

# Eider Reserve Power

20 September 2016

Ms Frances Warburton  
Partner, Energy Systems  
The Office of Gas and Electricity Markets  
9 Millbank  
London  
SW1P 3GE

Dear Frances,

## **Charging Arrangements for Embedded Generators**

Eider Reserve Power Limited and its related companies develop and in due course wish to own and operate gas fired reserve power generation facilities across the UK. Our first projects entered development in 2014 and in 2015 four of those entered the capacity market auction, receiving 15 year agreements starting in 2019. More sought to pre-qualify for this year's auction. In recognition of the power market shortages seen in November last year, in a mild winter, until receipt of your letter we were pressing forward with plans for a circa £50 million investment programme with 100MW of sites operational in the summer and autumn next year and a firm intention to follow this with more. We have now put parts of that investment programme on a slower path while we await the outcome of your deliberations.

We agree with the general remark in your letter that at this time of major change in the UK energy markets resulting from growth in intermittent generation sources, changing use patterns and against a future of smart metering and the electrification of transport it is right to look again at a charging regime which is increasingly unfit for purpose. We agree with little else in your letter however which appears to give encouragement to the very self-serving efforts by certain major utilities to undermine the growth in cost efficient reserve power in order to drive the capacity market auction clearing price higher, benefiting mostly existing generation across their portfolios to the detriment of consumers. The target for this year's T-4 auction was announced in the summer this year by DECC as 52GW; a mere £1/kW increase in the clearing price will see an additional £52 million in annual payments, a portion of which will continue for 15 years for those parties bidding new build into the T-4 auction. With the volumes of embedded generation likely to have to stand aside from or set high exit prices in this year's auction it would be reasonable to expect it to clear substantially higher than previously – maybe £20/kW higher. The consumer would pick up some £1 Billion in additional costs as a result in 2017/18 – most of this to existing utility owned generation and far more than would have been paid in embedded benefits. The prize for those seeking to destabilise the investment climate for embedded generation is large indeed and the uncertainty created for those of us working to address the UK's perilous energy security position is considerable. At a time when we should be investing on the back of a regulatory system that encourages efficient investment, we are unable to do so as a result of the confusion and concern in the minds of investors arising from your letter.

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The current CUSC charging regime is indeed causing significant distortions to the capacity market in our view but the problem does not lie with the comparatively small volume of embedded generation in receipt of embedded benefits and we disagree with the assertion that those are incorrect at their current level. Rather it lies with the larger plant now not paying but being paid in an increasing number of cases to connect to the transmission network, creating an additional burden on the hard pressed consumer and allowing plant which is inefficient at supplying reserve services to unfairly compete with embedded generators. As Eider is not a CUSC party we are not permitted to bring forward an amendment to drive change in this area and transmission connected parties are certainly not motivated to do so. This is the area where we consider Ofgem should be focussing its efforts but to date you are not. These payments are nothing short of scandalous. A Significant Code Review taking a holistic approach to charging is absolutely required.

We would indeed go further and say that the days of large generators supplying power through the transmission grid to consumers are fast running out and the artificial distinction between transmission and distribution connected generation is the real point at issue here. That needs to go away and all generation, irrespective of technology or location, needs to compete with other generation on a level playing field. That is only possible after full and detailed industry engagement through an SCR and is not a process to be rushed as it ripples through every facet of the industry.

Against our view of the general background as above, we respond to points you raise as follows using the headings from your letter:

## 2. Impact of TNUoS and BSUoS Embedded Benefit

You state a concern that “the current level of embedded benefits may not reflect the actual benefits that sub-100MW EG provide to the transmission system and increase costs for consumers”. Our focus in this letter is the larger issue of TNUoS rather than BSUoS – we make no comments on the latter.

Parties connecting to the transmission network experience a different charging regime to those of us connecting to the distribution network. These differences are stark, considerably favour transmission connected projects and are summarised as follows:

### TG

- i) Pay only for shallow connections but can do so by amortising these costs over 40+ years through the TO and at the TO's cost of capital, minimising required equity and debt funding for projects;
- ii) All deep connection costs have an extensive element of socialisation with 73% previously, now heading to 90% and possibly more, of all costs passed direct to consumers as an additional charge. Transmission connected generators do not bear the costs they create.

### EG

- i) Pay all connection costs up front at their cost of capital (much more expensive) – consumers carry none of our costs;
- ii) Receive embedded benefits which are intended to address the benefits enjoyed by transmission connected projects, going some way towards levelling the playing field.

Consumers pay a range of costs for power, the largest of which is the wholesale cost for suppliers buying energy in the power market. That price is the same regardless of whether the generator is transmission connected or embedded. In addition that portion of transmission costs to be borne by consumers is charged direct either through the Triad mechanism for half-hourly metered parties or by a general charge. This cost, for 2016/17, comes to £2.26 Billion. It is most certainly rising for a combination of reasons being principally:

- Construction of new infrastructure for offshore wind projects;

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- The increase in the portion being paid by consumers as a result of the €2.50 limit imposed by EU legislation;
- Changes in generation location, principally the growth in renewable generation in Scotland;
- Asset replacement programmes.

None of these factors include EG. All these costs to the consumer arise because of the continued existence of TG, which your suggested changes would help perpetuate and increase. The combination of the European cap and charges falling on offshore wind, themselves covered by additional subsidies paid by consumers through Government to those generators, are resulting in the rapidly falling generation TNUoS residual, turning negative in a number of instances as noted above. EG therefore clearly requires growth in the regulatory support structure to address this growing imbalance in favour of TG as you describe it.

Before moving to the challenge of quantifying the extent of embedded benefit we wish to make it abundantly clear that minimising TG, to the extent it can be done with alternative generation that does not give rise to these costs and is arms-length cost competitive, has to be the logical objective of any economic regulator. There is without any doubt whatsoever a clear benefit provided by EG in checking the growth of this consumer charge.

### **3. Impact of TNUoS Embedded Benefit**

We take issue with a fundamental point in your summary on this topic where you state that “The connection of an increasing amount of sub-100MW EG to the distribution system logically cannot help to avoid sunk/fixed costs of developing and maintaining the transmission network”. This is absolutely not correct. The scale of costs recovered each year by National Grid reflects the size of the transmission network as it is today. If we were able to install sufficient embedded generation to deliver all the electricity required at the same price as transmission connected generation today and if there were no embedded benefits then each generator would operate for half the time and both EG and TG would remain in place with the transmission network costs still being charged in full to consumers. Overlay embedded benefits and EG can sell at a cheaper price, driving TG to close. Many transmission assets would then become stranded and once they have reached the end of their useful life they would not be replaced. Since assets have a useful life of between 40 and 50 years, it would take that long for the charges to fall to zero but eventually they would do so. At that time all the network costs charged to consumers would have fallen away, as would the embedded benefits, and consumers would be billions per year better off for it.

You may take the view that stranding assets is a waste of assets and cannot be allowed. If we as EG pay for a connection to the distribution grid and you choose to undermine our income in a manner to make our project uneconomic then we have simply lost the money we spent on that connection. That is a risk we are facing today as you threaten to undermine our revenue stream. That should be the same in an environment where the consumer is the party taking that risk – by your choice in having a socialised asset approach. If EG can provide power at a lower cost when competing on a level playing field then if the consequence is the closure of TG and stranding transmission assets then that is the right economic outcome. It should not be resisted out of some misguided view that it is against consumer interests – it is not. Yes there is a substantial time delay before the beneficial effects of a move towards greater volumes of flexible EG are fully realised but that of itself is not a reason to stop such progress. It is worth pointing out that we are not in such a world yet and may not be for a long time to come as the challenge is to stop transmission costs growing rather than dealing with shrinkage in them.

## 3.1 *Our main concern – the TNUoS demand residual*

To date embedded benefits have failed to encourage EG at a level to significantly impact the growth in TG; the volumes of TG are not materially falling. Growth in demand for flexible generation as a result of the levels of penetration of intermittent generation coupled with the reduction in capacity margins giving rise to security of supply concerns is improving the economics of small scale reserve power plants, augmented by capacity market revenues, and this in turn is slowly leading to a growth in the EG market. Regulatory changes such as the move to single cash-out increase the price signals and intra-day volatility, creating a market where smaller embedded generators offer a better solution to near term price changes. Growth in embedded benefits is also without doubt a driver and that should be the case where such benefits can moderate the growth in annual transmission network charges being borne by consumers. The considerable growth forecast in the TNUoS demand residual is not created by the level of embedded benefits being paid – it is the result in large part of expenditure on network reinforcements for new transmission connected projects in the absence of sufficient volumes of EG being built to obviate the requirement for them. You should be focussed at this time in our view on ways to better incentivise embedded generation, not reduce the incentives on it.

You have mentioned five specific points and we address each:

1. *“leading to an inefficient mix of generation by encouraging investment in smaller distribution connected generation (which can take advantage of the embedded benefits revenue stream) over potentially more efficient larger transmission connected generators or over-100MW EG (which do not have that revenue stream)”*. Not all generation is built to meet the same needs and in today's liquid traded market some generation is much better at meeting specific needs than others. To operate the system effectively National Grid requires a growing range of services addressing needs such as fast frequency response, power factor variation and capacity which can run for short durations to meet local power needs. This can be Fast Reserve, ramping at 25MW/minute with at least 50MW, Short Term Operating Reserve, capacity procured in the capacity market for delivery at times of system stress, capacity traded in the day ahead market, capacity traded intra day and capacity traded after gate closure. A large CCGT plant running at base load will have a better efficiency factor (around 54%) than say the gas engines we use which are closer to 44% but because our engines are physically smaller, we can fast ramp them and provide energy across a range of these valuable products that are not accessible to the likes of a CCGT plant. To put it another way, if a CCGT plant were to be used to provide services supplied by smaller plant such as ours, the costs would be prohibitive and the manner of usage damaging to the turbines. It takes 2 minutes to ramp gas engines to full output but it takes circa 1.5 hours to do the same with a large CCGT plant. In a market increasingly valuing responsive generation it is a very wrong view to regard large-scale generation connected to expensive transmission assets as the generation method of choice. This will become increasingly true as smart meters on half-hourly charging allow demand to move quickly in response to price signals, requiring generation to turn up or down in the same time frame. The one area we are not commenting on here is over-100MW EG as we are not sufficiently familiar with that market.
2. *“leading to TG exiting because it cannot compete”*. That is the objective of competition – to drive down prices and allow the economically best projects to operate. TG exiting is not a conclusion that should concern the regulator if it is the intended best direction of travel that in time will reduce transmission costs passed to consumers.

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3. *“distorting dispatch by dampening prices at peak times when EG dispatch out of merit to generate in triad periods”*. The reason that triad payment are linked to times of peak demand is to reduce the peak on the basis that if EG were not generating at that time, the import required from the transmission grid would be higher, implying that network investment would be higher. When volumes of EG were minimal and power stations were base load, mid merit or peaker plants (e.g. hydro), centrally dispatched and all connected to the transmission grid as was largely the case back in 1990 when the CEGB was restructured, this made sense. Now it may make less sense and the method of attributing embedded benefit may be open to reconsideration through something other than the triad peaks. However it is a sweeping statement to suggest that high volumes of EG (the implication of your comment) generate at triads when it would otherwise be uneconomic for them to do so. To our knowledge no generating plant would be economic if it could only rely on triad revenues. In our case, for gas engines, we expect to operate for between 1200 hours and 1500 hours in a typical year and hours are more likely to grow than reduce as volatility rises in intra-day pricing. Absent triads we would almost certainly still be operating at those times in view of the high power prices on winter weekdays, 4pm to 7pm which is when historically all triad periods have occurred. That is not to say however that we do not need triads or at least that quantum of embedded benefit in some form – we most certainly do or the economics of our plant would not allow us to compete with TG given the structural advantages it enjoys as a result of the current charging regime.
4. *“distorting the outcome of the capacity market (CM) by holding down prices since smaller EG can bid in at significantly lower prices than larger EG and TG”*. If EG can bid in at lower prices, that suggests the plant is more economic. This goes back to the question of the level of embedded benefits and whether they are correct. The mere fact in isolation that economics of EG are currently more attractive than the economics of TG is not an indication that this is wrong or that there is a distortion of the CM clearing prices, indeed as discussed above we consider this to be the best outcome in the interests of consumers, leading in time to a reduction in the costs caused by TG.
5. *“distorting innovation in the market towards parties who can best capture this large payment”*. As we touched on above, the existence of embedded benefits is a result of the costs visited on the consumer by TG. Those parties capturing this benefit in EG are the parties innovating and responding flexibly to system requirements in order to capture sufficient revenue to be viable. This is promotion of innovation, not a distortion of innovation.

In our view you are mixing two quite different concerns in your letter, one being the growth in annual cost of the transmission network to consumers (caused, we repeat, by TG not by DG and reflecting the increased extent to which consumers are subsidising TG) and the second being the method of payment of embedded benefits. We consider there is more merit in your second concern about the appropriateness of determining these payments merely by reference to three half hours than there is in your first where you take the position that payments to embedded generators are too high and we would support focussed efforts to develop a better way to pay embedded benefits in a market with growing levels of EG. Addressing the timing of payments is a matter best addressed as part of an SCR in our view.

### 3.2 *The TNUoS demand and generation locational signals*

We agree with your comments on this section. It is appropriate that there is some element of locational signal and from our perspective the current signals appear to be at a suitable level but we are not averse to the idea of a more structured evaluation of them.

### **3.3      *The TNUoS generation residual***

We consider it is a surprising misrepresentation of the facts to suggest that avoidance of TNUoS generation residual is in some way an embedded benefit. If we were not to pay the connection costs of our generation to the local distribution grid then that would be a benefit but I would not characterise the absence of us paying competitors' connection costs as a benefit – they are not our connection costs and are costs of a system we do not use.

Furthermore you say that “avoidance of TNUoS generation residual charges is unlikely to be causing the sizeable distortion of a similar magnitude to those caused by the TNUoS demand residual payments” while apparently ignoring the distortion created by TG being PAID to connect to the grid as TNUoS generation residual charges go negative as is becoming the case for increasing volumes of TG, while funded by consumers you are charged with protecting. We suggest your focus is in the wrong place – you need to address the TG charging issue with some urgency. You do not have to do that against proposed CUSC mods however because, unsurprisingly, no CUSC parties have suggested that their benefits be cut – they prefer only to propose that payments to their competitors in EG be cut.

### **3.4      *The BSUoS demand and generation charges***

We agree that the level of charges at BSUoS level is not a matter of the same priority as others in your letter.

### **3.5      *Does EG provide any other benefit?***

There may be other benefits that a Regulatory Impact Assessment could properly identify. We are not aware of any specifically.

### **3.6      *Initial thoughts on our approach***

We are in broad agreement that a combination approach is required here. First there should be a clear direction of travel stated which has a rigorous economic and perhaps technical evaluation behind it to form a view of the indicative level of an economically justified embedded benefit, with such caveats as may arise as a result of that study. We would expect that result to compare EG against the economics of TG and the latter is itself driven by the transmission charging codes. As we have pointed out above, there is a clear problem in a code that results in growing volumes of TG being paid to impose more costs on consumers. Addressing the problems in TG charging will reduce the required embedded benefits if the result can be a reduction in the level of TG charges being borne by consumers. One aspect of this may be to segregate the considerable costs arising from offshore wind and charge those in a different way to consumers, recognising that they arise as a result of Government policy and therefore it makes no sense to have them ripple through to negative transmission charges nor to ripple through to increasing embedded benefits which is tantamount to encouraging EG to compete with technologies with which it simply cannot compete since they are in receipt of fixed subsidies. We have put forward a WACM for consideration that builds on this concept and trust it will be carefully considered when it comes before Ofgem in due course.

Having set out the background in a way that gives investors in EG (and to some extent in TG) some comfort about likely future revenues then a SCR should be undertaken to take those ideas of value streams and adapt them to come up with a cohesive and credible charging regime that is fit for the future. That will be a future with far less central inflexible TG and far more EG in our view. The process of developing a system fit for 2050 and beyond should not be left to industry to develop in an ad-hoc manner, skewed by vested interests and incumbents fighting to perpetuate an archaic system – it should be led by Ofgem to produce a world leading structure fit for purpose.

## 4. *Transitional arrangements*

The discussion of transitional arrangements implies an acceptance that the current system is broken and giving false results. We are of the view that it is far from a perfect system but from our perspective the flaw is that it potentially under-states rather than over-states the true benefits of EG. When the components of the annual transmission costs are reviewed, an element of these is the cost of the grid assets themselves. That cost is the cost of a system that is on average over 20 years old and this is said in the recognition that assets are amortised over periods of 40 to 50 years depending on type. Were those assets considered at current replacement cost, the implied avoided annual cost per MW would be higher. Against that and as mentioned above we feel the costs arising from offshore wind are in a different category and potentially should not form part of the calculation of embedded benefit, perhaps being charged to consumers on a gross consumption basis. Ideally we would be able to segregate out other assets built to support renewables but we cannot currently do so. If National Grid were to be able to better address this, charging for such assets in a different manner may be well worthwhile.

The decision on whether to accept any of the various proposed CUSC modification proposals will be yours in due course so on the assumption that you finally decide some change is warranted (although we do not share your view) while awaiting the outcome of a Significant Code Review, should that change involve the adoption of one of the more extreme reductions to embedded benefits then we would most certainly favour grandfathering and making a clear line for those parties who have existing operational EG or have contracted capacity agreements which obligate us to deliver generation. For us to be unable to do so because the economics of our projects had been undermined, even on a temporary basis pending the outcome of an SCR, would not be in the interests of consumers, investor confidence or security of supply. This has particular merit as you acknowledge that existing volumes of EG are low and it would avoid larger volumes bidding into the CM unless they found the economics of EG, when viewed in the light of enhanced CM prices, as still attractive. Subject to the inclusion of grandfathering, if change is to be imposed by Ofgem then there is merit in making it immediate as otherwise it will be overtaken by the SCR process.

One problem with grandfathering is the creation of additional complexity so a simpler way may be to accept a change that is reasonably minor in impact currently and can be implemented easily. Proposals which will take years to implement will merely create unnecessary cost while efforts should be better directed towards an SCR. We also note in passing that the larger generators, invariably with portfolios skewed towards TG, are the only ones with the resources to properly input into code reviews and National Grid themselves are not commercially unbiased, generating earnings from transmission assets only. You should be aware of this and be cautious about many of the representations made to you for this reason.

You ask a sub-set of questions in this section and we respond to each as follows:

1. *"whether any delay to implementation is needed to give parties time to adjust to the new arrangements"*. Subject to our grandfathering comment above we see no benefit in any implementation delay. Either you introduce some interim arrangement pending the SCR or you simply wait and undertake the SCR. Our preference, as described above, is a clear statement following both this consultation and an RIA, making clear your view on the justified range of embedded benefits having regard to the current TG charging regime which may well change and then go straight to an SCR, avoiding creating a distortion by a sticking-plaster approach to a complex issue.

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2. *“whether transitional arrangements introduce discrimination into the charging arrangements (e.g. between those users for whom change is implemented earlier than other users)”*. This risk exists between EG and TG but is not related to the transitional arrangements for any change to EG charging. If there is delayed implementation then there is no obvious negative to us but equally there is no obvious positive. The whole concept of near term change seems irrational if it is to be the subject of an SCR.
3. *“whether transitional arrangements introduce additional complexity into the charging arrangements”*. They certainly would.
4. *“whether the potential future savings to consumers are negatively affected and to what extent”*. We consider that any reduction in embedded benefits will negatively affect consumers by increasing consumer costs through the CM as well as perpetuating TG ill-suited to the needs to the system we have today.
5. *“whether distortion in further long term arrangements can be avoided (i.e. the 2016 CM auction for deliver year 2020/21 and onwards)”*. This question, as with others you pose, implies that you already consider there is a distortion that arises from embedded benefits, a point with which we disagree.
6. *“the extent of any impact on security of supply and whether transitional arrangements could mitigate these”*. Any adverse change in embedded benefits will undermine the economics of plant under construction. Already we are delaying our projects and there can be little doubt that others will be also in the current climate of uncertainty created by your letter. That of itself has adversely impacted security of supply and a continuation of this approach will only worsen the impact. Consumers could face lights going out if Ofgem does not address this in a sufficiently considered and timely manner.
7. *“the extent to which investor confidence is affected”*. Investors have supported parties seeking to build EG against the background of the current regulatory regime. Major changes to elements of that based on rushed decisions would inevitably have an adverse impact on investor confidence. Whilst it is Ofgem's duty to consider modification applications, the way in which that is done and a measured and fully considered approach is very important to investors. Major changes of direction on what appears to be a whim are extremely unwelcome.

## 5. Potential distortions from other charging arrangements

You state your initial thinking is that the different treatment of TG and EG in respect of connection charges does not significantly disadvantage EG. We find that comment surprising and wrong. We have set out above the major differences between TG and EG that disadvantage EG.

## 6. Ongoing code modifications related to embedded benefits

You cite a “widespread view” in the industry that the current level of TNUoS demand residual payments is higher than justified. That, we suggest, is the widespread view principally of incumbents and some who see this as a negotiation rather than an economic analysis of the respective positions. The current level is not too high – it is simply the arithmetic result of the costs. We presume you mean your comment to suggest, as you have said in many places in your letter, that it over-incentivises EG. We do not agree as we have made plain throughout our letter – if this is the cost created by TG and if EG, with the benefit of a similar benefit, can generate for less then that is the right result. Yes in that scenario EG is making a higher return than TG but it is exactly that result that will drive TG out of the market – the correct economic outcome. That in turn means transmission costs will fall over time, embedded benefits will fall and consumer costs go down.



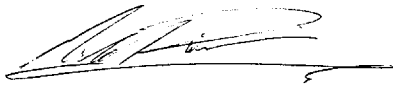
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## 7. Related work

We note your comments but have no additional observations on this.

In conclusion we are very happy to meet to discuss any of the matters above should you wish to do so. This is a key matter for the UK energy sector and there is an opportunity, through an SCR, to change charging to work in a very different world. There is also the opportunity to seek to provide a sticking plaster solution to a “defect” identified and promoted by a self-interested set of parties who have far more resources to promote their view than those of us in the EG sector; such an approach could do serious long term damage to a nascent industry. We urge caution in your approach.

Yours sincerely,



**Michael Davies**  
**Director**