Harmonised Ancillary Services
&
Other System Charges

Rates Consultation

8th June 2009

SEM-09-062

System Operator for Northern Ireland

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1 SUMMARY

Ancillary Services are products, other than energy, that are required to ensure the secure operation of the transmission system. The Transmission System Operators (TSOs), EirGrid in Ireland and SONI in Northern Ireland, are charged with providing a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary Ancillary Services (AS).

AS payments and Other System Charges are paid/levied outside the Single Electricity Market (SEM) by the TSOs. The structure, treatment and arrangements of these payments and charges are different in Ireland and Northern Ireland. The harmonised arrangements refer to the harmonisation of the payments and charges to service providers and system users. The harmonised AS rates, which are the subject of this consultation paper, form part of the arrangements. The harmonised arrangements are scheduled to "Go-Live" on the 1st October 2009 and the harmonised all-island rates to be set until the end of that tariff year – 30th September 2010.

These payments & charges will be specified in a statement of payments and charges approved by the regulators in Ireland and NI. The arrangements will be defined in both jurisdictions through the Ancillary Services policies, the statements of payments and charges and the Ancillary Service agreements. These arrangements are secured through direct contracts between the TSOs and the service providers.

More specifically, the harmonised AS and Other System Charges are reserve payments, reactive power payments, black start payments, trip charges, short notice declaration charges and generator performance incentive charges. This consultation paper gives participants an opportunity to comment on the harmonised all-island rates, empirical values used in calculations and the derivation of the short notice declaration charge calculation. This paper follows on from a previous consultation paper on the policy designs and implementation decision paper.

Details of how to respond to this consultation are included in Section 9 of this paper. The TSOs will host a briefing session to discuss the paper on Wednesday, 24th June 2009. Responses are due on Monday, 6th July 2009.

2 INTRODUCTION

2.1 THIS DOCUMENT

This document follows on from a number of consultation and decision papers. The previous decisions are not for consultation here. Where views and comments are sought from participants throughout the paper, the sub-section titles begin with the word "Proposed".

This document sets out proposed harmonised all-island rates in the following areas:

- Ancillary Services (Section 4)
- Other System Charges (Section 5)
- Generator Performance Incentives (Section 6)

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.

The rates are proposed for the first tariff year only from the scheduled harmonisation "Go-Live" date of 1st October 2009 to 30th September 2010. While the arrangements remain in place, the rates will be reviewed annually thereafter as system needs and service availabilities evolve. In particular, the addition of potential new services in the future, as provided for in the Regulatory Authority's decision paper will provide for balancing of intermittent generation.

The document also outlines the other developments in this implementation phase of the harmonisation project (Section 7), summarises associated developments beyond this harmonisation project (Section 8), sets out arrangements for submitting responses (Section 9), and the next steps which it is envisaged will lead to the implementation of the harmonised AS arrangements (Section 10). An appendix is also included which sets out the arrangement with regard to the Generator Performance Incentives and provides representative examples of the application of the combined harmonised policies, designs and rates.

The TSOs will host a briefing session on Wednesday 24th June 2009 to discuss the consultation paper, clarify any issue the participants may have and provide information on the transition from the current arrangements to the new harmonised arrangements.

2.2 GENERATOR TESTING, SECONDARY FUEL & RESERVE CAUSATION

The topics of generator testing charge, secondary fuel test compensation payment and reserve causation charge were referred to in the previous consultation papers. These three topics have been excluded from this consultation paper. They are to be treated as follows:

Generator Testing has two aspects - Generator Commissioning charges and SEM Testing tariffs – which are now subject to another all island consultation which will be published shortly after the publication of this consultation. One exception to general generator testing is black start testing which is included in this consultation.

Secondary fuel compensation payments are subject to a separate Ireland only jurisdiction consultation which will be published in Q3 2009.

A policy on the Reserve causation charge will be developed by the TSOs and presented to the Regulatory Authorities in Q3 2009.

2.3 BACKGROUND

In September 2006 the RAs approved(1) the continuation of separate commercial arrangements for AS and related charges within Ireland and Northern Ireland for "Day 1" of the SEM - the "Go-Live" date, 1st November 2007 - pending a full and proper review of suitable harmonised all-island arrangements for the longer-run.

As part of this review process, in August 2007 the RAs published a consultation paper(2) by the TSOs, SONI and EirGrid. This set out the high-level harmonised all-island policy options for AS and other system operations related payments/charges, for implementation at some stage post the SEM's "Go-Live" date.

Following this consultation period the SEM Committee issued a high-level decision (HLD) paper on 27th February 2008 that 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. The HLD paper established the high-level policy framework for the development of the proposed harmonised AS arrangements, and also addressed other payments and charges and generator performance incentives.

Following the publication of the HLD paper, the TSOs organised industry workshops on 29th April 2008 and 1st May 2008 on the detail of the possible services and invited feedback from participants. In September the RAs published a consultation paper(3) containing the TSOs' detailed proposals for implementing harmonised arrangements for AS, other generator payments and charges, and generator performance incentives. This consultation paper was the subject of an industry briefing session on 1st October 2008, chaired by the TSOs and involving both RAs, to explain the proposals.

The RAs reviewed the comments received to this consultation paper and the SEM Committee subsequently made decisions in January 2009(4) (referred to in the paper as "RAs' January paper") on the future implementation of harmonised arrangements for ancillary services, other related payments/charges and generator performance incentives across the island in the SEM, for implementation from 1st October 2009. This rates consultation paper is built upon all the previous RA decisions.

1 [AIP-SEM-160-06] "Day 1 Decision for System Support Services in NI and Ancillary services, Short notice redeclarations

2 [AIP-SEM-07-447] "Proposed System Operations Services' Payments & Charges in SEM"

3 [AIP-SEM-08-128] "Harmonised Ancillary Services, Other System Payments & System Charges' September 2008

4 [AIP SEM-09-003] "Harmonised All-Island Implementation Arrangements for Ancillary Services and Other Payments and Charges" Decision Paper

3 RATES FRAMEWORK

This section has been included for information. The specific aspects that affect the setting of the harmonised rates and the proposals for them are set out in the later sections of this consultation paper. This section describes the broader aspects that influence the setting of the harmonised rates. These have been mentioned in earlier industry consultations and discussed by the RAs and TSOs. This section provides a summary of the broader aspects which includes RA decisions.

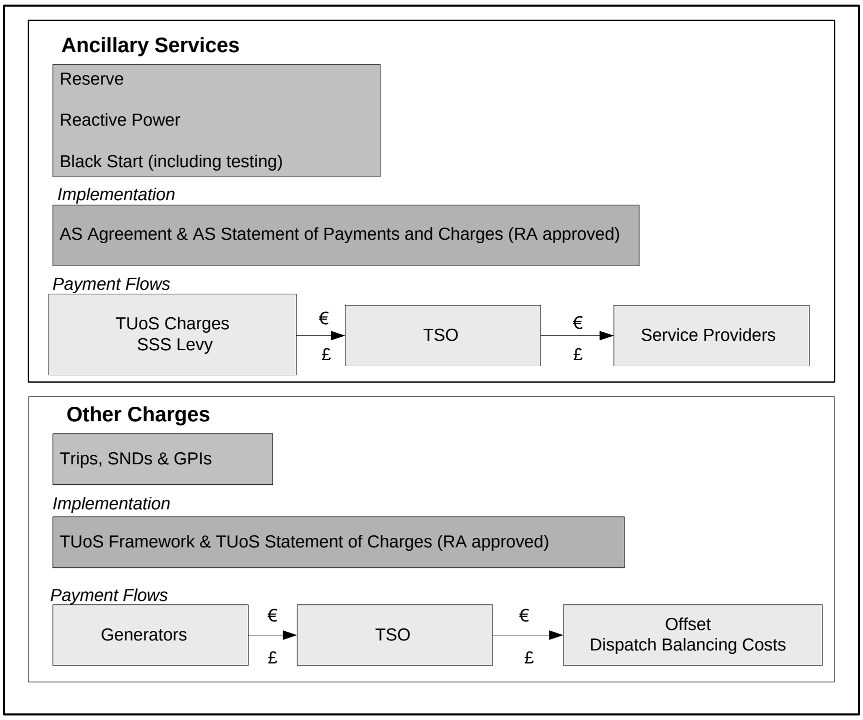
3.1 MONETARY FLOWS

Figure 3.1 below shows the relationships and interactions between the financial elements associated with the harmonised arrangements. The arrangements have a clear separation between AS and the Other Charges.

The three AS are to be formally defined by a harmonised AS Agreement and a harmonised annual AS Statement of Payments & Charges. AS payments to service providers are to be funded through Transmission Use of System (TUoS) charges in Ireland and the System Support Services (SSS) levy in NI. The AS funding, which is to be allowed to the TSOs, is then passed on to the AS service providers through the harmonised AS arrangements.

Other Charges, which are to be part of these harmonised arrangements, are the Trips, SNDs and Generator Performance Incentive (GPI) charges. These other charges are to be formally defined as part of the TUoS framework and the TUoS Statement of Charges. The other charges are to be levied on underperforming generators through billing systems which are to be administered by the TSOs and settled on a monthly basis. The other charges are to be used to offset future Dispatch Balancing Costs.

Figure 3.1: Implementation Arrangements & Monetary Flows



3.2 AS ALLOWANCES

The following requirements have been established and assumptions have been made to determine the AS allowances on which the harmonised AS rates are based.

1. There is to be no increase in either the NI or Ireland AS allowances as a result of the harmonisation process. This is a principal constraint for the model on which the harmonised AS rates are to be based.
2. The overall NI AS allowance includes system support services from Moyle interconnector and synchronous compensation which are contracted via regulatory-approved bi-lateral arrangements. The NI AS allowance used to determine the harmonised AS rates should exclude the allowance for Moyle and synchronous compensation as well as black start testing and any potential increased allowance for increased AS needs. Black start testing and the other payments are or will be provided for separately. For the purposes of setting the harmonised AS rates these four elements are excluded.
3. In the harmonised arrangements, the existing SONI System Support Services rebates and reductions become AS charges and Other System Charges. Therefore the current SONI net allowance figure (which assumes a level of rebates and reductions from both AS and GPI) should be converted to a gross allowance figure which establishes the NI AS allowance used to determine the harmonised AS rates.
4. The Ireland AS allowance used to determine the harmonised AS rates includes reserve, reactive power, black start (incl. black start testing). It excludes Moyle, STAR/IL, trips, SNDs, GPI charges, Winter Peak Demand Reduction Scheme, Powersave, secondary fuel compensation, generator testing/commissioning and any increased allowance for increased AS needs. The overall Ireland AS allowance includes these elements. For the purposes of setting the harmonised AS rates these elements are excluded.
5. The AS allowances should increase proportionally in anticipation to a need for higher levels of service. For the 2009/10 tariff year (1st October to 30th September), no increase in level of service has been identified (e.g. for the integration of intermittent generation). Therefore there is no increase to the 2009/10 AS allowances on account of a need for a higher level of service which reflects the RAs' January paper. The requirement for new services and the AS allowance will be reviewed annually.
6. The secondary fuel compensation payments (which is to be paid exclusively to generators in Ireland on completion of a successful fuel changeover test as is subject of a separate consultation process as outlines in Section 2.2) does not reduce the Ireland AS allowance. An additional to the overall Ireland AS allowance will be required in order to fund this new arrangement.

3.3 PROPOSED EXCHANGE RATE

Industry views are specifically sought on this "Proposed" section and on the similarly titled sections in this paper.

The Euro to Pound exchange rate is fixed for the tariff year. The derivation of the currency exchange rate used is provided below and is the same methodology as that used in the annual SEM Capacity Pot calculation.

The most suitable gauge for predicting future exchange rates is to use the current market forward FX rates for the period in question. The current market rate is the collective bargaining of the market to reach this (spot) price and the forward points are determined by the markets forecast for interest rates, relative to the period involved. Forecasts are less suitable as they are the view of one person or organisation.

The forward FX rate is simply the rate at which one currency can be exchanged for another currency, at any given date in the future, as at/agreed today. It is calculated using the current spot FX rate (current market price for delivery in 2 business days), and then adding or subtracting any relevant ‘forward points’ that may apply to that rate.

Forward points are a measure of the difference in the underlying interest rates for both currencies, expressed as a proportion of the underlying exchange rate price. Forward points are used to account for any benefit/disadvantage from the difference in these underlying interest rates (e.g. EUR interest rates are less than comparative GBP interest rates, and so there is an advantage from holding GBP until the maturity of the forward contract.)

Generally the spot rate is far more volatile than the forward points, and as such is the key driver/ determinant of the overall forward rate.

The rate used in this paper is €1/£0.85 which may be amended in the subsequent RA decision paper to more accurately reflect the rate at that time.

The exchange rates will be reviewed at the end of each tariff year to determine if re-benchmarking the two AS allowances is necessary for the coming year. This will be subject to ex-post review like all other aspects of allowed AS.

4 ANCILLARY SERVICES RATES

The policies and designs for Ancillary Services are set out in earlier RA decision papers. The purpose of this consultation is to obtain views from the industry on the TSOs' proposed harmonised AS rates and Other Charges rates. The Other Charges rates are considered in later sections.

4.1 HARMONISED AS RATES MODELLING ASSUMPTIONS

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.

Similarly for reactive power, 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.

A key assumption in creating the model to derive the harmonised reserve and reactive power rates is that the system needs and service availabilities are similar to previous levels. The data sources for the model to derive the 2009/10 rates are the unit availabilities per trading period, unit output per trading period, unit declarations, unit dispatch instructions and unit characteristics for 2008 for both NI and Ireland units. Sensitivity studies were carried out using 2007 and 2006 figures where data was available. Reserve capabilities were calculated at export point whereas reactive power capabilities were calculated at generated point in line with the harmonised arrangements.

The harmonised black start arrangements are based on the existing arrangements in Ireland. These arrangements are to apply for all existing black start service providers in Ireland and all future providers on the island. The harmonised hourly rates for the provision of the black start service include an element for testing. No separate payment is to be made to the service provider for testing.

The black start capabilities of the existing black start stations in Ireland will be reviewed. It is likely that for some of the black start stations, in order to be eligible for future black start payments, more than one black start unit must be available during the half hour trading period. This requirement will appear as part of the service provider characteristics in the harmonised AS agreement.

Existing black start providers in NI will receive a payment for incremental, variable costs directly incurred, and not recoverable through the SEM, as a consequence of the TSO initiating a black start test. Service providers submitting an invoice for such costs will have followed the same rigorous authorisation process specified in the NI Fuel Security Code. In the event that the service provider fails to perform as required on the day of the test then no incremental payments will be made.

4.2 PROPOSED HARMONISED AS RATES

The TSOs are required by licence to operate the transmission systems in a safe, secure, efficient and economic manner. They are obliged to contract for the availability of appropriate AS from service providers to enable them to discharge their obligations taking into account the quantity, nature and cost of the service in question. The proposed harmonised AS rates were set within the constraints outlined in Section 3, with the TSO licence requirement in mind and using the TSOs' knowledge and experience to best allocate the AS allowance. It is the TSOs' judgement that the appropriate split of the AS allowances between reserve and reactive power was 70/30. Furthermore it is the TSOs judgement that the appropriate split between POR, SOR, TOR1, TOR2 and RR was 20/25/25/15/15. The TSOs also believe that it is appropriate that the rates for the leading and lagging reactive power should be the same.

Based on the AS allowances outlined in Section 3, the TSOs propose the harmonised AS rates as per Table 4.1. The TSOs set the rates, using the AS allowances, by balancing a combination of the importance of service, the level of availability of each service, the application of incentive charges, the cost of provision and to a lesser extent historical rates.

In order to provide comment on this consultation paper, each service provider should consider these harmonised AS rates in conjunction with the approved policies and designs which have been published in earlier consultation and decision papers. Note that these rates are shown on an hourly basis. However settlement will be carried out on a half hour trading period basis.

4.2.1 Proposed AS Rates

Table 4.1: Proposed AS Rates

Service	Categories	Proposed Rate		Allowance %	Split %
Reserve	Primary Operating Reserve	€ 2.22 / MWh	£ 1.88 / MWh	70%	20%
	Secondary Operating Reserve	€ 2.13 / MWh	£ 1.81 / MWh		25%
	Tertiary Operating Reserve 1	€ 1.76 / MWh	£ 1.50 / MWh		25%
	Tertiary Operating Reserve 2	€ 0.88 / MWh	£ 0.75 / MWh		15%
	Replacement Reserve	€ 0.35 / MWh	£ 0.30 / MWh		15%
Reactive Power	Reactive Power Lagging	€ 0.13 / MVArh	£ 0.11 / MVArh	30%	
	Reactive Power Leading	€ 0.13 / MVArh	£ 0.11 / MVArh		
Black Start	Black Start (Aghada)	€64.71/h			
	Black Start (Ardnacrusha)	€ 22.84 /h			
	Black Start (Erne)	€ 22.04 /h			
	Black Start (Lee)	€ 9.82 /h			
	Black Start (Liffey)	€ 8.02 /h			
	Black Start (Turlough Hill)	€ 81.63 /h			

4.2.2 Proposed Alternative Replacement Reserve Option

This alternative option recognises that, as system characteristics and generation portfolios are beginning to change, a differentiation appears to be emerging between the service provisions of the reserve service. This is particularly true for replacement reserve. Under this proposed alternative replacement reserve option, the TSOs propose two different rates for replacement reserve – one for when a unit is already synchronised and the other for when a unit is de-synchronised but has the capability to provide capacity within the replacement reserve timescale. This recognised the increasing reliance on service provision from off line plant. The TSOs' proposal is to pay a higher rate for the de-synchronised service as there is value in the ability to provide replacement reserve from a standing start. This alternative proposal is not in contravention of the RAs' January paper but is further to it and is merely a sub-division of replacement reserve. The replacement reserve share of the AS allowances is the same as the proposed harmonised AS rate in Sub-Section 4.2.1 above.

Table 4.2: Proposed Alternative Replacement Reserve Rates

Service	Categories	Proposed Rate		Split %
Reserve	Replacement Reserve Unit Synchronised	€ 0.20 / MWh	£ 0.17 / MWh	30%
	Replacement Reserve Unit De-Synchronised	€ 0.51 / MWh	£ 0.44 / MWh	70%

5 TRIPS & SND CHARGES RATES

The subjects of this consultation paper are Ancillary Services and Other System Charges. The Other System Charges are split into two sections – this Section 5 on Trips & SNDs and Section 6 on GPIs. As both the Systems Support Services arrangements in NI and the AS arrangements in Ireland contain two different forms of trips and short notice declarations charges (SND), the designs for the harmonised arrangements were considered in earlier consultation processes. GPIs on the other hand are currently absent from the arrangements in Ireland and therefore the NI designs are being adopted on an all-island basis (See Section 6).

Both trips and SND involve the application of formulae that are a combination of MW values, empirical annual rates and empirical weightings. This consultation seeks views on the empirical constants and empirical charge rates.

5.1 TRIPS, FAST WIND-DOWNS & SLOW WIND-DOWNS

In the September 2008 consultation paper, the TSOs proposed detailed harmonised AS implementation arrangements for trips. The RAs' January paper adopted the arrangements. The arrangements included three trip categories as follows:

- Direct Trips
- Fast Wind-Downs
- Slow Wind-Downs

The charges only apply when there is a reduction in output from a generator. Proposed Empirical Trip Constants were included with the TSO's proposed arrangements in September 2008. The RAs considered these to be beyond the scope of the RAs' January paper and instructed the TSOs to include these in this consultation paper along with the Proposed Empirical Trip Charge Rates.

5.1.1 Proposed Empirical Trip Constants

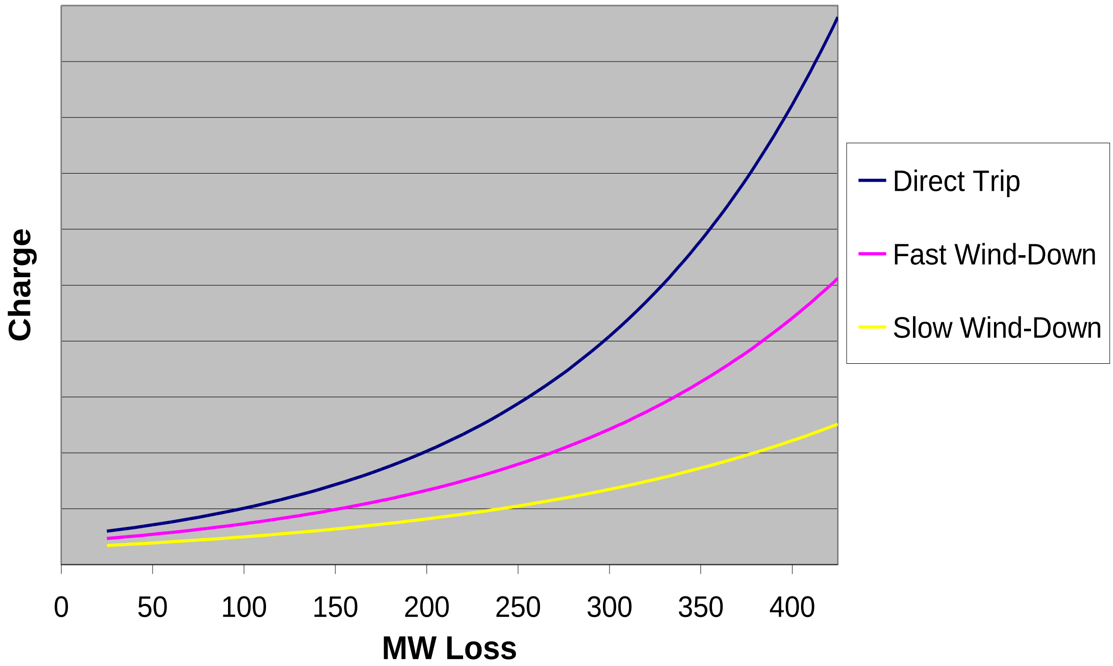
The Proposed Empirical Trip Constants associated with the three trip categories are in the charge calculation formulae in the table below which are unchanged from the September 2008 consultation paper. The proposed values of 0.007, 0.006 and 0.005 have the effect of ramping up the charges with increasing MW Loss. The effect of the Proposed Empirical Trip Constants can be shown in the Figure 5.1 on the next page. It is clear from the graph that the direct trip constant ramps more sharply than the fast wind-down constant which in turn ramps more sharply than the slow wind-down constant.

These three values are empirical and reflect the TSOs' view of the relative severity of the three tripping rates. As part of this consultation process, views are sought on the three values.

Table 5.1: Trip Charge Formulae & Proposed Numerical Values

Trip Charge Formulae
Direct Trip Charge = Direct Trip Charge Rate * EXP (**0.007** * MW Loss) Fast Wind Down Charge = Fast Wind Down Charge Rate * EXP (**0.006** * MW Loss) Slow Wind Down Charge = Slow Wind Down Charge Rate * EXP (**0.005** * MW Loss)

Figure 5.1: Proposed Empirical Trip Constants



5.1.2 Proposed Empirical Trip Charge Rates

The trip design is intended to minimise the number of trips and, when avoidable, to incentivise the unit to trip as slowly as possible. The TSOs have devised empirical rates for the three trip charge categories. The proposed rates are set at a level which seeks to recover an amount of costs which is representative of the power system impact while recognising that a level of tripping is inevitable.

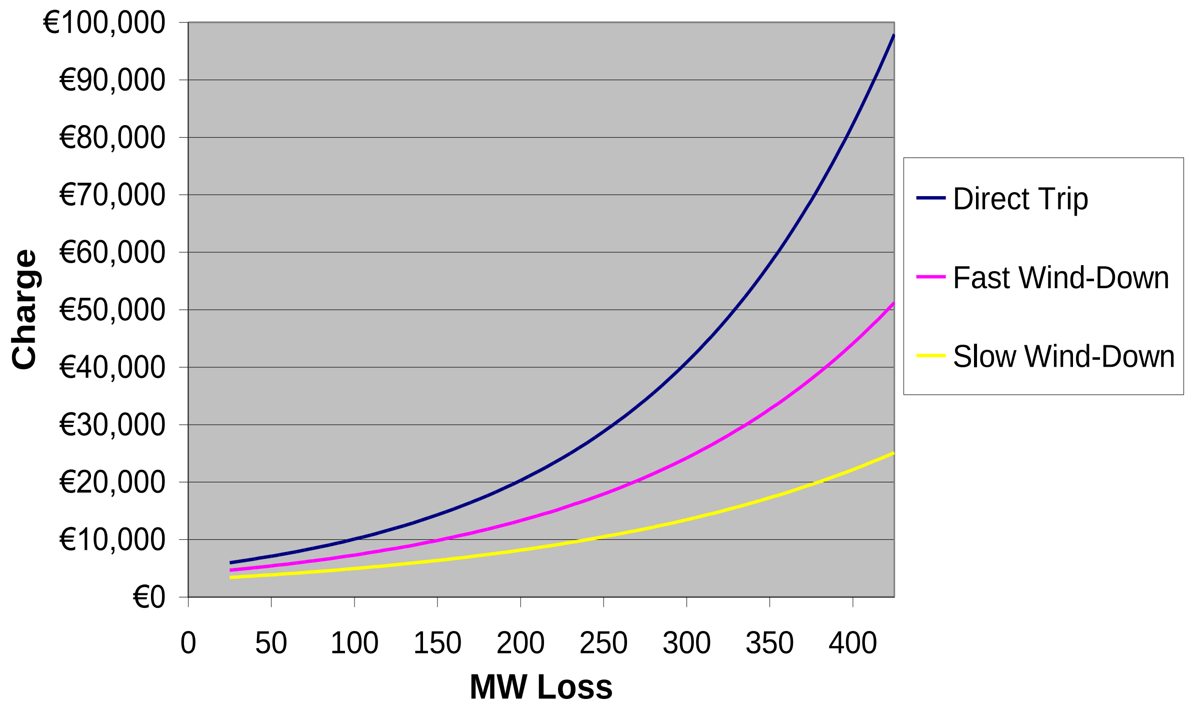
The proposed rates are listed in Table 5.2. These rates are unchanged from those used in the September 2008 consultation paper. As part of this consultation process, views are sought on the three charge rates.

Table 5.2: Proposed Trip Charge Rates

Charge	Proposed Trip Charge Rate	
Direct Trip	€ 5,000	£ 4,250
Fast Wind Down	€ 4,000	£ 3,400
Slow Wind Down	€ 3,000	£ 2,550

Figure 5.2 below graphically combines the proposed empirical trip constants with the proposed empirical trip rates to show the cost of every trip as a function of trip category and MW Loss. This is shown in one currency for simplicity.

Figure 5.2: Proposed Charges per Trip Category



5.2 SHORT NOTICE DECLARATIONS

The RAs' January paper supported the TSOs' proposal that the Short Notice Declaration (SND) charge should be calculated based on a MW reduction, SND charge rate and notice-time weight using the following formula:

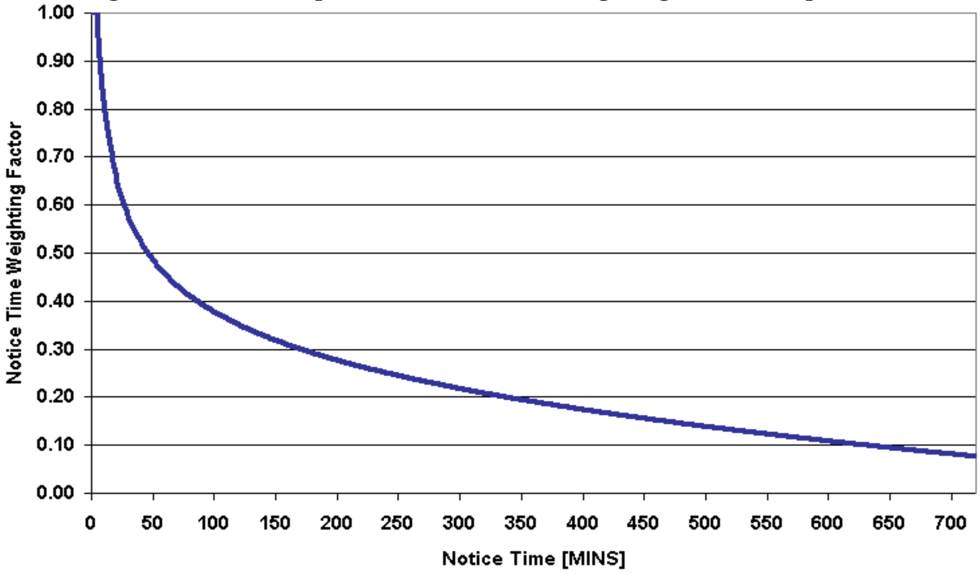
SND Charge = MW Reduction * SND Charge Rate * Notice-Time Weight

The SND charge rate is set annually. Both the SND charge rate and the notice-time weight are subject to this consultation paper.

5.2.1 Proposed Notice-Time Weight

The notice-time weight is obtained from a graph of notice-time weighting which produces a weight between 0 and 1 depending on the notice time given for the reduction in availability. The graph is shown below in Figure 5.3. The curve is flat from zero minutes notice to 5 minutes (Due to the scale, this short horizontal section is not apparent from Figure 5.3.) 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 20 minutes and then to begin to lessens off out to 12 hours notice.

Figure 5.3: Proposed Notice-Time Weighting Factor Graph



The curve is constructed from three sections. The first section is horizontal from 0 to 5 minutes. The second section uses a relatively complex equation to produce the steep curve. The final section uses another relatively complex equation to produce a less steep curve. The TSOs believe it is more useful to receive general comments from industry on the shape of the curve rather than on the equations themselves. Therefore comment is sought from the industry on the proposed shape of the curve.

5.2.2 Proposed Empirical SND Rate

In order to calculate the SND charge a single SND rate is required. The TSOs' proposal is to set the rate as follows. This rate has not changed since the September 2008 consultation paper.

Table 5.3: Proposed SND Charge Rate

Charge	Proposed Charge Rate	
SND	€ 100 / MW	£ 85 / MW

6 GENERATOR PERFORMANCE INCENTIVE CHARGES

In relatively small power systems, it is particularly important for the efficient and economic operation of the system to ensure that generators maintain the performance required in the Grid Codes and act in a manner that facilitates the operation of the system. Otherwise the safety, security and efficiency of the system could be compromised and/or costs could be imposed on other (compliant) users of the system, for example through higher Dispatch Balancing Costs. The Generator Performance Incentive (GPI) charges which are described in this section seek to incentives optimum behaviour for the benefit of the system. The GPI charges form part of the Other System Charges. The other two charges are described in Section 5.

6.1 GPI PARAMETERS

The SONI System Support Services Agreement (SSSA) considers generator performances and applies charges for generator underperformance in order to incentivise the generators to maintain required performance. The SSSA applies charges on generators based on the generator parameters which reflect the characteristics and behaviours that have a more significant impact on system operation.

In the RAs' January paper, the RAs instructed the TSOs to select parameters from the existing SONI SSSA that are to be included as part of the initial Generator Performance Incentive (GPI) scheme for implementation in the SEM and to provide details about the charging arrangements (from existing NI arrangements) including monitoring/measuring.

The SSSA rebates and reductions, which the TSOs have not selected for the initial GPI scheme, are discussed in Sub-Section 6.2. The GPI parameters selected by the TSOs and their proposed charge rates can be seen in the Sub-Section 6.3 below. The appendix sets out, in a formal manner similar to the SONI SSSA, how performance will be monitored and measured.

6.2 SELECTION OF GPI PARAMETERS FROM SSSA PARAMETERS

The SONI SSSA arrangements set out payments due to service providers in respect of the provision of services and reductions in and rebates of such payments in certain circumstances. The arrangements calculate the payment due each trading period in a single payment.

The harmonised arrangements unbundle the single payment. Payment for the provision of services is contained in the Ancillary Services arrangements, the rates for which are set out in the Section 4 of this consultation paper. The SSSA reduction in and rebates of payments are set out in this Section 6 (with the exception of Trip charges and SND charges which are set out in Section 5) in terms of the application unbundled charges. The stand-alone charges are derived from the SSSA arrangements but do not exactly replicate them.

The TSOs have considered all the elements of the SSSA. The TSOs have decided to include particular parameters in the initial GPI arrangements from the SSSA and exclude others for the first tariff period. Subsequent additions to the initial GPI parameters or changes to them will be consulted on by the RAs.

The SSSA arrangements incentivise the availability of particular services and flexibilities. In the harmonised arrangements these incentives are incorporated in a combination of SEM and Ancillary Services. The TSO have not selected these for the GPI charge arrangements with the exception of required levels of operating reserve and reactive power.

The SSSA arrangements consider units with low annual availability. These units are rebated based on their nominated running hours for the contracted year. The SEM considers availability and therefore a separate charge for low availability is not necessary. Therefore the TSOs have not selected these for the GPI charge arrangements.

The SSSA arrangements consider the timing of a planned outage with respect to the final outage programme. Should any planned outage not occur within twelve hours of the time and date specified in the final outage programme for the contract year, a sum equal to twenty percent of the annual SSS availability payment is re-paid by the unit. The SSS arrangements do allow for changes to the planned outage to be agreed between the unit and the TSO. The TSOs have not selected this outage-related element for the GPI charge arrangements.

The SSSA arrangements consider the flexibility of a planned outage. A planned outage that is categorised as 'flexible' received a reduction of the unit's availability payment which is less than the reduction of a planned outage that is categorised as inflexible. In order to replicate this rebate in the form of a charge, a separate charge could apply for inflexible outages. However the TSOs preferred not to continue this incentive in the initial GPI scheme.

6.3 PROPOSED GPI CHARGE RATES

The TSOs have selected the parameters below from the SSSA arrangements for the initial harmonised GPI charge arrangements. Their selection is based on their non-compliance having a significant impact on system operations, associated system costs and impact on other system users and SEM participants. The TSOs have, where possible, stayed as close as possible to the charge rates on the SSSA's arrangements, rates and empirical factors. Due to this approach, the TSOs welcome views on these GPI charge rates in particular.

The SSSA arrangements included a weighting factor for settlement period (weighted for time of day, time of year). The TSOs propose that the weighting factor should be removed as the strength of the signal from this weighting factor is insignificant when considered against time weightings within the SEM. By excluding the weighting factor (done by setting the SSSA weighting factor to 1 at all times), the calculations also become simpler.

The TSOs have based the rates on the current £0.50 /h SSSA credit and SSSA empirical multiplication factors. The time based rates (i.e. those with unit including hours) are expressed per hour. However settlement is done on a half hour trading basis as per SEM arrangements.

The GPI parameters' origins are either directly from the Grid Code, indirectly from a combination of Grid Code parameters or directly from the SSSA. As part of the process of assessing service providers for Ancillary Services contract values, the TSOs will assess generator units for the minimum GPI parameter levels.

Table 6.1: Proposed GPI Rates

GPI Charge	SSS-based Rate & Factors	Proposed Harmonised GPI Rate	
Minimum Generation	£ 0.50 /MWh * 2.0	£ 1.00 /MWh	€ 1.18 /MWh
Max Starts in 24 hour period	£ 0.50 /MWh * 1.7	£ 0.85 /MWh	€ 1.00 /MWh
Minimum on Time	£ 0.50 /MWh * 1.7	£ 0.85 /MWh	€ 1.00 /MWh
Reactive Power Leading	£ 0.50 /MVArh * 0.5	£ 0.25 /MVArh	€ 0.29 /MVArh
Reactive Power Lagging	£ 0.50 /MVArh * 0.5	£ 0.25 /MVArh	€ 0.29 /MVArh
Governor Droop	£ 0.50 /MWh * 0.5	£ 0.25 /MWh	€ 0.29 /MWh
Loading Rate	£ 0.50 /MWh	£ 0.5 /MWh	€ 0.59 /MWh
De-Loading Rate	£ 0.50 /MWh	£ 0.5 /MWh	€ 0.59 /MWh
Primary Operating Reserve	£ 0.50 /MWh	£ 0.10 /MWh	€ 0.12 /MWh
Secondary Operating Reserve		£ 0.10 /MWh	€ 0.12 /MWh
Tertiary Operating Reserve 1		£ 0.10 /MWh	€ 0.12 /MWh
Tertiary Operating Reserve 2		£ 0.10 /MWh	€ 0.12 /MWh
Early Synchronisation	£ 0.50 /MW * 4.5	£ 2.25 /MW	€ 2.65 /MW
Late Synchronisation	£ 0.50 /MW * 45	£ 22.50 /MW	€ 26.47 /MW

7 IMPLEMENTATION

This section considers the aspects to the implementation phase other than the rates. This has been included for information.

7.1 AS AGREEMENTS

The TSOs and RAs are developing the legal framework and harmonised AS agreements. These agreements will set out the general conditions, schedule of AS payment, charges calculations and an appendix of service provider-specific characteristics.

The implementation plan includes termination of the existing System Support Services Agreements (SSSA) in NI and replacing them with new harmonised regulatory-approved AS Agreements (ASA) covering reserve, reactive power, black start testing and an appendix of service provider-specific characteristics. Similarly the existing ASA in Ireland will be replaced with the new harmonised agreements which reflect the new arrangements for reserve, reactive power and black start. Counterparties will, however be invited to enter into a side letter to extend the agreements in the event that Harmonised Ancillary Services "Go-Live" was delayed for any reason.

The RAs are minded not to consult on the legal agreements on condition that any changes to the contracts are solely on the basis of this AS consultation rather than any other issues which are not part of this harmonisation project. The TSOs will be presenting draft agreements to the RAs and service providers for comment. It is intended that, at the same time as the notice to terminate is sent out (or earlier), parties will receive a draft copy of the new harmonised Regulatory-approved ASAs to take effect immediately on the termination of the SSSAs/ASAs.

7.2 OTHER CHARGES

The harmonised arrangements include the Trips and SND charge as well as the Generator Performance Incentive charges. The implementation involves using a feature in the existing Transmission Use of System Agreements (TUoSA) that are already in place with all generators and suppliers which require the party to pay use of system charges as set out in the Statement. The Statement will be supplemented with the required appendices to facilitate the above charges. There is, however, a requirement to make a small amendment to the existing TUoSAs in NI. This will be achieved by using the existing variation procedure in each of the agreements.

7.3 GRID CODE

In the event of conflict between the requirements of the Grid Code, connection agreement and AS agreements, the requirements of the Grid Codes and connection agreement will take precedence over AS agreements. In order to facilitate this harmonisation, minor changes are required to be made to the Grid Code(s). The work on the necessary minor changes will be carried out through submission of Grid Code(s) modifications to the Grid Code Review Panel(s) in parallel in the coming months.

7.4 BILLING SYSTEM DEVELOPMENT

In order to facilitate the new harmonised arrangements, SONI and EirGrid are developing their AS & GPI settlement systems. This process is underway. The programme for completion is very challenging. This programme is being closely monitored. Any significant delays will be notified to the industry.

8 FUTURE DEVELOPMENTS

8.1 NEW ANCILLARY SERVICES

It is widely accepted that the power system is evolving significantly at present and is expected to change extensively over the coming years and decades. The major driver for this is the changing generation portfolio. This change represents a major challenge which affects a broad range of subject, not least system operations.

To facilitate the changing portfolio while ensuring a safe, secure, efficient and reliable system operation, new ancillary services will be required as provided for in the RAs' January paper. These are being explored at present. The TSOs made some initial proposals in the September 2008 consultation paper. The industry response was mixed which has prompted the TSOs to investigate further. As a start, the TSOs have proposed an alternative option for the replacement reserve payment arrangement in Sub-Section 4.2.2 of this paper. Previously mentioned services such as fast start and warming contract continue to be explored along with others with input from the industry and normal regulatory oversight.

Overall, the development of new ancillary services will be done as part of the overall drive to facilitate the change in generation portfolio. Another aspects of the facilitation include considerations of the impact and treatment of renewable intermittent generation, consideration of the SEM structures, consideration of investment signals and, not least, incentivisation of high performance level of system users to optimise existing resources which is discussed in the next section.

8.2 GENERATOR MONITORING & PERFORMANCE INCENTIVES

As outlined early in this paper, it is important for the efficient and economic operation of the system to ensure that generators maintain the performance required in the Grid Codes and act in a manner that facilitates the operation of the system. The harmonised AS arrangements establish generator performance monitoring and performance incentives on an all-island basis. The arrangements will help quantify the performance of the current system, identify non-compliance with standards and help evaluate the performance gap between what is needed and what is being provided.

However to better analyse the gap, a systematic and objective performance reporting structure will be developed by the TSOs in the medium term, beyond the scope of this harmonisation project. The reporting will be technical in nature and will consider a greater number of characteristics than the GPI charges and will report against all users of the power system.

In addition to expanding the monitoring, reporting and the GPI charges, the Grid Codes will be developed to ensure that the standards reflect the technology of the time as well as the long term needs of the power system. These standards will be agreed with the industry on a cyclical basis and then power system assets will be built to meet them.

9 INSTRUCTIONS FOR RESPONSES

In order to focus the responses, views and comments are invited regarding the sections of the paper which are titled beginning with the word "Proposed". The TSOs will also host a briefing session to discuss the paper.

Responses should be sent to

Conor.Kavanagh@EirGrid.com and Leslie.Burns@SONI.ltd.uk and by Monday, 6th July 2009.

It would be helpful if comments were aligned with the sections and sub-sections of this consultation document. It would also be helpful if responses were 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.

10 NEXT STEPS

This section outlines the various elements of the harmonisation implementation phase. Participants should consider each element and understand how each element may affect them.

There are three major elements to the implementation phase as follows:

- Setting the harmonised rates
- Developing the EirGrid and SONI settlement systems
- Drafting, reviewing, approving and executing the legal documentation

The first element is the subject of this consultation process. The consultation process continues along the following timeline:

Timeline	Activity / Milestone
24th June 2009	AS & Other System Charges Briefing Session
6th July 2009	End of consultation on AS, Trips, SND & GPI rates
17th August 2009	Publication of RA Decision Paper
1st October 2009	"Go-Live" of harmonised AS & Other System Charge arrangements

The second involves the SONI and EirGrid settlement systems development which is underway. One particular aspect which will affect participants is that the Electronic Dispatch Instruction Logger (EDIL) will require additional parameters. The participants should expect these changes. They should also take the opportunity now to refresh their knowledge of the functionality of EDIL and their processes around it to begin to improve the accuracy and timeliness of their EDIL declarations. This will ensure a smooth transition to the harmonised arrangements and optimise the benefit from the new arrangements.

The last element has many aspects. Proposed modifications to the Grid Code(s) are under consideration and will be brought to the Grid Code Review Panel(s) as appropriate. The TSO expect to present draft copies of the new AS agreements to service providers in advance of the scheduled issue of the SSSA termination notice which is the 30th June – three months before the 1st October 2009 "Go-Live". The service providers should be in position to review the harmonised AS agreements and sign them in a timely manner. The TSOs intend to meet the service providers to discuss the unit-specific values, which will be required for the AS agreements, and would like to take the opportunity to discuss any practical aspects of the new arrangements with the service providers.

APPENDICES

APPENDIX A. GPI CHARGES FORMULAE

INTRODUCTION

The GPI Charges Formulae appendix set outs, in a formal manner, the details of how generator performance will be monitored and measured and how the incentives are calculated. The formulae used are based, where possible, on the NI System Support Services agreement (including the constants that appear).

Appendix subsections A1 to A6 set out GPI charges which are based on the comparison of declared capability levels and required minimum capability levels. Appendix subsections A7 to A10 set out GPI charges which are based on the comparison of actual performance and required performance. For the avoidance of doubt, Ancillary Services arrangements, Trips charge arrangements and Short Notice Declarations arrangements are not included in this appendix. The details can be seen in previous consultations. The Ancillary Services arrangements will also form part of the new harmonised regulatory-approved AS Agreements (ASA).

A.1 MINIMUM GENERATION

The Minimum Generation charge shall be applied in respect of each Trading Period in which the Minimum Generation of the Generator Unit has been declared to be above the highest of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$$\text{MG\_Charge}_X = \text{TP} * (\text{DMG} – \text{CMG}) * \text{MinGen\_RATE}$$

where:

MG_Charge_X is the charge for Minimum Generation underperformance in the Trading Period X [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

DMG is the Declared Minimum Generation [expressed in MW] which must be greater than CMG for this charge to apply.

CMG is the Minimum Generation [expressed in MW] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

MinGen_RATE is the Minimum Generation charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

A.2 GOVERNOR DROOP

The Governor Droop charge shall be applied in respect of each Trading Period in which the Governor Droop of the Generator Unit has been declared to be above the highest of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$GD\_Charge_X = TP * AP_{uh} * ((DGD – CGD) / DGD) * GD\_RATE$

where:

GD_Charge_X is the charge for Governor Droop underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

AP_{uh} Is the Availability Profile of Generator Unit u in Trading Period h [expressed in MW].

DGD is the Declared Governor Droop [expressed in %] which must be greater than CGD for this charge to apply.

CGD is the Governor Droop [expressed in %] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

GD_RATE is the Governor Droop charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

A.3 MAXIMUM NUMBER OF STARTS PER 24 HOUR PERIOD

The Maximum Number of Starts per 24 hour Period charge shall be applied in respect of each Trading Period in which the Maximum Number of Starts per 24 hour Period of the Generator Unit has been declared to be below the lower of the value based on Grid Code parameters or the relevant Grid Code Derogation or as specified in ASA Schedule, by an amount as follows:

$MxS\_Charge_X = TP * DMG * MxS\_RATE$

where:

MxS_Charge_X is the charge for Maximum Number of Starts per 24 hour Period underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

DMG is the Declared Minimum Generation [expressed in MW] which must be greater than CMG for this charge to apply.

MxS_RATE is the Maximum Number of Starts per 24 hour Period charge rate [expressed in €/MWh or £/MWh].

provided, however, that the declared Maximum Number of Starts per 24 hour Period is below the required value, the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

A.4 MINIMUM ON TIME

The Minimum on Time charge shall be applied in respect of each Trading Period in which the Minimum on Time of the Generator Unit has been declared to be above the higher of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$MoT\_Charge_X = TP * DMG * MoT\_RATE$

where:

MoT_Charge_X is the charge for Minimum on Time underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

DMG is the Declared Minimum Generation [expressed in MW] which must be greater than CMG for this charge to apply.

MoT_RATE is the Minimum on Time charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Minimum on Time is above the required value, the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

A.5 REACTIVE POWER

The generator performance incentive Reactive Power charge shall be applied in respect of each Trading Period in which the Reactive Power of the Generator Unit has been declared to be below the lower of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$RP\_Charge_X = TP * ((RPC – DRPC) + (RPP – DRPP)) * RP\_RATE$

where:

RP_Charge_X is the charge for Reactive Power underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

RPC is the Reactive Power Consumption [expressed in MVAr] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DRPC is the Declared Reactive Power Consumption [expressed in MVAr] which must be less than RPC for the Reactive Power Consumption aspect of the charge to apply.

RPP is the Reactive Power Production [expressed in MVAr] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DRPP is the Declared Reactive Power Production [expressed in MVAr] which must be less than RPP for the Reactive Power Consumption aspect of the charge to apply.

RP_RATE is the Reactive Power charge rate [expressed in €/MVArh or £/MVArh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration of either DRPC or DRPP, the charge is doubled.

A.6 OPERATING RESERVE

The generator performance incentive Operating Reserve charges shall be applied in respect of each Trading Period in which the Operating Reserve of the Generator Unit has been declared to be below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$POR\_Charge_X = TP * (POR – DPOR) * POR\_RATE$

where:

POR_Charge_X is the charge for Primary Operating Reserve underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

POR is the Primary Operating Reserve [expressed in MW] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DPOR is the Declared Primary Operating Reserve [expressed in MW] which must be less than POR for the charge to apply.

POR_RATE is the Primary Operating Reserve charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

$SOR\_Charge_X = TP * (SOR – DSOR) * SOR\_RATE$

where:

SOR_Charge_X is the charge for Secondary Operating Reserve underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

SOR is the Secondary Operating Reserve [expressed in MW] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DSOR is the Declared Secondary Operating Reserve [expressed in MW] which must be less than SOR for the charge to apply.

SOR_RATE is the Secondary Operating Reserve charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

$TOR1\_Charge_X =$ TP * (TOR1 – DTOR1) * TOR1_RATE

where:

$TOR1\_Charge_X$ is the charge for Tertiary Operating Reserve 1 underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

TOR1 is the Tertiary Operating Reserve 1 [expressed in MW] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DTOR1 is the Declared Tertiary Operating Reserve 1 [expressed in MW] which must be less than TOR1 for the charge to apply.

TOR1_RATE is the Tertiary Operating Reserve 1 charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

$TOR2\_Charge_X =$ TP * (TOR2 – DTOR2) * TOR2_RATE

where:

$TOR2\_Charge_X$ is the charge for Tertiary Operating Reserve 2 underperformance in the Trading Period x [expressed in € or £].

TP is a 0.5 hour Trading Period [expressed in h].

TOR2 is the Tertiary Operating Reserve 2 [expressed in MW] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

DTOR2 is the Declared Tertiary Operating Reserve 2 [expressed in MW] which must be less than TOR2 for the charge to apply.

TOR2_RATE is the Tertiary Operating Reserve 2 charge rate [expressed in €/MWh or £/MWh].

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

A.7 LOADING RATE

The Loading Rate charge shall be applied in respect of each loading of the Generator Unit following synchronisation in which the Actual Loading Rate of the Generator Unit is below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$LR\_Charge_Y = ((LR – ALR) / LR) * A * LR\_RATE * ((DpLT – ASyncT) /60) * 24$

where:

LR_Charge_Y is the charge for Loading Rate underperformance for loading event Y from synchronisation of the Generator Unit [expressed in € or £].

LR is the Loading Rate [expressed in MW/h] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule allowing for the heat state of the Generator Unit.

ALR is the Actual Loading Rate calculated as follows:

ALR = DpL / (DpLT - ASyncT)

Where

DpL is the Dispatched Load following a Synchronisation Instruction [expressed in MW].

DpLT is the Dispatched Load Time which is that time at which the Dispatched Load is reached [expressed in h].

ASyncT is the Actual Synchronisation Time [expressed in h].

A is the Availability of the Generator Unit [expressed in MW] prevailing at the Dispatched Load Time.

LR_RATE is the Loading Rate charge rate [expressed in €/MW or £/MW].

A.8 DE-LOADING RATE

The De-Loading Rate charge shall be applied in respect of each de-loading of the Generator Unit following a De-Synchronisation Instruction in which the De-Loading Rate of the Generator Unit is below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

DLR_Charge_Y = ((DLR – ADLR) / DLR) * A * DLR_RATE * ((DSyncT – DLT) /60) * 24

where:

DLR_Charge_Y is the charge for De-Loading Rate underperformance for de-loading event Y following a De-Synchronisation Instruction of the Generator Unit [expressed in € or £].

DLR is the De-Loading Rate [expressed in MW/min] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.

ADLR is the Actual De-Loading Rate calculated as follows:

ADLR = DLMW / (DSyncT - DLT)

where

DLMW is the MW Output at the time of the De-Synchronisation Instruction [expressed in MW].

DLT is the De-Synchronisation Instruction Time which is that time at which the De-Synchronisation Instruction was issued [expressed in h].

DSyncT is the De-Synchronisation Time [expressed in h] which is the time at which the Generator Unit actually de-synchronised time.

A is the Availability of the Generator Unit [expressed in MW] prevailing at the De-Synchronisation Load Time.

DLR_RATE is the De-Loading Rate charge rate [expressed in €/MW or £/MW].

A.9 LATE SYNCHRONISATION

Save where Late Synchronisation is specifically requested by the TSO and agreed by the Generator Unit, on each occasion upon which the Generating Unit synchronises to the Transmission System more than 5 minutes after the time that was instructed for synchronisation by a valid Despatch Instruction, the Generator Unit shall pay to the TSO a charge calculated as follows:

LS_Charge_Y = { (LS -5) / 55 } * A * LS_RATE

where:

LS_Charge_Y is the charge for the Late Synchronisation underperformance for synchronisation event Y following a Synchronisation Instruction of the Generator Unit [expressed in € or £].

LS is the number of minutes after the Despatched Synchronising Time that the Generating Unit was synchronising to the Transmission System.

A is the Availability of the Generator Unit [expressed in MW] prevailing at the Dispatched Load Time.

LS_RATE is the Late Synchronisation charge rate [expressed in €/MW or £/MW].

A.10 EARLY SYNCHRONISATION

Save where early synchronisation is specifically requested by the TSO and agreed by the Generator Unit, on each occasion upon which the Generating Unit synchronises to the Transmission System more than 15 minutes before the Despatched Synchronisation Time, the Generator shall pay to the TSO a charge calculated as follows:

$ES\_ Charge_Y = \{ (ES – 15) / 60 \} * A * ES\_RATE$

where:

ES_Charge_Y is the charge for the Early Synchronisation underperformance for synchronisation event Y following a Synchronisation Instruction of the Generator Unit [expressed in € or £].

ES is the number of minutes before the Despatched Synchronising Time that the Generating Unit was synchronised to the Transmission System.

A is the Availability of the Generator Unit [expressed in MW] prevailing at the Dispatched Load Time.

ES_RATE is the Early Synchronisation charge rate [expressed in €/MW or £/MW].

APPENDIX B. PAYMENTS & CHARGES EXAMPLES

This Appendix B gives three illustrative examples of payments and charge for three different representative units. The figures are based the harmonised designs (taking into account unit size, characteristics, running regimes and performance) and the proposed harmonised rates. The examples are intended to give a sense for the proposed harmonised rates. As all units are different it is not possible to show here the effect of the proposed harmonised rates on all units.

B.1 EXAMPLE 1 – TYPICAL 400 MW UNIT

This example considers a 400 MW unit. Its annual MW availability is 95%. It is generally base load and dispatched down at times for reserve. Its contracted ancillary services values are equal to its declared ancillary services values throughout the year. It is available for ancillary services any time it is available for capacity and its automatic voltage regulator is also always declared on. It can provide black start (unlike most units) and has its station-specific black start rate. Its behaviour includes tripping at different MW loss rates and changes to availability at short notice. Its declared Generator Performance Incentive values (for the ten associated charges which are based on a comparison of required values against declared values) are below the required values. It is liable on occasion to synchronise early and late and to load and de-load slower than required.
For the purpose of illustration, all currency dependent values are given in Euro.

Ancillary Services Payments			
	Annual Availability (Half Hour)	Annual Hourly Rate	Annual Payment
	MW half h	*€/MWh*	*€*
Primary Operating Reserve	237,832	2.22	263,993
Secondary Operating Reserve	262,077	2.13	279,112
Tertiary Operating Reserve 1	372,771	1.76	328,038
Tertiary Operating Reserve 2	434,367	0.88	191,121
Replacement Reserve	866,919	0.35	151,711
	MVAr half h	*€/MVArh*	*€*
Reactive Power (Leading)	2,361,168	0.13 (double for AVR on)	306,952
Reactive Power (Lagging)	3,697,092	0.13 (double for AVR on)	480,622
	half h	*€/h*	*€*
Black Start (site specific rate)	16,644	50	416,100

Ancillary Services Charges		
	Incident Description	Charge per incident
Primary Operating Reserve	20 MW shortfall	€ 31,968
Secondary Operating Reserve	20 MW shortfall	€ 30,672
Tertiary Operating Reserve 1	30 MW shortfall	€ 38,016
Tertiary Operating Reserve 2	No charge applicable	
Replacement Reserve	No charge applicable	
Reactive Power (Leading)	No charge applicable	
Reactive Power (Lagging)	No charge applicable	
Black Start (site specific rate)	Partial Fail	€ 36,000
	Outright Fail	€ 108,000

Trip Charges				
Pre-trip Output	Post-trip Output	Trip Charge	Fast Wind Down Charge	Slow Wind Down Charge
400 MW	200 MW	€ 20,275	€ 13,280	€ 8,154
400 MW	0 MW	€ 82,223	€ 44,092	€ 22,167

Short Notice Declaration Charges		
Reduction in Availability	Notice Time	Charge per event
400 MW	0 minutes	€ 40,000
400 MW	20 minutes	€ 26,390
400 MW	60 minutes	€ 17,398
400 MW	720 minutes +	€ 0

Generator Performance Incentive Charges (Required Performance vs Declared Performance)			
Charge Category	Requirement	Average Daily Declaration	Daily Charge
Minimum Generation	200 MW	220 MW	€ 566
Max Starts in 24 hour period	3	< 3	€ 5,280
Minimum on Time	4 hours	> 4 hours	€ 5,280
Reactive Power Leading	147 MVAr	100 MVAr	€ 327
Reactive Power Lagging	210 MVAr	150 MVAr	€ 418
Governor Droop	4%	5%	€ 557
Primary Operating Reserve	20 MW	15 MW	€ 14
Secondary Operating Reserve	20 MW	15 MW	€ 14
Tertiary Operating Reserve 1	32 MW	25 MW	€ 20
Tertiary Operating Reserve 2	40 MW	30 MW	€ 29

Generator Performance Incentive Charges (Synchronisation Charges)	
Early relative to Instruction	Charge per event
15 minutes	€ 0
16 minutes	€ 18
20 minutes	€ 88
30 minutes	€ 265
Late relative to Instruction	Charge per event
5 minutes	€ 0
6 minutes	€ 193
10 minutes	€ 963
60 minutes	€ 10,588

Generator Performance Incentive Charges (Loading/De-Loading Charges)		
De-Loading Rate Requirement	Actual	Charge per event
5 MW/min	5 MW/min	€ 0
5 MW/min	3 MW/min	€ 2,517
5 MW/min	1 MW/min	€ 15,104
Loading Rate Requirement	Actual	Charge per event
5 MW/min	5 MW/min	€ 0
5 MW/min	3 MW/min	€ 2,517
5 MW/min	1 MW/min	€ 15,104

B.2 EXAMPLE 2 – TYPICAL 200 MW UNIT

This example considers a 200 MW unit. Its annual MW availability is 95%. It is generally base load and dispatched down at times for reserve. Its contracted ancillary services values are equal to its declared ancillary services values throughout the year. It is available for ancillary services any time it is available for capacity and its automatic voltage regulator is also always declared on. It can provide black start (unlike most units) and has its station-specific black start rate. Its behaviour includes tripping at different MW loss rates and changes to availability at short notice. Its declared Generator Performance Incentive values (for the ten associated charges which are based on a comparison of required values against declared values) are below the required values. It is liable on occasion to synchronise early and late and to load and de-load slower than required.

For the purpose of illustration, all currency dependent values are given in Euro.

Ancillary Services Payments			
	Annual Availability (Half Hour)	Annual Hourly Rate	Annual Payment
	MW half h	*€/MWh*	*€*
Primary Operating Reserve	61,068	2.22	67,786
Secondary Operating Reserve	58,592	2.13	62,401
Tertiary Operating Reserve 1	64,016	1.76	56,334
Tertiary Operating Reserve 2	52,471	0.88	23,087
Replacement Reserve	140,500	0.35	24,587
	MVAr half h	*€/MVArh*	*€*
Reactive Power (Leading)	173,040	0.13 (double for AVR on)	22,495
Reactive Power (Lagging)	271,097	0.13 (double for AVR on)	35,243
	half h	*€/h*	*€*
Black Start (site specific rate)	16,644	10	83,220

Ancillary Services Charges		
	Incident Description	Charge per incident
Primary Operating Reserve	10 MW shortfall	€ 15,984
Secondary Operating Reserve	10 MW shortfall	€ 15,336
Tertiary Operating Reserve 1	15 MW shortfall	€ 19,008
Tertiary Operating Reserve 2	No charge applicable	
Replacement Reserve	No charge applicable	
Reactive Power (Leading)	No charge applicable	
Reactive Power (Lagging)	No charge applicable	
Black Start (site specific rate)	Partial Fail	€ 7,200
	Outright Fail	€ 21,600

Trip Charges				
Pre-trip Output	Post-trip Output	Trip Charge	Fast Wind Down Charge	Slow Wind Down Charge
200 MW	50 MW	€ 14,288	€ 9,838	€ 6,351
200 MW	0 MW	€ 20,276	€ 13,280	€ 8,155

Short Notice Declaration Charges		
Reduction in Availability	Notice Time	Charge per event
200 MW	0 minutes	€ 20,000
200 MW	20 minutes	€ 13,195
200 MW	60 minutes	€ 8,699
200 MW	720 minutes +	€ 0

Generator Performance Incentive Charges (Required Performance vs Declared Performance)			
Charge Category	Requirement	Average Daily Declaration	Daily Charge
Minimum Generation	100 MW	120 MW	€ 566
Max Starts in 24 hour period	3	< 3	€ 2,880
Minimum on Time	4 hours	> 4 hours	€ 2,880
Reactive Power Leading	74 MVArh	60 MVArh	€ 94
Reactive Power Lagging	105 MVArh	80 MVArh	€ 174
Governor Droop	4%	5%	€ 278
Primary Operating Reserve	10 MW	5 MW	€ 14
Secondary Operating Reserve	10 MW	5 MW	€ 14
Tertiary Operating Reserve 1	16 MW	10 MW	€ 17
Tertiary Operating Reserve 2	20 MW	10 MW	€ 29

Generator Performance Incentive Charges (Synchronisation Charges)	
Early relative to Instruction	Charge per event
15 minutes	€ 0
16 minutes	€ 9
20 minutes	€ 44
30 minutes	€ 133
Late relative to Instruction	Charge per event
5 minutes	€ 0
6 minutes	€ 96
10 minutes	€ 481
60 minutes	€ 5,294

Generator Performance Incentive Charges (Loading/De-Loading Charges)		
De-Loading Rate Requirement	Actual	Charge per event
2.5 MW/min	2.5 MW/min	€ 0
2.5 MW/min	1.5 MW/min	€ 1,259
2.5 MW/min	0.5 MW/min	€ 7,552
Loading Rate Requirement	Actual	Charge per event
2.5 MW/min	2.5 MW/min	€ 0
2.5 MW/min	1.5 MW/min	€ 1,259
2.5 MW/min	0.5 MW/min	€ 7,552

B.3 EXAMPLE 3 – TYPICAL 100 MW UNIT

This example considers a 100 MW unit. Its annual MW availability is 90%. It is generally used for peaking plant and can be dispatched down at times for reserve. Its contracted ancillary services values are equal to its declared ancillary services values throughout the year. It is available for ancillary services any time it is available for capacity and its automatic voltage regulator is also always declared on. It can provide black start (unlike most units) and has its station-specific black start rate. Its behaviour includes tripping at different MW loss rates and changes to availability at short notice. Its declared Generator Performance Incentive values (for the ten associated charges which are based on a comparison of required values against declared values) are below the required values. It is liable on occasion to synchronise early and late and to load and de-load slower than required.

For the purpose of illustration, all currency dependent values are given in Euro.

Ancillary Services Payments			
	Annual Availability (Half Hour)	Annual Hourly Rate	Annual Payment
	MW half h	*€/MWh*	*€*
Primary Operating Reserve	8,908	2.22	9,888
Secondary Operating Reserve	13,481	2.13	14,357
Tertiary Operating Reserve 1	17,255	1.76	15,185
Tertiary Operating Reserve 2	17,255	0.88	7,592
Replacement Reserve	1,265,548	0.35	221,471
	MVAr half h	*€/MVArh*	*€*
Reactive Power (Leading)	17,520	0.13 (double for AVR on)	2,278
Reactive Power (Lagging)	52,560	0.13 (double for AVR on)	6,833
	half h	*€/h*	*€*
Black Start (site specific rate)	15,768	8	63,072

Ancillary Services Charges		
	Incident Description	Charge per incident
Primary Operating Reserve	5 MW shortfall	€ 7,992
Secondary Operating Reserve	5 MW shortfall	€ 7,668
Tertiary Operating Reserve 1	5 MW shortfall	€ 6,336
Tertiary Operating Reserve 2	No charge applicable	
Replacement Reserve	No charge applicable	
Reactive Power (Leading)	No charge applicable	
Reactive Power (Lagging)	No charge applicable	
Black Start (site specific rate)	Partial Fail	€ 5,760
	Outright Fail	€ 17,280

Trip Charges				
Pre-trip Output	Post-trip Output	Trip Charge	Fast Wind Down Charge	Slow Wind Down Charge
100 MW	50 MW	€ 0	€ 0	€ 0
100 MW	0 MW	€ 10,069	€ 7,288	€ 4,946

Short Notice Declaration Charges		
Reduction in Availability	Notice Time	Charge per event
100 MW	0 minutes	€ 10,000
100 MW	20 minutes	€ 6,598
100 MW	60 minutes	€ 4,350
100 MW	720 minutes +	€ 0

Generator Performance Incentive Charges (Required Performance vs Declared Performance)			
Charge Category	Requirement	Average Daily Declaration	Daily Charge
Minimum Generation	50 MW	55 MW	€ 142
Max Starts in 24 hour period	3	< 3	€ 1,320
Minimum on Time	4 hours	> 4 hours	€ 1,320
Reactive Power Leading	37 MVArh	30 MVArh	€ 47
Reactive Power Lagging	53 MVArh	50 MVArh	€ 17
Governor Droop	4%	5%	€ 139
Primary Operating Reserve	5 MW	4 MW	€ 3
Secondary Operating Reserve	5 MW	4 MW	€ 3
Tertiary Operating Reserve 1	8 MW	6 MW	€ 6
Tertiary Operating Reserve 2	10 MW	8 MW	€ 6

Generator Performance Incentive Charges (Synchronisation Charges)	
Early relative to Instruction	Charge per event
15 minutes	€ 0
16 minutes	€ 4
20 minutes	€ 22
30 minutes	€ 66
Late relative to Instruction	Charge per event
5 minutes	€ 0
6 minutes	€ 48
10 minutes	€ 241
60 minutes	€ 2,647

Generator Performance Incentive Charges (Loading/De-Loading Charges)		
De-Loading Rate Requirement	Actual	Charge per event
1.25 MW/min	1.25 MW/min	€ 0
1.25 MW/min	0.75 MW/min	€ 629
1.25 MW/min	0.25 MW/min	€ 3,776
Loading Rate Requirement	Actual	Charge per event
1.25 MW/min	1.25 MW/min	€ 0
1.25 MW/min	0.75 MW/min	€ 629
1.25 MW/min	0.25 MW/min	€ 3,776