Harmonised Ancillary Services, Other System Payments & System Charges

23rd September 2008

SEM-08-128

Corrections made to Appendix (Highlighted in red)

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1 SUMMARY

Purpose and Introduction

This document has been developed jointly by the two Transmission System Operators – EirGrid and SONI. The purpose of this document is to set out the TSOs' proposals for harmonised arrangements for Ancillary Services, Other System Payments, Other System Charges, and Generator Performance Incentives. The arrangements cover Ireland and Northern Ireland. The proposals build upon the High Level Decision paper issued by the Regulatory Authorities, discussions at industry workshops, and subsequent comments.

Harmonised Ancillary Services

Proposals for the harmonisation of three existing Ancillary Services are presented; additionally, three potential new services are also described. All these services will be defined and administered by the Transmission System Operators according to a common set of policies.

The Transmission System Operators will propose annually a harmonised set of payment rates for each service (except Black Start provision). These will be proposed for approval by the Regulatory Authorities. This document includes indicative rates used in worked examples: actual rates will subsequently be published, consulted on, and approved by the Regulatory Authorities.

Funding: the Transmission System Operators will each propose an annual allowance for expenditure as part of their revenue submissions to the Regulatory Authorities. This sum will be recovered through Transmission Use of System tariff (Ireland) and the System Support Service tariff (Northern Ireland), with over or under recoveries being carried forward to the following year. It is envisaged that the total annual allowance will not increase significantly over current expenditure simply as a result of harmonisation. Expenditure may change as a result of, for example, changes in requirements, power system conditions, and inflation.

Procurement: The Transmission System Operators will procure the Ancillary Services to facilitate the secure and economic operation of the power systems. The Transmission System Operators will directly contract with service providers in their respective jurisdictions according to a set of harmonised principles. There will be a single contract with each service provider, which will include separate schedules for each service procured.

Ancillary Service contracts will set out payments for services delivered, and will also define charges to be paid in the event that the contractually defined service has not been delivered.

Settlement and payment terms will be harmonised.

Existing Ancillary Services

Providers of the Reserve service will contract to deliver reserve (in defined categories) up to a contractual capability limit. They will be paid on the basis of their declared availability and their realisable reserve (that is, after taking account of their reserve characteristic curve). If the service is not delivered when required, then a charge will be levied reflecting the degree of underperformance.

Providers of the Reactive Power service will contract to deliver reactive power up to a contractual capability limit. They will be paid on the basis of their declared capability, reactive power characteristic curve, and the status of their automatic voltage regulator. If the service is not delivered when required, then a charge will be levied.

The Transmission System Operators will contract individually with providers for the Black Start service. The rates offered for this service will reflect the costs of provision. The Transmission System Operators will require tests to be carried out to demonstrate that the service is available. If a service provider fails the test, then a charge will be levied.

Potential Ancillary Services

The Transmission System Operators have identified three candidates for new Ancillary Services. The views of service providers are sought as input to more detailed definitions and analysis.

Warming Contracts would pay service providers to maintain a unit's warmth state (or move to a specified warmth state) when the unit is desynchronised.

Contracts for CCGT Multimode Operation would pay service providers for flexible Combined Cycle Gas Turbine operation, including open cycle mode.

Contracts for Pre-Emptive Response would pay service providers to rapidly increase output in response to a Transmission System Operator signal, issued when a trip is believed to be imminent.

Other System Payments

Payments are proposed relating to the use of alternative fuels, covering the incremental costs of using an alternative fuel when directed to do so by the Transmission System Operator.

Other System Charges

A Short Notice Declarations Charge is proposed to incentivise generator units to declare availability as early as possible. The charge is a function of the notice given and the reduction in power declared.

A Trip Charge is proposed to incentivise generator units not to trip, or, if a trip is unavoidable, to wind down (that is, reduce output) as slowly as possible. The charge is a function of the reduction in power and the length of time taken to reduce output.

Generator Performance Incentives

Charges will be applied to incentivise generator units to meet the standards defined in the Grid Codes. In essence, it is envisaged that the arrangements currently in operation in Northern Ireland will continue (with only essential adjustments) on an interim basis, and equivalent arrangements will be put in place in Ireland. The Transmission System Operators will propose a process to move to a harmonised regime. There will be further consultation on the proposed approach and charge rates.

Responses

Views and comments are invited and should be submitted by 28th October 2008 to:

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Next Steps

The following overall timetable has been established

Briefing Session	Wednesday 1st October 2008
Consultation Concludes	Tuesday 28th October 2008
Q4 2008	TSOs submit participants' consultation comments and final detailed AS proposals to the SEM Committee for approval
Q4 2008	SEM Committee publishes detailed decision paper on AS
Q4 2008 - Q2 2009	TSOs implement detailed decisions followed by "go-live" (Highly dependent on the decisions reached and the systems selected to settle.)

2 INTRODUCTION

2.1 BACKGROUND

Establishing harmonised Ancillary Services, and other power system operation-related payments and charges, sets the framework for the secure and economic operation of the power systems by the Transmission System Operators (TSO) – EirGrid and SONI. These arrangements must both facilitate actions by the TSOs and also incentivise preferred behaviour by generator units and other connected parties. The arrangements need to be able to accommodate both current needs and also emerging requirements such as those resulting from increased wind penetration over the next few years.

In the High Level Decision (HLD) paper issued on 27th February 2008[1], the Regulatory Authorities confirmed the intention to have in place a set of harmonised arrangements for Ancillary Services/System Support Services (AS/SSS) across both Ireland and Northern Ireland[2]; this followed a consultation process managed by SONI and EirGrid[3]. The RA's HLD paper established a policy framework for the development of the proposed arrangements, and also addressed other power systems payments and charges and Grid Code underperformance.

Following the publication of the RA's HLD paper, the TSOs organised industry workshops on possible services (on 30th April 2008 and 1st May 2008)[4] and invited feedback from participants. A summary of the written views expressed by industry participants is included in Appendix A of this document.

SONI and EirGrid have now considered the responses from industry in developing the proposals described in this consultation paper.

At this stage, participants are given an opportunity to provide their views on the further detail which is now provided. However, respondents are asked to keep in mind the decisions already set out by the RAs – it is not envisaged that these will be revisited.

2.2 THIS DOCUMENT

2.2.1 Overview

This document sets out proposed harmonised arrangements in the following four areas:

- Ancillary Services (Section 3)
- Other System Payments (Section 4)
- Other System Charges (Section 5)
- Generator Performance Incentives (Section 0)

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[1] Harmonised All-Island Ancillary Services Policy - A Decision Paper SEM-08-013, SEM-08-013 - SEM Ancillary Services Decision Paper.pdf

[2] This document refers to the two jurisdictions on the island of Ireland as 'Ireland' and 'Northern Ireland'. The term 'island of Ireland' is used in all cases where both Ireland and Northern Ireland is being referred to.

[3] Ancillary Services Consultation Paper AIP-SEM-07-447 Ancillary Services Consultation Paper.pdf

[4] SEM-08-063 SEM-08-063- Harmonised Ancillary Services Workshop Slides 29 Apr-1 May 2008.pdf ; SEM-08-064 SEM-08-064 - Harmonised Ancillary Services Workshop Notes 29 Apr-1 May 2008.pdf

Whilst these are separate topics, the common theme is that they relate to the secure and economic operation of the transmission systems; they each involve agreements with the TSOs and consequential payments and charges.

Each of these four topics is covered in a separate main section in this document. Supporting appendices provide a schedule of proposed rates, and worked examples. Other sections of the document include an introduction to AS harmonisation (Section 2.1), and the treatment of dual currencies (Section 7).

The document also sets out arrangements for submitting responses (Section 8), and the next steps which it is envisaged will lead to the implementation of the harmonised AS arrangements (Section 9).

2.2.2 Ancillary Services

The proposed services are ***Reserve*** (Section 3.3*)*, ***Reactive Power*** (Section 3.4), and ***Black Start*** (Section 3.5).

This document sets out a proposed set of harmonised arrangements for AS, to be implemented in Ireland and Northern Ireland. The arrangements include overall principles and design guidelines, common features (including financial aspect, procurement, the legal and contractual framework, and settlement and payment administration). Each service is described in a separate subsection. Examples of the financial aspects of these services are included in appendices.

Separately the document describes a number of proposed new Ancillary Services intended to enhance system security in the changing operational environment. These candidate services, each described in a separate subsection, are: ***Warming Contracts*** (Section 3.6.2), ***CCGT Multimode Operation*** (Section 3.6.3), and ***Pre-Emptive Response*** (Section 3.6.4). Views on these services (in particular, whether generator units would be interested in providing them) are invited.

2.2.3 Other System Payments

Payments relating to the use of alternative fuels are described in Section 4.1.

2.2.4 Other System Charges

This document includes, in a separate section, proposed charges for certain operational behaviour and actions. The actions which are addressed are ***Short Notice Declarations*** (Section 5.1), ***Trips*** (Section 5.2), and ***Generator Testing*** (Section 5.3).

2.2.5 Generator Performance Incentives

Section 0 of the document describes proposed charges that will be applied in the event that performance parameters set out in the Grid Codes or Connection Agreements are not achieved.

3 ANCILLARY SERVICES

3.1 ANCILLARY SERVICES PRINCIPLES & DESIGN GUIDELINES

As the work on the proposals for Ancillary Services (AS) has progressed, a number of policy principles have emerged: in some cases these have already been endorsed through decisions in the RAs' HLD paper. Of these principles, those that apply generally are set out below in this section; those that apply only to individual topics are given in the appropriate section later in this document.

In the table below, and throughout the consultation paper, RA decisions are shown in *italics*.

General participant comments following the workshops are summarised in Appendix A.2.1

Id	Ancillary Services' Principles & Design Framework
ASP.1	The order of precedence of documents is as below: 1. Grid Codes 2. Connection Agreements 3. Ancillary Services contracts. Hence in the event of conflict, the Grid Codes' requirements and Connection Agreement values take precedence over AS contracted values. However, where no conflict exists, the provisions of all the above documents apply. AS characteristics will be agreed for each service provider based on technical capabilities and transmission system needs. This allows service providers to offer more than relevant Grid Code levels while also acknowledging that plants which are not compliant with the relevant Grid Code for a particular service can still provide a useful level of service.
ASP.2	The total costs of AS will be *socialised amongst consumers* and will be subject to regulatory review. However, *new generating plant and interconnectors may be subject to a reserve causation charge depending on their size and impact on system costs as determined by the TSOs and approved by the RAs*
ASP.3	*Payments for ancillary services should not duplicate payments from the SEM, or other schemes such as demand side management.*
ASP.4	There will be harmonised policies and rates.
ASP.5	*Charges will apply for underperformance.*
ASP.6	*Procurement of services will be based on the ability to deliver the service required for system operation and will be independent of the technology used in providing the service. However it is possible that the attributes of a service provider and therefore the value of a service may be different if provided by alternative technologies, due to their technical characteristics only, and as such may attract different payments from the TSOs.* *In general, it would be inappropriate to base payments on their system value as, being essential for the operation of the system; their value would almost invariably be disproportionate to the costs involved in their provision.*

The design guidelines below build on the design principles above to incentivise improved AS performance: service providers will have certainty of rates and hence increased predictability of income, provided they met the contracted service levels. This should increase their focus on delivery.

Id	**Ancillary Services Design Guidelines**
DG.1	The current focus in designing the harmonised Ancillary Services arrangements is to look at the needs for the next few years and not at possible longer term requirements. It is difficult to look too far ahead at present, and there is a danger that attempting to do so could result in current needs being inadequately addressed.
DG.2	Service providers should be able to reasonably predict their annual income from providing AS, assuming good performance. They should also be able to predict the financial outcomes of failure to fulfill the contract.[5]
DG.3	The magnitude of each charge should reflect the relative value of the associated service: that is, bigger impacts should incur higher charges. Both rates and charges will be set at adequately high levels in order to reward consistently high performing service providers and to incentivise poor performing service providers to either improve performance or declare realistic service levels.
DG.4	The greater the complexity of the payment mechanism, the less predictable it actually becomes. A simple, transparent payment is desirable.
DG.5	*The rates will be set annually by the TSOs and approved by the RAs.*

3.2 COMMON FEATURES OF HARMONISED ANCILLARY SERVICES

3.2.1 Annual Budget

Each year, the TSOs will plan the AS which has to be procured to ensure transmission system security and economic operation. Using the harmonised AS rates (see Section 3.2.6 below), the TSOs will then estimate an AS allowance for each jurisdiction. The proposed allowances will be reviewed in the context of overall power system costs including potential for savings in Dispatch Balancing Cost[6], Capacity Payment Mechanism and System Marginal Price. These allowances will form part of the annual Revenue Submissions of EirGrid and SONI, to be approved by the respective RAs.

There will be no significant increase in AS allowances or expenditure resulting from AS harmonisation.

[5] This Design Guideline reflects the opinions expressed by nearly all participants at the AS workshops, see Appendix A.2.1 .
[6] Dispatch Balancing Costs encapsulate constraints costs, uninstructed imbalance costs and cost of testing.

3.2.2 Annual Expenditure

Whilst the TSOs will seek to adhere to the agreed allowances, it must be recognised that actual expenditure on AS will be determined by transmission system conditions during the year. These could require expenditure either above or below the budget. If there are valid reasons for enhanced levels of service and or additional services (for example, to reflect the increased penetration of wind generation) then the total payments will increase over those planned.

In the rare circumstance where a new service provider unexpectedly becomes available during the year, they would be contracted with if they have proved they can deliver an existing contracted service. AS expenditure would then increase in size for the year over the allowance. The Black Start service is an exception to this, as a more competitive procurement arrangement (compared with the regulated rates approach) is proposed.

3.2.3 Funding Flows

The TSOs will contract with and pay service providers (and/or PPB, as appropriate).

Funding in Northern Ireland and Ireland will be recovered separately by each TSO through the SSS tariff and Transmission Use of System tariff respectively. Recovery will be on the basis of the approved allowances, with any over or under recovery against actual expenditure carried forward to the next year.

Any monies collected by the TSOs as charges will be used to contribute to the funding of the next year's AS expenditure.

3.2.4 Other Funding Matters

The interaction of AS funding with the capacity payments budget is outside the scope of this consultation. The following points, prompted by participant comments (see Section A.2.1), are included for information rather than requiring a response.

Participants have commented almost unanimously that they would expect to see the AS budget increasing significantly over time and have expressed concern that the RAs views have indicated that any change in the AS budget would have to be considered in the context of System Marginal Price, the capacity pot or DBC being reduced by the increasing volumes of wind energy in Single Electricity Market (SEM). Many also commented that they felt that AS were currently undervalued.

Currently, to calculate the capacity pot, the costs and revenue of the Best New Entrant (BNE) are calculated. As part of this calculation, estimated AS revenue for the BNE is deducted to derive the BNE price. For information, currently AS makes up approximately 6% of the BNE price. In relative terms, the capacity pot is 10 times the current combined AS allowances in Northern Ireland and Ireland.

3.2.5 TSOs Incentives Schemes

The SEM Committee has decided to include a performance review of each TSO with respect to AS. The precise scope and arrangements will be covered in a subsequent review by the TSOs and RAs. TSO incentive schemes will be developed and may include incentives on AS. These will be developed in the overall context of a scheme for their entire businesses.

3.2.6 Rates

The TSOs will review and set harmonised rates for services annually, in agreement with the RAs. An All Island Statement of Charges and Payments will be produced which will outline all rates and charges associated with AS.

Harmonised rates will be published in both Euro and Sterling (the treatment of the exchange rate is explained in Section 7.1).

In setting the annual rates the TSOs will assess the capability and eligibility of service providers individually for each AS. Annual rates and contracts with existing service providers will not change within year unless there is repeated underperformance. In setting the rates, the TSOs will take account of any expected additional service providers.

Indicative rates, used in worked examples, are included in this document (Appendix B). It is expected that the indicative rates will be similar to the actual rates. The actual rates will be published, consulted on, and approved by the RAs as part of the implementation programme.

3.2.7 Interaction with the SEM

The payments for AS will be independent from payments made in the SEM. Service providers should keep in mind any impact on participation in the SEM arising from testing or providing the AS service.

Specific comments are included in the descriptions of each service.

3.2.8 Procurement

Procurement of Ancillary Services will be based on common principles in Ireland and Northern Ireland.

At this stage, as set out in the HLD paper[7] the RAs have decided that open market tendering would not be appropriate due to the limited number of likely bidders (with the exception of Black Start). Instead, the selected approach is for the Regulatory Authorities to approve a set of rates, and for these rates to be applied in contracts between the TSOs and service providers.

The TSOs will assess the capability and eligibility of potential new service providers individually for each AS. While a regulated rate approach operates, all new service providers will be contracted with if they demonstrate the capability to deliver the contract services to the satisfaction of the relevant TSO. This approach will be kept under review.

3.2.9 Legal and Contractual Framework

The principles of the proposed harmonised contractual framework are summarised below. Some contractual arrangements may remain between Northern Ireland Electricity Power Procurement Business and certain generator units. Harmonised rates and policies will apply to all service providers in Ireland and Northern Ireland.

The policies will be captured in a regulatory-approved AS Agreement: it is proposed that there will be a standard form of agreement that will be the basis of the individual contracts between the TSO and each service provider. The standard form of agreement can be amended from time to time by the TSOs with the approval of the RAs. Each contract will comprise the standard agreement together with a series of schedules, one schedule for each service that the generator unit contracts to provide. The agreement will contain appendices which set out the contractual levels of the AS characteristics.

[7] Harmonised All-Island Ancillary Services Policy A Decision Paper, SEM-08-013, CER & NIAUR

The schedule for each service will also be standard. It will describe (or refer to a description of) the service to be provided, the deliverables/outcomes required, how these will be measured, the basis for payments, and any charges to be made in the event that the contract is not fulfilled.

As appropriate for each individual service, the contract may specify payments for establishment, testing, and operation of the service. Similarly, charges for non-fulfilment may relate to full or partial failure to establish the defined service, demonstrate it successfully during a test called by the TSO, or deliver the required service when called by the TSO.

The contractual levels can be reviewed by the relevant TSO on an annual basis based on technical performance and transmission system needs. There will be a start and end date for each contracted service and also a mechanism for periodic review. Maintenance of the contract document and content will be a TSO responsibility.

3.2.10 The Basis of Charges for Non-Fulfilment of Contract

If a service provider does not meet its contracted level of service, the TSO will apply a charge. The TSO will also apply a charge if a service provider declares that it cannot meet the contracted level of service. Where this situation endures, the TSO will consider offering a revised contract for a lower level of service.

In general, the charges for non-fulfilment of an AS contract will seek to reflect both the payments available for the service, and the relative magnitude of the impact of the non-delivery. Regarding the latter factor, it is recognised that it is not practical to reflect the actual power systems costs of non-delivery in a charge: these would be complex to assess accurately and would, in any case, greatly exceed the AS payments.

3.2.11 Settlement and Payment

AS settlement will be carried out on a monthly basis, and will be uniform across jurisdictions and across service providers. Monthly advice notes will show separately for each Ancillary Services:

- Payments for the provision of service
- Charges for non-delivery

It is anticipated that it will be necessary to invoice separately for payments and charges (i.e. no netting on invoices).

It is the intention that invoices and advice notes should show clearly for service providers the financial impact of any failure to provide the service that has been contracted for. To this end further information may be added (such as cumulative charges paid over the year).

3.3 ANCILLARY SERVICE: RESERVE

3.3.1 Introduction

In managing the transmission systems, the TSOs must be able to deal with unexpected losses of generation capacity or unexpected increases in demand. This is accomplished by maintaining a prudent level of operating margin. The operating margin is the amount of Reserve available (provided by additional generation or demand reduction measures) above that required to meet the expected power system demand. The more critical categories of Operating Margin are the Operating Reserve categories and Replacement Reserve. It is these constituents of operating margin around which the harmonised payment and charging schemes will be built.

The prudent level of operating margin required for the island is set jointly by the TSOs. Critical factors which input into setting that prudent level include the largest in-feed on the island, variability in load and generation in the operational timeframe, generation reliability and the reliability of provision by Reserve service providers. The variability of generation will increase significantly in the coming years with the addition of more renewable generation which in turn will increase the operating margin requirements and the need to increase the availability and reliability of Reserve service providers.

3.3.2 Proposed Harmonised Design

The harmonised design is intended to incentivise a high level of Reserve availability, accurate and timely declarations of availability and to encourage new providers of Reserve service.

Id	Proposed Reserve Design Features
OM.1	The provision of the following services is contracted for on a MW basis within the time criteria specified for each category (as defined in the AS contract and Grid Codes): • Primary Operating Reserve • Secondary Operating Reserve • Tertiary 1 Operating Reserve • Tertiary 2 Operating Reserve • Replacement Reserve
OM.2	Fixed minimum regulated payment rates for the services are set annually.
OM.3	Each unit contracts for its capability level and Reserve characteristic curve for each service.
OM.4	Each unit declares its Reserve availability to TSO for each trading period to a maximum of its contractual capability in accordance with the relevant Grid Code. Charges are applicable to units which, having declared a level of availability, fail to deliver the required level of performance.
OM.5	Each unit are scheduled and dispatched as per the common Grid Codes rules.

OM.6	Unit performance during low frequency events (e.g. a generator tripping) is monitored by reviewing the post event data.
OM.7	Payment is calculated separately for each category of Reserve for each trading period. Payment is calculated as realisable availability multiplied by the scaled payment rate. Realisable availability is calculated from the average MW generated by the unit over the trading period, the Reserve characteristic curve of the unit, and average declared availability of the unit over the trading period. The scaled payment rate is calculated from the percentage difference between the declared availability and the contracted capability.
OM.8	The charge depends on the level of underperformance during low frequency events. The charge is proportional to the difference between the expected provision (as calculated from declared availability, the Reserve characteristic curve, the output, and the governor response to power system frequency) and the actual provision. The charge is calculated as the underperformance during an event multiplied by the payment rate multiplied by 30 days.
OM.9	*As a complement to the above scheme , the TSOs will be also be allowed to enter into contracts with market participants for reserve to take into account longer term system requirements and facilitate investment in certain types of plant and equipment as system requirements evolve over time (for example, wind integration and plant retirements).*

3.3.3 Commentary

Participant comments following the workshops are summarised in Appendix A.2.2.

Worked examples of payments and charges for Reserve are given in Appendix C.1.

Provision of Operating Reserve is a mandatory service for generator units under the Ireland and Northern Ireland Grid Codes.

The design of the payment and charging scheme for Reserve follows the design criteria of harmonising arrangements within current budget levels. Payment rates are obviously influenced by this constraint. The budget constraint limits the number of effective signals that the design can successfully deploy, as the current budget is greatly overshadowed by energy payments and the Capacity Payments Mechanism (CPM). As a result the design focuses on signalling availability using fixed minimum regulated rates. The use of a variable component in the rates as allowed for in the RAs' HLD paper[8] has not been extensively utilised.

[8] "……*be able to increase these rates with discretionary variable amounts depending on system requirements and market participants' availability (for example, night and daytime variations)" ….."the scheme will take into account the characteristics of the capacity already made available to the TSOs due to the CPM signalling"*.

The definitions of Reserve categories have been harmonised between Ireland and Northern Ireland (with the exception of a minor difference in primary Operating Reserve which will be harmonised in parallel with settlement systems implementation). The harmonised definitions do not discriminate between service providers, which allows for new sources of Reserve to emerge. Encouragingly, a number of new potential sources of Reserve were identified in submissions to the TSOs following the workshops (see Appendix A) and these may develop to become Reserve service providers. Provided the quantity of reliable Reserve increases relative to Reserve requirements, more competitive procurement approaches will become appropriate.

Commentary on Proposed Design Features

The following commentary steps through the proposed design and outlines some of the specific reasoning behind the design.

The annual fixed minimum regulated payment rate is designed to provide increased predictability of annual income. This feature is strongly desired by service providers (see A.2.1). On an annual basis a service provider has certainty of the rate which will be paid, and can calculate its maximum income for each category of Reserve for the coming year based on the results from its running regime model for the year (which should indicate how often it is run and how often it is called on for Reserve). The annual fixed minimum payment rate is set based on the budget available for operating Reserve and the predicted level of provision throughout the year including assumptions related to new service providers. Were average availability to exceed that expected, total payments would increase.

The contractual capability level is agreed between each service provider and the relevant TSO based on past performance and expected future performance. It is independent of relevant Grid Code values, Connection Agreement values and transmission system requirements. The contractual capability level is the service level that the service provider commits to contractually: it may well indicate more demanding performance than the minimum values contained in the relevant Grid Code or Connection Agreement. Any contracted value in no way affects the requirements on a service provider to meet the relevant Grid Code requirements.

A service provider has contractual Reserve levels. However for various reasons it may not be able to reach the contractual Reserve level for short periods. The design allows for this scenario by requiring service providers to declare their availability.

The SEM rules are designed to ensure that providers of Reserve are made whole when scheduled down for Reserve. The Reserve payment is required to incentivise speed of response and not merely capacity which the SEM rules drive. It is therefore appropriate to pay independently for maintaining the capability to deliver the speed of response which is vital for the security of the power system.

The payment scheme is designed in a way that balances predictability of income, relative simplicity, and payment for truly deliverable service. A service provider which meets its contractual requirements will be able to predict its income by modelling. This is an improvement particularly for service providers in Ireland because the payment rate in the harmonised design is not scaled for each trading period dependent on the level of provision from other service providers as is done in the existing arrangements. The payment scheme also incentivises service providers to set the contractual capabilities at the expected declared availability by scaling down the payment rate depending on the difference. The scaling down is not overly onerous but should bring contractual levels close to realistic levels which will allow the TSOs jointly to better set the transmission system Reserve levels.

Basing the payment design on realisable availability has a number of impacts. A service provider can receive payments for some categories of Reserve when not synchronised depending on its characteristics. A service provider's declared availability will automatically be set to zero when the unit trips.

Both TSOs will review service providers' performance during low frequency events. This will be done after the event, using the best available information.

A complementary monitoring could be set up whereby service providers could hard wire the signal showing their frequency response control settings to the relevant TSO. This would be very useful as there is at present an issue with poor performance simply due to control settings. The TSOs would like a direct comment on the practicality of such an implementation.

Slower Reserves are more difficult to monitor than fast Reserves, and consequently it is more difficult to spot poor performance and therefore apply charges for these categories of Reserve. The payment rates and associated charges for these Reserves will be proportionately lower.

Reserve is vital to secure operation of transmission systems. The charging scheme is designed to incentivise service providers to accurately declare their availabilities and to make re-declarations in a timely manner; failure to do so may lead to the application of charges and, consequently, decreased predictability of payment.

The charging scheme reflects the impact on the system of underperformance when the Reserve is required. The charge for underperformance is not reduced to reflect good historic performance since historic performance has no beneficial influence on the power system during a frequency event. Similarly, the charge for underperformance is not reduced if the service provider has received little or no payment before the underperformance, since the payments received leading up to an event are not relevant to the impact on the power system during a frequency event. In short, all service providers that under-perform to the same level are charged on the same basis, regardless of past performance.

General Commentary on Reserve

The combined payment scheme and charging scheme allow service providers to control their income. The service provider knows its expected payments and knows the charge each time it underperforms. A service provider may minimise any charges by ensuring that its availability is declared accurately.

Demand Side Management (DSM) schemes are an important element of the Reserve provider portfolio. The RAs have previously indicated that there is a separate ongoing review of DSM over the first two winter periods of the SEM. Therefore the Reserve designs proposed here were developed with an awareness of DSM while not expressly setting out how DSM will be catered for. Current arrangements for DSM in Ireland and Northern Ireland will continue until the review is completed and the outcomes implemented.

3.4 ANCILLARY SERVICE: REACTIVE POWER

3.4.1 Description

The TSOs must maintain a voltage balance across the transmission systems in order to maintain secure and stable power systems and to avoid damage to connected equipment. To maintain the balance, the appropriate level of Reactive Power (leading and lagging) is required at appropriate locations in the transmission systems. The required level of Reactive Power varies in the operational timeframe.

Reactive power is mainly provided by generator units and transmission assets. Generally, Reactive Power must be provided close to the location where it is needed. Overall, therefore, the requirement is for the flexible provision of Reactive Power at appropriate points across the transmission systems.

3.4.2 Proposed Harmonised Design

The harmonised design is intended to incentivise a high level of Reactive Power availability and accurate and timely declarations of availability.

Id	**Proposed Reactive Power Design Features**
RP.1	A fixed payment rate for the service is set annually and approved by the RAs.
RP.2	The provision of Reactive Power service to the transmission system is contracted for on the basis of a Mvar capability range.
RP.3	Each unit contracts for its capability range and where appropriate its Reactive Power characteristic curve and its Automatic Voltage Regulator (AVR) capability.
RP.4	For each trading period, an applicable unit declares its capability range independent of output to the TSO in accordance with the Grid Codes. For a unit that cannot declare its capability range, its capability range is assumed to follow from the unit's actual MW output and its characteristic curve. The maximum capability range is equal to its contractual capability range. Each unit indicates the status of its AVR. Charges are applicable to units who do not deliver to their set capability range.
RP.5	Each unit is called upon to provide Reactive Power by TSO dispatch/set point.
RP.6	Unit performance is monitored in real time operation and by post real time review.
RP.7	Payment is made to units which are synchronised or have a separate Reactive Power device. Payment is calculated for each trading period. Payment is calculated as the capability range multiplied by the scaled payment rate. The scaled payment rate is calculated from percentage difference between the declared capability range and the contracted capability range.

	For units that can not declare a capability range, the capability range is calculated after real time operation from the unit's actual MW output and its characteristic curve and there is no scaling of the payment rate. The scaled payment rate is doubled if the AVR is active.
RP.8	The charge is equal to 30 days worth of contractual capability range payments.
RP.9	*The TSOs will be allowed to enter into long-term contracts with market participants for Reactive Power in order to take into account longer-term system requirements.*

3.4.3 Commentary

Participant comments following the workshops are summarised in Appendix A.2.3.

Worked examples of payments and charges for Reactive Power are given in Appendix C.2.

Provision of Reactive Power is a mandatory service for generator units under the Ireland and Northern Ireland Grid Codes. The SEM provides signals for the provision of active power. However, provision of active power does not directly lead to provision of Reactive Power, which is required to maintain a secure and stable power system. A stand alone payment targeted at the provision of Reactive Power is required.

The payment scheme proposed is designed in a way that balances predictability of income, relative simplicity and incentivisation of delivery for the required service. Specifically, payment for the provision of Reactive Power is intended to incentivise service providers to maintain the capability of providing Reactive Power and automatic voltage regulation. Payment is not intended to refund capital expenditure nor to provide a geographical signal for investment in plant. However, in limited instances it may indirectly influence the choice of some equipment over others.

The design of the payment and charging scheme for Reactive Power follows the design criteria of harmonising arrangements within current budget levels. The budget constraint limits the number of effective signals that the design can deploy, as the current budget is greatly overshadowed by SEM revenues. The potential signals include payment for capability, availability, utilisation, location and reliability. These potential signals were identified through discussions with industry participants. It was commonly thought that the more the payment is dispersed between features, the less transparent and the more complex the payment and charges arrangements would become. This is not desirable because it detracts from the ability to predict payment (a feature strongly sought by service providers, see Appendix A.2.1).

The design is structured to give service providers the desired improved predictability. The payments are calculated using pre-published annual rates, and the charges for identified failures are predictable. The TSOs expect that the design will assist service providers in focussing better on delivering the Reactive Power service to the transmission system.

Commentary on specific Reactive Power payment options

Payments based on capability are the best signal for the provision of Reactive Power. It incentivises provision by all service providers in the most effective and equitable manner. Unlike operating Reserve, Reactive Power provision is not and cannot be linked with the optimisation process in the SEM. Therefore similar arrangements to those for Operating Reserve (paying for availability based on SEM scheduling rather than the simpler capability) would not be equitable.

Payment for utilisation is not considered attractive. The design seeks to incentivise provision of capability which gives the relevant TSO the flexibility to call on the Reactive Power if required rather than to compensate for the minor cost of provision. It was also considered unattractive because it would significantly reduce the level of predictability of income for service providers. It would not reward the contribution of service providers when instructed to operate at unity power factor.

A locational payment element has not been included despite Reactive Power being strongly influenced by location. It is correct to say that some parts of the transmission system require more Reactive Power support than others on a daily basis. However, the capability is required in all areas to allow for unusual system scenarios. All service providers must be prepared to meet the Reactive Power requirement regardless of how often they are called upon to provide the capability range. A locational element could have the effect of influencing an investment decision incorrectly, since the Reactive Power requirements at a location can change both in real time and over longer periods. A further weakness of a locational element is that the calculation for the various locations is likely to be complex, requiring a new involved process.

A variable payment reflecting reliability is attractive. However, to demonstrate and assess reliability would be difficult and hence administratively complex. A reliability element would also dilute the capability payment, since the annual budget is fixed. For these reasons reliability was not included.

Commentary of the Proposed Design Features

The following commentary steps through the proposed design and outlines some of the specific reasoning behind the design.

The fixed payment rate is set annually based on the annual budget and predicted level of contracted provision throughout the year, including assumptions about new service providers.

Each service provider contracts with the relevant TSO for its contractual capability range. The contractual capability is set based on the level of service that can be provided to the transmission system at the connection point. The range is set based on past performance and expected future performance. For clarity, neither NIE nor ESB Networks are regarded as service providers to the transmission system and it is not envisaged that either would be eligible for AS payments.

The payment scheme is designed in a way that balances predictability of income, relative simplicity and incentivisation of delivery for the required service. As with Reserve, a service provider which meets its contractual requirements will have a predictable income, based on published rates A service provider that is dispatchable for Reactive Power can calculate its annual payment using its estimate of its time synchronised, its contractual capability range, it AVR status and the annual fixed payment rate. For service providers such as wind farms that cannot meet their contractual capability at all times, another calculation step is required to estimate their capability range. The range can be calculated using the load factor and the Reactive Power capability curve. (As Reactive Power is not linearly proportional to active power this estimate may be somewhat approximate and some alternative method to predict the annual payment may be preferred by service providers.) Further calculations may be required for more complex service provider configurations.

The payment per trading period is straightforward. As with Reserve, the annual payment rate is scaled to incentivise the service provider to contract to an achievable level and to aim to meet the contractual level at all times.

Automatic voltage regulation also enhances the provision of Reactive Power and it is therefore appropriate to reflect AVR capability in the payment calculation. The payment is increased to reflect the availability of the AVR simply by doubling the payment rate. By including this in the payment scheme, service providers should be encouraged to return the AVR to service as soon as practically possible. The status of the AVR is currently being included in service providers' declarations. It would be beneficial to both system operation and AS settlement to have the AVR status hard-wired to the relevant TSO. Similarly it would be beneficial to system operation for the status of every power system stabiliser to be hard-wired to the relevant TSO. As with the status of the governor for Reserve, the TSOs would like specific comment on this proposal.

Each TSO will monitor service provider performance. Monitoring will be carried out at two stages – the first will be compliance with dispatch instructions and set points in real time, the second will be data review post real time operation.

If a service provider fails to deliver according to contract, a charge will be applied. Due to the nature of Reactive Power, it is difficult to determine the exact level of underperformance and therefore a reasonable tolerance will be used in assessing performance. For the same reason, the applicable charge will be proportionate to the contracted capability and independent of the degree of underperformance.

General Commentary on Reactive Power

The TSOs will be allowed to enter into long-term contracts with the SEM participants for Reactive Power in order to take into account longer-term system requirements. The TSOs will avail of this flexibility in rare circumstances, including, amongst others, delayed transmission system reinforcements, generator unit retirements, non-mandatory Reactive Power devices and longer-term transmission outages.

It is intended that Reactive Power costs will be borne by the TSOs and will act as a network investment signal. Further consideration is required to develop this incentive and incorporate it into the overall incentive scheme for each TSO.

3.5 ANCILLARY SERVICE: BLACK START

3.5.1 Description

The TSOs need to be able to re-establish system operations after an extensive failure of the system. This entails isolated power stations being started individually, establishing customer load, and gradually being reconnected to each other in order to re-establish an interconnected system.

3.5.2 Proposed Harmonised Design

The selection of new Black Start sources and payment arrangements will be transparent to all participants. The harmonised design is intended to incentivise availability and performance in accordance with the contract during Black Start tests and actual events. The proposed Black Start service will apply to existing Black Start sites in Ireland and all future Black Start sites in Northern Ireland and Ireland. Existing Black Start sites in Northern Ireland (all of which provide the service) will receive testing payments; payment for providing the service is implicit in their existing connection conditions.

Id	Proposed Black Start Design Features
BS.1	The provision of the Black Start service to the transmission system is contracted for based on a number of technical requirements on a site-by-site basis.
BS.2	A fixed payment rate for the service is set individually and adjusted annually in accordance with the contract.
BS.3	*Each site contracts through long-term contracts for its capability to Black Start local areas on the transmission system including other generator sites.*
BS.4	For each trading period, an applicable unit declares its Black Start status in accordance with the Grid Codes.
BS.5	Each site is required to carry out three levels of Black Start tests. Test 1: Black start unit test (planned and scheduled by the service provider) Test 2: Local Black Start site test (e.g. Energise dead busbar) Test 3: Black start path test (e.g. Provide supply to remote generation site) Tests 2 & 3 will be called by the relevant TSO.
BS.6	Site performance is monitored for Tests 2 & 3 by the relevant TSO.
BS.7	Payment is calculated for each trading period. Payment is due when both the generator site and the Black Start facility are declared available. Payment per trading period is equal to the half the contracted hourly rate.

BS.8	A charge is applicable for failure of either Tests 2 or Test 3. Two levels of charges apply. Charge 1: Partial failure where a site fails to meet some contractual element incurs a charge equal to 30 days maximum payment Charge 2: Outright failure to Black Start incurs a charge equal to 90 days maximum payment.

3.5.3 Commentary

Participant comments following the workshops are summarised in Appendix A.2.4.

Published Information

Each TSO will publish information on the Black Start requirement for their system. This will include an overview of the system restoration plan, an indication of favourable locations for new Black Start investment, a minimum set of Black Start criteria for a Black Start service provider, and a list of Black Start service providers and their annual payment rates.

The minimum technical criteria will include the minimum requirements for the service provider's plant and the minimum requirements for the plant to interact with the system.

The TSOs encourage all potential services providers to discuss the possibility of becoming a Black Start service provider with them at any time. Such potential service providers must meet the minimum technical criteria. Alternatively a TSO can approach a potential service provider ensuring that all appropriate procurement rules are followed and the relevant RA has been advised. The procurement rules will include tendering where appropriate.

The payment rate for the provision of Black Start will be based on cost of provision. The onus will be on the service provider to justify costs. Therefore, in advance of negotiating the payment rate with the TSO, the potential service provider should understand the cost of provision of the service over the lifetime of the additional Black Start equipment and also the other revenues that would be gained from installing the Black Start capability.

The additional costs to provide the service may include elements such as the additional fixed cost, maintenance cost, testing cost, training cost, carbon costs, insurance cost. The additional revenues may include energy revenue, capacity revenue and other Ancillary Services revenue.

The correct assessment of these costs and revenues will be heavily dependent on how the potential service provider intends to have the Black Start equipment interact with the SEM: there could be an increase to the maximum export capacity, a boost to the capacity when it is below the maximum export capacity on given days, or the service provider might opt not to run the unit at all in the Market.

Note that the cost incurred in carrying out the financial assessment for Black Start will be carried by the potential service provider.

The contract length will be subject to negotiations between the TSO and individual service providers.

The minimum rate of return will reflect the cost of capital for the TSOs (which is currently approximately 5%). The onus will be on the potential service provider to justify a rate of return above this level. For example an additional level of service above the minimum requirements for Black Start may warrant a higher rate of return.

The cost of retrofitting Black Start into operational units may be prohibitively high. Therefore there is potentially merit in investing in the minimum equipment required to economically install Black Start on site in the future. The negotiation on payment arrangements for such an option would follow similar steps to that described for fully Black Start capability implementation.

Procurement Process

The provision of Black Start is a long term commitment. Therefore Black Start contracts must reflect this long term commitment. It is not appropriate however to link the provision of Black Start with the life of plant. Plant life may be extended for the plant to provide a new function which would not suit the provision of Black Start.

The procurement of a new Black Start service provider will follow negotiation between the service provider and the relevant TSO and will be based on cost of provision.

Contracts will be established either following a tender process or via a direct award (for examples when a new plant connects to the system).

Once the potential service provider and TSO are in a position to begin negotiation, one of the key factors for negotiation is how the potential service provider intends to utilise the Black Start equipment. If additional equipment is required solely for Black Start then the Black Start contract payments will reflect the total costs of this equipment. If the Black Start equipment is used for any additional purpose, the Black Start contract payments will be less. This is central to avoiding any double payment.

The TSO will have to carry out a system study to assess if a particular site is suitable. This will be done in a reasonable timescale to try to fit in with a potential service provider's schedule; however such studies may take some time to complete.

The contract as negotiated between the potential service provider and the TSO will be subject to approval by the relevant RA.

Ongoing Process

Payment is a function of the Black Start unit availability and the hourly rate which is reviewed annually. Payment will be calculated separately for each trading period.

The contract will have provision for an annual test by the TSOs of the site which on a two-year basis will include a restoration path on the transmission system. The site itself should also carry out its own separate tests more frequently and the relevant TSO should be made aware that such a test is being performed and the results of the test. Should a TSO call for a Black Start test on a site, the relevant units will be dispatched according to a pre-agreed schedule. In doing so the relevant units will be made whole in the SEM and no payment for a test will be due.

In the event of a test failure, the relevant TSO will retest as it deems appropriate. A failed Black Start test due to service provider failures will incur a charge. There are two charge types. Failures such as slow response would incur a partial failure charge. Complete inability to Black Start a site would incur an outright failure charge. Should other units be affected by a test, they will also be put under test in the SEM and therefore made whole for the testing period.

3.6 POTENTIAL NEW ANCILLARY SERVICES

This section of the document introduces potential new AS which the TSOs believe would enhance secure, reliable and economic operation of the transmission system. The section gives a broad overview of the Ancillary Services. Further detail will be developed subject to participants' feedback and subsequent further TSO consideration.

Participant comments following the workshops are summarised in Appendix A.2.5

3.6.1 Introduction: System Need for Additional Reserves

In order to operate a power system securely reserves are required which are available in timeframes ranging from seconds to hours. Fast-acting reserve is required to control transients after the sudden loss of generation and to re-establish system conditions to limit the effect of further generation loss. Reserve in longer timeframes is required to replace fast-acting reserve sources that are normally expensive or have energy limitations. In the past the main risk being mitigated was the unexpected loss of large generating units: open cycle gas turbines and pumped storage were used to replace the lost generation until off load plant could be started.

With the introduction of large-scale wind generation additional variability arises. As large amounts of wind generation appear on the system there is an increasing dependence on wind forecasting. Forecasting errors will produce over and under generation events that the system operators must deal with to maintain the generation / demand balance.

Under generation i.e. an expected output from wind generation that does not arrive when expected or sudden reductions in wind generation output due to adverse weather conditions, drives the requirement for additional system reserve levels and additional reserve categories to follow the wind variation. The additional reserve to meet these requirements will be needed in the range of minutes to hours.

Reserves can be obtained in this timeframe from the following existing sources:

- Demand Side Units
- Inter system exchanges.
- Loading of already synchronised plant.
- Off load available plant.
- Open cycle gas turbines.
- Pump storage plant.

From the above, it is currently envisaged that additional services would be sought from off load available steam plants and Combined Cycle Gas Turbines (CCGTs), as described below. Further analysis and development work would be required to take the other possibilities forward.

3.6.2 Off load Plant: Warming Contracts and Maintenance of Heat State

Conventional steam plant that is not connected to the system but available to start becomes colder, takes longer to re-synchronise, and is slower to load up, the longer it is off load. The warmth state of a unit, which directly relates to its time to resynchronise, moves from hot to warm to cold after desynchronising. The plant becomes slower to react to system needs the longer it remains off load. Plant that can change to or maintain a hotter warmth state will reduce quick start plant running periods, Open Cycle Gas Turbine (OCGT) capacity requirements, and meet additional reserve requirements.

Two products are proposed:

i. The ability to change to and maintain a hotter warmth state

ii. The ability to maintain hot warmth state after resynchronisation

There will be some interaction between warming contracts and payments for categories of reserve. This interaction will be taken into account in setting the payment for the warming contract.

The design would include:

- Payment would be a fixed rate per hour to maintain warmth state.
- The service would be tested by the TSO: a test failure would incur a charge.
- Delivery or non-delivery of the service would be assessed by the TSO by reviewing the time to synchronise of the unit. Non delivery would incur a charge.
- There would be an interaction between warming contracts and the SEM which would need to be considered in developing the warming contract arrangements.

3.6.3 Combined Cycle Gas Turbines (CCGT) Multimode Operation

CCGTs can operate in either open or closed cycle modes. In normal closed cycle operation power is generated by combusted gas in the gas turbine and by steam produced in the boiler using the exhaust gas in the steam turbine. The two cycles result in a higher overall unit efficiency.

Other modes of operation are available if the boiler cycle is not used. If the steam turbine is bypassed using boiler gas side bypassing, the gas turbine will operate independently at efficiencies of approximately 30% and be fully available within relatively short timeframes (<20 mins) for full gas turbine output. Without boiler bypassing available the steam turbine does not necessarily have to be started up, but the output of the gas turbine is limited with the boiler steam output being produced and going to waste.

Open cycle operation with boiler bypassing provides a fast run up ability similar to an OCGT.

The SEM does not currently facilitate multimode operation being offered. The minimum stable generation output level and pricing relates to closed cycle operation. To facilitate quick start / open cycle operation an additional Ancillary Services payment could be provided to secure the service and encourage flexible CCGT operation / investment.

The product required is:

- Open Cycle Gas Turbine operation
- Flexibility to continue to closed cycle operation after dispatched on open cycle

OCGT operation would be paid on the basis of the difference between SEM income and an agreed income for operating in OCGT mode (determined on a costs plus basis in the procurement process).

3.6.4 Pre-Emptive Response

Generator unit trips have a major impact on power system operation. A description of the implications of tripping and appropriate incentives on generator units to incentivise them not to trip, or at least to trip as gradually as possible is given in Section 5.2. The proposed Pre-Emptive Response service also focuses on the impact on trips.

The proposed Pre-Emptive Response service goes beyond those incentives to lessen the effect of some trips. The essence of the proposed service is that it is possible in some cases to recognise when a trip is imminent. If the TSO has this information, it may then instruct a fast response unit (or interconnector) to increase output; if this increase can be achieved before the full impact of the trip has materialised, then any frequency transient may be prevented or lessened. It may be possible and desirable to design an automated an instruction process as part of the service.

A mechanism would be required to take advantage of the proposed service. The proposed mechanism has three components:

- A generator unit that has to trip, winds down (i.e. drops load in a controlled way) rather than tripping instantly (this would be incentivised by the charges described in Section 5.2)
- The generator unit provides a “wind down” signal to the relevant TSO which would alert the relevant TSO to the impending loss of generation.
- The TSO instructs a fast response unit or an interconnector to adjust output;

The main “product” of the Pre-Emptive Response is envisaged to be the response by a fast response unit to a “wind up” signal. A payment would be made for the pre-emptive response. The payment could be based on availability or event-driven.

4 OTHER SYSTEM PAYMENTS

4.1 ALTERNATIVE FUEL PAYMENT

4.1.1 Description

Certain generator units have the capability of using multiple fuels. This capability enhances system security (as well as providing different technical characteristics which improves flexibility). For system security reasons, some of these generator units are tested periodically using alternative fuels to assess performance. Other generator units may switch fuels routinely. In either circumstance operational costs are likely to differ according to the fuel being used. Currently, no provision for change of fuel within day is made in the SEM. One aspect of this lack of provision is being addressed in this paper. Others are being considered elsewhere.

The relevant TSO may instruct a unit to use the alternative fuel to test the capability of running on the alternative fuel or, in Northern Ireland, to comply with the Fuel Security Code. In these circumstances, the generator unit may be required to use a less economic fuel than it would otherwise choose. This imposes a cost on the generator unit that would not be recovered under the current SEM arrangements. It is proposed that, where the generator unit is instructed to change fuel in this way, a compensating payment is made by the TSO. This section addresses the compensation payment for running on the alternative fuel. The compensation payment should reflect incremental cost of running on that secondary fuel.

For clarity, the term alternative fuel is used to mean a fuel other than that used predominantly by the generator unit. Similar terminology is being used in the context of generator units which can operate on multiple fuels. The terminology includes Dual Fuel, Secondary Fuel and Dual Rating. The term Dual Fuel is referred to in the Fuel Security Code which is applicable to generator units in Northern Ireland. The term Secondary Fuel is used in a current consultation process being run by CER which applies to generator units in Ireland. The term Dual Rating is central to a proposed modification to the Trading & Settlement Code (TSC). The compensation payment proposed in this paper is relevant to both Dual Fuel and Secondary Fuel. For this section the term alternative fuel is used to cover both.

4.1.2 Design

The proposed design sets out a process to compensate a generator unit when instructed by the relevant TSO to run on its alternative fuel.

Id	Alternative Fuel Proposed Design Features
AF.1	Compensation payment for alternative fuel follows from requirements within licenses and the Grid Codes.
AF.2	The relevant TSO schedules the tests for each eligible unit.
AF.3	The relevant TSO monitors each test to assess its success.
AF.4	No payment is made in the event of a failed test unless adequately justified by the generator. Payment for a test is only made where a test of the use of alternative fuel is executed

	on instruction from the relevant TSO.
AF.5	In addition in Northern Ireland, payment is also made when a generator unit changes fuel in a circumstance where SONI instructs the use of alternative fuel (or would have been reasonably expected to dispatch the change. SONI judge the reasonableness of this circumstance.)
AF.6	A payment is made monthly for any month for which alternative fuel operation is instructed.
AF.7	The payment period is defined by the instructions issued by the relevant TSO. Start and finish times are based on the technical characteristics of individual units. The payment covers up to three phases: change to alternative fuel; operation using alternative fuel; change back from the alternative fuel. The payment is based on the incremental fuel and running costs incurred by the generator unit in using the alternative fuel.

4.1.3 Commentary

Participant comments following the workshops are summarised in A.2.5.

The issues relating to alternative fuel are being progressed in Ireland and Northern Ireland separately. The alternative fuel arrangements and the accompanying testing regime are not harmonised across jurisdictions at present. The design for the harmonised compensation payment is set out here in a way that should accommodate both developments.

CER and NIAUR, through the JSG Sub-Committee on Security of Electricity and Gas Supply, will consider the common arrangements, procedures and recovery mechanism that may be required in the event of an emergency.

For background, in 1992 in NI, a Fuel Security Code (FSC) was introduced by the Department of Economic Development to enforce co-operation by Electricity Industry licence holders regarding strategic contingency planning in respect of fuel stocks. The FSC set out the means by which certain costs incurred by Licence holders in preparing for and during a Fuel Security Period could be identified, audited and recovered. The recovery of these costs from suppliers and ultimately customers in NI is facilitated in the document by the "Power Procurement Manager". DETI in conjunction with NIAUR are currently reviewing the existing document as a consequence of the introduction of the SEM. It is likely that SONI payment to a generator unit would be reclaimed through the PSO levy.

CER have arrangements in place with regard to secondary fuel requirements. CER are currently consulting on modifying these arrangements. Included in the revised arrangements is a proposal to remunerate generator units for testing on a secondary fuel. The proposals on this were initially set out in a consultation paper which was published in late 2007. A draft decision was then published in February 2008. Views were sought by participants on the Commission's proposals in both the consultation paper and the draft decision paper. A decision is due to be published shortly. This paper is intended to set out what costs should be remunerated and that these costs should be remunerated through the AS mechanism.

The compensation payment given to generator units may be based on a set formula based on the Bidding Code of Practice, and the principle to bid the short run marginal cost. At present the CER-proposed eligible costs are as follows and will be confirmed in the CER decision paper on secondary fuel:

- The additional cost of the running on the alternative fuel compared to running on the primary fuel.

- The cost of water that may be required for controlling NO_x emissions.

- The cost of the additional carbon allowances required, as there are more emissions generated when Combined Cycle Gas Turbines run on distillate rather than gas.

In addition to the proposed eligible costs, it is intended that the number of tests that the TSO can perform per year on each generating unit would be set out in the decision paper on secondary fuel. The process and procedure will need to be developed following a decision on secondary fuelling.

For information, a modification to the TSC is being developed in relation to Dual Rating. This modification is also relevant to generator units which can operate on multiple fuels and in particular considers SEM capacity payment to such generator units.

5 OTHER SYSTEM CHARGES

This category includes charges for two systems events (Short Notice Declarations, and Trips) originating at generator units. The purpose of these charges is to incentivise behaviour that enhances the security of the system and reduces operating costs.

Also included in this section is a description of the treatment of the charging tariff for generators under test.

5.1 SHORT NOTICE DECLARATIONS

5.1.1 Description

When a participant declares down availability at short notice additional generation is required to compensate for the loss. This may result in the dispatch of expensive plant to meet the operational need. This in turn may cause the real time dispatch of the system to differ further from the SEM schedule; this additional difference will then be reflected in increased constraint costs that must be recovered. In general, the less notice that the TSO has of the SND, the less opportunity there is to minimise the economic impact.

Consequently, short notice declarations of availability impose costs on the TSO and hence on other users of the transmission system.

It is therefore desirable to incentivise generator units to avoid changing their declarations at short notice, or, at least, to provide the maximum possible notice of a change in availability to the relevant TSO.

5.1.2 Design

The purpose of the SND charge is to incentivise generator units to avoid changing their declarations at short notice, or, at least, to provide the maximum possible notice

Id	Proposed Short Notice Declarations Design Features
SND.1	The Short Notice Declaration Charge is a function of Megawatt reduction, notice time and SND charge rate. The SND charge rate is reviewed annually.
SND.2	The SND charge applies for downward availability declarations within a 12-hour period. There is a minimum threshold of 10 MW. SND charges apply to larger re-declarations. Re-declarations below the 10MW threshold more than three times in one hour are subject to a SND charge. The charge is calculated as the MW difference between the availability prior to the first declaration and availability after the last declaration; the notice provided will be set to zero.
SND.3	Each unit makes declarations in accordance with the TSC.
SND.4	The relevant TSO schedules and dispatches the unit in accordance with the Grid Codes, the TSC and the unit's declarations.
SND.5	The SND charge is calculated as follows: SND Charge = MW Reduction * SND Charge Rate * Notice Time Weight The SND charge rate is set to a single value annually. The Notice Time Weight is an empirical weighting corresponding to the relative importance of notice time from 12 hours up to real time.

5.1.3 Commentary

Worked examples of charges for Short Notice Declarations are given in Appendix C.4.

The SND charge will be levied on all generator units dispatched through the EDIL interface. It will therefore apply to conventional plant, Controllable Wind Farm Power Stations, Demand Side Units, and interconnectors.

The applicable charge will be calculated from a notice-time weight. The charge is intended to incentivise longer notification, therefore the longer the notification the smaller the charge.

A significant new feature is the MW threshold of 10MW. This is proposed so as to exclude from consideration small fluctuations in output due to ambient temperature changes: generator units have very little control over such fluctuations.

The charge imposes a clear incentive for generator units to provide increased notice. A generator unit that does not comply will face a Short Notice Declaration Charge.

The proposal is simpler than the current arrangement in Ireland. This simplification is achieved by excluding “interacting SNDs”.

Trips and short notice declarations are similar to the extent that a downward declaration at short notice may also be classified as a trip; however the charges are used to incentivise two completely separate things. A trip charge is associated with the loss rate of actual output while the short notice declaration charge is associated with availability declarations. The short notice declaration charge is applied to incentivise timely notification of availability while trip charges are applied to incentivise generator units to trip slower (or even not at all) in order to reduce direct tripping which may lead to system instability. For these reasons short notice declaration charges and trip charges should remain separate. The consequence of this is that a single incident at a generator unit may give rise to both an SND charge and a Trip charge

5.2 TRIPS

5.2.1 Description

Generator unit trips cause a rapid reduction in the power available to the system, leading to a fast change in system frequency. If this is not ameliorated, then load shedding may become necessary so as to match available generation with demand. The faster a trip occurs, the greater the effect on the system.

A further danger is that additional generator units will trip in response to the initial event.

Once a trip occurs, reserve generation must be activated. Over short timescales this is accomplished through generator governor response and by activating static reserve sources by frequency deviations.

Over longer time-scales the system must be re-dispatched into a stable state. This may involve the TSO calling on fast response plant, the interconnector, and demand reduction customers. These actions have costs that are greater than those in the optimum SEM schedule.

In the current SEM systems, the ex-post availability and ex-post dispatch instruction are set to zero following a trip. Therefore the unit is not exposed to uninstructed imbalances as the metered generation and dispatch quantity match. The SEM, when scheduling the system treats the trip as a known unavailability of the unit due to the perfect foresight effect of the SEM. The unit suffers the loss of payments that are normally associated with an outage, thus all units are incentivised to declare re-available. Therefore, avoiding the trip and incentivising behaviour that minimises disruption to system frequency needs to be included in the design.

5.2.2 Design

The purpose of the charge is to minimise the number of trips and, when a trip is unavoidable, the charge should incentive a unit to trip as slowly as possible.

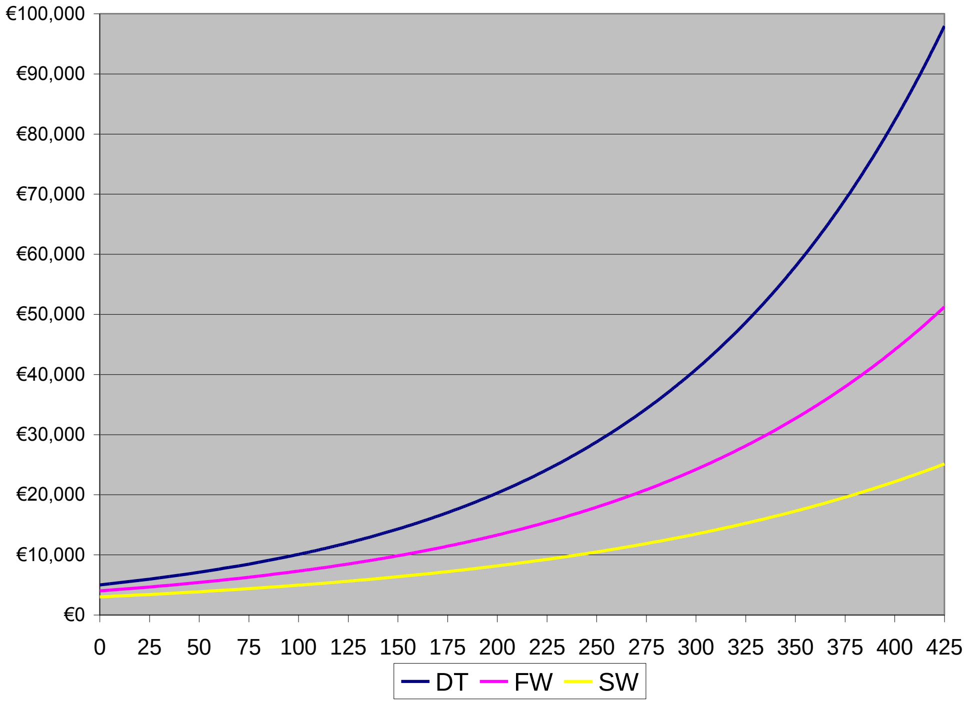
Id	**Proposed Trips Design Features**
TR.1	A trip charge is levied on all forms of generation including conventional generation, wind farms, demand side units, distributed connected generator units and future generator technologies. The higher the MW loss, the higher the trip charge. The faster the trip, the higher the trip charge. A charge is levied for full trips (i.e. trip to zero) and partial trips (e.g. loss of Steam Turbine)
TR.2	The charge rates are reviewed annually.
TR.3	Three categories of trips are defined as follows based on the rate of MW loss: Direct Trip — Rate of MW Loss >= 15 MW/s Fast Wind-down — Rate of MW Loss >= 3 MW/s & < 15 MW/s Slow Wind-down — Rate of MW Loss < 3 MW/s
TR.4	The TSOs monitor generator units as they run on the power system and can identify that a trip has occurred through analysis of SCADA.
TR.5	<u>Application of charges:</u> A charge applies for all full trips. A charges applies for partial trips for MW losses of 100 MW and greater.
TR.6	<u>Calculation of charges:</u> Trip charge is a function of MW loss, speed of loss of output and an empirical rate. The charge is calculated from the following formulae: Direct Trip Charge = Direct Trip Rate * EXP(0.007 * MW Loss) Fast Wind Down Charge = Fast Wind Down Rate * EXP(0.006 * MW Loss) Slow Wind Down Charge = Slow Wind Down Rate * EXP(0.005 * MW Loss)

5.2.3 Commentary

The empirical charge rates are set to reflect the relative impact of the trip charge categories.

Worked examples of charges for Trips are given in Appendix C.5. Figure 1 below shows the proposed charges varying by increasing MW loss for the Direct Trips, Fast Wind Downs and Slow Wind Down charge types.

Figure 1: Trip Charges v MW Loss (showing the three trip types)



Consideration has been given to making trip charges fully reflective of the overall cost to system that the trip causes. However this would be likely to increase the trip charge very significantly. Considering this and recognising that a level of generator unit tripping is inevitable, it is proposed that full cost recovery via the charge is not attempted.

Consideration was given to imposing differing charges according to system state, such as unavailability of NW tie-line, EW interconnector or amber alert status. However, it was decided that these conditions remain outside of the control of generator units and should not be included in the charge calculations.

Sympathetic tripping was also considered as a parameter in the trip charge. A historic review of trips showed that groups of trips occur more frequently than independent tripping events, which would suggest there is evidence that units trip sympathetically. However it would be very difficult to confirm in settlement timescales that a trip is indeed sympathetic. This situation will be monitored into the future but sympathetic tripping will not be part of the design.

Consideration has been given to include the unit start up cost in the trip charge. The rationale for this would be that after a tripping, the relevant TSO may restart the unit. The SEM may not restart the unit as it has perfect foresight. This would lead to constraint costs which would reflect the unit's submitted start up cost. Including the start up cost in the trip charge would balance out the constraint cost. However the TSOs believe that including a start up cost would bring SEM interaction into what is intended to be an operational charge.

Implementing SEM measures to penalise for trips has also been considered. After analysing different implementation methods, it was decided that dedicated TSO trip arrangements would:

i) simplify the charge calculation

ii) create a transparent charge calculation

iii) incentivise the behaviour required during a trip

iv) avoid re-design of the SEM market scheduler

v) not require alterations to SEM system and/or TSC.

As described in the Section on Short Notice declarations, it is proposed that separate charges are made for Trips and SNDs. The consequence of this is that a single incident at a generator unit may give rise to both an SND charge and a Trip charge

5.3 GENERATOR TESTING CHARGES

5.3.1 Description

New generator units undergo extensive commissioning testing when first connecting to the transmission system. Generator units also carry out many different tests on a regular basis. In order to manage generator unit testing there is an impact on system operation. For example, the TSOs may dispatch out of merit, may increase reserve requirements and may increase run hours on other units. The impact on system operation in turn increases Dispatch Balancing Costs[9] (DBC). Therefore it is appropriate to charge for generator testing.

Major generator unit testing (e.g. testing after refits, major maintenance, and load rejection tests) is catered for in the Trading & Settlement Code (TSC) by putting the unit under test in the SEM. The TSC applies a testing charge to generator units which are formally put under test in the SEM. The testing charge is based on a testing tariff.

5.3.2 Design

The purpose of charging for tests is to encourage generator units to finish testing in a timely manner and also to recover a proportionate level of the DBC incurred by the testing.

The TSOs propose to go forward with two test charge components as follows:

1. Existing SEM Testing Charge:	A basic charge which is representative of the system impact of tests commonly undertaken.
2. Proposed Commissioning Charge:	An additional charge applied by TSOs to commissioning generator units.

[9] Dispatch Balancing Costs encapsulate constraints costs, uninstructed imbalance costs and cost of testing.

Id	**Existing SEM Testing Charge Design Features (No change proposed)**
TC.1	TSC Testing tariffs is reviewed annually.
TC.2	A SEM testing charge applies to all units under test in accordance with the TSC.
TC.3	The generator unit goes under test in the SEM and supplies data in accordance with the TSC and Grid Codes.
TC.4	The generator unit is dispatched by the relevant TSO in a manner to facilitate the specific test.
TC.5	The charge is calculated by the SEM system in accordance with the TSC.

Id	**Proposed TSO Commissioning Charge Design Features**
CC.1	A commissioning tariff is set annually. The rates vary based on both unit size, an assessment of the risk of trip. Three major cost components are considered when calculating the TSO commissioning tariffs. 1. Reserve Constraint: Cost of providing additional operating reserve. 2. Additional Run Hours: Extra run hours of generator units run to cover the instability of a unit under test. 3. Trips & Fast Wind-downs: Cost associated with the tripping of units under test.
CC.2	The TSO commissioning charge applies to new units being commissioned.
CC.3	The generator unit goes under test in the SEM and supplies data in accordance with the TSC and Grid Codes.
CC.4	The generator unit is dispatched by the relevant TSO in a manner to facilitate test.
CC.5	The generator unit is charged a testing charge through the SEM. In addition the generator unit is charged a TSO commissioning charge by the TSO. The TSO commissioning charge is calculated by the relevant TSO once all testing phases are complete. (Generator units progress through test phases while commissioning as the risk of tripping reduces.) The commissioning charge is calculated from meter readings, commissioning tariff based on unit size, system alert state and commissioning test phase.

5.3.3 Commentary

The existing SEM testing tariff mechanism will remain in place until the new arrangements are implemented. The proposed SEM testing tariffs for 2009 are included for information in Appendix E.

The TSOs propose having two testing charge components as this is a practical balance between a complex design and an overly simplified design. The impact of testing on DBC varies widely depending on the test type. The TSOs believe that, relative to the importance of the charge, it would be too complex to cater for each test type with a specific tariff as this would involve a combination of significantly adapting the SEM systems, performing many tariff calculations and establishing involved ongoing processes. The TSOs also believe that applying the same tariff to all test types would either significantly over or under charge for specific test type. From a practical view, there is a step change in DBC between ongoing common testing and commissioning testing. The TSOs proposed design is a compromise between the complex and basic charges which reflect this step change in the testing charge calculation.

The SEM testing charge component will be applied using a testing tariff in accordance with the TSC. The TSOs believe the calculation of the testing tariff should to be relatively straight forward. The tariff is intended to be representative and not to be cost reflective.

Generator units that were commissioned in Ireland in recent years will be familiar with the calculation of the proposed TSO commissioning charge component. The TSO commissioning charge component has a number of proposed features. The application of this simple charging structure reflects the relatively low frequency of occurrence and relatively small costs incurred.

For commissioning purposes, the TSOs operational policies will set out that when a unit goes under test it is placed into a test phase. The phases are banded by the relative stability of the generator unit under test. For example, generator units in phase one are considered most unreliable, those in phase two are slightly more reliable and those in phase three are considered reliable enough not to carry any extra reserve. These phases will be reflected in the commissioning charge. The system alert state is also taken into account. No charge is applied during periods of alert as commissioning units are providing capacity, albeit less reliable capacity.

The cost of TSO commissioning charges will incentivise units to move through the commissioning test phases as quickly and as reliably as is possible. Also a TSO commissioning tariff that varies according to unit size (rather than unit output) allows the recovery of more cost reflective charges for the unit under test. Larger units going under test and failing pose a far greater risk to the transmission system than smaller units failing whilst under test. Once the annual tariff is set, the calculation of the commissioning charge is straight forward and can be easily verified by the generator unit.

The TSO commissioning tariff will be based on three cost drivers – increased reserve constraint, increased running of units and trip charges[10]. Units under test are not exposed to a trip charge. Instead units that are under test for commissioning purposes are assumed to trip unexpectedly a number of times based on historical performance of commissioning units and therefore the charge associated with the trips will be built into the commissioning tariff. It is proposed that during 2009 a remodelling of the cost drivers for commissioning testing charges will be performed using PLEXOS modelling software. This modelling was last undertaken in 2005, the results of which form the basis of the current tariff. Generation costs (and hence the cost in providing reserve and extra run hours) have risen significantly since 2005, mainly driven by the increase in fuel costs. As a result, it is expected that the TSO commissioning tariff would increase significantly.

It should be noted that the testing charges above do not apply to any within day testing and therefore there is no charge for a significant number of common tests agreed between the generator units and the TSO. The treatment of within day testing is being considered by the TSOs and is not in the scope of this consultation.

[10] Further information available in document '2005 Generator Testing Charges Background and Calculation' www.eirgrid.com

6 GENERATOR PERFORMANCE INCENTIVES

6.1 THE PROPOSED APPROACH

The performance standards required and expected of generator units are set out in the Grid Codes and, for unit specific parameters, in Connection Agreements. If generator units do not achieve the specified standards, then the TSOs must arrange to compensate for the shortfall; in doing so, the TSOs incur costs which have to be passed on to other users. In short, performance shortfalls by individual generator units impose costs on all system users.

It is therefore appropriate to put in place arrangements to encourage good generator unit performance.

One proposed aspect of such arrangements is to incentivise generator units to meet the specified standards by applying charges for underperformance. This charging regime should in time be harmonised across Ireland and Northern Ireland. However, so as to make rapid progress in this area, it is proposed that the following approach is taken:

- The charging regime already in place in Northern Ireland will continue in some form on an interim basis.
- A charging regime will be implemented in Ireland, based on current Grid Code parameters and standards. EirGrid will propose a process to achieve this.
- A fully harmonised charging scheme will be developed and implemented.

There are a number of topics that must be covered before a fully harmonised charging scheme can be put into operation. These include:

- The performance parameters to which the charges will apply must be harmonised across the Grid Codes.
- A harmonised standard must be established for each harmonised performance parameter.
- A harmonised derogations process should be in place.
- The formulae (including the values of parameters included in the formulae) used to calculate charges must be harmonised.
- Charging rates must be harmonised
- Harmonised arrangements for monitoring and measuring performance must be in place
- Harmonised arrangements for invoicing and payments need to be ready.

It is envisaged that the TSOs will propose a process to put the above in place. The following description in this document sets out some broad concepts that will need to be addressed.

Relationship to Ancillary Services and other System Charges

Charges for generator unit underperformance would be distinct from and additional to any charges made for the non-delivery of AS, or Other System Charges described in this document.

Charges for the non-delivery of AS arise from the failure to fulfil an AS contract; charges for generator unit underperformance would arise from a failure to meet the terms of the Connection Agreement and its requirement to meet the Grid Code requirements.

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6.2 PRINCIPLES & DESIGN GUIDELINES

The following principles underlie the proposed approach:

Id	Generator Performance Incentives Principles
GP.1	Meeting Grid Code requirements is important and any proposed exceptions should be robustly challenged. All new users of the transmission system should be able to meet the requirements; some old units built before the Grid Code came into force may not be able to achieve Grid Code standards (but should maintain the standards they were built to).
GP.2	All exceptions to Grid Code standards should be encapsulated in RA approved derogations.
GP.3	An approved derogation relaxes a Grid Code requirement and reduces it to a new standard. Consequently, any charges for underperformance apply to the derogated standards rather than the base Grid Code values.
GP.4	Performance of units against standards will be observed by TSOs. If appropriate, TSOs may require a unit to demonstrate that it can meet a particular requirement.
GP.5	Charges for Grid Code underperformance are separate from, and in addition to, any charges for non-delivery under an AS contract.

The following design guideline build upon the principles:

Id	Proposed Generator Performance Incentives Design Guidelines
GD.1	Performance of units against standards are be observed by TSOs. If appropriate, TSOs may require a unit to demonstrate that it can meet a particular requirement.
GD.2	*Charges will be applied to generator units that fail to meet their obligations under the Grid Code.*
GD.3	The charges are proportionate to the costs that the underperformance imposes on the TSOs and, consequently, on other users of the transmission system. Charges are banded to reflect the severity of the deviation from the requirement in the Grid Code.
GD.4	Monies collected through these charges are used to reduce the Dispatch Balancing Costs.

6.3 LEGAL AND CONTRACTUAL FRAMEWORK

The provisions of the Grid Codes are contractually applied through the Connection Agreement. Unit specific requirements may be specified in individual Connection Agreements.

The Grid Codes will be modified to include references to charges for underperformance. In general these provisions will be added where currently there is a provision for disconnection as a sanction: these provisions for disconnection will remain in the Grid Codes. Charges will be applied contractually through the Connection Agreement, by reference to the Grid Code as necessary.

Details of the charges to be levied in the event of underperformance will be included in a separate schedule of charges, which will also be referenced in the Grid Codes. Of necessity certain of these charges may be unit-specific, since they will be related to unit technical parameters. The schedule of charges will be reviewed and approved by the RAs, and will be included in the Connection Agreements for each service provider.

Where a distribution-connected unit is concerned, the generator unit will need to sign up to the appropriate sections of the Grid Code. This would be formally applied by adding a reference to these sections in the generator unit's distribution Connection Agreement.

6.4 INVOICING AND PAYMENT

Charges for underperformance will be separately invoiced on a monthly basis.

6.5 COMMENTARY

The Grid Codes set out requirements that are necessary for the safe, secure, reliable, and economic operation of the systems. Consequently, generator units are required by their licences to comply with the relevant Grid Code. Compliance is seen to be off such importance that the TSOs may disconnect generator units who fail to meet their obligations. Whilst this sanction would be employed in the event that non-compliance threatened safe, secure, or reliable operation of the system, it is clear that this extreme measure might be difficult to invoke where impacts were of a more limited and economic nature. This likelihood is reinforced when the overall system margin is low.

Nonetheless, such non-catastrophic underperformance may impose considerable financial impacts on other users of the transmission system. In essence, in response to such an occurrence the TSO will need to manage the system in a way that diverges from the planned optimum established assuming the compliant performance of all generator units. A typical outcome of this is that constraint payment costs are increased, and these must be recovered from other transmission system users.

It is expected that appropriate charges would encourage performance in accordance with Grid Code standards, and hence help minimise costs to other users of the transmission system.

6.6 RELATIONSHIP WITH DEROGATIONS

A Grid Code derogation is a relaxation of the obligation to satisfy a particular provision of the Grid Code.

It is proposed that a derogation should remove any charge for underperformance associated with the Grid Code requirement for the derogated provision. However, the approved derogation should specify a lesser requirement (and appropriate charges for underperformance), in which case charges will apply to that standard instead of the original Grid Code value.

Consequently, generator units granted a derogation would still be liable to pay any charges associated with underperformance against the adjusted obligation. Further, in some cases a derogation may be granted subject to compensation payments.

6.7 CHARGES

It is proposed that charges for underperformance be applied under harmonised arrangements in relation to the following parameters. This list of parameters is derived from current practice in Northern Ireland.

Parameter	
Minimum Load (Min Generation)	**Ramp Up Rate**
Operating Reserve	**Ramp Down Rate**
Frequency Regulations	**Min synch time hot**
Fault Ride Through	**Min synch time warm**
Reactive Power lagging	**Time to synchronise**
Reactive Power Leading	**Time from Synchronising to min load**
Minimum Down Time	**Time to deload from min load**
Minimum Up Time	**Max number of starts in 24hr period**

A specific charging methodology will be developed for each of the above parameters. In summary, the charging methodology will comprise the following harmonised elements:

- Parameter
- Standard from Grid Code
- How measured
- Charge principle

7 OTHER CONSIDERATIONS

7.1 CURRENCY

7.1.1 Rates

Harmonised rates (except for Black Start) will be quoted in the local currencies of each TSO and will be reviewed and adjusted annually to reflect the impact of variations in exchange rates.

7.1.2 Invoices and Payments

Payments for AS and other payments and charges will be invoiced and made in the local currency of the TSO. There will be no adjustments for currency variations within year or through the settlement and payment cycle.

The VAT rate associated with the particular jurisdiction will be applied.

8 INSTRUCTIONS FOR RESPONSES

Views and comments are invited regarding all aspects of this document.

Responses should be sent to

Conor.Kavanagh@EirGrid.com and Leslie.Burns@SONI.ltd.uk by 28th October 2008

It would be helpful if comments are aligned with the sections and sub sections of this consultation document. It would be helpful if responses are not confidential. If confidentiality is required, this should be made clear in the response. Please note that, in any event, all responses will be shared with the RAs.

9 NEXT STEPS

The following overall timetable has been established

Briefing Session	Wednesday 1st October 2008
Consultation Concludes	Tuesday 28th October 2008
Q4 2008	TSOs submit participants'consultation comments and final detailed AS proposals to the SEM Committee for approval.
Q4 2008	SEM Committee publishes detailed decision paper on AS
Q4 2008 - Q2 2009	TSOs implement detailed decisions followed by "go-live" (Highly dependent on the decisions reached and the systems selected to settle.)

APPENDICES

APPENDIX A. INDUSTRY VIEWS

A.1 INTRODUCTION

On 28th February 2008, the Regulatory Authorities published a High Level Decision paper[11] setting out their policy framework for the development of harmonised arrangements for Ancillary Services and System Support Services (AS/SSS) on the island of Ireland. This Paper also addressed the topics of system charges and Grid Code compliance.

Subsequently, EirGrid and SONI held two workshops on the 29th April and 1st May, 2008 to initiate a consultative dialogue with all interested parties on the detailed design and implementation of the harmonised arrangements.

The workshops provided an opportunity for Market Participants and other stakeholders to inform the TSOs' and RAs' thinking of how to implement harmonised Ancillary Services on the island. Over sixty people attended the two workshops, which were designed to be highly interactive events.

The workshops took the format of a series of presentations by the TSOs and RAs on each of the unbundled Ancillary Services[12], with workshop participants being encouraged to offer their own thoughts. In addition, the workshops discussed generator unit performance and sought views on how associated incentives might be implemented.

A comprehensive note of the workshop discussions was subsequently issued in May 2008 and all interested parties were asked to provide further comment through written responses to the TSOs.

EirGrid and SONI would like to thank all those who participated at the workshops and/or sent in written responses on this important topic. These contributions have been extremely helpful in informing the development and evaluation of the detailed proposals contained in the main body of this consultation paper

Notes of the workshop discussions are available on the AIP website[13], together with a copy of the slides presented on the day.

This Appendix seeks to summarise additional points from the written responses that were received by the TSOs. It, therefore, does not seek to replicate all of the comments previously captured from the workshops, but instead to focus on common themes and new views/comments not previously aired and published. All views are unattributed.

It should be noted that the comments received are not mutually exclusive and in many cases a range of views on a given topic was forthcoming. However, in the majority of cases, commonality of view was more prevalent than any differences expressed.

EirGrid and SONI do not seek to provide in this Appendix a commentary on the views expressed. Instead, all views have been considered and addressed in the main body of this consultation paper. Hence, the reader is referred to the main body of this paper for an explanation of the TSOs' deliberations and recommendations.

[11] SEM 08-013
[12] Black Start, Operating Reserve, Reactive Power, and Other Services.
[13] www.allislandproject.org

A.2 WORKSHOP RESPONSES

A.2.1 General

All respondents welcomed the workshops and the opportunity to provide comment on the proposals. There was universal agreement that the process was useful.

A number of general themes emerged, which were not specific to a given service:

- Transparency, predictability, certainty and clarity are essential.
- Unbundling of Ancillary Services was welcomed.
- Detail of proposals awaited.
- Impact on Annual Capacity payment pot needs to be clearly communicated.
- Importance of Ancillary Services is set to increase significantly over the short to medium term because of the projected large increase in renewables.

Additional points included:

- "Causer" should pay for Ancillary Services.
- Appropriate mix of penalty and reward is required – too greater emphasis on penalties will increase risk to investors and costs to customers.
- Further substantive detail on the specific key objectives of harmonisation should be included in the consultation.
- Legacy PPA contracts in Northern Ireland must be taken into account – unbundling Ancillary Services from the PPAs would be complex, potentially requiring legislation.
- Unbundling should recognise the ancillary service capabilities of existing generator units.
- The decision not to increase significantly the overall Ancillary Services pot will limit the scope for change without playing off one Ancillary Service against another, which is undesirable.
- Penalty payments could be used to fund additional Ancillary Services.
- Clarification requested on whether an Ancillary Service provided via a distribution connected device is recompensed for the value it provides to the transmission system?
- The value of Ancillary Services to the island of Island is not significantly recognised by the current size of the combined Ancillary Services pot for the island.
- Cost, administration or complexity of payment calculations should not unduly influence the design of any incentive mechanism, given the critical nature of the services being procured and provided.

- A clear and established methodology is required for determining the various Ancillary Service revenue streams and these should not be arbitrarily capped by the size of the existing Ancillary Services pot.

A.2.2 Reserve

Common themes focused on:

- Stable revenue stream required – implies a simple price structure, with availability preferred.
- Payment pot should not be fixed - a fixed annual pot per service dilutes revenue streams as more availability is offered, discouraging new investment.
- Rebates of payment are reasonable where a generator unit fails to deliver a Reserve service for which they had declared their availability.
- Contracts should be public, open and transparent – with all rates published.

A number of additional points were also made:

- Operating Reserve is the Ancillary Service requiring the greatest focus – due to materiality and the interaction with the SEM (energy and capacity).
- TSOs need to make a clear statement of which costs are being minimised, where prices are bid or tendered prices are optimised. This assessment needs to discriminate between total cost minimisation and the minimisation of Reserve alone.
- Harmonisation of Grid Code definitions for Operating Reserve is a pre-requisite.
- Risk that the regulated price for Reserve under values the provision of Reserve.
- Smart metering could contribute to the economic provision of Ancillary Services.
- Water based heat storage can be used to allow heating related loads to be interrupted to reduce the need for Operating Reserve.
- Need to facilitate legacy plant characteristics and contracts (e.g. PPB) – for example, through Grid Code derogations.
- Pumped storage should be appropriately rewarded for the provision of Operating Reserve.
- Wind generators should not be excluded from eligibility for Operating Reserve payments in the future.

A.2.3 Reactive Power

Common themes focused on:

- Simple price structure – with weighting in favour of availability over utilisation, as this can be controlled by the service provider.

- Fixed payment for availability – significant variable element based upon utilisation is unnecessary as already provided through capacity payments.

- Payments should be rebated in full where a generator unit is unable to deliver its declared Reactive Power capability, payable until it next reproves.

- There was a diversity of view over the merits of locational payments for Reactive Power payments, but a general agreement that more debate is required.

A number of additional points were also made:

- Price paid for Reactive Power should be related to the cost of producing Mvars, based upon plant efficiency reductions and cost of maintenance.

- The more the payment is split into components - such as availability, utilisation, controllability and location - the less transparent and predictable it becomes.

- Metering should be at the point of connection and moving to the LV side of grid transformers would be unnecessary and costly.

A.2.4 Black Start

The written responses largely reiterated the points made in the workshop, most notably:

- Transparency, certainty and an early indication is required by developers.

- Intention to publish a list of minimum criteria welcomed.

- Technical parameters should be clearly set out.

- Prices should reflect cost of provision and provide a competitive rate of return.

- Testing and verification of Black Start capability should be an integral part of any proposals developed and consulted on by the TSOs.

A number of additional points were also made:

- A common definition of Black Start is required (e.g. site v. unit approach).

- All units on the system should be neutral to dispatch constraint costs introduced by Black Start testing, due to the Unconstrained Schedule and cost reflective bidding principles in the SEM. Constraint costs could be recovered from the Market Imperfections Charge or from Ancillary Services monies.

- Penalties for failures should reflect the reasonable endeavours of a generator unit to subsequently remedy faults which occurred on test and should not depend upon (infrequent) Black Start retests before being removed.

- Is there a requirement for a supplier of last resort?

- Demand could be held-off or limited for a period to reduce Black Start requirement.

- Black Start should encompass the environmental complexity of carbon as part of the costs to be recovered.

A.2.5 New Services

A number of common themes emerged:

- Reward needed for services valuable to the operation and security of the transmission system, which are not provided by the SEM.
- Additional services to reward flexible, thermal plant needed to support large amounts of 'base load' wind energy. Should specifically provide incentives for flexibility in plant operation and/or investment in new flexible plant.

A number of additional services or service providers were suggested:

- Dual fuel capability. Payment could be linked to the amount of secondary fuel storage and the cost of providing the capability.
- Costs associated with secondary fuelling that cannot be recovered from the SEM should be recoverable via an Ancillary Services payment.
- Short Term Maximisation.
- Specialist Ancillary Services, such as installation of synchronous compensators, automatic generator control, power system stabilisers and mechanical inertia.
- Load management to provide fast response/frequency control.
- Generator aggregation platforms could be used as an Ancillary Service.

Additional points regarding new services included:

- Economic attractiveness of providing new services to the TSOs as Ancillary Services will depend upon size of payment being greater than any Capacity Payments forgone from the SEM.
- Demand side should be incentivised to deliver Ancillary Services.

A.2.6 Generator Performance Incentives

Common themes focused on:

- Meeting Grid Code standards is important for the safety and reliability of the transmission system.
- Penalties should be proportional and reasonable; seeking to incentivise performance/compliance, whilst focusing on what is technically possible.

- Penalties should not be imposed where Derogation exists, as they are deemed to be "Grid Code" compliant.

Additional points raised, included:

- Penalties and/or rebates collected from under performing generator units should be redistributed to those generator units that have been called upon to provide additional services in their place.

- Different connection standards need to be harmonised.

- Threshold levels for penalties should depend upon technology and fuel type of unit.

- Costs to consumers should not be increased by the imposition of penalties.

- Parameters for measuring Grid Code compliance (or deviation), should be those that have a material impact on the operation of the transmission system.

- A Minimum Functional Specification (MFS) for new plant should sit alongside the Grid Code. Only new plant meeting the MFS can connect to the system. For such plant, derogations from the Grid Code would be for a limited time and require the generator unit in question to pay a "buy out" sum.

- Existing derogations should be grandfathered, except those which are temporary which need to be addressed to ensure that plant is incentivised to comply with the Grid Code.

- Appropriate, application fees should be charged for derogations, which reflect the administrative costs associated with processing the application.

- Blanket annual testing of Grid Code compliance is excessive and would impose a drain on resources.

- If penalties are applied to a plant where a technical solution does exist, a generator unit should be able to make a commercial trade off between paying penalties and the cost of modifying the plant.

- It would be unreasonable to impose penalties which exceed the cost of alternative provision.

- The robustness and cost effectiveness of determining penalty costs via modelling was questioned.

- If a net benefit of a non Grid Code compliant generator unit being on the system exists, then they should not be subject to polluter pays penalties.

- The Short Run Marginal Cost (SRMC) bidding principles, which are enforced on generator units by Licence Conditions, also require consideration in the assessment of the impact of penalties – i.e. should these costs form part of a generator unit's SRMC and therefore be included in its bid?

APPENDIX B. INDICATIVE PAYMENT & CHARGE RATES

Table 1: Indicative Ancillary Services Payment Rates for Calculations

Service	**Payment Rate**		**Charge**
Operating Reserve			
Primary Operating Reserve	€1.00/MWh	£0.79/MWh	Separate charge for each category equivalent to 1 month's payment pro rata'd by underperformance
Secondary Operating Reserve	€0.90/MWh	£0.71/MWh	
Tertiary 1 Operating Reserve	€0.80/MWh	£0.63/MWh	
Tertiary 2 Operating Reserve	€0.70/MWh	£0.55/MWh	
Replacement Reserve	€0.60/MWh	£0.47/MWh	
Reactive Power			
Lagging & Leading	€0.15/Mvarh	£0.12/Mvarh	Equivalent to 1 month maximum payment
Black Start			
ESB Aghada	€65.78/h	NA	Partial Fail Equivalent to 1 month maximum payment Outright Fail Equivalent to 3 month maximum payment
ESB Ardnacrusha	€23.21/h	NA	
ESB Erne	€22.40/h	NA	
ESB Lee	€9.98/h	NA	
ESB Liffey	€8.16/h	NA	
ESB Turlough Hill	€82.98/h	NA	

Table 2: Indicative Operational Charges Rates for Calculations

Charge	**Charge Rate**	
Short Notice Declaration	€100/MW	£79/MW
Direct Trip	€5,000	£3,939
Fast Wind Down	€4,000	£3,151
Slow Wind Down	€3,000	£2,363

APPENDIX C. WORKED EXAMPLES

This appendix gives worked examples to enhance the understanding of the design proposals set out in the main body of the consultation paper. Sterling figures are omitted where it is impractical to fit them in the page.

C.1 RESERVE

Table 3: Example of payment for ½ hour trading period for a generic category of Reserve

Payment Example *per Reserve Category*		Capability / Availability: Contracted [MW]	Capability / Availability: Declared [MW]	Capability / Availability: Actual [MW]	Payment Rate Setting: Annual Rate [€/MWh]	Payment Rate Setting: Declare/Contract Scaling Factor	Payment Rate Setting: ½ h Trading Period Rate [€ / MW ½TP]	½ h Trading Period Payment [€]
		A	B	C	D	E = B/A	F = D*E*0.5	G = C * F
OMP.1	Dispatched to max output	30	30	0	0.70	100%	0.35	0
OMP.2	Dispatched to max reserve	30	30	30	0.70	100%	0.35	10.5
OMP.3	Max Declared ≠ Contract	30	20	20	0.70	67%	0.2335	4.67
OMP.4	Declared off for Reserve	30	0	0	0.70	0%	0	0

Table 4: Example of annual payment estimate for a generic category of Reserve (ex charges)

Annual Payment Example *per Reserve Category*	½ h Trading Period Payment	Number of Trading Periods	Annual Payment
	[€]	(Unit always on)	[€]
	A	B=365*24*2	= A * B
OMAP.1	0	17,520	0
OMAP.2	10.5	17,520	183,960
OMAP.3	4.67	17,520	81,818
OMAP.4	0	17,520	0

Table 5: Example of applicable charge for single failure to provide a generic category of Reserve

Charge Example	Declared Availability	Expected Provision	Actual Provision	Annual Rate	Charge
	[MW]	[MW]	[MW]	[€/MWh]	[€]
		A	B	C	= (A-B) * C *24 *30
OMC.1	0	0	0	0.70	0
OMC.2	30	30	30	0.70	0
OMC.3	30	20	20	0.70	0
OMC.4	30	20	10	0.70	5,040
OMC.5	30	20	0	0.70	10,080

C.2 Reactive Power

Table 6: Example of payment for ½ hour trading period for Reactive Power

Payment Example (Part 1 of 2)		Unit Synchronised	Contracted Range		Declared/Calculated Values		
			Lead	Lag	Lead	Lag	AVR Status
			[Mvar]	[Mvar]	[Mvar]	[Mvar]	[On or Off]
			A	B	C	D	E
RP.A		No	-	-	-	-	-
RP.B	Base case	Yes	70	90	70	90	On
RP.C	AVR Off	Yes	70	90	70	90	Off
RP.D	Declared Off	Yes	70	90	0	0	On
RP.E	Declare ≠ Contract	Yes	70	90	40	60	On

Payment Example (Part 2 of 2)		Payment Rate Setting				½ h Trading Period Payment
		Annual Rate	Declare/Contract Scaling Factor	AVR Factor	½ h Trading Period Rate	
		[€/Mvarh]	[%]	[2 or 1]	[€Mvar/ ½TP]	[€]
		F	G = (C+D)/(A+B)	H from E	I= F*G*H*0.5	=(C+D)*I
RP.A		-	-	-	-	0
RP.B	Base case	0.15	100%	2	0.150	24.00
RP.C	AVR Off	0.15	100%	1	0.075	12.00
RP.D	Declared Off	0.15	0%	2	0.000	0
RP.E	Declare ≠ Contract	0.15	63%	2	0.094	9.38

Table 7: Example of annual payment estimate for Reactive Power (ex charges)

Annual Payment Example		Contracted Range	Average Declared/ Calculated Range	% AVR On	Payment Rate	Time Sync'ed	Annual Payment
		[Mvar]	[Mvar]		[€/Mvarh]		[€]
RPAP.A	Regular Service, Regular Sync	160	150	85%	0.26	40%	136,738
RPAP.B	High Service, Regular Sync	160	160	95%	0.29	40%	163,987
RPAP.C	High Service, High Sync	160	160	100%	0.30	95%	399,456
RPAP.D	Low Service, High Sync	160	100	0%	0.09	95%	78,019
RPAP.E	Low Service, Low Sync	160	100	100%	0.18	20%	32,850

Table 8: Example of applicable charge for single failure to provide Reactive Power

Charge per Confirmed Failure Example	Contracted Values		Charge Rate Setting			Charge
	Consumed	Produced	Annual Rate	AVR Factor	½ h Trading Period Rate	
	[Mvar]	[Mvar]	[€Mvar/h]	[@ Max]	[€Mvar/ ½TP]	[€]
RPC.A	70	90	0.15	2	0.15	34,560

C.3 BLACK START

Table 9: Example of payment for ½ hour trading period for Black Start

Payment Example	Generator Site Availability	Black Start Facility Availability	Contracted Black Start Rate	Half Hour Trading Period Payment
			[€/h]	[€]
			A	= A * ½ hour
BSP.1	Yes	Yes	50	25
BSP.2	No	Yes	50	0
BSP.3	Yes	No	50	0

Table 10: Example of applicable charge for single failure to provide Black Start

Charge Example	Failure Type	Contracted Black Start Rate	Charge
		[€/h]	[€]
		A	Partial =24*30*A; Outright=24*30*A*3
BSC.1	Partial Failure	50	36,000
BSC.2	Outright Failure	50	108,000

Table 11: Example of annual payment estimate for Black Start (including examples with charges)

Annual Payment Example	Contracted Black Start Rate	Combined Unit & Black Start Facility Availability	Number of Failures	Annual Payment	
	[€/h]	[%]		[€]	
	A	B		=365*24*90%*A - Charge	
BSAP.1	50	90%	0	394,200	= Annual Payment
BSAP.2	50	90%	1 Partial	358,200	= Annual Payment – 36,000
BSAP.3	50	90%	1 Outright	286,200	= Annual Payment – 108,000
BSAP.4	50	90%	4 Outright	(37,800)	= Annual Payment - (4*108,000)

C.4 SHORT NOTICE DECLARATIONS

The SND charge is calculated based on a MW reduction, SND Charge Rate and Notice-time weight using the following formula:

SND Charge = MW Reduction * SND Charge Rate * Notice Time Weight

The SND charge rate is set annually. This consultation paper indicatively sets the rate at €100/MW.

The Notice-time weight is obtained from a graph of Notice Time Weighting which produces a weight between 0 and 1 which is shown below in Figure 2. The curve is flat from zero minutes notice to 5 minutes (This is not apparent from Figure 2.) After 5 minutes notice, it is practical for the TSO to dispatch additional plant in order to recover from the lost availability. The curve is shaped to capture that "every minute counts" for the first while and it lessens off out to 12 hours notice.

Figure 2: Notice-Time Weighting Factor Graph

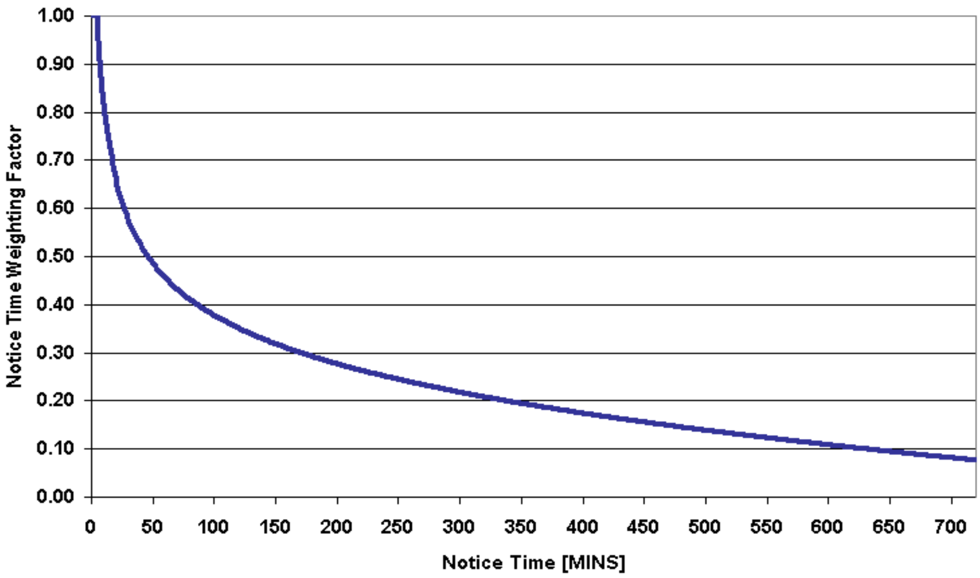


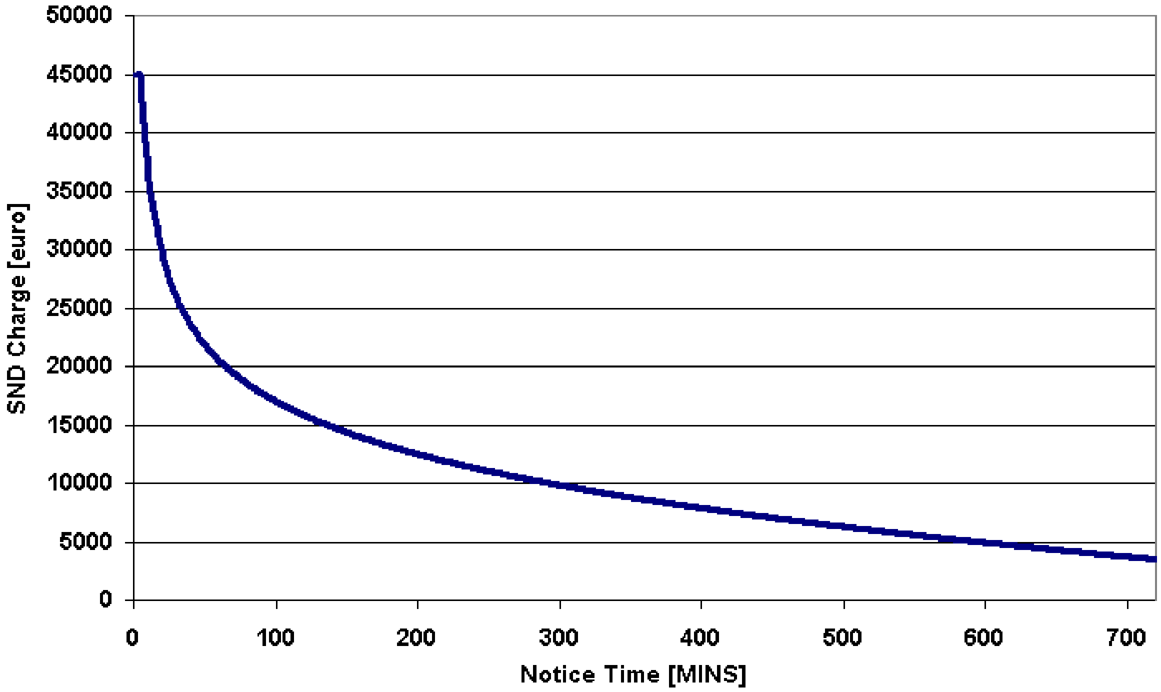
Table 12 below shows sample SND charges based on the SND Charge Rate of €100/MW.

Table 12: Examples of SND Charges

Notice Time	MW Reduction	Weight	Charge	
[min]	[MW]	[-]	[€]	[£]
0	10	1	1,000	788
0	200	1	20,000	15,760
0	450	1	45,000	35,447
100	10	0.378	378	298
100	200	0.378	7,560	5,955
100	450	0.378	17,010	13,399
240	10	0.25	250	197
240	200	0.25	5,007	3,944
240	450	0.25	11,266	8,874
720	10	0.076	76	60
720	200	0.076	1,524	1,200
720	450	0.076	3,430	2,702

Figure 3 below is a sample charge curve for a reduction of 450MW with varying notice time, the rate used to calculate the charge is based on the indicative SND charge rate of €100/MW.

Figure 3: Graph of SND charges for 450 MW unit with increasing notice time



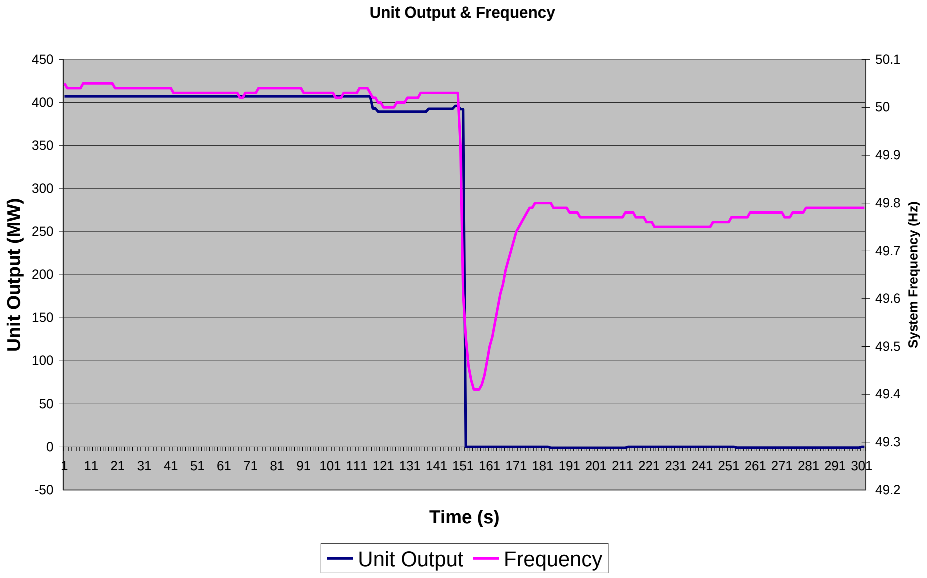
C.5 TRIPS

This section of the appendix outlines the varying effect on the power system frequency for various trip categories and in each case it calculates the applicable charge which would apply based on the proposed charge design and indicative rates.

C.5.1 Direct Trip

Figure 4 below outlines the typical impact on the power system of a 400 MW unit directly tripping from the power system. The power system frequency (shown in purple) drops from 50 Hz to 49.4 Hz in less than 10 seconds following the direct trip and recovers to 49.8 Hz in approximately 20 seconds.

Figure 4: Typical frequency dip associated with a Direct Trip



The Direct Trip charge is calculated as follows:

The MW Loss = 408.42 MW

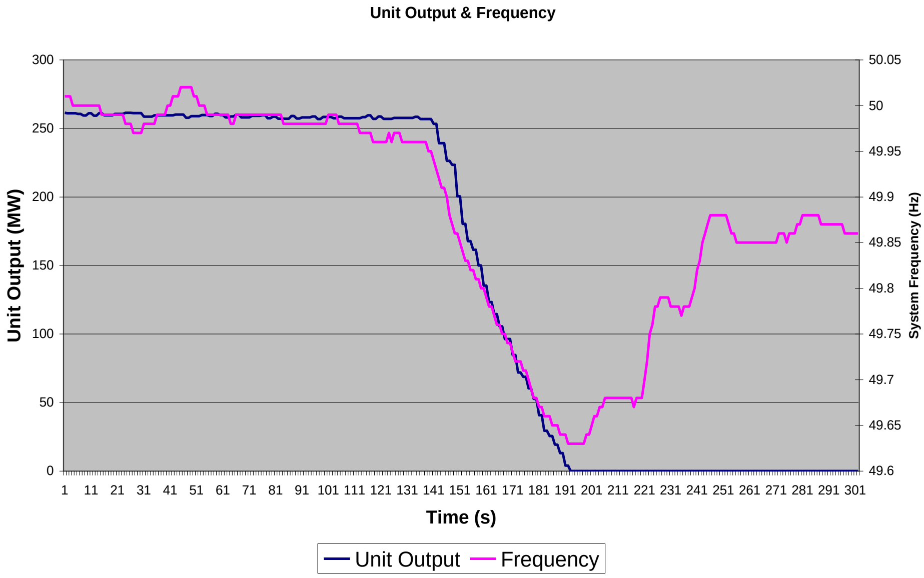
Rate of Loss = 102.1 MW/s which is categorised as a Direct Trip

The Direct Trip Charge = 5000 * EXP(0.007 * MW Loss)
= 5000 * EXP(0.007 * 408.42)
= € 87, 215.14
= £ 68, 700 (approximately)

C.5.2 Fast Wind-Down

Figure 5 on the next page outlines the typical impact on the power system of a 250 MW unit winding down fast from the power system. The power system frequency (shown in purple) drops from 50 Hz to 49.65 Hz over 50 seconds following the fast wind down and recovers to 49.85 Hz in approximately 2 minutes.

Figure 5: Typical frequency dip associated with a Fast Wind Down



The Fast Wind Down charge is calculated as follows:

The MW Loss = 259.55 MW

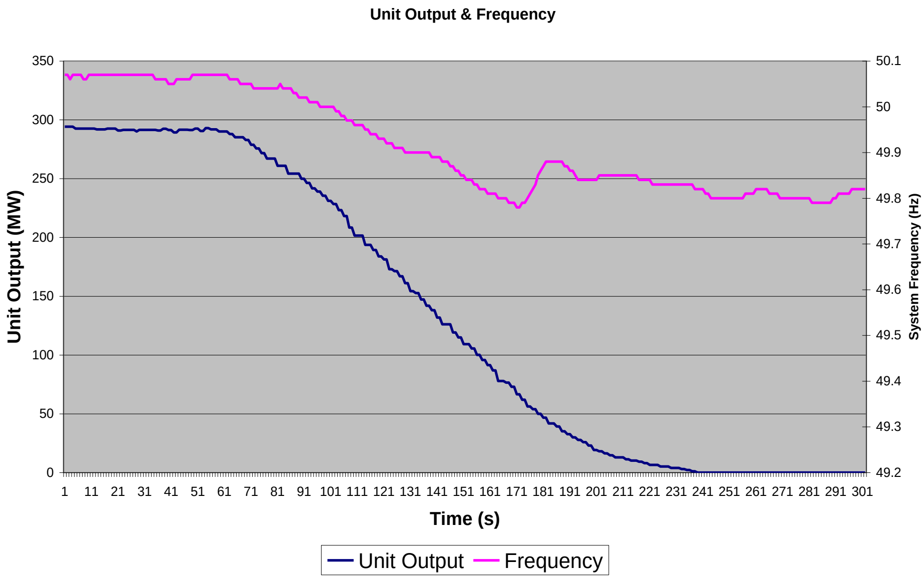
Rate of Loss = 3.415 MW/s which is categorised as a Fast Wind Down

The Fast Wind Down Charge = 4000 * EXP(0.006 * MW Loss)
= 4000 * EXP(0.006 * 259.55)
= € 18, 983.96
= £ 14, 950 (approximately)

C.5.3 Slow Wind-Down

Figure 6 below outlines the typical impact on the power system of a 300 MW unit winding down slowly from the power system. The power system frequency (shown in purple) drops from 50 Hz to 49.8 Hz over 2 minutes following the direct trip. Unlike the previous two examples there is no low frequency spike. Avoiding such a spike is clearly beneficial to support power system security.

Figure 6: Typical frequency dip associated with a Slow Wind Down



The Slow Wind Down charge is calculated as follows for the example show on the previous page:

The MW Loss = 294.21 MW

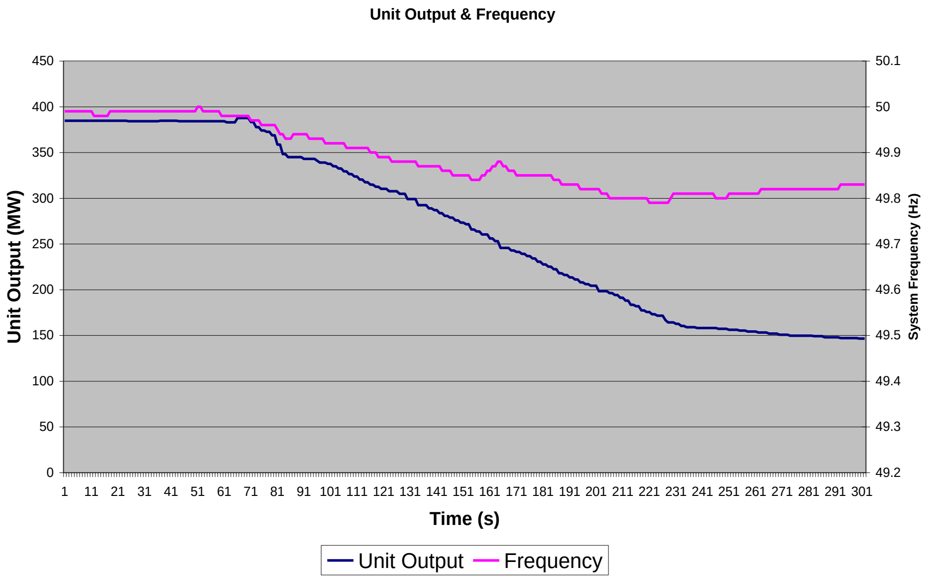
Rate of Loss = 1.592 MW/s which is categorised as a Slow Wind Down

Slow Wind Down Charge = 3000 * EXP(0.005 * MW Loss)
= 3000 * EXP(0.005 * 294.21)
= € 13, 061.41
= £ 10,300 (approximately)

C.5.4 Partial Trip

Figure 7 below outlines the typical impact on the power system of a 400 MW unit partially tripping. The generator unit drops its output by 250 MW. The rate of MW loss is such that the partial trip is categorised as a slow wind down. The power system frequency (shown in purple) drops from 50 Hz to 49.8 Hz over 2.5 minutes following the direct trip. As in the Slow Wind Down trip example there is no low frequency spike.

Figure 7: Partial Trip and Slow Wind Down



This Partial Trip Charge example is calculated as follows:

The MW Loss = 241.13 MW

Rate of Loss = 1.048 MW/s which is categorised as a Slow Wind Down

Slow Wind Down Charge = 3000 * EXP(0.005 * MW Loss)
= 3000 * EXP(0.005 * 241.13)
= € 10, 016.79
= £ 7, 900 (approximately)

APPENDIX D. EXAMPLE FOR OF GENERATOR PERFORMANCE INCENTIVES

D.1 DESCRIPTION

Section 6 describes the approach that will be taken to applying charges to Grid Code Parameters so as to create Generator Performance Incentives. As an example, this appendix shows how one parameter ("Time to Synchronise") might be incentivised via observations of early or late synchronisation. At this stage, the following should be considered as an illustrative example only.

A TSO issues a dispatch instruction to a generator unit to synchronise with the system at a defined time taking into account its declared availability and start-up time. If the generator unit does not achieve synchronisation at the instructed time then the TSO must, at short notice, change the dispatching of other units to account for the unexpected late or early synchronisation of the unit: this would result in an increase in constraint costs.

The late or early synchronisation charge is designed to incentivise synchronisation at the instructed time.

D.2 DESIGN

The basis of the design will be as described in the table below.

Id	Proposed Late Synchronisation Design Features
LS.1	If a unit has not achieved synchronisation more than 5 minutes after the instructed time, then a late synchronisation charge applies.
LS.2	The late synchronisation charge is proportional to the availability of the unit (in MW) prevailing at the instructed synchronisation time.
LS.3	The late synchronisation charge increases linearly dependent on the length of delay in synchronising, up to a maximum of a one hour delay.
LS.4	If a unit does not achieve synchronisation within one hour of the instructed dispatch time, then the unit is deemed unavailable from the instructed dispatch time, with a deemed notice of 5 minutes. The unit is therefore liable for a Short Notice Declaration Charge as defined in Section 5.1.
LS.5	If a unit synchronises with the system more than 15 minutes earlier than instructed by the TSO, then an early synchronisation charge applies.
LS.6	The early synchronisation charge is proportional to the availability of the unit (in MW) prevailing at the instructed synchronisation time.
LS.7	The early synchronisation charge increases linearly dependent on how far in advance of the instructed time that synchronisation takes place.

D.3 COMMENTARY

A unit which fails to synchronise on time may incur other charges which will be levied in addition to the early or late synchronisation charges. These might include:

- Any uninstructed imbalance charges that may be incurred in the SEM.
- Any short notice declaration charges that are incurred.
- Any trip charges that are incurred.
- Any charges that are incurred as a result of failing to achieve contracted reserve response.

APPENDIX E. SEM TESTING TARIFF FOR 2009

The consultation paper refers to considers charges for testing. The TSOs have proposed two charge components for generator testing. The first is the existing SEM testing charge which is levied through SEM systems. The second is a TSO levied charge. As there is a strong link between the two charges it has been deemed appropriate to refer to the SEM testing charge while not making any new proposals on it design.

It is the RAs intention to inflate the 2008 SEM testing tariff pending the implementation of the harmonised arrangements discussed in this consultation paper. For information, Table 13 below sets out the 2008 SEM testing tariff values which will be inflated suing an RA-approved inflation rate.

Table 13: SEM Testing Tariff 2008 which will be inflated for 2009

2008 Testing Tariff	
Single Test Phase	
Unit Capacity [MW]	**[€/MWh]**
GEN ≤ 50	3.53
50 <GEN≤ 100	3.28
100 <GEN≤ 150	3.48
150 <GEN≤ 200	4.06
200 <GEN≤ 250	4.82
250<GEN≤ 300	6.01
300 <GEN≤ 350	8.31
350 <GEN	11.12