

To - electricitynetworkcharging@ofgem.gov.uk

Andrew Self
Head of Electricity Network Charging
Ofgem
9 Millbank
London
SW1P 3GE

Flexible Generation Group
Gables Lodge
62 Kenilworth Road
Leamington Spa
CV32 6JX

Telephone: 020 8239 9917

18 April 2017

Dear Andrew

Ofgem's minded to position and IA on CMP264/5

Introduction

The Flexible Generation Group (FGG) represents the owners of and investors in small scale, flexible generation. These power stations are embedded in distribution networks and provide a variety of services to the system operator to help it deliver secure, economic supplies to electricity customers. While not a new sector in the market, it is becoming increasingly vital that the SO has access to flexible generators to help maintain system security in the most economic manner. All of the FGG businesses are and/or are expecting to be in receipt of embedded benefits, which were a crucial income stream for our investors when choosing to back our businesses. These modifications will therefore have a material impact on our businesses.

Rather than answer Ofgem's specific questions, we have instead outlined our thinking on a number of the substantive areas in the document and the associated LCP/ Frontier modelling. We have broken these down into a number of areas.

FGG do not agree with Ofgem's minded to position and believe that their document lacks the academic rigor we would hope a regulator to apply to any decisions to remove such a substantial element of any businesses' income.

We would note that all FGG members have agreed that the growth in the TDR is an issue that needs to be addressed. The escalating nature of the Triad payments was not something we foresaw, but we have never argued that this does not need to be tackled.

We do believe that Ofgem's proposed solution will cause material damage to our businesses and should not be progressed. A more measured, proportionate response is required to strike a balance between the interest of investors, who acted in good faith, and Ofgem's desire to alter transmission charges in a timely manner.

FGG would propose that Ofgem accepts a WACM that effectively stops the escalation in Triad payments, such as WACM7, 8 or 10, while a full SCR is undertaken.

In relation to the CUSC, FGG recognises that Ofgem has to convince itself only that any change to the CUSC is "better than the baseline". We note too that Ofgem itself rightly points out it has wider duties, for example to promote competition, act proportionately and be non discriminatory (4.2). We consider its minded to position fails on these last three obligations. To fulfil its duties, Ofgem must undertake the SCR it is now considering so that it can properly investigate the issues raised in this response.

Regulatory issues

FGG has significant concerns over Ofgem's position that they are going to take a "principles based decision", rather than undertaking robust analysis that would allow for an evidence based decision. Ofgem is an economic regulator, overseeing the electricity and gas sectors where investors have sunk billions of pounds. The redistribution of income between different classes of investor within these markets must be done with a full grasp of the facts, not based on unsubstantiated assertions.

The holding of principles is of course the right thing for a regulator, and one could argue that it is the principles that are enshrined in law. However evidence based regulation is vital if investor confidence is not to be undermined and businesses built in good faith not destroyed. Ofgem's position is even more concerning when the "wrong" decision could impact security of supply and increase the cost of capital for all new generation.

FGG also wants to register its disappointment in the way that the governance of CUSC has worked in the case of these two modifications, bringing the reputation of the CUSC Panel into disrepute. The voting at the CUSC Panel has shut down rights of FGG parties to undertake a merits-based appeal (a serious issue with the process on which Ofgem's IA does not pass any comment). On page 91 of Ofgem's document, under a section entitled "Make-up of the CUSC panel", Ofgem does not explain the concerns that have been raised by embedded generators over the way the governance process has operated. The Panel did not recommend to Ofgem ANY of the proposals supported by the majority of the Workgroup. There is also evidence that the Panel members voting was influenced by their employees' positions (rather than being independent); for example only the EdF employee supported the EdF original modification - why? We believe this process needs a review of its own, but we are very disturbed by the lack of any evidence that Ofgem, as a CUSC Panel observer, raised any of the concerns about governance that non-Panel parties have.

We also note that one of our members, Alkane Energy, has been trying to raise an urgent change proposal that is a direct alternative to CMP264/5, and was intended to be in front of Ofgem at the same time so it can be considered alongside these two modifications. We understand that Ofgem has required Alkane to provide "substantive evidence" that it is a "materially affected party" under the CUSC. As all generators, embedded or not, are impacted by TNUoS charges, it is unclear why Ofgem has not allowed the Alkane modification to progress in a timely manner. In its own document Ofgem acknowledges explicitly that businesses like Alkane's may be affected so severely they may leave the market (4.85 and 5.8). It appears to FGG that Ofgem is blocking the modification's progress for reasons known only unto itself. Such a delay in designation only serves to bring the governance process into further disrepute, indicating that only larger parties can progress changes, however discriminatory or unbalanced they may be, despite Ofgem's

assertions that it believes that the market design would benefit from input by smaller parties¹.

Investor Confidence

Ofgem does not seem have fully grasped the regulatory risks they are creating. The investors who reviewed NG's last embedded benefits review in 2013/14 would have reasonably assumed that if this was an urgent issue then Ofgem would have publically commented on their concerns at that time, for example by issuing the same sort of range guidance as contained in their July 2016 open letter. The review itself was on an invitation only basis, and no FGG members were invited, so had to rely on the meeting notes, as would new market entrants and their investors. The notes do not record any issues raised by Ofgem and no public letters were sent or statements made. Had Ofgem been concerned about the scale and continued growth in embedded benefits, then it should have raised those at that time and ensured that they were correctly recorded. There is a case for asserting that Ofgem has been negligent in not so doing.

Likewise in its decision on CMP239 (grandfathering the small generator discount), in August 2015, Ofgem did not raise any wider concerns with the scale of embedded benefits. We note that in the IA footnote 85 references documents from 2007/9, but parties would have referred to the most recent work in this area not work from 7 years earlier. Seeing the scale of the Triad rising, investors may have assumed that Ofgem could undertake a review of Triad payments, but there is no evidence to suggest that Ofgem would be minded to remove 95% of the TDR benefit that generators were receiving in very short order.

Ofgem's document focuses on EG that participates in the CM and its impact on power costs. It notes impacts on CfD parties, but seemingly ignores the impact on RO plant. A number of our investors are also investors in other sectors of the energy market such as renewables. They can confirm that in all cases the Triad benefit was considered to be an ongoing income stream. We note that Ofgem seems to discount the Triad benefit as being unlikely to underpin the investment decisions of some EG (section 5.3). While some plant will have been justified based on wider considerations, this does not mean that the Triad payments were not the tipping point that made a plant economic as they are often a significant source of income. Focusing on revenue and ignoring all other costs of a generator is an irrelevant comparison.

The fact that no clauses in the CfD contracts exist that specifically deal with transmission charges is not evidence that BEIS or CfD parties expected Ofgem to alter transmission charges. Instead it is more likely that parties took the view that most changes were, if material, likely to impact all parties in a similar manner, not just that some parties would be substantial losers. It is a reasonable expectation that changes in monopoly charges should not create windfall gains or losses on particular subsets of users who have the same impact on those charges as others who are left unscathed, and particularly on such a material scale as would Ofgem's minded to decision here.

¹ CAP180 - Amendments to the CUSC Governance Process - Authority Decision letter June 2010, "...enabling more parties to get involved in the CUSC amendment processes should better facilitate competition."

Competition

We support Ofgem wanting to level playing fields and competitive markets where different technologies, located in different places can access the wholesale market on equitable terms. FGG fully supports competitive markets. However, Ofgem does not define the markets where competition should be occurring. While embedded power stations may compete with larger plant in the capacity market and for the provision of some (though not all) ancillary services, they rarely compete directly in the wholesale energy markets, but should be seen as direct competitors with DSR.

Despite oral protestations to the contrary from Ofgem representatives to FGG members, generally Ofgem's document sounds like it is attempting to promote large CCGT new build over EG. It identifies a distortion in the transmission charging regime, but does not consider the distortions that our members have identified in the wider market arrangements. For example the lack of access for smaller plants to the wholesale and balancing markets, the different treatment of connection charges and the different taxation regimes that different sized generators face, are all material distortions to the market. FGG members believe that they can compete against larger generators across the energy markets, but we need Ofgem to address all of the material distortions together rather than only picking off a few, tipping the playing field from one set of parties to another while other issues remain unresolved.

FGG has tried to move this debate forward itself, with two of its members seeking to raise a BSC modification to gain access to the wholesale market. However, Ofgem has yet to give the parties that status of impacted parties and thus the right to raise changes. We cannot understand why Ofgem has not allowed these parties to bring forward a change proposal which specifically aims to increase competition. This is creating the perception that Ofgem is favouring larger plant over smaller plant and is specifically creating barriers to these key market changes that would help facilitate the effective competition Ofgem claims it is seeking.

In other areas our calls for equitable treatment have gone unheeded, most recently when the embedded power stations were not allowed to participate in the Supplemental Balancing Reserve (SBR) tenders, though they would have been likely to provide the service cheaper. At the time, it was argued that it was too complicated for the SO, but since 2013 the SO has done nothing to make market access easier for non-BM plant. The need for SBR was driven by security of supply concerns, yet Ofgem now claim that potentially shutting some plants has no security of supply implications! There is no attempt to quantify or provide any evidence of this, Ofgem merely expresses an opinion.

Ofgem's IA makes numerous references to the despatch of EG not being in merit order, thus not economic and creating market distortions. These assertions are not backed up by any robust disclosed analysis. It is of huge concern to us that Ofgem here seems to be in ignorance of how NETA/BETTA changed the way wholesale prices were set and generating plant chosen to operate in the GB power market. **ALL** plant is self despatched against contract obligations set up by bilateral trading ahead of time (or it ends up in the BM where it takes pot luck on increasingly by design random imbalance prices). A merit order is only implied. There is no commercial structural reason why a particular plant of lower cost should run in place of a higher cost plant. It all depends on ownership,

contractual position and market access. Spot prices will frequently be below a prior forward price that traded for the same time period. A generator that has locked in a high price by forward selling can generate profitably even if the spot price for that period either day ahead or within day is considerably lower. Whilst a generator may be able in theory to buy back more cheaply than its own marginal cost of generation, there are many commercial and operational factors that may constrain why it does not do so – it may not be a matter of choice or of ignorance. After gate closure the SO can exert some control via acceptance of bids and offers, but this is limited by the parameters placed on those bids and offers.

The majority of EG cannot be "despatched" in the BM, as the SO does not have access to it. Our members will self-despatch to try and earn Triad payments, but this means that they are running at times of peak demand, which is when we would expect our plant such plant to be required to meet demand. Other EG, such as renewables or those generators associated with industrial process, run for reasons other than wholesale prices, so to say a particular plant runs out of merit seems to show a disturbing fundamental lack of understanding about the market Ofgem is regulating.

The focus on the TDR and its effect solely on EG is discriminatory, because it ignores how the high TDR payment arises. The EU cap on generator transmission charges of €2.50/MWh, which is creating a direct cost transfer to customers, is forecast to rise to around £600m/year by 2021. It is unclear why this distortion is not being addressed with equal urgency and rigour given its comparable distortionary impact. To maintain the competitive position of the EG and TO connected generators, it would seem reasonable to add any negative generation residual to the value of X in a new charging regime, unless a change in EU law is bought forward. Ofgem's arguments against this seem weak, as they appear based totally on a potential positive payment of TGR being non reciprocal under a flooring arrangement.

It is important that Ofgem address the greatest distortions in the market in a holistic and timely manner so that all plant types really can compete fairly against each other. Ofgem talk about "equalisation of regimes" (4.64) and we would support that. In particular FGG would like to see Ofgem ensure EG has:

- Access to the wholesale energy and balancing market which is "sufficient" (as Ofgem suggest in 4.84) to ensure that while there is no direct disincentive (4.3) not to run, market access would ensure the economics of running could be realised;
- The structure of connection charges, notably the issues around statement of works where DNOs then request gencos pay for wider reinforcement of the TO networks must be stopped (a wider issue Ofgem parks only looking at benefits 2.5);
- The lack of ability to compete in all ancillary services markets must be resolved;
- The right to raise changes to all codes that can directly impact on embedded generators' assets and business interests must be easily realised in practice not just theory; and
- Removal of charges on energy used on embedded sites including ROCs, CfD, FITs and in the longer term CM charges, so the costs of EG gencos align more closely with their larger competitors.

LCP Frontier Model

FGG has a number of concerns with the modelling work undertaken by LCP and Frontier Economics for Ofgem, which we have detailed in Annex 1 below. Here we want to draw attention to the most material issue. LCP use an incorrect efficiency of 32% HHV for new gas reciprocating engines (GRE), rather than the 39%-42% HHV that our plants typically achieve. We can provide Ofgem with evidence of the efficiencies if required, but suggest that they check with GRE manufactures so that the number used is independently verified.

If the efficiency is updated then the position of CCGTs and GREs is reversed in the CM auction and in the "stack" for economic despatch within the LCP model. This obviously has a significant impact on the conclusions that can be drawn from the modelling. Not only would the scale of the results be incorrect, for example the efficiency savings may be higher, but because GRE is built the results are pointing in the wrong direction; LCP should be forecasting not building CCGTs at all.

As noted in Annex 1, there are a number of other areas where FGG believe that the model is out of step with the actual investment environment that energy companies face, for example the unreasonably low pre tax discount rate (particularly given the increased appreciation of the potential impact of regulatory risk arising from this issue). But the very material effect of incorrect plant efficiencies means that Ofgem cannot reasonably rely on the model outcomes it has published as a basis for a policy decision.

Transport Model

Over the course of the CMP264/5 process FGG members have tried hard to engage in the debate and understand the technical details driving the structure and level of transmission charges. As a result it is our firm belief that locational elements of the charges are not cost reflective looking forward or backward. Analysis by our members has shown that the model may create some locational signals, but not in a way that is close to being cost reflective. The details of this analysis are discussed in Annex 2 below.

The model uses existing nodes and circuits to model the flows on the system, i.e. it looks as the system which exists and does not try to derive a system that would have to be built to balance existing generation and demand patterns. The model then calculates a relative locational signal, signalling where generation and demand should locate. It does not try to reflect the actual costs of the changes to the assets that would be needed to actually accommodate parties responding to the signal. NG's licence condition (SLC6F) shows that a new generator located in say London would result in a negative TNUoS charge, but would create new costs that would need to be recovered via the price control.

Even if it was to be assumed that the locational charges were cost reflective, indicating to parties where to connect, they also seem to fail to feed into the price control of NG's forward investment plans. The South West, where the locational signal has been high for years, still has no capacity for new build in either the TO or DNO networks. This seems to be as a result of the delayed investment to accommodate Hinkley. Looking East, the area is congested by interconnection, with NG not obviously planning any reinforcement works and instead working with UKPN on new load management projects. In Wales, there has been no capacity for years, with NG writing to parties saying no further connection of conventional plant will be accommodated. Ofgem should have serious concerns that parties wish to build new plant in the "right" areas are stopped from doing so by lack of

investment. The outcome will be old plant shutting, but holding onto their connections to potentially redevelop sites, but in the interim blocking new entry.

In the IA, Ofgem says that recovery of the residual should not be avoidable, as it is a revenue recovery tool and not a locational signal, (e.g. sections 4.37 and 4.54). Yet that is exactly what customers managing Triad do, and other customers pay for this behaviour as well! Ofgem does not mention this issue, yet CMP276 (the modification currently blocked by Ofgem) aims to address exactly this, ensuring that not all cost recovery can be avoided by load management. It therefore seems odd that Ofgem does not want to consider CMP276 with CMP264/5.

In terms of the impact that EG and TO connected plant has on the system costs, Ofgem seem to rely on a drawing by one working group member. Those FGG members who did attend the working group on these modifications do not believe that Ofgem has done enough analysis to identify the actual impacts, as the system is not the simple line diagram that the picture shows. Ofgem refer to CMP264/265 "analysis" of EG's impact on TO costs (4.39), but our members who were on the workgroup refute that the group did any robust analysis as the accelerated timetable did simply not allow for such work. In fact the treatment of different types of connections and flows in the combined networks (TO and DNO) needs careful analysis.

In terms of the £1.62/kW on which WACM4 relies, the workgroup undertook no analysis. The number originates from a few paragraphs in an old consultation document, and FGG do not fully understand the rationale behind the number, not having been part of the embedded benefits review (which was by invitation only). However, it is unclear why the original calculation excluded the cost of a Super Grid Transformer (SGT). It is irrelevant who pays for it, TO or DNO, the cost is ultimately born by consumers. Under the terms of the current price control, NG has an incentive around demand related infrastructure² which varies dependent on the number of SGTs that NG actually install. Under the formula, NG appears to receive an allowance of £3.9m for each SGT irrelevant of the DNO paying for the asset itself; arguably the customers could pay NG and the DNO for the same asset. These assets therefore do represent an avoided cost for the consumers, so should be considered when looking at the "avoided cost" of new GSP investment.

FGG has not had time to undertake any robust analysis on this area, and as noted above neither did the workgroup. However, if we were to assume an SGT capacity of 60MVA-240MVA the incremental capex would be in the region of £16-£65/kW, which would then need to be inflated to 2017/18 prices and annualised, giving a figure in the region of £1.34-£5.45/kW. It is worth noting that original "avoided cost" from the embedded benefit review was £1.47/kW in 2009/10 prices, and it is unclear why appropriate indexation has not been used by Ofgem, which would give a 2017/18 value of £1.87/kW.

Both the original modifications and WACMs have some issues, partly as they were designed as interim solutions while a robust review was carried out by Ofgem. The accelerated timetable forced on the Workgroup by Ofgem made undertaking robust consideration of the issues outline above impossible. Ofgem's IA also fails to check that the numbers used were arrived at in a robust manner, with reference to where the costs

² Special Licence Condition 6L

reappear in the various price controls and the actual cost reflectivity of specific charges. Some of the assumptions in the transport model need questioning, such as the scaling factors applied to all generation irrelevant of age or technology and the single expansion constant based on the cheapest transmission asset. In practice undergrounding of lines is a very real requirement, but it does not even merit a mention. This may be due to it being seen as out of scope in a prejudicially defined defect. FGG believes that Ofgem need to consider these issues together properly and fully supported by robust evidence and analysis.

There are also some very obvious differences in the connection regimes as they stand, which Ofgem also brush aside in looking at the modifications:

- The embedded power plants are paying up front for deep connections (i.e. the customers are not carrying the risk that a plant will only run for a short time and create stranded assets);
- Where an embedded plant cannot be accommodated by the local network without some form of interruption regime, the plant pays for the controls to allow for interruption, not the TO (as happens for larger plants), i.e. there is no connect and manage; and
- Where EG is taken off the network for constraint or other system reasons they are not compensated, unlike TO plant.

Taking these points together it is easy to see that the cost of 500MW connecting on a constrained part of the TO network does not have the same costs, or risks for the customers, as 500MW connecting in the DNO behind the same constraint.

Avoidable Costs

Ofgem's minded to decision suggests that the embedded benefit should reflect only the avoided costs of reinforcement at the Grid Supply Point (GSP). During the workgroup it was asserted that this represents the only saving that embedded generators bring to the costs paid by customers. However, one of our members has analysed National Grid's price control and the savings to customers are far wider than stated by Ofgem.

The RIIO incentive mechanism actually varies the TO's allowed revenue based on the changes to the outputs over the price control period. The baseline allowances were set on the basis that 33GW of generation would connect over the price control period. Three years into the control, the latest annual report³ shows that NGET has under spent on their Load Related Expenditure (LTE) allowance to the tune of £663m and is forecasting that for the control period the under spend will be in the region of £544m. The LR capex is the costs of investments in the network to accommodate "changes in the pattern and level of electricity generation and demand"; i.e. new generation, new demand and wider works. Where the LRE is not incurred there is a direct saving to the customer as the TNUoS charges are lower than they would otherwise be.

The variant capex rate in the price control is currently £27/kW (in 2009/10 prices) for each MW that NG connect, and £1.1m for each km of overhead lines. While we understand the costs going into the allowed revenue are linked to actual NG expenditure, and a sharing factor exists, the price control clearly shows that NG's allowed total expenditure is increased by £27/kW for each connected MW. This also means that where NG incurs no,

³ RIIO ET-1 Annual Report 2015-16

or little, cost when a new generator is built on the site of an existing generator, reusing all/most of their assets, NG's allowed revenue still increases by more than the cost of that connection.

As noted above, some works are classed as "wider works", where NG has to undertake reinforcement at the boundary. The incremental wider works capex totals £1.4bn over the price control, so is £1.37 per £ of generation connection allowance. Add these costs to the £27/kW allowance the avoided costs are in the region of £64/kW in 2009/10 prices, so today are worth c£81/kW (using the TNUoS charging model inflator).

As well as the variant allowances, the price control also includes a non-variant allowance which also adjusts based on the actual investments undertaken during the control period. These costs can include delays or cancellations, changes in scope of work, etc. Again looking at the most recent Annual Report, and a total of £208m has not been spent, adding a further saving to customers.

This analysis shows that there is a clear financial benefit to customers of not connecting plant to the transmission system. FGG would not argue that the values outlined above are necessarily the "right" level of embedded benefits, but it does demonstrate that the savings to customers are far greater than the £1.62/kW outlined in Ofgem's IA. It also illustrates the very complex nature of the price control and the way that actual costs feed into the TNUoS pots, and highlights the difference with the completely different theoretical approach of the tariff setting model. The latter is simply not remotely cost reflective, and this is a major contributor to the sub optimal locational pricing signals and thence to increases in TDR.

While we recognise that there are a few regions (notably in Scotland) where the embedded generation has triggered the need for TO reinforcements, this has largely been driven by renewable generation not peaking plants. This is because our members will not try to connect where there is a transmission constraint due to the Statement of Works process. Instead we seek out areas in the DNOs where our generation can be accommodated. Given the way the connection regime works, it cannot be argued that a MW connecting to a DNO has the same impact on the TO as a MW connecting directly to it, as the embedded plant will connect where no TO work is required, whereas for a TO connected plant work is always required (though it may be minimal).

Undue Discrimination

As well as the way that EG is treated when trying to connect to their local network (see above), Ofgem needs to be mindful that a change that does not address behind the meter generation will not be unduly and unnecessarily discriminatory. There is no evidence offered as to why the customer and the generator would not split the benefits of the avoided TNUoS in the same way that the supplier and generator do. Therefore any existing distortions would remain, for these users and a new incentive to move generation behind the meter would also be created. This simply highlights the need for a holistic review.

FGG would also note that EdF and Scottish Power when raising these change proposals must have thought their proposals were enough to address the competition concerns they believe they face. It was only where there was a clear signal from Ofgem that an SCR

would not necessarily take place that Workgroup debate shifted and the Workgroup as implicitly encouraged to go far further than the original proposals put to them. We can understand why the owners of larger plants would like to see EG no longer operating, with the obvious impacts on peak prices, but Ofgem are appearing to be complicit in trying to make some businesses uneconomic to the benefit of a different sector of the market. It is not obvious that the larger players are closing anything other than older, less efficient plant, or coal plant where there is a clear policy direction to shut it regardless.

Ofgem refers to RO plant not accounting for a significant proportion of EG, but do not provide any analysis (beyond the pie chart in 5.2) of their actual contribution to the market (despite administering the RO and therefore knowing the actual volumes of installed capacity). Ofgem should therefore be concerned that it has not analysed the impact on these plants. We cannot see how they are able to make up the "missing money" that removing Triads would create. If this plant shuts early what is the impact on security of supplies? The work undertaken by LCP for Ofgem does not appear to take any account of RO plants, focusing only on CM plant as Triad payments reduce (6.16).

Ofgem does not assess other reasons embedded may still be the favoured future investment, because of facts such as planning, cost of capital, regulatory burden, etc. Given the modelling shows a reduction in peak prices, we cannot understand how an investor could justify a new build, 800MW CCGT. It would seem far more likely that the model should show smaller plant still filling any capacity gap, but with no embedded benefits and different system costs (more ancillary services possibly). We would encourage Ofgem to do a sense check as most market experts would surely agree that building large scale CCGTs looks at best challenging, even if CM prices are quite high, as the CM contracts are only 15 years at most.

Furthermore in constrained areas, such as South Wales, NG is connecting renewable plant but not conventional plant, in a manner that is obviously discriminatory between technologies. As noted above, the different treatments of TO and DNO connections means peak EG are effectively stopped from creating reinforcements on the TO networks and instead incentivised to find areas where capacity to connect them already exists.

Grandfathering and Phasing

Generally FGG does not support grandfathering as it creates distortions into the future that can be difficult to manage. However, Ofgem has previously used grandfathering, for example under the DNO charging regime, where they have recognised that parties cannot adjust to the changes being brought forward. As Ofgem claim that the EG losing Triad income can make-up that revenue from increasing CM and power prices, it would seem logical to acknowledge that plants on longer term CM agreements clearly cannot make up their CM revenue for at least 15 years, and all EG do not have access to the wholesale energy market. There therefore seems to be a very good case for grandfathering, if Ofgem insist on implementing WACM4. In deed the original CMP264, as proposed by Scottish Power, did grandfather all existing plant.

Ofgem asserts that grandfathering would see developers rush to hit deadlines (4.26). Does Ofgem have any data, for example from the CM Register to back up this assertion? The committed CM plant looks largely built and the CfD plant has an incentive to build out

earlier anyway. The "distortion" may therefore not be as great as Ofgem claim. We cannot see any properly quantified evidence, only a rather bland statement in 6.9.

If Ofgem decide not to grandfather Triads, then they need to find a pragmatic solution to protect 2014/5 longer term capacity market plants and those under the RO. After NG's embedded benefits review in 2013/4, parties going into the first CM auctions had a "reasonable expectation" that embedded benefits would continue for a reasonable period. At the very least it looked like a very low probability of almost total removal (4.23) and, as noted above, Ofgem had not raised concerns in the NG review. Ofgem says that the Triad is giving parties a "competitive advantage" (4.91), but it could be argued that for plants on longer term commercial arrangements that grandfathering may maintain their current position and they cannot exploit that further given their contractual obligations and the market structure.

FGG believes that phasing can be a good way to allow parties to adjust to market changes. Given the nature of power station investments, with long asset life, while phasing from 2018 to 2020 sounds like a long time, it is not. We agree with Ofgem that it is useful to allow time for parties to adapt, but would want phasing over 10 years as a minimum. As this itself does not sound very attractive, FGG feels it would be more pragmatic to set the value of X to the lowest locational value, under WACM7, while Ofgem carry out a holistic review, and then may be able to implement a more robust change in a shorter timescale. We would reiterate, Ofgem needs to resolve the wider market distortions including a fix of the current non cost reflective charging regime as finding a longer term solution to the increasing levels of TDR.

Proportionate Response

The main variable in the CMP264/5 WACMS is the level of "X", the absolute reduction in Triad payments. FGG believes that Ofgem has totally underestimated the benefit that embedded generation brings to the market⁴:

- EG avoids investment in the transmission networks;
- By avoiding TO investment, the embedded plant also results in better visual amenity (less pylons) and other unsightly equipment which customers are keen to avoid (and which the TO price controls allows them to avoid in some regions);
- EG is providing peak margin from which customers benefit;
- EG adds to security of supply, adding to plant margin, also in a distributed fashion which creates less risk to security if one fails;
- It is likely that EG, on average, operates with lower carbon emissions as it is either renewable or only runs for short periods when required; and
- EG reduces electrical losses.

Ofgem describes the distributional impacts as "not disproportionate" (5.17), but if parties are going to be put out of business then that would surely appear to most independent observers be a disproportionate. Regulators must be mindful of the investments made in good faith or they undermine **ALL** investors' confidence. Ofgem says that the regulatory regime should be "predictable" (6.2, 7.25), but we do know parties would have not have predicted such a dramatic loss of Triad revenue. If they had they would be supportive of

⁴ [Whole power system impacts of electricity generation technologies](#) - Frontier Economics, March 2017

Ofgem's position, but only parties not impacted directly have shown any support at all and even then the whole of industry has all called for an holistic review, not piecemeal changes.

Carbon

Without seeing the way the stack would work with limited EG it is difficult to comment on carbon emissions levels over time (4.76). However, given NG is now developing "Super SEL" to get CCGTs to run part loaded, if they are going to be the future providers of security they would look likely to increase carbon emissions compared to a base line with more EG. The problem with larger CCGTs is that they cannot undertake multiple starts without increasing their operational and maintenance costs. They are simply not designed to turn on and off as require by changes in intermittent plant in particular.

While CCGTs have a high efficiency when up and running, their ramp rates and need to run for extended hours make them produce more carbon dioxide when needed for balancing over say one hour when compared to smaller, flexible plants. CCGTs are less attractive for balancing if they are needed to come on and off numerous times in a day and will give dynamic parameters that require the SO to hold them at SEL between the periods that they are needed. This means they are polluting while not providing useful energy.

Future Market Structure

As Ofgem's document on the proposed targeted charging review makes clear, the network and the energy market as a whole are facing a period of unprecedented change. It is therefore vital that Ofgem communicate the reasons why the TOs' networks are becoming simultaneously more expensive and less used. There are now a substantial set of green policies that are aimed at encouraging expensive renewables, located far from demand.

Furthermore, FGG suspects that in a world with lower Triads, the CM will still bring forward smaller plant over CCGTs. This is because smaller plants are: cheaper to build; more flexible; have an easier planning regime; represent less capital at risk for individual investors; can more easily be adapted for different running regimes; and can even be moved to other markets. Ofgem must therefore be clear that a regime change, as proposed, may still not result in new CCGTs. If CCGTs are the result either Ofgem and/or BEIS want to see they need to quickly say that and come up with a different market design that gives them what they want. We note Ofgem's words that it is technology agnostic, but its modelling assumptions are anything but.

FGG would argue that the type of plant that has been built has been as a direct response to Government policy. Successive governments have had a number of policies on encouraging local, community energy providers, smaller green schemes, industrial generation and back-up generation to support intermittent plants, etc. This is on top of the CM, which we have noted will likely go on favouring smaller plants.

Wider Issues

- **BSUoS** - FGG agree that there is a case for reviewing the costs that are going via BSUoS. However, we would note that this would probably best be done as a discrete process.
- **SO forecasting** - Ofgem refer to the difficulties the SO face in forecasting the operation of all EG (4.86). However, the SO has never asked for data and at the

Operations Forum say solar and wind are their forecasting challenges, but they seem to have only recently looked to seriously address this. FGG agree this is an issue, but one that seems not to be linked to EG likely to respond at Triads in particular. We would also note that the "BM Lite" mod FGG members are trying to progress would allow for more information to go to the SO.

- **Networks as a route for new technologies** - FGG is surprised that Ofgem does not think network charging is an appropriate way to support innovation (5.16) given the LCN projects are used for this purpose. By and large we would agree with Ofgem that all new technologies should be treated equally and subject to the competition (rather than always involving a DNO). Ofgem may want to consider internally how these types of projects are taken forward in future.

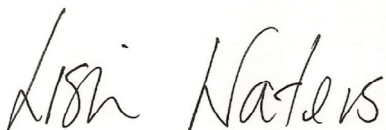
Conclusions

FGG has provided substantive evidence that Ofgem's IA and associated analysis cannot be relied on to reach a robust decision on any material changes to the TNUoS regime. We have illustrated that there are significant issues that require considerably more analysis than we have had time for, the workgroup never did within its rushed accelerated timetable set by Ofgem and that we see Ofgem has not yet undertaken either. We have demonstrated that the embedded benefit is significantly greater than £1.62/kW and highlighted the escalating cross subsidy between customers and TO connected generators as a result of the EU cap.

FGG therefore believe that Ofgem should accept a WACM which controls the Triad at a similar level to now, such as WACM7, 8 or 10, while it undertakes the SCR that is needed to examine the charging regime, and related price controls and incentive regimes. Once all of the interactions and underlying economics are properly understood, Ofgem will be in a position to develop a robust charging regime for the future.

FGG remains available to Ofgem staff to discuss any of the issues raised in this paper if that would be helpful.

Yours sincerely



Lisa Waters
lisa@waterswye.co.uk
On behalf of:

Mark Draper
CEO, PeakGen Power

Matthew Tucker
CFO, Welsh Power

Graham White
CEO, Mercia Power Response

Paul Jenkinson
CEO, Alkane Energy



George Grant
Director, Prime Energy Ltd

Paul Barker
Investment Director, Oxford Capital

Mike Davies
Director, Eider Power

Annex 1: Issues identified with the LCP/Frontier modelling work

LCP's model has CCGT winning over GRE (gas reciprocating engines) in a capacity auction: it assumes CCGT needs £30/kW and GRE needs £33/kW. The way the LCP model looks at what wins in a CM auction is to find “missing money” after looking at the margins obtained from wholesale generation – existing LCP assumptions are zero wholesale power margins for GRE, but increasing the efficiency lowers cost of generation and increases load factor and would mean material wholesale margin for GRE. So the auction outcome would be completely reversed if LCP used the correct GRE efficiency of 39%-42% HHV instead of the 32% used to date. Ofgem's conclusion that new CCGTs would be forthcoming is therefore totally incorrect. This undermines the whole system cost savings argument, which is largely based on assumed fuel cost savings.

Within the CCGT economics it has been confirmed to FGG that LCP use negative generator residual as an income stream, assuming the status quo of generator TNUoS charging is continued indefinitely (slide 19). This was at the time close to £10/kW annual revenue post 2020/21. Ofgem has said that they have made no decision on this, so it could not be assumed it would definitely not exist, but FGG believe that no rational investor would assume that revenue in investment economics now, given Ofgem's statements to date on the subject, and given Ofgem's behaviour over embedded benefits here, regardless of Ofgem's ultimate decision. So this is an additional “benefit” in the LCP investment case CCGT economics that is erroneous and if removed it also improves competitive position of GRE.

In LCP's deterministic model the wind output is smoothed equally across a day. The daily level of wind is accommodated in different scenarios, and the hourly volatility in LCP's parallel reserve cost model, but FGG believe that this is a far too benign picture and fails to capture the inherent within day variability of wind. The likelihood of most CCGT getting such a fixed volume run is low, and that places a value on the quick/cheap start GRE plant above the slower/dearer to start CCGT.

FGG considers that overall the CCGT start/stop min load etc. parameters look reasonable, though FGG question whether the risk of a CCGT not starting is totally factored into the £40/kW start cost which we understand the model uses.

The wholesale price shapes, with premia at the super peak added, are based on historic price patterns. LCP's report states that this historic price pattern may not be safe to assume for the future, and accepted it is odd that a GRE would stand idle watching prices climb above its marginal cost – it would instead seek to enter the market and generate. So there is likely to be more competition at the superpeak in future pushing down prices (and margins for CCGT) than LCP have assumed. Furthermore, despite having a capacity market so there is/should be no generation shortage, LCP still expect prices at peak tend to spike, where it would seem more rational that they would clear at or close to the short run marginal cost of a high marginal cost peaking plant.

LCP take the view that the efficiency of a CCGT degrades linearly and this leads to new CCGT pushing old CCGT down the merit order, with lower load factors. This does not seem credible. There were big strides in CCGT performance during the 1990s, leading to a nearly 10% point efficiency gain from 50% LHV in the late 1980s to close to 60% LHV by

2000, but since then the elusive 60% barrier has been found hard to crack especially for flexible operation. There is no reason to think that a new CCGT now would be so readily able to displace an early 2000s age plant on efficiency/marginal cost grounds. CCGT lose performance over the maintenance cycle, but much of this is recovered at a major (6 year typical) overhaul. So the whole argument about new CCGT materially improving the efficiency of the UK fleet is suspect and not based on the evidence of the last decade plus.

An assumption of only 800MW battery connection by 2030 seems unduly cautious, given the existing commitments, the depth of bidders in the EFR auction, and the sliding capital cost curve of batteries. It was agreed higher battery capacity may more negatively impact peak generation like gas recip than mid merit CCGT.

The model simply assumes that transmission charges (under WACM4) are cost reflective, and it ignores the fact that connecting additional transmission generation results in payment of the generator residual, and an increase in National Grid's allowed revenue (somewhere in the range 10 – 20 £/kW).

The model carries on building new diesel, despite DEFRA rules which are intended to stop this. It would be an irrational party indeed who had missed all of the notices from DEFRA and BEIS on this. It also forecasts lower wholesale prices in future which would logically stop new build CCGTs without some significant increase in the CM prices to adjust for this.

LCP use 7.5% real pre tax discount for investment decisions within their forecasting i.e. to determine whether plant gets built or not, which is set the same for all technologies. FGG would challenge whether this is correct and we think a rate of 9.8% is more appropriate, as independently proposed by NERA in its November 2016 report to BEIS. We note a higher hurdle rate acts to deter higher capital cost options from market entry compared with those that have lower capital cost.

Conclusion

The outcome of these issues is that the LCP valuations are quite possibly not just wrong in magnitude, they are potentially wrong in direction too. There is therefore no robust quantitative case that has been made for early action. GRE is what is most economic and therefore necessary to fulfil the function in the system required by new plant. There is no proven case of market distortion – gas recip plant would win against CCGT anyway, but with higher CM prices that would cost consumers more money. GRE is simply a better and more economic solution than CCGTs for the lower, flexible load factors needed from conventional plant in future. If EG is getting currently over rewarded that needs to be fixed, but in a proper robust evidentially based way without the distortive impact of CMP264/5.

Paradoxically Ofgem may well be slamming the brakes on the construction of the type of capacity that IS needed, allowing old dirty plant to continue to pollute in the short term and potentially wrongly encouraging larger more expensive capacity onto the transmission system for the long term.

Annex 2: The Locational Charges

It has been asserted that the locational charges are cost reflective. Analysis undertaken by one of our members has illustrated that the locational charge does not sufficiently recover the cost of investment and the demand residual contains forward looking costs.

Figure 1 illustrate the annual allowed revenue for the main interconnected transmission system (MITS), excluding offshore assets and generation only assets (blue area), alongside the forecast payments resulting from the negative generation residual (red area). The green line illustrates the forecast income from the locational element of the demand and generation locational charge . The difference between the costs (including the generation residual payment) and the locational revenue makes up the demand residual.

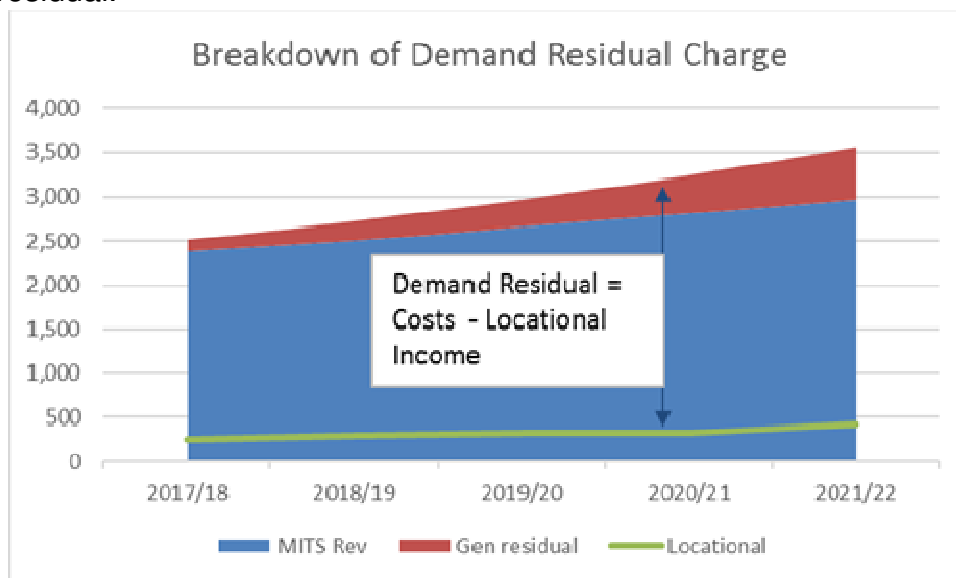


Figure 1: Development of MITS costs, generation residual payment and income from locational charges 2017 - 2021 (source National Grid⁵)

Analysis of the data shows that the statement that the locational charge is forward looking and the residual charge is sunk is demonstrably untrue. Between 2017 and 2021 the cost of the MITS rises by £560 million, however the rise in the locational charge only recovers £160 million of this revenue meaning that the location charge recovers less than 30% of the cost increase. While FGG recognises that there can be no perfectly cost reflective charge, to only be covering 33% of the costs would imply that significant improvements could be made to this charging element so that it sends a more meaningful locational signal to parties.

The model always sees the demand locational charge recovering zero revenue, and the total revenue recovered from generation is set at a fixed level, meaning an increase in the generation locational charge is neutralised by the offsetting part of the generation residual payment.

The net effect of the model is that all of the additional costs of the allowed revenue for the MITS permitted by Ofgem is recovered from the demand residual.

⁵ <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939106>

This demonstrates that **all of the forward-looking costs are recovered from the demand residual, not from the locational charges.**

	2017/18	2018/19	2019/20	2020/21	2021/22
MITS Cost (£ million)	2,391	2,506	2,665	2,804	2,959
Gen residual (£ million)	125	214	304	436	592
Locational (£ million)	261	294	323	322	421
Demand Residual (£ million)	2,255.6	2,425.6	2,645.6	2,916.9	3,129.5

Table 1: Supporting data for figure 1