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13 April 2017

Dear Andrew

Response to Ofgem's "Minded to" position on embedded benefit

Thank you for the opportunity to respond to your draft impact assessment and minded to position on CMPs 264 and 265. At all times in this process we have tried to engage fully and constructively and we appreciate the time of both you and your staff in meeting with us and responding to various issues we raised.

The "minded to" statement addresses the complex issue of the level of benefit embedded generators bring to the system, and if it is justifiable to pay them some, or all, of the residual element of the avoided TNUoS demand charge. We are fully supportive of cost reflective charging; however, our view is that the high level of the residual charge is a symptom of the existing charging methodology failing to allocated costs properly, rather than a problem in its own right. The costs of the transmission system are rising, but the charging methodology is failing to allocate much of the new costs, which results in the residual charge rising.

The review of the residual paid to embedded generation has been undertaken in accelerated timescales, and many important issues have been deemed out of scope of the CUSC process (for example if the charging model is correctly allocating costs). A result of this is the poor selection of options now available for Ofgem to consider.

Notwithstanding this, we remain, fully supportive of a full review of transmission charging, as ultimately the correct allocation of costs means better competition and better value for the end customer, and this is consistent with both the CUSC objectives and Ofgem's wider objectives. However, we believe that the current minded to position, where embedded generation is simply paid the estimated avoided grid supply point infrastructure is inadequate for the following reasons:

- i. Underlying the proposals, there is an assumption that the locational charge is "forward looking and cost reflective", whilst the residual charge reflects "unavoidable sunk costs". Because of weaknesses in the charging methodology we believe that this is untrue. In fact, the demand residual charge contains forward looking costs that are not sunk. I explain this in Annex 1 attached to this letter.
- ii. The security and quality of supply standard (SQSS) treats smaller embedded generation differently to larger transmission connected generation. The uncertainty of small generators' output is noise against the level of demand

uncertainty However, this is not true for larger generating units. The SQSS determines the required investment in the transmission system, and previously it has been Ofgem's position that as the SQSS drives the costs of the transmission system, its requirements should drive the allocation of transmission costs. Smaller embedded generation should be rewarded for its savings in transmission investment based on the SQSS' requirements. I deal with this in Annex 2 to this letter;

- iii. By embedding generation in the distribution system, a reduced amount of generation is required to be connected to the transmission system. By having less transmission connected generation, payments of the generation residual (forecast at approximately 7 GBP/kW in 2020) are reduced. This is a direct cost saving from the use of embedded rather than transmission connected generation. I detail this saving in Annex 3 to this letter; and
- iv. Under the RIIO incentives, National Grid is paid an incentive for the connection of new generation to the transmission system, along with wider works payments to reinforce transmission system boundary capabilities. Analysis of these incentive payments suggests an additional avoided cost by connecting embedded rather than transmission connected generation in excess of 10 GBP/kW as shown in Annex 4 to the letter.

Overall, we believe that we can clearly evidence savings in the range of 15 – 20 GBP/kW in addition to the locational benefit from connecting embedded rather than transmission connected generation.

In light of the directly quantifiable benefits of embedded generation identified above, and the limited options available to Ofgem in terms of WACMs we would recommend approval of WACM 7, which would pay embedded generators the lowest negative location charge which approximates to the value quantified above. This would be for an interim period whilst a more detailed review of network charging is undertaken.

Avoided GSP infrastructure	~ 2 £/kW
Avoided Generation Residual	~10 £/ kW
Avoided payment under RIIO for transmission Connected generation	~ 7 £/kW
Total	~19 £/kW

I attach formal answers to your consultation question in Annex 5.

Yours sincerely,



Mark Draper, CEO PeakGen.

Annex 1: The locational charge does not sufficiently recover the cost of investment and the demand residual contains forward looking costs

In Figure 1 we show 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). In addition, we show the forecast income from the locational element of the demand and generation TNUoS charge (green). The difference between the costs (including the generation residual payment) and the locational revenue makes up the demand residual.

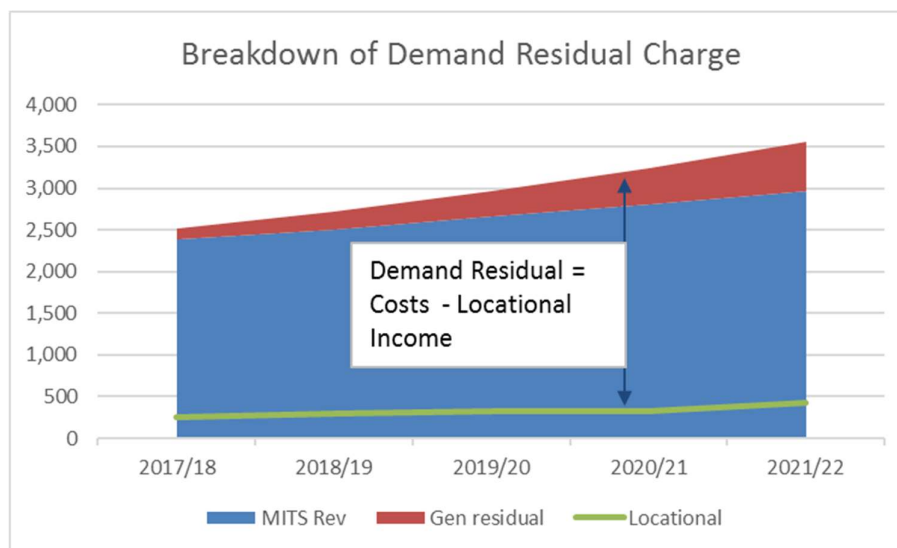


Figure 1: Development of MITS costs, generation residual payment and income from locational charges 2017 - 2021 (source National Grid¹)

Analysis of the data shows that the statement that the locational charge is forward looking and the residual charge is sunk is clearly 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. This would suggest that the locational charge is simply failing to recover costs and potentially resulting in generation and/or demand making incorrect locational signals.

The situation is further exacerbated because the demand locational charge always recovers zero revenue, and the total revenue recovered from generation is set at a fixed level, so the increase in the generation locational charge is neutralised by an offsetting increase of the generation residual payment.

The net effect is that all of the additional costs of the allowed revenue for the MITS permitted by Ofgem is recovered from the demand residual. **Therefore, all of the forward-looking costs are recovered from the demand residual.**

¹ <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939106>

	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

Annex 2: Different treatment of transmission and small embedded generation under the SQSS

National Grid's investment in the transmission system is determined by the *security and quality of supply standard* (SQSS) which determines the necessary amount of infrastructure required by National Grid.

The SQSS treats smaller embedded generation differently to large embedded generation and transmission connected generation and requires different levels of investment in the transmission system to accommodate them. The key difference is:

- i. Small embedded generation is treated as negative demand (see definition of ACS demand on page 54, and section 4.4, "minimum transmission capacity requirements") and reflects the generation's actual behaviour over peak;
- ii. Larger generation is scaled according to different scenarios, as set out in Appendix C ("security planned transfer") and Appendix E ("economy planned transfer")

The difference is due to the transmission system needing to be robust against generation and transmission faults. Where generation sets are small compared to the level of demand that they are embedded in, the occasional unavailability of a set can be treated as part of the general uncertainty of the level of demand (for example a 10 MW generator in a 200 MW demand group). However, where a set is large compared to the level of demand, the uncertainty of the generator's availability dwarfs the level of demand uncertainty and it has to be treated separately (for example a 500 MW generator in a 200 MW demand group).

This difference is illustrated in figure 2 where the different levels of investment resulting from the connection of a large 450 MW transmission connected generator at Canterbury North are contrasted with a number of smaller and independent generators being embedded in the distribution network with a total capacity of 450 MW.

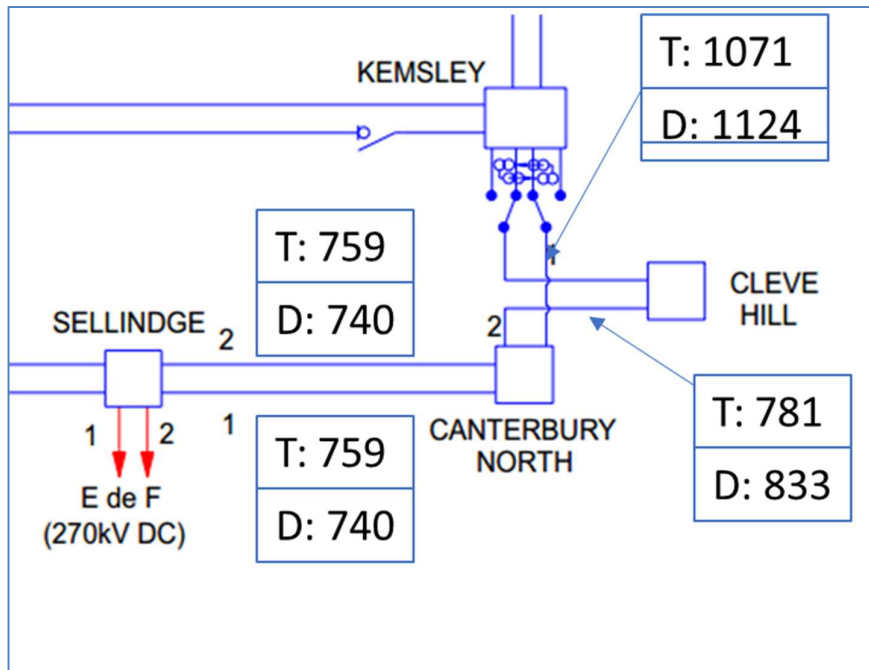


Figure 2: MW requirements against the SQSS for either a 450 MW transmission connected generation (T prefix); or 450 MW of small embedded generators connected at Canterbury North (D prefix). Calculated using 2016/17 Final External Model for the economy planned transfer.

Clearly, smaller embedded generation has a different impact on the investment required in the transmission system and therefore the costs of the transmission system. For cost reflective charging this difference in investment needs to be recognized.

A further point to highlight is that the SQSS treats embedded generation as negative demand. Therefore, if two suppliers connect to the same GSP as follows (Figure 3):

- i. Supplier A has 60 MW of demand and 40 MW of embedded generation. The SQSS requires 20 MW of demand import capability
- ii. Supplier B has 20 MW of demand and no generation. The SQSS requires 20 MW of demand import capability.

Both suppliers impose the same cost on the system, and cost reflective nondiscriminatory charging (a requirement if EU law) would require that they face the same charge.

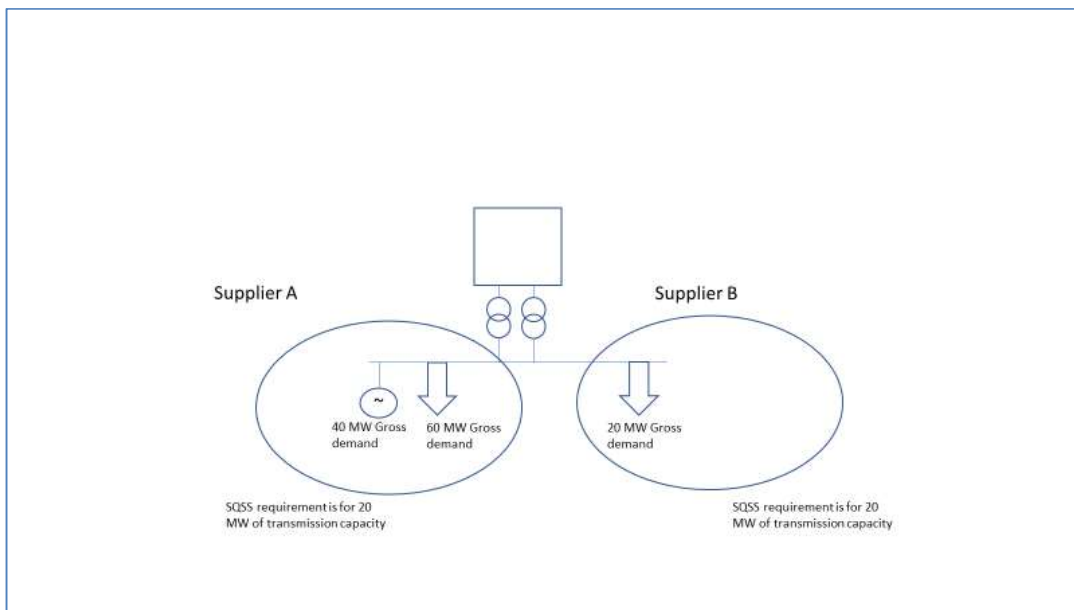


Figure 3: Two suppliers connecting to the same GSP. One supplier has 60 MW of demand and 40 MW of generation, the other supplier simply has 20 MW of generation. Under the SQSS, both suppliers have the same investment requirement and therefore have the same cost impact on the transmission system.

Annex 3: Substituting embedded generation for transmission connected generation avoids payment of the generation residual – this is a direct saving for consumers

In accordance with EU law, the revenue that the transmission owners can recover from generation is capped at 2.50 EUR/MWh generated. To meet this cap, National Grid forecasts² in 2020/21 needing to offset the TNUoS locational charge by a payment of 7.61 GBP/kW to all transmission connected generation. This payment increases the demand residual charge and is a direct cost to customers.

If an embedded generator connects to the system and displaces a transmission connected generator, this reduces the payment of the generation residual and results in a direct saving to the consumer via a reduction of the demand residual.

The reduction of the demand residual is not a one to one relationship with the generation residual, but is impacted by:

- i. The load factor of the embedded generator (as this impacts the volume of energy delivered by transmission connected generation and therefore the revenue cap); and
- ii. The TNUoS charge the displaced transmission connected would have paid.

The LCP analysis provided by Ofgem suggests that new embedded generation will be gas or diesel reciprocating engines with a very low load factor, so the connection of such plant will have a negligible impact on the volume (MWh) of electricity delivered by transmission connected generation and therefore have a negligible impact on the revenue cap.

The location of the displaced transmission generation is significant. If we assume that renewable incentives mean that renewable generation will not be displaced, the most likely generation to be displaced will be non-intermittent generation with a higher cost base. A significant part of a generators cost base will be its TNUoS charge. Assuming that the displaced generation would be in the top 40% of TNUoS charges, the volume weighted average TEC charge for the potentially displaced generation is about 8.40 GBP/kW (assumes that the displaced generation has a near 0 annual load factor).

This assessment suggests that a reasonable approximation of the value of connecting embedded generation is the avoided generation residual charge.

² <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939106> (table 13)

Annex 4: Avoidance of RIIO costs from embedded rather than transmission connected generation.

Full details of the impact of the RIIO incentive on allowed revenues has been submitted by Welsh Power. A summary of the impact is (2010 prices):

- i. Avoided generation connection cost of 27 GBP/kW
- ii. Avoided wider system works cost of 37 GBP/kW
- iii. Avoided super grid transformer cost between 16 and 65 GBP kW

Applying National Grid's annuity factor of 6.6% and converting to 2017/18 prices gives an annualised saving in excess of 10 GBP/kW

Annex 5: Response to formal consultation questions

Question 1: Do you agree with our problem definition and that the Transmission Network Use of System (TNUoS) Demand Residual (TDR) payments to sub-100MW Embedded Generation (“smaller EG”) are distorting dispatch, wholesale price, the capacity market (CM) and that they pose an increased cost to consumers?

No. There is clearly an issue with transmission network charging, with costs of the transmission system failing to be correctly allocated to the parties causing them. A symptom of this problem is a rising demand residual charge, however, it is not the cause and the problem has been ill defined.

The poor definition of the issue has meant that the change process run under CMP 264 and CMP 265 has been flawed as tackling the key cause of the problem was out of scope of the process.

This poor process has resulted in poor solutions being brought forward as CMP 264 and CMP 265 WACMs and Ofgem now faces a dilemma where none of the available options tackle the underlying defect in the transmission charging methodology. In making this decision Ofgem needs to balance investor confidence (with the knock on impact on costs), security of supply, timing, customer costs and the effects on the close out programme for coal.

Question 2: Do you agree that rising TDR payments to smaller EG is a problem which needs to be addressed?

No.

As we indicated in Q1, the high level of the demand residual is a symptom of an underlying problem with the network charging methodology. As we show in Annex 1, there are clearly forward costs feeding into the demand residual, as is the cost of the negative generation residual.

Ofgem should tackle the underlying problem with network charging such that all parties face proper cost reflective network charges.

Question 3: Do you agree with our interpretation of the applicable CUSC objectives?

Yes

Question 4: Do you agree with our assessment against the applicable CUSC objectives and statutory duties? Please provide evidence for any differing views.

No

We consider that CUSC objective A, “*facilitating competition*” is, in this context, best met by delivering cost reflective network charging (and accept that generation with more expensive connections are less likely to success than those with cheaper connections). Please refer to our answer below where we do not believe that WACM 4 delivers cost reflective charging.

In terms of objective B, “*cost reflective charging*”, we have identified that the demand residual charge clearly contains forward looking and avoidable costs (Annex 1) and we have identified additional benefit from embedded generation totalling around 17 GBP/kW from the avoided generation residual (Annex 3) and saving costs under National Grid’s RIIO formula (Annex 4)

In terms of objective D, *complying with relevant legislation*, we note that EU law requires non-discrimination in charging where the same costs are incurred. In Annex 2 we demonstrate that under the SQSS, investment in the transmission system is driven by demand net of smaller embedded generation. To charge on a gross basis (unless the different costs can be justified) would be discriminatory and therefore breach the CUSC objective.

Question 5: In our assessment against the objectives, do you believe there are any relevant assessments we have not taken into account?

Yes – please see our response to Question 4 and 6.

Question 6: Do you agree with our assessment that, in this instance, grandfathering as set out in the WACMs would be unlikely to best facilitate the CUSC objectives when compared to the other options available to us?

No. Should Ofgem go ahead with their minded to position, there is strong expert opinion that unbuilt plant will not go ahead and there would be significant security of supply issues

This has been confirmed by various industry players and experts:

- Statement from UK Power Reserve³: *“UKPR has committed to building over 500MW of new, small-scale, fast-ramping, gas-fired power stations to help ensure that lights stay on as old power stations come to the end of their lives. But the potential for retrospective reform puts that investment programme at risk and may well snuff out the new, fledgling, independent generation businesses that are innovating and disrupting the power sector. The end result if this happens will be less competition, higher energy bills for consumers and an increased risk of the lights going out as new investment fails to come online.”*
- Statement from Dan Roberts, Frontier Economics⁴: *“The investors I’ve spoken to have said that most of them [economics of the plants] ‘just don’t work’ [without Triad payments] – in other words, you can’t get a positive internal rate of return with any sensible assumptions There is a strong risk the owners of these ‘options’ – they are not yet projects – just pay the penalty [for non-delivery] and move on.”*
- *If the Minded to position is confirmed, we will not build the remaining 116 MW of capacity we were awarded agreements for in the CM 2015 auction (we have already commissioned 20 MW and all of our 2014 obligations).*

For further details please see our response to Question 14

³ <https://ukpowerreserve.com/news/uk-power-reserve-responds-ofgems-charging-update-212/>

⁴ ICIS European Electricity Markets 31 March 2017 “‘Looming scandal’ over sale of UK capacity market new build options”

Question 7: Do you agree with our assessment that the value of the avoided GSP investment cost best facilitates the applicable CUSC objectives?

We strongly disagree that value of the avoided GSP investment cost best facilitates the CUSC objectives

1. Facilitating Effective Competition:

Ofgem has repeatedly asserted that TDR payments favour EG more over the larger transmission connected generators, however, it hasn't provided any evidence to support the claim. Therefore we don't think there is a basis for Ofgem to argue that avoided GSP investment cost facilitates this CUSC objective.

2. Ensuring Cost Reflectivity

While we agree with Ofgem's concerns that rising TDR payments for EG are no longer cost reflective, we have repeatedly provided evidence to Ofgem (as set out in Annex 1) that neither elements of transmission charging is cost-reflective.

Given that the current charging methodology is broken, we strongly argue for a whole charging system review as per the Targeted Charging Review issued by Ofgem rather than changing one single element of network charging which could have significant cost implications on the consumer.

Ofgem's position is based on an estimate of GSP infrastructure costs avoided (£1.62/kW) that is an arbitrary number based on out of date assumptions and fails to take account of the benefit to the consumers of the avoided transmission costs of the network.

Furthermore, replacing 1 kW of transmission connected generation with 1 kW of small/medium embedded generation avoids £7.61/kW generation residual payment to generation, funded via the demand residual. This is a direct cost saving from the connection of embedded generation, and for cost reflective charging should be passed on the embedded generation (see Question 9).

3. Take account of developments in transmission licensees' transmission business

Ofgem has not provided any evidence on the proposed changes being more cost reflective than Status-Quo or other WACMs. The modelling conducted is flawed (See answer to Question 14)

4. Taking account of European Legislation

Article 14 of EU Regulation 714/2009 requires cost reflective and non-discriminatory charging. We believe that avoided GSP investment cost benefit is both non-cost reflective and discriminatory towards standalone Embedded Generators.

SQSS clearly treats 20 MW of gross demand as having the same investment requirement as 60 MW of gross demand offset by 40 MW of embedded generation exactly the same, and in both cases we would expect a supplier to be charged for 20 MW of net demand (see Annex 2).

Furthermore, Ofgem has made clear that “behind-the-meter” generation will continue to receive TDR payments rising to £70/kW by 2020.

Question 8: Do you agree with our assessment of the impacts on security of supply? Please provide evidence for provided views.

No. We believe that there will be a significant impact on security of supply. Please see response to Questions 6 and 14.

Question 9: Please provide evidence to show if there are other cost savings which small EG drive in comparison to larger (over 100MW) EG on the distribution system.

There are three broad direct financial savings:

- i. By connecting more sub 100 MW embedded plant, less capacity of large plant is connected either to the transmission or distribution system. This avoids the payment of the 7.61 GBP/kW generation residual payment with is a direct cost to customers (paid via the demand residual). Refer to Annex 3 for details.
- ii. In the SQSS, smaller embedded plant is treated differently to 100MW+ plant (refer to SQSS, 3.5.1 and 3.7.3, Appendix C and Appendix E) and therefore trigger different levels of investment in the transmission system. See Annex 2 for details.
- iii. Under National Grids RIIO framework, there are savings in excess of GBP 10/kW for embedded rather than transmission connected generation. See Annex 4 for details.

Question 10: Is there other evidence that payment above avoided GSP/generation residual would better facilitate the applicable objectives?

Yes. We set this out in Annexes 2, 3 and 4 of this letter

Question 11: Do you believe you have a legitimate expectation or contractual right for the continuation of TDR payments? If so, please provide evidence.

Yes. Article 14 of EU Regulation 714/2009 requires cost reflective and non-discriminatory charging. The SQSS explicitly treats smaller embedded generation as negative demand with the SQSS driving both National Grid’s investment and therefore costs base.

By charging a supplier based on their gross, rather than net, demand, different suppliers with the same impact on transmission system costs will be charged different amounts. This is neither cost reflective or non-discriminatory. See Annex 2 for details.

Because the demand residual clearly contains forward looking costs that are not sunk (annex 1) the argument that this is simply about cost recovery is not valid.

Question 12: Do you agree with our assessment of the distributional issues?

No. Your assessment states that customers will face a lower cost if money is transferred from embedded generators to customers. This would be correct if embedded generators were not avoiding transmission system costs. However, we have provided substantial evidence (Annexes 1 – 4) that this is not the case.

Question 13: Are there any sectors that we may have overlooked?

Yes. The retrospective changes will impact the ability of current investors to deliver a 'Smarter, More Flexible' power system and increase the costs to consumers.

The 'Minded to' position would represent a retrospective policy change, breaking with the long tradition of 'grandfathering' in the way that UK policy and regulation evolves.

This will have a negative impact on investor confidence at a time where the Government and Ofgem are trying to encourage new players and a significant amount of capital into the market.

Ofgem have made clear that '*prudent investors should know that arrangements are subject to change*'. We agree. But investors also expect that Capacity Market contracts entered into in good faith in 2014 and 2015 will not be retrospectively impacted to such a dramatic extent and in such a short timescale by a subsequent significant policy change. Investors also expect Ofgem to follow the process as set out in their statutory duties and consider all arguments before making any changes – which has not been the case with this review. Furthermore, technologies such as DSR and battery storage have been incentivised based on these current market signals. (We ourselves have been investing in battery storage.) Any sudden changes would impact investor confidence and the market's ability to deliver innovative technologies in the future and thereby make it harder for small companies like ours to help with the transition to the smarter power system of the future.

Question 14: Do you agree with our modelling approach?

The impact of changing the embedded benefits system on the GB Power Market as modelled by Ofgem appears to have a number of **gross oversights and inconsistencies**. Considering the potential impact on the consumer and unintended consequences, we believe it would be inappropriate for Ofgem to make a decision before a full holistic review of charging arrangements is undertaken.

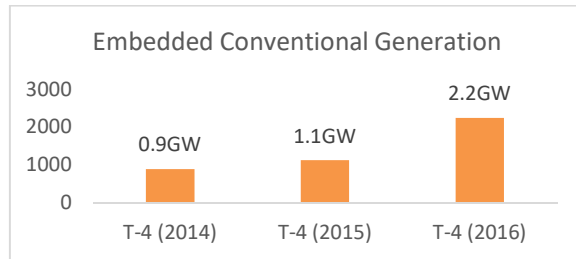
The current modelling conducted by Ofgem does not take a whole system approach and does not capture the benefits of embedded generation on avoiding transmission costs. It is essentially a market model that is unable to capture the benefits of embedded generation on avoiding transmission costs. Without accounting for the transmission system costs benefits, the analysis pre-determines the negative residual payment simply as a redistribution effect (it moves money from end customers to embedded generators), therefore removing embedded benefits will always show a customer saving.

- **Costs to the consumers due to increased regulatory uncertainty have been ignored**
The decision will inevitably drive up risk and increase the cost of capital for investment into the energy market. This comes at a time where Government is seeking to attract over a £100bn in the energy sector by 2021⁵ and will therefore undoubtedly drive up the cost to the consumer of the total investment. Ofgem's own modelling suggests that this could be in the magnitude of £1-8bn⁶ yet this has not been taken into account in the final system cost-benefit analysis to the consumer.
- **Security of Supply concerns**

⁵ Infrastructure & Projects Authority (March 2016). *National Infrastructure Delivery Plan 2016-2021*

⁶ Ofgem modelling shows that the impact on cost of capital could be between 1.7%- 6.4%. Frontier & LCP (March 2016) *Transmission Charging Arrangements for Embedded Generation*. p. 33

Embedded generators have been awarded circa. 4GW of new build capacity across the 2014, 2015 and 2016 T-4 auctions, of which only 185 MW have been completed to date.



Source: Capacity Market Registers

The investors for these plants factored in revenues from triad payments in their Capacity Market bids. Ofgem's own modelling suggests that plants that have secured Capacity Market agreement in the 2014, 2015 and 2016 CM auctions would now become economically unviable as they would need to replace £10-15/kW/year⁷ of revenue lost in Triad income. The proposed retrospective change will result in developers re-evaluating their Capacity Market contracts and not delivering on agreements as planned which the analysis fails take in to account. This could lead to security of supply issues, where the capacity will need to be replaced by older and more inefficient existing coal and gas fired generation. Furthermore, if embedded generators do not deliver as planned, it could require life extensions to either coal plants or existing CCGTs that are more CO₂ intensive than new-build efficient peaking embedded plants, increasing the amount of CO₂ emissions to 2025. This has also not been considered as part of Ofgem's modelling.

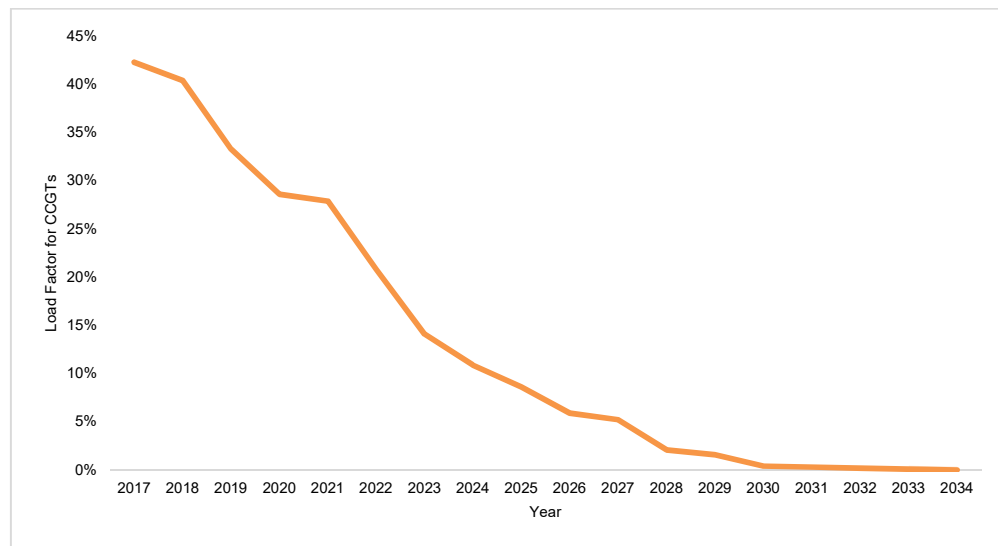
We believe, Ofgem modelling has underestimated the impact on Capacity Market costs to the consumers and ignored the unintended consequences. Non-delivery of new build capacity (c. 2-4GW) will require more capacity to be procured in the T-1 auctions, leading to higher T-1 auction clearing prices.

- **Higher wholesale prices**

We disagree with Ofgem's assertion that wholesale prices fall as a result of decreased embedded generation. The analysis is based on a model that contains errors as the analysis assumes that the efficiency of embedded generators is 33%, rather than 40 - 44% as in gas reciprocating engines. This increases wholesale prices artificially in the status quo scenario against other modelled scenarios where CCGTs replaces gas engines.

Furthermore, Ofgem assumes that the higher efficiency of CCGTs will decrease the wholesale prices through operating at a lower short run marginal cost. However, CCGTs can only operate efficiently when operating at full load. Ofgem's own analysis suggest that CCGT plant will operate as peaking plant in the future. This can be seen in the below chart as load factors fall to 2035.

⁷ Frontier & LCP (March 2016) *Transmission Charging Arrangements for Embedded Generation*. p. 15-17



Source: Ofgem Analysis, Scenario 3 phased

The modelling conducted by Ofgem is not detailed enough to take account of the different efficiency rates dependent on the load factor. This gross simplification ignores the actual costs to the consumer which will be much higher than predicted.

Furthermore, when correcting for the errors in efficiencies of gas engines (from 33% to 43%) and removing the TNUoS generation distortion, the model shows that gas engines will be built over CCGTs, removing any and all benefits of higher efficiency CCGTs on the wholesale market.

- **Higher than modelled CM clearing prices**

The Capacity Market clearing prices modelled by Ofgem are unlikely to deliver new CCGTs. Timera energy's⁸ analysis shows that the required Capacity Market clearing prices of £42/kW rather than £36/kW modelled, underestimating the cost to consumer by a factor £400m/year.

- **Higher Balancing Costs**

Due to the modelling errors (efficiency of embedded plants) the analysis conducted by Ofgem shows that the balancing costs will fall as a result of less embedded generation. However, the rise in embedded generation has significantly increased the competition in the National Grid Balancing Services market, keeping the costs to consumers lower even in a more intermittent electricity system. Currently, the proposed changes will lead to lower investment in embedded generation (due to damage to investor confidence) leading to higher balancing costs.

There will also be unintended consequences from these changes...

- **Higher CO₂ emissions**

The modelling shows that the CO₂ emissions will fall. However, the analysis fails to take account of the fact that in the short-term, circa. 2-4GW of new build embedded generation is unlikely to deliver on its Capacity Market agreements thus requiring coal and older CCGT to remain online and generate for longer to ensure security of supply. This will increase the amount of CO₂ emissions till new capacity comes on the system.

⁸ <http://www.timera-energy.com/the-uk-ccgt-new-build-challenge/>

- **Increased “Behind-the-meter” generation**

The proposed minded-to-position only impacts the stand-alone embedded generation and fails to capture the “behind-the-meter”/ on-site generation. Penalising stand-alone generation over on-site generation creates an un-levelled playing field in the embedded generation market that Ofgem has ignored. This will lead to significant market distortions as embedded generation gets pushed behind the meter before the Targeted Charging Review is implemented.

Question 15: Do you think that our background assumptions and using FES data is an appropriate approximation for status quo?

We have not focused our attention on this area of the analysis and therefore currently have no view.

Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate (see appendix 8 for detail)?

It will reproduce the errors detailed in the answer to question 14. Beyond this issue, we have not felt it worth identifying further issues.

Question 17: Of the options available to us, do you agree that WACM4 best facilitates the applicable CUSC objectives?

No.

We accept that that the current network charging arrangements are unsustainable and are in need of a full holistic review. This is highlighted by the fact that forward looking and avoidable costs are “bleeding” into the demand residual (Annex 1). Whilst the full impact of small embedded generation on the system is investigated (Annex 2) we note that approximately 17 GBP/kW of additional savings has been identified (Annex 3 and 4) and that WACM 7 is the closest option Ofgem has available to delivering this value.

We fully accept that WACM 7 is not a sustainable approach going forward, but given Ofgem is currently consulting on a targeted code review for network charging, the replacement of WACM 7 could be part of this process.

Of the limited options available to Ofgem we believe that WACM 7 will offer some degree of ongoing investor confidence and will not result in customers being penalized by higher than necessary CM clearing prices which would be the case if gas reciprocating engines were to continue to set the CM clearing price but with a higher costs base due to missing “embedded benefits” should Ofgem go ahead with its “Minded to” position

Question 18: Do you believe that an implementation date of April 2018 best facilitates the applicable CUSC objectives?

April 2018 would be an appropriate implementation date for WACM 7, provided transmission charging was also subject to a holistic review.