43], so that excess infra-marginal rents to dispatched down VPT generation are not necessarily accompanied by the under-allocation of infra-marginal rents to plant actually required to meet demand.

The availability of intermittent generation is hard to measure. Clearly, where an intermittent generator is dispatched to its full output then actual output becomes a good proxy for availability. However, where a VPT is dispatched at below full output, then the availability used for the purposes of constructing the market schedule is based on a declaration by the generator. To the extent that infra-marginal rents are based on this declaration, there is a clear incentive for these generators to overstate their availability in this declaration. These

42 See TSC Table 5.1.

43 It is not assumed that the output of the VPT in the market schedule is equal to its availability, and so other generation is also included in the market schedule – and hence awarded infra-marginal rents – in order to meet demand.

inflated availability declarations, whilst increasing infra-marginal rents for such generators, will also reduce infra-marginal rents to other generators that are required to meet customers' demand, thus distorting incentives for efficient investment. Consequently, greater scrutiny of these declarations is likely to be increasingly necessary as the quantity of Variable Price-Taking plant increases and the dispatching down of Variable Price-Taking plant becomes more frequent.

The cost of these additional rents will have to be borne by demand, which could have to pay considerably more than SMP under these circumstances. Consequently, it has already been proposed that the current rules limiting access to the market schedule to the maximum of the actual dispatched quantity and FAQ should apply also to VPT generating units in order to provide consistency of treatment with Price Making units. Whilst this proposed rule should be adopted for consistency with the current arrangements, if any of the options in Section 4.5 for limiting the allocation of infra-marginal rents behind export constraints is adopted, it will be redundant.

Proposal: If any of the options in Section 4.5, for allocating infra-marginal rents behind export constraints, is adopted then that option should apply also to Variable Price Takers. If none of these options is adopted and the existing arrangements for allocating infra-marginal rents being export constraints retained, then Variable Price Takers should be limited in the market schedule to the maximum of actual output and FAQ (or MEC when infrastructure works are complete and the VPT becomes fully firm).

4.11. Determination of SMP when demand is met by Price Takers

Under existing TSC rules, PFLOOR is set by the Regulatory Authorities[44], currently at minus €100/MWh[45]. PFLOOR is used to set SMP when an "Excessive Generation Event" occurs, whereby the quantity of Variable Price Takers exceeds the demand they are required to meet, it also acts as a limit on the minimum value of SMP in circumstances when SMP would otherwise fall below this level. This price was set[46] following responses to the RAs' initial

44 See TSC 4.12. The RAs are consulting on the 2010 value for PFLOOR in June 2009.

45 "Review of the Effectiveness of PCAP & PFLOOR. A Response and Decision Paper.",SEM-08-090, 1 September 2008, http://www.allislandproject.org/en/trading-settlement-code-decision.aspx?article=8abe327a-845c-4b37-9f11-6e61d3dbd393. Also "A Review of the Effectiveness of PCAP & PFLOOR. A Consultation Paper", SEM-09-067, 17 June 2009, http://www.allislandproject.org/en/trading-settlement-code-consultation.aspx?article=e1cf127c-f359-4f0e-ba12-df16ad4ac158

46 See: The Value of Lost Load, the Market Price Cap and the Market Price Floor. A Response and Decision Paper. All Island Project. 18th September 2007.AIP-SEM-07-484. http://www.allislandproject.org/en/trading-settlement-code-decision.aspx?page=2&article=118adb39-4eef-472d-a95f-09c5320d2c2c.

consultation which originally proposed that PFLOOR should be minus €500/MWh, with the rationale for a price of minus €100/MWh being that it would ensure that prices were set at an appropriately negative value when an Excessive Generation Event occurred, but which would also allow headroom for renewable generators to become price-makers and bid their Renewables Obligation Certificate (ROC) buy-out price so as to avoid exposure to PFLOOR with a margin to spare. At the time, the buy-out price for ROCs was £34.30/MWh and now stands at £37.19.

Although this has not been raised in previous consultations, under current arrangements, when an Excessive Generation Event occurs, SMP will be set at below the likely marginal cost – taking into account any subsidy, much as is being proposed in Section **Error! Reference source not found.** Option (2c) – of most renewable generators. This is consistent with the treatment of plant having priority dispatch as having an effective price of minus infinity, with PFLOOR preventing SMP falling below -€100/MWh. However, in terms of the *true* avoidable cost, whether or not taking into account any subsidy, SMP is actually being driven lower, and hence PFLOOR is not acting as a floor preventing SMP falling lower but rather as a level down at which SMP is being set. In terms of the principles in the February 2008 discussion document, pricing is not reflecting value. To avoid being exposed to PFLOOR during Excessive Generation Events, generators afforded VPT status have to elect to be Variable Price Makers and bid economically, as allowed by the bidding principles.

If Option 2 in Section 4.8 is adopted, effective prices for the purposes of dispatch and the creation of the market schedule will be defined for Price-Taking generating units. Consequently, it may be appropriate for these effective prices for Variable Price-Taking plant to be used to set SMP, rather than PFLOOR, as this would better reflect the true avoidable costs of meeting demand in the market schedule. PFLOOR would still be used as a lower limit on SMP.

Proposal: The RAs propose that if Option 2(a) or 2(c) in Section 4.8 is adopted, SMP should be set using the effective bid prices of the marginal Variable Price-Taking generation, rather than at PFLOOR, in the event that the quantity of price-taking generation exceeds demand and reflecting any external subsidies received by the plant (i.e. it should reflect the price used in the dispatch of the plant by the TSOs). PFLOOR would still be used as a lower limit to SMP.

4.12. Quantity of Generation Paid PFLOOR

As discussed in Section 4.11, in Excessive Generation Events, PFLOOR is paid to Variable Price Taking generators on the maximum of their availability and actual output. Thus PFLOOR will be paid to more generation than there is demand. The rationale for paying market price – more correctly allocating infra-marginal rents - to more generation than there is demand under this one condition, is unclear. That PFLOOR is negative means that VPT generation is penalised for merely being available at the time of an Excessive Generation Event, and would act as a further disincentive to plant electing to be Variable Price Taking. In order to rectify this anomaly, it is proposed that in an Excessive Generation Event, the MSQ for Variable Price-Takers is set such that the total quantity of MSQs allocated to Price Takers is equal to Scheduled Demand. This would be achieved either by modelling VPTs in the market schedule using their effective bid prices or scaling pro-rata should VPTs continue to be scheduled, as now, regardless of cost. The effect would be to reduce the quantity of Variable Price-Taking generation being remunerated at PFLOOR (in practice charged, because PFLOOR is negative – or, paid at the revised SMP if the proposal set out in Section 4.11 is adopted) when an Excessive Generation Event occurs.

Proposal: The RAs propose that the quantity of generation charged PFLOOR (or paid at the revised SMP set out in proposal 4.11) in the event of an Excessive Generation Event arising from an excess of Price Taking Generation should not exceed System Demand. The MSQs of Price Taking Generation should, in such circumstances be pro-rated down so that the total quantity is equal to System Demand.

4.13. Tie-breaks

4.13.1. Introduction

In discussions with various parties in relation to the treatment of renewables, the issue of how to deal with tie-break situations has arisen, in particular how the Transmission System Operators should choose between Variable Price Taking Generating Units, where it is necessary to re-dispatch a quantity of such generation, e.g. to avoid breaching an export constraint limit. This section considers the options available and makes a proposal on how the issue should be managed going forward.

4.13.2. Options and Proposal

The resolution of this issue should, in principle, be no different from that applied to conventional price-making generation, i.e. that, unless there are other system reasons for doing so, the TSOs should constrain down units on an economic basis starting with the most expensive units first, such that the most economic use is made of the existing resources available at any given time.

Whilst it is understood from discussions with renewable generators, that there is a general view that they would be willing to submit prices for such purposes, where there are no such relevant prices, or the decremental prices for such units are the same, then, again, unless there are system reasons for doing so, and depending upon the solution for implementation of priority dispatch, a fair methodology for dealing with such units would be to ensure that the de-loading is instructed on a pro-rata basis, i.e. the necessary MW de-load should be shared over all affected units pro-rata on the previously instructed output.. Whether this pro-rating is effected each time such units are required to de-load or whether it effected so as to average the de-load pro-rata over a longer period of time is a matter for detailed implementation by the TSOs. For example, if there were a pre-fault constraint affecting a number of equally priced generators over a period of a week, then it would be for the TSO to decide whether the output of the affected generators was constrained equally on a daily or weekly basis. Any other approach, for example by the development of very prescriptive rules which the TSO had to follow would result in a myriad of rules based on the variety of generator / transmission system configurations available.

Proposal: The RAs propose that where tie-break rules are required, de-loading should be instructed on a pro-rata basis in a manner determined by the TSOs.

4.14. System Operator and Asset Owner Incentives

In both a number of responses to the February 2008 discussion document and bilateral meetings, parties raised the issue of incentives on the TSOs and asset owners to ensure that generation dispatch and scheduling, and, transmission planning and development is undertaken efficiently and expeditiously. In particular for example, it has been argued that in some instances, wind generation is being dispatched down and being replaced by conventional plant at times when the TSOs perceive that there is a reasonable chance of there being reductions in wind output (for example because of a potential drop in wind speed), rather than the scheduling additional conventional reserve to protect against such circumstances. This, it has been argued, discriminates against wind plant because the TSOs do schedule additional reserves to protect against large generator in-feed losses and consequently they should do the same to protect against reductions in wind output. It is clear also that, irrespective of the design of the SEM trading arrangements, specifically the extent to which they do or don't underwrite the risks faced by generators, if the necessary transmission infrastructure is not delivered by the transmission companies then targets for renewable generation will not, and cannot, be met.

It is acknowledged that incentive arrangements in other markets (e.g. England and Wales) have brought substantial benefits to the effectiveness of the transmission sector and there is a case for considering such incentives for the TSOs and asset owners in the SEM. Consideration should also be given to providing incentives on the TSOs to resolve the dispatch and technical wind-related issues in an expeditious manner and to provide a degree of transparency in the progress of such matters to market participants.

These issues are being progressed separately by the RAs and further proposals on these matters will be brought forward in due course.

4.15. The Capacity Payment Mechanism and Ancillary Services

On the 9th March 2009 the SEM Committee published a consultation paper on the Scope of the CPM Medium Term Review[47]. In this paper the SEM Committee signalled its intention to carry out a further review of the Capacity Payment Mechanism (CPM) in the medium term and the paper documents the scope of work that the SEM Committee intend to carry out. It is highlighted that with the increase in renewables, the requirement for more flexible plant will increase and, if necessary, there is the option of creating incentives via the CPM to attract the appropriate mix of plant and to reward accordingly.

On 30th January 2009, the SEM Committee published a decision paper on the Harmonised All-Island Implementation Arrangements for Ancillary Services and Other Payments and Charges[48]. Whilst this paper did not explicitly address the need for reform in the ancillary services arrangements in response to the increasing level of renewable generation, the paper highlighted the RAs' view that the TSOs should continuously consider the benefits derived from the introduction of new (or modified) services as system requirements change, for example with the increased penetration of renewable sources, and approach the RAs for consideration of new services in the SEM.

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47 Single Electricity Market Scope of the CPM Medium Term Review. Consultation Paper, April 2009. SEM-09-035. http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=8620a1e1-202d-4b35-9f05-206828afa4a4.

48 Harmonised All-Island Implementation Arrangements for Ancillary Services and Other Payments and Charges. A Decision Paper. SEM-09-003. 30th January 2009. http://www.allislandproject.org/en/transmission.aspx?article=78f3993b-363f-4b8b-9e1c-15deca01ec12.

5. Conclusions and Summary of proposals and requests for response

The fundamental purpose of the SEM arrangements, including dispatch and the Trading & Settlement Code, is to minimise costs both in the short term and, by providing incentives in the form of infra-marginal rents for efficient investment, in the long-term. Costs to customers will be minimised by minimising the cost of production in dispatch, subject of course to the requirement for system security and the legal requirement for priority dispatch. Allocating infra-marginal rents appropriately will give incentives for the appropriate investment in generation given the capability at any given time of the transmission system to accommodate its output and also for investment in the appropriate portfolio of generation as a whole that is necessary to meet customers' demand at least cost.

A wide range of issues that have been raised, both through previous consultation and through discussions with industry, can be viewed purely in terms of which plant is dispatched and which plant is allocated infra-marginal rents by being included in the market schedule. In particular, curtailment, whereby plant may be dispatched down without compensation, and constraints, whereby plant may be dispatched down but compensated, are matters entirely addressed by which plant is dispatched and which plant is included in the market schedule. Firmness and access (including deemed access), too, are principally issues of which plant has option of competing for inclusion in the markets schedule, whilst priority dispatch is, clearly, about the basis on which plant is selected for dispatch. A number of issues have also been raised concerning the treatment of Variable Price-Taking plant (which to a large extent also involves priority dispatch). Issues include the quantity of plant which is included in the market schedule and, though the mechanism for setting SMP has not been a focus of this paper - the way SMP is determined during Excessive Generation Events. Tie breaking between plant of identical merit has also been considered.

Specifically, the RAs make various proposals or set out options upon which specific responses are sought, and these are summarised/referenced below:

(i) The RAs should seek to ensure that the construction of the market schedule is such that infra-marginal rents are allocated to generating units that are of values to the real-time operation of the system and, where deemed appropriate, the RAs will make the necessary changes;

(ii) The TSOs and asset owners should continue to make available information relating to:

(a) their understanding of what changes to the scheduling and dispatch of generation are being contemplated in light of the increasing level of renewable generation on the system, including where there may be technical limitations on the quantity of certain types of plant that can be accommodated on the system; and

(b) their view of how technical issues (for example system inertia, fault levels etc.) will be resolved;

(iii) In relation to the Grid Code;

(a) the current initiative from the TSOs to place additional emphasis on enforcing existing Grid Code obligations on incumbent and new generating units should continue; and

(b) the TSOs should also keep the Grid Code under review in order to ensure that future generation portfolios continue to support the satisfactory operation of the system;

(iv) The RAs would welcome views on how access to the market schedule for plant situated behind export constraints should be limited, on the options described in Section 4.5. Alternative options are also welcomed.;

(v) The RAs propose that "Deemed Firm Access", whereby FAQ or MEC is allocated in advance of the completion of necessary transmission system infrastructure reinforcements, should not be introduced to the SEM;

(vi) Given that it would represent the most efficient short-term use of available resources, and is consistent with existing dispatch processes, the RAs propose that the TSOs should continue to dispatch the system to minimise production cost of generation, taking into account system security requirements and, as now, disregarding any concept of firmness in the dispatch process;

(vii) The Regulatory Authorities welcome comments from interested parties on the options for priority dispatch, as presented in Section 4.8;

(viii) The RAs propose that the rules applying to hybrid plant should depend upon which of the options for treatment of priority dispatch plant are eventually chosen. The RAs welcome views on how the principles of priority dispatch should be extended to hybrid plant as part of the response to this consultation;

(ix) If any of the options in Section 4.5, for allocating infra-marginal rents behind export constraints, is adopted then that option should apply also to Variable Price Takers. If none of these options is adopted and the existing arrangements for allocating infra-marginal rents being export constraints retained, then Variable Price Takers should be limited in the market schedule to the maximum of actual output and FAQ (or MEC when infrastructure works are complete and the VPT becomes fully firm);

(x) The RAs propose that if Option 2(a) or 2(c) in Section 4.8 is adopted, SMP should be set using the effective bid prices of the marginal Variable Price-Taking generation, rather than at PFLOOR, in the event that the quantity of price-taking generation exceeds demand and reflecting any external subsidies received by the plant (i.e. it should reflect the price used in the dispatch of the plant by the TSOs). PFLOOR would still be used as a lower limit to SMP;

(xi) The RAs propose that the quantity of generation charged PFLOOR (or paid at the revised SMP set out in proposal 4.11) in the event of an Excessive Generation Event arising from an excess of Price Taking Generation should not exceed System Demand. The MSQs of Price Taking Generation should, in such circumstances be pro-rated down so that the total quantity is equal to System Demand;

(xii) The RAs propose that where tie-break rules are required, de-loading should be instructed on a pro-rata basis in a manner determined by the TSOs;

6. Next Steps

Views on the proposals and issues raised in this consultation document and related matters are requested by 17.00 September 18th, 2009.

In order to help to inform responses to this consultation, the RAs propose to hold an industry seminar to discuss its subject matter during the consultation period. Details of the venue and date of the seminar will be published in the near future.

Further to the receipt of responses to this consultation document, the RAs may hold further discussions with one or more industry parties to discuss their responses and/or other relevant matters.

A decision document covering the matters raised in this consultation is currently scheduled to be published in late 2009.

Other areas of ongoing related work will also continue to be progressed in parallel. These areas include:

- the review of the capacity payment mechanism being undertaken by the RAs; and
- the ongoing review of Ancillary Services being undertaken by the TSOs[49].

As discussed in the September 2008 initial response paper, a review of the incentive arrangements applying to the TSOs will be undertaken following the conclusions on the matters raised in this document.

49 See Ancillary Services section of the EirGrid website. http://www.eirgrid.com/EirgridPortal/DesktopDefault.aspx?tabid=Ancillary%20Services&TreeLinkModID=1451&TreeLinkItemID=17

Appendix 1: Market & Operational Treatment of Wind, Non-Firm or Partially Firm Generation

This Appendix describes the current treatment of wind, non-firm or partially firm generation from a market and operational perspective. References within the section are to TSC v4.5.

Registration

Under the current trading arrangements generation is permitted to participate within the SEM on completion of the registration process during which the generator must provide:

- Evidence of metering (2.33)
- Evidence of License to generate (2.33)
- Evidence that connection agreement and use of system agreement are in place, valid and effective (2.33)

Note that under the TSC a generator has non-firm access where it operates under a connection agreement with a Firm Access Quantity (FAQ) less than the Maximum Export Capacity (MEC) of the site (2.69).

Within the registration process generator units must specify, amongst other things, whether they are wind power, energy limited or pumped storage units. Wind and other generators with "priority dispatch" may register as price makers, price takers or as autonomous units. Furthermore, these generators must also register as variable or predictable. A predictable generating unit means a generator unit with predictable availability which is dispatchable, and can include all types of generator unit, except wind power units and run-of river hydro units which are considered as being variable generator units. Currently, all wind power units are registered as either Variable Price Takers (VPT) or autonomous units.

Treatment in the Market Schedule

For the purposes of the indicative market schedule, generator units submit commercial and technical offers to the market operator by 10am day ahead (4.4 and Appendix I).

Commercial offers comprise:

- bid-offer pairs from 1 to 10 can be submitted (4.10)
- must be monotonically increasing (4.13)
- They cannot exceed PFLOOR or PCAP (4.11)

- Technical offers (4.25 & Appendix I)
- Must be consistent with Grid Code parameters
- Availability must be technically feasible

However, neither Variable Price Takers (VPT) nor autonomous units submit commercial or technical offers but instead must:

- Provide a Nomination Profile for each trading period for the trading day (5.15)
- A decremental price of €0 (5.16)

In addition to the generator offer data, the Market Operator also utilises forecast date submitted by the TSOs, namely demand and wind forecast data, to facilitate production of the market schedule (4.31). This data is:

- Four day rolling demand forecast
- A rolling Wind Power Unit Forecast (aggregated at a jurisdiction level), covering the next 2 days, which is updated every 6 hours

Indicative Market Schedule

In executing the Indicative Market Schedule (IMS) the Market Operator runs the schedule so that price making plant meets, at lowest production cost, the Scheduled Demand, where Scheduled Demand is equal to Forecast Demand minus the aggregate total of Price Taking Plant (variable & predictable).

It is noted that:

- The IMS does not schedule reserve.
- The IMS honours firm/non-firm quantities i.e. the availability of non-firm and partially-firm plant is limited to FAQ.
- Market Schedule Quantities (MSQs) are not calculated for Price Taking Plant. The output of Price Takers is assumed to be their nominated quantities and is treated as "must run" or alternatively as being priced at -∞ within the schedule.

Treatment in the TSO Scheduling Process

The TSOs utilise a Reserve Constrained Unit Commitment programme (RCUC) to advise on unit commitment and economic dispatch in the control room. RCUC utilises the same underlying algorithm as used by SEMO to produce the IMS.

RCUC incorporates trading day commercial offers and updated technical offers, forecast demand, wind power unit forecasts to provide updated advice to the control room operators. It also includes:

- Reserve Requirements
- Reserve Capability Curves
- North-South Tie Line restrictions
- Specified Transmission Constraints Groups
- Forbidden Zones

Furthermore RCUC accurately models

- Loading up and down rates from zero to Min Load
- Actual Ramp Rates (averaged in the Market Schedule)

However, RCUC takes no consideration of firm or non-firm status and so will schedule plant based on price whilst respecting reserve, transmission constraints and plant dynamics.

RCUC is executed in two separate time frames day-ahead and in-day.

Day-ahead schedules are jointly produced by EirGrid and SONI. They cover the time period from 06:00 on D up to 11:30 on D + 1 and are completed and published by 16:00 on D-1. They are updated as required and republished at 01:00.

In-day schedules again are jointly produced in real time by EirGrid and SONI. The day ahead schedule is updated with the latest information and becomes the in-day schedule at 6am. New in-day schedules are produced if changes in the following items mean that either TSO cannot meet their demand and maintain the tie line and reserve schedules without deviating from the existing plan:

- System Demand
- Wind Generation
- Availability of Plant
- Transmission Plant operation

Neither VPT nor autonomous plant are currently modelled within the SOs' RCUC software and are therefore effectively treated as must run generation. As such variability in VPT output is managed in a similar manner to demand forecast error. Wind forecasts are updated, assessed and further RCUC runs are executed if the deviation is material. As the scale of VPT and autonomous plant increases, so their potential impact on system operation increases, as such the TSOs have indicated that they will have to change this approach to their treatment as the number of such generators increases.

Dispatch

Dispatch of the transmission system in Ireland and Northern Ireland is the responsibility of EirGrid and SONI. Dispatch is delivered on an all-island basis, in accordance with licence obligations.

Within dispatch timescales there are a number of operational inputs which the TSOs must consider to ensure a safe & secure operation of the power system. In practice these issues are not distinct nor considered in isolation but as part of the holistic system control problem. However, for the purposes of this paper we have separated the critical elements of the operational problem into the following three elements:

- Meeting operational standards (maintaining sufficient frequency response, spinning reserve and replacement reserve)
- Managing transmission constraints (thermal, voltage and stability)
- Scheduling plant to meet the forthcoming demand profile

In meeting operational standards in dispatch timescales, the TSO will utilise the advice of the RCUC to ensure that there is sufficient frequency response, spinning and replacement reserves available to the system. In practice this is currently delivered primarily by part-loading price making generation including hydro and pumped storage.

In the management of transmission constraints arising in dispatch timescales, the TSO currently uses the following hierarchy in making any necessary redispatch decisions:

1. Reconfiguration of the transmission/distribution system including post-fault demand transfers
2. Redispatch of price making generation
3. Redispatch of price taking generation in the following order as available to manage the particular constraint:
    a. Peat
    b. Hydro

c. Wind, and within the category of wind generators

    i. 1st - Variable Price Taker

    ii. 2nd - Autonomous

In the scheduling of plant to meet future system peaks, the TSO currently utilises a number of data inputs:

1. Demand forecast
2. Interconnector flows
3. Forecast of Wind Generation Output
4. Generation availability (including plant dynamics)
5. Reserve & response requirements

Should any of the above forecasts or assumptions about interconnector flows or plant availability change then the control engineer can be forced to make decisions in short timescales in order to meet the mix of objectives he has to meet:

1. Redispatch of price making generation
2. Redispatch of price taking generation in the following order as available to manage the particular constraint:
    a. Peat
    b. Hydro
    c. Wind, and within the category of wind generators
        i. 1st - Variable Price Taker
        ii. 2nd - Autonomous

For example, if during the night actual demand is lower than forecast or the wind output turns out to be higher than forecast then the result can be too much generation on the system. In these circumstances the TSO must consider operational standards, transmission constraints and its ability to meet the forthcoming demand profile in its decision making. As such the TSO may redispatch price taking generation instead of price making generation due to plant dynamic restrictions such as minimum off-time, run-up rates etc.

The TSOs have indicated in discussions with the RAs that the objective function of the dispatch process, respecting system security and safe operation of the transmission system, is to minimise production costs whilst facilitating the nominations and output of price taking generation. The TSOs have also confirmed that in the dispatch phase no consideration is taken of firm and non-firm access but instead the objective is to dispatch cheapest generation portfolio available within the confines of operational standards, transmission system capability and system demand.

Appendix 2: Modelling Analysis

1. Overview

A number of studies have been conducted in recent years to assess the effects of increasing wind generation on the island of Ireland. The results of the All Island Grid Study (AIGS), examining different scenarios of wind penetration in the year 2020, were released in January 2008. The RAs published a follow-up study to the AIGS in January 2009, focusing on the ability of the SEM as currently designed to remunerate existing and new generation capacity in 2020.

Building upon these previous studies, we have undertaken further detailed modelling of the all island generation and transmission system in order to build up a picture of the evolution in SEM constraint and dispatch costs as wind penetration increases. The RA's January 2009 study was primarily concerned with modelling the unconstrained schedule and the Capacity Payment Mechanism (CPM) under the current SEM design. To inform the consideration of potential changes to the market rules, this latest modelling exercise seeks to examine how wind plant may operate in actual dispatch as well as in the unconstrained market schedule. Key differentiators from the previous RA study therefore include the consideration of transmission constraints, reserve requirements and non-firm access rights. In comparison with previous studies, it should also be noted that input assumptions have been updated in several areas, with material changes most notably to commodity prices, demand levels and renewables targets.

2. Methodology

This section describes the methodology that was adopted to examine the potential impacts of increasing wind penetration upon the SEM over the period 2010 to 2025. Constrained dispatch and unconstrained market schedules were first modelled under the current TSC arrangements. Potential changes to the market arrangements were then modelled against this baseline, with the objective of addressing the following questions:

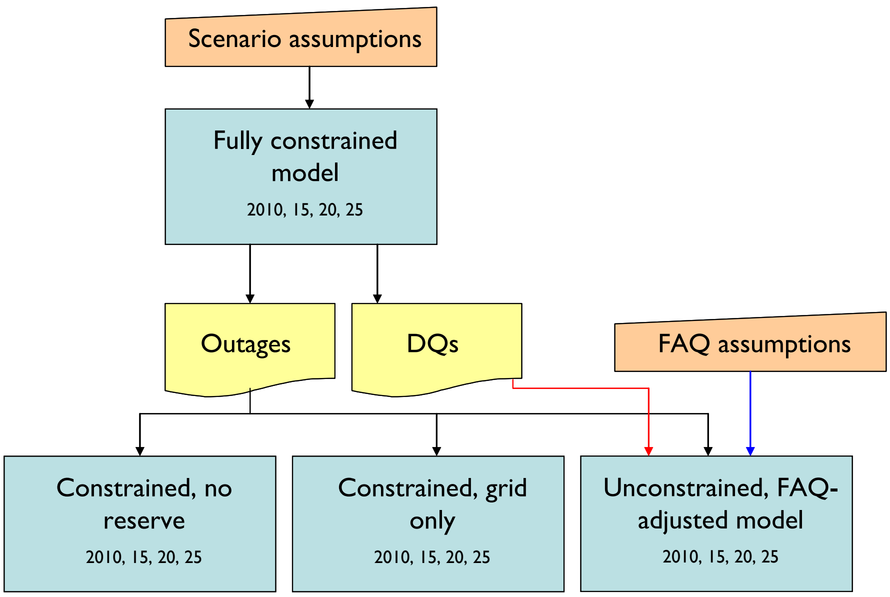
- How do overall system costs differ between the baseline and alternative market arrangements?
- How are infra-marginal rents allocated in the market schedule?
- To what extent are intermittent renewables likely to be "curtailed"?
- What is the outlook for constraint costs?

- How do carbon emissions and the output from renewable generation evolve?
- What are the expected gross margins and returns for different plant types?
- How do the incentives for new build (renewables, conventional) differ between policy options?

As with the RA study published in January 2009, the PLEXOS market simulation tool was used to conduct the majority of the modelling analysis. Previous RA studies have utilised the publicly available, validated SEM PLEXOS models as a starting point for simulating market schedules. In this instance, a constrained model of the SEM was also required to incorporate transmission and system operation constraints. The TSOs provided the RAs a PLEXOS model[50] with a detailed representation of the all island transmission network for 2009. We have developed constrained PLEXOS models for four spot years (2010, 2015, 2020, 2025), starting with the network configuration in the TSOs' 2009 model and incorporating planned and potential network reinforcements.

As described below, a Base scenario was constructed encompassing background assumptions on commodity prices, demand growth, plant build and transmission system evolution. The constrained and unconstrained variants of the PLEXOS model were then run for the Base scenario for each spot year, as illustrated by the schematic shown below.

Schematic to show the deployment of different versions of the PLEXOS model



50 This model had previously been used by the TSOs in 2008 to forecast constraint costs.

A ***fully constrained schedule***, capturing line ratings, reserve requirements and transmission constraint groups (TCGs) was run to derive baseline dispatch quantities. The dispatch quantities (DQs) from the constrained model, together with assumptions on firm access quantities (FAQs), feed into an ***adjusted unconstrained*** model, which represents the ex-post market schedule under the TSC. Two further versions of the constrained model were run to build up an understanding of how the components of constraint costs vary over time: one with no reserve, another with only the grid represented. Note that the generation outage pattern from the fully constrained schedule was manually replicated in all of the other models to avoid over-estimating constraint costs due to non-aligned outages.

The market schedule availability[51] of plant with non-firm access was modelled under three policy variants:

- Capping market schedule availability at the higher of DQ and FAQ for price makers (per the TSC as currently drafted);
- Capping market schedule availability at the higher of DQ and FAQ for price takers as well as price makers;
- Capping market schedule availability at FAQ for price takers and price makers.

Other sensitivities were performed for selected spot years. These included:

- Varying the effective bid price of wind plant in the optimisation from zero to extreme negative levels;
- Modelling the impact of Grid Code derogations for the dynamic parameters of conventional plant; and
- Modelling the incorporation of reserve requirements in the market schedule.

3. Assumptions

This section summarises the key assumptions made in the modelling analysis. Further details are provided in Appendix 3.

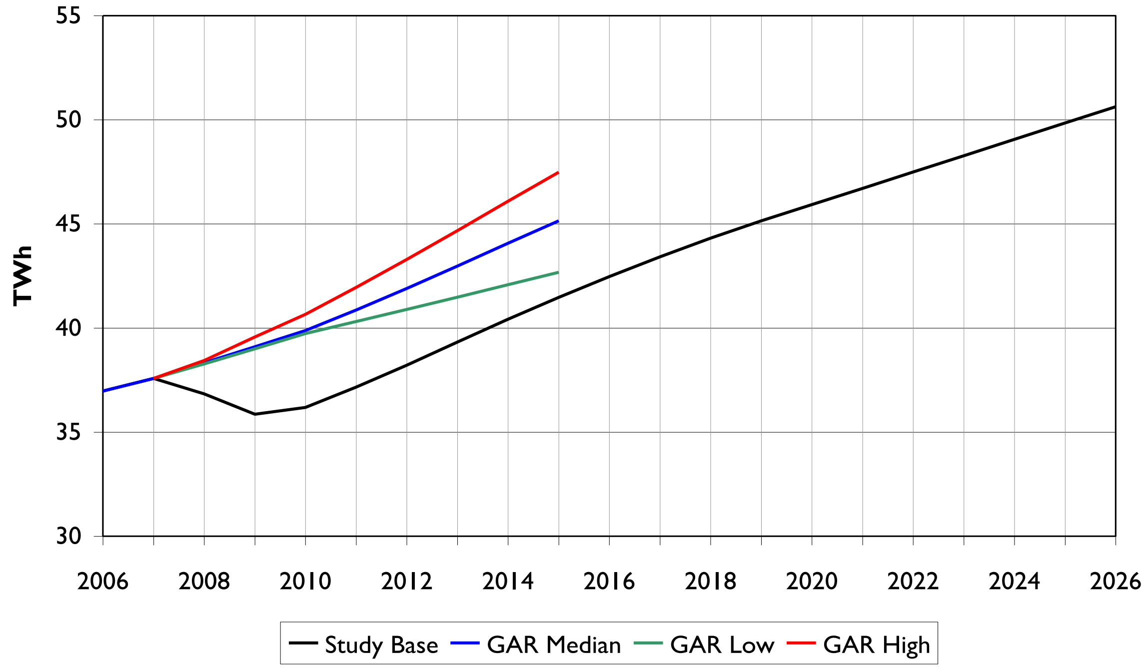
3.1. Demand

In the current economic environment there is significant uncertainty over the short- to medium-term evolution of demand. Demand projections were published by the TSOs

51 In each case, market schedule availability also takes account of generation outages and the resource (wind) profile.

towards the end of 2008 in the Generation Adequacy Report (GAR) and the Seven Year Statement (SYS). The starting point for our demand projections is a consolidated GAR/SYS All-Island demand projection based upon these documents. However, we note that these published TSO projections are based upon underlying GDP growth projections that are significantly different from current consensus views. We have used the published GAR/SYS views to back-calculate an implied energy intensity, which we then adopt as our energy intensity assumption. We have then layered back in more recent IMF GDP projections[52] to arrive at the total energy demand assumption outlined in Figure 1 Total Energy Demand (at station gate).

Figure 1 Total energy demand (at station gate)



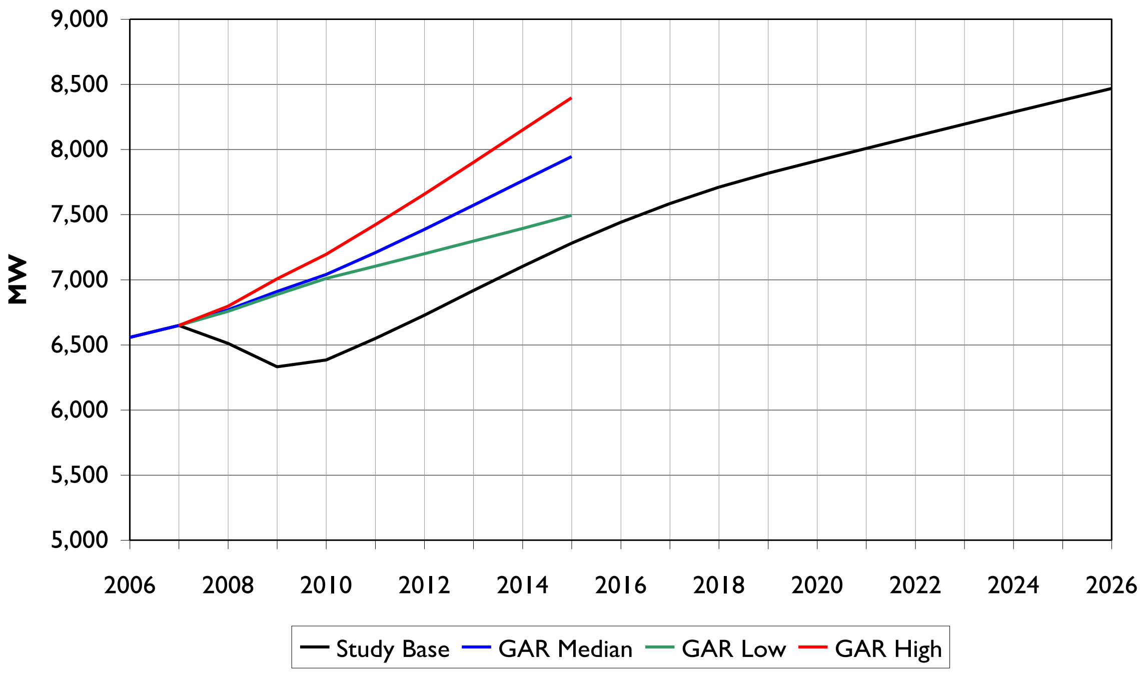
Beyond the scope of the IMF GDP projections we assume that the longer term growth rate is 3.5%, driven by the IMF's measure of potential GDP growth; we assume that this decreases to 2.5% by 2020.

52 The Euro-area GDP projection published in January 2009 was the latest available when the modelling assumptions were finalised. The difference between this projection and the October 2008 World Economic Outlook projection is combined with the country-level projection published in October 2008. The IMF has subsequently published revised GDP projections in April 2009 which imply a more pessimistic economic outlook in the short-term.

As shown in Figure 2, the resulting all island demand projections are significantly below those presented in the GAR. As another comparison, the projected annual demand for 2020 is 46 TWh compared to 60 TWh in the RAs' January 2009 study.

The GAR/SYS projections show peak demand growing at a rate that is of order 0.2% below the total energy demand growth. We have adopted this assumption for the period within the scope of these projections; by 2020 we assume that this has increased to a 0.5% differential, largely as a result of energy efficiency measures. The resulting peak demand projection is shown in Figure 2 Peak Demand. Other than the reduction in peak demand growth rate, other changes in load shape e.g. for electric vehicles, have not been considered for this exercise.

Figure 2 Peak demand



3.2. Commodity prices

Forward curves for oil, natural gas, coal and carbon were taken as February 2009. As described in Appendix 3, longer term price assumptions were set by extrapolation to benchmark references such as those published by the IEA.

Commodity prices have fallen sharply since scenarios were developed for the RA study published in January 2009. As a result, the Base commodity price projections assumed for this project are below the Low scenario prices in the previous study.

Relative rather than absolute fuel prices are important in driving the merit order of dispatch. By 2020, the Base scenario projections favour CCGTs over coal plant in SRMC terms. Figures 3a and 3b show the changing fuel prices over time with and without the costs of Carbon.

Figure 3a Changing Fuel Price over time, excluding the costs of carbon

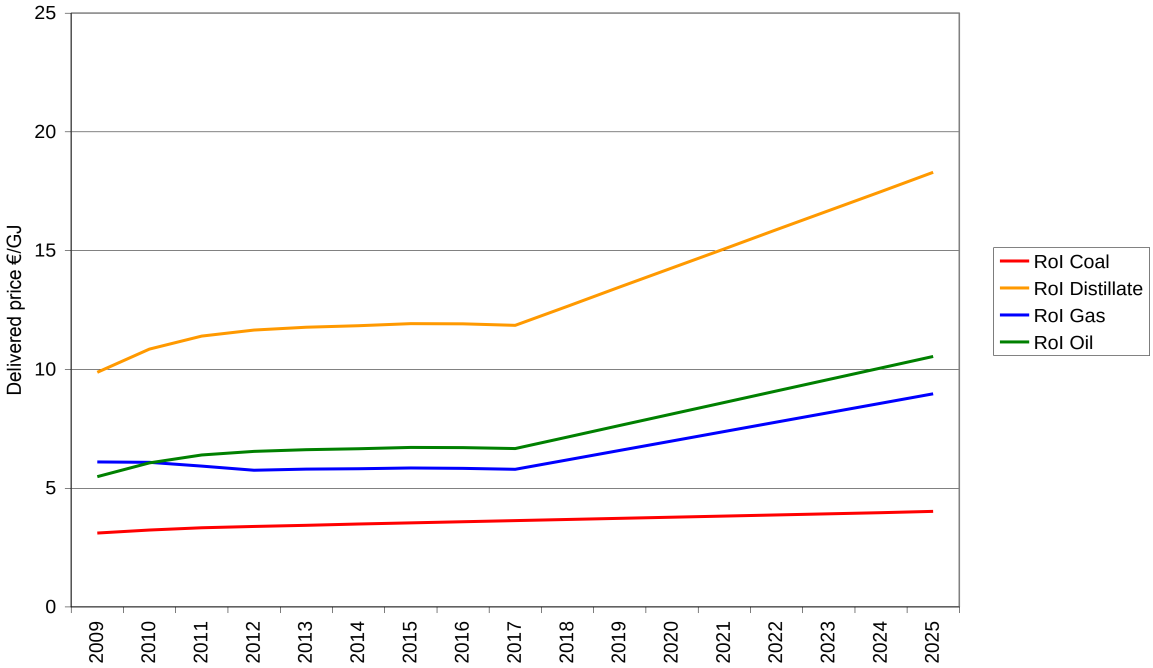
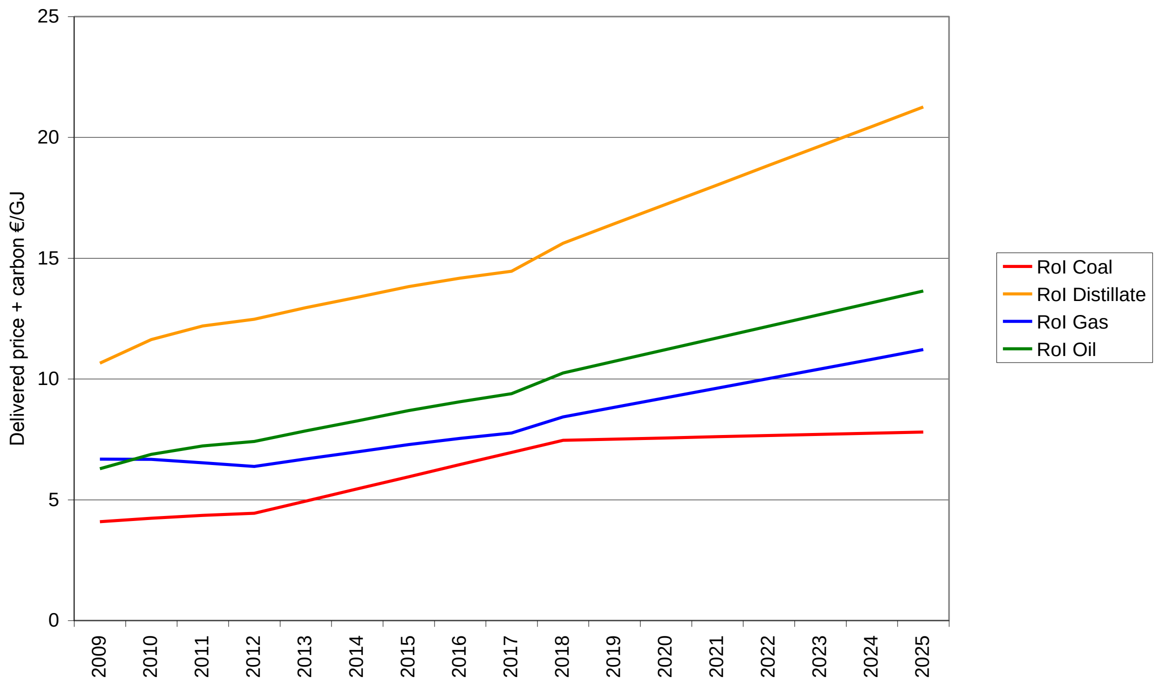


Figure 3b Changing Fuel Price over time, including the costs of carbon



3.3. Generation developments

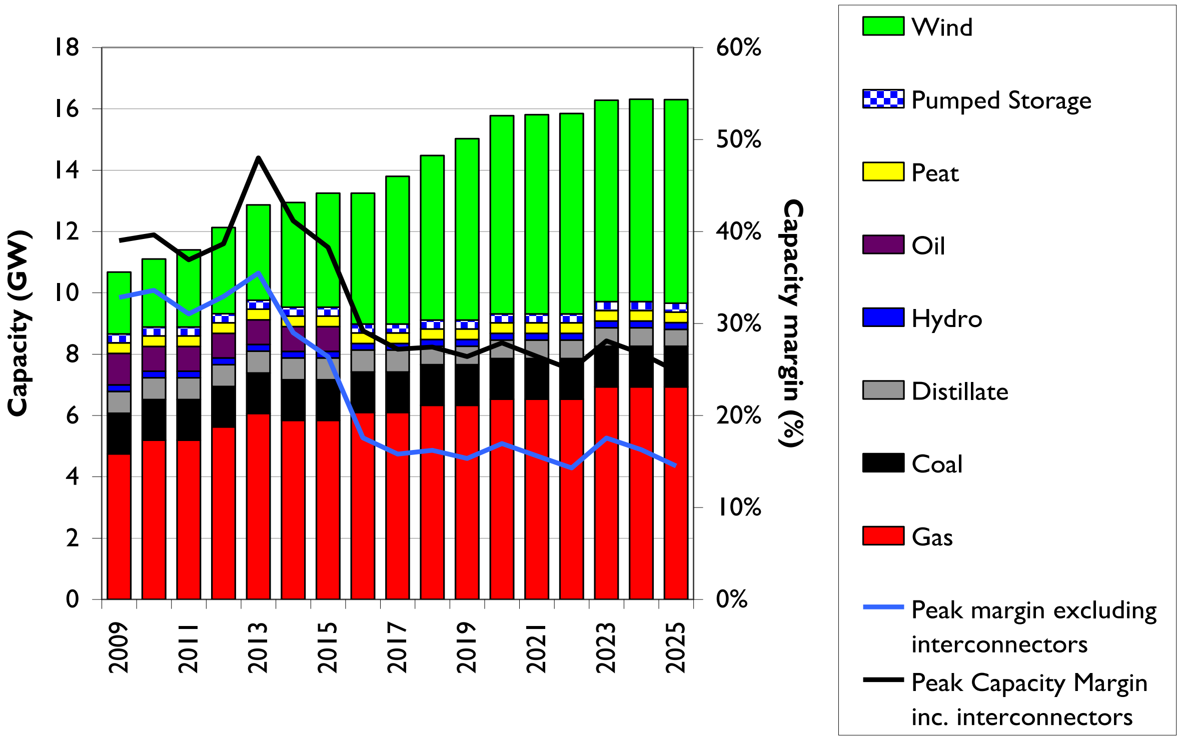
The starting point for our assumptions regarding the evolution of generation capacity is EirGrid's GAR and SONI's SYS, both last updated at the end of 2008. Further retirement and build assumptions are set out in Appendix 3.

The Base scenario assumes that wind plant are developed with the aim of meeting a 40% renewable electricity target on an all island basis in 2020. Compared to the 2020 assumptions in the AIGS and follow up RA study, total wind capacity in 2020 is marginally higher at 6.3 GW than the high penetration (AIGS Portfolio 5) value of 6 GW.

Given the relative fuel prices in the Base scenario, new thermal build is assumed to be dominated by CCGTs, together with OCGT peaking capacity. The capacity build levels are set to maintain a de-rated capacity margin over the longer term.

Figure 4 illustrates the evolution of generation capacity across the SEM.

Figure 4 Evolution of system-wide capacity



3.4. Transmission developments

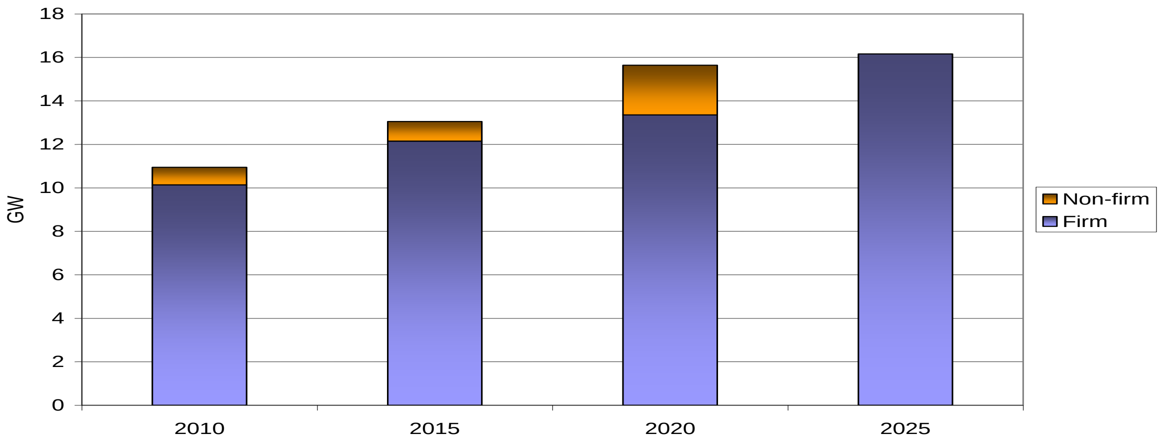
The starting point for the modelling of the transmission system has been the TSOs' 2009 constrained PLEXOS model. This includes some transmission grid reinforcements to be carried out in the near future. Medium-term grid evolution assumptions are taken from the Transmission Forecast Statement (TFS) 2008-14 for the 2010 and 2015 models. Further assumptions are then made about the evolution of the transmission network beyond 2015, guided by the high level vision set out in EirGrid's Grid25 project.

We have assumed that tertiary reserve requirements increase over time with wind penetration levels. Assumptions on transmission constraint groups reflect current operating practice, as modified by plant retirements and additions. We assume some relaxation of both reserve constraints and transmission constraint groups following the completion of the North-South upgrade.

New plant are assumed to obtain non-firm access at a specified percentage of their maximum capacity. This percentage is assumed to vary on a regional basis across Ireland, as informed by the opportunities for connection indicated in EirGrid's Transmission Forecast Statement (TFS). On average, it is assumed that new plant operates on a partially firm basis for five years before deep reinforcements are completed.

Figure 5 illustrates the total levels of firm and non-firm capacity in each spot year.

Figure 5 Firm and Non-Firm Capacity by Type

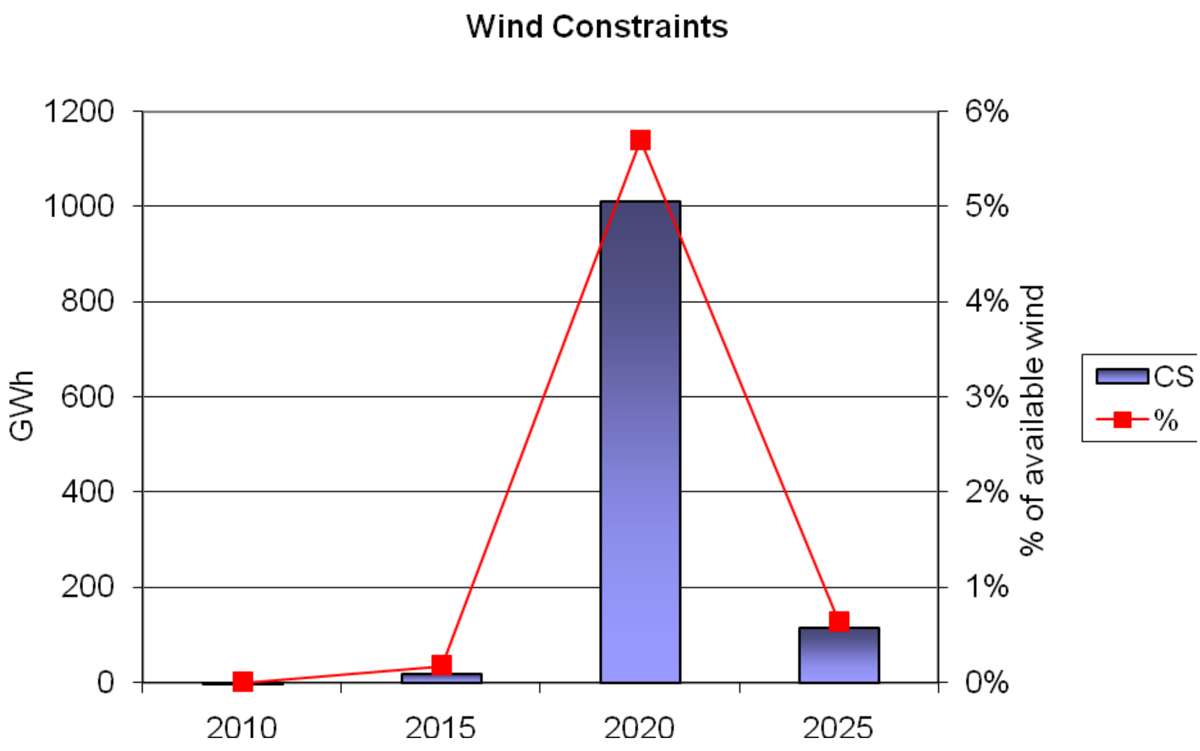


4. Findings

4.1. Wind Output Constraints

By comparing the scheduled wind output in each run to the assumed wind availability profile, a view can be formed on the likelihood of constraining wind output. Results from the fully constrained schedule for the Base scenario indicate that wind constraints represents around 0.2% of available wind energy in 2015, rising to 5.7% in 2020 and then falling to 0.6% in 2025 following extensive grid reinforcements.

Figure 6 Wind Constraints



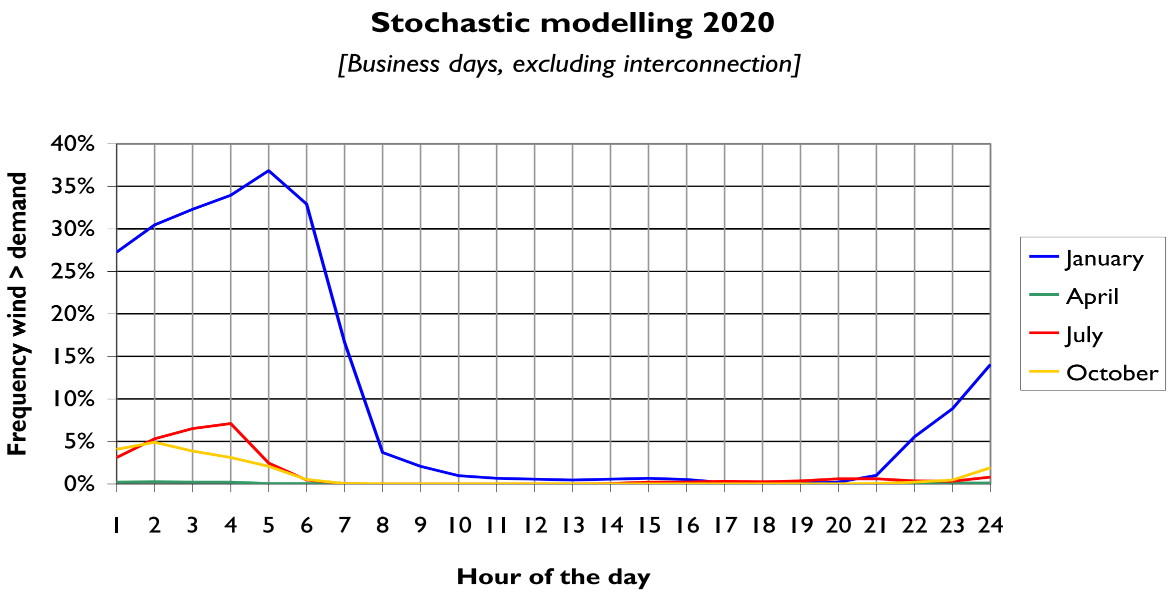
In these runs, wind was modelled with an effective price of zero (a nominal variable operating cost of 0.4 €/MWh was assumed). The results imply that grid constraints and reserve requirements could lead to a shortfall against 2020 renewables targets in actual dispatch if wind is priced at zero cost (and assuming as is the case here that grid reinforcements lag behind wind plant commissioning by some five years).

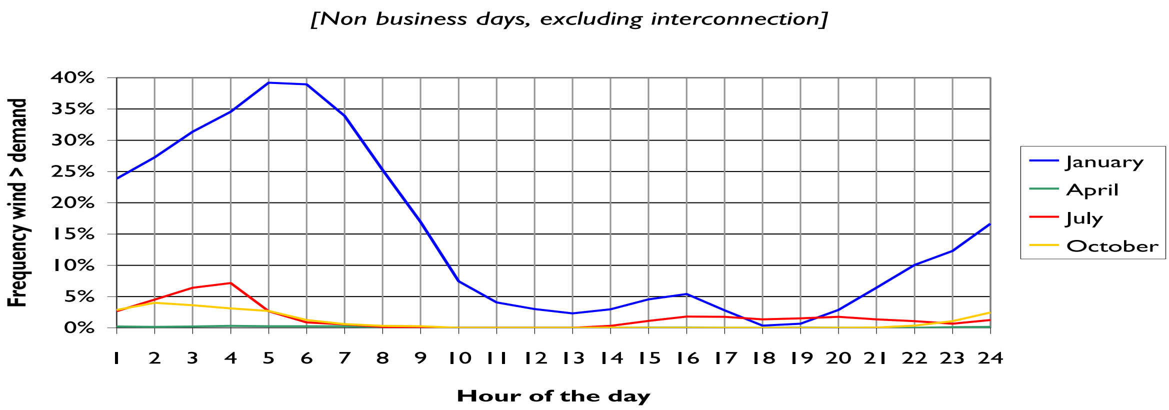
By comparison, the market schedules showed negligible constraining of wind output reflecting the low incidence of "excessive generation" or economic re-dispatch in the Base scenario.

4.2. Stochastic Modelling of Wind Constraints

The wind constraint results above were obtained by running PLEXOS in a deterministic mode. The input demand profile, for example, is representative of average weather conditions but does not capture the potential distribution of demand around the expected level. To further explore the potential for excessive generation in a high wind penetration scenario, we have also utilised a stochastic modelling framework to simulate the distribution of wind output, plant availability, commodity prices and demand in the SEM and GB. Applying a Monte Carlo process, 2000 simulations were conducted for business and non-business days in each month. Figure 7 shows the frequency by time period in which excessive generation events were modelled to occur in a fully unconstrained[53] market schedule for 2020. Excessive generation is defined here to occur whenever wind availability is simulated to exceed SEM load, excluding potential interconnector exports. The results indicate that wind generation is most likely to exceed SEM demand during January night time periods, with excessive generation observed in over 35% of simulations.

Figure 7



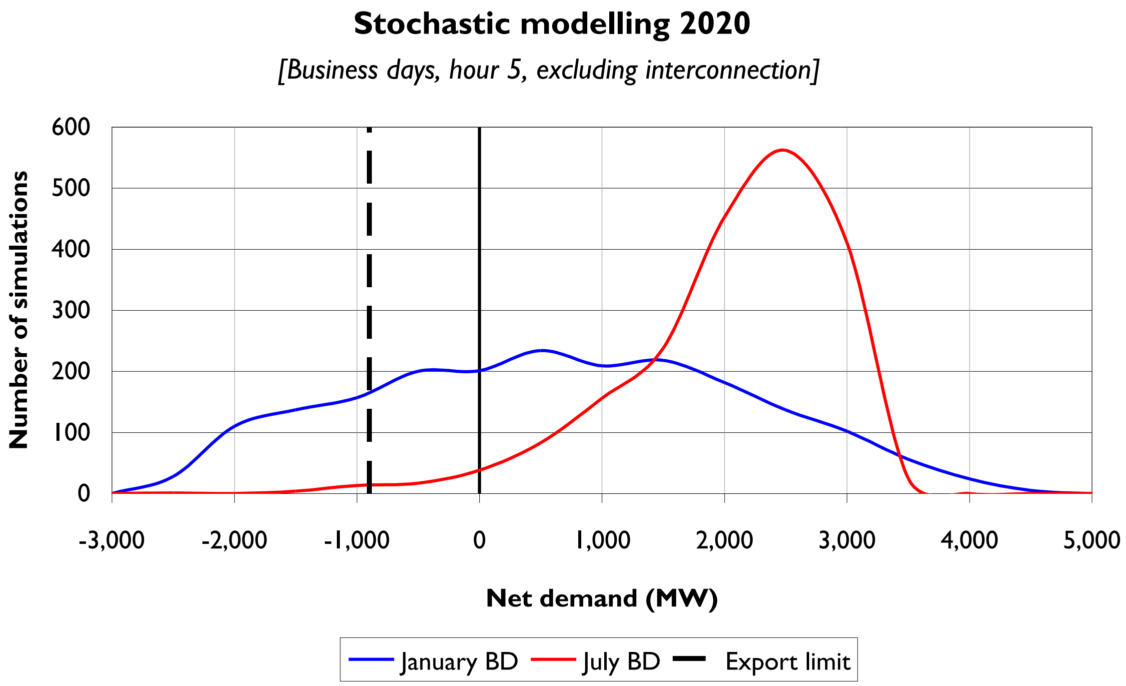


To illustrate the potential volume of excessive generation during overnight periods, Figure 8 plots the histogram of net demand (SEM load minus wind generation) in hour 5 for business days in January and July 2020. The interconnection export limit is also shown for reference. Excessive generation events, with the consequential collapse in SMP, may be mitigated by exports to GB, although the scope for exports will be limited by both the likelihood that high

53 The stochastic modelling framework is based upon on a generation stack approach, and ignores FAQ restrictions and plant dynamic constraints.

wind output in the SEM will coincide with high wind output in GB also and by charges or any other impediments to the use of the interconnector.

Figure 8



4.3. Priority dispatch

To consider a world in which price takers continue operating at any cost, a sensitivity was conducted modelling wind with an extreme negative offer price (minus 1000 €/MWh). Constraining of wind output was observed to be lower (4.9%) in 2020 in this sensitivity, although overall SEM generation costs were higher, reflecting increased two-shifting and start-up costs.

Total SEM production costs in the constrained schedule for 2020 were €85m higher in the sensitivity with negative wind bid prices. However, production costs in GB actually fall, as a result of a change in interconnector exports and/or imports. If this benefit were to accrue to the SEM, i.e. through additional revenue for exports or reduced costs for imports, the differential would fall to €42m.

4.4. Infra-marginal rents

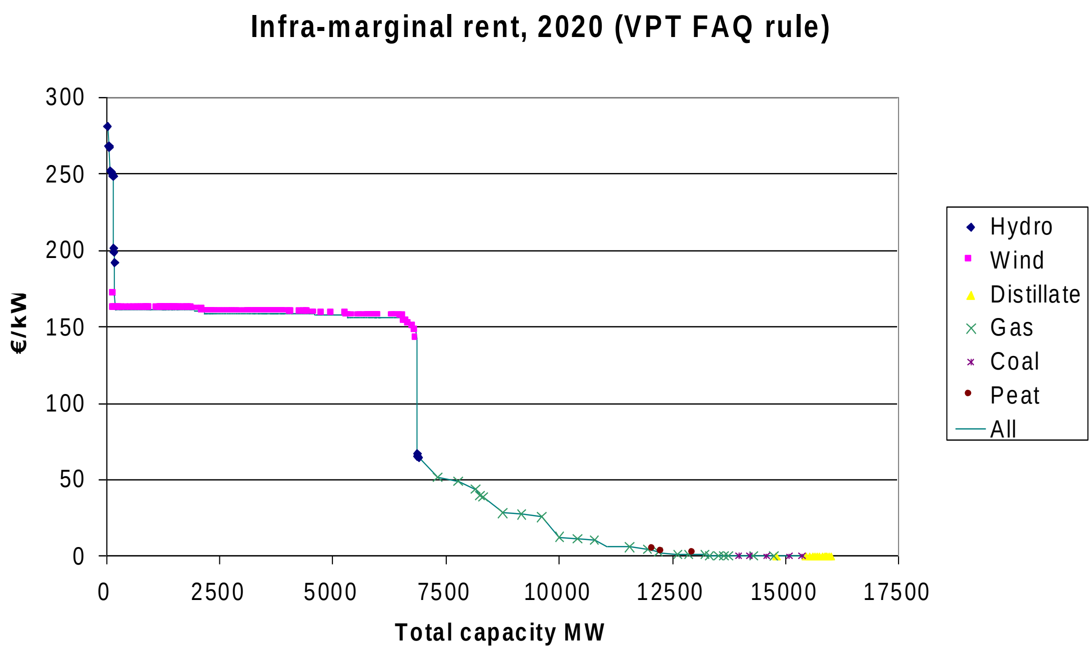
The potential allocation of infra-marginal rents under high wind penetration scenarios can be assessed by analysis of the unconstrained market schedules. In the Base scenario, wind plant were observed to capture around 85% of annual infra-marginal rents by 2020, relative to a generation output share of around 38%. Per unit of installed capacity, the infra-marginal rents accruing to wind plant under this scenario were of the order of 165 €/kW in 2020. Gas-fired CCGTs obtained annual infra-marginal rents ranging from 1 to 50 €/kW in 2020, depending on plant efficiency, FAQ and location.

Alternative market schedules were modelled applying the FAQ restriction on non-firm plant just to price makers (reflecting the current TSC rules) and to all non-firm plant. Applying the non-firm access rule to price takers reduced the infra-marginal rent for affected wind generators by 10 to 50 €/kW.

A further restriction was also applied to all non-firm plant, restricting its MSQ to the maximum of FAQ in all circumstances (i.e. even when it was dispatched above this level in the constrained schedule). This result reduced the annual infra-marginal rents to non-firm wind plant by around 60 €/kW on average.

Figure 9 shows the allocation of infra-marginal rents by plant type in 2020 in a market schedule with the DQ/FAQ rule applied to non-firm price takers.

Figure 9



4.5. Constraint costs

The net margins of constrained on thermal plant were estimated by first considering infra-marginal rents and then netting off fixed / capital costs to the extent they exceed those assumed for a BNE Peaker. The potential income shortfall was estimated to be 20 to 40 €/kW for constrained on thermal plant in 2020.

5. Summary of Key Results

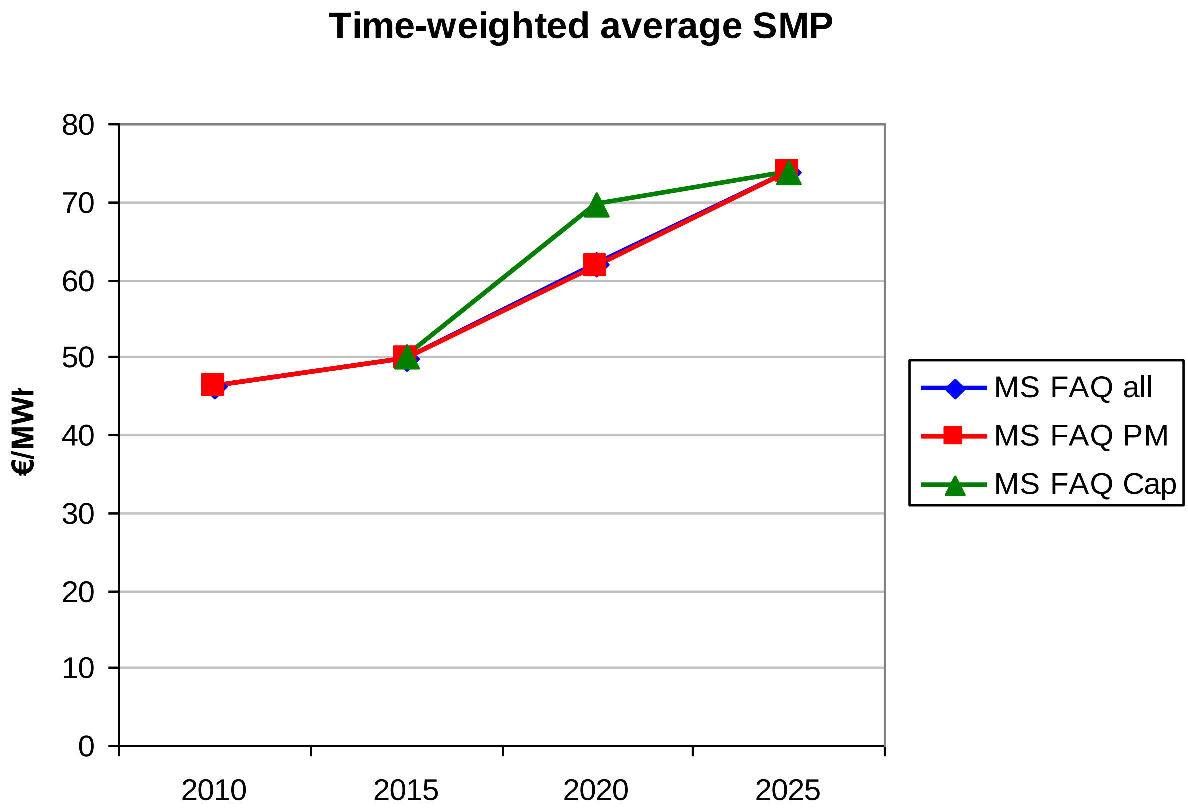
In this section, the key results of the modelling are summarised, results are presented for the following types of schedules:

CS	A constrained schedule including modelling of thermal ratings, group transmission constraints and reserve requirements. This is intended to model the actual dispatch that will be undertaken by the TSOs;
MS FAQ PM	A market schedule (i.e. without transmission constraints or reserve) with the availability of price makers capped at the maximum of their estimated FAQ and their constrained schedule output. This is intended to model the existing TSC rules;
MS FAQ all	As above, but with the cap on FAQs described above applying to both price-making plant and price-taking plant. This is intended to model the impact of changing the TSC rules to cap the availability of price-takers to FAQ in the market schedule in circumstances when they are dispatched below their availability;
MS FAQ Cap	As MS FAQ all, but with the availability of non-firm plant capped at FAQ (rather than the maximum of FAQ and the constrained output). This is intended to model the impact of changing the market rules to limit access to the market schedule to FAQ even where plant operates above this level in actual dispatch.

5.1. Time Weighted Average SMP

Figure 10 shows the time-weighted average SMP values for the three market schedule runs plotted over time from 2010 to 2025.

Figure 10



As might be expected, with the additional restrictions placed on access to the market schedule in the MS FAQ Cap models, the time-weighted value of SMP is increased, particularly in 2020 prior to the infrastructure reinforcements.

5.2. Renewable Output and Wind Constraints

Figure 11 shows the quantity of renewable outputs in the various modelling studies and highlights the quantity of wind constraints – i.e. the difference between availability and scheduled quantity for wind in the various schedules.

Figure 11

Renewable output / SEM demand

<table>
<tr><th>% demand</th><th>2010</th><th>2015</th><th>2020</th><th>2025</th></tr>
<tr><td>CS</td><td>17.5%</td><td>25.1%</td><td>37.9%</td><td>37.5%</td></tr>
<tr><td>MS FAQ all</td><td>17.4%</td><td>25.1%</td><td>38.7%</td><td rowspan="3">37.6%</td></tr>
<tr><td>MS FAQ PM</td><td>17.4%</td><td>25.1%</td><td>39.9%</td></tr>
<tr><td>MS FAQ Cap</td><td>0.0%</td><td>22.1%</td><td>33.9%</td></tr>
</table>

Wind “curtailment”

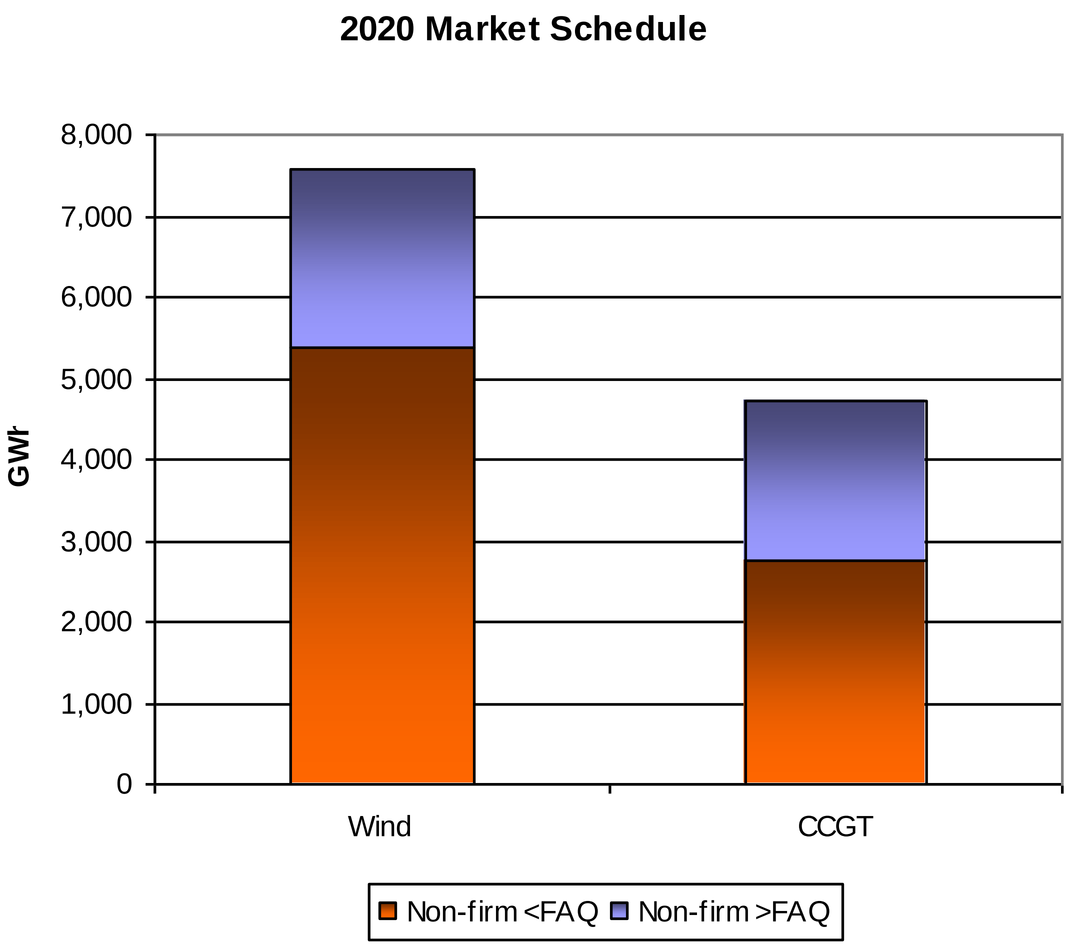
<table>
<tr><th>GWh</th><th>2010</th><th>2015</th><th>2020</th><th>2025</th></tr>
<tr><td>CS</td><td>0.1</td><td>17.7</td><td>1,012.0</td><td>115.9</td></tr>
<tr><td>MS FAQ all</td><td>0.0</td><td>0.0</td><td>2.1</td><td rowspan="3">11.9</td></tr>
<tr><td>MS FAQ PM</td><td>0.0</td><td>0.0</td><td>13.8</td></tr>
<tr><td>MS FAQ Cap</td><td></td><td>0.0</td><td>0.0</td></tr>
</table>

The first table shows that renewable (wind+hydro) output is generally lower in the constrained schedule (CS), except for MS FAQ Cap. The second table shows wind constraints relative to schedule availability (full availability for CS and FAQ PM, whereas FAQ all and FAQ Cap have a lower starting point). It should be recognised that the market schedule quantities are measures of which generating units receive infra-marginal rents, and not a measure of the quantity of renewable generation output produced. It is also noted however that the treatment of generators in the market schedule may have an impact on the timing of their investments, and that this effect has not been included in the modelling analysis.

5.3. Non-Firm Running

Figure 12 shows the quantities of firm and non-firm running of wind and CCGT plant in the 2020 market schedule.

Figure 12



The orange shaded areas show the quantity of running at levels below FAQ, whilst the blue areas show levels of operation above FAQ.

5.4. Infra-marginal Rents

Figure 13

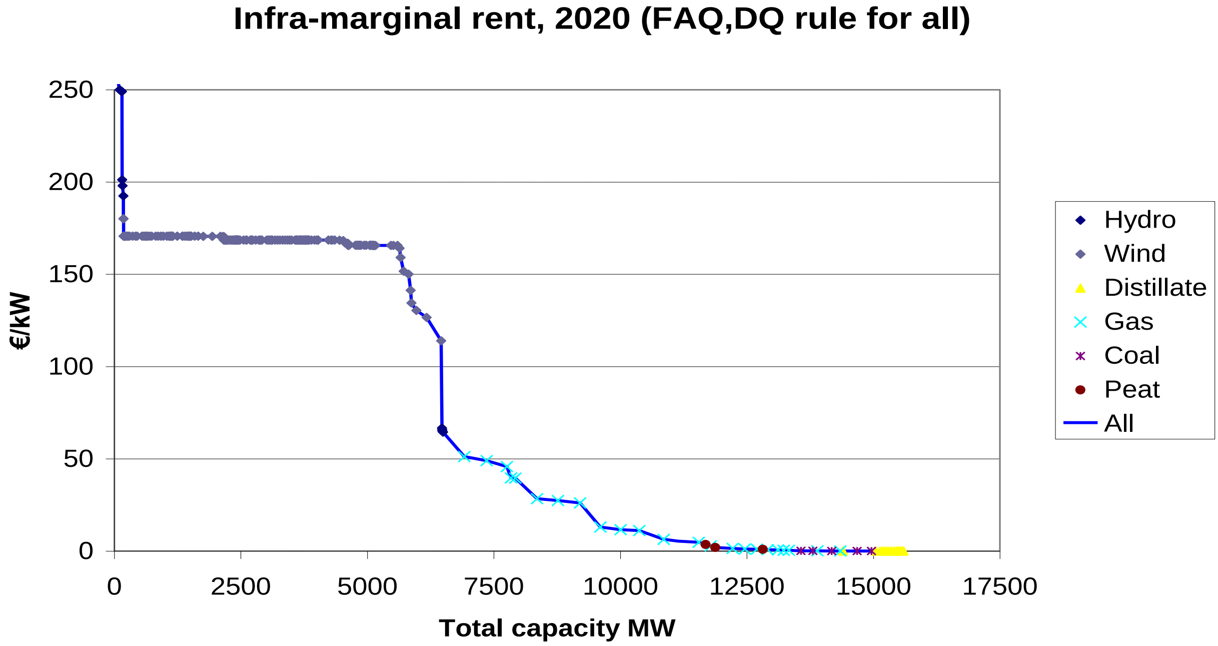
€m	2010	2015	2020	2025
MS FAQ all	499	663	1,200	1,474
MS FAQ PM	500	663	1,218	
MS FAQ Cap		616	1,360	

Figure 13 shows the total infra-marginal rents paid under the various options. It is noted that capping the market schedule availability at FAQ in the MS FAQ Cap model reduces total infra-marginal rents by €47m in 2015 but increases total infra-marginal rents by €142m in 2020. However it is also noted that generators located on the import side of export constraints (i.e. those that are useful in meeting actual demand) gain an additional €277m in infra-marginal rents under this proposal in the same year.

5.5. Infra-marginal rent allocation in 2020 MS FAQ all

Figure 14 shows the allocation of infra-marginal rents across different plant types under the MS FAQ all modelling scenario.

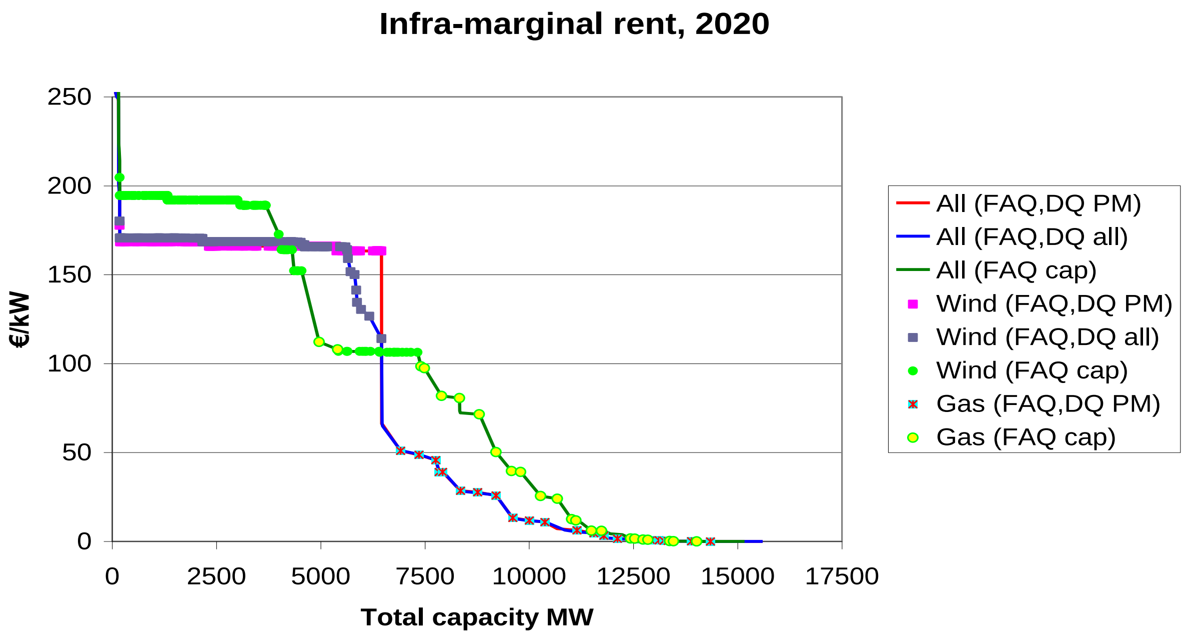
Figure 14



5.6. Infra-marginal rent allocation in 2020 other schedules

Figure 15 shows the allocation of infra-marginal rents across different plant types under the alternative market schedule scenarios.

Figure 15



This shows the reallocation of infra-marginal rents to different plant types under the alternative market schedule scenarios, most particularly under the MS FAQ Cap option under which infra-marginal rents accrue to a reduced quantity of wind and a greater quantity of gas fired generation.

5.7. Fixed cost assumptions

For the purposes of assessing the impact of the various scenarios on generators' ability to recover fixed costs, the following assumptions relating to fixed costs were used[54].

Figure 16 Fixed Costs

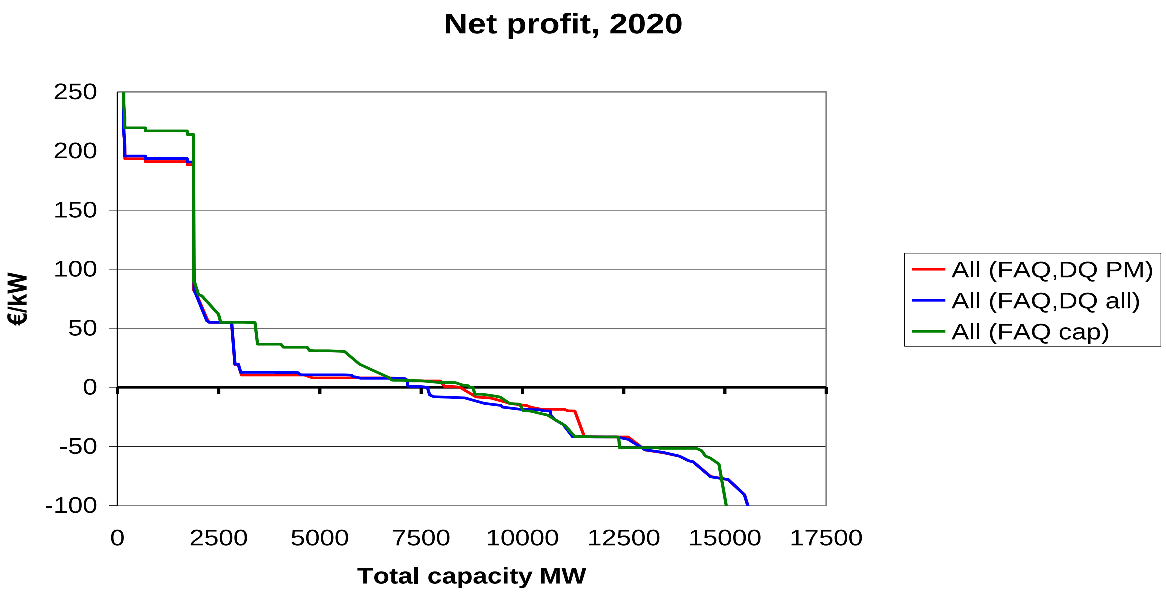
	Investment Costs (€000 per MW)	Fixed Costs (€000 per MW)	Total (€000 per MW)	Cost vs. New OCGT
Plant Additions				
New CCGT	100	90	190	104
New OCGT	59	27	86	0
New Coal	270	85	355	269
New Wind	183	61	244	158
Existing Plant				
Coal		128	128	42
Peat		150	150	64
Gas Baseload		104	104	18
Gas Mid Merit		108	108	22
Hydro		70	70	-16
Pumped Storage		35	35	-51
Peakers		31	31	-55
Wind (1000MW)		61	61	-25

54 These assumptions are consistent with those in the RAs' January 2009 study for 2020.

5.8. Net Profits

Figure 17 plots the net profits in 2020 against generation capacity (by plant type), taking into account the infra-marginal rents received and the fixed costs assumptions set out above.

Figure 17 Net Profits

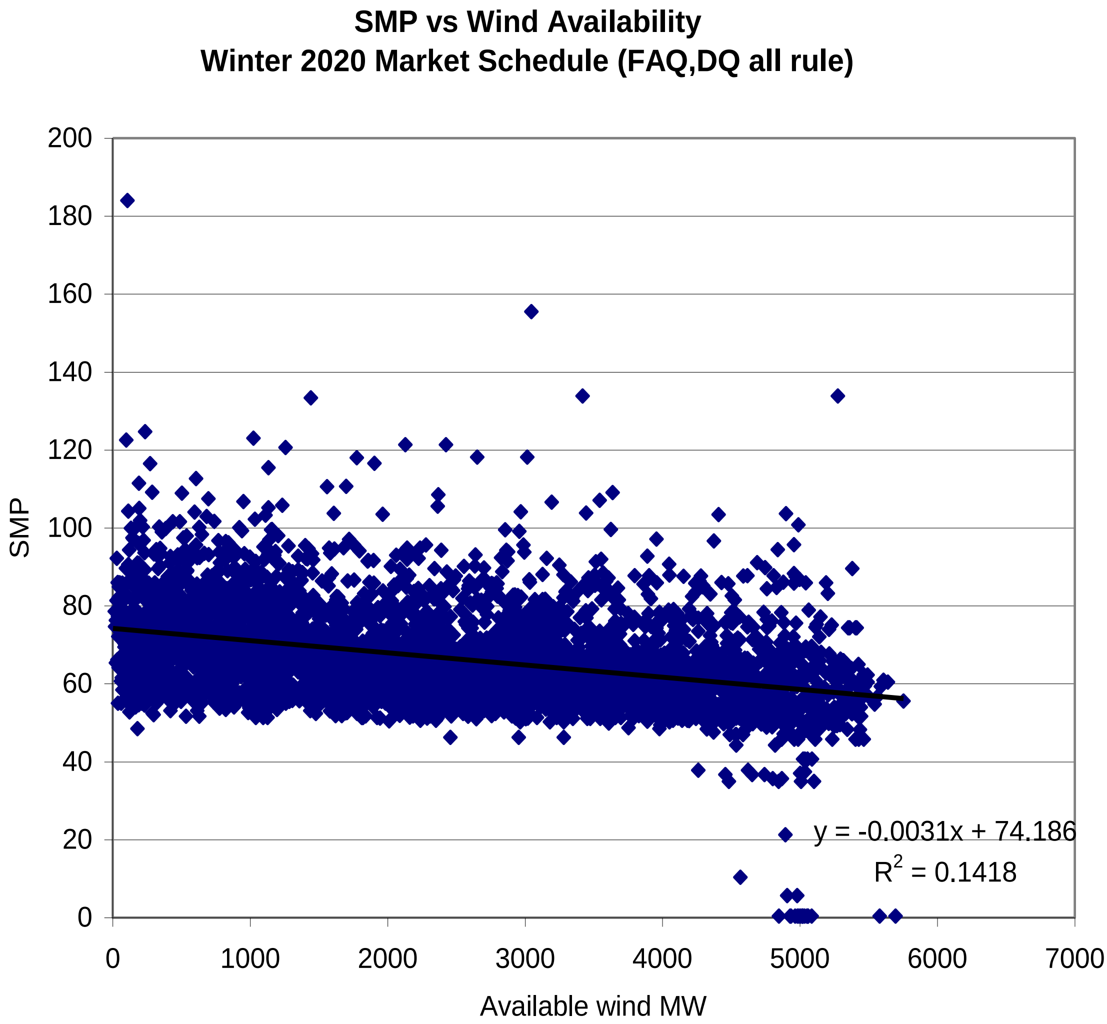


It may be seen that the effect of the MS FAQ Cap option is to increase the net profits of plant higher up the merit order.

5.9. Impact on SMP

Figure 18 shows the impact on SMP of increasing wind availability in the MS FAQ all market schedule.

Figure 18



The gradient of the best fit line shows that SMP is reduced by €3.1/MWh/GW. Whilst this reduction shows the benefits that wind can bring to reducing SMP, it also shows the potential extent to which SMPs may be depressed below market levels if over-allocation of access to the market schedule behind export constraints occurs.

5.10. Production Costs

Figure 19 shows the production costs for SEM and SEM+GB in the various modelling runs. Production cost is determined as the product of bid price and scheduled output summed over all generating units over the year.

Figure 19

SEM only

<table>
<tr><th>€m</th><th>2010</th><th>2015</th><th>2020</th><th>2025</th></tr>
<tr><td>CS</td><td>1,180</td><td>1,354</td><td>1,854</td><td>2,232</td></tr>
<tr><td>MS FAQ all</td><td>1,104</td><td>1,314</td><td>1,643</td><td rowspan="3">2,004</td></tr>
<tr><td>MS FAQ PM</td><td>1,104</td><td>1,313</td><td>1,617</td></tr>
<tr><td>MS FAQ Cap</td><td></td><td>1,366</td><td>1,772</td></tr>
</table>

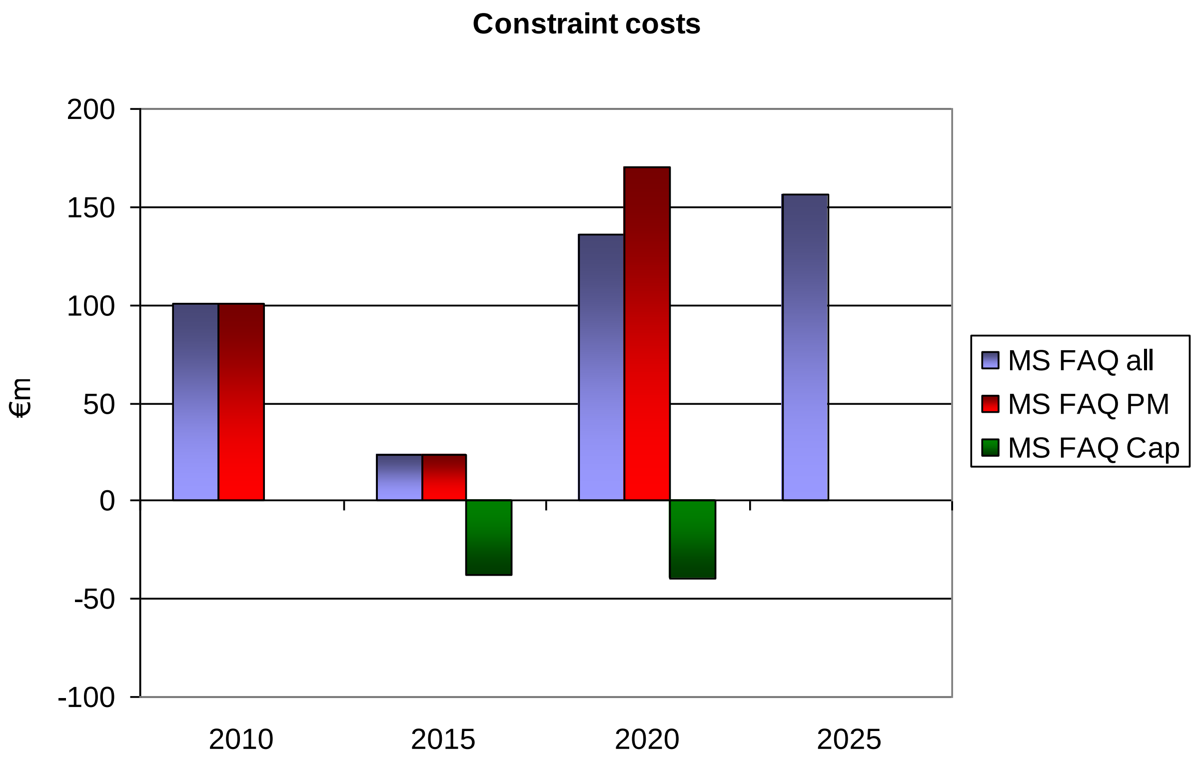
SEM + GB

<table>
<tr><th>€m</th><th>2010</th><th>2015</th><th>2020</th><th>2025</th></tr>
<tr><td>CS</td><td>11,842</td><td>14,149</td><td>19,209</td><td>17,812</td></tr>
<tr><td>MS FAQ all</td><td>11,742</td><td>14,126</td><td>19,073</td><td rowspan="3">17,655</td></tr>
<tr><td>MS FAQ PM</td><td>11,742</td><td>14,125</td><td>19,038</td></tr>
<tr><td>MS FAQ Cap</td><td></td><td>14,187</td><td>19,248</td></tr>
</table>

5.11. Constraint Costs

Figure 20 shows the constraint costs for the various schedules, determined as the difference in production cost between the constrained schedule and the relevant market schedule.

Figure 20



In the case of the MS FAQ Cap model, constraint costs are negative reflecting the fact that in actual dispatch, cheaper generation behind the export constraint is available to the TSOs for dispatch, whilst it is only available to the level of FAQ in the market schedule.

5.12. Impact of priority dispatch

Figure 21 shows the difference in production cost between the constrained schedules for 2020 (SEM and SEM+GB). The difference between the two modelling runs is that in the first, wind is given has a price of +€0.4/MWh and in the second, a price of -€1000/MWh.

Figure 21

€m	2020 SEM only	2020 SEM+GB
CS wind @ +0.4	1,854	19,209
CS wind @ -1000	1,939	19,251
Δ costs	85	42

Modelling wind with a price of -€1000/MWh increases the quantity of renewable output by 40GWh with additional generation offset by hydro spill (levels of wind constraints are 1012 GWh and 878 GWh respectively in 2020 when wind is modelled with a price of -€1000/MWh and +€0.4/MWh respectively).

However, the effect of modelling wind with a large negative price serves to increase, not decrease the costs of production. This increase in overall production costs reflects increased starts/ part-loading on thermal units and hydro spill.

Appendix 3: Modelling Assumptions

1. Commodity prices

Our commodity price projections are based upon two key sets of inputs:

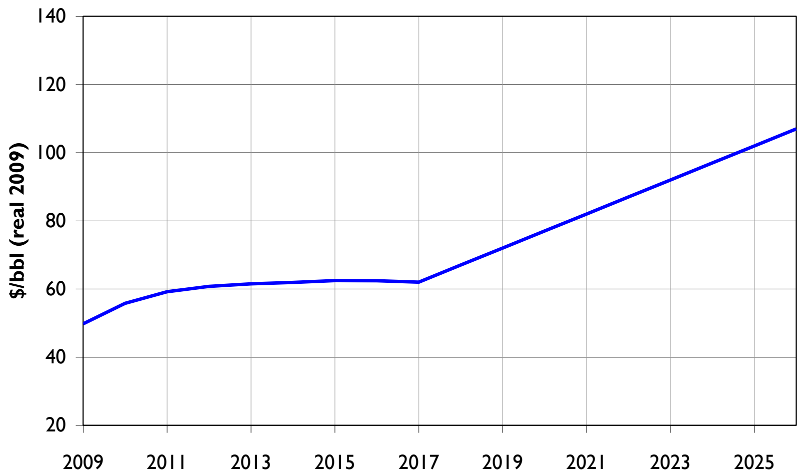
- Where available and of sufficient liquidity we use the forward curve for the commodity. All forward curves used in our assumptions are dated February 5, 2009
- A long term price 'anchor' is used, where possible this is cited from a well documented third party source

2. Brent oil

Figure 1 shows our Brent oil price projection. We have used the full quoted ICE forward curve for the front end of the projection. Beyond this we have used the IEA's World Energy Outlook 2008, which projects a 2030 price of 122 $/bbl in real 2007 terms. Beyond the end of the available forward curve, our price projection trends towards this anchor.

For gas oil and fuel oil we use ratios of 1.22 and 0.7 respectively to convert the Brent prices to prices for each of these products. The transport costs and excise duty costs, where applicable, are taken from the 2008 PLEXOS validation report, commissioned by the RAs.

Figure 1 Brent oil projections[55]



3. NBP gas

The gas price projection shown in Figure 2 is based upon a combination of the first few years of the forward curve and an indexation against Brent oil prices. Our indexation is based upon historical analysis of Brent and NBP prices. For 2009 we adopt the forward

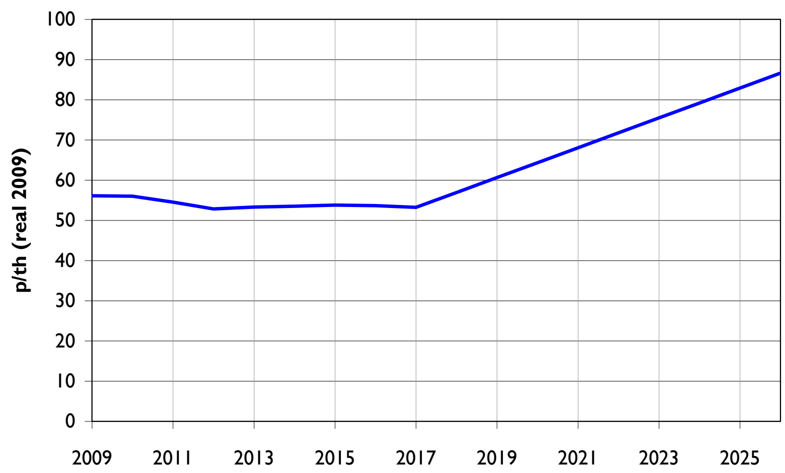
55 *Source:* ICE, IEA World Energy Outlook 2008.

curve price and by 2012 we rely entirely upon the regression parameters. Between these dates we apply a weighted transition between the two.

The prices shown in Figure 2 are annual average prices; in our modelling we apply a basic seasonality to this. In winter (October-March) we apply a factor of 1.1; in summer (April-September) we apply a factor of 0.9. These parameters are applied throughout the modelled period.

In ROI 90% of the transport charge for gas is fixed and so is not captured in our modelling; the variable charge in 2009 is assumed to be 0.089 €/GJ. In NI the current fixed/variable split is even, but we assume that this trends towards a 10% commodity charge, as for ROI, by 2012.

Figure 2 NBP gas projections[56]

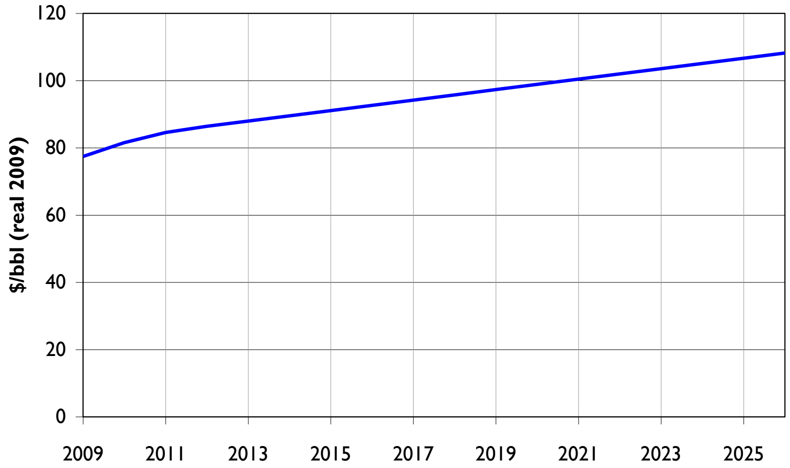


4. Coal

For the first four years of the price projection shown in Figure 3 we again use the forward curve. A 2030 anchor price of 110 $/t in real 2007 terms is taken from the IEA's World Energy Outlook 2008. As with the Brent oil price projection we extrapolate the trend between the end of the deployed forward curve and the longer term anchor price. Coal transport charges are assumed to be in line with those disclosed in the 2008 PLEXOS validation report.

56 *Source:* Platts.

Figure 3 Coal price projections[57]



5. Peat

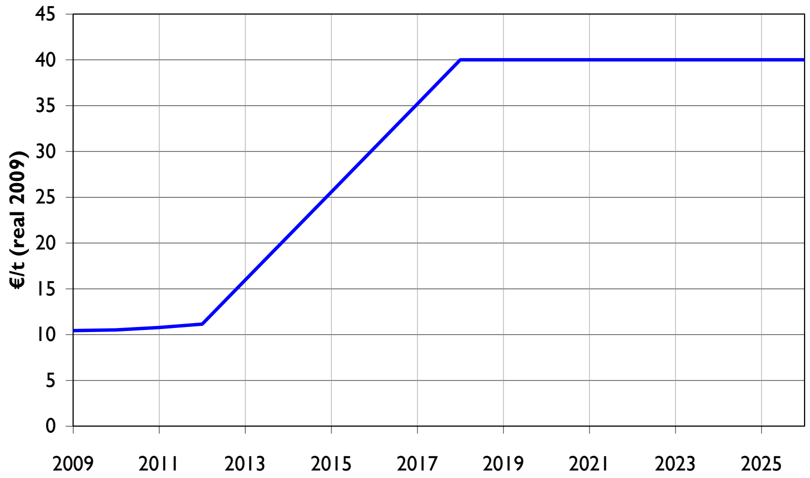
Peat is currently treated as 'must run'. We understand that the underlying contract for Edenderry expires in 2015 and we assume that this applies to other peat plant as well in our modelling. From 2016 we assume that, in real 2009 terms, the price of peat is 3 €/GJ; our understanding is that there is a contract in place to support this number. As with all other fuels, we add the carbon cost.

6. Carbon

For the remainder of Phase 2 of EU-ETS we again use the existing forward curve. From 2020 onwards we assume that the EUA price is 40 €/t in real 2009 terms. The EUA price rises steadily to this level as expectations are raised for a further tightening in carbon policy. At a 40 €/t EUA price, and with the longer term gas and coal price projections, the SRMCs of gas and coal are broadly competitive with each other.

57 *Source:* EEX, IEA World Energy Outlook 2008.

Figure 4 Carbon price projections[58]



7. Exchange rates

Spot exchange rates from 5 February 2009 were used in the derivation of delivered fuel prices, as shown in Table 1.

Table 1 Exchange rate assumptions[59]

Currencies	Rate
€/£	1.13
$/£	1.45

8. Plant retirement and new build

8.1. Retirement of existing plant

The starting point for our assumptions regarding the retirement of existing plant is EirGrid's GAR and SONI's SYS, both last updated at the end of 2008. Of the plant that are indicated as retiring in these documents, we have revised to 2015 the retirement dates of both the Great Island and Tarbert in light of the likelihood of these plants running until their replacement by new units. We do not expect this assumption to have a significant impact on merit order; the main impact on plant economics is likely to be through the dilution of the capacity payment pot. Beyond the timeframe of the GAR/SYS we have assumed that some

58 *Source:* EEX.

59 *Source:* FT.com.

of the remaining older units on the system, such as Northwall, are also retired. Our full set of retirement assumptions are summarised in Table 2.

Table 2 Retirement of existing plant[60]

Name	Year	Capacity (MW)
Gas		
Ballylumford 5, 6	2013	340
Aghada	2015	258
Marina	2015	112
Northwall	2017	163
Oil		
Great Island 1-3	2015	216
Poolbeg 1-3	2009	261
Tarbert 1-4	2015	589
Distillate		
Northwall	2017	109
Tawnaghmore	2024	52

8.2. New plant build

Our new build assumptions are laid out in Table 3. Most of the conventional plant build within the timeframe of the GAR/SYS are again taken from those two documents. We have added a Quinn CCGT to these assumptions, which is not included in the GAR. Beyond the temporal scope of these documents we have assumed that further generic CCGT and OCGT plant are built. Generic new CCGT plant have an LHV efficiency of 57.5%, new OCGT plant have an LHV efficiency of 41.4%. Note that the technical parameters for other plant are driven by the 2008 PLEXOS validation report. In the Base scenario, wind plant are effectively modelled with a bid price close to zero, assuming a VOM cost of 0.4 €/MWh.

As illustrated in Table 3 we assume that the wind build rate increases throughout the next decade as 2020 approaches. The location of the wind installations in ROI is guided by the Gate 3 list and, in the early years of the modelled period, by some of the larger installations shown in the GAR.

60 Note that retirement dates indicate the year at the end of which the plant is retired.

Table 3 New plant build assumptions[61]

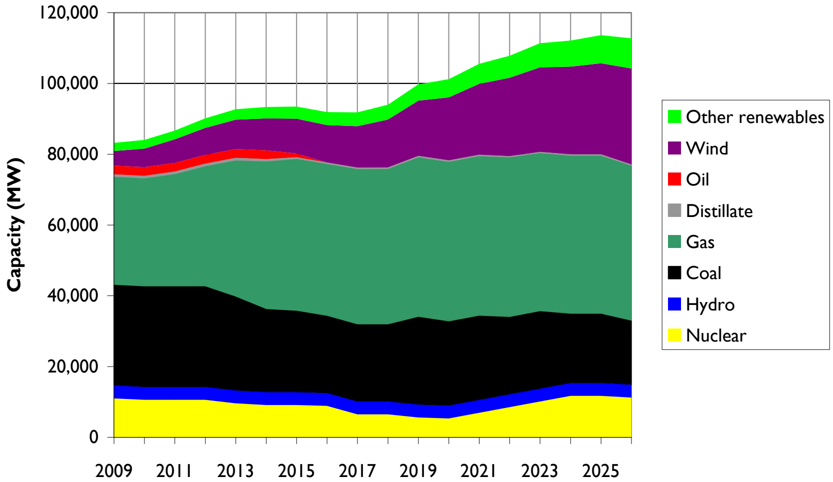
Name	Year	Capacity (MW)	Initial FAQ / Capacity (%)
Gas - CCGT			
CCGT A	2009	430	100%
CCGT B	2010	430	100%
CCGT C	2012	430	100%
CCGT D	2013	440	100%
CCGT E	2016	400	50% [for 5 years]
CCGT F	2018	400	50% [for 5 years]
CCGT G	2023	400	100%
Gas - OCGT and peaking units			
OCGT A	2009	70	100%
OCGT B	2014	120	100%
OCGT C	2016	200	100%
OCGT D	2020	100	100%
OCGT E	2020	100	50%
New wind	2009-2010	c.200 p.a.	25% - 75% [for 5 years]
	2011-2015	c.300 p.a.	
	2016-2020	c.550 p.a.	

8.3. Modelling GB and interconnectors

We have modelled the GB generation sector using a simplified representation of the stack, shown in Figure 5. Individual units are not modelled, but we do represent three separate tranches of coal capacity and four of gas. This follows the same principles as the previously validated PLEXOS models but makes use of recent Redpoint Energy modelling of capacity build in the GB market. We also include a wind profile file for the GB wind capacity so that the volatility and implied correlation from real GB wind data is captured in the modelling.

61 Note that commissioning dates indicate the years at the start of which commissioning is assumed to take place.

Figure 5 **GB generating capacity evolution**



Two interconnectors are included in the model. Moyle is assumed to have an import capacity of 450 MW and an effective export capacity of 80 MW. It is assumed that the export constraint is relaxed in 2020 such that the export capacity equals the import capacity. We also assume in the Base scenario that one of the proposed East-West interconnectors is built and that this introduces 500 MW of two-way capacity in 2013.

In the PLEXOS model, the starting point for interconnector flow drivers is the difference in the SRMC of the marginal plant or shadow price between the two markets. The remuneration beyond this price differs in the two markets and we have taken this into account through the use of a pre-defined matrix of wheeling charges (24 hour by 12 month) for the import and export flows. The matrices are held constant from year to year. Based upon recent historical data, these matrices take into account the seasonal and/or diurnal variation shown in the charges and revenue streams considered:

- SEM capacity payments – we have assumed that the capacity payment expectation for bids across the interconnector at the day-ahead stage is driven by the shape in our modelled fixed capacity payment weighting factors;
- GB TNUOS charges – for importing to the SEM we assume that GB supplier TNUOS charges are incurred in the relevant TNUOS region; these are spread across the peak hours of November to February. For exports from the SEM, generator TNUOS charges are incurred and these are spread evenly across the year; *and*
- Uplift – uplift shapes in the two markets are taken into account through analysis performed on 2005-07 data for the GB market and SEM market data for the first year of the market's operation.

Finally, a 5 €/MWh risk premium is assumed both for importing and exporting (to take account of the uncertainty over ex-post capacity payments and the overall risk in locking in bids day-ahead).

9. Transmission system evolution

9.1. The transmission grid

Our starting point for the modelling of the transmission system has been EirGrid's 2009 constrained model. This includes some transmission grid reinforcements to be carried out in the near future. For our medium- to long-term grid evolution assumptions we have used the Transmission Forecast Statement 2008-14 for our 2010 and 2015 models; it is possible to develop the 2009 constrained model in a fairly detailed way against the plans put forward in this document. Beyond 2015 we rely largely on Grid25. This is a much higher level document and does not in most cases specify individual projects/lines/nodes. We have therefore been adding lines into the network in line with the broad strategy outlined in Grid 25 but it is important to note that the actual grid evolution may differ materially from the evolution modelled in the study. We have discussed our approach regarding the grid evolution, and parameters for individual new lines, with the TSOs, who have agreed that our approach appears reasonable in light of the many uncertainties.

Planned grid extensions completed by 2015 include:

- The new 400 kV North-South interconnector
- A 500 MVA East-West interconnector

Speculative grid extensions completed by 2025 include:

- Extension of the 220 kV network in the north west into Mayo (Bellacorick) and Donegal (Letterkenny)
- Reinforcement of the 220 kV network in the south and south west, linking the 400 kV lines in the midlands to Cork (Knockraha) and Waterford (Cullenagh) via Cahir
- Extension of the 275 kV network in Northern Ireland to Omagh
- Additional cross-border 110 KV linkages between Northern Ireland and the north west
- General reinforcement of the 110 kV network via doubling up or uprating, particularly in the north west and south west

9.2. Reserve

Our understanding, corroborated through discussions with the TSOs, is that currently the main driver in the size of the required reserve is the largest thermal in-feed. Over time we assume that each 5 years the all island tertiary reserve requirement increases at a rate of 50 MW per 1 GW of new wind generation capacity. Additionally, we assume a one-off 20 MW increase across all reserve types in 2009 as a result of the Aghada CCGT commissioning as this unit becomes the largest thermal in-feed. Although wind plant may be capable of providing reserve following ancillary services harmonisation, the potential contribution of wind to reserve has not been modelled for this exercise.

In the TSOs' 2009 model there are constraints at the ROI/NI level that constrain the geographical location of reserve availability. From 2015, with completion of the improvements to the north-south interconnection, we assume that this constraint falls away.

9.3. Transmission constraint groups

To model constraints imposed by the TSOs for system security reasons above and beyond those imposed by pure grid limitations we use the published Transmission Constraint Groups (TCGs) valid from October 1, 2008. We have assumed the following changes to these published constraints:

- For the OpTime and MINNIU constraints, which require a certain number of thermal units to be operating in each of NI and ROI, we assume that this requirement drops by one unit when the north-south interconnection is improved; and
- Where new units are commissioned we add them to TCGs where we believe this to be applicable. For example, we add the Aghada and Whitegate CCGTs to the SW_MW and SW_NB constraints.

9.4. Firm Access Quantities (FAQs)

Plant commissioning dates are assumed to coincide with shallow connection dates. We assume that as of these dates some firm access is available, defined as a proportion of the MEC of the unit. These proportions are guided by the information given in the TFS that outlines the ease with which new capacity can be added to the system at given nodes.

- In the south west, the far north west, and on the southern border between ROI and NI we set FAQs at 25%; this corresponds to regions A, B (north-west), D, E, F, and G in Gate 2;

- Other new installations in the north west of the island (i.e. region C and the remainder of B) are given firm access of 75%; and
- New capacity in the remainder of the island is given a FAQ of 50%.

We adopt these assumptions both for new wind generation capacity and also for new generic conventional build where we have no alternative information. In these cases we assume that full firm access is given 5 years after the initial connection. The following exceptions are made to the generic FAQ assumptions:

- The Whitegate, Kilroot and Quinn CCGTs are given full firm access on connection;
- The Aghada plant in total are given an FAQ of 690 MW. We assume that this is apportioned to favour the most efficient units;

The assumptions outlined above are relevant for our modelling of 2010, 2015, and 2020; in 2025 we assume that all plant has full access and that the required deep reinforcement works are complete.

Appendix 4: Responses to February 2008 Discussion Document and RAs' Views

This Appendix summarises the main issues raised in response to the February 2008 discussion document insofar as the responses relate to matters relevant to this consultation document, and gives the RAs' views on the points raised in the responses.

A general view in the responses was that the SEM is not robust against high levels of wind generation and that the fixed costs of some plant that will be required by the system will not be covered. Others argued that wind generation would reduce the infra-marginal rents for thermal generators needed for back-up. Other comments suggested that the level of future wind was being restricted by the lack of flexibility of other generation and that future market mechanisms would need to provide more rewards for flexibility whereas presently generators could profit from a lack of such flexibility. Also, there was considerable criticism of the concept of "curtailment", whereby generators could be constrained down without compensation, with some respondents suggesting that it would likely penalise wind generators for the inflexibility of other generators, as well as calls for debate on the respective treatments of generators having firm and non-firm access.

The RAs believe that these principal issues have been addressed within the analysis and proposals within this consultation document. In particular, by ensuring that infra-marginal rents are allocated to plant that is useful in meeting actual system demand, investment signals from the SEM should ensure that an efficient plant mix of both renewable and conventional technology capable of meeting future requirements will be delivered. The proposals in this paper also cater for the remuneration of flexible plant, again by ensuring that the investment signals arising from infra-marginal rents ensure that, to the extent that flexible plant is needed to meet demand, such plant should receive appropriate payments under the SEM. Support for the current SO initiative to enforce Grid Code requirements should also help to ensure that existing and new conventional and renewable plant has the right technical characteristics to meet system requirements.

A number of respondents commented on the question of "Altering the Grid Code for Conventional Generation". Broadly the responses concluded whilst there were benefits in improving the technical performance of the generation portfolio it had to be recognised that these would likely incur additional costs and may be constrained by the ability of generator manufacturers. The Regulatory Authorities recognise these limitations but are of the view that Grid Code is a "living" document that should be updated in line with the developing requirements of the power system. Although no specific changes to the Grid Code are proposed here, as set out in Section 4, the RAs are supportive of the Grid Code Review Panel and the Grid Code Compliance work programme initiated by the TSOs, through which Grid Code changes will continue to be progressed.

A number of comments were made regarding the broad category of Ancillary Services. These comments have been forwarded to the TSOs for consideration within their Ancillary Services workstream. Specific issues raised concerning ancillary services product development, reserve requirements, reserve provision and causer pays will be progressed under that workstream.

A substantial number of comments were received on the issue of constraints and curtailment. Respondents generally agreed that constraints on the output of generation, whether wind or conventional, were a fact of operating a dynamic power system. Further, respondents acknowledged that the compensation of generation for constraints should be non-discriminatory and therefore was a matter for the construction of the Market Schedule. Two respondents stated that non-firm generation should not be compensated for constraints.

The concept of curtailment received the most vociferous comment. Two respondents stated that the definition of curtailment proposed in the February 2008 discussion document was reasonable; however many other respondents disagreed with the concept. In their criticism of curtailment, respondents were broadly unclear as to the rationale for the concept, were confused by the definition, considered the concept discriminatory, considered it would be difficult to implement and if it were implemented would required detailed transparent rules so that participants could clearly understand and validate its application. Respondents also questioned the basis for the concept as no research or evidence was available to support the described “wind issues”.

The RAs are of the view that a separate concept of “curtailment” is not a necessary feature of the SEM. The idea of “curtailment” has been used in some contexts essentially to mean constrained off without compensation. In others, it has been used to describe the reduction in output of certain generating plant (usually wind) when certain system-wide conditions arise that mean that there is a limitation on the aggregate amount of such plant that can be accommodated. The discussions in this consultation paper have centred around how the market schedule should be constructed and under what circumstances plant should be dispatched. Essentially it is proposed that the TSOs should dispatch to minimise production cost and taking into account technical limitations, whilst the purpose of the market schedule should be to allocate infra-marginal rents to plant that is useful in meeting actual demand.

Between them, the processes for actual dispatch and the construction of the market schedule will determine whether generators are able to run on the day and whether or not they receive infra-marginal rents, and hence a separate concept of "curtailment" does not, at this juncture, appear necessary.

Respondents commented on the Dispatch & Scheduling processes. Broadly respondents felt these were issues best managed by the SO but specific issues raised included the need for improved wind forecasting, the need for clear and transparent rules in dispatch, a desire for shorter gate closure and more regular updates of the generation schedule although one participant stated that the current arrangements were sufficiently flexible. The RAs note these comments and agree that it is important that the TSOs keep market participants up to date with prospective and actual changes in dispatch processes in light of increased levels of renewable generation. Furthermore, the RAs agree that it is important that the rules for dispatch are transparent. In this context it should be recognised that the TSOs themselves have recognised that as the level of renewable generation increases, additional clarification is required as to how different plant types should be treated in dispatch and they themselves have requested the RAs to provide clarification on what the dispatch processes should be.

A number of comments were made regarding how to determine which priority dispatch generators should be constrained down (if required), given that all are effectively priced equally as price takers. Respondents generally accepted that system security should be the primary concern of the SO and that when faced with a tie-break situation should consider technical grounds or pro rata constraining down. One respondent proposed that a "First Come First Served" approach may be appropriate in some circumstances so long as compensation was paid to constrained generation. Other respondents suggested that priority dispatch plant should be allowed to provide a bid /off loading price so that the SO could choose on the basis of economics. The RAs have noted these comments and in Section 3 set out the proposed principles for generation dispatch and, in particular, in Sections 4.8 and 4.13 set out the options for the treatment of priority dispatch and tie-breaks.

A number of respondents raised the issue of the Market Price Floor, proposing that the PFLOOR be set at €0 rather than -€100 and that the modelling of price takers quantities as negative demand should be revisited. One respondent suggested that an ever increasing portfolio of Price Taking generation was unsustainable and that the appropriateness of the category should be revisited. Another respondent suggested that the PFLOOR should not apply to wind generation that was not dispatched. The RAs note these comments and in Section 4.11 and 4.12 consider the issue of the PFLOOR.

A number of respondents commented on the requirements for flexible generation on the island. The comments acknowledged the benefits flexible plant affords to the power system but suggested that flexibility was inadequately rewarded in the SEM. The RAs are of the view that in order to ensure that appropriate degree of flexibility, the TSOs should ensure that Grid Code requirements (including those applying to distribution connected plant through the Distribution Codes) make appropriate provision for the necessary technical characteristics of generating plant and furthermore, support the TSOs' current initiative to take further steps to enforce existing Grid Code requirements. Furthermore, by ensuring that infra-marginal rents are paid to plant that is necessary in dispatch, the necessary flexible plant should be appropriately rewarded in the SEM.

A number of respondents raised the issue of modelling the impact of wind generation from both a technical and economic perspective. The RAs note these comments and in Appendices 2 and 3 set out the economic modelling that has been conducted as part of this project. Further technical modelling of the impact of renewable generation is also proceeding under the auspices of the TSOs.

A significant number of respondents commented on the issue of priority dispatch, referring to both European and Irish legislation. It was generally acknowledged that priority dispatch exists within the requirements of transmission system security and as such dispatch could not be guaranteed in all circumstances. Respondents highlighted the need for clear and transparent guidelines for the treatment of priority dispatch plant including hybrid generation. The RAs have noted the comments and set out in Section 4 options for the treatment of priority dispatch plant on the island.

Seven respondents commented on the treatment of non-firm access. Respondents broadly welcomed the proposed change to the TSC to make consistent the treatment of non-firm price taking plant with price making. Two respondents raised the issue of "Deemed Firm Dates" suggesting that these may be appropriate going forward. The RAs note these comments. Whilst the use of Deemed Firm Dates would not necessarily be consistent with a principle that the market schedule should reward plant that is capable of running to meet demand, this does not mean that the concept of Deemed Firm Dates is no longer valid. The RAs accept that it is important to ensure that the TSOs (and TOs) have appropriate incentives to deliver new infrastructure in a timely manner and that this issue should be progressed further under the auspices of developing more appropriate incentive mechanisms TSOs and TOs.

Ten respondents commented on the treatment of wind within the unconstrained (market) schedule. A number of respondents stated that the current arrangements, although bedding in, were working satisfactorily and that there appeared no compelling reason or technical evidence to alter the price taking / price making arrangements. Some respondents suggested that there were likely to be technical limits on the quantity of price taking generation that could be accommodated on the system, it was suggested that the construction of the market schedule could be adapted to cap the quantity of price taking generation at these technical limits. One participant was concerned that were such technical limits not modelled in the market schedule then plant constrained on because of such limits would only receive constrained on payments at bid price. Again this issue is primarily addressed by the proposal that the RAs should commit to ensuring that infra-marginal rents are paid to plant that is useful in meeting actual demand. Whilst there are a number of significant future uncertainties over precisely how the system will be operated with higher levels of renewable generation, it is intended that this commitment will give market participants a degree of certainty that useful plant will be appropriately rewarded.

Appendix 5: Assessment of options against criteria in the February 2008 Discussion Document

Option/Proposal	Equity	Cost Minimisation	Value reflective pricing	Competitiveness	Transparency	Security of supply
Commitment to ensure that the market schedule broadly allocates IMRs to generating units that are of value to the real-time operation	The proposal allocates IMRs on an economic basis, taking into account which generators are needed to meet demand, and is therefore considered equitable.	The proposal is intended to ensure that appropriate signals for an efficient mix of generation plant needed to meet demand is delivered. Modelling suggests that in 2020, €277m of infra-marginal rents are reallocated to plant at times when it is needed to meet demand.	SMP will better reflect the marginal cost of serving a unit of demand	The proposals should improve competitiveness by extending competition for infra-marginal rents to more plant that is needed to meet demand.	By setting out clearly the principles that the RAs propose to adopt in this area, it is expected that the transparency of the market arrangements will be enhanced.	Ensuring that infra-marginal rents are paid to plant at times when it is used to meet demand should contribute to ensuring a more efficient plant mix and hence reduce the costs of meeting security of supply.

Access rights allocation Option 1	Some incumbent generators may consider this option to be inequitable because they may be denied access to the market schedule whist they await infrastructure reinforcements triggered by new entrants.	N/A	No material impact	This option allows new entrants to compete sooner for access to the market schedule.	By setting out clear rules for how new entrants and incumbent generators are treated, this option should bring additional transparency.	N/A
Access rights allocation Option 2	Some new entrant generators may consider this option to be inequitable because they are denied access to the market schedule to the extent that they are non-firm, even if they are dispatched to run.	As above	SMP might be higher than it should be at times when firm generators are not scheduled up to the limit of any export constraints in the market schedule and non-firm generators are not permitted to be scheduled for any spare capacity.	New entrants are prevented from competing to access the market schedule until the relevant transmission infrastructure reinforcements are complete.	As above	As above
Access rights allocation Option 3	As above, although to less of an extent as the unused capacity behind export constraints is reallocated to non-firm units in the market schedule.	As above.	This option corrects the issue identified with option 2 above and consequently should deliver a solution similar to option 1.	As above, but new entrants are permitted access to the market schedule to the extent that firm generation is not scheduled up to the limit of export constraints.	As above	As above

There should be no granting of Deemed Firm Access prior to completion of necessary infrastructure	New entrants may be concerned that they would be exposed to delays caused by the TSOs and/or asset owners.	Infra-marginal rents would be better allocated to plant at times when it could run to meet demand.	SMP will better reflect the marginal cost of serving a unit of demand	This proposal should allow plant that is able to run to meet demand to compete for infra-marginal rents at such times.	By bringing additional certainty and clarity to the arrangements, this proposal should improve transparency.	Ensuring that infra-marginal rents are paid to plant at times when it is used to meet demand should contribute to ensuring a more efficient plant mix and hence reduce the costs of meeting security of supply.
The TSOs should dispatch to minimise production cost disregarding any concept of firmness in the dispatch process;	Some incumbent generators may consider this option to be inequitable because they may be displaced in dispatch whist they await infrastructure reinforcements triggered by new entrants.	This approach would make most efficient use of existing resources and result in the minimum cost of production.	N/A	As now, new entrants would be permitted to compete for dispatch as soon as they had the physical ability to export power.	As above	N/A

Priority dispatch Option 1	It may be considered that this option confers a disproportionate treatment to priority dispatch generators	Modelling studies show that if priority dispatch plant is given a high negative price, the additional costs are €43m in 2020.	Unless the way in which SMP is determined is changed, it will not reflect the negative costs of meeting additional demand at times when conventional plant is two-shifted to accommodate priority generation.	Priority dispatch plant and non-priority dispatch plant do not compete on an equal footing under this option.	Because the rules associated with priority dispatch would have been made clear, this option would bring additional transparency.	N/A
Priority dispatch Option 2a	All generators would be treated on an equal basis under this proposal. Renewable generators may consider it inequitable that they are not permitted to bid in prices that reflect external subsidies.	Costs of production and SMP would not be minimised because they would not reflect the external subsidies being paid to some plant.	Where a plant receiving external subsidies is marginal, prices would not reflect the external subsidy.	This option allows all generators to compete on an equal footing.	As above	As above.
Priority dispatch Option 2b	Substantially as above as it is unlikely that the tie-break rules would need to be used often.	As above	As above	As above. It is unlikely that the tie-break rules would need to be used often.	As above	As above

Priority dispatch Option 2c	This option may be considered equitable as the inclusion of renewables subsidies in effective bid prices would simply reflect the statutory subsidies afforded such generators.	Costs of production and SMP would be minimised because they would reflect the external subsidies being paid to some plant.	Prices would be set to equal the true marginal cost of production at times when plant with external subsidies met demand.	This option may be considered to be competitive because the inclusion of renewables subsidies in effective bid prices would simply reflect the statutory subsidies afforded such generators.	As above	As above
Priority dispatch Option 2d	As per priority dispatch option 1.	The extent of any additional costs imposed would depend on the effective price chosen for priority dispatch plant.	As per priority dispatch option 1.	As per priority dispatch option 1.	There is the possibility that it would not be clear precisely how the effective price for priority dispatch plant had been chosen.	As above.
SMP set to the price of the marginal price-taker rather than at PFLOOR when price taking plant meets demand	Setting SMP to better reflect marginal costs of production is likely to be considered more equitable than existing arrangements.	Generators would not be potentially exposed to PFLOOR at such times but instead a price more reflective of economics. This may serve to reduce costs.	SMP would better reflect marginal costs when price-taking plant met demand.	N/A	By setting prices which more clearly reflect marginal costs, this may be considered to bring additional transparency.	Setting prices to reflect avoidable costs should ensure more effective market operation and hence improve security of supply.

The quantity of generation charged PFLOOR (or paid the revised SMP as indicated above) in the event of an Excessive Generation Event arising from an excess of Price Taking Generation	This should result in a more equitable solution as only a quantity of generation equal to actual demand will be settled at this price.	This proposal may reduce costs slightly as it reduces the risks faced by Price Taking generation in the SEM.	N/A	N/A	N/A	N/A
Where tie-break rules are required, de-loading should be instructed on a pro-rata basis.	If requires, this proposal would share the de-loading over affected units and consequently appears to be equitable.	N/A	N/A	N/A	Transparency should be improved principally because the rules applied would be made clear.	N/A