Ofgem’s embedded benefits reform – minded to decision

Summary and Aurora’s commentary

1. Background

The first two Capacity Market auctions held in December 2014 and December 2015 delivered results that largely defied the government's expectations. Over 2 GW or new embedded reciprocating engines, including a large proportion of Diesel, secured capacity agreements; Trafford, the only large-scale new-build CCGT successful in the auction, failed to secure financing for the project and ultimately gave up its agreement.

In March 2016, the then Energy Secretary, Amber Rudd, announced a series of reforms to the mechanism aimed at boosting security of supply and levelling the playing field between different technologies. One of the key proposals focused on changes to transmission charging arrangements, perceived by the government as inadequate in a rapidly evolving market.

In particular, the so-called embedded benefits – avoided transmission costs and additional revenue streams available to sub-100MW ('smaller') embedded generators (EG) – have been criticised by the government as excessive relative to the actual savings that they generate for the grid. This lack of cost-reflectiveness has been indicated as a source of a sizeable market distortion, where a significantly higher proportion of new build plant connect to distribution networks than would be economically optimal.

The government tasked Ofgem with conducting a review of embedded benefits, with a view of implementing the necessary changes ahead of future capacity auctions. On 29 July 2016, Ofgem published an open letter, announcing that TNUoS Demand Residual (Triads) – the most material of all embedded benefits - would be the key focus of its scrutiny and potential reforms[1]. The letter also stated that Ofgem would aim to address the issue in a timely fashion, and hence rather than triggering a Significant Code Review (SCR), it will focus instead on two existing Connection and Use of System Code (CUSC) modification proposals. One of the proposals, CMP264, would prevent any new embedded generation connected after 30 June 2017 from receiving the embedded TNUoS Demand Residual benefit, at least until Ofgem has completed a more substantial reform of transmission charges. The other proposal, CMP265, sought to prevent embedded generation with Capacity Market agreements from receiving TNUoS Demand Residual payments from 1 April 2020.

A second open letter on this issue was published by Ofgem on 2 December 2016, and broadly reiterated its intention to target TNUoS Demand Residual as the main priority.[2] It also emphasized that embedded generators should be entitled to receive payments for avoided Grid Supply Charges (GSP), valued at £1-6/kW. The letter was released after the Connection and Use of System Code (CUSC) Modification Panel released its Final Modification Report[3] (FMR), in which, alongside the original proposals CMP264 and CMP265, 23 additional solutions termed Workgroup Alternatives (WACMs) were considered. Amongst all the WACMs, seven – WACM 1,2,3,4,5,6 and 7 - were voted by

[1] https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf
[2] https://www.ofgem.gov.uk/system/files/docs/2016/12/update_letter_-_charging_arrangements_for_embedded_generation.pdf
[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

the panel as superior to the baseline (no modifications). These proposals placed the Triad benefit in the range of between £0-22/kW.

On 1 March 2017, Ofgem published its 'minded to' decision[4] (together with an Impact Assessment), which outlined plans to change electricity transmission charging arrangements for Embedded Generators. In the decision, Ofgem proposes that WACM4 be made, and hence that Triad payments be reduced by a third each year over a three-year period, starting in April 2018. Overall, this would reduce Triad payments from the current level of £45/kW to £1.62/kW by 2020/21.

Ofgem is currently consulting on its 'minded to' decision, and will be accepting stakeholder's views on the proposal until 10 April 2017, before making a final decision in May 2017.

The following sections provide a summary of the proposed changes and a commentary on their potential impact.

2. Summary of Ofgem's findings and proposals

2.1. Key findings

1) Transmission charges and Triads are expected to rise significantly

Transmission charges – and consequently, the amount of benefits received by embedded generators – have been rising over time. The TNUoS demand residual currently stands at £45/kW, up from £15/kW a decade ago, and Ofgem believes that in the absence of reform this would reach in excess of £70/kW by 2020/21.

2) Embedded benefits could lead to serious distortions

Ofgem highlighted several distortions that would result from rapidly rising TNUoS Demand Residual payments to embedded generators.

Firstly, the regulator found that embedded generators could be incentivised to generate against what the "merit order" would stipulate. In a well-functioning market, generators provide supply according to their respective marginal cost, with the most cost effective plant entering first. With significant non-electricity market revenues, embedded generators can operate even if they are not the next most-efficient generator. Therefore, embedded generators would run excessively to capture triad payments; if triad periods are not aligned with the highest peak prices, peak wholesale prices would be depressed.

Secondly, Ofgem indicated that smaller embedded generators have a competitive advantage when bidding into the capacity market, reducing their possible bid prices and depressing the clearing price.

Thirdly, Ofgem highlighted that embedded benefits distort investment decisions, leading to an excessive amount of capacity being located on distribution networks, relative to what would be economically optimal.

[4] https://www.ofgem.gov.uk/system/files/docs/2017/03/minded_to_decision_and_draft_impact_assessment_of_industrys_proposals_cmp264_and_cmp265_to_change_electricity_transmission_charging_arrangements_for_embedded_generators_0.pdf

2.2. Key proposals

1) Reduction of TNUoS Demand Residual payment as an embedded benefit to £1.62/kW

In considering proposals, Ofgem focused on identifying and quantifying the value of "x" – the representative measure of benefits that a smaller EG brings in terms of avoided transmission costs as compared to larger generation in the same area. Of the 11 alternatives examined, Ofgem decided that the value of "x" should be equivalent to the avoided Grid Supply Point (GSP) cost – last estimated to be £1.62/kW[5].

In its decision, Ofgem recognised that embedded generation can offset the need for reinforcement at the GSP, which arises from an increase of demand at the GSP, compared to a transmission generator connected at the same location.

2) Phasing over a three-year period

If implemented, the Ofgem proposal would reduce triad payments by a third each year over a three-year period, starting in April 2018. This gradual phasing-out is intended to provide asset owners enough time to "adapt their despatch and business model" as well as alleviate short-term security of supply concerns. Overall, payments from the current level of £45/kW will decrease to £1.62/kW by 2020/21.

3) No grandfathering offered

Ofgem decided not to grandfather the existing arrangements for any specific sub-sets of smaller EGs. Some of the analysed WACMs included proposals to grandfather generators commissioned before a certain date, or those that hold a CfD agreement or a CM contract from the 2014 or 2015 CM auctions. Ofgem concluded that the case in favour of grandfathering is less convincing that the case against it, quoting specifically the negative impacts of grandfathering on competition, value for consumers, administrative costs and flexibility in implementing any future changes.

4) Implementation through an "embedded benefit tariff"

In implementing the change, Ofgem intends to replace the current net charging of the TNUoS demand residual charges with a new structure where demand is measured on a gross basis (i.e. gross demand without smaller embedded netted off). Embedded generators would recoup the new demand residual embedded benefit through an explicit "embedded benefit tariff" which is applied to smaller EG exports on a gross basis.

2.3. Targeted Charging Review (TCR)

Reiterating their position from July and December 2016, Ofgem proposed undertaking a Targeted Charging Review (TCR) in the "transitional period", before the new levels for TNUoS Demand Residual become effective. The TCR will consider other embedded benefits, and the broader question of how to efficiently recover transmission costs. Amongst other matters, the review will target the question of behind-the-meter (BTM)

[5] The value of £1.62/KW was last calculated in £1.62/kW by National Grid's review in 2013/14, where the average annuitized cost of the infrastructure reinforcement was taken and divided by the average capacity delivered by a supergrid transformer to provide a unit cost of the avoided infrastructure reinforcement at the GSP.

generation, which is treated as DSR and is therefore not affected by the currently proposed reform. Ofgem expressed concern that this differential treatment of BTM generation could lead to its unintended proliferation.

3. Aurora's commentary on potential impacts

1) 2016 and future CM auction winners largely unaffected; average CM price in the 2020s will increase by £7-9/kW

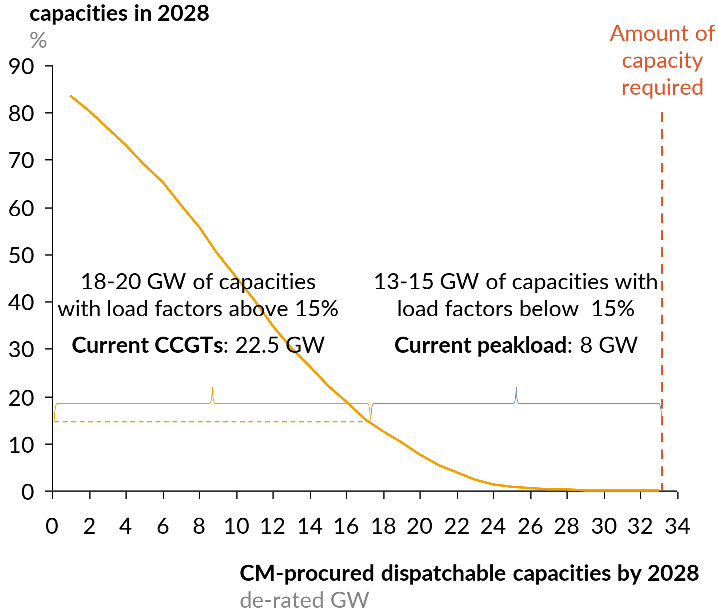
Considering that Ofgem's change was announced in advance of the latest CM auction, we expect the winners of the latest auction to have accounted for the decrease in embedded benefits revenue in their business models and CM bids. The 2016 T-4 auction cleared 25% (£4.5/kW) above the price of the 2015 auction, largely reflecting the increase in capacity payments required to break even following cuts to Triad payments.

Similarly, future embedded capacities will factor in the new Triad levels into their bids, recouping the value lost through the reform. As a result, we expect the average CM price to increase by £7-9/kW in the 2020s, relative to a "no change to Triads" scenario. Importantly, in contrast to Triads, the value recouped via CM is "bankable" – capital provided against secure 15-year CM contracts is significantly cheaper and more accessible than in the case of volatile benefits stemming from transmission charging arrangements.

While the Capacity Market price will increase, there will be relatively little impact on the capacity mix. We expect that a further 1 to 3 GW of CCGT capacity will be delivered throughout the 2020s, at the expense of small, flexible, embedded generation. The primary reason for this limited impact on generation mix relates to future system needs. On a fundamental level, the system is still long on baseload and short on peakload capacities. With substantial nuclear, renewable and interconnector capacity additions, the load factors of dispatchable technologies are expected to decline substantially, and increasing levels of capacity will be required to predominantly provide security of supply, rather than power. Our modelling indicates that up to 15 GW of capacity in 2030 will achieve load factors below 15% (see Exhibit 1 below). This market environment naturally favours technologies with relatively low CAPEX and high variable costs, such as DSR or recips. Additionally, growing intermittency from renewables enhances the value of flexibility, with technologies able to ramp up and down quickly poised to capture substantial premia through electricity, balancing and ancillary services (such as EFR) markets.

The future system will require at least 13 GW of capacity with load factors lower than 15%; these won't be CCGTs

Max load factor achievable for dispatchable[1] CM-procured capacities in 2028



- Below 15% load factor CCGTs are very uncompetitive against peaking capacities like recips
- If the current pipelines of nuclear, interconnectors and renewables materialise, the residual load duration curve implies a space of 18-20 GW for CCGTs in the late 2020s
- With 22.5 GW of currently contracted CCGTs[2] and ca. 7.5 GW of expected CCGT retirements, this implies between 3 and 5 GW of space for new CCGTs in 2028
- New high-efficiency CCGTs could enter by pushing existing assets of the market, but with high CAPEX and low inframarginal rents, they're typically uncompetitive against existing plants

1. Includes CCGT, OCGT, recips, DSR, batteries and others; excluding nuclear and interconnectors 2. Contracted in the T-4 2020/21 CM auction.

Source: Aurora Energy Research, National Grid

Exhibit 1

2) 2014/15 contracts at risk

The drastic reduction in Triad payments proposed by Ofgem has significantly more severe consequences for existing generators that secured contracts in the 2014 and 2015 T-4 auctions. The reform reduces the future gross margins of recip projects by up to 40% relative to what their owners had assumed when submitting their CM bids. Unlike for new projects, which are expected to recoup the lost value via CM, any compensation for existing projects is less straightforward (please see point 3 below).

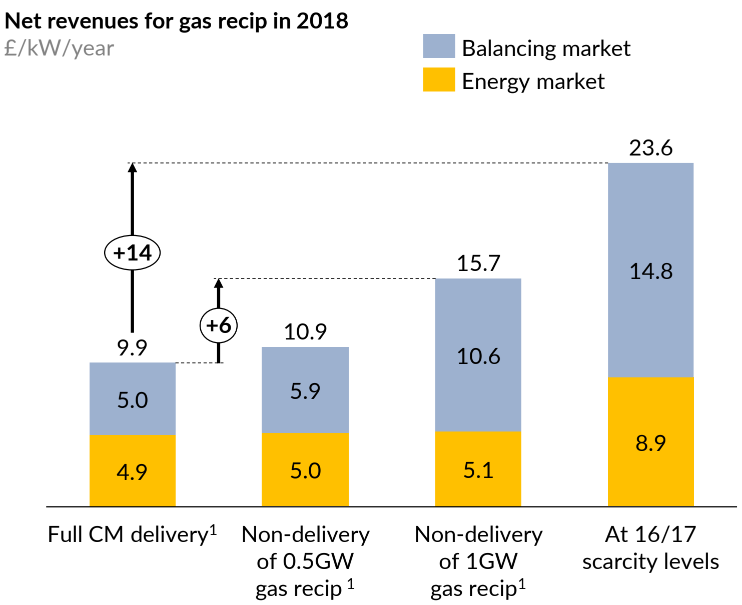
For some of the more marginal projects the proposed cuts may be enough to make them unviable. We estimate that up to a half of the 2.2 GW of embedded capacities successful in the first auctions may elect to give up their contracts.

Any potential security of supply concerns that this would give rise to can be largely addressed in the corresponding T-1 auctions. CM contract holders from the 2014 and 2015 auctions who decide to give up their contracts are strongly incentivised to do so before, rather than after, the T-1 auction. After the T-1 auction the penalty for non-delivery increases 5-fold, from £5/kW for terminating the agreement before the T-1 auction to £25/kW after the auction.

The resulting increase in procurement targets for the 2018/19 and 2019/20 T-1 auction will predominantly benefit existing generators, including older coal and CCGT assets. It is also possible that embedded generators who choose to give up their T-4 contracts will bid in the same projects into T-1 on the expectation of a significantly higher clearing price. Batteries, which are able to deliver on very short time scales, are also expected to benefit.

While the T-1 auction should successfully address most of the security of supply concerns, some projects could still renege after the T-1. Should this risk materialise, the 2018/19 and 2019/20 delivery years could see increased levels of scarcity, benefitting dispatchable thermal plant, including the embedded generators that do get delivered. We estimate that a 1GW capacity shortage could result in up to £6/kW of additional value in the energy and balancing markets. Exhibit 2 illustrates.

Potential non-delivery of capacity can provide up to £6/kW of additional revenues for peaking plants



- For peak plants expected to run a small number of hours, values captured from scarcity can affect their business case materially, relative to baseload plant
- Developers that bet on scarcity from capacity market non-delivery will thus bid lower, based on this additional revenue

1. Based on revenues from 2018 delivery year

Source: Aurora Energy Research

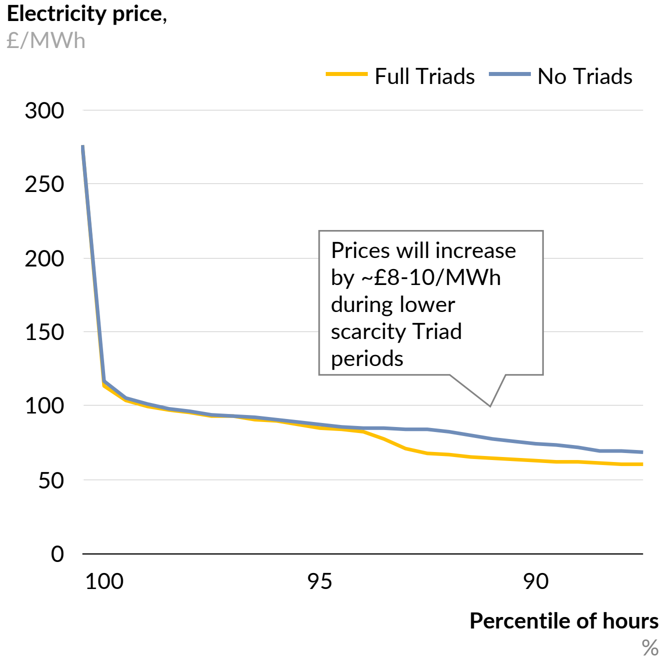
Exhibit 2

3) Electricity and balancing prices will increase; production will come via different routes

The removal of embedded benefits will alter the economics of dispatch during peak periods, exerting upward pressure on balancing and electricity prices. Under existing arrangements, in periods where embedded plants are "chasing Triads", their effective marginal cost of dispatch in the energy and balancing markets is zero. They act as "price takers", dispatching even when their variable costs would not have been covered by the market price. Where Triad warning periods do not correspond to the actual peaks, the embedded plant dispatches "out of merit" – i.e. pushing less expensive generators beyond the margin. This has a direct impact on reducing the price.

With the new arrangements, this dispatch distortion is removed. To incentivise the embedded peaking plant to generate during the peak periods, prices will have to increase at least to cover their marginal costs. As a result, embedded generators are expected to operate less, but when they do, they will capture higher prices in the electricity and balancing market. Exhibit 3 illustrates this phenomenon. Importantly, this shift will also benefit transmission-connected plant, including CCGT.

When Triads are reduced, additional value will accrue in the wholesale electricity market and Balancing Mechanism



- National Grid estimates ~7.5GW of embedded generation currently run at peak
- This 7.5GW of Triad-chasing embedded generation will still be required during periods of peak winter demand
- Prices will rise in the wholesale electricity market and Balancing Mechanism to reflect increased demand

Source: Aurora Energy Research

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Exhibit 3

Additionally, as the incentive to dispatch during peak periods is lower without the Triad payments, this may increase the National Grid's incentive to procure additional back-up generation under STOR contracts. This could be an additional route for existing embedded generators to recoup some of the value lost with the removal of Triads.

4) Other considerations: investor confidence will suffer; transmission charging economics still far from solved

An important, albeit less quantifiable impact of Ofgem's review pertains to the investment environment. Ofgem's drastic reform to Triad payments follows a previous review by the National Grid concluded in 2014, which did not result in any changes to embedded benefits[6]. The fact that the regulator decided to launch another review only two years later, and arrived at a radically different decision, could have potentially deleterious long-term consequences to confidence of investors in the GB power market. This in turn can increase the cost of capital and investment.

The period of increased regulatory volatility is likely to last, with a Targeted Charging Review expected to be launched in H1 2017. At least until the conclusion of that review, any inclusion of costs or benefits stemming from transmission charging arrangements in valuation or business planning will by necessity only be provisional. The cost of this uncertainty will be ultimately borne by the consumer.

[6] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

CONTACT DETAILS

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