3a.

Yes, it will open up areas for further low carbon development as large areas of the country are currently sterilised due to the requirement for costly EHV reinforcement. There are arguments for going further with generation to meet decarbonisation targets. It is not always possible to locate renewable generation in the areas of best resource and grid availability due to land constraints, so it may need to be located in less optimal areas which have less room in the financial model for additional costs. Going further for generation could create a more sustainable and distributed geographical spread.

This also needs to be applied again to transmission reinforcement. Whole GSP groups are currently sterilised due to the requirement for new SGTs or unviable levels of TANM curtailment. An alternative would be to implement a proper apportionment mechanism for this pass through costs – with an analogue for third party works for transmission customers.

3b.

Site searching for new generation is mostly grid led and as the grid becomes more subscribed and constraints become more acute, vast areas of the country are now inaccessible. This means areas of high costs or high curtailment are avoided. In the past year it has got exponentially harder to find more viable connections, with more companies fighting for reducing capacity. This puts decarbonisation targets and jobs at risk. Land and planning constraints also need to be taken into account, meaning some areas of high grid resource are unusable.

The recent lifting of the battery planning cap has also caused more grid to be subscribed. There needs to be more co-ordination between DNOs, LPAs and central government to zone and invest in areas for renewable energy.

3c.

It currently appears fair to pay an apportioned cost however I'd like to see this go further to include works to alleviate physical and communications constraints, not just electrical ones. This also needs to be extended to all users across all systems – i.e. D customers impacting the T system and vice versa.

While the proposed changes are welcome I do wonder how the DNOs will fund it as I believe the impact will be high, particularly if ED-2 is less generous. It would be welcome if it encouraged DNOs to seriously consider active solutions further, improve data provision and efficiently plan reinforcement when active solutions are exhausted.

3d.

Putting more cost onto the DNO should encourage them to look at flexibility procurement and active network management more; however there will be less incentive for the customer to opt for a curtailed connection.

3f.

Regarding TNUoS pass through this certainly needs to be considered alongside wider reforms. The present system is not fit for purpose as it looks only at transporting the power to the load, rather than appreciating where renewable resource is. It needs a more nuanced approach to aid decarbonisation. Current forecasts are indicating that the entire solar industry in the north of

England and Scotland could become unviable if TNUoS is passed through – this would destroy large progress towards net zero.

The current level of TNUoS in North Scotland (where there is high renewable resource) is a distortion nationally and also across Europe. This needs to be resolved urgently. At present TNUoS in the entire of Scotland is making T connected solar schemes unviable. When comparing a 132 kV connected solar scheme in Scotland compared to England and Wales, the Scottish scheme will pay many times more over the lifetime of the project even when taking into account the larger up front cost for the D scheme south of the border.

Any implementation of TNUoS should come at the same time as the SCR.

I preferred the original proposal when T reinforcement costs were not to be passed through at all. Many GSP groups are now sterilised by the requirement for new SGTs, which no one distribution customer will fund. However my understanding is that once the pipeline of tertiary connections are connected, each site will become “infrastructure” meaning the TO will absorb the cost anyway – but timescales are long and the need to decarbonise is now.

3g.

I think it will cause people to delay their connection dates until post-2023. I think there’s a fair argument to say that customers are contractually obliged to pay for the reinforcement (or perhaps an apportioned amount) if they cancel after the DNO has financially committed.

3h.

People who were due a rebate under ECCR must not find themselves at a detriment due to this change. Any works done under ECCR must be grandfathered. ECCR rebates are a bonus and could make a scheme more palatable, especially if an area is busy, but investment decisions would not be made on the basis that it would happen.

4a.

Yes, I did think shared access was a good idea, but anything that gives more defined levels of access and up to date curtailment info is a good idea.

4b.

Yes, particularly for schemes like solar and battery.

4c.

Yes, for complementary generation technologies in an area like wind, solar that do not generate at the same time. ANM somewhat resolves this but is less defined.

4d.

Restricted access should come with restricted charges.

4e.

Unsure.

4f.

All DNOs should be standardised across the board.

4g.

This seems suitable. However it needs to be clarified what would happen with projects that are accepted but not connected before this date and connect after.

5a.

The DNOs should have this info from their power flow modelling. I think it's totally reasonable to expect a small generator, embedded far into the system, in an area of high load to not utilise the transmission system.

The ethos of distributed generation is localised generation near load, this should ideally not use the transmission system at all. It is much cheaper to generate and consume near load rather than paying for the costly transmission system.

Instead of a one size fits all approach the requirement to pay for TNUoS should be assessed annually based on up to date power systems modelling.

5b.

No, see above. A 1 MW generator could have different impacts depending on where it is located.

5c.

If connected at a GSP it is likely to be further from load so will make use of more of the system. It may also be more likely to flow up onto the transmission system as the path of least resistance as it is far from load. This compounds reverse power flow issues that are currently sterilising many GSPs. Charging should perhaps reflect this. If power flow modelling shows that generation mostly flows upwards more TNUoS should be charged, but the principles of the answer to 5a should be applied.

5d.

Unsure.

5e.

There should be transitional arrangements and full impact assessments. As the answer to 3f explains, entire areas of the country could be killed by the reforms.

5f.

Utilise power systems modelling to assess true impact on the T system.

5g.

A more nuanced approach taking into account areas of high renewable resource/planning suitability and noticing that they may not be close to areas of high load. A full study in conjunction with industry, LPAs and central government should be undertaken to zone areas for renewables and charge them preferential TNUoS. It makes no sense to kill off an area of world class wind resource for example (north of Scotland) with high TNUoS charges that are out of kilter with the rest of the European market.

7.

The issue of passing through costs of transmission works to distribution customers and distribution works to transmission customers needs to be resolved urgently. The same principles of “one voltage level”, ECCR and cost apportionment must be applied.

At present large volumes of viable renewable distribution projects are not progressing due to the requirements for new SGTs or similar. No single customer is going to accept this cost, but without a proper apportionment or socialisation mechanism no projects will progress as this cost falls to the triggering party.

The same issue occurs for D works triggered by the third party works process. Something CMP328 and DCP392 are trying to address.

Alternatively, the DNO connection assets should perhaps be considered as infrastructure as they support many D customers and attributable securities applied instead and the costs socialised. This may require some other rules tweaking as all D customers will be below a MITS node, where attributable securities are currently not applied.