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

A CONSULTATION RESPONSE TO THE REGULATORY AUTHORITIES

Introduction

Bord Gáis Éireann (BGE) welcomes the opportunity to respond to the consultation paper issued by the Regulatory Authorities (RAs) on the *Principles of Dispatch and the Design of the Market Schedule in the Trading & Settlement Code* (SEM-09-073).

The RAs raise fourteen issues in the consultation paper plus a principle of the single electricity market design. Rather than respond separately to each of the fourteen issues and to the question of principle, we have organised the consultation response around a small number of themes. The consultation paper is structured as follows:

- General comments in relation to the overall objectives and scope of the review.
- Specific comments relating to:
  - investment incentives;
  - market schedule and dispatch; and
  - priority dispatch.

However, for ease of reference, we set out the individual proposals from the consultation document addressed in each section, along with a short summary of our position.

As a potential investor in efficient flexible plant BGE agree that it is timely to look at the investment signals needed to bring plant on other than BNE Distillate peakers. The following problems present themselves in the market

- The energy market does not reward an efficient flexible mid-merit /peaking plant compared to a less efficient, less clean and lower capital cost peaking plant
- The ancillary services market does not, in its current form, reward the more efficient plant either.

Although a stated aim of this consultation is to address the first of the two issues above BGE do not feel any of the proposals will ultimately provide sufficient confidence for investors to enter.

Therefore we feel it is important that the ancillary services market receives adequate attention to ensure new products be created (be they bilateral or contracted through the market). We feel this should be done immediately. The recent Ancillary Services consultation decision allows Eirgrid to put new products in place and BGE believe that potential new products should be produced in parallel with the decision document on these matters in late 2009. We also believe Eirgrid's incentives should be enhanced to give them a financial interest in the development of new products.

While the market presently enjoys a healthy capacity margin the time taken to bring a conventional generation project, which will best serve a more intermittent generation mix, from inception to energisation means the market needs the appropriate signals now. Without such signals, customers risk facing higher bills in the future because the supply of flexible plant may lag the system's requirements. The significant level of intermittent wind will emphasise this. While the baseload plant currently on the system consists of a relatively modern fleet, the flexible plant is generally older and at much higher risk of failure. Also, it is becoming clear that the existing fleet of baseload plant will struggle to provide the flexibility that the system operator requires.

General comments

Government policy in both the Republic of Ireland (RoI) and in Northern Ireland (NI) is for a significant increase in the proportion of electricity demand to be met from renewable energy sources. RoI has a target of 40% of electricity demand to be met from renewable sources by 2020 and NI has a target of 12% of electricity generated to be met from renewable sources by 2012. These targets imply a significant and rapid increase in the quantity of installed renewable generation capacity. For example, a simple calculation shows that to meet the 40% target, the quantity of wind capacity required in RoI is equivalent to about 90% of peak demand.[1] In addition, energy efficiency, smart meters / demand side management (DSM) and energy storage are all likely to become more prevalent by 2020.

The RAs must design and implement an electricity market to *facilitate* the achievement of the Governments' targets, to *manage* the resulting increase in generation from renewable sources (much of which is likely to be in the form of intermittent wind powered generation) and to facilitate increased use of DSM. If the RAs fail to achieve the right changes, the risk is that it will deter potential investments in the type of power plants and other equipment required by the system to help manage large quantities of wind generation. As a result, either the Governments' policies will not be met or they will be met but at an unnecessarily high cost to consumers.

The RAs should therefore undertake a *holistic review* of what is needed for the market to deliver the required outcomes and of the implications for the network companies. As an example, Ofgem is undertaking two fundamental reviews:

- Project Discovery is Ofgem's review as to whether the British electricity market is likely to deliver security of supply over the coming decade, while meeting objectives related to consumers' interests and sustainable development.

- RPI-X@20 is Ofgem's review of the current approach to regulating Britain's energy networks, part of which is looking at how network regulation will need to adapt to changes in future generation, demand and technical conditions.

This is not to say that the principles underlying the SEM or the current approach to network regulation require fundamental change. However, it is important that the RAs have an overview of the potential barriers to the change required to

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1 If the 40% renewable target is met only from wind power plants, the wind power plants have an average capacity factor of 30%, and the demand on the system has a load factor of 65%, this implies that the total capacity of wind on the system is equivalent to about 90% of peak demand.

support the government's targets, and of the problems that may arise if the changes required do not happen in a timely manner. This holistic view can then inform detailed changes of individual areas of the SEM arrangements.

The RAs have launched a number of separate consultations concerning a different aspects of the market arrangements.[2] However, the consultations do not have an explicit set of common guiding principles and proper coordination. In this market rules consultation, the RAs present a series of alternative market design options in isolation. This means that respondents to the consultation are almost certain to consider the market design options in a piecemeal fashion and their responses will therefore not consider the full effects of each option. To properly consider the full effect of a given design option, one must understand all other aspects of market design – including those aspects which are being consulted on through separate processes.

Prior to taking any final decisions in relation to the current set of consultations, it would therefore be sensible for the RAs to conduct such a holistic review, considering the desirable objectives for market outcomes and how those objectives can be achieved.

We think there are three desirable objectives:[3]

- **Security of supply.** Security of supply needs to be considered in the context of a large and rapid increase in the quantity of renewable generation on the system. Achieving security of supply (at efficient cost) requires the right incentives to be put in place for investors in generation, renewables and their back-up (either thermal generation or energy storage) and the networks.

- **Economic efficiency.** Economic efficiency applies to both the short term (operational timescales) and the long term (investment timescales). This means that the market rules should achieve efficient dispatch outcomes and also incentivise efficient investments in generation and networks.

- **Regulatory certainty.** Regulatory uncertainty increases the risk investors face thereby increasing the target return required to incentivise an investment. In the long run this would increase the price of electricity. Particularly at present, when securing financing even for relatively low risk projects is difficult, ensuring ongoing regulatory certainty is critical.

The three desirable objectives map to the guiding principles for decision making, which are set out on page 11 of the consultation document.

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2 The four consultations relate to this market rules consultation, capacity payments, ancillary services, and transmission charging (TUOS and TLAF).

3 All three could be considered as stemming from the overall objective of economic efficiency. However, to aid understanding it is useful to explicitly identify all three separately.

Specific Comments

Notwithstanding the suggestion in the previous section that the RAs undertake a holistic review of the market arrangements, in this section we comment on three specific themes raised by the consultation paper, relating to:

- investment incentives;
- market schedule and dispatch; and
- priority dispatch.

Investment incentives

We consider two aspects related to investment incentives. First, we consider aspects of investment incentives for generation that can assist with integration of wind generation. Second, we consider the role of the TSO in achieving efficient market outcomes in the context of integrating large quantities of wind generation capacity.

Investment incentives for generation

View on consultation document proposals: in this section we address issues related to the capacity payment mechanism and ancillary services. However, we note that the RAs do not make specific proposals regarding these issues as part of this consultation.

The RAs assume a clear approach to the design of investment incentives for new power plants. That is, they assume that the overall incentive for generation investment comes from a combination of infra-marginal rents provided through the market schedule, the capacity mechanism and revenues from the sale of ancillary services to the TSO.

The economic logic behind this approach is broadly rational. If generators bid their short run marginal costs into the energy market and the capacity payment is set such that a peaking plant would be able to recover its fixed costs:

- the peaking plant would recover very little or none of its fixed costs through infra marginal rents since it will have the highest short run marginal cost on the system (aside from demand side actions) but may recover some of its fixed costs through the sale of ancillary services; and
- power plants with lower short run marginal costs recover their fixed costs (which are higher than the peaking plant) through a combination of infra marginal rents from sales in the energy market, the capacity payment and the sale of ancillary services.

Given an optimal generation mix, all plant should recover their fixed costs, including the required return on investment.

We note that distortions which shift bids away from short run marginal costs will result in distorted investment incentives. In this regard, therefore, we believe the RAs should consider further the way in which the Synergen gas contract interacts with bidding behaviour.

However, given the future changes likely to be required in the sector, we believe there are questions which the RAs should be asking in relation to each of the potential sources of investment incentive for new generation.

In relation to **infra-marginal rents**:

- for thermal generation that backs up volatile renewable generation, the frequency with which infra-marginal rents are earned may be low. Therefore, while over a long period the NPV of expected infra-marginal rents may be sufficient to incentivise entry, the uncertainty around this NPV may act as a barrier to sufficient investment (or at least it may cause investment delay and hence additional higher electricity prices for customers); and
- at present, uncertainty regarding the implementation of rules for dispatching power plants makes it difficult for an investor to predict whether or not they will be dispatched. This in turn makes it difficult for a potential investor with non firm access to predict the quantity of infra-marginal rents likely to be recovered through the market schedule (we return to this issue below).

In relation to the **capacity payment**, the mechanism currently in place creates significant uncertainties for investors.

First, the size of the total funding rises and falls with the capacity requirement. This appears intuitively appealing, since it reflects the (short term) market needs for new capacity. However, it creates an uncertain price for capacity since the quantity of generation capacity on the system cannot rise and fall in line with demand. Rather, investors are being asked to project the way in which the regulator will respond to significant changes in peak demand which, given uncertainties around demand side management on one hand and new uses for electricity on the other, are likely to be more of a feature of the sector going forward.

Second, within investment timescales (i.e. once they have committed funding) investors face regulatory uncertainty in relation to the allowed price for capacity. Such uncertainty serves to deter (or raise the cost of) investment in power plants that cannot easily exit the Irish power market (such as gas-fired plant).

Conversely, investors in peaking plants that can enter and exit the market at short notice (e.g. skid mounted or barge mounted liquid fuelled OCGTs) are better able to manage the risk of variable capacity payments. They can do so by moving their plants between the Irish market and other markets – effectively cherry-picking high capacity payments.

The effect of the variability is therefore to encourage mobile peaking capacity and discourage committed peaking capacity. It is unclear that this approach will encourage the most efficient plant mix required to manage intermittent wind generation. Equally, encouraging entry of more highly emitting liquid fuelled peaking plant is not in line with the overall thrust of government decarbonisation policy.

Third, it is not clear that, given the current testing arrangements, older, more unreliable plants that do not contribute to security of supply are always appropriately excluded from eligibility for capacity payments. To the extent that unreliable plant receives a capacity payment, it serves to dilute the overall capacity pot, thereby reducing the incentive for new entry. In addition, the application of capacity payments to unreliable plant discourages old, unreliable plant from closing and freeing up scarce transmission capacity for new entrants.

The RAs current review of the capacity mechanism should consider the desirable objectives of a secure power system and an efficient generation mix - needs to consider the issue of uncertainty over the capacity price, the level of commitment to the system required to secure capacity payments, and a more rigorous approach to availability and reliability testing.

However, it is not clear to us that this will be enough (i.e. that the objectives set out at the start will necessarily be achieved through the operation of a reformed capacity mechanism and the payment of infra-marginal rents through the market schedule).

Therefore, in relation to **ancillary services**, we believe the RAs should consider the TSO's ability to strike new types of ancillary service contract more appropriate to managing the intermittency of wind generation. For example, it may be that the technical requirements of plant required to manage wind intermittency are less onerous than those in current reserve contracts.[4] Equally, however, going forward, the TSO will need to hold higher levels of wind-related reserve than it currently does.

If this is the case, then both these facts should be clearly signalled to the market in order that they can inform the plans of potential generation developers.

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4 For example, EnBW procures 60 minute reserve to help manage wind intermittency. See http://www.enbw.com/content/de/netznutzer/strom/stundenreserve/index.jsp;jsessionid=DEE797B3A03B9D90B288B6812E8340F2.nbw05

Role of the TSO

View on consultation document proposals: in this section we address the issues of "Deemed Firm Access" and system operator incentives. We disagree with the RA's proposal that such arrangements should not be introduced to the SEM. However, we propose that this should be accompanied by stronger system operator and asset owner incentives. We note that the RAs do not make specific proposals regarding these issues as part of this consultation this area).

The current regulation of the TSO is better suited to a steady state world than a world where there is significant change and uncertainty regarding the future need for transmission capacity, the costs of managing congestion and the type of generation, storage or demand management capacity best suited to helping to manage intermittent wind generation.

Networks have a critical role to play in securing renewable generation capacity through connections and access rights. Therefore network operators should have an incentive to develop the network in an efficient and timely way and to manage the costs of congestion and balancing in the lowest cost way.

At present, the TSO benefits (through retained depreciation and the return on assets) from underinvestment in network capacity through the transmission price control period. However, the TSO does not bear a material proportion of the cost of underinvestment, which manifests itself in terms of higher costs of congestion management and in lost revenues for generation developers. The risk of a delay to transmission investment is effectively worn by generation developers and customers, who are unable to control or manage that risk.

From the perspective of renewable (and other generation) developers, it is also important that there is some certainty as to the timing of network investment. Without this certainty, generators are effectively being forced to bear the risk (through holding non-firm rather than firm rights) of transmission investment delays. Generators clearly have no control over the timing of transmission investment, and therefore this approach does not allocate risk efficiently – namely that risk should be allocated to those best placed to manage it.

Equally, the TSO has little or no incentive to look forward and consider actions today that would help to reduce the future cost of managing the system – for example by encouraging investment today in generation capacity, power storage, interconnectors and demand side management.

Therefore, we believe TSOs should be incentivised to connect new plant in a timely manner.

Implementing a system of "deemed firm access" rights coupled with TSO incentivisation could increase the efficiency of generation and transmission investment decisions. If the TSO was required to commit to providing firm rights to generators from a given date[5], and was then required to bear a proportion of congestion management costs if associated transmission investments were delayed, this would:

- provide some insurance to generators against a risk they cannot manage;
- provide a financial incentive to the TSO to ensure that transmission investment is undertaken in a timely manner (and to ensure that TSOs consider carefully the approach they take to securing planning consent[6]); and
- allocate some of the risk of delay to transmission investments from customers to the TSO.

We also believe that the TSO should also be incentivised to consider market actions that will improve the efficient management of the system. In particular, if the TSO faced a financial incentive in relation to the cost of procuring future ancillary services (including reserve to manage wind intermittency – which is, for example in the German market, defined as a separate product) it may be that the TSO would pay more attention to the sufficiency of current market arrangements.

This may in turn lead the TSO to consider developing alternative ancillary service products and contracts for the management of intermittency, which could add to the investment incentives from the capacity payment and the market schedule.

Finally, the current approach to operating the system leaves significant discretion as to precisely how the TSO dispatches the power system. This discretion coupled with a lack of transparency and incentives leads to potential inefficiency in system operation and uncertainty with respect to market outcomes, which in turn leads to higher investment costs.

TSO incentives are part of the solution. In addition, there needs to be transparency of dispatch and a rationale for dispatch decisions such that participants can see and understand market outcomes. One approach would be to set out clear principles that all operators must apply in undertaking the dispatch. In this regard, it is important to note that Directive 2009/72/EC requires "rules adopted by transmission system operators for balancing the electricity system shall be objective, transparent and non-discriminatory."

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5 Of the TSO's choosing, with the right of generators to appeal to the regulator if it were set unduly far into the future

6 TSOs can argue that the time taken to secure planning consent is outside their control. However, there are clearly approaches that the TSO can take in relation to scheme design and the level of proactivity during the regulatory process that will influence both the speed and nature of the final decision.

Market schedule and dispatch

The market schedule is used to determine the infra-marginal rents captured by each power plant and is therefore an important driver of investment incentives in generation. The way in which the market schedule is constructed in terms of the treatment of non-firm power plants and technical characteristics of power plants is therefore an important issue.

In this response, we consider six issues in the context of the market schedule and dispatch schedule:

- the principle applied to constructing the market schedule;
- uncertainty of the dispatch schedule;
- which generators should be included in the market schedule;
- treatment of technical characteristics in the market schedule;
- treatment of grid code non-compliance in the market schedule; and
- the construction of the dispatch schedule

Principle applied to constructing the market schedule

View on consultation document proposals: in this section we address the proposal that the RAs should seek to ensure that the construction of the market schedule should reflect the actual dispatch pattern. While we agree the principle is broadly sensible, there are situations in which it would be inappropriate. Therefore we do not believe it should be considered a guiding principle in all cases.

A generator would be unwilling to invest in a power plant with higher fixed costs than the best new entrant even if that power plant were required for the dispatch if it were not also expected to be included in the market schedule.

To the extent that the market schedule differs from the dispatch schedule, the investment incentives to build new power plants will differ from the investment incentives to build new power plants that are actually required to meet demand. In addition, existing power plants would under or over recover their fixed costs compared to a situation whereby the market schedule and the dispatch schedule were aligned.

Therefore, the principle proposed by the RAs that the market schedule and dispatch schedule be consistent is broadly sensible.

However, if applied in some circumstances this principle may have the effect of expropriating incumbents' rights. Take the case of a low operating cost new entrant power plant with non-firm transmission rights located in an export constrained region. Suppose this plant is dispatched in place of a higher operating cost incumbent power plant with firm transmission rights located in the same export constrained region. If the market schedule adopted the principle that infra-marginal rents should be allocated to those power plants used in the dispatch, the incumbent power plant would in effect have non-firm transmission rights (at least in terms of the financial implications of the rights). This would amount to expropriation of rights on which past investment decisions have been based – a dangerous regulatory precedent which would reduce the efficiency of investment decisions by raising the perception of market risk and the return required on generation investments.

To avoid enshrining a principle that could lead to expropriation of incumbents' rights, we do not believe the principle that the market schedule allocate infra marginal rents to power plants that are used for the dispatch should be adopted. Rather, the relationship between the market schedule and the dispatch should be developed according to the guiding principle of economic efficiency applied on a case by case.

Uncertainty of the dispatch schedule

View on consultation document proposals: in this section we address issues related to system operator incentives. However, we note that the RAs do not make specific proposals with regard to this issue as part of this consultation.

The market schedule and the dispatch schedule will inevitably differ not least because the dispatch schedule takes account of transmission constraints and the market schedule assumes that there are none (i.e. the market schedule is an unconstrained schedule). In addition, the market schedule and the dispatch schedule will differ if the market schedule does not take account of all of the technical characteristics of generators and the system that are included in the dispatch schedule.

A further reason for the difference is the result of different operating rules being applied to the market schedule and dispatch schedule. 7 The market schedule is developed according to a clearly defined and transparent set of rules. However, the rules for the dispatch schedule are not transparent or well defined. The dispatch schedule cannot be predicted with any level of accuracy.

The consultation paper proposes keeping the market schedule in line with the actual schedule. We believe it that supporting analysis is required to understand what is causing the differences:

- Grid constraints
- Reserve,
- Dispatch decisions

It may be that the actual schedule can be brought closer to the market schedule through dispatch rules and incentivisation on the TSO.

Uncertainty regarding the dispatch schedule at present affects investment decisions for those not likely to secure firm rights since whether or not a power plant is included in the dispatch schedule affects that power plant's infra marginal rents from the market schedule. Therefore, making the dispatch schedule transparent, as well as being potentially required by EU law, will improve generation investment decision making. In addition, clearly defining the rules for the dispatch schedule allows the TSO to be incentivised with respect to the costs of system operation.

While this specific issue may become less important depending on the outcome of the consultation and the proposed rule changes, we believe it important for the RAs to adopt two changes with respect to the dispatch schedule:

- set out clear rules for constructing the dispatch schedule[7]; and
- incentivise the performance of the TSO with respect to constructing the dispatch schedule.

Which generators should be included

View on consultation document proposals: in this section we address the issue of how access to the market schedule for plant situated behind export constraints should be limited and consider the options described in Section 4.5 of the consultation document. We indicate that our preference would be for the adoption of option 3. We also address issues related to the capacity payment, though we note that the RAs do not make specific proposals regarding the capacity payment as part of this consultation.

The broad issue being faced in relation to the creation of the market schedule is the existence of legacy rights for thermal generators to access the network, in parallel with a demand for access in similar locations from low cost renewable generators before the transmission system has been reinforced.

The consultation paper sets out three options for the treatment in the market schedule of power plants with non-firm transmission rights:

- Option 1. The market schedule would be changed to include export constraints, limiting the quantity of generation in an export region to which infra marginal rents are allocated to be no greater than the size of the export constraint.

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7 Precise rules cannot be adopted to deal with every situation faced by the system operator. However, where precise rules cannot be adopted, a clear set of principles for system operator decision making can be applied.

- Option 2. The market schedule would be changed to allocate infra marginal rents only to those power plants that have firm transmission rights. Power plants with non-firm transmission rights would be excluded from the market schedule.[8] Power plants with non-firm transmission rights that are included in the dispatch schedule would receive only their bid price. A variant of this option (Option 2a) is to facilitate trading of access rights to allow for the efficient allocation of rights between power plants in the export constrained region.

- Option 3. The market schedule would be modified to allocate infra marginal rents first to those power plants that have firm transmission access. To the extent that there is spare export capacity, in-merit power plants with non-firm transmission rights would also be included in the market schedule.

Whether or not a power plant is included in the market schedule is important for efficient investment decision making (i.e. efficiency in investment timescales), and potentially also for incentivising power plants to be available when they may be required to generate (i.e. efficiency in operational timescales).

With Option 1, generators with firm transmission rights could be "constrained off" in the market schedule even though their short run operating cost was below the SMP. Such power plants would not receive a constrained off payment in these circumstances. The danger with this proposal is that it sets the precedent that firm transmission rights are *not financially firm*, which appears to be expropriation of incumbent's rights. Indeed, there appears to be little differentiation between firm and non-firm rights under this option. With Option 1, the uncertainty surrounding transmission rights created by the possibility of future expropriation may actually be a deterrent to future power plant investments – reducing efficiency in investment timescales.

Option 2 retains the rights of incumbents but may deter an efficient new entrant from entering the market until such time as it is able to obtain firm rights since an entrant with non-firm rights would not receive infra marginal rents. Indeed, the most critical problem with this is that it would deter renewable entry.[9] The variant of Option 2 (i.e. Option 2a), to facilitate the trading of firm transmission rights, would allow the reallocation of firm rights to a new power plant project if the reallocation were beneficial to the incumbent and to the entrant. Therefore, Option 2a could in theory lead to efficient market outcomes. However, the issue

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8 A power station with partial firm and non-firm transmission rights would be included in the market schedule to the extent of its firm transmission rights. The consultation paper is unclear as to precisely how this would be done since some of the technical and economic characteristics of a power plant are non-divisible, e.g. start costs and minimum stable generation.

9 Unless the approach to priority dispatch does away with the distinction between firm and non-firm transmission rights – in which case the meaning of Option 2 would not be clear.

of "hold up" by incumbent holders of transmission rights[10] would need to be addressed and any mechanism to allow trading of transmission rights is likely to be complex.

Option 3 retains the rights of incumbents but given the expected large and rapid increase in the renewable generation capacity on the system, it could (as would be the case with Option 2) still result in inefficiency if transmission rights are not able to be traded.

Of the three options presented, Option 3 appears to be the best compromise in terms of its treatment of incumbents and new entrants. Trading of transmission rights could be introduced at a later stage once the new arrangements had been bedded in. However, the regulators would need to implement some form of arrangements to deal with the possibility of "hold up" of incumbents unwilling to release their transmission rights and unwilling to use their transmission rights.

Given the basic issue of the treatment of generators with legacy rights and the ability of new entrants to connect to the transmission network, there is a clear need to reveal the true life of aging power plants. This would give potential new entrants transparency in the availability of transmission capacity and would not grant an incumbent with the value of transmission capacity in perpetuity. Therefore, in parallel with implementing Option 3, RAs should put in place a process for defining finite rights for existing generators.

Treatment of technical characteristics

View on consultation document proposals: in this section we address the question as to whether further technical constraints on system operation should be included in the market schedule or the grid code. We conclude that neither approach is necessarily desirable, and that a solution based on contracting for ancillary services would be better if the technical requirements can be addressed through this route. We support the proposal that 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.

The consultation paper sets out two options for the treatment in the market schedule of technical constraints on system operation:

- Option 1 would include technical requirements of the system in the market schedule.

10 Incumbent holders of firm transmission rights in an area which is expected to be export constrained for some time into the future would be able to extract significant rent in the trading of those rights.

- Option 2 would impose further technical requirements in the grid code rather than in the market schedule.

If further technical requirements of the system were included in the market schedule, the market schedule would become even more complex than it is today. Price signals are likely to become more volatile and increasingly difficult to understand. The increased uncertainty would have the result of deterring investments and raising the cost of entry (since a higher return would be required on the investment). Therefore, we consider that further technical requirements of the system should not be included in the market schedule.

If technical requirements of the system were included in the grid code this would mean that *all* power plants are required to provide those technical characteristics irrespective of the costs and benefits of provision. Depending upon the cost of provision, this may impose significant costs on generators (and, in the end, consumers) and could even prevent certain classes of generators from connecting to the system. There would be no way of balancing the marginal cost of imposing the requirement against the marginal benefit to the system. This would result in inefficient costs being imposed on the system.

A third option is to incentivise the TSO to efficiently manage the system and to procure additional services to meet the technical requirements of the system through bilateral contracts or an ancillary services market. This option has the advantage of allowing the TSO to balance the costs and benefits of provision while procuring the service from those generators best able to provide the service. In this way efficiency in operational and incentive timescales can be maintained.

We believe that the RAs should adopt the third approach to ensuring the technical requirements of the system continue to be met in future. Only where it is not possible to develop a market for the procurement of technical requirements should their provision (or capability) be mandated through the grid code.

Treatment of grid code non-compliance

View on consultation document proposals: in this section we address the proposal that in relation to the Grid Code that (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. We do not support recouping gains from grid code non-compliance from individual parties, as we believe it is too difficult to identify such gains robustly. We believe the Grid Code should be reviewed to address the lack of consistency between its requirements and the reality of the system.

The consultation paper states that the TSO has the option of recouping gains from grid code non-compliance. This option is likely to prove unworkable in practice and could only be implemented using *ad hoc* arrangements that increase the revenue uncertainty of market participants – thereby adversely affecting investment decisions.

For example, in the case that multiple power plants are not grid code compliant it will be almost impossible for the TSO to develop a mechanism to determine the *individual* gain of each power plant from non-compliance. This is because the resultant market schedule is the result of the interaction of all generators, making it impossible to disaggregate the effect of multiple non-compliant generators.

Therefore, we oppose the ability to claw back gains resulting from grid code non-compliance.

However, we note that many power plants are grid code non-compliant. This suggests that the grid code should be reviewed to bring it in line with the technical needs of the system and the technical capabilities of power plants. If the grid code is not brought in line with technical realities, it will become increasingly obsolete and ad-hoc as the number of non-compliant power plants increases over time.

Construction of the dispatch schedule

View on consultation document proposals: in this section, we support the proposal 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.

From the perspective of the short term efficiency of operation of the power system, and the minimisation of costs to customers, it is important that demand is met by the lowest cost combination of generation plant.

We therefore believe that the dispatch process should be grounded in cost minimisation *given* the actual technical constraints on the system.

Priority dispatch

We first consider the interpretation of requirements for priority despatch, and then turn to the scope of plant which should be accorded priority.

Interpretation of priority despatch

View on consultation document proposals: in this section we address the proposals for the treatment of priority dispatch. We do not support absolute priority despatch. We do not believe the other options presented in the consultation document are sufficiently worked up to allow a judgement to be made on their merit. However, we support the principle that power plants with priority dispatch be allowed to announce their own preferences with respect to their costs of dispatch, rather than have a value administratively applied to them.

Priority dispatch is where renewable and other identified power plants are dispatched in preference to other power plants. The consultation paper sets out five options for the treatment of priority dispatch generation in the dispatch schedule:

- Option 1. Renewable generation and other priority dispatch generation would be given *absolute priority* in the dispatch schedule, which means they would run in preference to other generation unless prevented by technical or security of supply reasons.
- Option 2a. Renewable and other priority dispatch power plants would need to bid a price for their curtailment (which could be a negative price) and the dispatch and market schedule would be formed on the basis of *strict economic merit.*
- Option 2b. Renewable and other priority dispatch power plants would need to bid a price for their curtailment (which could be a negative price) and the dispatch and market schedule would be formed on the basis of *economic merit with tie breaks*, i.e. with priority dispatch power plants being dispatched in preference to other power plants only in cases where there was no other way to differentiate between the power plants on economic grounds.
- Option 2c. Renewable and other priority dispatch power plants would be dispatched in *economic merit taking account of subsidies.*
- Option 2d. Renewable and other priority dispatch power plants could be included in the dispatch at an arbitrary price for curtailment such as minus 1000/MWh or minus VOLL.

Option 1, absolute priority dispatch, is equivalent to priority dispatch power plants having a bid price of minus infinity. In addition to a willingness for the system to incur unlimited operating costs in order to avoid curtailment of priority generation, this option implies that the TSO should be willing to incur unlimited investment costs to avoid curtailment of priority generation / allow for the injection of additional priority generation. Option 1 would be disproportionate, as it could involve incurring infinitely high costs in order to avoid renewable curtailment. Therefore, we do not support Option 1.

We are not entirely clear about the specific design of the remaining four options for the application of a qualified priority dispatch. We believe further work would be required to clarify them before a decision can be made.

However, we believe that the key principle that should be adopted in considering efficiency in operational timescales is that power plants with priority dispatch be allowed to announce their *own preferences* with respect to their costs of dispatch (that is their own prices for production or curtailment). The principle of economic merit should then be applied to constructing the dispatch schedule. This compares to a value being administratively applied to them.

Scope of priority despatch

View on consultation document proposals: in this section, we consider which plants should be accorded priority despatch. While we agree with priority despatch being applied to renewables, we do not believe it should continue to be applied to peat plant. We note the RAs do not make specific proposals on this issue as part of this consultation

In the consultation document, the RAs note that EU legislation provides discretion for priority dispatch to be accorded to those using indigenous primary energy fuel sources, and that in Ireland this discretion has been exercised in relation to generation from peat.

The purchase of electricity generated from peat is the subject of a Public Service Obligation (PSO) on the Public Electricity Supplier. The inclusion of peat in the PSO is, according to the CER, "in following Government aims for security of supply."

It is not clear how according priority despatch to peat is consistent with the objective of the inclusion of peat in the PSO. If anything, increased use of peat (as a result of priority despatch) will reduce the availability of this finite indigenous resource, and arguably therefore reduce security of supply.

Therefore, we do not believe that peat plant should be accorded priority despatch provided it remains inside the PSO.

I hope you find the comments above useful in finalising your decision. Please do not hesitate in contacting me should you have any comments or queries.

Yours sincerely,

Noel Regan

Strategic Investments

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{by e-mail}