PrePayPower Response to SEM19-031 Imperfections Charge Consultation Paper

Utility Regulator,
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Dear Billy,

PrePayPower (PPP) welcome this consultation and the opportunity to respond to it.

In our response below, and in tandem with our response to SEM 19-024, we set out to respond to the consultation with reference to some of the key balancing market issues we feel are negatively impacting electricity consumers on the Island since the beginning of ISEM. We identify situations where we believe market power exists. We identify how this market power is driving up consumer costs through the Balancing Market price and mainly through imperfections costs. Further we also identify some means to address these issues.

1 Executive Summary

PrePayPower are a non-vertically integrated Electricity and Gas supplier with over 190,000 meter points active in the prepaid residential energy market in the Republic of Ireland. In the ISEM we operate both a Supply and an assetless trading unit active across all market timeframes. We also trade an assetless unit in GB. As such we offer a unique perspective on certain market issues.

Since the beginning of the ISEM, we have become increasingly concerned at the lack of competition for both energy and non-energy actions in the Balancing market and the ability of generator participants to benefit excessively from operational and network constraints to the detriment of the end consumer. It is now proposed in this consultation document to double the cost of imperfections to be recovered from energy customers from approximately €21 per customer per annum to €42 per customer per annum.

We believe that an imbalance price and a balancing market should incentivise market participants to be balanced in real time. The imbalance price should not however be so high as to drive up energy prices contrary to the economic price of producing energy. There should also be sufficient revenue streams available for generators to be in a position to operate in the balancing market and provide necessary services and capacity, however that revenue should not be so high as to significantly increase the cost of energy for the end consumer.

There is evidence continuously since ISEM go-live that certain generators have the opportunity and ability to exercise market power. This has increased the cost of balancing energy since October 2018 over and above the economic cost of providing energy. So far this year this increased cost has been mainly reflected in the imperfections cost which is significantly over budget in the 2018-19 tariff year and in total is forecast to require a doubling of cost for the forthcoming year. We believe the estimate for the 2018-19 outturn and the 2019-20 forecast are too conservative. As time moves on we believe both balancing market prices and the cost of imperfections will continue to increase over and above what would be considered economically optimal to encourage participants to be in balance and provide necessary services to the Grid. We do not believe these costs are being incurred efficiently and are gravely concerned that the end consumer will be on the hook for large costs for many years to come as a result of these market design issues. Indeed it is likely that any energy cost savings for consumers brought about by the ISEM this year have been wiped out already by these costs increases.

We believe that most large conventional generators in the ISEM balancing market have a degree of locational Market power and are able to have offers accepted close to or at the effective market cap with bids accepted at the price floor. This is the case in particular for generators in constrained areas like Dublin, Northern Ireland and in other areas which are constrained frequently. Generators who are regularly online because of system operational rules, who are located in Dublin and can start quickly, or who are behind a network constraint are in a particularly strong position. This behaviour is obvious when examining accepted offers with certain conventional generators offering energy at just below the RO strike price of €500/MWh in order to avoid triggering it, and with generators constrained by network power flows having bids to turn off or down accepted at -€1,000 / MWh. In contrast, the production cost of a peaking generator is approximately €130/MWh, while a CCGT should cost between €40/MWh and €50/MWh at present.

Since the beginning of the ISEM we do not believe that the System Operators have had access to a sufficient volume of energy actions priced in a cost reflective and efficient manner. As the rules stipulate that a generator must be paid the greater of their offer/bid and the imbalance price, these high prices are being compensated through imperfections.

So far in 2018/19 according to the TSO revenue requirement paper, the cost of running the power system reflected in imperfections costs is running €80m over budget. The €80m figure for 2018-19 reflects approximately a doubling of the over-budget position from the most recent Q2 19 imperfections report. The over budget position in Q1 was approximately €14m. This nearly doubled to €27m in Q2 giving a cumulative year to date position of €41.6m. Given the rate of change of increase quarter on quarter there is a reasonable chance with 6 months[1] of the year remaining that imperfections could end up significantly more than €80m over budget. The over-budget position is reflected mainly in the premium and discount components, CPREMIUM and CDISCOUNT. The €58.7m cost of the Discount component at six months shows the true cost of paying generators large negative bid prices to turn down or off for power that had been sold at a fraction of the price at the day ahead timeframe. Indeed we believe that this cost appears to be spread between relatively few large generators.

The coming year's imperfections tariff will need to recover this €80m plus a further €80 - €100m[2] to cover the forecast extra cost of paying for the balancing market next year. We believe these estimates are too conservative and if left unchecked both the cost of balancing energy through the imbalance price and the imperfections charge will rise to a point where any gains from ISEM are wiped out and replaced with significantly increased consumers costs. This is not a question of forecasting accuracy, we recognise and support the methodology employed by the TSOs in forecasting imperfections costs. This is fundamentally a question of ensuring that energy and non-energy actions are delivered at an economically acceptable cost to the end consumer. These consumer costs are not driven by any change in market fundamentals, they are solely the result of the exploitation of market rules by generators with market power.

With regards to the increase in consumer costs for the forthcoming tariff year, we believe the overspend costs are inflated and not in line with market fundamentals. However it is our position that

[1] Relative to the last imperfections report

[2] Range represents difference between requested / proposed revenue and allowed 2018-19 revenue

the downside risks to spreading the increase out over more than one year are too large and that any increase should be taken up front.

The long term solution to these market power issues is through grid build out to alleviate constraints and mitigate locational market power of generators. However we recognise major grid roll-out takes place over a long period of time and there is no certainty that the required projects will be built. In the interim, we believe a fundamental rethink is required for the balancing market. In our response to SEM 19-024, PPP supported Simple NIV tagging as a step in the right direction. However we felt that it does not go far enough. It on its own will not be enough to prevent generators setting high prices close to €500 / MWh through locational market power. The changes required will also take some time to implement, requiring some form of intervention in the short term.

The only way to protect consumers from locational market power issues is to reintroduce controls on pricing for generators who are in positions of market power. Such controls are within the scope of the high level design, and the circumstances under which they come into being were discussed in the ISEM Market Power consultation and Decision papers. We believe that these circumstances are now a matter of fact within the Balancing markets, and that the controls can be implemented quickly. These controls can then be removed when market power issues have been mitigated, either through increased competition on the generation side from independent power producers, or through grid roll out or both.

We would further suggest, that it should be considered that both sides of the market, both supply and dispatchable generation, should pay for the cost of imperfections. This is how imperfections are paid for in the British Balancing market, with both suppliers and generators paying on a metered MWh basis. As the dispatch balancing costs component of imperfections can be itemised, it should be possible to split the cost of energy actions amongst both dispatchable generators and suppliers. Making such a change would incentivise generators to not inflate balancing market costs which are borne through imperfections out of line with market fundamentals.

2 Current locational constraints in the ISEM

At present a complex and detailed set of rules[3] exist in order to maintain a stable and secure electricity supply. These rules are published and updated periodically by the Transmission system operators as required. They detail on a unit and locational basis which generators are required to run and during what conditions. As such it is usually possible for any participant to forecast when a generator would be called upon to run and satisfy one of these rules. In addition weekly updates[4] to these rules give further insight into where more infrequent or localised restrictions may occur. It is necessary to understand the interaction between these power system constraints and the rules of the balancing market in order to understand how a generator may be in a position of locational market power. The following sections highlight at a high level the implications of those operational rules and the power system constraints that drive them. The fundamental consequence of these locational constraints is that there are insufficient volumes of economically priced generation available to the system operators to balance the grid. As the system operators must always maintain the security of the grid, they have no choice but to use expensive energy actions. This cost is then borne by consumers mainly through imperfections but increasingly through balancing prices.

[3] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_83_June_2019.pdf

[4] https://www.sem-o.com/documents/general-publications/Wk29_2019_Weekly_Operational_Constraints_Update.pdf

2.1 Dublin

In Dublin at least 2 large generators and sometimes 3 are required at all times. In addition most of the system demand is concentrated in the Dublin area meaning that it is generally required to have additional generators online in Dublin to meet any changes in demand. Of the 7 generators in Dublin, only 5 are capable of satisfying the must run requirements. Of the remaining 2 one has notified its intention to close before this coming winter and the other operates as priority dispatch limiting its ability to respond to changes in demand. Of the 5 generators, only 2 of these, which can elect to operate in open cycle mode, can be thought of as fast start in the context of balancing market timeframes. Both of these open cycle generators are owned by the same participant. As there is insufficient network capacity to bring power into Dublin, when demand is high enough these are the only two generators who can start quickly enough to meet demand. The operator of these generators has frequently been observed having energy actions accepted at prices close to €500/MWh. We would also note that the owner of these two generators was the only participant in the recent T-4 capacity auction who secured new generation capacity in Dublin. The new T-4 capacity are fast start generators. Thus the same participant will own all fast start plant in Dublin for the foreseeable future. Unless the rules change this participant will enjoy significant market power.

Any generator in Dublin which is brought on for non-energy reasons to satisfy an operational rule and is part loaded is also in a very strong position to be used to provide energy actions.

At present one of the 5 large generators in Dublin is providing energy actions at cost price under a local reserve services contract. This is helping to keep the imbalance price and imperfections costs lower than they would be as this generator is frequently marginal. When this generators contract finishes in September 2019 it will be free to price as it chooses which could increase prices further.

Additionally from this winter onwards another Dublin generator will be losing an advantageous fuel price contract which will result in its price of generation increasing. As this generator is currently always scheduled at a day ahead level it is already on in balancing timeframes – satisfying one of the must run requirements. When it's operating regime changes there is likely to be an associated change in Balancing market prices and costs.

2.2 Northern Ireland

In Northern Ireland 2 main rules exist to ensure system security and to serve local demand. The first rule requires that 3 large generators are online at all times. Another rule exists to ensure that at least one generator is running in the North West of the province when demand is high enough. There are only 6 Generators located in 3 different power stations capable of satisfying the first rule, and there is only 1 generator capable of satisfying the second rule. We believe that Northern Ireland participants have a strong degree of market power in that they are always required in balancing time frames and when turned on to satisfy an operational rule can then provide energy balancing. We also note the high complex costs submitted by some NI participants for a portion of their load which are generally above €300/MWh and at times peak in excess of €500 / MWh. We understand that some of these costs relate to Gas Transport. It is questionable whether these costs are economically rational given the predictability of running some of these participants appear to have given their location.

2.3 South West Ireland

There are other examples at present where a small subset of generators are required on in the south west of the Republic of Ireland in order to manage voltage when wind levels are low. These generators which ordinarily would be out of merit are turned on to satisfy this operational rule but then are available to provide energy actions and have been observed providing energy at €490 /MWh.

2.4 400kV Network

In order to maintain the stability of the 400kV network linking the west and east of the country there is a requirement to run at least 1 of a subset of 4 generators at all times. At times all 4 of these generators will be outside of merit from an economic standpoint and may not have achieved an ex-ante position. The generator chosen will be in a position from time to time to set energy prices if it so chooses. This doesn't appear to have happened so far in ISEM.

2.5 Interaction with Interconnector imports

At present in the ISEM, Interconnector flows enjoy a similar form of priority to wind and other renewables. Interconnector imports on EWIC flow into the Dublin end of the 400kV network. This can lead to constraining of generators exporting onto the 400kV network from the west of the country. As Interconnector imports are forecastable and generally correlated with Low wind levels these generators could be in a position of market power if they hold an ex-ante market position higher than the available capacity on the 400kV network when EWIC is importing.

2.6 General transmission restrictions and constraints

The limitations of the transmission grid mean that technically all generators to some extent experience restrictions in their output. This can be because of delays to upgrades on the grid and can be made worse during the outage season in the summer or when an item of equipment is forced out. In this case the meshed nature of the grid is reduced meaning several parts of the power system may have only one connection to the wider grid or have reduced capacity deeper into the grid which restricts their ability to export power.

At present several power flow constraints exist in the South and South west of the Republic of Ireland limiting power flows from in merit conventional generators in those areas at times which are generally forecastable. There are also restriction in the midlands as generation can come into conflict with wind power flowing from the west to the east of the country. There are delays to network upgrade projects in the midlands also which restricts the output of certain peaking generators.

In Mod 09_19 the TSOs state the following:

"During the development of the wholesale market rules, it was the position, based on the SEMC decisions and industry feedback, that any units whose output could be identified as constrained for non-energy reasons should be flagged out of the pricing process. This resulted in any possible transmission system based constraint being flagged on the units whose output is restricted by the constraint.

However, it was found that it was not possible to accurately identify which units contribute to which thermal limit constraints on the transmission network model. This is because on a meshed network every generator has some influence on every network line and without a locational signal to determine where an imbalance arises, it is not possible to determine the units which should be flagged out. Therefore, network constraints highlighted through the network model are not flagged"

Simply put this means that generators who cannot get their power out onto the grid are not flagged in the pricing and settlement process. From an imbalance pricing perspective if the NIV is short – then bids from generators generally don't feed through to pricing. However as the market rules entitle a generator to the better of their bid and the imbalance price, generators do receive payment if they have negative bid prices during such events. In these situations we have observed generators selling energy in the ex-ante markets for €40 to €50/MWh or less only to be paid to not produce this energy in the balancing market for a price of up to €1,000 / MWh. We believe the gross costs of constraints such as this so far has run to at least €60m. This is a cost to consumers and is mainly paid through imperfections costs. We are concerned that this type of behaviour will continue unabated through the summer outage season as power flow constraints increase increasing imperfections costs above the projected €80m.

3 Market Power in the ISEM Balancing Market

The All-Island electricity grid is one characterised by uneven development with the majority of demand concentrated on the east coast in Dublin and Belfast, and the lowest cost generation spread across the west coast and in the South of the Republic of Ireland. Despite the best efforts of the transmission system operators, the grid linking the west and east of the country does not have sufficient capacity to transfer all of the cheapest energy to where it is required. The extra transfer capacity required to do this is substantial and will require several large linear infrastructural projects which are not deliverable for at least 5 years. As a result of this there is a must run requirement for several large dispatchable generators at all times in the high demand areas to ensure that demand is met, but also to guarantee the stability of the grid. Even if sufficient transfer capacity were to exist there is always likely to be some extent of must run generation requirement.

As a result of the constrained nature of the All-Island Power system, Market Power exists in the ISEM Balancing market on a locational basis. The market power can be considered static or dynamic. Generators with static market power are generally located in areas with high demand and insufficient grid capacity, such as Dublin or Northern Ireland, and are subject to one or many operational rules which require a certain number of large generators to run at all times of the year. Such must run requirements are generally permanent in nature. There is a limit to the amount of generators who can satisfy these rules or serve locational demand – hence those generators can be considered to have market power if they can use that position to their advantage.

Generators who have market power from time to time due to transmission restrictions can be considered to have 'dynamic market power' in that it exists only under specific conditions which while generally forecastable may be conditional, adhoc or unplanned in nature. These instances of dynamic market power generally mean that a single or small number of dispatchable generators are subject to a power flow restriction. If that generator is outturn available and has an ex-ante market position, then under the current balancing market rules it can set its own price to turn down. In this situation the generators ex-ante position is effectively an energy imbalance and the generator itself is the only participant who can solve the imbalance. This gives it market power.

In the balancing market must run rules and requirements to serve demand generally result in generators being turned on or up, whereas network restrictions will generally see generators turned down or off. Offers to turn up or down for energy reasons are settled at the simple offer or bid price for generators – which are not subject to bidding controls. A rule also exists in the ISEM that generators are paid the better of their bid / offer price or the imbalance price. These additional costs are borne by consumers through the imperfections charge.

As the balancing market takes place in or close to real time, the energy balancing options available to the system operators must also be available in or close to real time. This generally means that only generators that can start quickly or that are already online can provide energy balancing actions. If a generator is already online because it is used to satisfy an operational constraint or if it is located in an area where it can serve changes in demand and is able to start quickly then it can be considered to have market power. Furthermore if a generator has an ex-ante market position but it is behind a constraint then it and only it can alleviate that constraint. In this case it again holds market power.

The strike price of the reliability option sets an effective cap of €500/MWh on generator simple offers because if the balancing price rises above this price then generators not producing sufficient power will need to pay out on their reliability option. Further, these high prices are being set during times when the system is not under stress, and not all generators need to be called as most generators are part of a portfolio it is in their interest not to disadvantage any of the rest of the portfolio by triggering the strike price. Simple offers are frequently accepted in the balancing market at prices in excess of €400/MWh but just below the strike price of €500/MWh.

As part of our SEM 19-024 analysis, we have conducted our own analysis looking at prices from go-live up until the end of June. We have produced this analysis using the Price of the marginal energy action as a proxy measure for the price of accepted offers. This does however significantly underrepresent the amount of high price offers.

We believe that there is evidence that the frequency of accepted offers is actually increasing in the higher end of the price band as more generators with market power are able to price up to the level of the RO strike price. We also believe that there is a clustering of offer prices beginning to happen with a cluster of offer prices between €0-€120 / MWh and another cluster in the higher end of prices above €400/MWh. We are concerned at the lack of offers in between the two clusters. We are also concerned that when the system is short that prices tend to increase quickly as the system shortens. Whilst this is to be expected to some degree, we don't believe the level of price increase is justified as the generators providing energy in these situation have a far lower cost of production that the energy offered. There is also a clear pricing deadband between €250/MWh and €450/MWh. There is no economic justification for this to exist.

We believe that a significant portion of the PMEAs in the 0-100 €/MWh range are energy actions from a unit in Dublin with a local reserve services contract which is provide balancing energy at cost as per its contract. This is keeping the price of balancing energy low as the unit is offering energy at its short run marginal cost. When this contract expires at the end of September 19 we expect the amount of higher prices to increase.

The following analysis examines pricing in the ISEM when the system was short.

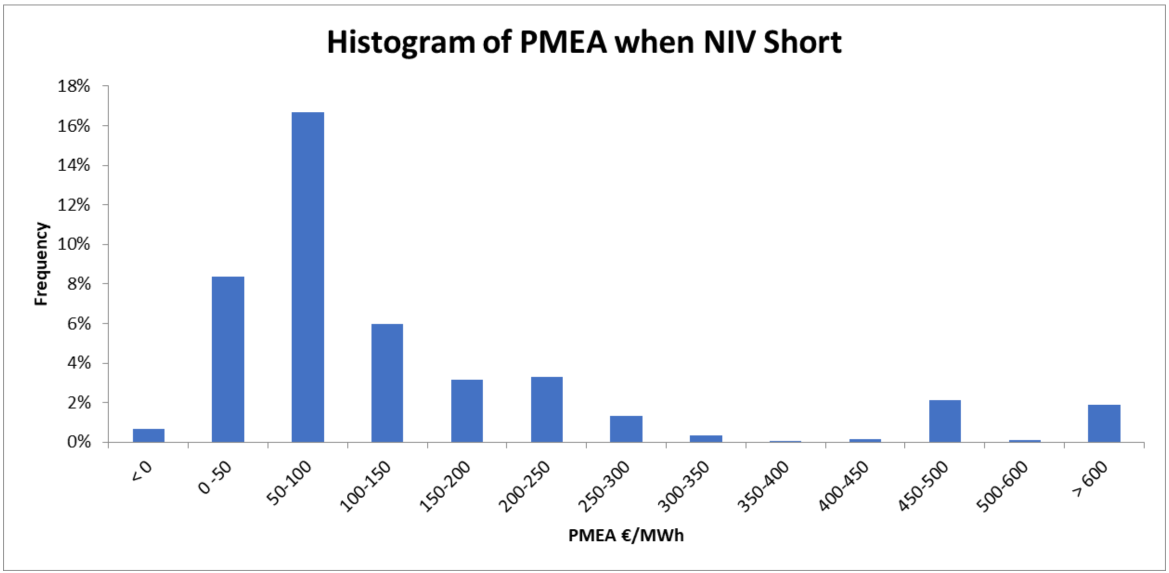
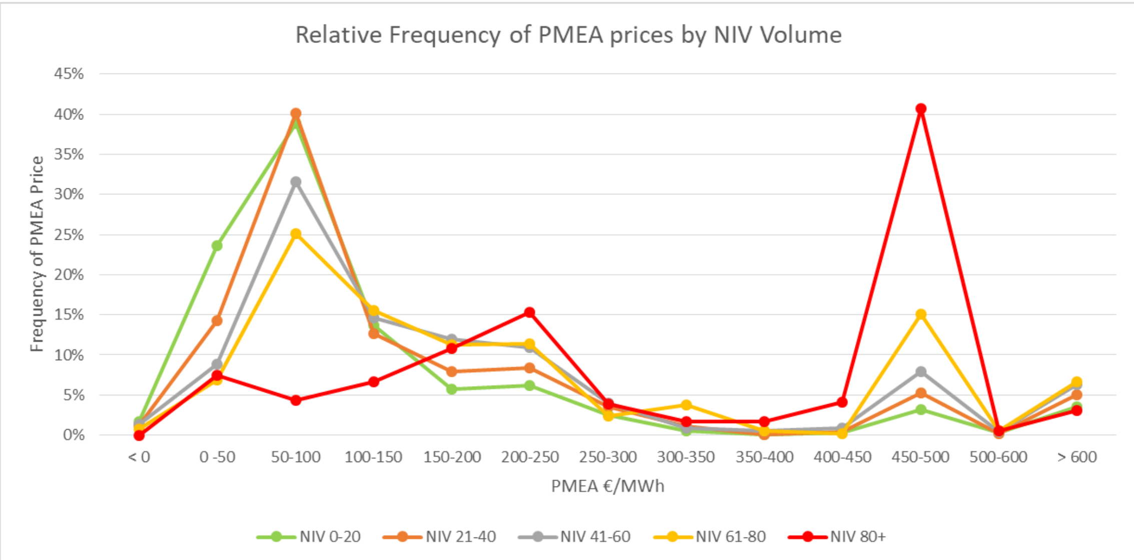


Figure 1: Histogram of PMEA prices when ISEM short

In figure 1 there is a substantial concentration of periods where prices are between 0 and €150/MWh.

This is to be expected as it represents the range where most generators short run marginal costs would lie. There is a further concentration between €150/MWh and €300/MWh which is further away from the cost price of the generation portfolio in the ISEM. There is a deadband with effectively zero prices between €300 / MWh and €450/MWh. The concentration of prices grows above €450 / MWh.

We have also examined the relative frequency of PMEA for different levels of short NIV. This is shown in figure 2.



It is clear from figure 2 that for low short NIV levels that prices are strongly clustered between 0 and €150/MWh. However as Short NIV levels increase the concentration moves to higher prices with a further cluster between €150 and €250/MWh and a peak between €450/MWh and €500/MWh. It is also evident again that there are almost no PMEAs in between €250/MWh and €450/MWh. It is difficult to understand the economic rationale for this pricing behaviour without coming to the conclusion that generators are pricing up to the RO strike because they believe that they have the market power to do so. It is also worth noting that for relatively small NIVs there is still a concentration of prices between €450/MWh and €500/MWh.

We have also examined generator behaviour on the bid side of the market. In the case where transmission constraints exist, we have seen evidence of generators who are outturn available achieving an ex-ante position generally in the Day ahead market only to be constrained down or off due to power transfer restrictions on the transmission grid. The participants in question have submitted large negative bid prices in order to be turned down or off by the TSOs. It would appear from market data that certain large generators are frequently constrained by the grid and have had ex-ante market positions of several hundred MW reduced to zero metered generation for long periods of time at prices up to -€1,000 /MWh. The generators submitting these bids are the only ones who can resolve the constraint. This has resulted in payments of tens of millions of Euros to a handful of generators to not produce energy sold previously for a fraction of the cost in the day ahead market.

These transmission restrictions are usually due to the existing grid having insufficient transfer capacity to transfer power or due to outages of transmission equipment or a combination of both. Information on transmission plant outages along with grid capacity restrictions are published in advance. Transmission constraints are usually made worse by high wind levels. High wind is forecastable. Generally speaking it is possibly to forecast transmission constraints with a reasonable degree of accuracy.

These transmission restrictions do not get flagged out as non-energy actions due to the market design. They frequently do not set or contribute to the imbalance price meaning that these actions are paid through imperfections.

The cost of these actions is given in the CDISCOUNT component in the Q2 Imperfections report as €58.7m for the first 6 months of ISEM. This is a net positive cost reflecting the fact that generators are being paid large sums of money to not produce power. Whilst there will be a cost to a generator to not produce their market scheduled quantity we do not believe it is anywhere approaching the price of the bids that are being submitted in ISEM.

3.1 Economic pricing of Simple Offers

We believe that the cost of providing energy through simple offers has been grossly inflated in the Balancing market to date, and as shown in section 2.3 there is an increasing skew towards higher prices. Without controls on offers we would expect this trend to continue. In complex offers Generator allowed recoverable operating costs are controlled and given according to prevailing fuel prices and the operational characteristics of the generator. Simple offers are not cost controlled but the generator has to internalise all of their operating costs into their price quantity pairs. If the generator in question is a peaking plant expecting to operate over a short period of time at a relatively low load, then their start cost will form a large part of their simple offer. It is not unreasonable to expect peaking distillate oil generators to need to offer energy at a cost in excess of €400 / MWh in order to recover their start costs.

Larger generators who can start quickly and are used to provide energy will generally have larger start-up costs but this will be counteracted by the time they are online for and the size of the minimum output of the generator.

Table 1 below shows a selection of typical operating costs for ISEM generators extracted from complex offer data which is then used to show their economic cost under simple offers by internalising all elements into the simple offer.

Clearly the economic cost of operating under a simple offer structure is far less than some of the prices observed in ISEM to date.

In the context of market power, it should also be noted that when a generator is turned on in order to satisfy a locational or operational constraint that it is settled under its complex offer data receiving its start cost. In that case if it goes on to provide energy under a simple offer it should not need to recover its start costs again. Indeed, there is a provision under the market rules to prevent double recovery of start costs through settlement. However, where a generator has an offer accepted for a very high price it still impacts the imbalance price and imperfections. It does appear that some generators are clearing simple offers at very high prices when they have been turned on to satisfy an operational rule and received their start cost through their complex offers.

Type of Generator	Operating Hours	Min Gen (MW)	Complex Start Cost (€)	Complex Offer Price / SRMC (€/MWh)	Simple Offer Price (€/MWh)
Distillate Peaking	1	10	3000	130	430
	5	10	3000	130	190
Large OCGT	1	80	20,000	80	330
	5	80	20,000	80	130
	8	80	20,000	80	111
Large Oil	4	40	60,000	120	495
	5	40	60,000	120	420
	8	40	60,000	120	308
CCGT	2	150	80,000	45	312
	5	150	80,000	45	152
	8	150	80,000	45	112
	10	150	80,000	45	98
Coal	4	90	65,000	50	231
	5	90	65,000	50	194
	8	90	65,000	50	140
	10	90	65,000	50	122

3.2 ISEM Market Power in the context of SEM 15-094 and SEM 16-024

In 2015 and 2016 the regulatory authorities consulted on measures to control market power in the ISEM. SEM 16-024 decided that cost controls through the use of the 3 part offers would be applied to generators providing non-energy actions in order that these participants could not exercise market power. It would appear however, that some of the instances of potential market power identified in the consultation are now occurring in the balancing market.

SEM 16-024 Section 4.1.5 describes market power as:

The key implication of local market power is the incentive it creates for the generator that possesses it. If a generator knows that it will have to be dispatched by the TSO in real time (e.g., in order to meet *demand in a load pocket), it will have less of an incentive to bid competitively, since it is all but guaranteed to run in the BM, such that its bids and offers are not at competitive levels.*

And further in 4.3.5 and 4.3.6:

4.3.5 In light of the above, a generator participant in I-SEM should be incentivised to be available and should be incentivised to be dispatched by the TSO. Given the above, generators should be incentivised to bid at their true opportunity cost in the same way as today with SRMC referenced to opportunity cost. The SEM Committee does not expect that the operational efficiency of the physical markets will be sacrificed (by market participants consistently offering above SRMC) by generators attempting to incorporate fixed cost into their offers if the market is competitive these will get competed away. Inefficient plant will exit if the capacity and DS3 revenue plus inframarginal rent is not sufficient to cover their fixed costs.

4.3.6 If there are widespread instances of generators being dispatched and bidding significantly above opportunity cost, this would indicate a lack of competition. Further to this, in general, cost recovery is a matter for overall market design and the objective of this is for revenues to recover efficiently incurred costs, not to recover fixed costs of all existing plants

Further consideration was given to the situation where part loaded generators could exercise market power by bidding up to just below the level of a peaking generator knowing that they would likely have offers or bids accepted at this price.

Paragraphs 8.16.4 and 8.16.5 from SEM 16-024 discussed this behaviour further (our emphasis added):

8.16.4 The SEM Committee has carried out some analysis of the BM and acknowledge that there might be a significant step change in the supply curve in the BM where the part loaded plants will likely have lower incremental costs while the peaking plants are likely to be higher. However, the SEM Committee believes there should be sufficient competition between part loaded plants to lead to competitive outcomes. Also, any manipulative behaviour would be addressed through REMIT.

8.16.5 If however, the behaviour observed in I-SEM is that the part loaded units can always successfully bid up to peaker plant levels, the SEM Committee would give the issue consideration as to whether such behaviour would be providing misleading signals as to the supply demand balance. If intervention was deemed to be warranted it could be through the application of Option 3 from the Consultation Paper in addition to Option 2b.

The consultation paper in appendix C also examined some examples of where market power could arise. The first example considered a generator who had a reasonable expectation of being dispatched up or down in the Balancing market who is then able to adjust their offers and bids above or below their production cost in order to profit from their market power. This example considers a participant who has an ex-ante position.

We would slightly modify this example to add on the possibility that a participant who does not have an ex-ante position but who has been turned on to satisfy a constraint also holds similar market power. In ISEM We believe that several generator participants have market power such as this.

We would also highlight example 3 in Appendix C *where a generator clears an ex-ante position but cannot be dispatched in real time due to a transmission constraint*. The examples goes onto outline that *if the generator can reasonably expect that the constraint will be binding, it may put in a very low*

DEC bid. As above, imbalance prices should not be affected since this is a non-energy action by TSO, but balancing costs will be higher.

Again we believe there is evidence that the sort of behaviour outlined in example 3 has already cost customers tens of millions in imperfections charges.

We believe that there is sufficient evidence that the type of market power examined in SEM15-094 and SEM 16-024 exists in the ISEM. We believe that at this time that the only way to resolve this market power is through the measures identified in the consultation, in particular option 3 (shown below) which applies SRMC based offers to all generators who have either long term or short terms market power.

Option 3: Prescriptive Bidding Controls

8.7.15 Option 3 involves prescriptive ex-ante bidding controls where all generator bids are set mandatorily at formulaic SRMC levels for all trades in the BM (not only with the aim of mitigating local market power). Under this option, SRMC-based offers would be maintained as the default for the BM. The MMU would verify the SRMC-based offers on an ex-post basis and require bids to be changed to comply if needs be.

8.7.16 This option is broader than the first two options and its aim would be not only be to mitigate local market power but also short-term market power in the BM for energy-actions which can arise from there being a limited number of generation plants available to meet system demand. As exemplified in the modelling results in section 6, this need can lead to increased structural market power in the BM compared with the DA and ID markets, and therefore may justify a market power mitigation measure to cover all trades in the BM.

4 Summary

In summary we believe that a combination of a relatively weak and heavily constrained grid with the current balancing market ruleset is creating situations where market power exists. We believe that the participants who hold market power are able to use it to price up to just short of the RO strike price on the offer side, or to price down to the balancing market floor price on the bid side. Some participants are pricing in line with their production costs but others aren't. The constrained nature of the Grid will be a facet of the Irish energy market probably for the next decade. As such some participants will always hold market power. The net cost of these high energy prices is increasing consumer prices through both the imperfections charge and increasingly the price of balancing energy. There is also outside of market costs borne by consumers through TuoS to pay for local reserve service agreements.

Without action these consumer costs will continue to increase driving up the cost of energy for all. Indeed we believe that the figures presented this consultation paper may be too conservative. However, this is not a question of forecasting accuracy, it is fundamentally a question of ensuring that energy and none energy actions are delivered at an economically acceptable cost to the end consumer.

With regards to solutions, we welcome the consultation by the regulatory authorities to introduce simple NIV tagging and believe it is an important step in the right direction. In combination with Mod 09-19 it will eliminate some of the extremely high price incidents and we believe it should stop participants some of the time being able to bid themselves off at very negative prices when constrained. However, as per our pricing analysis in the preceding sections we are concerned that any move to simple NIV tagging will be hampered by participants with market power who continue to bid up their prices to the effective market caps. We do not believe that simple NIV tagging will prevent part loaded generators offering energy just below the RO strike price when the market is short. This proposal fundamentally doesn't change the way that energy is balanced so the TSO will still only be able to use generators who can start quickly or who are already online and part loaded to provide energy.

The only way to fully ensure that participants who have market power cannot exercise that power is by implementing price controls on generators as per those described in SEM 16-024. We would propose that option one be combined with such price controls in order to be fully effective. We would also suggest that it would be in the consumer interest to ensure the TSOs can schedule long notice generators far in advance under complex offers when energy imbalances are known about or forecast in advance.

Furthermore as it will take a significant period of time to implement any changes we suggest that price controls are implemented immediately in order to protect consumers as soon as possible.

We would further suggest, that it should be considered that both sides of the market, both supply and dispatchable generation, should pay for the cost of imperfections. This is how imperfections are paid for in the British Balancing market, with both suppliers and generators paying on a metered MWh basis. As the dispatch balancing costs component of imperfections can be itemised, it should be possible to split the cost of energy actions amongst both dispatchable generators and suppliers. Making such a change would have a similar effect to Directed Contracts, as it would incentivise generators to not inflate balancing market costs out of line with fundamentals which are borne through imperfections

It is also an equitable proposal for consumers as it will see the cost of imperfections drop with the charge spread across a larger base with all participants encouraged to trade in an equitable fashion. If the charge were to be implemented for the 19/20 tariff year it would reduce the cost to consumers, ensure that those who caused the increases pay their share, and incentivise good behaviour by participants in future.

With regards to the recovery of costs for the 2018/19 year, whilst we believe the overspend costs are inflated and not in line with market fundamentals, we believe that the downside risks associated with recovering that overspend over a period longer than one year are too large. Hence costs should be recovered fully in the coming tariff year.