Peak Gen’s response to Ofgem’s ‘Access and Forward Looking Charges SCR – consultation on minded-to decision’

[16] August 2021

About Peak Gen

Peak Gen owns and operates approximately 200 MW of reciprocating engines primarily in the south of England and Wales. Our existing sites have multiple engines, typically with 20 MW of generation capacity. The sites are primarily focussed on delivering grid services, rather than energy, and operate with a very low load factor, often less than 1%. Peak Gen also operates a battery storage site and is in the process of commissioning a 400 kV reactor under NG ESO’s pathfinder programme.
We operate both through supplier meter connections and we also hold a BEGA for one site and register the meters and participate under the BSC on our own behalf.

Introduction

We welcome the review of network charging and note the considerable work to date. Due to our own resource pressures, we have limited our response to section 5 of your consultation – “proposals for TNUoS charging for Small Distributed Generation”. Below I set out:

1. Comments on section 5 of the report where we believe that there are factual inaccuracies;
2. Responses to each of your 7 consultation questions; and
3. A justification for why we don’t believe a case to change has been made.

Most importantly, the questions focus on if embedded generation has a similar effect on the transmission system as transmission connected generation and whilst there are similarities there are also significant differences. The paper ignores the fact that 1MW of embedded generation operating in an *importing* GSP has *exactly* the same effect on the network as 1 MW of demand reduction, hence for charging purposes, treating embedded generation in an importing GSP as negative demand is correct.

We hope these comments are useful. In previous consultations we have received feedback that Ofgem was “unconvinced by the evidence”. On any of the points made we are happy to expand the points made and provide additional evidence and would appreciate being contacted before any points are dismissed.

Review of Section 5

These issues are set out in the order that they appear in the report.

Figure 4 (page 60) “Indicative locational variation in charging arrangements” shows Britain split into three zones. The first bullet point against the Northern zone states “TG/LDG: pays high charges for capacity”. We think that this statement is misleading. For example, a “carbon” generator operating with a 5% load factor in zone 4, “Skye and Lochalsh” has a trivial TNUoS charge of 0.87 £/kW (see table 1 for derivation). Hence statements like “TG/LDG: pays high charges for capacity” are misleading.

Table 1: Derivation of TNUoS tariff for a Carbon generator with a 5% load factor in Skye and Lochalsh

	Charging Rate (£/kW)	Multiplier	Product
System Peak	-0.60	1	-0.60
Shared Year Round	18.12	0.05	0.90
Not Shared Year Round	19.91	0.05	1.00
Adjustment	-0.43	1	-0.43
Total			**0.87**

In para 5.9, bullet 3 states "SDG would receive a perverse signal to reduce export during winter system peak, in order to avoid charges" referring to paying network charges over a peak. It has already been established that the network charge relates to peak demand and is cost reflective. For the generator to run over the peak, it needs the power price to be greater that its variable cost including the network charge. Even if a generator faces a network charge to export over peak, it will do so provided the market price is high enough. There is nothing perverse about the power price needing to be high enough to cover a generator's cost. Capping the network cost supresses the peak power price and distorts the market.

Para 5.12 (bullet 2) states "It [1 MW] is also the threshold at which users can take part in the Balancing Mechanism (BM) either directly or through wider access and so can access other revenue streams to offset the impact of these TNUoS generation charges". This is incorrect. 1 MW is the smallest size bid or offer that can be submitted in the BM, however it is possible for multiple small generators, in the same GSP group, to be aggregated in a secondary BM Unit and participate in the BM. Further, if the 1 MW bid/offer size was a material impact on the participation of small generation in the BM, then it would be appropriate to modify the BSC to allow smaller increments. Regardless of this point, some embedded generation already participates in the BM and so this is not an untapped revenue stream they could use to cover the costs of paying additional TNUoS charges. Similarly, it is difficult to see how some classes of generation (typically inflexible or intermittent generation with a small short run marginal cost) such as solar could participate in the BM profitably.

Para 5.12 (bullet 3) states "Finally, generators about this size are required to be included on DNO capacity registers…". It's difficult to see how being included (or excluded) from an arbitrary register determines if they should pay generation TNUoS charges or not. No transmission connected generation appears on these registers – this doesn't make the case that they should not pay generation TNUoS.

Para 5.24 refers to Grandfathering. In its decision on CMP 264 Ofgem set out the following reasons against grandfathering:

- "We do not consider that a lack of grandfathering would result in unfairness to smaller EG since prudent investors know that charging arrangements are subject to change through the code governance process." (page 7);
- "However, grandfathering options maintain a distortion of competition between grandfathered EG and other generation. They also introduce a significant new distortion to competition between two types of smaller EG – those who receive grandfathering and those who do not. This distortion is both large and enduring as the grandfathering options preserve this distortion for many years." (4.59)
- "We consider the "double benefit, double loss" argument is a potential investment risk that may have arisen from an over-reliance on revenue streams that are subject to change through an industry code change management process. … We do not think grandfathering would be appropriate as it would shift investment risk on to consumers…" (4.64)

- “We have concerns that the introduction of a distortion such as grandfathering in a sector that is rapidly changing (due to technological developments) could be harmful to innovation” (4.65)
- “If there was a standard policy of grandfathering for changes to network charging arrangements, then we could accept that any decision not to accept grandfathering proposals would need to set out why we were proposing to deviate from such a standard practice. However, there is not a standard practise of grandfathering of such changes, and hence there should not be any current expectation of grandfathering.” (4.91)

Question 5a: Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?

Yes.

Figure 1 shows a distribution network with 200 MW of demand. The demand is met from 200 MW of embedded generation. As a result, there is no flow associated with the demand or generation on the 400 kV substation connecting the distribution network, or the associated SGTs. Under certain circumstances the SGTs can be classified as infrastructure, not connection assets, and therefore also form part of the transmission system along with the other transmission substation infrastructure assets.

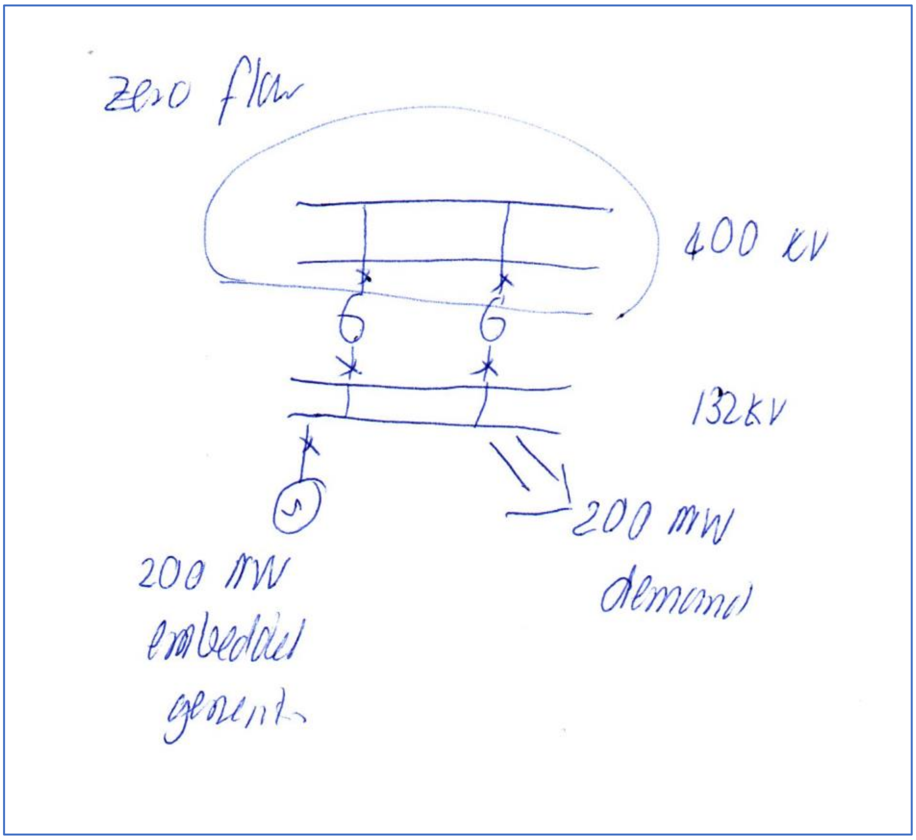

Figure: 200 MW of demand completely supplied by embedded generation

Figure 2 shows an identical network with 200 MW of demand connected to the distribution system. However, there is no embedded generation, and the demand has to be supplied via flows imposed on the 400 kV substation. For completeness, a 200 MW generator is shown connected to the local transmission substation which shows that the flows change on the transmission system even if the transmission generation is connected locally.

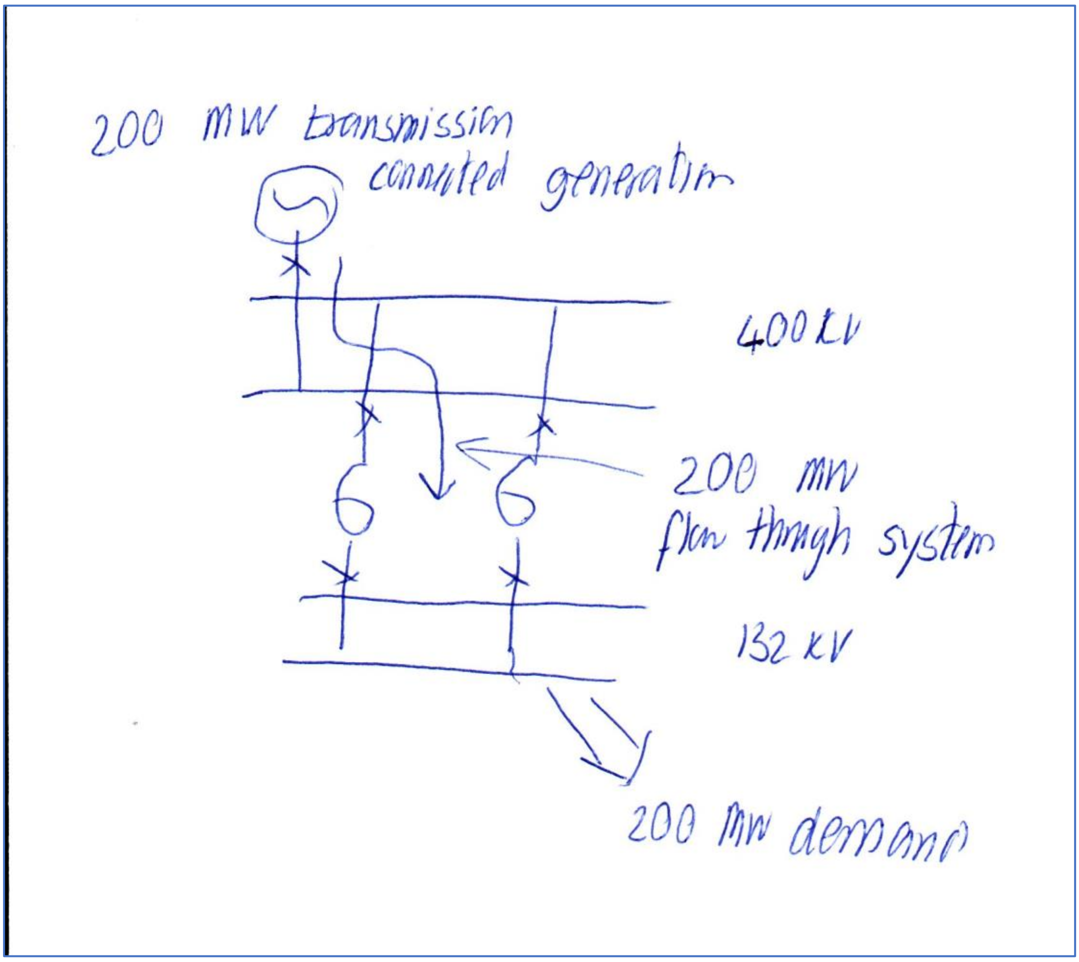

Figure 1: 200 MW of demand met by 200 MW of local transmission generation. Note flow through substation infrastructure and via transformers

For completeness, these two examples show the replacement of embedded generation with locally connected transmission generation. *Moving from embedded to transmission connected generation changes the flows on the transmission system*.

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

No.

Para 5.12 sets out they justification for using a 1 MW cut off. All three reasons given relate to arbitrary thresholds, and there seems to be no economic or technical reason for selecting this arbitrary value.

Further, the use of 1 MW is likely to create unintended consequences. Where a 15 MW windfarm is made of 20 × 0.75 MW turbines connected as a single farm, if there is a commercial advantage to being sub 1 MW then the developer will make 20 individual sub 1 MW power stations rather than a single 15 MW wind farm.

The logical solution would simply be not to have a threshold. Instead tread all generation on a demand network as negative demand (for TNUoS charging purposes). However, if the DNO network exports onto the transmission network it should be required to hold generation TNUoS for the *net export*.

For completeness, an analogous situation exists where a generation connection has on site demand. The generation is only required to hold enough TEC for its net export (generation less on-site demand). Similarly, the on-site demand is subject to normal TNUoS demand charges – if the generation over the triad is less than the on-site demand, the net demand (demand less on side generation) is subject to the TNUoS demand charge. On the assumption that both the generation TNUoS charge and the demand TNUoS charges are cost reflective based on the flows imposed on the system this methodology delivers the correct cost reflective charging.

Adopting a different charging mechanism for transmission connected generation with on-site demand and distribution systems with embedded generation would be unduly discriminatory.

Question 5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

Yes

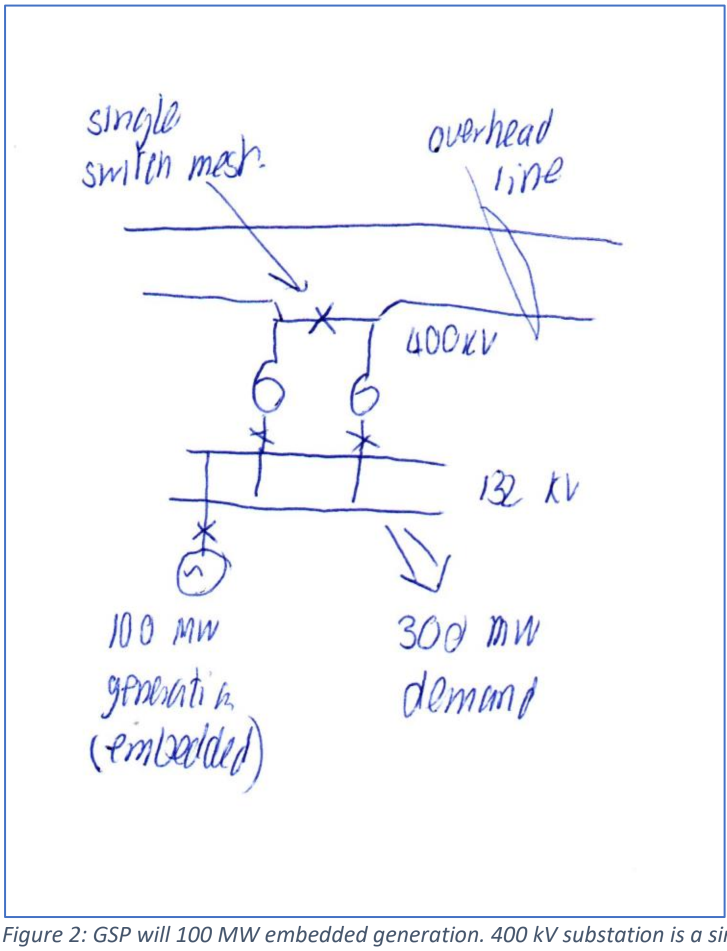

Figure 2: GSP will 100 MW embedded generation. 400 kV substation is a simple/cheap single switch mesh

Figure 3 shows a distribution network with 300 MW of gross demand and 100 MW of embedded generation connecting to the transmission system. The transmission system design is a “single switch mesh” – the minimum acceptable for such a configuration.

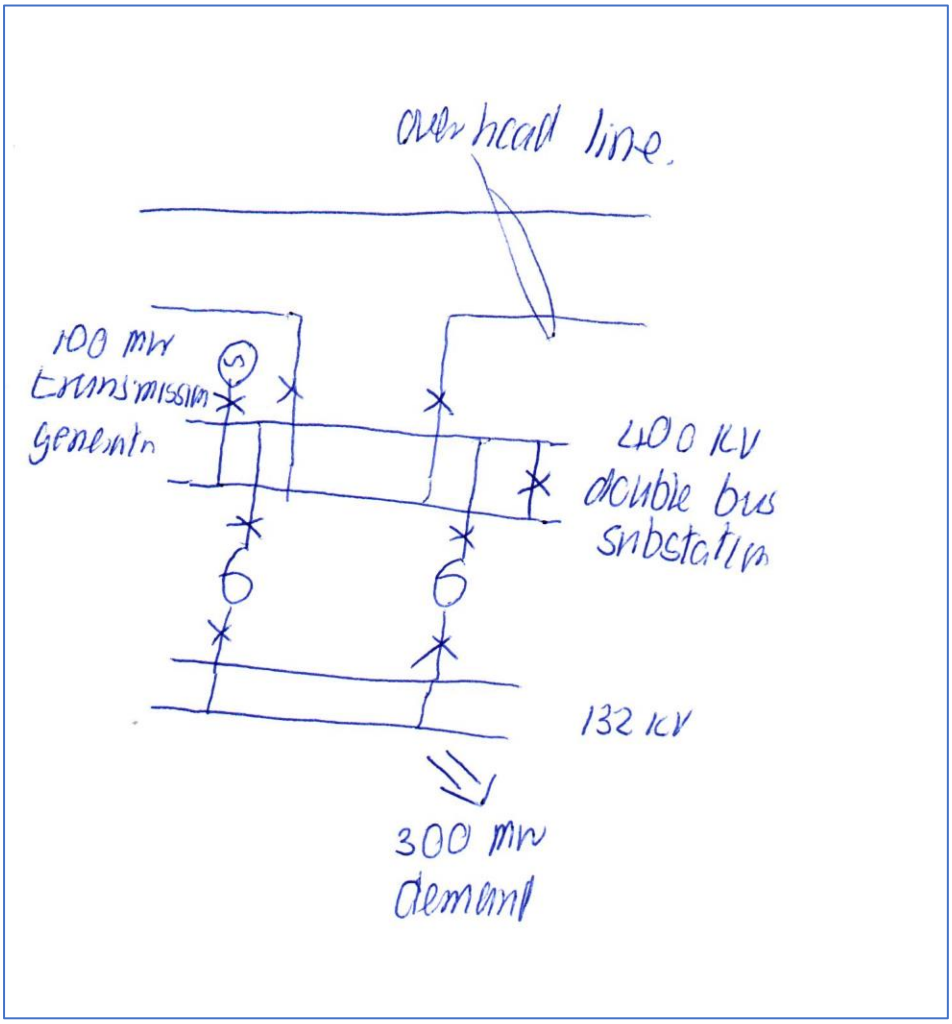

Figure 3: Identical GSP but 100 MW of generation is now connected to transmission system. Note the much more complex/expensive 400 kV double bus substation

Figure 4 shows a similar distribution system with 300 MW of demand, but no embedded generation. Instead, the 100 MW of generation connects directly to the transmission system. The transmission system design is a "double busbar substation" – the minimum acceptable for such a configuration.

The single switch mesh (with embedded generation) is a much lower cost solution that the double busbar substation with transmission connected generation. *This is a clear example of the embedded generation (in an importing GSP) leading to lower cost solution than transmission connected generation.*

Question 5d: Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your views on pros and cons. Are there any options we have missed?

All the options have limitations.
The problem goes away for local circuit charging if TNUoS is charged on a nodal basis, rather than averaged across a zone.
TNUoS charging (provided that the ICRP model is extended to include assets like transformers) can identify the avoided substation cost triggered by embedded generation. This can be reflected in network charging provided that TNUoS charges are allocated on a nodal basis (the current zonal

charging method would share the embedded generation savings across embedded and transmission connected generation giving the wrong pricing signals).
In question 5c we illustrated that distribution generation can have a lower substation cost than required by transmission connected generation. No case has been made that distributed generation triggers (or should pay) the substation cost.

Question 5e: Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

Yes
It is helpful to industry and investors to "confirm intention to address distortion but delay until greater clarity about strategic direction". Without this clarity industry risks multiple piecemeal modifications to codes and systems with the costs borne by consumers.
For this route to be justified, the strategic direction needs to be set out as a quickly otherwise you create many of the disadvantages of grandfathering. This allows investors to develop projects knowing the direction of travel and to avoid stranded investments.
Given Ofgem's previous statements about grandfathering, a very high justification is required before adopting it. Whilst the need to replace carbon generation with renewables is unequivocable, grandfathering can lead to sub optimal decisions such as refurbishing an existing but remote windfarm when building a new windfarm closer to demand may be the economic and efficient solution.

Question 5f: Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

We have not developed any alternative options.
All options are relatively straightforward to achieve. Some points to consider are:
Options 1 and 3 where supplies charge SDG for TNUoS can become complex if a generator changes supplier part way through a charging year (and only works where there is a supplier)
Option 2 where NGESO charges the SDG directly is the current process for embedded generation holding a BEGA. We use this process and it works well.
Option 4 where the DNO pays the TNUoS and recovers it through the supplier would appear to work by using existing processes.

Question 5g: Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

The treatment of exporting GSPs (see below)
Ensuring that embedded generation and demand reduction are treated equally in network charging (see below)

Has a case been made to change?

We think that there are distortions in transmission charging which need to be rectified, including:

i. Charging exporting GSPs for the generation that they put on to the system;
ii. Embedded generation over 100 MW pays a different charge to sub 100 MW embedded generation;
iii. There is no TNUoS charge for exporting GSPs
iv. The embedded generation export tariff is capped at zero.

The present charging regime where embedded generation pays negative demand TNUoS has two significant advantages that should not be discarded lightly:

i. A MW of embedded generation has the same impact on charges as a MW of demand reduction (it also has the same impact on network flows and infrastructure requirement, unlike transmission connected generation as illustrated in our answers to 5a and 5c); and
ii. For fundamental scenarios like a GSP where demand and embedded generation exactly match it gives the correct net charge of £0 as there is no use of the transmission system. The proposed solution fails even simple test cases like this.

Ideally, we would have a single charging mechanism to cover any grid connection point regardless of if it is:

i. An importing GSP, potentially with embedded generation
ii. An exporting GSP with significant exporting generation; or
iii. A generation connection potentially with on-site demand

Transmission generation with on-site demand is required to pay TNUoS for its net export onto the transmission system, whilst any net demand taken over the Triad pays TNUoS demand changes. This mechanism works and appears to meet all the criteria set out by Ofgem for network charging. This method should also be applied to embedded generation (including embedded generation over 100 MW) such that:

i. Where the generation offsets demand in the GSP, it should face a negative demand TNUoS charge
ii. For any embedded generation exported (if embedded generation is greater then demand) then the net export should face a generation use of system charge.

This mechanism then properly applies standard rules that:

i. *Anyone* taking demand off the *transmission system* pays demand TNUoS charges; and
ii. *Anyone* exporting power onto the *transmission system* pays generation TNUoS charges.

Electrically, generation with on-site demand and distribution networks with embedded generation are identical. *Charging them differently would be discriminatory*.