Harmonised
Other System Charges
Recommendations Paper

Tariff Year

1st October 2020 to 30th September 2021

1st July, 2020

EXECUTIVE SUMMARY

EirGrid and SONI (the TSOs) published a consultation paper on 8th April 2020 concerning the Harmonised Other System Charges for the upcoming tariff period, 1st October 2020 to the 30th September 2021. Comments on the consultation paper were received from nine (9) respondents. Having reviewed the responses, in this paper the TSOs propose a number of recommendations to the Regulatory Authorities (the RAs) for their consideration and approval.

Proposed arrangements for tariff year 2020/2021

1. Retain the OSC rates approved for the 2019/2020 tariff year, only adjusting for inflation at the forecast rate of 1.7% for the tariff year 2020/2021 for the following GPIs:

    - Minimum Generation;
    - Governor Droop;
    - Secondary Operating Reserve;
    - Tertiary Operating Reserve 1;
    - Tertiary Operating Reserve 2; and
    - Reactive Power.

2. Increase the rate of Trip Charges and Short Notice Declarations (SND) for generators without a Day Ahead Market position (QEX) to that which aligns with 2017/18 tariff before the introduction of the revised SEM arrangements, adjusting for inflation.

3. Retain the reduced rate of Trip Charges and Short Notice Declarations for generators with a Day Ahead Market position (QEX), adjusting for inflation.

4. Retain the Primary Operating Reserve GPI rate from 2019/20, adjusted for inflation.

5. Retain the Secondary Fuel GPI rate from 2019/20, adjusted for inflation.

6. Retain the RoCoF GPI rate from 2019/20, adjusted for inflation.

7. No DSU SND rate for 2020/21 with a view to liaising further with the Industry prior to proposing OSC for 2021/22.

No further changes are recommended for this tariff period.

ABBREVIATIONS

AGU	Aggregated Generator Unit
BOA	Bid Offer Acceptance
CCP	Controllability Categorisation Policy
CRM	Capacity Remuneration Auction
DAM	Day-Ahead Market
DBC	Dispatch Balancing Costs
DMOL	Design Minimum Operating Level
DSU	Demand Side Unit
DS3	Delivering a Secure Sustainable System
EDIL	Electronic Dispatch Instruction Logger
GPI	Generator Performance Incentive
HAS	Harmonised Ancillary Services
HICP	Harmonised Index of Consumer Prices
IDM	Intra-Day Market
I-SEM	Integrated Single Electricity Market
LTS	Long-Term Schedule
MMS	Market Management System
MPI	Market Participant Interface
NI	Northern Ireland
NIE	Northern Ireland Electricity
OSC	Other System Charges
PPM	Power Park Modules
QEX	Ex-Ante Quantity
RA	Regulatory Authority
RO	Reliability Options
RoCoF	Rate of Change of Frequency
RPI	Retail Prices Index
SEM	Single Electricity Market
SEMC	Single Electricity Market Committee

SND	Short Notice Declaration
SNSP	System Non-Synchronous Penetration
SONI	System Operator Northern Ireland
SPS	Special Protection Scheme
TSO	Transmission System Operator
TUoS	Transmission Use of System

1 INTRODUCTION

The TSOs consult on an annual basis regarding proposed changes to Other System Charges and associated rates. The purpose of this paper is to make recommendations for approval to the RAs in Ireland and Northern Ireland. They are based on a consideration of the responses received by the TSOs to this year's Harmonised Other System Charges Consultation paper for the tariff year 1st October 2020 to 30th September 2021[1].

The TSOs will publish revised Statements of Charges and the Other System Charges Methodology Statement for the 2020-2021 tariff period reflecting the approved rates and arrangements.

Responses were received from the following parties:

Party	**Abbreviation**
Bord Gáis Energy	BGE
ESB Generation and Trading	ESB GT
Power NI Energy Ltd Power Procurement Business	PPB
Scottish and Southern Energy	SSE
Tynagh Energy Limited	TEL
Demand Response Aggregators of Ireland	DRAI
Energia	Energia
Bord na Móna	BnM
Powerhouse Generation	PHG

No confidential responses were received. Copies of the responses received have been appended to this recommendations paper.

[1] http://www.soni.ltd.uk/media/documents/OSC-Consultation-2020-2021.pdf

2 OTHER SYSTEM CHARGES CONSULTATION RESPONSES

2.1 Trip Charge and Short Notice Declaration (SND) Charge

2.1.1 Respondents' Comments

SSE stated that Trip Charges are a blunt instrument to exercise market oversight. SSE also expressed the view that Trip Charges and SNDs are a legacy from the previous market arrangements and were designed with that market in mind. The retention of both is therefore a disincentive and/or double penalty for generators.

SSE outlined four suggested alternatives for remedying issues that SSE believe Trip and SND Charges are attempting to solve. These include changes to the market design, addressing the issue of units not trading within DAM, and a new approach to how units manage trips within Market Operations.

SSE believes that the TSOs need to address the confirmed principle that the market is already balance responsible. SSE also highlighted that they believe that the trip charges do not consider the potential efforts of units to trade out of their DAM position in the IDM. This means that the proposed regime of Trip Charges could be a possible disincentive for a unit to trade out of its market position and remedy the energy imbalance, as once the unit has traded out of its QEX, it would be exposed to a larger trip rate.

BGE is of the view that units which have a QEX are already considerably incentivised to remain fully operative, and thus should not be exposed to Trip and/or SND Charges. BGE stated that the reduced rates introduced in 2017/18 do not go far enough, considering imbalance charges paid by units.

BnM also favoured that the proposed rates for units with a QEX should be reduced by 100% vs 2017/18 rates, subject to review in two years. An alternative approach was proposed which encompassed Trip Charges and SND Charges being capped at the greater of the Net Imbalance Charges vs the sum of Trip and SND Charges.

ESB GT stated that they strongly believe that units with a QEX are exposed to significant costs through imbalance settlement, and hence Trip Charges should be set to zero for generators with a QEX.

PPB stated that the charges should be reduced to 5-10% of their 2017/18 rates. PPB believes that doubling the rates are a punitive charge, and that the charges should be equitable and proportionate to the impact on the system.

Several responses (ESB GT, BGE, Energia, BnM, PPB) outlined the belief that Reliability Options are another potential penalty for generators under the new market arrangements and as such an incentive for generator performance. DRAI also stated that units participating in the Balancing Market are at a greater risk of Difference Charges than those that already have a market position. Therefore, the comment by the TSO that such units are not incentivised is not a true reflection of the charges that are applicable in the markets.

With regard to units without a QEX, BnM is of the opinion that there is no strong rationale for an increase and believes that double penalties are occurring. BnM believes that the TSOs are not factoring in the element of exposure to Difference Charges (under an RO contract) regardless of the DAM position. BGE supported the need for costs to be appropriately levied on units such that they are incentivised to be balance responsible and mitigate DBCs, but asked for further supporting quantitative information to support the decision regarding the appropriate charges for units without a QEX.

Energia outlined that a Trip or SND event is almost always due to technical issues which are unavoidable, and that having a DAM position has no influence on the event. PPB also outlined that trips and SNDs are the result of technical issues with the generating units and are not connected in any way to OSC financial incentives.

PPB stated that units operating without a QEX will be paid as per their Balancing Market Complex offers and that there is no profit in running as a result.

TEL stated that the TSOs should eliminate Trip Charges associated with units that have a QEX. TEL believe that under the current regime, units with a QEX are being penalised by two mechanisms during trips.

It is the view of ESB GT that the Balancing Market should be utilised to signal the impact of trip events on the system rather than the application of Trip Charges. ESB GT suggests that Trip Charges could be retained in the short term for these without a QEX, but priority should be given in the development of an in market-based solution.

ESB GT states that SND charges are no longer appropriate under the revised SEM arrangements, since the changes to the capacity remuneration mechanism have removed the link between a unit's availability and its capacity market revenues, and has introduced exposure to changes for failure to deliver during periods of scarcity. ESB GT therefore puts forward the view that if a long notice period unit that is providing no system services becomes unavailable with no notice, there may be little or no impact on system security. On this basis the SND charging framework risks being arbitrary and unreflective of underlying cost drivers.

ESB GT also expressed the view that SND charges should be replaced with modifications to the DS3 performance monitoring framework. The performance monitoring framework under the DS3 framework includes outline provisions for performance scalars, for service providers, to be reflective of their ability to meet their forecast level of service provision over a six-hour window. ESB GT welcomed the opportunity to engage on this initiative.

2.1.2 TSOs' Response

The TSOs welcome the comments received in relation to the impact of the revised market arrangements on Trip and SND charges. In responding to the comments, the TSOs believe it is helpful to revisit the mechanisms for the creation of Imbalance Charges, Imperfections Charges, Trip Charges and SND Charges. The TSOs also believe it is helpful to outline the interrelationships and dependencies between them.

The sudden unavailability of generation triggered by a trip and/or SND and resultant energy imbalance will impact on both Market Operation and Power System Operation. For Market Imbalance Settlement, an imbalance other than those caused by the TSO, is settled at the Imbalance Settlement Price. In the case of a trip, there will be an Imbalance Charge. In the immediate aftermath of a trip or SND when the System Operator dispatches a unit away from its

QEX to restore the power system to a secure state, then the TSO action is settled at the better of the Imbalance Settlement Price and the unit's Bid Offer Price.

In doing so, a settlement imbalance is created where payments out can be greater than the charges in to cover them. This triggers the creation of Premium and Discount Components and the resultant Imperfections Charges which are covered through an additional charge to Supplier Units (and thus the end-consumer). The purpose of the Imperfections Charge is to recover costs which cannot be recovered through the other charges in Imbalance Settlement.

In addition, the TSOs will take action to hold online regulating reserve[2] in anticipation of a trip, and this will include moving units away from their QEX position.

Example of Generator Tripping and Actions taken to Secure the Power System

The tripping of a large unit (above 100 MW) will often trigger the dispatch-up of an online unit at a price higher than the Imbalance Settlement Price, and/or synchronisation of fast start-up units. These fast start-up units usually have the ability to ramp up from cold iron to base load within the 5-20 minute timeframe. These technologies help to stabilise frequency and restore reserve provisions, which may have been exhausted by the tripping. There can also be other non-energy system concerns for the TSOs after a tripping, such as reactive power control, active power flows and the transient stability of the system. All of these can be adversely impacted by a trip and/or SND and will likely require that the TSOs dispatch units out-of-merit. These actions are often referred to as non-energy actions.

Non-energy actions taken as a result of a trip cannot always be made as per merit-order, with the dispatch decisions being centred around time constraints and system security concerns. As a result, these actions are likely to create additional Dispatch Balancing Costs (CDISOUNTS, CPREMIUMS) and Fixed Costs Payments (CFCs). These costs contribute towards Imperfections Charges, and are not linked to operational constraints but are caused by the action taken to restore system stability in the short term. These costs will exist regardless of whether or not the causer unit had a QEX and are levied on all Supplier Units and therefore ultimately on the end consumer.

It is recognised that with a QEX, energy balancing costs are covered through the imbalance arrangements. In doing so, the TSOs agree that Imbalance Charges capture to a certain extent the impact of trips and SNDs, on the cost of running a balanced system in real-time. However, this does not change the fact that there are non-energy costs associated with the trip/SND which could still arise even when the system has regained energy balance. Therefore, the TSOs recommend Trip/SND Charges as a direct method of reducing imperfections triggered by trip/SND related non-energy actions. Rather than Trips/SND Charges being an instrument with which to exercise oversight on a market (as perceived by some participants), the Trip/SND Charge is a levy to represent the additional non-energy cost of the trip/SND, on a causer pays basis, rather than socialising it across all consumers through imperfections.

[2] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_94_May_2020.pdf

Incentivisation for Reducing Imperfection Charges Associated with Trips and SNDs

It is the TSOs' opinion that effective incentives need to be in place to minimise sudden changes in availability of units, which will have a negative impact on power system security and the cost of maintaining a secure Power System for all users (i.e. increase Imperfection Charges).

The TSOs view Trip and SNDs Charges to be direct incentives for reducing Imperfection Charges, since they incentivise good performance and are netted off Imperfection Charges over the year.

Imbalance Charges/Payments are a Market Settlement mechanism to account for the differences between a unit's traded volumes and its actual metered output when the difference was not instructed by the TSO. With regard to Imperfections, the TSOs view Imbalance Charges as an indirect incentive in minimising the non-energy cost impacts of trips/SNDs. The charges cover the energy balancing costs and can contribute towards good generator behaviour in terms of availability, but do not directly mitigate the cost of securing the Power System against sudden loss of generation infeed and/or availability (i.e. they are not netted off Imperfection Charges caused by trips/SNDs).

The TSOs believe that a direct incentive is still needed under the revised market arrangements, regardless of a unit's QEX, to protect the end user from the additional costs triggered by trips/SNDs. Imbalance Charges alone without Trip Charges and SNDs, would leave the end consumer exposed to Imperfections Charges, without a direct method of cost recovery. The TSOs do recognise the positive impact of Imbalance Charges on capturing the impact of trips and SNDs on the cost of running a balanced system, and thus proposes the continuation of the reduced rates for units with a QEX.

TSOs' response in relation to Imbalance Charges, Trip Charges and SND Charges

With reference to SSE's assertions that Trip Charges and SNDs are a blunt instrument for market oversight, that they are the legacy of the old market and that the TSOs need to address the confirmed principle that the market is already balance responsible. The TSOs would like to reiterate the purpose of Trip and SND Charges (as explained above). The TSOs do not agree that Trip and SND Charges are an instrument to exercise market oversight. The aim of these charges is to reduce Imperfection Charges by creating a direct incentive for generators to minimise trips and SNDs. They are not utilised for ensuring balance responsibility and are not a market mechanism. The rates are focused on the recovery of some of the costs associated with non-energy actions, triggered by trips/SNDs, on a causer pays basis, rather than these costs being socialised across consumers through imperfections.

Trip and SND Charges are paid by the generator, to offset some of the Dispatch Balancing Costs caused by the sudden change in availability. SND Charges incentivise timely notification of availability changes and Trip Charges incentivise slow wind-downs rather than trips. Both these incentives will reduce the potential impact on the Power System and Dispatch Balancing Costs.

With reference to the comment from SSE that trading out of a unit's DAM market position after a trip, is not considered in the levying of trip charges. In the determination of the Trip Charge rate to be applied, the TSOs are proposing to use the QEX position over a number of trading periods, immediately after the trip, for which the gate closure time will have expired. Since the unit will not be able to trade out of these QEX positions, due to gate closure, then the lower Trip Charge rate will apply, and the unit can trade out of any subsequent trading periods, without any interference on the applied rate.

With regard to a trip, it is expected that the unit Trip and SND Charges will be less than the system cost as a result of the trip, including the costs of holding reserves. As such, the charges are an incentive and will not recover the entire cost borne by the consumer.

Regarding BGE's assertion that units with a QEX should be exempt from Trip and SND Charges. The TSOs have outlined how Imperfection Charges can be increased by the tripping of a unit, regardless of whether the unit has a QEX or not. The TSOs recognise the incentive of balance responsibility (i.e. exposure to Imbalance Charges), but this does not directly reduce the impact when a trip or SND triggers Imperfection Charges, nor does it account for the cost of holding reserve in anticipation of a trip. Hence a reduced rate for units with a QEX is prudent, but completely removing would have an unfair negative impact on Imperfection Charges, since it does not account for the need to recoup the cost of non-energy actions.

In response to the comments from PPB surrounding the proportionality of Trip Charges; the formula that calculates the quantity of the charge does account for the amount of MW lost to the system. Slow wind-downs are also incentivised. This was outlined in the 2019/20 Recommendation Paper[3] in response to PPB. An example was also outlined to demonstrate that the larger the trip, the larger the charge.

PPB also stated that doubling the rates is punitive. The TSOs maintain that the charges were reduced by 50% in 2018/19 in anticipation that the energy balancing costs of a trip would be covered by the imbalance arrangements of the revised market arrangements. This is not the case for units without a QEX, leaving the consumer exposed to potential energy balancing costs and non-energy action costs. Hence the proposal to return to the 2017/18 rates, adjusted for inflation, for units without QEX.

Energia outlined that a Trip or SND event is almost always due to technical issues, which are unavoidable, and that having no QEX has no influence on the event. PPB also outlined that trips and SNDs are the result of technical issues with units and are not connected in any way to OSC financial incentives. The TSOs cannot comment on methods that might be taken by participants to improve the reliability of Generation Units. However, the TSO can comment on the cost associated with these technical issues in terms of Imperfection Charges, and are of the opinion that consumers should not be unfairly burdened when these Imperfection Charges arise. The TSOs therefore propose the current causer pays charging basis rather than socialising the costs across consumers.

Regarding the statement from Energia, that there is no evidence that units without a QEX are tripping more often, or are creating more SNDs. The introduction of two rates for units with and without a QEX, is not in recognition of a difference in behaviour. The TSOs would like to clarify that a reduced rate for units with a QEX, is in recognition of the fact that energy imbalance costs are covered by imbalance arrangements, and that Imbalance Charges are also an indirect incentive, in reducing Imperfections.

With reference to the comment from PPB, that units without a QEX will have no profit from running because of settlement using Complex Offers. Complex Offers must be submitted under the Bidding Code of Practice and are often lower than Simple Offers. The TSOs cannot comment on the profitability of operating units and/or trading strategies.

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[3] http://www.eirgridgroup.com/site-files/library/EirGrid/OSC-19-20-Recommendations-Paper-With-Responses.pdf

In relation to SSE's suggested alternatives, such as removing locational constraints and addressing the 'must-run' approach. The TSOs believe it worth noting that many of the constraints are not locational constraints but are active system-wide constraints, such as Reserve (regulating and replacement), Inertia and SNSP (System Non-Synchronous Penetration).

The TSOs are continuously endeavouring to remove constraints and reduce the need for 'must-run' units, and are incentivised by the RAs to do so. Most recently, the TSOs have reduced constraints associated with the 400 kV network in Ireland[4] and the North West Generation constraint in Northern Ireland. There is also a DS3 programme that will reduce the constraints associated with SNSP and Inertia. SNSP has increased permanently from 50% to 65% in April 2018, which was a world first. There are plans to increase to 75% in a phased approach in the near future. These changes will be introduced alongside a reduction in the inertia limits, increase in RoCoF limits and a reduction in the number of 'must-run' units on the island of Ireland.

Regarding the second SSE suggestion of addressing the issue of units not trading in the DAM; Trip Charges are not intended as a market mechanism or an incentive to trade in the DAM.

With regard to the third SSE suggestion of an initiative to manage trips by trading out of the lost capacity to cover the impact on security of supply; any market mechanism for trading out of lost capacity would not deal with the real-time System Operations non-energy impact. For example, any proposed mechanism should incentivise the speed of wind-down during a tripping event to reduce the impact on the system. The current mechanism which includes incentivising slow-wind downs is effective at doing this.

The final SSE proposal was to review complex BODs to address the specific issues trying to be managed. The TSOs believe that a market mechanism such as this would not be effective at mitigating the non-energy impacts of trips and SNDs.

Regarding the statement from BnM that they do not see a strong rationale for the proposed increase and their belief that double penalising is occurring. The TSOs are of the opinion that Trip and SND Charges are not double charging but are a reasonable method for recouping some of the costs from associated non-energy actions.

BnM also stated that Trip Charges for units with a QEX should be reduced by 100%. The TSOs believe in a causer pays basis for Trip and SND Charges. It is the TSOs' opinion that this is preferable to socialising the costs across consumers through Imperfections. The TSOs are also of the opinion that Trip/SND Charges do not cover the total Imperfections cost of trips/SNDs, including the cost to hold reserve (regardless of QEX).

TEL stated that with Trip Charges, units with a QEX are being penalised by two mechanisms during a trip. As already stated, regardless of a unit having a QEX, the tripping of that unit will trigger non-energy action by the TSOs to stabilise the power system. The TSOs are of the opinion that the cost of these actions should be on a causer pays basis.

The TSOs acknowledge the proposal from ESB GT for a market-based solution for solving the impact of trip events on the system. The TSOs are of the view that the development of a market-based solution/incentive is not realistic now given the continued development of the revised market arrangements, and the need to incentivise slow-wind downs.

Regarding the assertion from ESB GT that SND Charges are not appropriate under the revised SEM arrangements, and the scenario of the sudden unavailability of a desynchronised long-term

[4] http://www.soni.ltd.uk/media/documents/OperationalConstraintsUpdateVersion1_94_May_2020.pdf

notice unit having little impact on system operations. The TSOs believe that the sudden unavailability of a desynchronised unit in the 8-hour window could have an impact on the power system, both in terms of meeting system margin requirements, and enabling secure and efficient scheduling. There are at least six Long-Term-Schedules (LTS) published in a 24 hour period, and depending on system conditions and generator heat states, the MMS may schedule a long notice unit in any of these schedules for a number of reasons. These reasons include changing market positions, cross-border flows, forecast errors and system events. Long-term notice desynchronised units which are included in LTS runs may be available within a 1-2 hours notification timeframe depending on their heat state.

The TSOs believe that the most equitable manner to incentivise behaviour in relation to availability is to impose a charge, proportional to the impact, and this is how the methodology is implemented (i.e. based upon the notice time and MW reduction).

ESB GT also proposed utilising the DS3 programme to replace SND Charges, in monitoring unit MW Availability. The DS3 Performance Scalar referred to in the ESB GT response is known as the Availability Discount Factor, which has yet to be implemented. Implementation will require industry consultation and final approval by the Regulatory Authorities. It should be noted that this Performance Scalar is based on System Services availability and not MW availability. This is not to say that the eventual Performance Scalar could not include MW availability. The TSOs welcome the offer from ESB GT to engage in the development and implementation of the Availability Discount Factor Performance Scalar. However, the initiative or any variation of the initiative will not be in place for the 2020/21 year.

<u>TSOs' Response in relation to Reliability Options</u>

Several respondents (including BnM, PHG & PPB) highlighted a view that Reliability Options (RO) are another potential penalty for generators in the new market arrangement and as such an incentive for generator trip performance. However, BGE asserts that units without a QEX avail of RO payments and thus must deliver value for the consumer, and not add to consumer costs via Dispatch Balancing Costs. BGE have requested quantitative information to support the decision as to the appropriate charge levels for units without QEX. BnM have asserted that the consultation does not account for the risk associated with significant charges, which units having an RO contract are exposed to (regardless of DAM position).

Reliability Options are used to incentivise behaviour to reliably provide energy when it is most needed (i.e. during a scarcity pricing event). RO's are a Capacity Market mechanism creating the correct incentives which enact the policy around energy security. This ensures that the system has the level of capacity required to maintain security of supply in future years.

If the imbalance settlement price is above the strike price for a trading period, units that have been awarded capacity in a Capacity Remuneration Auction (CRM), must pay back the difference, while Suppliers must be paid the difference. This ensures that energy security is linked to the physical reality of meeting demand in real-time.

Since Difference Charges are designed to ensure that capacity awarded in a CRM auction is fully available when demand requires that they generate, then it can be regarded, to an extent, as a mechanism that encourages balance responsibility in real-time. However, in the case of a trip or SND, Imperfection Charges can also arise (explained earlier), which are not accounted for in Difference Charges.

As a result, the TSOs are of the view that Trip and SND Charges are still needed to recoup some of the cost of the non-energy actions taken after a trip/SND, to secure the power system.

2.1.3 TSOs' Recommendations

The TSOs recommend increasing the rate of Trip Charges and SND Charges for generators without a Day Ahead Market position (QEX) to that which aligns with 2017/18 tariff, before the introduction of the revised SEM arrangements, adjusting for inflation. The TSOs also recommend retaining the reduced rate of Trip Charges and Short Notice Declarations for generators with a Day Ahead Market position (QEX), adjusting for inflation.

2.2 Demand Side Unit (DSU) Short Notice Declaration (SND) Charge

In the consultation paper the TSOs proposed the introduction of a SND Charge, with a threshold of 5 MW, for the 2020/21 tariff year.

2.2.1 Respondents' Comments

DRAI and PHG highlighted their concern in relation to the proposal to include SND Charges for DSUs. Both DRAI and PHG stated that SNDs are inappropriate for DSU technologies, and the inclusion of the DSU SND in the consultation emphasised the need for the DRAI and the TSOs to work together.

Both the DRAI and PHG responded to the TSOs' comment that trips/SNDs can impact on Imbalance Price, stating that DSUs are usually used for system support and hence any DSU SND would not have an impact on the price.

DRAI and PHG stated that the majority of DSUs participate in the Balancing Market only. As a result, they are both of the opinion that the introduction of OSC for DSUs should be deferred until such time as their contributions and payments are properly recognised, and they can be treated equally with other participants.

Regarding the proposed SND threshold of 5 MW over a time window of 8 hours, the DRAI and PHG were concerned that a number of declarations (each under 5 MW) could materialise within the 8 hour window.

DRAI and PHG stated that the forecast availability, provided via the Balancing Market MPI, is not expected to match exactly what is declared in EDIL during the day, and that this is the nature of forecasting. An alternative approach was proposed, utilising the forecast, along with the many EDIL declarations throughout the day, to identify if a DSU is giving a Short Notice Declaration, or if it is just following its expected availability reduction.

The DRAI and PHG also suggested that no decision is made and that the issue is addressed in subsequent consultations due to the intention to enact the SND in October 2020. This would give time to examine the issues thoroughly, with full industry engagement.

BGE accepted the intent behind applying such charges to DSUs, but stated that it seemed unintuitive to not also be applying appropriate charges to wind and solar.

Energia stated their support for the introduction of the SND Charges for DSUs

2.2.2 TSO's Response

The TSOs are aware of the challenges with regard to forecasting availabilities for DSUs, and do not have an expectation that EDIL declarations will exactly match submitted MPI Forecast Availability. However, effective scheduling of DSUs can only be achieved through submission of appropriate MPI Forecast Availability (for scheduling), and EDIL declarations (for dispatch) that reflect forecasting, which is as accurate as possible.

Currently there are issues in relation to the accuracy of submission of MPI DSU forecast availability, which can distort the scheduling process, not only for DSUs but for all technologies. The TSOs have observed at times, MPI DSU forecast availability that is a factor of 4-5 times greater than the corresponding EDIL real-time declaration. This is not considered to be within the boundary of forecast error.

Consequently, the TSOs are of the opinion that a mechanism is clearly needed, which will incentivise improved submission of DSU availability. Such improvements will enable more effective and economic scheduling.

The TSOs accept that the current SND methodology may not be the most appropriate for DSU technologies and that methodology modifications may be required.

The TSOs welcome meaningful engagement from the DSU Industry in developing a robust mechanism that is fair for DSUs, but also improves forecasting and real-time declarations, which will enable effective scheduling.

2.2.3 TSOs' Recommendations

The TSOs recommends delaying the introduction of a DSU SND Charge until 2021/22 to allow time to engage further with the Industry, in the development of a mechanism for improving DSU Availability submissions. The TSOs recommend immediate engagement with the Industry, with a view to a submitting revised proposal in the 2021/22 OSC Consultation.

2.3 Secondary Fuel GPI

In the consultation paper, we proposed the retention of the Secondary Fuel GPI Charge at the rate for 2019/20, apart from adjusting for inflation.

2.3.1 Respondents' Comments

ESB GT outlined their recognition for the need for an appropriate incentive structure to ensure that all system users are encouraged to fulfil their Grid Code Obligations. However, ESB GT highlighted that any charges should be cost reflective under Article 18 of the Electricity Regulation (EU2019/943). ESB GT stated that in consideration of Article 18, it is not clear that some of the current GPIs are sustainable, particularly the Secondary Fuel GPI. ESB GT also asserts that the requirements under the Grid Code for secondary fuel capability are placed on a subset of generators, with no mechanism in place for the resulting incremental costs to be recovered, and in this context it is arguably discriminatory to levy a charge when secondary fuel is unavailable.

ESB GT believes that security of supply in the case of a gas supply interruption is an important policy goal, but it is not considered to be related to the recovery of efficiently incurred cost in operating the network.

ESB GT also expressed concerns regarding possible impacts on the competitiveness of secondary fuel providers within the capacity auction. ESB GT outlined that units which provide secondary fuel are being displaced within the capacity auction by other categories of capacity providers, thus undermining the policy of maintaining secondary fuel capability. ESB GT also stated that if a secondary fuel provider does clear the auction, they will do so at a price reflective of maintaining secondary fuel capability, while other categories of capacity will clear and extract rent from end users for a service they do not provide.

ESB GT proposed that secondary fuel services should be defined as an additional service under the HAS framework that has remained in place to remunerate the provision of Black Start Capability. This remuneration for this Secondary Fuel Capability service could be targeted as the incremental cost for the provision of secondary fuel capability from the Best New Entrant unit over its economic life.

PPB began with the assertion that GPIs are not required in the current market system. There should be no double charging and that it is important to consider the impact of large overly punitive charges.

PPB believes the introduction of a Secondary Fuel GPI charge was unnecessary and discriminatory. PPB stated that the introduction of a charge when there is no corresponding payment for the provision of this service is unfair. PPB assert that the charge is discriminatory since it only applies to providers of the service and does not engender equal and fair treatment of all technologies.

PPB also stated the secondary fuel has been available for many years and had rarely been required. As a result of the lack of use, PPB believes that to apply penalties is totally unacceptable particularly when conditions on the system are normal and there is no risk or potential requirement for a fuel switch.

2.3.2 TSOs' Response

The TSOs welcome the comments received in relation to the Secondary Fuel GPI.

Regarding the assertion from ESB GT and PPB that the application of a Secondary Fuel GPI is discriminatory since a mechanism for remuneration does not exist. GPIs are solely used to incentivise Grid Code compliance and there are no service payments for any of the GPIs. GPIs are particularly important in a relatively small power system to ensure that units maintain the performance required in the Grid Code. For the Secondary Fuel GPI, this is especially relevant for an island system with little interconnection and a dependence on gas-powered generation stations. Without proper controls and checks for secondary fuel compliance, the security of the power system could be compromised in event of a natural gas emergency. In terms of possible mechanisms of remuneration, the TSOs are of the opinion that this is a matter for the Regulatory Authorities.

ESB GT also outlined their reservations regarding the impact of secondary fuel provision on competitiveness within the capacity auctions. The TSOs believe that the issue raised is outside the scope of this OSC consultation.

Regarding PPB statements concerning the lack of use of secondary fuel, and there being no risk or potential requirement for a fuel switch. The TSOs would like to highlight that secondary fuel changeovers are required so that generators can continue to operate in the event of a natural gas emergency. There is no expectation to utilise the service unless an emergency arises. Despite various initiatives to mitigate the risk of a gas interruption, there still remains a level of risk of an interruption occurring, hence a potential need for a fuel changeover. The service is integral to the security of supply of both jurisdictions, and frequency of use is not an indicator of value of this service.

The TSOs would like to highlight that there has been a significant improvement in the performance of secondary fuel availability in 2019 with the introduction of this GPI.

2.3.3 TSOs' Recommendations

The TSOs recommend retaining the Secondary Fuel GPI rate from 2019/20, adjusted for inflation.

2.4 Minimum Generation GPI

The TSOs highlighted the increasing need for units not only to meet their Minimum Generation obligation, but also to provide essential system services reliably at minimum MW output. The TSOs did not propose any changes to the current format of the Minimum Generation GPI, but did highlight the need to investigate and monitor potential impacts in the coming years.

2.4.1 Respondents' Comments

PPB believe that the current Minimum Generation GPI is not required and is already addressed in the DS3 market. PPB believe that the DS3 payments are enough of an incentive and that a second incentive through a GPI is not needed. PPB also state that there should be no "double charging".

BGE stated that any changes would require further specific industry engagement, given the interactions between minimum generation and the ability to provide system services.

2.4.2 TSOs' Response

The TSOs welcome the comments on the Minimum Generation GPI.

The TSOs believe that the requirement for the Minimum Generation GPI has not changed following the introduction of the revised market arrangements. There is an increasing need going forward for units to comply with their Minimum Generation Grid Code obligations, to facilitate the operation of a low-carbon, cost effective power system. An increase in minimum generation can have a significant impact on both Imperfection Charges and renewable penetration on the island.

The TSOs do not agree that a reduction in DS3 payments as a result of declaring an increase in minimum generation is enough of an incentive to replace the Minimum Generation GPI. The TSOs would also like to highlight the fact that if a unit complies with its Grid Code requirements, no charges will be levied.

2.4.3 TSOs' Recommendations

The TSOs believe that the provision of system services at minimum generation is needed and will become even more important as the proportion of generation from renewable sources continues to increase. Therefore the TSOs will continue to monitor this issue, and the need to introduce GPIs in future consultations. For 2020/21, the TSOs recommend retaining the Minimum Generation GPI rate from 2019/20, adjusted for inflation.

2.5 New Other System Charges

2.5.1 Power Park Modules

The TSOs highlighted the possible future need for a GPI in relation to Power Park Module reactive power provision. This is driven by the increasing need for reactive power control in areas of the transmission network with a high amount of wind farm connections. The issue is integral to the safe and secure operation of a power system with a high penetration of renewables.

2.5.1.1 Respondents' Comments

SSE began by stating that should a wind farm become unavailable, that it would seem fair that the unit should be subject to some charge to reflect the impact imposed on the system. However, SSE stated that windfarms are already subject to the TSO Controllability Categorisation Policy (CCP). SSE also advocated that legacy windfarms be excluded from additional incentives where compliance with current Grid Code requirements is already challenging.

SSE stated that the TSO was minded to include windfarms in the current framework for Trip Charges. SSE stated that windfarms only trip for TSO activation of Special Protection Schemes (SPS) or TSO Over-Frequency Schemes. Since these are TSO driven actions, SSE stated the current blunt approach to trip charges would not be appropriate. SSE also outlined that the current charging regime would need to be adapted to take account of the smaller contracted position of windfarms relative to conventional units.

SSE also outlined several concerns in relation to the possible future application of a GPI for Operating Reserve to non-conventional units.

BGE stated that given the increasing share of wind and solar units in the market, and given the importance of performance monitoring and ensuring units act in line with grid requirements, BGE believes that they should be treated in the same way as conventional generation in the application of OSCs.

PPB stated that with the increase in non-conventional technologies, it is important that these technologies are incentivised to be reliable in the same manner as conventional units. Therefore, PPB believes that if GPIs are to remain, then they should be applied to all technologies.

2.5.1.2 TSOs' Response

The TSOs consulted on the potential future introduction of a GPI for Power Park Module reactive power provision. The consultation did not address any other Power Park Module GPI or charges, as outlined by SSE. There are currently no proposals for Trip Charges, SND Charges, or Operational Reserve GPIs, for Power Park Modules. It should also be noted that most Power Park Modules are below the 100 MW threshold for Trip Charges.

Regarding the comments from BGE and PPB, the TSOs are committed to the continued monitoring of Power Park Module performance, in terms of their Grid Code compliance. If issues arise that warrant the introduction of a new GPI, the TSOs will make proposals in future OSC Consultations.

2.5.1.3 TSOs' Recommendations

The TSOs are not recommending a GPI for Power Park Modules for 2020/21. However, the TSOs will continue to monitor the reactive power Grid Code compliance of Power Park Modules, and may propose a GPI, if appropriate, in the OSC Consultation for future years.

2.5.2 Emerging New Technologies.

The TSOs commented in the Consultation Paper that it was too early to propose a GPI in relation to evolving technologies, but that the situation would be monitored into the future.

2.5.2.1 Respondents' Comments

PPB stated that with the increase in non-conventional technologies, it is important that these technologies are incentivised to be reliable in the same manner as conventional units. Therefore, PPB believes that if GPIs are to remain, then they should be applied to all technologies.

It was the view of BGE that given the increasing share of wind and solar units in the market, and given the importance of performance monitoring and ensuring units act in line with grid requirements, that they should be treated in the same way as conventional generation in the application of OSCs.

BnM expressed concern that if new technologies are to be welcomed, it is important that they are not given overly beneficial conditions, thereby placing conventional generation at an unfair competitive disadvantage.

2.5.2.2 TSOs' Response

The TSOs have taken note of the responses and plan to continue to monitor the compliance of emerging non-conventional technologies.

2.5.2.3 TSOs' Recommendations

The TSOs are not recommending any GPIs for emerging technologies for 2020/21. The TSOs will continue to monitor the potential application of GPIs in future consultations.

2.6 Inflation Rate

The TSOs proposed a blended rate of 1.7% for inflation, which is based on the RA approved methodology.

2.6.1 Respondents' Comments

BGE began by acknowledging that under normal economic situations an inflation rate of 1.7% (or close to it) could have been supported. However, given the evolving economic situation due to COVID-19, BGE noted that consideration should be given to an inflation rate of zero or negative.

ESB GT stated that the rates applied for the OSC should be applied for Black Start under the HAS agreement.

2.6.2 TSOs' Response

In the current environment there is limited, if any, updated forward looking financial forecasts.

The Office of Budgetary Responsibility has not yet issued a revised report, on the latest budgetary inflation forecast for the UK, since the March 2020 report, which was used for the OSC consultation, forecasting an inflation rate of 1.7%.

The Central Bank of Ireland, and others, are not producing conventional forecasts of the outlook. The Central Bank Q2 Bulletin (for example) stated that *"Given the extent of the unknowns, it is not possible to produce a conventional forecast of the outlook. Instead, making heavy use of judgement and drawing on a range of analytical tools, an attempt is made in this Bulletin to provide some assessment and estimate of the impact of the crisis under certain assumptions."* Even where such assessments are made no firm forecast figures are called.

While the TSOs note that there is some monthly data available, given the context, the short term nature and uncertainty, it would not be appropriate to seek to extrapolate this data, for use in tariff setting, when even the banking and economic institutions themselves, have not endeavoured to do so.

The inflation rate used for the OSC Consultation was set by reference to the Q1 economic data (Central Bank report Q1 2020 and Office of Budgetary Responsibility report Mar 2020). It remains the view of the TSOs that this data is the best available, for this purpose.

The rates applied under the HAS agreement are outside the scope of this consultation.

2.6.2.1 TSOs' Recommendations

The TSOs recommend the forecast blended inflation rate of 1.7%, as per the OSC Consultation, is used.

2.7 Other Comments

ESB GT stated that they were concerned at the current approach to OSC, and the amounts levied under the mechanism. ESB GT believes that under the current regime, there is an incentive for the TSO to maximise the charges levied against generators. It is the view of ESB GT, that the OSC should be included in the DBC incentive scheme.

ESB GT also stated that the SEMC determined that the RoCoF GPI values should be excluded from the incentive calculation. As a result, ESB GT seeks clarity on the basis against which the RoCoF GPI has been charged.

2.7.1.1 TSOs' Recommendations

The TSOs would like to highlight, that any delay in the completion of the RoCoF implementation project, will contribute to delays in the updating of system-wide operational constraints, which will facilitate the move to 70% SNSP. These updates include the reduction of the inertia floor and the reduction of the minimum number of large conventional units needed on the island. This delay will increase Imperfection Charges, as the TSOs continue to 'must-run' conventional units, at the expense of curtailed wind generation. The TSOs recommend retaining the RoCoF GPI rate from the tariff year 2019/20, adjusting for inflation.

In terms of the SEMC decision, the TSOs are of the opinion that this is a matter for the Regulatory Authorities.

3 PROPOSED RATES

With respect to the blended inflation rate, the TSOs are aligning to the methodology approved by the RAs in applying a blended rate. However, the Utility Regulator has indicated that the Consumer Price Index (CPI) should be used going forward, instead of the Retail Price Index (RPI).

The TSOs, therefore, propose the following methodology to be applied:

- 75% * Central Bank HICP forecast from the latest available quarterly report adjusted for the relevant tariff timeframe; plus
- 25% * Office of Budgetary Responsibility CPI forecast from the latest available quarterly report adjusted for the relevant tariff timeframe.

According to the latest Office of Budgetary Responsibility report (Mar 2020) the current CPI year on year inflation forecasts in the UK for the 2020/21 tariff year equates to c.+1.7% while the latest Central Bank report (Q1 2020) forecasts HICP in Ireland for the same period at c.+1.7%.

Source		**2020**	**2021**	**Tariff Year Methodology**	**2019/2020 Tariff Year**	**Blended Rate Methodology**	**Blended rate**
OBR March 2019	CPI	1.4%	1.8%	(0.014*25% + 0.018*75%)	1.7%	1.7*25%	0.425
Central Bank Q1 2020	HICP	1.4%	1.8%	(0.014*25% + 0.018*75%)	1.7%	1.7*75%	1.275
Blended Rate							**1.7%**

Table 4.0: Proposed Inflation Rate Increase

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate for the forthcoming 2020/21 period is 1.7% as shown in Table 4.0.

3.1 Trip Charges

The proposed Trip Constants for the 2020/21 tariff year are shown in Table 4.1. There are no changes proposed.

	2018-2019	2019-2020	2020-2021
Direct Trip Rate of MW Loss	15 MW/s	15 MW/s	15 MW/s
Fast Wind Down Rate of MW Loss	3 MW/s	3 MW/s	3 MW/s
Slow Wind Down Rate of MW Loss	1 MW/s	1 MW/s	1 MW/s
Direct Trip Constant	0.01	0.01	0.01
Fast Wind Down Constant	0.009	0.009	0.009
Slow Wind Down Constant	0.008	0.008	0.008
Trip MW Loss Threshold	100 MW	100 MW	100 MW

Table 4.1 Proposed Trip Constants

Based on the reasoning in Section 3.2, Table 4.2 contains the Trip Charge proposals for units with a QEX while Table 4.3 contains the Trip Charge proposals for units without a QEX.

Charge	**2017-2018**	**2018-2019**	**2019-2020**	**2020-2021**
Direct Trip Charge Rate	€4,322	€2,161	€2,190	€2,227
Fast Wind Down Charge Rate	€3,242	€1,621	€1,642	€1,670
Slow Wind Down Charge Rate	€2,161	€1,081	€1,095	€1,114

Table 4.2: Proposed Trip Rates For Units With a QEX[1]

Charge	**2017-2018**	**2018-2019**	**2019-2020**	**2020-2021**
Direct Trip Charge Rate	€4,322	€2,161	€2,190	€4,454
Fast Wind Down Charge Rate	€3,242	€1,621	€1,642	€3,340
Slow Wind Down Charge Rate	€2,161	€1,081	€1,095	€2,228

Table 3:3: Proposed Trip Rates For Units Without a QEX[2]

[1] The 2019/20 & 2020/21 Proposed Trip Rates For Units With a QEX have been changed(marginally reduced) from those in consultation paper to reflect approved 2019/20 rates, rather than recommended 2019/20 rates.

[2] The 2020/21 Proposed Trip Rates For Units Without a QEX have been changed (marginally increased) from those in consultation paper to reflect application of inflation for every year since 2017/2018.

3.2 Short Notice Declarations

A SND can have the same impact on scheduling and dispatch as that of trips. These short notice outages can have a significant effect on the ability of the TSO to schedule and dispatch in an economic manner and also to manage Transmission Constraint Groups which are essential to the secure operation of the transmission system.

Similar to Trip Charges, the TSOs believe the reduced rate of SND introduced in 2018/19 is not appropriate for generators without a QEX. If the unit does not have a QEX, then the reduced rates do not reflect the cost to the TSOs of a SND, since the unit will not be liable for Imbalance Charges in the Balancing Market if they are scheduled.

There must be adequate incentives for generators without a QEX to optimise their availability in the Balancing Market to allow the TSOs to manage system constraints, trips and sudden drops in wind generation (compared to forecasts), and ultimately reduce costs to the end consumer.

Table 4.3 shows the proposed SND Constants for 2020-21.

SND Constants	2018-2019	2019-2020	2020-2021
SND Time Minimum	5 min	5 min	5 min
SND Time Medium	20 min	20 min	20 min
SND Time Zero	480 min	480 min	480 min
SND Powering Factor (Notice time weighting curve)	-0.3	-0.3	-0.3
SND Threshold	15 MW	15 MW	15 MW
Time Window for Chargeable SNDs	60 min	60 min	60 min

Table 4.3: Proposed SND Constants

Table 4.4 shows the proposed SND Charge Rate for Generating Units with a QEX.

SND Charge Rate	2017-2018	2018-2019	2019-2020	2020-2021
SND Charge Rate	€76 / MW	€38 / MW	€38 / MW	€39 / MW

Table 4.4: Proposed SND Charge Rate for units with a QEX

Table 4.5 shows the proposed SND Charge Rate for Generating Units without a QEX. The TSOs are proposing a return to the 2017/2018 tariff year adjusted for inflation.

SND Charge Rate	2017-2018	2018-2019	2019-2020	2020-2021
SND Charge Rate	N/A	N/A	N/A	€77 / MW

Table 3:5: Proposed SND Charge Rates for units without a QEX

3.3 GPI Charges

The proposed GPI Constants, GPI Declaration Based Charges and GPI Event Based Charges for the 2019/2020 tariff year are outlined in Table 4.6, Table 4.7 and Table 4.8 respectively. The TSOs are proposing to make no changes, apart from adjusting for inflation.

GPI Constants	2018-2019	2019-2020	2020-2021
Late Declaration Notice Time	480 min	480 min	480 min
Loading Rate Factor 1	60 min	60 min	60 min
Loading Rate Factor 2	24	24	24
Loading Rate Tolerance	110%	110%	110%
De-Loading Rate Factor 1	60 min	60 min	60 min
De-Loading Rate Factor 2	24	24	24
De-Loading Rate Tolerance	110%	110%	110%
Early Synchronous Tolerance	15 min	15 min	15 min
Early Synchronous Factor	60 min	60 min	60 min
Late Synchronous Tolerance	5 min	5 min	5 min
Late Synchronous Factor	55 min	55 min	55 min
Secondary Fuel Availability Factor	0.9	0.9	0.9

Table 4.6: Proposed GPI Constants

	2018-2019	2019-2020	2020-2021
GPI Declaration Based Rates	**€ / MWh**	**€ / MWh**	**€ / MWh**
Minimum Generation	1.29	1.31	1.33
Max Starts in 24 hour period	0.00	0.00	0.00
Minimum On time	0.00	0.00	0.00
Reactive Power Leading	0.32	0.32	0.32
Reactive Power Lagging	0.32	0.32	0.32
Governor Droop	0.32	0.32	0.32
Primary Operating Reserve	0.52	0.53	0.54
Secondary Operating Reserve	0.13	0.13	0.13
Tertiary Operating Reserve 1	0.13	0.13	0.13
Tertiary Operating Reserve 2	0.13	0.13	0.13
Secondary Fuel Availability	0.03	0.03	0.03

Table 4.7: Proposed GPI Declaration Based Charge Rates

The Event Based GPIs will remain at zero (i.e. Loading Rate, De-Loading Rate, Early Synchronisation and Late Synchronisation).

4 NEXT STEPS

Once the RAs have considered these recommendations and made their final decisions, the TSOs will publish revised Statements of Charges and an Other System Charges Methodology Statement for the 2020/2021 tariff period.

5 RESPONSES

Integrated Single Electricity Market

Harmonised Other System Charges Consultation
Tariff Year
01 October 2020 to 30 September 2021
8 April

Consultation Response from

May 2020

Recommendations

Context & Recommendation:

Bord na Móna welcomes the opportunity to respond to this consultation.

We understand that Trip, SND & GPI Charges are put in place to incentivise behaviours – having originally been set before the new market arrangements.

In this regard, we recognise and appreciate that Trip and SND charges were reduced by 50% in 2017/18, in recognition of SEM and of ISEM and the market signals from exposure to imbalance pricing.

While this was a welcome development at the time we note now that market conditions have changed in that Day Ahead prices are low and are likely to remain so with low-priced gas for the foreseeable future as well as low energy prices due to increased renewables on the system. The effect of this, in general, is to magnify the difference between the much-reduced Day Ahead prices and the relatively higher Imbalance price.

This is relevant in consideration of the treatment of ***Trip Charges and SND Charges for Generators with a QEX Day Ahead position***

Because of this increased pricing differential, there is likely to be for some time, an increased market signal to generators to be balance responsible. Given that additional Trip and SND Charges are excessively punitive, it follows that there is no need to have extra market signals in the form of any Trip or SND Charges. RO difference charges also need to be considered, and the risks associated with same, which we do not believe are factored in with these proposals.

Consequently, we put forward that the proposed rates should be reduced by 100% vs 2017/18 rates, subject to review in two years. This is our favoured proposal.

We believe that this is a strong and justified proposal but also set out an alternative, less favoured back-up proposal should our initial proposal be rejected.

This back-up proposal is that for generators with a QEX Day Ahead position, that there are sufficient market signals within new market arrangements that Trip Charges and SND charges should be capped at the greater of Net Imbalance Charge vs the Sum of Trip and SND charges.

We believe that both of these approaches have merit on the basis that they both support desired market behaviours. We recognise that to do otherwise would be to have what is effectively a double charge, which is market inefficient and which reduces social welfare, with our favoured proposal being considerably more market efficient than the second.

Secondly, with regard to the treatment of ***Trip Rates and SND Rates for Generators without a QEX Day Ahead position***. We do not see a strong rationale for their proposed increase to the level which aligns with the 2017/18 tariff before the introduction of the revised SEM arrangements.

We note that it appears from the statistics that the occurrence of trip and SND events has increased since the introduction of SEM due to the unavoidable technical issues behind the events which arose, with no noted unexpected bias towards units with or without a QEX.

We feel that it is important to emphasise that SEM has brought its own market incentives which help define desired behaviours and that we do not see merit in double penalising. In this regard, we would note that the consultation does not appear to be factoring any element of risk, or exposure, to the very significant difference charges which units having an RO contract have – regardless of their QEX Day Ahead status. This risk needs to be taken into consideration given the impact of the previous RO events under the new market arrangements.

Lastly, we note the importance of equal terms, specifically between conventional and new emerging technologies. We note that TSOs recognise the changing nature of the transmission system and the emergence of new technologies and services, and their expression that it is still deemed too early to propose any GPI in relation to evolving technologies. While these new technologies are to be welcomed it is important that they are not given overly beneficial conditions, thereby placing conventional generation at an unfair competitive disadvantage.

We hope that you find these comments of use and submit them for your consideration. We would be pleased of course to discuss any aspect of our responses should you so wish.

For and on behalf of Bord na Móna

Justin Maguire

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Other System Charges 2020-21

SSE response

Introduction

SSE welcomes the opportunity to comment on Other System Charges 2020/21 issued for public consultation by EirGrid*.* For the avoidance of doubt, this is a non-confidential response.

Other System Charges (OSC) are levied on generators, which fail to provide necessary services to the system. The OSC includes charges for generators if its unit trips, or make downward re-declarations of availability, at short notice.

The consultation proposes:

- A rate of Trip Charges and Short Notice Declarations for generators with and without a Day Ahead Market position (QEX), and
- Retain OSC rates approved for the tariff year 2018/19 for specific Generator Performance Incentives (GPIs), only adjusted for inflation.

SSE Response

The majority of the paper relates to existing GPIs and OSC generally. In large part these are more applicable to thermal units, however there are some impacts to our renewables units as well. We have provided commentary relating to the impacts of these proposals on renewables, in addition to general comments on these proposals and their impact on generators.

General comments relating to GPIs and OSCs

The TSOs are proposing increases to trip charges and Short Notice Declarations (SND), in addition to rates updates for specific GPIs.

We are not supportive of retaining trip charges and SNDs, where they are clearly a legacy from the old market and were designed with that market in mind. In our view, retaining these specific charges as currently cast, creates disincentives and/or double-penalises generators in a new market that creates the market forces and signals necessary for appropriate participant behaviour. We provide further detail below.

We also note the intention to retain the OSC rates approved for the 2018/2019 tariff year for a selection of GPIs, adjusting for inflation at forecast rate only. We would consider that these rates should rather be reset given the lag and significant market changes since they were last calculated, e.g. commodities. We would not be in favour of simply adjusting for inflation at the forecast rate.

Trip charges and SNDs

We acknowledge that trip charges were reduced in recognition of the new SEM market arrangements and the assumption that as all units would be balance responsible, this would incentivise trading on the Day Ahead Market (DAM). The TSOs are now proposing increasing the levels for those without a traded QEX position to pre-SEM levels and retaining the lower level rates for those with a QEX position. We are not in favour of this approach.

Trip charges for those with a QEX position

We are not in favour of trip charges being retained for those with a QEX position. The RAs have recently confirmed that the current system is compliant with balance responsibility principles, which indicates that it has sufficient consequences and benefits to motivate the appropriate behaviour. Thus, rendering trip charges & SNDs for these types of units unnecessary.

Trip charges are a blunt instrument with which to exercise oversight on a market that otherwise provides the correct consequences and benefits where a unit causes a system imbalance. For instance, it is not clear which one of the periods in the DAM auction should be allocated as a unit's QEX position. In the case that a unit is trading in the wrong DAM period, they could still be levied a trip charge should they trip. It is also clear that if there is a traded position in another market, this appears to be irrelevant. Where a unit seeks to be responsible in trading out its position in the Balancing Market to cover the imbalance their unit trip has caused, (bearing in mind that Intra-Day markets suffer from low liquidity and may not be suitable), this is not a factor considered in the levying of trip charges. The current cast of the trip charge mechanism thus encourages a unit not to try to remedy the impact their trip has had on the market.

Finally, under this new market, the retained OSC does not account for unintended consequences in imbalance settlement. The management of trips would be accounted for in imbalance settlement but isn't considered in the penalty framework of trip charges.

Trip charges for those without a QEX position

We are not in favour of increasing the trip charges to seek to incentivise a narrow margin of units to trade positions on the DAM. Levying trip charges on all units as a purported incentive, is not the method to encourage specific units to trade a position on the DAM. Specifically, not under the new more sophisticated market design, where such incentives should be adjusted to reflect the new market forces present.

The trip charges appear to be being used to incentivise alternative behaviour as it relates to locational constraints. Units behind a locational constraint have the advantage that the constraint weakens the need to sell the assets. TSOs seek to penalise these units (correctly) for a trip on a BOA relating to a locational issue but are doing so via a blanket approach relating to having a single traded position or not. This is disproportionate and lacking in sufficient clarity. There is also no evidence that the current approach is having the desired effect. The overall effect is rather to increase EirGrid revenue, with no clarity as to how this will ultimately benefit customers.

Finally, the unintended consequences of this blunt instrument, are not clear. For instance, if the trip is intra-gate and therefore cannot be changed within gate, this will have an unfair impact on settlements. Unintended consequences and complexities of the new market arrangements have not been considered when retaining the current cast of these incentives.

Better solutions to the issues trying to be remedied by trips charges & SNDs would be:

- to remove locational constraints and address the must run approach (which may impact the appetite for certain units to trade on the DAM)
- address the issue of units not trading positions on the DAM. It could be considered whether all units should be required to hold single specific daily positions in the DAM. Though an aside on this is the impact of Brexit and a decoupled DAM.
- if trip charges are still needed under the new market arrangements, they should be adjusted to reflect the new market design. One consideration is how units manage trips. Management of trips should include for instance consideration of other traded positions and trading out of the capacity to seek to cover the impact. We think these are behaviours that should be encouraged and can be seen to be helping to address security of supply.
- Another approach could be to review complex BODs to address the specific issues trying to be managed (i.e. non-DAM positions for some units, and reduced incentives to sell assets behind locational constraints), rather than resorting to a centralised revenue metric.

The new SEM went live in 2018, and with it, a new market system that provides balance responsibility and appropriate consequences if a unit causes a system imbalance. TSOs need to address the confirmed principle that the market is already balance responsible, and the application of this incentive structure designed for the old market. Therefore, under the new framework, trip charges and SND should no longer be required.

Comments relating to windfarms under OSC

We note that the consultation considers introducing GPIs for windfarms. Given that windfarms have contracted with the TSOs and are being scheduled for their capability, it would seem fair that should a windfarm become unavailable (at short notice or due to their own trip), this site should be subject to some charge to reflect the impact imposed on the system.

However, we would not be supportive of including windfarms in the current OSC framework without sufficient justification. We have provided some issues for consideration, given that the current cast of the GPIs would not account for the complexities associated with introducing these requirements for windfarms.

Application of OSC to windfarms

In the first case, windfarms are already subject to the TSO Controllability Categorisation Policy (CCP), which is not explicitly an OSC but has the function of incentivising windfarm generators to comply with Grid Code Requirements. The existing CCP is fair in that windfarms which aren't responding to Active Power Setpoints get switched off first. Otherwise, these units would benefit from seeing no dispatch while compliant windfarms have to take an additional burden. This appears to then act as an incentive in the same way as GPIs. Having two sets of similarly driven incentives would be a disproportionate additional burden for relevant windfarms.

We note that the paper does consider legacy windfarms who may have lodged derogation requests since they are currently non-compliant with newer Grid Code requirements (i.e. they are compliant with the Grid Code V4.0). A large majority of the windfarms seeking derogations would be older than 2014 and would not contribute such a large portion of the overall windfarm portfolio on the system, given the high degree of development since 2014. We would advocate that legacy windfarms be excluded from additional incentives where it is clear that compliance with current Grid Code requirements is already challenging.

Application of trip charges

We note from the paper the TSO is minded to include windfarms in the current framework for trip charges. Generally, windfarms only fully trip out for TSO SPS or TSO Over-Frequency scheme activations. These are clearly TSO driven actions. In the case of genuine windfarm trips, it is much more likely a windfarm will lose an individual wind turbine for a fault rather than the entire site being lost. Loss of one or a number of turbines is only going to degrade performance by a small percentage, and not result in a loss of the entire capability. The current blunt approach to trip charges would not be appropriate in this case.

The current charging regime would also need to be adapted to take account of the smaller relative contracted position of windfarms relative to conventional units. The current OSC framework would not be suitable in its current format to account for this. If the TSO is minded to include windfarms under GPIs, we would urge that there is clear industry participation to agree on a charging regime which is fair and proportionate, and that there is clarity on these incentives as compared to the existing CCP.

Application of GPIs for Operating Reserve

In addition to the above, further considerations must be noted when considering applying specifically GPIs for Operating Reserve to non-conventional units in the future.

For windfarms which have contracted with the TSOs for DS3 services, it's important to note that these contracted units are only a subset of the all windfarms on the island. Generally, these would be newer windfarms too. This differentiation must be accounted for rather than a blanket approach which would result in certain types of non-conventional technology or specific models being disproportionality penalised.

Also, there is an important distinction between relatively few conventional units providing a large amount of Operating Reserve, versus many windfarms geographically dispersed, each providing a small volume of Operating Reserve. Whilst in aggregate, windfarms can at times be providing a larger proportion of Operating Reserve to the system, the loss of any one windfarm is unlikely to have a major impact on the system (in relation to Imbalance Charges).

Furthermore, TSOs only allow windfarms contract for the volume provided responding to a 49.8Hz injection, versus a 49.5Hz injection for conventional units. This results in a much larger proportional volume of Operating Reserve, relative to the Registered Capacity, being made available from conventional units. These capabilities need to be considered, if the TSO is minded to include windfarms in the current GPI framework.

Summary

The new market arrangements introduce a complexity and sophistication that the current OSC framework does not address. There is the contradiction between the market being deemed balance responsible and the continued necessity to apply these incentives, where we would argue there are sufficient consequences for units if they cause a system imbalance. We acknowledge that if certain behaviour needs to be addressed, this should be targeted, rather than a blanket approach that affects all units. There are several likely unintended consequences in settlement which has not been clarified. Equally, there is positive behaviour possible under the new arrangements, which should be accounted for. Finally, in relation to the inclusion of windfarms in the current framework, this also recommends that a higher degree of granularity and complexity is needed within OSC to prevent a disproportionate effect on renewables.

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11th May 2020

RE: Harmonised Other System Charges (OSC) Consultation, Tariff Year 1 October 2020 – 30 September 2021

Dear Sir / Madam,

Bord Gáis Energy (**BGE**) welcomes the opportunity to respond to this consultation on Harmonised OSC for 2020/ 2021.

Trip and Short Notice Declaration (SND) Charges

BGE's views on the application of Trip charges and Short Notice Declaration (**SND**) charges to the SEM are based on the principle that units which cause a system disturbance resulting in the TSO having to take balancing actions with related costs, need to be penalised appropriately. This should happen in a manner aimed at recovering the system costs accrued by the TSO in its balancing actions, particularly with a view to minimising dispatch balancing costs (**DBCs**), while taking into account relevant commercial penalties certain units may already be subject to.

BGE is of the view that units with a Q_{EX} are already considerably incentivised to remain fully operative, and considerably penalised if they do not, and that they should not therefore be subject to any Trip or SND charges for the following reasons. A trip or SND will expose them to relevant trip and SND charges as well as likely significant imbalance charges and exposure to Reliability Option (**RO**) payments.[1] These numerous charges are altogether significantly penal but also remain penal even without inclusion of trip or SND. In this regard, we note that in the old (pre-October 2018) SEM that if a unit tripped, it incurred only trip and SND charges, whereas in the current SEM, plant with a Q_{EX} now have to pay trip, SND and Imbalance charges as a minimum. The current proposal to continue with these trip and SND charges at a 50% markdown to 2017/ 18 levels for units with a Q_{EX} does not go far enough particularly considering that imbalance charges payable by units with a Q_{EX} contribute towards minimising costs for consumers. Trip and SND charges are legacy charges and while (noting our view on cost recovery above) they have a role to play, they should be obsolete for those units that have a Q_{EX} position and so eliminated for these plants. The focusing of trip and SND charges to units without a Q_{EX} position aligns to the confirmation of the TSOs that the proposal is "*to ensure that revenue is collected from Trips and SND's where the unit in question would not have been exposed to the balancing market*[2]".

Units with no Q_{EX} position include those scheduled by the TSO on the basis of "….*operational security requirements*.[3]" and so their reliability is critical not just to the system security but also to the minimisation of consumer costs in the form of DBCs within SEM. As stated at the outset we believe that all units must appropriately cover the costs they cause the TSOs when a trip/ SND applies to them. Units with no Q_{EX}

[1] Where contracts are held by the unit in the DS3 and capacity markets respectively
[2] Harmonised Other System Charges Recommendations Paper (2019/ 20) June 21st, 2019 (section 2.1.2, p6)
[3] p7

position needed for secure supply or constraint driven running can and mostly do avail of RO payments, and so must deliver value for the consumer and not unnecessarily add to consumer costs via DBCs where at all possible. These units, as is the case for all units[4] must be balance responsible in line with the expectation of Article 5 of the Regulation on the internal market for electricity (EU) [5] and from the information presented in the Consultation the suggestion is that their past payments under the reduced tariff arrangements have been insufficient to cover the costs incurred by the TSO in instances of them incurring a Trip/ SND. We therefore support the need for costs to be appropriately levied on such units such that they are balance responsible and mitigate DBCs but would ask for further supporting quantitative information to support the decision as to the appropriate charge levels for units without Q_{EX}. From a consumer perspective, the quantum of impact these units are having on DBCs is of particular importance and should in our view be published to ensure that overall the consumer is receiving best value for money.

Inflation Rate

It is appreciated that the analysis and detail contained in this consultation paper would have taken time to collate and capture, and a degree of forecasting would have been involved especially in the proposed rate of inflation. Normal economic situations could have supported the proposed inflation rate of 1.7%, or a rate close to it, but we are now not operating in a normal economic situation. Should the evaluation of a useable inflation rate prove too complex and uncertain, BGE would ask for the consideration of a zero or negative rate for inflation in the period.

The economic impact of COVID-19 on businesses, utilities and the wider society has been unprecedented and the duration, and potential worsening, of the impact is largely unknown. The suddenness of the impact means there is little data to measure the fall but the Eurozone composite Purchasing Managers' Index (PMI) being reported during April / May is at record lows and March data is showing double digit declines in retail sales and manufacturing in key EU countries.

As we understand it this consultation is considering the effective tariffs for the October 2020/21 period based on inflation data relevant to the economic situation pre COVID19. However, given that the 2020/21 period is likely to be key to economic recovery within Ireland, and notwithstanding some of the economic unknowns, we urge the SEM Committee to take account of the evolving economic situation and updated information related to COVID-19 when setting the inflation rate for the Other Service Charges in the 2020/21 period.

Generator Performance Incentive Charge

In general, we are supportive of the proposals in the consultation to retain the GPI Operating Reserve, GPI RoCof, GPI Secondary Fuel, and GPI Reactive Power charges at a level adjusted for inflation (but on inflation rates please see above).

We note the proposal in the consultation that the TSOs are investigating whether there is merit in imposing penalties on units that are not able to provide system services when at their minimum generation levels. In this regard, BGE wishes to highlight that further specific industry engagement is necessary for this given the interactions between set minimum generation levels and the ability to provide system services in both the regulate up and down directions. Any incentives set in this space should take account of the potential that a level of flexibility in minimum generation levels may work best for the system in minimising the risks of trips and to security of supply.

[4] Except for certain limited exceptions

[5] REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

New Other System Charges (OSC)

The sizeable challenges associated with the transition to a low carbon energy system and the increasing part the renewable energy sources[6] have to play in this shift is appreciated. The growing contribution of power from renewable sources onto the system does however bring an increasing risk of impact of these sources to system stability and a potential increase in costs to maintain system security.

Given the evidential increasing share of wind and solar units in the market and given the importance of performance monitoring and ensuring units act in line with the grid requirements and what they are contracted to do (from a systems and DS3 perspective in particular), BGE believes that they should be treated in the same way as conventional generation in the application of these other system charges.

We note the proposed change in approach this year to the introduction of SND charges for DSUs. While we accept the intent behind applying such charges to DSUs, it seems somewhat unintuitive to not also already be applying appropriate charges to wind and solar not least from a level playing field perspective (considering that wind at least is becoming more akin to a baseload unit). Furthermore, we believe that measured application of the charges to emerging market technologies such as DSUs is laudable such that these units are not unfairly burdened such that it would undermine the growth of new technology and competition in the market.

I hope you find the above comments and suggestions helpful. If you have any queries thereon please do not hesitate to contact me.

Yours faithfully,

Ian Mullins
Regulatory Affairs – Commercial
Bord Gáis Energy

{By email}

[6] Renewable energy sources are inclusive of wind and solar generation, but can include wave/ tidal, biomass and biofuels.

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11th May 2020

FTAO: EirGrid-SONI – Tariff Design Team,

RE. "Harmonised Other System Charges Consultation Paper" -- Response from Demand Response Aggregators of Ireland (DRAI)

I am writing to you on behalf of the Demand Response Aggregators of Ireland (DRAI), the trade association representing Demand Side Unit (DSU) and Aggregated Generating Unit (AGU) providers in the all-island Single Electricity Market (SEM). Today, we represent over 700 MW of demand and embedded generation response across hundreds of industrial and commercial customer sites throughout the island of Ireland. These sites are managed by our eight members each of whom actively participate in the Capacity, DS3, and energy markets, within the SEM. Through the DRAI we express a single voice on policy and regulatory matters of common interest to our members.

The DRAI welcomes the opportunity to respond to the recent consultation on Harmonised Other System Charges and trust that you will consider it in your deliberations

Introduction

Fundamentally, the DRAI recognise that Other System Charges need to be levied on generators in order to provide appropriate signals to stimulate actions that ultimately lead to the lowering of Imperfection Charges. We also recognise that there can be a cost associated in providing alternative generation from that scheduled through the Transmission System Operators (TSO) systems. The DRAI also understands that such scheduling is reflective of the expected generation available in the 'Long-Term', 'Short-Term', and 'Real-Time'. The generation availability data within 24 hours can be obtained from EDIL and from the Balancing Market systems.

The DRAI would however like to highlight their concern in relation to the proposal to include Short Notice Declarations for Demand Side Units (DSU). Our members consider that this measure is not appropriate for DSU technologies and believe that it's inclusion in this consultation serves to emphasise the need for the DRAI and the TSOs to work together to improve the understanding of the capability and interactions of the Demand-Side Flexibility.

Specific Comments on Section 2

The DRAI notes the consultation recommendation on maintaining links with the Day Ahead Position to lower penalties, whilst increasing the penalties to those who have no Day Ahead Position and operate mostly in the Balancing Market.

Whilst the TSO mention that they believe that those operating in the Balancing Market only are not 'Balance Responsible' it should be noted that both the Day Ahead and Balancing Markets are of equal value in providing a stable and efficient system. Those units participating in the Balancing Market are at a greater risk to Difference Charges than those that already have a market position. Therefore, the comment by the TSO that such units are not incentivised is not a true reflection of the charges that are applicable in the markets.

Currently those conventional generators that operate in the Day Ahead and Balancing Market obtain a revenue for the energy they provide. This is at the Day Ahead price or the Balancing Market price. The DRAI would like to point out that Demand Side Units do not receive this revenue and as such there is no market embedded incentive. There is however also no financial impact to the market as it does not have to pay for this provision.

The TSOs comment that the new market arrangements can lead to an impact on the Imbalance price should a Short Notice Declaration (SND) occur. Since Demand Side units do submit pricing under the rules of the Trading and Settlement Code (T&SC), they do not actually receive any of that energy revenue. Any changes to the Imbalance price would not benefit any other Demand Side participant unit and any additional generation required would place a true reflective cost to the system. The Imbalance price would also only be impacted should the Balancing Market require these units for balancing; however, it is more usual for Demand Side units to be used for System Support and that would not have an impact on the price.

Since the majority of Demand Side units participate in the Balancing Market then, under current market rules, the cost burden is on the Demand Side units in providing the dispatched energy. This lack of revenue (actual cost) to DSUs raises the question as to how they can be asked to pay any Charges under the OSC whenever other participants do receive revenue. The DRAI does not believe that this reflects equitable treatment and as such we can not support such proposals. The introduction of OSC for DSUs should be deferred until such time as their contributions and payments are properly recognised and they can be treated equally with other participants.

The DRAI understands the approach that the TSO are taking regarding units with QEX in relation to the expected provision of energy. With a QEX there is a <u>forecast</u> and therefore a reliability on that volume being provided and those units would indeed be open to Imbalance Charges.

Specific Comments on Section 4

<u>Proposal to apply a 5MW threshold for SNDs to DSUs</u>

The TSO consultation proposes to introduce a new OSC specifically for Demand Side Units (DSU).

The DRAI argue that Demand-Side Flexibility provides the capability to allow the TSOs to facilitate more Renewables and other technologies, whilst also lowering the overall system reliance on Conventional power stations. We would also argue that effective use of these Demand-Side Flexibility services ultimately delivers an overall reduction in cost to the consumer.

We acknowledge that that the scheduling of generating plant by the TSOs is intended to provide an efficient and effective use of resources, we would also like to highlight that the current T&SC rules do not recompense demand side units for the cost of such energy provision.

Nevertheless – the DRAI recognises the system balancing challenges that arise when Conventional and other such generation disappear at short notice, and we therefore appreciate that it is necessary for such generation to be given a threshold of 15MW, in relation to SND.

The DRAI would however ask for evidence that supports the TSO proposal to apply a 5MW threshold for SNDs to DSUs, which would highlight an unequal approach to that taken for other generators?

<u>'Time Window' specified in the OSC Methodology</u>

Fundamentally, Demand-Side Flexibility depends on its Individual Demand Sites (IDS) providing the service. A service which fluctuates over the day and week and can be seasonal. Demand Side is therefore always adjusting its availability and for this reason our members are required to send a number of EDIL declarations throughout the day. Logically this means that the availability can drop, rise, and drop again – depending on the granularity of the declarations. The norm may see a reduction towards the end of a normal factory workday.

The DRAI are therefore concerned that a number of declarations (each under 5 MW) could be caught under the 'Time Window' as specified in the OSC Methodology. This would not accommodate the responsibility that Demand Side Units have under the Grid Code, insofar as they have to declare their true ability to the TSO.

In addition, since the ability of the TSO to schedule all units is reliant on the <u>forecast</u> availability provided via the Balancing Market MPI. These figures are not expected to match exactly what is declared in EDIL during the day. That is the nature of forecasting.

As an alternative approach the DRAI utilising the forecast along with the many EDIL declarations through the day to identify if a DSU is actually giving a Short Notice Declaration or if it is just following its expected availability reduction – reflecting the ability of its IDSs.

Since the Forecast is submitted via the Balancing Market MPI, it would be an additional burden should that be required to be performed in EDIL. The EDIL platform is an 'operational' tool and requires manual submissions which do not easily accommodate forecast submissions. We are also unsure how advance declarations via EDIL would be considered in light of SND applications.

Specific Comments on Methodology document and Settlement systems.

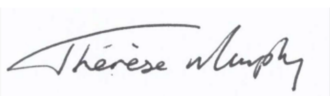
The TSOs have identified that SNDs would not be applied due to the elapse of the time the DSU could be dispatched. **This approach would need to be reflected in the methodology document, along with DSU specific terms and calculations.**

In addition, the DRAI would propose that more comprehensive analysis is provided in how the proposals are to be implemented, whilst accommodating the specific capabilities of Demand Side Flexibility units. This should include the '5MW threshold', the 'Time Window'.

The DRAI understands that the proposals within this consultation are intended to be enacted as from October 2020. Given the lack of analysis provided, the likely requirement to change methodologies and settlement systems (specifically concerning DSUs), the need to examine these issues thoroughly with full industry engagement, the DRAI suggests that no decision is made on this currently and that it is addressed further in subsequent consultations.

On behalf of the DRAI I hope that you find our response helpful and constructive, and we look forward to hearing from you in due course.

Yours sincerely,



Therese Murphy
DRAI Secretary

Submission by Energia to EirGrid on Harmonised Other System Charges Consultation Paper

Tariff Year 01 October 2020 to 30 September 2021

11th May 2020

1. Introduction

Energia welcomes the opportunity to respond to the TSO Consultation Paper titled "Harmonised Other System Charges Consultation Paper – Tariff Year 01 October 2020 to 30 September 2021" (the "Consultation Paper").

The Consultation Paper has proposed two changes in relation to the Other System Charges (OSC) which are levied on generators for the tariff year 2020/21, with the remaining OSC to remain the same. The proposed changes are as follows:

- Increase the rate of Trip Charges and Short Notice Declarations (SND) forgenerators without a Day Ahead Market position (QEX) to that which aligns with 2017/18 tariff before the introduction of the revised SEM arrangements;
- Introduce SND for Demand Side Units (DSU) above a SND tolerance of 5 MW.

Energia has only submitted comments on those OSC which the TSO is proposing to change for tariff year 2020/21, with no comment on those OSC for which the current tariff is to be retained. Energia are opposed to the increase of SND and Trip Charges tariff rates for generators without a QEX, however are supportive of introducing SND for DSU above a 5 MW tolerance.

We have outlined our comments in relation to the Consultation Paper in General Comments below.

2. General Comments

Proposal to Increase Trip Charges and SND rates for generators without a QEX

Both SND and Trip Charge tariff rates were reduced in advance of the new market arrangements due to these market arrangements making generators balance responsible. However, the Consultation Paper has outlined a proposal for increasing Trip Charges and SND Charges for those generators with no QEX. The basis for this recommendation is that, upon review of data under the revised SEM arrangements, generating units with no QEX pay less than those with a QEX as they are not exposed to imbalance charges, and therefore are not incentivised to avoid trips or SNDs.

However, Energia do not agree with this proposed increase to SND and Trip Charge tariff for those units which do not have a QEX for several reasons. Primarily, a trip or SND event for a generating unit is almost always incurred due to technical issues at the unit which are unavoidable. Whether or not a generating unit has a QEX has no bearing on the likelihood of such a technical issue occurring. This can be evidenced by the reference in the Consultation Paper to an increase in the number of trips and SNDs in the 2018/2019 tariff year (i.e. the first year of the new market arrangements). Therefore, despite the introduction of the balance responsible market arrangements, and accordingly the exposure to imbalance charges, the occurrence of trip and SND events increased due to the unavoidable technical issues behind these events.

Furthermore, the Consultation Paper has not provided sufficient justification and data in respect of its proposal. For example, whilst there is reference to an increase in the number of trips and SNDs in the 2018/2019 tariff year, no evidence has been provided to show that the increase was due to units without a QEX as opposed to units with a QEX i.e. there is no evidence of a correlation between units without a QEX and a change in their relative trip or SND performance. The Consultation Paper also provides a rationale for the proposed tariff change that *“the lower rate for units without a QEX is no longer an appropriate incentive for good behaviour.”* However, no evidence has been provided to demonstrate that the rate of trips from units without a QEX has increased as a result of the current tariff structure.

In addition to the above, the Consultation Paper seeks to highlight both the cost differential of a trip or SND to a unit with and without a QEX and the wider potential impacts of a trip or SND under the new market arrangements in terms of volatility caused to the Imbalance Price. However, under the new market arrangements, those generating units which have secured a Reliability Option (RO) under the Capacity Remuneration Mechanism (CRM) are potentially exposed to RO Difference Charge payments up to one and a half times their annual capacity income should an RO event coincide with the generating units trip or SND. The risk of being exposed to a RO Difference Charge payment has significant financial implications for a generating unit. Neither the potential cost or associated risk of a generator unit having to make a RO Difference Charge payment during periods of unavailability due to a trip or SND has been factored into the proposal. Consideration of this risk, which is indifferent to whether a generating unit has a QEX or not, needs to be taken into consideration given the impact of the previous RO events under the new market arrangements.

<u>Proposal to Introduce SND MW for DSU above a SND tolerance of 5 MW</u>

The Consultation Paper also outlines a proposal to introduce a new OSC in terms of SND charges for DSUs. The proposal is to introduce a SND, with a threshold of 5MW, to apply for sudden unavailability of DSU capacity. Given the increasing volume of DSU capacity within the market and therefore the increasing importance of the TSO to be able to rely on their availability for the secure operation of the transmission system, the introduction of a SND charge related to DSU availability is appropriate.

Energy for generations

esb.ie

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ESB Generaton and Trading Response:

Other System Services Consultation 2020-21

11th May 2020

General Comments

ESB Generation and Trading (ESB GT) welcomes the opportunity to respond to the consultation on the Harmonised Other System Charges for the tariff period 2020/21. ESB GT recognises the need for an appropriate incentive structure to ensure that all system Users are encouraged to fulfil their obligations under the Grid Code and act in line with prudent ulitity practise to ensure the safe and efficient operation of the system. ESB GT believes that in many respects the Other System Charges (OSC) framework has served this purpose but is minded that as the OSC framework is leived through the Use of System agreement is a network charge and as such must adhere to the requirments of Article 18 of the Electricity Regulation (EU 2019/943). Under Article 18 network charges are required to be cost reflective, non-discriminatory and not include unrelated costs supporting unrelated policy objectives.

Tested against this bar it is not clear that some of the current GPIs are sustainable particularly the Secondary Fuel GPI. While the security of supply in the case of a gas supply interruption is an important consideration it is not the case that there are direct costs incurred in operating the system where one or more generators' secondary fuel capability is unavailable. It is also the case that the requirements under the Grid Code for secondary fuel capability are placed on a subset of generators with no mechanism in place for the resulting incremental costs to be recovered, in this context it is arguably discriminatory to levy a charge on these generators when their secondary fuel capability is unavailable. As noted, security of supply in the case of a gas supply interruption is an important policy goal but it is not considered to be related to the recovery of efficiently incurred cost in operating the network.

In addition, the current arrangements for the provision of secondary fuel in the context of a competitive capacity auction are distortive and contrary to the long-term interests of end users. Under the current arrangements' generators, both new and existing, required under the Grid Code to provide secondary fuel capability are placed at a competitive disadvantage to other categories of capacity providers that do not face this obligation. Where this results in those generators being displaced by the other categories of capacity providers the policy of maintaining secondary fuel capability is undermined and where the generators clear the auction at a price reflective of maintaining secondary fuel capability the other categories of capacity that also clear in the auction extract rent from the end users through the capacity market for a service they do not provide. To correct this situation and maintain an incentive to ensure secondary fuel capability is available, a secondary fuel services should be defined as an additional service under the HAS framework that has remainedin place to remunerate the provision of Black Start Capability. This renumeration for this Secondary Fuel Capabilty service could be targeted as the incremental cost for the provision of secondary fuel capability from the Best New Entrant unit over its economic life. Noting that the current BNE unit is a distillate fired unit, but this position is not aligned with the requirements under Article 22 of the Electricity Regulation that does not permit capacity renumeration to units that emit above 550gCO2/kWh which were not in operation prior to 4th July 2019. In this way the provision of Secondary Fuel Capability would be appropriately renumerated and would be able to compete on an equal basis with other categories of capacity providers.

Seperately, ESB GT remains concerned at the treatment of sums levied under the OSC framework in the TSO Despatch Production Cost (DPC) incentive mechanism. ESB GT supports the objectives of the DPC incentive mechanism in seeking to lower the costs faced by end users through Imperfection Charges incurred in securely operating the system however, it is considered that the current approach to, sums levied under the OSC, is appropriate. As TSOs, SONI and Eirgrid have a central role in the operation of the system their independence and maintaining the perception of that independence is key to investor confidence. The current postion where there is an incentive for the TSO to maximise the charges levied against generators under the OSC framework acts to undermine this perceived independence. This is not to say that SONI or Eirgrid have in anyway sought to inflate the charges faced by generators, but it is noteworth that in the most recent DPC incentive outturn decision the SEMC determined that the RoCoF related GPI values should be excluded from the incentive calculation. Rather then ad-hoc decisions on which elements of the OSC should be included in the incentive calculation ex-post, ESB GT proposes that the current position where an assumed value of 0 for the value levied under the OSC framework is applied to the ex-ante forecast of DPC instead of the value being benchmarked against the value levied in the preceeding years. In addition, ESB GT notes that the SEM Committee, in making their decision to exclude the RoCoF GPI, did so on the basis that the timing of a generator's compliance with the revised RoCoF standard did not impact on DPC. However, it is ESB GT's understanding that the premise for levying GPIs is to reflect the impact of Grid Code non-compliance issues on the cost of operating the system. Given the SEMC decision ESB GT urgently seeks clarity on the basis against which the RoCoF GPI has been charged.

ESB GT appreciates the role Other System Charges framework played during the original SEM design and the importance for incentivising generation unit performance as well as availability. Under the revised SEM the impact of balance responsibility as envisaged under the revised electricity regulation is significant and is considerably more aggressive then that previously experienced and no longer simply reflects unit costs. As such, it is key to remove all charges that are related to creating incentives that were not intrinsic to the original SEM but have become part of the revised market arrangements.

ESB GT notes the proposed application of a blended indexation rate of 1.7% to the relevant rates in the consultation paper, it is the case that the rates paid under the HAS agreement have not been indexated for an extended period and as such the real value received by the providers of Black Start services has been eroded over time, ESB GT proposed that the same rate of indexation should be applied to rates for the provision of Black Start as those proposed for the OSC charges.

Trip Charges

In the consultation it is proposed that there is the return to the higher rates for Trip/SND charges for generators without Ex-Ante market position. The consultation supports this proposal by highlighting that generators that have tripped with an Ex-Ante market position have faced much higher penalties then those faced by generators without an Ex-Ante market position as a result of BM exposure. ESB GT has experience of exposure to imbalance settlement as a result of generation outages but drawns a very different conclusion to the consultation on the appropriate rates for trip charges

ESB GT recognises that generators without an Ex-Ante position are not currently exposed to the imbalance settlement in current SEM arrangements but considers that this is due to the nature of despatch instructions typically issued to generators in SEM, i.e. open instructions rather then closed and how a generator trip is currently treated within imbalance settlement calculations. The revised SEM arrangements were developed at significant cost so that, in part, market participants are provided signals on the impact of their imbalances on the system through the imbalance price in line with the requirements of the EU target model. In ESB GT's view the BM should be utilised to signal the impact of trip events on the system rather than the application of Trip Charges as part of Use of System charging. While Trip charges could be retained in the short term for those without an Ex-Ante position, priority should be given the development of an in market-based solution. It is worth noting that even where a unit does not have an Ex-Ante position, they are incentivised to minimise the risk of trips due the potential unit damage and related outage that could result from tripping given the resulting cost of repairs, the potential of foregone market revenues and the exposure to RO events.

Specifically, in relation to generators with an ex-ante market position, as is acknowledged in the consultation paper, these generators are potentially exposed to significant costs through the imbalance settlement, ESB GT strongly believes that this undermines the requirement for any Trip charges to continue to be levied against these units. On this basis, Trip Charges rates should be set to zero for generators with an ex-ante market position.

SND Charges

ESB GT believes that SND charges are not appropriate under the revised SEM arrangements, specifically the changes to the capacity remuneration mechanism has removed the the link between a unit's availability and its capacity market revenues and has introduce exposures to changes for failure to deliver during periods of scarity. There is no requirement under the Grid Code, Trading and Settlement Code or Capacity Market Code for a generator to be able to perfectly forecast their availability over an eight-hour window. However, there is a requirement under the Grid Code for a generator to declare a unit availability in line with its technical capability against which the SND charges incentive structure is not aligned and effectively penalises generators in adhering to this requirement

ESB GT understands that where a generator, which is meeting the system security requirements of the TSO, is declared unavailable with no notice, this could result in the requirement to re-schedule other units, for example a short notice period unit that is providing desync'd replacement reserve becomes suddenly unavailable could result in the need to start another unit to provided sync'ed replacement reserve, resulting in cost to the system to maintain security standards. However, it is also possible that if a long notice period unit that is providing no system services becomes unavailable with no notice there may be little or no impact on the system security and therefore no requirement on the TSO to re-schedule other units. On this basis the SND charging framework risks being arbitrary and unreflective of underlying cost drivers. The continued retention of these charges would, in ESB GT view, be contrary to regulatory best practice of having effective and targeted interventions (including penalties).

In ESB GT's view the impact of a unit being suddenly unavailable is best reflected in the level of system services the unit provides and therefore SND charges should be replaced with modifications to the DS3 performance monitoring framework. The performance monitoring framework under the DS3 framework includes outline provisions for the performance scalar for service providers to be reflective of their ability to meet their forecast level of service provision over a six-hour window. This mechanism which has yet to be implemented but could ensure that there is an appropriate incentive on all service providers to deliver their forecast service availability. ESB GT would welcome the opportunity to engage with the system operators on the further development and implementation of DS3 performance scalar framework to replace the SND charging regime.

If you have any questions in relation to any of the points raised in this response, please do not hesitiate to contract me to discuss further.

Yours sincerely,

William Carr

Regulation, ESB Generation and Trading

Power NI Energy Limited
Power Procurement Business (PPB)

Harmonised Other System Charges Consultation

Response by Power NI Energy (PPB)

11 May 2020

Introduction

Power NI Power Procurement Business (PPB) welcomes the opportunity to respond to the consultation paper on Harmonised Other System Charges (OSC).

PPB is the counter-party to Power Purchase Agreements, which were established in 1992 as part of the restructuring and privatisation of the electricity supply industry in Northern Ireland. PPB purchases both the capacity of the contracted generating units and any electricity generated by those units on terms specified in the agreements. The generating units are extremely flexible and reliable and therefore with the changes in the generation mix and typology of the system these units are likely to play a significant role in helping the System Operator manage the system. Flexibility is required to securely operate the system, which requires ongoing re-design to accommodate ambitious renewable targets.

Existing OSC Developments

Trip Charge and short Notice Declaration Charge

PPB agrees that the ISEM requirement for balance responsibility and the cost of imbalances provides substantial incentives for participants to perform. We therefore agree that the reduction of the Trip and SND rates introduced in October 18 was the right decision. However, we still see no rationale for the 50% reduction and believe the proposed Trip and SND charges are still much too high. Imbalance costs and potential Reliability Options payments in the ISEM provide a very significant incentive and therefore the need for any further OSC penalty is questionable. Even to the extent one is justified, we do not believe the arbitrary application of 50% of the pre-ISEM rates is proportionate and consider that if a charge is to be retained that it should be 5-10% of the pre-ISEM charge. The TSOs provided no analysis to support the arbitrary reduction of only 50% in the last 2 years and they have not provided any further evidence to confirm that this was the correct level of incentive, in this year’s consultation paper. While a review has taken place it does not provide any justification for the rate. Continuation of the same level of charges cannot be accepted without justification on a year on year basis.

PPB does not agree that the units without a QEX should have their Trip/SND charges doubled. Again, as above, no evidence has been provided to support this overly punitive charge and where generators without QEX are still subject to potential Reliability Options (RO) payments and so do have incentives in the market (there may be justification for a higher charge where a unit has no capacity contract and therefore has no RO exposure). This proposal of simply doubling the penalty for a unit with no QEX is also flawed as a very small QEX will result in the lower charge but the system impact could be much larger due to the dispatched level of the unit, whereas a few MW’s trip or SND on a unit with no QEX may have little system impact. The Trips/SND charges should be equitable and proportionate to the impact on the system so PPB does not agree that having different charges based on the QEX is an appropriate approach.

The consultation paper suggests that the incentive on units without a QEX is less than those that have a QEX when it comes to SND’s and Trips. This is not the case, tripping and SND's are the result of technical issues on the generators and are not connected in any way to OSC financial incentives. The costs of maintenance, repairs, downtime and RO risk are sufficient to ensure generators are available at all times possible. The overly punitive charge for SND's and Trips will have no effect on these events.

In addition, a unit operating in the SEM with no QEX will be paid using its BM Complex offers. This being the case there will be no profit at all in running, not like those running under a QEX as they have potentially captured some profit due to the DAM prices and will have the ability to add some risk margin to their offers. If the constrained on unit then trips it will actually be losing money as it was only covering its SRMC before the trip. Due to the Bidding Code of Practice for Complex Offers, these units cannot apply any uplift to cover risk. Therefore, the risks for the constrained units are already greater than those successful in the Ex-Anti markets.

Further, the TSOs provide no evidence to support the statements made in the consultation paper in relation to their "extensive analysis". This analysis should be set out to ensure transparency and enable informed appraisal and critique of the analysis. In addition, while the paper notes there was a slight increase in the number of SNDs and Trips in 2018/19, there is no detail on the split of this "slight increase" between units with and without a QEX. There is no indication of any further change in the levels of Trip and SND performance in 2019/20 which may be more relevant after a period of bedding in of the new markets (and BM pricing that is not subject to manifest error).

Generator Performance Incentive Charges

PPB believes that GPIs are not required in the current market. Some GPI's have already been removed based on the rationale that the ISEM provides adequate incentives; the same approach can be used with other services where there is already an incentive in another market. The current rational is to retain the Minimum Generation GPI but performance in this area is already addressed in the DS3 market as any increase in Minimum Generation will result in a reduction in DS3 payments. This is enough of an incentive and does not require a second incentive through a GPI. Similarly, a re-declaration of Governor Droop will be likely to reduce the provision of Reserve and so will impact the Reserve Performance Scalar which will subsequently result in a reduction in DS3 payments.

It is an important principle that there should be no "double charging" and that where no other incentives exist then any GPI penalties and charges must be justified and proportionate to the costs they impose and any derivation of costs must be based on robust analysis and evidence rather than conjecture.

It is important to consider the impact of large overly punitive charges which may disincentivise any short period declarations and so disadvantage the system by having units impaired with no knowledge by the TSO.

With the increase in non-conventional technologies it is important that these technologies are incentivised to be reliable in the same manner as conventional units.

Therefore, PPB believes that if GPI's are to remain then they should be applied to all technologies in the same way.

Secondary Fuel GPI

PPB believes the introduction of a Secondary Fuel GPI charge in Oct 18 was unnecessary and discriminatory. This introduction of a charge for non-availability on secondary fuel when there is no corresponding payment for the provision of this service is unfair. If there is no payment for the provision there should be no subsequent penalty.

Such a charge is discriminatory since it does not apply equally across all units but is only directed against those units that can provide the service. These units are providing security and flexibility to the system and yet under the proposal the only thing they receive is a penalty, while other units with no secondary fuel have no exposure. This does not engender equal and fair treatment of all technologies and provider types.

Further, there is no cost to the system if a unit is available on its primary fuel and there is no requirement to switch fuel. Secondary Fuel has been available for many years and has rarely been required. Therefore, to apply penalties is totally unacceptable particularly when conditions on the system are normal and there is no risk or potential requirement for a fuel switch.

Payment to maintain a unit with a Secondary Fuel would be a much better solution as the costs associated with this provision are considerable especially with very little likelihood of prolonged use. This provides vital confidence for the TSO in managing customer expectations and so should be rewarded. Without payment, charges are unjustified.

Additional Comments

As discussed at the time of the introduction of the Harmonised Ancillary Services arrangements PPB still believes that the TUoS Agreement is not the correct agreement to contain Generator Performance Incentives. For example, disputes in relation to RoCoF GPIs could end up being referred to the Utility Regulator as a Licence breach. Interconnector owners have also argued that GPIs should not be applicable to them as they do not sign up to a TUoSA. As new technologies come on board, they must be treated in the same manner as other participants and so must receive GPIs and so there needs to be a mechanism for charging these even if there is no requirement for them to sign up to a TUoSA.

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11th May 2020

EirGrid-SONI – Tariff Design Team,

RE. “Harmonised Other System Charges Consultation Paper” -- Response from Powerhouse Generation Ltd

Powerhouse Generation (PHG) welcomes the opportunity to respond to the recent consultation on Harmonised Other System Charges and trust that you will consider it in your deliberations

Introduction

PHG recognises the requirement for Other System Charges to be levied on generators in order to provide signals, so that resulting actions are taken that lead to the lowering of Imperfection Charges. There is a cost in providing alternative generation from that scheduled through the Transmission System Operators (TSO) systems. That ability to provide alternative generation can be further challenged if less notice is given. PHG understands that such scheduling is reflective of the expected generation available in the ‘Long-Term’, ‘Short-Term’, and ‘Real-Time’. The generation availability data within 24 hours can be obtained from EDIL and from the Balancing Market systems.

The inclusion within this consultation of Short Notice Declarations for Demand Side Units (DSU) is a disappointment and highlights the requirement to better understand the ability and interactions of the Demand Flexible sector with the TSOs.

Specific Comments on Section 2

PHG notes the consultation recommendation on maintaining links with the Day Ahead Position to lower penalties, whilst increasing the penalties to those who have no Day Ahead Position and operate mostly in the Balancing Market.

Whilst the TSO mention that they believe that those operating in the Balancing Market only are not ‘Balance Responsible’ it should be noted that both the Day Ahead and Balancing Markets are of equal value in providing a stable and efficient system. Those units participating in the Balancing Market are at a greater risk to Difference payments than those that already have a market position. Therefore, the comment by the TSO that such units are not incentivised is not a true reflection of the charges that are applicable in the markets.

Currently those conventional generators that operate in the Day Ahead and Balancing Market obtain a revenue for the energy they provide. This is at the Day Ahead price or the Balancing Market price. PHG would like to point out that Demand Side Units do not receive this revenue and as such there is no market embedded incentive. There is however also no financial impact to the market as it does not have to pay for this provision.

The TSOs comment that the new market arrangements can lead to an impact on the Imbalance price should a Short Notice Declaration (SND) occur. Since Demand Side units do submit pricing under the rules of the Trading and Settlement Code (T&SC), they do not actually receive any of that energy revenue. Any changes to the Imbalance price would not benefit any other Demand Side participant unit and any additional generation required would place a true reflective cost to the system. The Imbalance price would also only be impacted should the Balancing Market require these units for balancing; however, it is more usual for Demand Side units to be used for System Support and that would not have an impact on the price.

Since the majority of Demand Side units participate in the Balancing Market then, under current market rules, the cost burden is on the Demand Side units in providing the dispatched energy. This lack of revenue (actual cost) to DSUs raises the question as to how they can be asked to pay any Charges under the OSC whenever other participants do receive revenue. PHG does not believe that this reflects equal treatment and as such we cannot support such proposals. The introduction of OSC for DSUs should be deferred until such time as their contributions and payments are properly recognised and they can be treated equally with other participants.

PHG understands the approach that the TSO are taking regarding units with QEX in relation to the expected provision of energy. With a QEX there is a forecast and therefore a reliability on that volume being provided and those units would indeed be open to Imbalance Charges.

Specific Comments on Section 4

Proposal to apply a 5MW threshold for SNDs to DSUs

The TSO consultation proposes to introduce a new OSC specifically for Demand Side Units (DSU).

PHG believes that that the support that demand side flexibility can provide allows the TSOs to facilitate more Renewables and other technologies, whilst also lowering the overall system reliance on Conventional power stations. We believe that this support also allows for the overall reduction in cost to the consumer.

We acknowledge that that the scheduling of generating plant by the TSOs is intended to provide an efficient and effective use of resources, we would also like to highlight that the current T&SC rules do not recompense demand side units for the cost of such energy provision.

Nevertheless – PHG recognises the system balancing challenges that arise when Conventional and other such generation disappear at short notice, and we therefore appreciate that it is necessary for such generation to be given a threshold of 15MW, in relation to SND.

PHG would however ask for evidence that supports the TSO proposal to apply a 5MW threshold for SNDs to DSUs, which would highlight an unequal approach to that taken for other generators?

'Time Window' specified in the OSC Methodology

Fundamentally, Demand-Side Flexibility depends on its Individual Demand Sites (IDS) providing the service. A service which fluctuates over the day and week and can be seasonal. Demand Side is therefore always adjusting its availability and for this reason our members are required to send a number of EDIL declarations (to the TSOs?) throughout the day. Logically this means that the availability can drop, rise, and drop again –

depending on the granularity of the declarations. The norm may see a reduction towards the end of a normal factory workday.

PHG are therefore concerned that a number of declarations (each under 5 MW) could be caught under the 'Time Window' as specified in the OSC Methodology. This would not accommodate the responsibility that Demand Side Units have under the Grid Code, insofar as they have to declare their true ability to the TSO.

In addition, since the ability of the TSO to schedule all units is reliant on the forecast availability provided via the Balancing Market MPI. These figures are not expected to match exactly what is declared in EDIL during the day. That is the nature of forecasting.

As an alternative approach PHG suggests utilising the forecast along with the many EDIL declarations through the day to identify if a DSU is actually giving a Short Notice Declaration or if it is just following its expected availability reduction – reflecting the ability of its IDSs.

Since the Forecast is submitted via the Balancing Market MPI, it would be an additional burden should that be required to be performed in EDIL. The EDIL platform is an 'operational' tool and requires manual submissions which do not easily accommodate forecast submissions. We are also unsure how advance declarations via EDIL would be considered in light of SND applications.

Specific Comments on Methodology document and Settlement systems.

The TSOs have identified that SNDs would not be applied due to the elapse of the time the DSU could be dispatched. **This approach would need to be reflected in the methodology document, along with DSU specific terms and calculations.**

In addition, PHG would propose that more comprehensive analysis is provided in how the proposals are to be implemented, whilst accommodating the specific capabilities of Demand Side Flexibility units. This should include the '5MW threshold', the 'Time Window'.

PHG understands that the proposals within this consultation are intended to be enacted as from October 2020. Given the lack of analysis provided, the likely requirement to change methodologies and settlement systems (specifically concerning DSUs), the need to examine these issues thoroughly with full industry engagement, PHG suggests that no decision is made on this currently and that it is addressed further in subsequent consultations.

On behalf of PHG I hope that you find our response helpful and constructive, and we look forward to hearing from you in due course.

Yours sincerely,

Brian Mongan

Director of Commercial and Operations
Powerhouse Generation

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D04 E7K5

Ref: TEL/CD/20/083

11th May 2020

RE: Harmonised Other System Charges Consultation 2020/21

Dear Sir/Madam,

Tynagh Energy Limited (TEL) welcomes the opportunity to respond to this Harmonised Other System Charges Consultation.

Re: Section 5: Proposed Rates

TEL believe Eirgrid should eliminate trip charges for units with a QEX. Units with a QEX already have ample incentive to be available and reliable in I-SEM due to balance responsibility and the significant losses that these generators endure in a trip event.

Generators with a QEX should not be penalised by two separate mechanisms during trips.

Should you have any queries, please do not hesitate to contact me.

Yours sincerely,

Cormac Daly

Cormac Daly
Regulation and Market Strategy Manager

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