Harmonised Other System Charges Recommendations Paper

Tariff Year
1st October 2019 to 30th September 2020

21st June, 2019

EXECUTIVE SUMMARY

EirGrid and SONI (the TSOs) published a consultation paper on 5th April 2019 for the upcoming tariff period running from the 1st October 2019 to the 30th September 2020 outlining a number of proposals. Comments on the consultation paper were received from five (5) respondents, having reviewed the responses, we are now making a number of recommendations to the Regulatory Authorities.

1. Retain the OSC rates approved for the 2018/2019 tariff year, only adjusting for inflation at forecast rate of 1.325% for the tariff year 2019/2020 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 charges back to the 2017/2018 tariff rate, adjusting for inflation at the forecast rate of 1.325%, for units with no day ahead market position (QEX).

3. Retain the rate of Trip Charges and Short Notice Declaration charges as per 2018/2019 tariff year, adjusting for inflation, for units with a day ahead market position (QEX).

4. Retain the charging rate of zero for the Minimum On Time GPI and the Maximum Number of Starts in 24 hours GPI.

5. Retain the Primary Operating Reserve GPI rate from 2018/2019, adjusted for inflation, with a view to carrying out a review for the tariff year 2020/2021.

6. Retain the Secondary Fuel Availability declarations GPI rate from 2018/2019, with a view to carrying out a review for the tariff year 2020/2021.

7. Retain the charging rate of zero for the early and late synchronization GPIs.

8. Retain the charging rate of zero for the loading and de-loading GPIs.

No other changes are recommended for this tariff period.

ABBREVIATIONS

AGU	Aggregated Generator Unit
DETI	Department of Enterprise, Trade and Investment
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
I-SEM	Integrated Single Electricity Market
UK	United Kingdom
OSC	Other System Charges
NI	Northern Ireland
NIE	Northern Ireland Electricity
QEX	Ex-Ante Quantity
RA	Regulatory Authority
RoCoF	Rate of Change of Frequency
RPI	Retail Prices Index
SEM	Single Electricity Market
SND	Short Notice Declaration
SONI	System Operator Northern Ireland
TSO	Transmission System Operator
TUoS	Transmission Use of System
WFPS	Wind Farm Power Station

1. INTRODUCTION

We 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 on this year's Harmonised Other System Charges Consultation paper[1] for the tariff year 1st October 2019 to 30th September 2020.

If the recommendations are approved by the RAs, we will publish revised Statements of Charges and Other System Charges Methodology Statement for the 2019-2020 tariff period.

We received responses from the following parties:

Party	**Abbreviation**
Bord Gáis Energy	BGE
ESB Generation and Wholesale Markets	ESB GWM
Power NI Energy Ltd Power Procurement Business	PPB
Scottish and Southern Energy[2]	SSE
Tynagh Energy Limited	TEL

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

[1] "Harmonised Other System Charges Consultation" 5th April, available at http://www.eirgridgroup.com/site-files/library/EirGrid/OSC-19-20-Consultation-Paper.pdf and http://www.soni.ltd.uk/media/documents/OSC-19-20-Consultation-Paper.pdf

[2] Response from SSE was received 6 days after the consultation had closed.

2. OTHER SYSTEM CHARGES CONSULTATION RESPONSES

2.1. Trip Charge and Short Notice Declaration (SND) Charge

In the consultation paper, for units with a QEX, we proposed the retention of Trips and SND charges at the same rate as 2018/2019 adjusting for inflation only. For units without a QEX, we proposed to return Trip and SND charges to the rate set in 2017/2018 adjusting for inflation. We have observed that since the new SEM began, a number of units have tripped without a QEX. As a result they are not balance responsible and paying Trip and SND charges which had been cut by 50% from 2017/2018. We have committed to carrying out a full review of the impact of these changes for 2020/2021 when an entire year worth of new SEM data is available to us.

2.1.1 Respondents' Comments

All respondents expressed their views (BGE, ESB GWM, PPB, SSE and TEL) in relation to the proposals on Trip and SND charges following the initial months of I-SEM. Two of the responses were broadly in support of the proposals while three were of the view that the proposals represented a retrograde action.

BGE supported the increase in Trip and SND charges to the 2017/2018 rate provided the logic for doing so was to ensure enough revenue is collected from units that are not balance responsible. BGE cautioned against the over-use of market positions to determine the level of charges to be paid. They described that they could not support the proposal if the logic behind the decision was to incentivise market participant behaviour.

TEL welcome the proposal to revert Trip and SND charges for units without a QEX to 2017/2018 rates due to these units not being exposed to balance responsibility under the new SEM. TEL also suggest that, due to the risk of significant financial penalties as a result of balance responsibility, units with a market position should no longer be liable to pay Trip and SND charges as they already have a large enough incentive to avoid trips.

ESB GT expressed their disappointment that rather than removing remaining OSCs, the TSO has proposed to increase Trip and SND charges to 2017/2018 levels. It is the belief of ESB GT that charging units that trip with an ex-ante market position both via the balancing market and through the Use of System agreement is an excessive and penal double charge. ESB GT questioned whether the TSO has seen an increase in the frequency of trips by units with no QEX to justify the proposal. ESB GT are also of the belief that units without an ex-ante market position not being balance responsible represents a significant failure within the market framework and have expressed their position that applying Trip and SND Charges to constrained units will only act as a stop gap measure or even accelerate the rate at which generators exit the market. ESB GT have also highlighted their position that trips and SNDs bring with them an increased risk of significant maintenance costs which in itself acts as an incentive to units to avoid Trip and SND events.

PPB supported the decision to decrease Trip and SND charges as a result of the new balance responsibility requirement in the new SEM; however they believe the existing rate at which they are set is excessively high. PPB do not agree with the proposal to increase Trip and SND charges for units without a QEX. PPB have expressed their belief that charges should be proportional to the impact a Trip or SND has to the system and are of the view that basing charges on market position alone is an inappropriate way of applying them.

SSE have expressed their view that, due to the balance responsibility requirement in the new SEM, Trip and SND charges are now amounting to a double charge for units that trip with a market position. As a result, SSE have advocated for the removal of Trip and SND charges for units with a market position. SSE have suggested that any increase for units without a market position needs to be justified and also suggest indexing any such increase to match the approach regarding dispatch balancing costs. SSE have also queried why the proposed increase in these charges has been indexed against inflation and have suggested that indexing should follow the drivers of costs the TSO expects to face in the event of a trip.

2.1.2 TSOs' Response

The TSOs welcome the comments received in relation to the impact of the new market on Trip and SND charges.

With reference to the comment from BGE around the logic behind the decision to increase Trip and SND charges for units with no market position. We can confirm that the reasoning behind this proposal was 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. The intention behind this was not to incentivise market participant behaviour.

With regard to comments received around the arbitrary application of the 50% reduction in Trip and SND charges for 2018/2019 we believe that, until there is sufficient experience and data gathered on the new SEM and understanding the scale of associated imperfections costs, the retention of these charges at a reduced rate was necessary. Given that we do not have a full year's worth of data in the new SEM we believe it would be inappropriate to remove the reduced charges at this time. As stated in the consultation paper, we propose to conduct a thorough review of Other System Charges in advance of the 2020/2021 consultation paper.

In response to the comments from PPB surrounding the proportionality of Trip charges, the formula that calculates the extent of a charge takes into account the amount of MW lost to the system. This applies to Direct Trips, Fast Wind Down Trips and Slow Wind Down Trips.

$$DT\ Charge = DT\ Charge\ Rate\ x\ e^{(DT\ Constant\ x\ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$
$$FWD\ Charge = FWD\ Charge\ Rate\ x\ e^{(FWD\ Constant\ x\ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$
$$SWD\ Charge = SWD\ Charge\ Rate\ x\ e^{(SWD\ Constant\ x\ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

The formulae above demonstrate that the larger the trip the larger the trip charge. As a result we disagree with the position stated by PPB that Trip Charges do not take into account the impact to the system.

In response to a number of requests for evidence and justification for the recommended changes to Trip and SND charges, Example 1 below provides this.

Example 1

Two units are generating 150 MW, Unit A without a traded market position and Unit B with a traded market position. Unit A is not balance responsible and is only liable to pay the reduced trip charge in the event of a trip. Unit B is liable to pay the reduced trip charge rate while also being balance responsible through the payment of CIMB charges (The TSO has observed that these can be very significant sums, often of the order of tens and hundreds of thousands of euro).

In the scenario above, both units have a direct trip from 150 MW. Using the appropriate formula detailed above, and assuming the reduced trip charge rates from 2018/2019, they will both pay the same trip charge.

DT Charge = €2,161 x $e^{0.01\,x\,(150\,-100)}$
DT Charge = €3,566

Under the existing set of rates Unit A and Unit B will both pay €3,566 in trip charges. However, Unit B is also balance responsible due to its traded market position and is now liable to pay CIMB charges. It is our experience as stated above, that CIMB charges are significantly greater than trip charges. We have observed CIMB payments from generators range from €38,000 to €213,000. This means that for the same loss of energy to the system, Unit B has a much greater financial obligation to the market than Unit A.

Under the TSO's recommended Trip Charge rates Unit A will pay a larger trip charge than Unit B, but will still pay significantly less once CIMB charges are taken into account. Using the recommended rates set out in Table 4.4 the new Trip Charge for Unit A is as follows.

DT Charge = €4,380 x $e^{0.01\,x\,(150\,-100)}$
DT Charge = €7,227

2.1.3 TSOs' Recommendations

We recommend that Trips and SND charges are retained at the same rate as 2018/2019, having been adjusted for inflation, for all units with a traded market position. We also recommend that Trip and SND charges for units without a traded market are reverted back to the 2017/2018 rate having been adjusted for inflation.

2.2. Generator Performance Incentive Charge

In the consultation paper, we outlined our position that insufficient data is available since the new SEM went live on the 1st October 2018 to accurately evaluate the impact of changes made to GPI rates for the 2018/2019 tariff year. These changes were implemented as a result of a comprehensive review of the charges applied over the previous two tariff years (2015/2016 and 2016/2017) and resulted in the setting to zero of GPIs for early and late synchronization, loading and de-loading, Minimum On Time and Maximum Number of Starts in 24 hours.

Due to the changes made last year and the lack of data since the implementation of the new SEM, the TSOs do not believe there is merit at this time in changing any of the existing GPIs apart from adjusting them for the assumed inflation rate. We have committed to conducting a comprehensive review of the appropriateness of all GPIs ahead of the 2020/2021 tariff year.

2.2.1. Respondents' Comments

PPB disagrees with the retention of the GPI rates from 2018/2019. They state that charging GPIs and charging through the various markets that exist in I-SEM amount to an overly excessive double charge. PPB give the example of a unit that increases its Minimum Generation will result in a GPI being applied while also seeing a reduction in its DS3 payments. They also state that similar will happen to any re-declaration of Governor Droop.

SSE confirm they are supportive of GPIs being linked to inflation but have asked for further detail on why the magnitude differs among the list of GPIs.

2.2.2 TSOs' Response

We believe, until we have sufficient evidence from market experience that the main objective of GPIs, to incentivise Grid Code compliance, continues to have validity for the tariff year 2019/2020. Indeed, if a unit complies with its Grid Code requirements, no charges will be levied. The requirement to achieve Grid Code compliance has not changed as a result of the introduction of the new SEM.

With reference to the comment from PPB regarding the Minimum Generation and Governor Droop GPIs, again we would like to highlight that if a unit complies with its Grid Code requirements no charges will be levied.

2.2.3 TSOs' Recommendations

The TSOs recommend retaining the same GPI rates as the 2018/2019 tariff year adjusting them for the inclusion of the assumed inflation rate. We will conduct a comprehensive review of the validity of all GPIs in advance of the 2020/2021 tariff year.

2.3. Operating Reserve GPI

In the consultation paper we proposed to retain the POR GPI rate set for the 2018/2019 tariff year apart from the inclusion of the assumed rate of inflation. This retention is as a result of the limited amount of data since the introduction of the increased charging rates, meaning it is not possible to determine the full impact of the increase in this GPI between 2017/2018 and 2018/2019.

2.4.1. Respondents' Comments

One comment was received from PPB in relation to the proposal to retain the POR GPI rate from 2018/2019.

PPB stated their belief that the increase in the POR GPI rate for 2018/2019 was made without the support of any analysis to justify the change. They also state that they believe the increase may be counter-productive, leading to units being reluctant to declare down their operating reserve availability for short periods of time.

PPB also make the point that if non-conventional units are reluctant to declare down for short periods as a result of overly punitive GPI charges, the TSO may have no sight of units that are impaired and the system will be disadvantaged as a result.

2.4.2. TSOs' Response

We welcome the comments received from PPB.

We believe that the introduction of this higher rate was a necessary requirement in order to send a strong signal to industry reminding them of their obligation to comply with Grid Code. We would like to highlight at this point that if a unit complies with its Grid Code requirements no charges will be levied.

We would also like to highlight that existing performance monitoring of DS3 system services should ensure compliance regarding units incorrectly declaring availability. For example, units that fail to deliver POR when required may have their performance scalars impacted.

2.4.3. TSOs' Recommendations

We recommend retaining the POR GPI rate at the level that was set for the 2018/2019 tariff year apart from adjusting for the assumed inflation rate.

2.4. New Other System Charges

2.4.1. Secondary Fuel Availability GPI

In the consultation paper for 2019/2020 we proposed that, due to the limited amount of data available since 1st October 2018, there would be no change to the secondary fuel availability GPI or the secondary fuel availability factor. We have committed to conducting a more detailed review of these charges for the next tariff year (2020/2021).

2.5.1.1 Respondents' Comments

Three comments were received (ESB, PPB and SSE) in relation to the proposal to retain the Secondary Fuel GPI at the existing rate adjusting for the assumed inflation rate.

ESB began by stating that in the absence of a remuneration scheme, as not every generation technology type has an obligation to provide secondary fuel, the application of the GPI is overly penal on generators that do provide it. They highlight that provision of the service brings security of supply to the grid and complying with this obligation comes at significant financial cost.

ESB would like to see a remuneration mechanism initiated that makes provision for applying a secondary fuel levy on all generators (even those that don't have an obligation to supply secondary fuel) which they believe will act to support the long term availability of the secondary fuel capability.

PPB believe that the introduction of a secondary fuel availability GPI, in the absence of a corresponding payment for the provision of the service, is unnecessary and discriminatory. They believe this to be the case as the charge is only applicable to units that are capable of providing the secondary fuel service.

In addition, PPB make the point that in the absence of Fuel Switching Agreements there is no justification to continue with a secondary fuel availability GPI. They also suggested that the GPI is a secondary penalty on top of the costs incurred under the NI Fuel Switching Agreement for failing a fuel change over test as this can result in the termination of the Fuel Switching Agreement.

PPB also stated their belief that payment to provide secondary fuel would be a better solution as generators incur significant costs to provide the little used service.

SSE commented that they believe the secondary fuel availability GPI should be indexed against an energy index. They believe this is necessary to ensure that the GPI is not susceptible to an inverse impact linked to fuel prices. SSE argue that since secondary fuel availability is a requirement regardless of price signals it should not be linked in such a manner as to disincentivise it when prices are extreme.

2.5.1.2 TSOs' Response

We welcome the comments received from the three respondents.

It has been the TSO's experience that the requirement for relevant units to be available on secondary fuel was not a sufficient incentive to ensure adequate availability. As stated in the consultation paper for 2018/2019, the justification for implementing this GPI was because of Ireland and Northern Ireland's dependence on gas as a primary fuel. This GPI was brought in with the intention of signalling to industry the importance of secondary fuel availability to system security. This point was acknowledged by ESB in their response.

Both ESB and PPB have called for the establishment of a remuneration mechanism for the provision of secondary fuel. We believe that while the requirement for relevant units to provide this service is clearly laid out in the Grid Code and Fuel Security Code in Northern Ireland any attempt to implement such a mechanism would be inappropriate at this time.

While we acknowledge the added costs provision of this service brings to affected units, we argue that an element of remuneration already exists. When secondary fuel availability testing is carried out, units are compensated for any fuel that may have been used to demonstrate this capability to the TSO.

We would also take this opportunity to note the impact of this GPI on the availability of secondary fuel to the system. In December 2018 the total secondary fuel capacity available was 1,070 MW. This represents approximately 31% of the total. As of the end of May 2019 the total availability was 2,211 MW which represents 63% of total capacity. This is a signifcant improvement in a relatively short period of time and contributes to ensuring there is security of supply.

2.5.1.3. TSOs' Recommendations

The TSO recommends retaining the GPI as proposed in the consultation paper. As with all other elements of Other Systems Charges, we intend to conduct a comprehensive review ahead of the 2020/2021 tariff year.

The TSO recommend a secondary fuel charge rate, SecFuel_Rate of €0.03 and a secondary fuel availability factor, SFA_F, of 0.9.

3. NON-CONVENTIONAL TECHNOLOGIES

In the Consultation Paper we made reference to the fact that, as more and more non-conventional generation has been awarded capcity in the various auctions, it would be necessary for us to review our treatment of them in the coming years in relation to Other System Charges. With that in mind, we offered industry the opportunity to express their views as part of the consultation.

3.1 Respondents' Comments

We received four responses (BGE, ESB GT, PPB and SSE) to our call for views on how to treat non-conventional technologies in respect of other system charges and GPIs.

BGE are of the view that, given their increasing market share and ensuring that all units are behaving in line with their respective contracts, non-conventional technologies should be treated exactly the same as conventional units. They expressed their desire for moves towards a level playing field regardless of technology type and believe applying GPIs is a step in the right direction.

ESB GT make the point that, as an ever growing integral part of reliable system operation, the incentives faced by non-conventional technolgies must align with the delivery of their Grid Code connection requirements. ESB GT also caution that, given all capacity providers compete in the RO auction process, it is necessary to ensure Grid Code and OSC frameworks don't distort the capacity market outcome by placing an over reliance on one particular or set of technologies.

PPB comment that with the increasing amount of non-conventional technologies on the system, it is important that they are treated in the same manner as conventional units and are incentivised as such.

SSE have stated that any rationale for applying GPIs to non-conventional generation is misplaced. Specifically in relation to windfarms SSE are of the opinion that in the majority of cases, trips are as a result of external system issues such as outages due to storms etc. SSE also make the point that the Category 1 framework is already in place to address performance monitoring issues. They also note the absence of any indication as to how GPIs may apply to different categories of windfarms.

3.2 TSOs' Response

We welcome the responses received on this issue from industry. As discussed in the consultation paper, we are conscious of the fact that non-conventional technologies have rapidly grown in importance over the last number of years. With government policy in both jurisidictions making commitments towards various climate change abatement objectives we expect this trend to continue.

We are minded that given this increasing market share, we will need to review how these technologies and others that emerge (battery, solar etc.) are treated over the coming years in respect of GPIs and Other System Charges. As stated in last years Recommendations Paper, our view is that all generating units must be levied in the same manner.

We acknowledge the responses from BGE and PBB which emphasise the need for a level playing field regardless of technology type. We also acknowledge the reponse from SSE which highlights their view that there is already a mechanism in place which penalises wind farms not in compliance with performance monitoring standards and that applying GPIs to them would be misplaced. We are conscious that these are two contrasting views and we will only be able to construct any potential charging framework once a more comprehensive analysis is complete. We also acknowldge ESB's cautioning against an over reliance of any one technology type as a result of Other System Charges innapprorpiately influencing capacity auctions.

If it is deemed necessary to introduce them, any new charges to non-conventional technologies will be consulted with industry. The Regulatory Authoriteis would then have final say over the level of any charges and the date from which they are effective.

4. ADDITIONAL COMMENTS

PPB commented that as discussed at the time of the introduction of the Harmonised Ancillary Services arrangements they still believe the Transmission Use of System (TUoS) Agreement is not the correct agreement to contain GPIs. 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 TUoS agreement. PPB further stated that 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 TUoS Agreement.

3.1 TSOs' Response

As stated in the 2018/2019 recommendations paper, regarding PPB's comment on the TUoS agreement not being the correct agreement to contain GPIs, the RAs Decision Paper SEM-10-001[3] published on 4th January 2010 provided a policy framework for the all-island harmonisation of Ancillary Services (HAS) and Other System Charges (OSC).

3 https://www.semcommittee.com/publication/sem-10-001-harmonised-all-island-ancillary-services-rates-and-other-system-charges

3. PROPOSED RATES

In the Harmonised Ancillary Services Rates and Other System Charges Decision paper for 2011-2012, the SEM Committee was satisfied that the exchange rate methodology be aligned to that utilised in the SEM. We will use the same methodology for 2019-2020 using the last five working days of July.

In the consultation paper, we detailed the following methodology to be applied going forward:

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

At the time of publication of the consultation paper according to the Office of Budgetary Responsibility report[4] (Mar 2019) the current RPI inflation was forecast in the UK for the 2019/20 tariff year at 2.825% while the Central Bank report[5] (Q1 2019) forecast HICP in Ireland for the same period at 1.175%.

Source		**2019**	**2020**	**Tariff Year Methodology**	**2019/2020 Tariff Year**	**Blended Rate Methodology**	**Blended rate**
OBR Mar 2019	RPI	2.9%	2.8%	(.029*25% + .028*75%)	2.825%	2.825*25%	0.70625
Central Bank Q1 2019	HICP	0.8%	1.3%	(.008*25% + .013*75%)	1.175%	1.175*75%	0.88125
Blended Rate							**1.5875%**

Table 4.0: Proposed Inflation Rate Increase as published in the consultation paper

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate published in the consultation paper for the forthcoming 2019/2020 period was 1.5875% as shown in Table 4.0.

At the time of publishing this recommendations paper the latest available Office of Budgetary Responsibility report[4] (Mar 2019) the current RPI inflation forecasts in the UK for the 2019/2020 tariff year is 2.825% while the Central Bank report[6] (Q2 2019) forecasts HICP in Ireland for the same period at 0.825%.

[4] https://obr.uk/efo/economic-fiscal-outlook-march-2019/
[5] https://www.centralbank.ie/publication/quarterly-bulletins/quarterly-bulletin-q1-2019
[6] https://www.centralbank.ie/publication/quarterly-bulletins/quarterly-bulletin-q2-2019

Source		2019	2020	Tariff Year Methodology	2018/2019 Tariff Year	Blended Rate Methodology	Blended rate
OBR Mar 2019	RPI	2.9%	2.8%	(.029*25% + .028*75%)	2.825%	2.825*25%	0.70625
Central Bank Q2 2019	HICP	0.7%	1.1%	(.007*25% + .011*75%)	0.825%	0.825*75%	0.61875
Blended Rate							**1.325%**

Table 4.1: Recommended Inflation Rate Increase using the latest available forecast values

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate for the forthcoming 2019/20 period is 1.325% as shown in Table 4.1.

The recommended rates are displayed with 2 decimal places in Euro and have been calculated using the latest available forecast values giving a forecasted blended rate of 1.325%. The TSOs would like to clarify that 4 decimal places from the current tariff year rates are used in the calculation of the inflationary increase.

4.1 Trip Charges

The following tables recommend the Trip Charges and Constants for the 2019/2020 tariff year. As seen in Table 4.2 and Table 4.3. We recommend retaining the rates set for 2018/2019 for units with a traded market position taking into account the appropriate inflation rate. In Table 4.4 we recommend doubling the rates for units without a traded market position to 2017/2018 levels taking into account the appropriate inflation rate.

	2017-2018	2018-2019	2019-2020
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 4.2: Recommended Trip Constants

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

Table 4.3: Recommended Trip Rates For Units with a QEX

Charge	2017-2018	2018-2019	2019-2020
Direct Trip Charge Rate	€4,322	€2,161	€4,380
Fast Wind Down Charge Rate	€3,242	€1,621	€3,284
Slow Wind Down Charge Rate	€2,161	€1,081	€2,190

Table 4:4 Recommended Trip Rates For Units Without a QEX

4.2 Short Notice Declaration (SND) Charges

The following tables recommend the SND Charges and Constants for the 2018-2019 tariff year. As seen in Table 4.5, 4.6 and 4.7. We recommend retaining the rates set for 2018/2019 for units with a traded market position taking into account the appropriate inflation rate. In Table 4.7 we recommend doubling the rates for units without a traded market position taking into account the appropriate inflation rate.

SND Constants	2017-2018	2018-2019	2019-2020
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 4.5: Recommended SND Constants

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

Table 4.6: Recommended SND Charge Rate for units with a QEX

SND Charge Rate	2017-2018	2018-2019	2019-2020
SND Charge Rate	N/A	N/A	€76 / MW

Table 4.7: Recommended SND Charge Rate for units without a QEX

4.3 GPI Charges

The recommended GPI Constants, GPI Declaration Based Charges and GPI Event Based Charges for the 2019/2020 tariff year are outlined in Table 4.8, Table 4.9 and Table 4.10 respectively. We recommend retaining the rates set for 2018/2019 while adjusting for the appropriate inflation rate.

GPI Constants	2017-2018	2018-2019	2019-2020
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	N/A	0.9	0.9

Table 4.8: Recommended GPI Constants

	2017-2018	2018-2019	2019-2020
GPI Declaration Based Rates	**€ / MWh**	**€ / MWh**	**€ / MWh**
Minimum Generation	1.28	1.29	1.31
Max Starts in 24 hour period	1.08	0.00	0.00
Minimum On time	1.08	0.00	0.00
Reactive Power Leading	0.31	0.32	0.32
Reactive Power Lagging	0.31	0.32	0.32
Governor Droop	0.31	0.32	0.32
Primary Operating Reserve	0.13	0.52	0.53
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	N/A	0.03	0.03

Table 4.9: Recommended GPI Declaration Based Charge Rates

	2017-2018	2018-2019	2019-2020
GPI Event Based Rates	**€ / MWh**	**€ / MWh**	**€ / MWh**
Loading Rate	0.64	0.00	0.00
De-Loading Rate	0.64	0.00	0.00
Early Synchronisation	2.86	0.00	0.00
Late Synchronisation	28.60	0.00	0.00

Table 4.10: Recommended GPI Event Based Charge Rates

4.4 Respondents' Comments

No comments on the proposed rates section were received.

4.5 TSOs' Recommendation

A blended inflation rate of 1.325% is recommended to be implemented.

4. NEXT STEPS

Once the RAs have considered these recommendations and made their final decision, the TSOs will then publish a revised TUoS Statement of Charges for the 2019/2020 tariff period.

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3rd May 2019

RE: Harmonised Other System Charges (OSC) Consultation, Tariff Year 1 October 2019 – 30 September 2020

Dear Sir, Madam,

Bord Gáis Energy (**BGE**) welcomes the opportunity to respond to this Consultation on Harmonised OSC for 2019/ 2020.

BGE's view with regard to the proposal to increase the TRIP and Short Notice Declaration (**SND**) charges back to 2017 levels for those units that have a balancing market (**BM**) position only (while maintaining current rates for units that have ex ante positions), differs depending on what the TSOs' logic behind the proposal is. We note the TSOs' reference to the observation of a "trend" whereby units that are in the BM only and trip, only have reduced BM revenue and trip charges to pay, but no imbalance charges to pay (due to their lack of an ex ante position). Ideally more insight on this trend would have been outlined in the Consultation itself, as there are two possible interpretations of this trend in our view. The two possible interpretations of this trend and BGE's view on the TSOs' proposal to increase TRIP/ SND charge depending on the interpretation, are as follows:

i. If the TSOs' logic behind the increase back to 2017 rates for units with a BM position only is, that when these units trip, because they are not liable for imbalance charges it means that the TSOs are not receiving enough revenue from these units to cover the cost of their trips – then BGE can understand the logic of trying to bolster revenues to better cover the costs of trips by units with positions in the BM only by increasing the TRIP/ SND costs for those units;
ii. However, if the trend that the TSOs are referring to is that participants that have a high probability of tripping are going into the BM (and intentionally avoiding the ex ante) due to the lesser charges risk[1], then the driving logic behind the proposal appears to be the incentivisation of which trading timeframe (ex ante or BM) participants trade in. If this is the TSOs' logic, then the logic is flawed in our view. Using these OSC charges to incentivise or influence market participation behaviour cannot be supported by BGE.

We would also urge caution against the over-use of market positions in determining what level of charges should be paid by a participant. Sub-dividing charge levels on the basis of whether a unit traded ex-ante or in the BM only, adds a layer of complexity to market participants' forward-looking assessments as to likely charges they will be exposed to. Notwithstanding this however we can support the change in TRIP/ SND charges proposed if they are aligned with the logic outlined in (i) above, and also if supporting information for that logic can be included in the decision on OSC for 2019/ 2020.

Finally, BGE notes the TSOs' request for views on whether from 2020/ 2021, non-conventional technologies, DSUs and wind should be considered to be subject to GPIs also. Given the increasing share of such units in the market and given the importance of performance monitoring and units acting in line with 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. Moves towards a level playing field need to occur and exposing these units to GPIs is a move in the right direction.

[1] I.e. is the trend that the TSOs call out a trend that market participants are making decisions as to which timeframe to trade in based on the fact that having no imbalance charge when they have no ex ante position is lower risk (cost) than having an ex ante position and risking imbalance charges on top of TRIP/ SND charges?

I hope you find the above commentary and suggestions helpful. If you would like to discuss anything further please do not hesitate to contact me.

Yours faithfully,

Julie-Anne Hannon
Regulatory Affairs – Commercial
Bord Gáis Energy

{By email}

ESB Generation and Trading

Harmonised Other System Charges Consultation Response

Tariff Year 01 Oct 2019 to 30 Sept 2020

3rd May 2019

Introduction

ESB Generation and Trading (ESB GT) welcomes the opportunity to respond to the TSOs' Consultation Paper on the Harmonised Other System Charges for the tariff year 1st October 2019 to 30th September 2020.

Please note that the sections of our response are aligned with the sections and subsections detailed in the Consultation Paper.

Trip and Short Notice Declaration Charges

ESB GT had given qualified support to the reduction in Trip and Short Notice Declaration (SND) charges by the TSOs for the 2017/18 tariff year. It is disappointing to see that rather then removing the remaining charges the Consultation Paper proposes to revert to the application of Trip and SND charges to the levels in 2017/18 tarrif year for generators that are constrained on to resolve a system issue.

In the intial six months of the revised SEM framework there have been a number of occasions where units within the ESB GT portfolio have suffered a trip or a short notice redeclaration. Where these units have had an ex-ante market position the cost to the system of rebalancing, as a result of these units being unable to deliver their contracted volumes, has been levied through the balancing market. These imbalance charges are an integral part of the market design and act as a strong incentive on generators to deliver in line with their ex-ante contracted volumes. The levying of additional charges through the Use of System agreement in the revised market framework has become a penal and unnecessary double charge. Retaining these tariffs would not be reflecting an unrecovered cost nor does it create an appropriate incentive to shape generator behaviour but rather levying a tax on generators.

The Consultation Paper further proposes to return the Trip and SND charges to the level in 2017/18 tarrif year on generators that are constrained on to resolve a system issue. ESB GT would challenge whether the TSOs have observed a significant increase in the rates of Trips and SND events since the implementation of the revised SEM framework. And further, if there has been an observed difference in the rate of Trip and SND events between generators with and without an ex-ante market position. In the absence of this data ESB GT believes the proposal to increase in the tariff rates is unfounded.

The first six months of ISEM have highlighted that the majority (>95%) of TSO actions are being settled/price using complex offers, therefore where a generator is constrained on to resolve a system constraint, the unit's bid price will typically be flagged out of the imbalance price calculation and as such its costs will not set prices for any other market participants. The cost of constraining on the unit is bourne in the first instance by the TSO in Dispatch Production Costs and then by suppliers through Imperfection Charges but the cost is not driven by the units but rather the system constraint that requires the unit to be dispatched.

Where a unit in this position trips, the TSO will resolve the system constraint by scheduling and dispatching further units in a least cost manner. The market cost of the unit tripping is then the increase in cost faced by the TSO in resolving the system constraint. The consultation identifies that constrained on units have no exposure to imbalance prices relating to undelivered ex-ante traded volumes in the market and the resulting incentive to avoid Trip and SND events which could expose the TSO and ultimately suppliers to the increased cost but it is equally the case that the units see limited benefit from creating this value when running to resolve a system constraint.

This issue represents a significant failure within the market framework, it was the case under the pre-October '17 market arrangements generators in this position where signalled to remain in the market by receipt of the availability based capacity payment. Since the introduction of the RO and related auction process it has revealed that a highly constrained market, such as Ireland, that fails to reward generators who can resolve system constraints will through signalling the exit of these units undermine the resilence of the system or the market framework itself through an increasing reliance on out of market side contracts.

ESB GT is mindful that this issue, while related to this Consulation Paper, runs through to the core of the SEM high level design. However the application of Trip and SND charges to constrained units will at best act as a stop gap measure or at worst acceralate the rate at which these generators see a signal to exit the market.

Further any unit that suffers a Trip or SND faces the risk of significant maintainace costs, the opportunity costs of foregone revenue for the period of its unavailability and the risk of being exposed to a RO event. The combination of these risks/costs place a significant incentive on generators to minimise instances of Trip and SND events without the application of any explicit penalities.

Secondary Fuel GPI

As set out in the CER/09/001 Decision paper, specific technology types are required to hold fuel stocks; the level of fuel stocks required is dependent on the generators' run hours (merit). Not all technology types have an obligation to provide this requirement, however the fuel stock obligation is required to provide security of supply to all electricity customers. It remains ESB GT's view that the secondary fuel GPI is not appropriate as the secondary fuel requirement is an obligation on a specific subset of generators as opposed to all market participants and there is currently no remuneration to provide this service. Compliance with the secondary fuel requirement for those generators impacted represents a significant capital cost and ongoing administration and maintance cost. Where the Grid Code imposes additional costs on a subset of participants in a competitive market, these costs will act as a distortion in the outcome of the market. To rebalance this distortion, ESB GT believes that a secondary fuel capability levy should be charged against all contracted capacity units to fund a remuneration mechanism for those units who provide the services. A remuneration mechanism of this nature would also balance the incentive seen by secondary fuel service providers which will act to support the long term availability of the secondary fuel capability.

Wind and Demand Side Units

ESB GT welcomes the TSOs' recognition that wind and demand side units are central to the reliable operation of the system and as such the incentives faced by the operators of these units must align with the delivery of their Grid Code connection requirements. This is evidenced by the outcome of the 2022/23 T-4 capacity auction where over 30% of the new contracted capacity will come from Wind and Demand Side units. Given that all capacity providers compete through the RO auction process, there is a requirement that the Grid Code and the related Other Sytem Charges framework do not distort the capacity market outcome and risk undermining their own objectives by placing a reliance for system resilence on one particular technology or group of technologies.

If you have questions in relation to any of the issues raised in this submission please do not hesitate to contact me.

Yours sincerely,

____

William Carr

Regulation

Energy for generations

ESB Generation and Traiding

Power NI Energy Limited
Power Procurement Business (PPB)

Harmonised Other System Charges Consultation

Response by Power NI Energy (PPB)

3 May 2019

Power Procurement Business

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 restricting 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 a system, which is being re-designed 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 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 GPI 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% last year and they have not provided any further evidence to confirm that this was the correct level of incentive, in this year's consultation paper. We do welcome the intention of the TSO to do a detailed review before next year's consultation. 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 generators without QEX are still subject to potential Reliability Options payments and so do have incentives in the market. 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 GPI 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.

Generator Performance Incentive Charges

We disagree with the position, stated in section 2.2.2 of the consultation paper, that certain GPIs are unaffected by ISEM and hence should be retained. Based on the rationale for removing the other GPIs i.e. 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.

Operating Reserve GPI

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 GPI’s should be applied to all in the same way.

The increase in the POR GPI rate by a factor of 4 in October 18 was also made without any analysis to justify this charge rate. No further evidence has been provided to support the continuation of this increase, for example to prove the increase imposed has reduced the number of these POR declarations. This rate increase could also be counter productive causing units to be reticent to declare down for short periods.

If other technologies are declaring their Reserve like conventional units, and subject to GPI’s, then 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.

New Other System Charges

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.

Fuel Switching Agreements are still not in place and hence there is no justification to continue with a Secondary Fuel availability GPI.

This charge also imposes a second penalty on the generator who is already exposed to costs under the NI Fuel Switching Agreement (FSA) for failure during fuel switching events, which includes fuel switching tests required by SONI. Such failure can also lead to termination of the FSA. 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.

Harmonised Other System Charges Consultation

01 October 2019 to 30 September 2020

Introduction

SSE welcomes the opportunity to comment on the *"Harmonised Other System Charges Consultation"* (OSC). For the avoidance of doubt, this is a non-confidential response.

We have included data sheets using publicly available data to compare cash-outs to trips, to support our comments below.

SSE Response

We note that the TSO proposes the following for the tariff year specified (up to September 2020):

- increase the rate of Trip Charges and Short Notice Declaration charges back to the 2017/2018 tariff rate, adjusting for inflation, at the forecast rate of 1.5875%, for units with no day ahead market position (QEX);
- retain the rate of Trip Charges and Short Notice Declaration charges as per 2018/2019 tariff year, adjusting for inflation, for units with a day ahead market position (QEX);
- retain the charging rate of zero for the early and late synchronization GPIs;
- retain the charging rate of zero for the loading and de-loading GPIs;
- retain the OSC rates approved for the 2018/2019 tariff year, only adjusting for inflation at forecast rate of 1.5875% for the following GPIs:
    - Minimum Generation
    - Governor Droop
    - Secondary Operating Reserve
    - Tertiary Operating Reserve 1
    - Tertiary Operating Reserve 2
    - Reactive Power
- retain the charging rate of zero for the Minimum On Time GPI and the Maximum Number of Starts in 24 hours GPI;
- retain the Primary Operating Reserve GPI rate from 2018/2019, adjusted for inflation, with a view to carrying out a review for the tariff year 2020/2021;
- retain the Secondary Fuel Availability declarations GPI rate from 2018/2019, with a view to carrying out a review for the tariff year 2020/2021

We have provided comments against some of the proposals, as follows.

Trip charges and Short Notice Declaration charges (with and without QEX)

Under the old SEM, it is our understanding that these charges operated in the absence of a cash-out mechanism. However, now that a cash-out mechanism is in place within the new market, it is not clear what these charges are designed to achieve under the new market. There is mention that these charges are still necessary to ensure managed shut downs and advance/timely notification of outages. We don't see why this is the case for units who are committed in the energy market.

The Grid Code already provides suitable obligations in this regard and furthermore, we consider that there is a mechanism to encourage early notification, i.e. cost borne via imbalance price.

We also note that the increases in charges is indexed against inflation. We find that the increase in these charges doesn't reflect the underlying drivers of these charges – i.e. the costs the TSO notionally faces above and beyond the cashout penalty already inflicted on the unit. In addition, we would welcome justification for why indexation has been set against inflation, in the first instance. We would suggest that, ideally, indexing should follow the drivers of the costs the TSO expects to face in managing any additional dispatch balancing cost resulting from these events. For example, these charges could be indexed in a similar way to the dispatch balancing costs forecast. .

Finally, we consider that these charges are already paid for through imbalance charges to generator units. If a Generator has a trip with a traded PN, all the cost is incurred by the generator via the imbalance price. Therefore, for units with traded positions (which should include IDC & IDA, not only DA), these charges should go to zero. Otherwise, the persistence of these charges, coupled with the risk borne in totality by generators via the imbalance price, amounts to an unjustified double penalty.

Therefore, we would advocate that these charges be removed for units with traded positions, to reflect the fact that generators bear the full cost of trips via cash-out. For those units without a traded position, we would suggest that the increases need to be justified and indexation adjusted to match the approach regarding dispatch balancing costs.

Retained OSC rates for the list of GPIs above

For the above list of GPIs, the consultation does not demonstrate and substantiate why these costs vary with inflation. We are supportive of these being linked to inflation, but question why the magnitude differs amongst the list of GPIs. Further detail is welcome.

Furthermore, in relation to wind generation, we have the following comments relating to GPIs.

It is relatively rare for a wind farm to trip due to a fault in its equipment. In the majority of cases, wind farms trips as a result of external system issues, e.g. transmission loss due to a storm. Therefore, the approach for setting of GPIs for non-compliance due to trips, appears to be misplaced, given that this will only deal with a rare instance of cases.

In relation to new GPIs, the TSO acknowledges that, *"implementation of an OSC for non-conventional generation where there is a cost to the end user due to their non-compliance."* The TSO also notes that *"GPIs are designed to incentivise compliance with respect to the Grid Code and are not linked with DS3 System Services Agreements".* In the first instance, we question the necessity for additional GPIs to address non-compliance, given that Category 1 policy is already exercised to address non-compliance by wind farms. Both mechanisms together would seem to us to be excessive.

Secondly, we request clarification and clear examples to illustrate those specific instances were non-compliance may cause a cost to the end user, bearing in mind as above, that trips are due to external factors in a large number of cases.

We also note that there is no indication of the application of these GPIs to different categories of wind farms—i.e. newer units which the TSO notes are largely Grid compliant (Section 3.2), versus older wind farms which by virtue of permanent derogations, are also Grid compliant. On this point, we would also consider that should newer units be majority Grid complaint, this supports our query above, regarding the necessity for additional non-compliance measures.

Secondary fuel

We note that this has been carried over at the rate for 2018/19. We would argue that this metric should be indexed against an energy index, to ensure that it is not susceptible to an inverse impact linked to prices (i.e. incentive low when prices high and vice versa). Secondary fuel is a requirement to be maintained regardless of price signals, and therefore, should not be linked in such a manner as to disincentive it when prices are extreme.

TYNAGH ENERGY

LIMITED

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Ref: TEL/JC/19/076

3rd May 2019

RE: Harmonised Other System Charges Consultation 2019/20

Dear Sir/Madam,

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

Re: Section 4: Proposed Rates

TEL welcome Eirgrid's decision to revert Trip Charges for units without an ex-ante market position (QEX) to 2017/18 rates, as constrained on units are not exposed to balance responsibility in the I-SEM arrangement. However, 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 generators endure in a trip event (as TEL found to their cost for an event in November 2018). 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,

John Casley
Market Strategy & Regulation

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