Powerhouse Generation Ltd response to

SEM-21-042

Discussion Paper and Call for Evidence on Scarcity Pricing and Demand Response in the SEM

28/06/2021 Author: - Brian Mongan

Powerhouse Generation (PHG) welcomes the opportunity to comment on the discussion regarding Demand Side Response and Flexibility in the SEM, and also the discussion on Scarcity Pricing. We understand that the thrust of the paper is to identify the tight generation/demand margin witnessed over the winter of 2020/2021 and the similar expectation this upcoming winter. PHG expects that any decision shall be only for the near future and not an enduring solution.

Overview

The reference to 3 Amber Alerts in the SEM, for 2021, is incorrect. The Single Electricity **Market** supported by the T&SC and the CMC, neither of which have any references to "Alerts". There are references to "Alert" in the Eirgrid Grid Code

The alerts are within the TSO control function, under Grid Code. These alerts raise the concern of the TSOs regarding security of Supply and encourage generators not to place their ability to deliver at risk. This normally results in reduction of in-house testing for conventional generation and some limited preparations for Demand Side response. It should also be noted that the alerts are not an indication of a scarcity of generation across the island but rather an indication of the expected ability of each TSO in balancing their jurisdictional System.

When alerts are issued by both TSOs then there is an acceptance that the whole island is experiencing a risk of balancing supply and demand. There was one single alert in 2020 (09/12/2020) and one single alert in 2021 to date (06/01/2021). The 9th December 2020 had only 81% of dispatchable generation covering the total demand. Wind contribution was 19% which places a greater reliance on other dispatchable generation to meet demand. However, there was also an 11.5% demand from the Interconnectors which placed further reliance on the available dispatchable generation. The price did rise towards €500 which meant that the Irish consumer was paying for exporting power from the island.

The remainder of the alerts were a resultant of the inability of the TSO to avail of all the available generation and to allow such to flow through the Transmission System in an efficient and economical manner. This is not a reflection of the **market**, nor should it result in influencing the market price and a direct cost to consumers. The cost of investments in the electricity transmission network is a matter for the RAs and the TSOs and is discussed in a separate forum.

What is missing from the analysis is how much dispatchable generation was left in each jurisdiction. This should include reserve and also non-scheduled generation. Was there an impact from the 'long notice' requirement to conventional generation?

There is also information shown in figure 1 which suggests that the forced outage rate is getting worse. The reason for this has not been explained in detail. All conventional power stations have maintenance cycles of 3 or 4 years. It is interesting that the rate increased from 2013 to 2016 and then fell. The rate is a weighted percentage and therefore it must be asked if there is a specific group of generators that degrade following their overhaul, over the period of 3 years. PHG acknowledges that due to COVID19 there is likely to be an extension to the FO rate. As highlighted in the paper, there are a couple of generation units that are on a forced outage for the majority of 2021. PHG would again suggest that applying a high ASP will not bring these units back to being available to generate.

The comment on page 9 of the paper that "*If, as is forecast, all-island demand increases, while older capacity exits the market. The number of System Alerts may increase in the short term*" would suggest a level of bad planning.

Why should prices rise to reflect scarcity? If the market can balance the system with prices below €500 then that benefits the consumer. The market shall provide prices above €500 when there is a true cost to provide such expensive generation, and that may show that the TSOs had exhausted all the economic generation available to them.

There is a fundamental flaw in the thinking that increasing the price of an item shall make that item appear. This of course is based on the assumption that the item is deliberately being held back for other reasons, and that the provision of a higher price shall miraculously make it appear. If it doesn't exist then it shall not turn up, despite the price. Therefore, the idea that an Administered Scarcity Price shall help with additional generation or demand side response being provided is to be challenged. The only way to balance the system at that point, is to look at the Suppliers and their consumers and see which of them can be turned off.

Section 2

There are many comments in the paper around the Reserve Scarcity Price and the Administered Scarcity Price and if they should be adjusted to encourage better price signals. The Capacity Auctions were run on published factors which all participants used to evaluate risk, specifically to do with Difference Charges. Any adjustments to the Reserve Scarcity Price away from the value of the Reliability Option strike price shall introduce an economic risk that was not there at the time of the capacity auction. This is an unwanted additional risk which would undermine the capacity auctions themselves.

Artificially increasing the price could increase the amount of Scarcity Events and therefore the Difference Charges that would be imparted onto the generators. This would have a financial impact but still wouldn't provide additional generation from the existing fleet of registered units. The Suppliers are the section of the market participants that need to have their Reliability Hedge lifted, if they are to be incentivised to help balance the system.

It is noted that the paper correctly states, in section 3.1, that "Supplier's risk is capped by the RO Strike Price". This effectively means that all the discussions around adjustment of the RSP or the ASP are expected to impact the generation side of the market. This is a one-sided approach, and the risks fall solely on the generators, despite their inability to respond to short notice 'Alerts' with plant that is broken (forced outage).

It would be useful for simple examples to be provided to show how each level of participant would be impacted be the suggested changes, application of ASP, lower RSP, higher RSP, etc. Not all those reading the Discussion Paper fully understand the references in Appendix 2 of the paper.

<u>SECTION 3</u>

Implicit Demand Response

For Suppliers to be interested in higher market prices then the RO scarcity trigger value would need to be increased, such that they and their customers would be exposed to additional costs. This would help in incentivising consumers to respond in providing further reduction. This may appear through Demand Side Response or through the natural response to forecasted high prices, as alluded to in the paper – "Suppliers can still get the full marginal benefit of selling back any load reduction".

Explicit Demand Response

It is difficult to incentivise additional Demand Side Response provision within dispatch by the TSO, as demand side unit (DSU) response is not paid for the provision of energy. The only requirement is for the demand side operator to match the RO volume of its awarded capacity. Doing this avoids any difference charges and the associated financial penalties.

One action for the RAs is to provide energy payments for all energy provided by Demand Side operators. This would incentivise them to provide above the RO level.

The core belief of the market design is that the demand response is provided through consumption reduction through turning devices off. This saves the site from paying higher costs to the Supplier. To increase this provision would mean the sites increasing their consumption, in order for it to turn it off later. This would have an unwanted consequence to the balancing of the system. The other mode of operation is to generate the sites own requirement. This is still limited to the original site demand and thus cannot be adjusted.

Having said that there may be an ability to enhance sites to turn further devices off, which may impact their production or safety, but which they may do so for extra revenue.

PHG **does not** support any proposed changes to the RSP in relation to the RO Strike Price that may increase the commercial exposure to Demand Side Units for non-performance. If a DSU is unable to perform then there is no need to penalise it further as that will not facilitate the balancing of the electrical system, it will just make the DSU more reluctant to participate in the future. Such signals are counterproductive to the goal of ensuring the island can facilitate high levels of renewables and reduce the dependence on conventional fossil fired generation.

Advance Notification

Giving advance notice of alerts is always a good thing for demand side as it allows advance communication to the sites and maybe offset planned maintenance.

<u>Alternative approaches</u>

If the TSOs believe that there is a likelihood of tight generation margin through the upcoming winter then they have the ability to procure additional generation, similar to the contracting of the Ballylumford plant in recent years. This may be a temporary flexible provision and it may be provided by existing or by new generation. This would need a locational indication by the TSOs to reflect the restrictions they experience on the transmission system.

The TSOs could also look at the limitations they currently place on the system, regarding reserve and potential line drop out. The North/South tie line has a current limitation of 400MW although scheduling may not reach this limit.