CRA Insights:
Energy

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Why is the missing money still missing?

Lessons from the US for the GB Capacity Market

Introduction

The GB Capacity Market was developed with the expectation that it would help to fill the looming capacity gap by contributing to the funding of substantial investments in new combined or open cycle gas turbine capacity. But after two Capacity Market auctions, no new large-scale capacity has been successful in gaining a capacity agreement.[1] Instead, the mechanism has been a catalyst for hundreds of MWs of small-scale, diesel- and gas-fired distributed generation capacity which benefits not just from funding from the Capacity Market but also from favourable transmission charging arrangements.

This has shifted the focus of policymakers to the transmission charging arrangements in GB. While such a review is necessary, it may still not be sufficient to bring new large-scale generation online. Experience from the US markets shows that still more may be required to find the “missing money”.

Distributed generation and GB’s discriminatory incentive mechanisms

In an effort to ensure that small-scale distributed generation is not over-compensated, policymakers have recently focused on the “embedded benefits” that accrue to small-scale generation connected to the distribution network. Table 1 summarises the extent of the potential distortion created by the current GB charging arrangements for two illustrative units in the same zone. One is a small-scale, distribution-connected generator, while the other is a large-scale, transmission-connected Open Cycle Gas Turbine (OCGT). Our analysis indicates that embedded benefits can add up to around £55/kW-year.[2] This means that small-scale peaking distributed generation with slightly lower capital costs than large-scale OCGTs can bid in significantly lower prices in the Capacity Market, undercutting other forms of

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1 Trafford Power, a 1.6 GW CCGT received a 15-year contract in the 2014 T-4 auction, but has failed to reach financial close since then. Carrington, a new CCGT under construction since 2013, received a 1-year contract in the 2015 T-4 auction.

2 This is based on a representative region in the GB market. While the residual benefit of TNUoS is non-location specific and represents the majority of the benefit, locational elements do vary across the GB market. This analysis assumes that the embedded generator captures all triads and that all the embedded benefits are accrued by the generator. In reality, some sharing of these benefits may occur with either suppliers or aggregators.

generation. Further, the magnitude of this benefit suggests that even more distributed generation has not been developed due to factors such as permitting and siting challenges.

Table 1: Transmission and system-related charges and benefits for distribution-connected and transmission-connected generation

		Unit	Distribution -Connected	Transmission -Connected
Assumptions	Capacity	kW	1,000	1,000
	Annual Load Factor	%	10%	10%
	CAPEX	£/kW	£302.7	£339.9
	FOM	£/kW-Year	£5.3	£10.5
	Levelised Cost	£/kW-Year	£36.0	£50.3
Transmission and balancing costs	Transmission Losses, TNUoS and BSUoS	£000		£5.1
Distribution benefits	Distribution Losses and DUoS	£000	Up to -£7.2	
Transmission benefits	Transmission Losses, TNUoS, BSUoS	£000	Up to -£47.3	
Total transmission and distribution costs (incl. embedded benefits)		£000	Up to -£54.5	£5.1
Revenues Needed from the Energy and Capacity Market - with 50% of embedded benefits		**£/kW-Year**	**£8.75**	**£55.4**
Revenues Needed from the Energy and Capacity Market - without embedded benefits		**£/kW-Year**	**£36.0**	**£55.4**

Source: CRA analysis

In an effort to ensure that small-scale distributed generation is not over-compensated, renewed attention has been given to three main areas:

- Legislation that would set binding emission limits values on relevant air pollutants from diesel engines;
- Re-assessment of the charging arrangements for distribution-connected generators and suppliers, including Transmission Network Use of System (TNUoS) charges, which represent the largest source of embedded benefit;
- Review of the interaction of the Capacity Market with the Enterprise Investment Scheme (EIS) and the Venture Capital Trust Scheme (VCT).

Given the potential scale of distortion to the Capacity Market created by embedded benefits, the priority for the Office of Gas and Electricity Markets (Ofgem) will be to limit the ability of distributed generation to benefit from both Capacity Market revenues and triad avoidance payments (TNUoS charges). Such a change would either significantly reduce the participation of distributed generation in the Capacity Market, or increase its need for higher Capacity Market revenues in order to maintain the same target internal rate of return (IRR). However, it should also be clear from the comparative cost analysis presented above, that removing these benefits by itself may not be sufficient to lead the Capacity Market to clear at a price level sufficient to support new OCGTs or CCGTs.

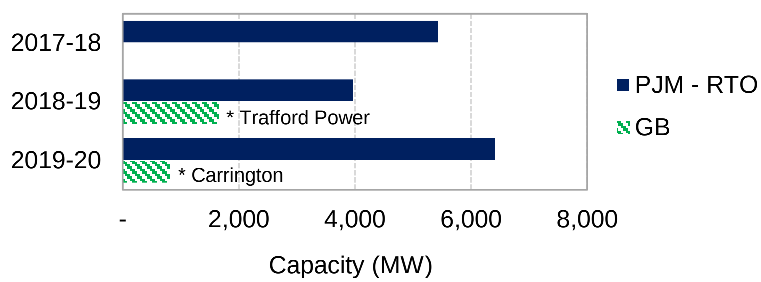
The Government has determined that 52 GW of capacity will be procured in the next Capacity Market auction for delivery in 2020/2021. This represents a 7 GW increase from the last auction. In light of recent coal retirements, this means that (for the first time since the market's inception) the capacity requirement exceeds the amount of operational capacity and therefore requires new build capacity to clear. This will also help to raise clearing prices, but if capital cost differences favour peaking plant, how can new CCGTs be incentivised? The results from recent US capacity market auctions provide some insights.

Why are the US capacity markets delivering CCGTs?

The last two PJM[3] capacity auctions have cleared over 10 GW of new gas-fired capacity at RTO-wide[4] prices of only around 33% of Net Cost of New Entry (CONE).

By contrast, in GB, while the auction cleared at 37% of Net CONE, only one new CCGT cleared the auction in 2018–2019 and it has not yet achieved financial close. The CCGT that cleared the 2019–2020 auction was Carrington, which has been under construction since 2013.

Figure 1: New generation cleared in capacity market auctions



Source: CRA analysis

Why, then, can the PJM market incentivise new build CCGT while the GB market has so far failed?

There are important differences in the detailed design of both mechanisms, with some having a significant impact on capacity prices:

- The capacity requirements in GB tolerate tighter margins than system operators in the US, which target reserve margins of around 15%
- Gross CONE is estimated at higher levels in the US, with much lower revenues attributed to energy and ancillary services revenues to calculate Net CONE
- US capacity markets include locational price differences aimed at targeting capacity investment in congested areas

3 PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

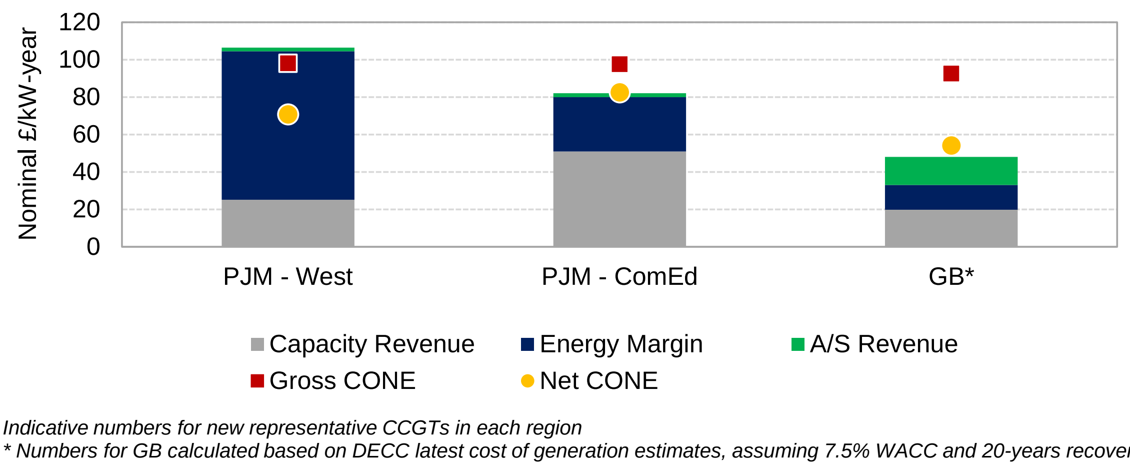
4 In the context of the recently cleared PJM auction, the RTO-wide price refers to the clearing price across the whole region, before any locational adders.

These differences are discussed in more detail in CRA's presentation, ***What next for the GB Capacity Market?***[5]

The role of the energy market

While there are important differences in the detailed design of the PJM and GB capacity markets, a key driver for new build in PJM has been energy revenues. Importantly, there is no missing money in large areas of the PJM market (see PJM-West in Figure 2). The low gas price environment in PJM-West continues to lead to the displacement of coal-fired generation (of which there is a lot in PJM) to the benefit of baseload and mid-merit CCGTs. This means that coal-fired generation is setting the price during a growing number of hours. As a result, new CCGTs with access to low cost natural gas from the Marcellus and Utica production regions, can expect to achieve annual load factors of around 90% and cover over 100% of the administered net CONE with energy margins. Therefore, new CCGTs in PJM-West are bidding in as price takers in the capacity market, with auction prices set by existing generation.

Figure 2: CONE and revenues comparison between PJM and GB



Source: CRA analysis

Congestion in regions like PJM-ComEd has resulted in higher capacity prices (set by existing generation) than PJM-West, but has not attracted any new build in the last couple of auctions. This is consistent with revenues falling short of the estimated gross CONE for the region (See PJM-ComEd in Figure 2).

The energy market dynamics in GB are distinctly different. While CCGTs are also increasingly displacing coal in the market, higher gas prices and high CO_2 emission compliance costs result in much lower energy margins. Our analysis indicates that while some CCGTs may be able to achieve load factors of between 40% and 60% around 2020 as more coal retires, under current forward curves, energy margins are only expected to cover around 20-30% of the Government's administered Net

5 http://www.crai.com/publication/what-next-gb-capacity-market.

CONE of £49/kW-year. It must be noted that this is in relation to a Net CONE estimate that is much lower than those for the PJM market. Even assuming revenues from the balancing market grow over the next few years, our analysis shows that new large-scale generation is unlikely to be investible below a capacity clearing price of around £35 to £40/kW-year. Whether CCGTs get built at this level depends on how high generators believe energy prices will go into the mid to late 2020's.

Experience from more mature capacity markets in the US consistently indicates that CCGT development follows from the combination of strong energy market fundamentals and clear capacity remuneration mechanisms. In other words, not surprisingly, capacity markets will tend to deliver low capital cost (and low load factor) capacity where energy market margins are depressed.

What next?

Higher demand and higher Capacity Market revenue requirements from distributed generation are likely to result in higher capacity clearing prices for the T-4 2020/2021 auction later this year. But clearing prices may still be insufficient to incentivise substantial mid-merit generation. This means that – absent further Capacity Market reforms – as capacity margins tighten, plant with high operating costs will be setting energy market prices a growing number of hours. Such electricity price increases have customarily tried the tolerance of policymakers but would, in time, support new CCGTs.

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