Electricity-Grid Transition in the U.K.

As Coal-Fired Generation Recedes, Renewables and Reliable Generation Can Fill the Gap

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Executive Summary

This report presents a detailed recent snapshot of the U.K. electricity market.

It specifically assesses the performance of this market, four years after reforms were implemented that were intended to increase the cost-effectiveness of new-build renewable power and bolster grid security by incentivising reliable new generation.

The hope at the time of the reforms was that the introduction of capacity markets — mechanisms by which standby power is subsidized — would prepare the U.K. adequately for a modernized energy security. So far, the effort has done little more than support the status quo.

Main Findings

- **The U.K. electric grid is coping successfully with a coal phase-out which is well under way and that is scheduled for completion by 2025.** Last year, U.K. coal generation declined by 60%. The grid was resilient. National Grid, the transmission system operator, took no demand control action, issued only a handful of emergency margin alerts, and had no need for "last resort" standby power plants.

- **Grid security would be bolstered enormously if U.K. markets were to deliver on a large pipeline of renewable energy and interconnection projects.** IEEFA sees renewable energy and interconnection forming the backbone of the U.K. grid in the medium and long term. We estimate that the combined total of renewable and interconnection projects in the immediate pipeline or targeted will deliver more than 80 terawatt hours (TWh) of generation annually by 2025. For comparison, this amount exceeds the U.K.'s total nuclear generation today. Gains in demand reduction and efficiency would further enhance grid security.

- **Tight margins in supply and demand show that new reliable peaking generation is also needed, and it is far from certain that current capacity markets will provide it.** While the goal of the capacity market was to drive investment in reliable new generation, the scheme—with £3.4 billion in awarded contracts to date—has yet to incentivise a single large new power plant. This support for existing generation is distorting energy markets and has subsidized outdated investment, including more than £450 million for existing coal-fired power plants. Smaller, targeted capacity auctions solely for flexible, new-build generation, including gas peakers, demand-side response (DSR) and storage, should reduce this distortion. It should also reduce energy consumer bills.

- **Brexit offers an opportunity to reform the market again — and with better results.** The U.K.'s departure from the European Union may eliminate the need for EU approvals for auctions that support certain technologies, such as battery storage, and for policies that eliminate aging forms of technology, such as coal-fired generation.

- **Efficient energy-only markets—as opposed to subsidized capacity markets— still have a place.** This has been demonstrated in the U.S., where some electricity systems are delivering a rapid, low-carbon transition without the need for capacity markets. These competitive markets are successfully managing the transition from coal to renewables, while the number of scarcity hours has decreased dramatically.

- **Concrete reforms in the U.K. balancing market would bolster energy markets by strengthening the price signals that drive investment.** Such reforms could drive market participants to invest in flexibility themselves — a more efficient approach —and thus help avoid the large-scale government intervention implied in the capacity market. Other balancing-market reforms could include shortened settlement periods, from 30 minutes to 15 minutes, following a trend already established in continental Europe.

Introduction

This Report:

This report is organised as follows:

- Section 1 offers background context.
- Section 2 investigates the resilience of the U.K. electricity grid in 2016 following a 60% decline in coal-fired generation.
- Section 3 reviews the U.K. pipeline for new renewables generation, interconnectors and expectations for energy demand.
- Section 4 examines the performance of the U.K. capacity market to date.
- Section 5 reflects on whether electricity can be delivered effectively through energy markets, drawing on market examples in the U.S. and potential reforms in the U.K. balancing market.
- Section 6 offers a brief concluding discussion.

Electricity Market Reform: Background

Four years ago, the U.K. government's energy department introduced electricity market reforms intended to drive some £100 billion of new private sector investment in U.K. electricity infrastructure. The goal was to accommodate projected increases in electricity demand, and to replace aging power plants.

These reforms had two components: 1) an auction-led mechanism meant to increase the cost-effectiveness of new renewable energy delivery and 2) a capacity market apparatus geared to drive investment in new build, non-renewable generation.

This report focuses on the capacity market side of these reforms.

Under the current setup, the delivery body, transmission system operator National Grid, conducts capacity market auctions for generating capacity both one year and four years ahead of actual delivery. The auctions are restricted to conventional generation — including gas, coal, nuclear and hydropower — as well as storage, DSR and interconnection. Under this system, participants are paid simply to be on the grid and ready either to dispatch electricity or to reduce demand. They are not paid for actual generation. Capacity contracts are denominated in pounds per kilowatt of capacity per year, and they provide utilities with a source of ratepayer subsidized revenue on top of what regular, competitive energy markets pay.

This new capacity market was supposed to help the U.K. cope with narrowing capacity margins, defined as the surplus of supply over demand, and to help the grid integrate growth in variable renewables (wind and solar). The capacity market was also intended to provide guaranteed revenue to generators, to ensure that new power plants were built, even in the face of declining competitiveness, and to maintain sufficient flexible back-up for when variable wind and solar power were unavailable.

Various arguments were used to support the capacity market:

1. That it would rectify recent utility failure to contract new investment in gas generation, a failure attributed partly to the growth of renewables.
2. That it would address the "missing money" problem that can prevent operators of conventional power plants from recovering their fixed costs in a grid with high renewables penetration (with shorter running times, conventional power plants require higher and higher wholesale power prices when they do run).
3. That the cost of the capacity market is good value as insurance against power cuts, compared with the cost of actual loss of load.
4. That energy markets are broken or no longer reliable, and that markets in capacity — instead of electricity — and/or government intervention are the way forward.

There are arguments aplenty *against* capacity markets, however, and in favor of the possibility that regular energy markets can function quite well with high levels of renewables.

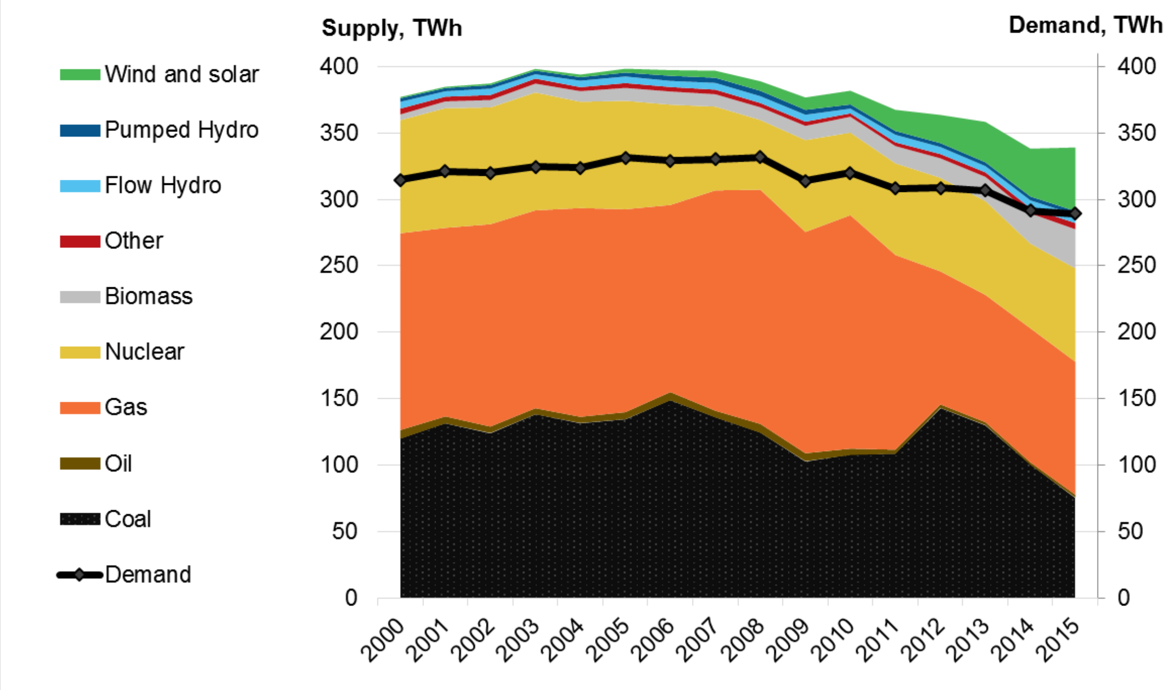
1. A non-traditional approach can be used to balance supply and demand. This alternative includes expanding the contribution to grid balancing of intermittent renewables themselves. This is an increasingly viable path as forecasting accuracy improves, load factors rise and battery storage allows renewables to better respond to energy market price signals.
2. Growth in U.K. demand-side response, electricity storage and cross-border interconnection will smooth variation in demand and supply.
3. The trend toward less energy demand across the U.K. is likely to lower the vulnerabilities associated with conventional capacity retirement, and make capacity markets less needed.
4. The "missing money" problem can be addressed through various market design reforms.

U.K. Grid Resilience: Functioning with Less Dependence on Coal

Evolving Power Supply and Demand Through 2015

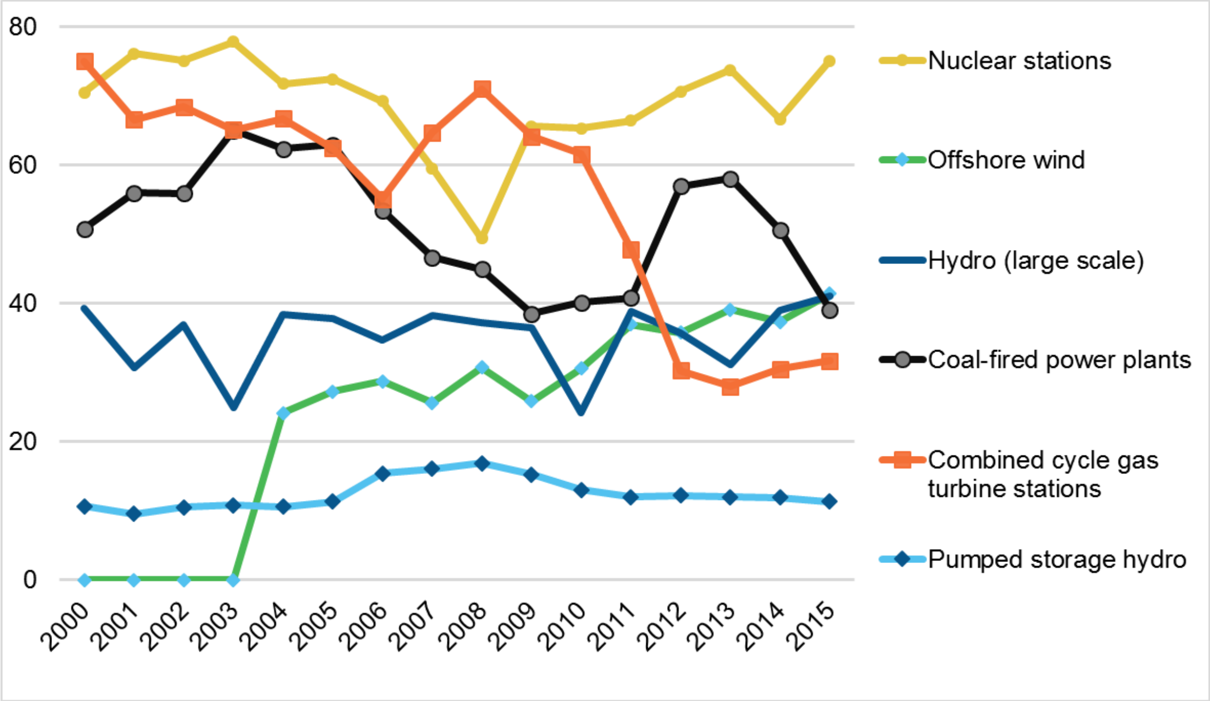
Figure 1 below shows the recent evolution of Britain's electricity supply and demand. It shows how a drop in combined gas and coal generation from 2010 to 2015 (down 108TWh) was balanced by a combination of falling demand (down 31TWh), plus growth in variable renewables (up 38TWh) and biomass (up 17TWh).

Figure 1. Evolution of U.K. Generation and Demand, 2000-2015 (TWh)



The drop in conventional gas and coal generation shows how the economics of these power plants have suffered in recent years, largely as a result of lower running times. Load factor is defined as the actual generation of a power plant as a percentage of its theoretical maximum, based on available capacity. Higher load factors are critical for profitability, even if power plants are generating positive cash flows. Gas power plant load factors reached a record low 28% in 2013 (see Figure 2 below) and subsequently fell below those of offshore wind. Preliminary data indicates a sharp upswing in gas load factors, following higher power prices and more coal power plant closures in the second half of 2016.

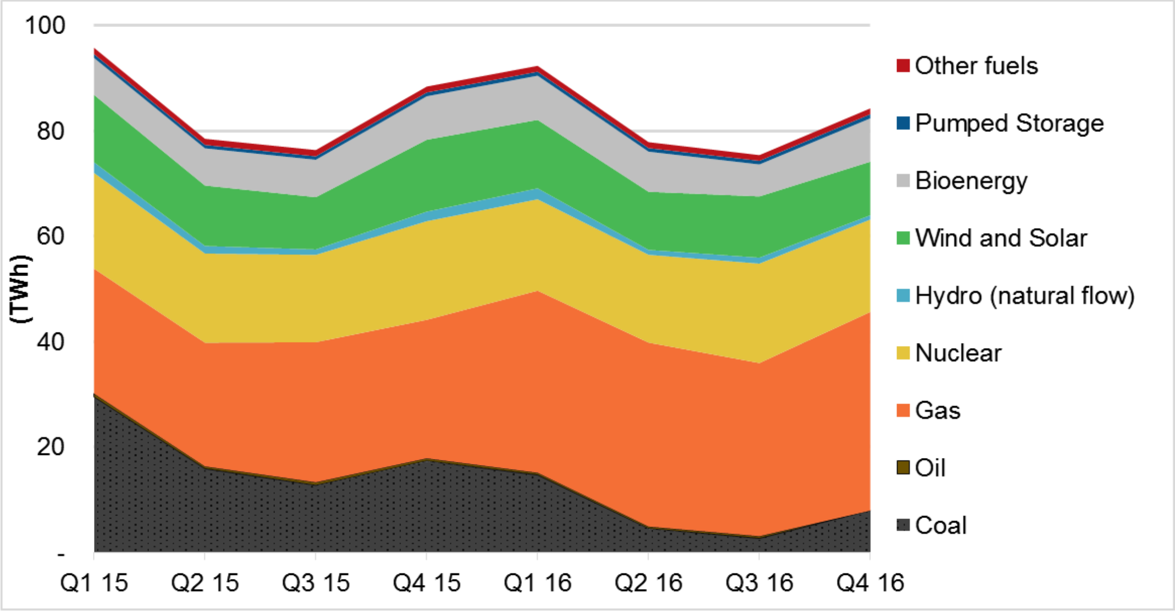
Figure 2. Load Factors of Power Sources Participating in Capacity Markets, plus Offshore Wind Generation, 2000-2015 (%)



Coal Decline in 2016

Preliminary data shows that coal generation in the U.K. declined by about 60% in 2016 (see Figure 3 below). This decline can be attributed to the closure of about one-fifth of all coal capacity and by the persistence of low load factors at the remaining coal-fired plants. At its lowest point in the third quarter, coal generation fell to just 2.7TWh or 4% of total generation, implying a load factor of below 9%. Most of coal's year-on-year decline in 2016 (46TWh) was met by an increase in gas (40TWh). Even in 2016, however, gas generation was operating at only about a 50% load factor, hinting that there is ample U.K. capacity to handle a complete phase-out of coal.

Figure 3. Quarterly U.K. Generation by Fuel Type, 2015-16 (TWh)



Can the U.K. Grid Function Without Coal?

How well did the U.K. grid function with the rapid decline in coal generation in 2016? In the following sections, we review various indicators that point to answers to this question. But first, a brief description of the delivery of electricity in the U.K.

Power market participants buy and sell electricity on wholesale markets across various timeframes, from the day of delivery to years ahead. On the day of delivery, the basic trading period for electricity is half an hour; each day is therefore divided into 48 settlement periods. For each half hour period, suppliers calculate the estimated electricity requirements for their customers and enter into contracts with generators to ensure customers receive the correct amount of electricity. Market participants can only trade up to one hour before each settlement period, at which point National Grid takes over, balancing demand and supply in real time.

In this balancing market, National Grid uses various tools to match actual demand and supply. In particular, it can invite offers to increase the supply of electricity if the system is short (when demand exceeds supply) or it can invite bids to reduce it (when supply exceeds demand). If the system is acutely short of electricity, National Grid can call up generation under various pre-arranged bilateral contracts with power plants held in reserve. In extreme cases, it can curb demand by forcibly reducing voltage levels or by load shedding (causing brownouts or blackouts).

Balancing Market Auctions

While coal generation declined sharply in U.K. wholesale markets last year, it remained a significant player in balancing market auctions.[1] In December, coal was responsible for only a fraction of total U.K. generation but accounted for 24% of accepted offers in balancing market auctions, while gas accounted for 69%. Coal accounted for 30% in November 2016 (gas 62%); 29% in October (gas 63%); and 27% in September (gas 67%). Such volumes reinforce that while the U.K. electricity grid will be able to function without coal, it is important that the ongoing transition is well managed and occurs gradually.

We note also that last year saw higher offer prices in the balancing market, showing that concerns for U.K. grid security are justified. National Grid subsidiary Elexon reports that higher priced offers were accepted during periods of scarcity last year, leading to a sharp rise in the cost of balancing the grid ("system prices") at these times. It says: "There were 751 Settlement Periods with prices over £100/MWh in 2015/16 compared to 48 in 2014/15. 2015/16 has also seen six System Prices over £1,000/MWh in November 2016. There were no prices over £1,000/MWh in the previous four years."[2]

De-rated Margins

De-rated margins (DRM) are the key metric by which National Grid estimates grid security. DRM measures the excess capacity above demand on the system, over various timescales, until one hour before delivery. The measure adjusts, or de-rates, power plant capacity according to likely availability. The lower the de-rated margin, the higher the loss of load probability, meaning the higher the chance that supply will fail to meet demand.

Figure 4 below shows daily minimum values for DRM as estimated one hour before delivery through last year and into early 2017. Continuous data only goes back one year, making meaningful comparisons difficult, given the seasonality of U.K. demand, which peaks in winter. We note that DRM fell to very low levels from mid-September through to the end of October, probably due to a combination of lower U.K. generation, including from coal, and lower cross-border interconnector flows that occurred as a result of French nuclear power plant closures. On October 31, 2016 (the first business day after the clocks went back), DRM was at its lowest level of the season, 387MW, and its highest loss-of-load probability, 29%. After that, Supplemental Balancing Reserve (SBR, see below) capacity kicked in, and margins remained at higher levels of around 2-6 GW throughout the winter. We note that in October of last year National Grid anticipated an average DRM of 3.6 GW through the 2016/17 winter, equivalent to a 6.6% margin, which it described as "tight but manageable."[3] The SBR was critical to achieving this.

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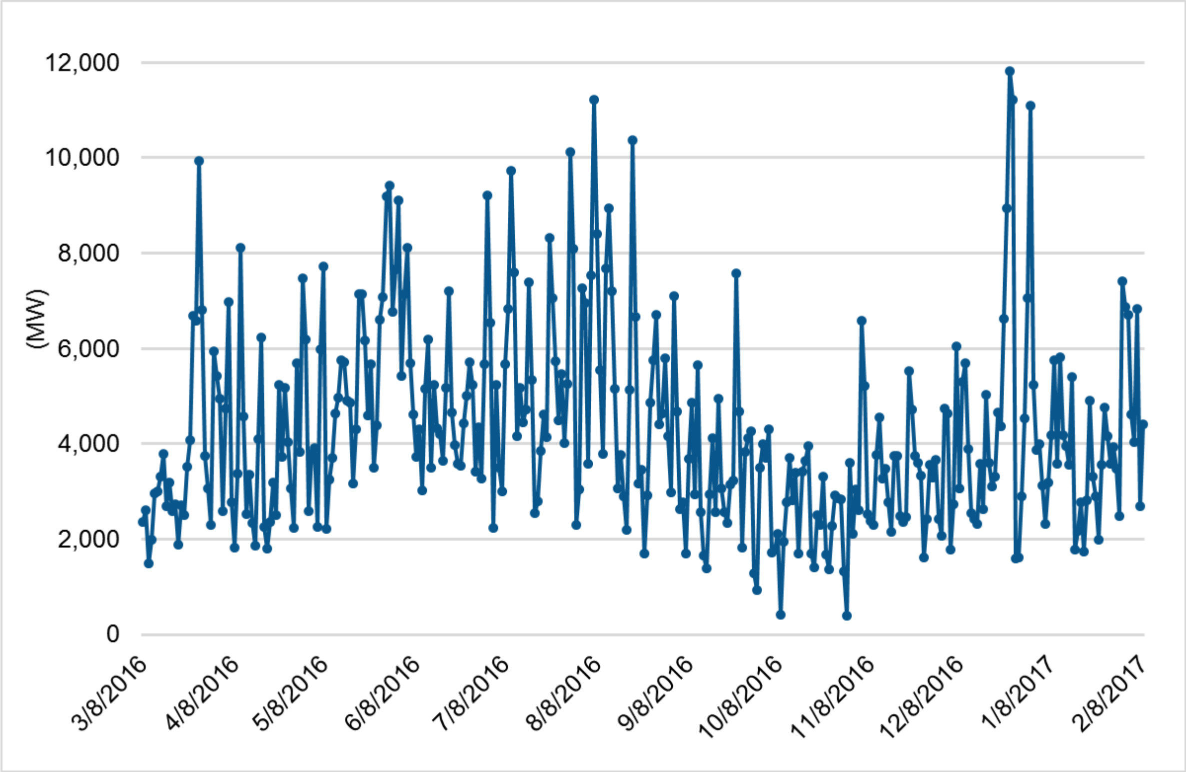
[1] https://www.elexon.co.uk/wp-content/uploads/2011/10/BSC-Ops-Headline-Report-reporting-on-November-and-December-2016.pdf
[2] https://www.elexon.co.uk/wp-content/uploads/2011/10/P305-Post-Implementation-Review-Summary-and-Key-Points.pdf
[3] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Aside from the scarcity events of September and October, on average the system last year was no more stressed than usual — even with its declining dependence on coal. Elexon reports that the balancing market was "long" (supply exceeded demand) more frequently in 2015/16 than in previous years: "The net imbalance on the system was long in 69% of Settlement Periods from December 2015 to November 2016, compared to 57% in the same period for the preceding year. In 2013/14, 65% of Settlement Periods were long." [4]

Figure 4. De-Rated Margins, One Hour Before Delivery, March 2016-Feb 2017 (MW)



[4] https://www.elexon.co.uk/wp-content/uploads/2011/10/P305-Post-Implementation-Review-Summary-and-Key-Points.pdf

Use of Reserve Capacity

In addition to tendering for regular generation, National Grid can call upon various reserve services in the balancing market:

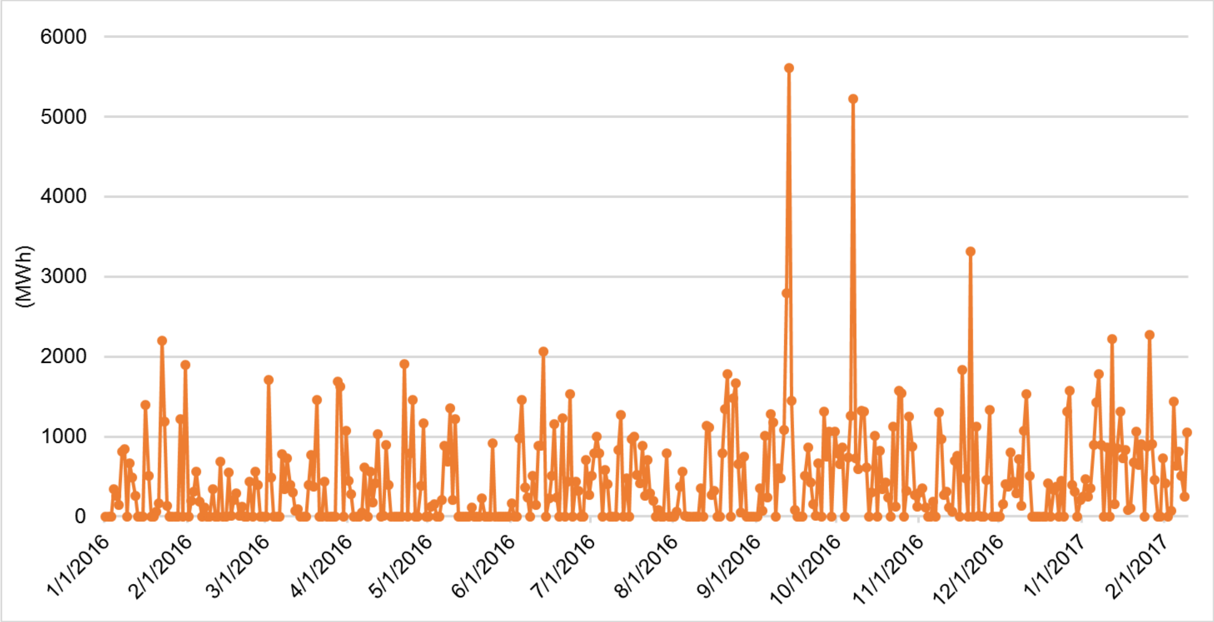
- The Supplemental Balancing Reserve (SBR) is held outside the regular electricity wholesale market and is intended as a supply of last resort. It subsidises the continued availability of generation which would otherwise be closed or mothballed.[5] SBR capacity is required to be available on non-holiday weekdays between 06:00 and 20:00 in the coldest months, from November 1 to February 28. National Grid contracted some 3.5GW of SBR in the winter of 2016/17.
- Demand-Side Balancing Reserve (DSBR) is a similar last resort measure, but is different in that it rewards demand reduction by non-domestic consumers. National Grid did not contract any DSBR in the winter of 2016/17.[6]
- The Short-Term Operating Reserve (STOR), which is used more routinely, is designed to give National Grid sufficient reserve to replace sudden generation losses or to respond to unpredictable changes in demand, at any time between four hours ahead and responding in real time. A large proportion of STOR units are required to be available within 20 minutes. National Grid tenders for generation or demand reduction under the STOR are presented in six auctions annually and aim for around 2,300MW of capacity availability at any given time. Actual use of the reserve depends on cost compared with other options such as bids and offers in National Grid's regular balancing market auctions.

Even with a steep decline in coal generation last year, National Grid contracted no DSBR and made no use of contracted SBR. National Grid's use of STOR outside the balancing market (the most readily available data) appeared normal, apart from two spikes on September13 and October 7 (see Figure 5 below). While it went unused, SBR was critical because its availability from November 1 explains higher capacity margins through the remainder of the winter (see Figure 4 above).

[5] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/Methodologies/

[6] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/DSBR-Tender-Documentation/

Figure 5. Total Daily STOR Used Outside the Balancing Market, Through 2016 and Early 2017 (MWh)



Emergency Grid Alerts

As we have seen, the purpose of the capacity market is to guarantee that capacity is ensured ahead of time, through forward auctions. Market participants are rewarded for committing to availability, if required, during extreme, highly unlikely system stress events. National Grid communicates if and when such stress events are considered a risk four hours ahead of real time through a Capacity Market Notice. Delivery under the 2016 capacity market began on October 1 2016, under the Transitional Auction for the 2016/17 winter (see below). To date, just two Capacity Market Notices have been issued (on November 7 and October 31 2016). Both were cancelled without a stress event or the required use of any capacity commitments.[7]

More generally, National Grid can alert the market to urgent imbalances through escalating warnings, from an Electricity Margin Notice, to a High Risk of Demand Reduction, and ultimately a Demand Control Imminent notice. Only one such notice — an Electricity Margin Notice — was issued last year, on May 9, balancing market data show.[8]

[7] https://gbcmn.nationalgrid.co.uk/

[8] https://www.elexonportal.co.uk/category/view/10701?cachebust=dfsx26u79f

Options to Replace Aging Conventional Generation

Under a coal phase-out already in progress, U.K. will see the retirement of its remaining 14GW of coal-fired generation by 2025. In addition, about 4GW of gas and nuclear will be retired (see Table 1 below). More gas and nuclear retirements will occur in the late 2020s and 2030s.

Table 1. Outlook for Existing U.K. Conventional Power Plants, 2016 - 2025*

	2016		2020		2025	
	MW	GWh	MW	GWh	MW	GWh
Coal	15,053	31,063	9,586	19,781	0	0
Gas	30,774	140,009	29,312	133,358	28,852	131,265
Nuclear	8,918	70,380	8,918	70,380	6,998	55,227

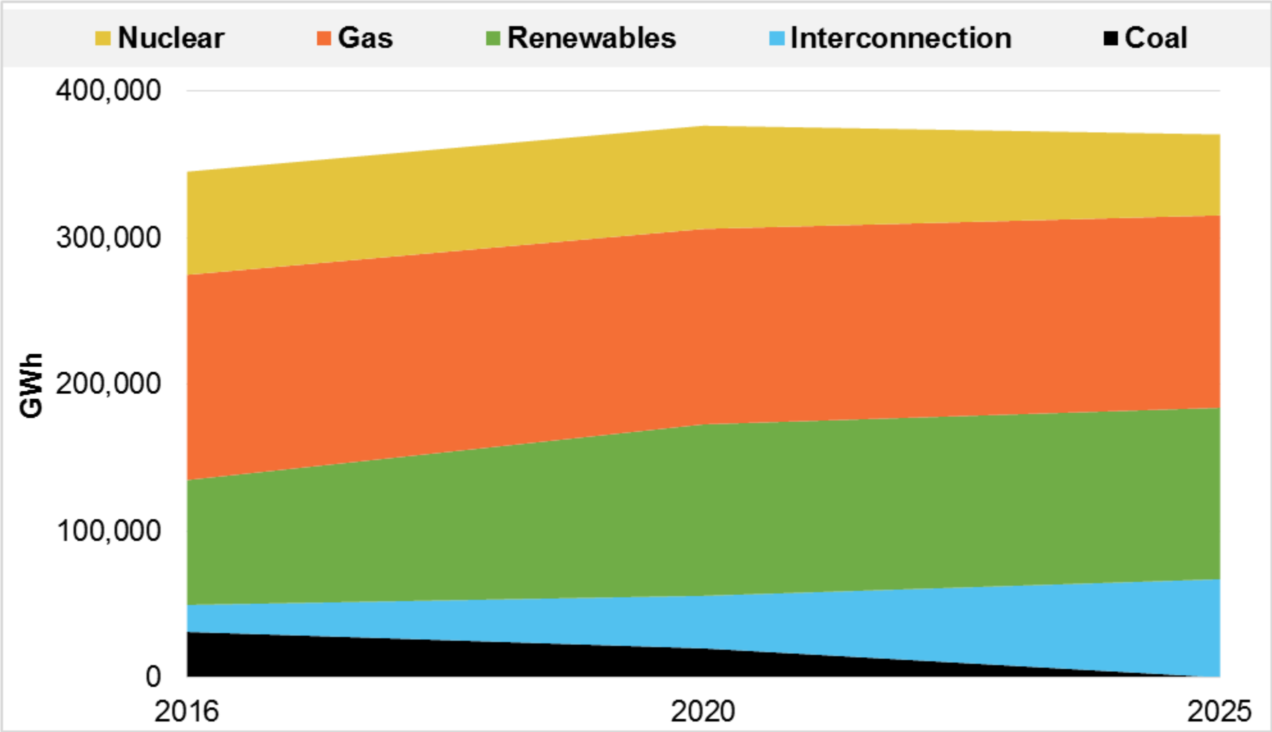
**We apply estimated 2016 load factors to calculate future generation.*

The previous section presented evidence that the U.K. grid effectively managed a rapid decline in coal generation in 2016. But how will it handle the final phase-out of coal in run-up to 2025, in addition to retirements of aging gas and nuclear plants in the medium term?

To begin to answer that question, we turn to the opportunities for various technologies to step up. In this section, we focus on alternatives to new gas generation, namely renewables, interconnection and efficiency investment. The following section discusses new gas generation.

Figure 6 compares the potential growth in renewables and interconnection with projected declines in gas, coal and nuclear in the years to 2025. This outlook is based on the highly conservative assumption that there is no growth in renewables after 2020, given a lack of firm targets for this period, despite continuing, rapid cost reductions. The reality is that renewables will certainly continue to grow. The estimate for interconnection growth is based on an existing pipeline of announced projects. Figure 6 does not account for expected demand reduction, which would further ease grid pressure caused by conventional power retirement. It indicates that the U.K. already has a strong pipeline of new electricity supply, implying that the country's greatest need may be for new flexible backup of variable renewables, rather than substantial new baseload of the sort that would be supplied by new gas and nuclear, for example. The following sections provide more detail behind these estimates.

Figure 6. Growth in U.K. Renewables and Interconnection Versus Retirement of Conventional Generation



Source: IEEFA estimates

Growth in Renewables

Table 2 compares current renewable power generating capacity with the U.K.'s 2020 targets under its National Renewable Energy Action Plan.[9] It shows the potential for high growth in renewables capacity and generation. In total, the targets imply an additional 32TWh of renewable power by 2020, equivalent to nearly half of all nuclear generation in 2016, and more than all coal generation. The negative "gap to 2020" for solar power indicates that the UK has massively over-achieved its 2020 target already for this technology, in part reflecting unexpectedly rapid cost reductions.

[9] https://www.iea.org/media/pams/uk/PAMs_UK_NREAP.pdf

Table 2. Potential Growth in U.K. Renewable Energy Through 2020

	UK 2016 estimated		UK 2020 target		Gap to 2020	
	MW	GWh	MW	GWh	MW	GWh
Hydro	1,797	6,001	2,130	6,360	333	359
Geothermal	0	0	0	0	0	0
Solar	10,944	9,662	2,680	2,240	-8,264	-7,422
Marine	8	0	1,300	3,950	1,292	3,950
Onshore wind	9,814	22,699	14,890	34,150	5,076	11,451
Offshore wind	5,094	17,625	12,990	44,120	7,897	26,495
Biomass	2,781	19,354	3,140	20,590	359	1,236
Other bioenergy	2,710	9,875	1,100	5,570	-1,610	-4,305
TOTAL	**33,148**	**85,215**	**38,230**	**116,980**	**5,082**	**31,765**

Growth in Interconnection

The U.K. is currently encouraging new investment in interconnectors - sub-sea cables linking its grid to neighbouring countries. Such investment is overdue, given present interconnection stands at 4GW, or 5% of existing generating capacity; just half the 10% benchmark proposed by the European Commission. Interconnection can smooth variability in wind power by reaching into wider weather systems, and it can diversify generation. For example, the U.K. can tap hydropower in Norway, where peak supply matches U.K. peak demand in winter, various generation technologies elsewhere in continental Western Europe and wind power in Ireland. In the U.K., interconnection can also help the U.K. access cheap imports. National Grid estimates that doubling U.K. interconnection capacity would lead to consumer savings of £1 billion annually as a result of cheaper electricity imports.[10]

Table 3 calculates potential electricity imports through interconnectors, based on expected capacity and de-rating factors supplied by the energy watchdog Ofgem.[11] The table suggests a potential additional supply of 49TWh by 2025, if all projects proceed. This would be equivalent to more than a third of U.K. gas generation in 2016.

[10] http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/
[11] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

Table 3. Potential Growth in UK Electricity Flows Through Interconnectors

Country link	Name	De-rating factor	Start date	2016		2020		2025	
				MW	GWh	MW	GWh	MW	GWh
France	IFA	55%	1986	2,000	9,636	2,000	9,636	2,000	9,636
Nthn Ireland	Moyle	25%	2002	500	1,095	500	1,095	500	1,095
Netherlands	BritNed	75%	2011	1,000	6,570	1,000	6,570	1,000	6,570
Ireland	East West	25%	2012	500	1,095	500	1,095	500	1,095
France	ElecLink	65%	2019	0	0	1,000	5,694	1,000	5,694
Belgium	Nemo Link	65%	2019	0	0	1,000	5,694	1,000	5,694
France	IFA2	70%	2020	0	0	1,000	6,132	1,000	6,132
Norway	NSL	85%	2021	0	0	0	0	1,400	10,424
Ireland	Green Link	80%	2021	0	0	0	0	500	3,504
France	FAB Link	70%	2022	0	0	0	0	1,400	8,585
Denmark	Viking Link	70%	2022	0	0	0	0	1,400	8,585
Iceland	Ice Link	N/A	2027	0	0	0	0	0	0
TOTAL				4,000	18,396	7,000	35,916	11,700	67,014

Source: IEEFA estimates

The Potential for Demand Reduction

IEEFA expects continuing but moderating declines in U.K. electricity demand in the years to 2025. Electricity sales could decline by as much as 50 TWh annually by 2025 compared with 2015 levels. U.K. electricity sales peaked before the global financial crisis, and since 2015 have fallen at an annual rate of 1.9%.[12] Extrapolating this rate forward, electricity sales would fall by a further 51TWh annually between now and 2025.

The U.K.'s energy department recently forecast unchanged electricity demand up to 2025.[13] But the government's statutory advisor on climate change, the Committee on Climate Change, has used alternative modelling to project an annual reduction in electricity supply of about 10%, or 40 TWh, by 2025, before steady rises from 2030, reflecting growth in electric vehicles.[14] Many analysts, think-tanks and environmental groups have urged greater investment in energy efficiency as the best way to achieve affordability and security of supply while driving carbon emissions reductions. Last year Greenpeace estimated that a nationwide switch to LED lightbulbs could reduce peak winter demand by up to 15%.[15] Switching households alone to LEDs would reduce peak demand by 5%.

[12] https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
[13] https://www.gov.uk/government/collections/energy-and-emissions-projections
[14] https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/
[15] http://www.greenpeace.org.uk/sites/files/gpuk/Keeping-the-lights-on-LEDs-report-cover.pdf

U.K. Capacity Markets Have Failed to Deliver

In the previous section, we reviewed the potential for new renewable power and interconnection to replace aging gas, coal and nuclear. We showed that there is a potential pipeline of about 80TWh of additional electricity supply.

However, renewable power is variable, and interconnection can be a double-edged sword, with the potential for promoting electricity exports as well as imports, depending on price signals. Neither is "reliable" capacity in the sense of being available on demand. In the second half of 2016, for example, the U.K.-France interconnector saw dramatically reduced U.K. imports in the wake of French nuclear outages and higher French wholesale power prices, plus damage to the interconnector itself. We note nonetheless that actual net U.K. imports through the interconnector last year were still in line with its capacity and Ofgem de-rating factors.

Given the "tight but manageable" reserve margins mentioned in Section 2, the U.K. needs additional investment in new-build, flexible generation, including in gas peakers (open-cycle gas turbine, or OCGT, quick-response gas generation) and perhaps new combined cycle gas turbine (CCGT, mid-merit gas generation) power plants.

The government recently estimated that a CCGT power plant built in 2020 would cost £66/MWh of electricity generated, rising to £100/MWh for plants built in 2030.[16] These estimates assume a very bullish 93% load factor. Given recent wholesale power prices of around £40/MWh, and actual load factors of 30-50%, we can see how new CCGT power plants will struggle to make money. We note that individual power plants are part of a utility's portfolio of different technologies and vintages, and we know that older, fully depreciated power plants can help finance newer ones over multiple economic cycles. However, it is unclear as to whether the market can provide new-build gas generation. This is where the capacity market was intended to step in — by providing an additional investment incentive through ratepayer-funded capacity payments. In the following sections, we review the performance of this capacity market.

[16]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

Capacity Market Auctions to Date

Four-Year Auctions

The National Grid has held three main U.K. auctions to date for delivery four years ahead (see Table 4). The T-4 auctions have allocated some £3 billion, or about £1 billion annually, mostly to existing generation units, and predominantly to gas, coal and nuclear. Table 4 shows how the auctions have failed to contract significant new capacity: some 80% of capacity payments have been allocated to existing generation. Table 4 shows that the top three participating technologies for delivery from 2018-2020 were CCGT, nuclear and coal/ biomass.

Table 4. T4 Auction Payments, by Status (New Versus Existing Units) & Technology for Delivery 2018-2020*

Auction year	2014	2015	2016			
Delivery year	2018/19	2019/20	2020/21			
Clearing price, £/ kW/ year	19.4	18	22.5	Cumulative		
Power plant status	**£m**	**£m**	**£m**	**£m**	**GW**	**%**
Existing generation	610.1	756.3	1,000.4	2,366.8	117.9	79.70%
Pre-refurbishment	136.8	1.5	3.9	142.2	7.3	5.68%
New build generation	154.6	0.0	14.0	168.6	8.6	5.47%
Refurbishing	50.8	34.8	76.8	162.5	8.0	4.79%
Existing interconnection	3.2	8.1	30.8	42.0	2.0	2.90%
Unproven DSR	0.1	0.1	1.0	1.3	0.1	1.42%
Proven DSR	0.0	0.0	0.0	0.0	0.0	0.04%
New build interconnection	0.0	33.5	52.7	86.2	4.2	0.00%
TOTAL	**955.6**	**834.4**	**1,179.6**	**2,969.5**	**148.0**	**100.00%**
Energy technology	**£m**	**£m**	**£m**	**£m**	**GW**	**%**
CCGT	431.8	392.6	508.4	1,332.8	66.7	44.88%
Nuclear	82.2	75.7	99.2	257.0	12.8	15.71%
Coal	179.1	84.3	137.0	400.4	20.0	13.48%
CHP & autogeneration	3.4	8.6	31.7	43.7	2.1	8.66%
Storage	13.2	12.5	16.0	41.7	2.1	5.78%
OCGT and reciprocating engines	152.8	136.4	177.3	466.4	23.3	5.72%
Interconnection	40.8	43.7	85.2	169.7	8.3	2.90%
DSR	52.4	47.1	72.0	171.5	8.5	1.47%
Hydro	0.0	33.5	52.7	86.2	4.2	1.41%
TOTAL	**955.6**	**834.4**	**1,179.6**	**2,969.6**	**148.0**	**100.00%**

**Does not account for generation subsequently withdrawn from the capacity market.*

One-Year Auctions

In February 2017, the U.K. concluded its first year-ahead auction, for delivery from October 2017. Such year-ahead auctions are intended to fine-tune the capacity contracted under T4 auctions as capacity needs become clearer. Given there was no corresponding T4 for 2017/18, this T1 (or "early capacity auction") was much bigger, in fact the largest to date, contracting some 54.4GW of capacity. Table 5 tells a similar story for previous T4 auctions, with existing generation dominating successful contracts, in particular existing gas, coal and nuclear.

Table 5. Successful Contracts Awarded in 2017 T1 Auction, for Delivery

Auction year	2017		
Delivery year	2017/18		
Clearing price, £/ kW/ year	6.95		
STATUS	**£m**	**MW**	**%**
Existing generation	348.390	50,128	92.09%
Existing interconnection	16.416	2,362	4.34%
New build generation	12.051	1,734	3.19%
Unproven DSR	1.154	166	0.30%
Proven DSR	0.299	43	0.08%
Refurbishing	0.000	0	0.00%
Pre-refurbishment	0.000	0	0.00%
New build interconnection	0.000	0	0.00%
Total	**378.309**	**54,433**	**100.00%**
TECHNOLOGY	**£m**	**MW**	**%**
CCGT	153.331	22,062	40.53%
Coal	72.836	10,480	19.25%
Nuclear	54.752	7,878	14.47%
CHP & autogeneration	31.998	4,604	8.46%
Storage	18.835	2,710	4.98%
Interconnection	16.416	2,362	4.34%
OCGT/ engines (gas)	15.318	2,204	4.05%
OCGT/ engines (diesel)	5.484	789	1.45%
Hydro	4.719	679	1.25%
OCGT/ engines (other)	3.044	438	0.80%
DSR	1.453	209	0.38%
Oil-fired steam generators	0.118	17	0.03%
Total	**378.302**	**54,432**	**100.00%**

Technology-Specific Auctions

As well as holding technology-neutral auctions for reliable, non-renewable generation (renewables are supported separately), the UK has also held one so-called "transitional arrangement" (TA) auction. This auction was intended to boost demand-side response (DSR), or the reduction of electricity demand below a certain baseline by consumers, at times of peak demand when the grid is stressed.[17] The auction was held in January 2016, for delivery one year ahead, in 2016/17. A second TA auction is due in March 2017. The first auction contracted 802MW of capacity at a cost of £27.50 per kilowatt per year, including some 475MW of DSR. It also supported small-scale, distributed generation, which allows consumers to reduce demand by using alternative, on-site sources of electricity, including combined heat and power (CHP), open cycle gas turbines (OCGT), diesel engines and oil-fired generators.

Failure to Drive New Investment

The main goal of the U.K.'s capacity market was to incentivise new generation in order to address the grid security issues raised by narrowing capacity margins, increased reliance on intermittent renewable generation, and poor economics of existing conventional generation. In the three T4 and one T1 auctions to date, the overwhelming majority — more than 80% — of successful contracts were for existing generation (see Tables 4 and 5 above). This is despite increasingly direct government intervention to contract new generating capacity. For example, in 2016, the government decided to increase the size of T4 auctions to drive up capacity prices and so attract new-build projects.

> "The overarching message has been that the volume of capacity procured needs to rise and the clearing price needs to increase as a result, in order to provide the appropriate incentives for the market to bring forward new gas capacity."
> (Department for Energy and Climate Change 2016)[18]

The enlarged T4 auction took place in December 2016, but achieved only a tiny increase in new generation as a proportion of the total contracted capacity, from 4% to 7% (see Table 1 above). Auction results to date show that the U.K. grid requires very little new capacity in the years to September 2021. We also note that the biggest "new-build" gas power plant was a 370MW brownfield extension of an existing power plant, at Kings Lynn.

[17] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/248885/Definition_of_CMUs_and_portfolios.pdf

[18] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf

Failure to Reward Flexibility

In the medium to long term, a low-carbon grid will include no coal power, declining generation from gas-fired plants, increased generation from renewable and flexible technologies that can integrate renewables. The latter will include "gas peakers" (OCGT), storage and DSR. The capacity market to date has effectively consolidated today's energy mix, however, by rewarding existing gas, nuclear and coal the most, and flexible generation the least. Table 4 above shows that OCGT, reciprocating engines, storage and DSR combined reached a lower proportion of successful contracts in the three T4 auctions to date (13%) than coal (13.5%) or nuclear (16%) individually. Coal is a less flexible form of generation, although it is participating more and more in balancing markets at times of system stress in the U.K., partly because it is less economic in regular wholesale markets. Nuclear power is the least flexible form of generation and therefore most susceptible to zero margin cost and renewable energy carve-outs (Table 6 below).

These results support the conclusion of the Regulatory Assistance Project (RAP) that capacity mechanisms may do a poor job of prioritising flexible resources because of the difficulty in measuring and valuing flexibility.[19] A capacity market may actually undermine flexible generation, by creating over-capacity, which depresses price signals in wholesale and balancing markets.

Table 6. Flexibility of Different Conventional Generating Technologies

	Start-up time - cold	Start-up time – warm	Ramping up gradient	Minimum load
Pumped hydropower	c. six minutes	c. six minutes	> 40% per minute	c. 15%
CCGT	< 2 hours	< 1.5 hours	c. 4% per minute	< 50%
Hard coal	c. 6 hours	c. 3 hours	c. 2% per minute	40%
Lignite	c. 10 hours	c. 6 hours	c. 2% per minute	40%
Nuclear power	c. 40 hours	c. 40 hours	c. 5% per minute	50%

Source: Eurelectric [20]

[19] http://www.raponline.org/knowledge-center/hitting-mark-missing-money-ensure-reliability-least-cost-consumers/
[20] http://www.eurelectric.org/media/61388/flexibility_report_final-2011-102-0003-01-e.pdf

An Alternative Approach

Given the failure of the capacity market to drive new investment in flexible generation, it is probably time to review alternative solutions. One such alternative would be to scrap the general capacity market as presently applied and focus instead solely on more targeted auctions for new-build peaking generation. Much smaller, more targeted capacity auctions or other support for new-build capacity could focus on DSR, battery storage, pumped hydro and fast-response gas.

Choosing Efficient Energy-Only Markets Over Subsidized Capacity Markets

Growth in renewable generation threatens to upend traditional modes of baseload electricity delivery. Renewables have near-zero marginal costs, are supported by various policy incentives, and are dispatched to the grid first under a marginal cost merit order priority. As a result, renewables themselves do not respond to price signals, even while they suppress such signals for other generation. But schemes intended to counteract this problem — like capacity markets — threaten to distort energy markets further by suppressing peak demand price signals.

Indeed, creating an increasingly unresponsive grid defined by the best compensated rather than the most capable or most efficient technologies is dangerous. A wiser course — especially in a time of major energy system transition like the one many countries and certainly the U.K. are presently undergoing — may be allowing markets to chart the most efficient transition path, rather than the government picking winners. Energy-only markets, by definition, eschew capacity schemes, delivering electricity in sync with demand.

In this section, we review the U.S. experience of delivering a low-carbon transition through energy markets, and then highlight the opportunities for balancing-market reform to strengthen price signals in the U.K.

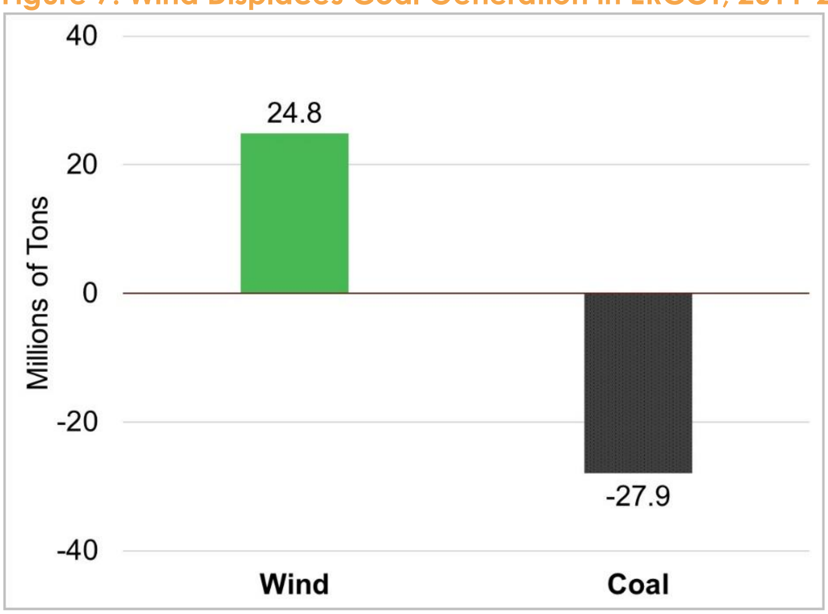
Lessons from the U.S.

U.S. energy markets provide a useful test of the performance of more established capacity markets. In the U.S. experience, IEEFA sees clear evidence in favor of a market path toward a low-carbon grid.

The U.S. has seven competitive wholesale markets. Two of these, PJM and ISO New England (ISO-NE), have three-year ahead forward capacity markets. Two more, New York ISO (NYISO) and Midcontinent ISO (MISO), have "prompt" capacity auctions in which capacity is acquired only months ahead of the delivery period. NYISO has auctions for two capacity periods each year, summer and winter, while MISO has only one auction, in March, for the capacity delivery year that begins the following June. None of the remaining three competitive markets — California ISO (CAISO), Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) — have capacity markets.

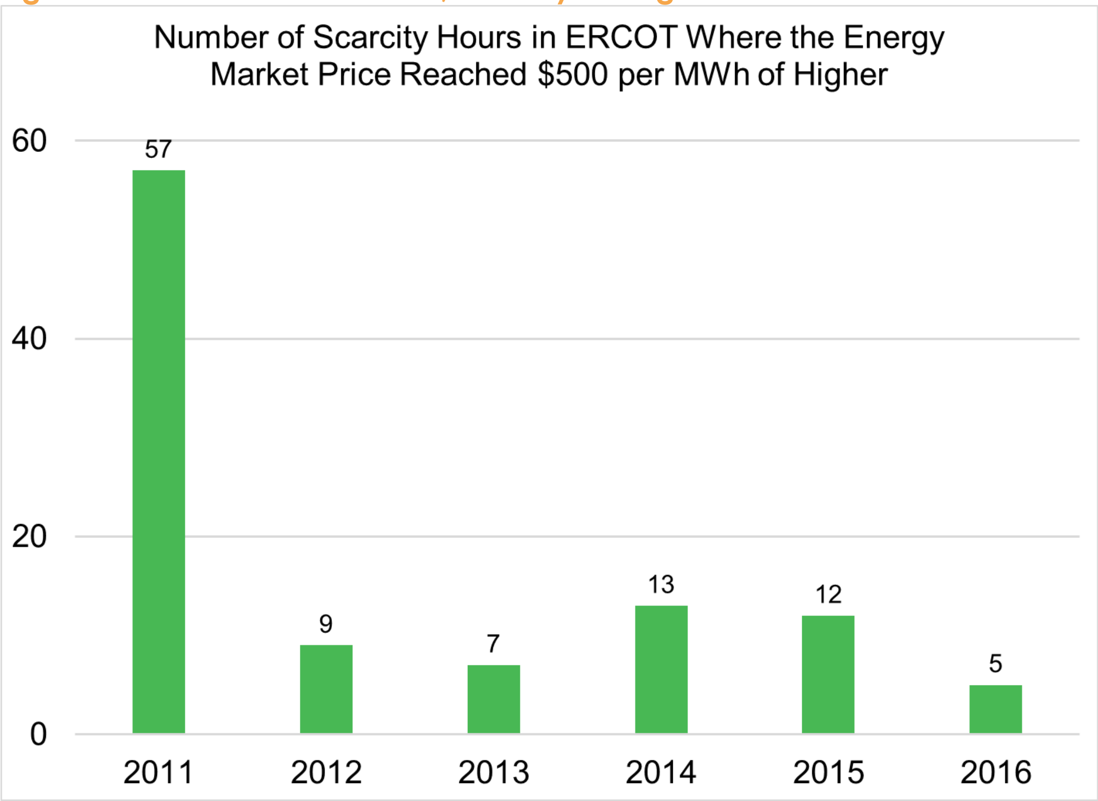
To differing extents, each of these seven markets has managed to significantly reduce reliance on coal-fired generators and begin a major transition to renewables, supported by the ongoing flat demand profile due as a result of energy efficiency measures. In just five years from 2011 to 2016, coal-fired generation in ERCOT fell by nearly 28,000 gigawatt hours (GWh), or almost 22%, at the same time that generation from wind rose by nearly 25,000GWh, or almost 90% (see Figure 7). Similarly, coal-fired facilities generated more than 65% of the power in the Southwest Power Pool (SPP) in 2008, but generated less than 50% by 2016. This occurred even as SPP expanded into areas very dependent on coal. Wind generation in SPP increased by more than 60% in two years, rising from 12% of SPP's fuel mix to 17.5%.

Figure 7. Wind Displaces Coal Generation in ERCOT, 2011-2016



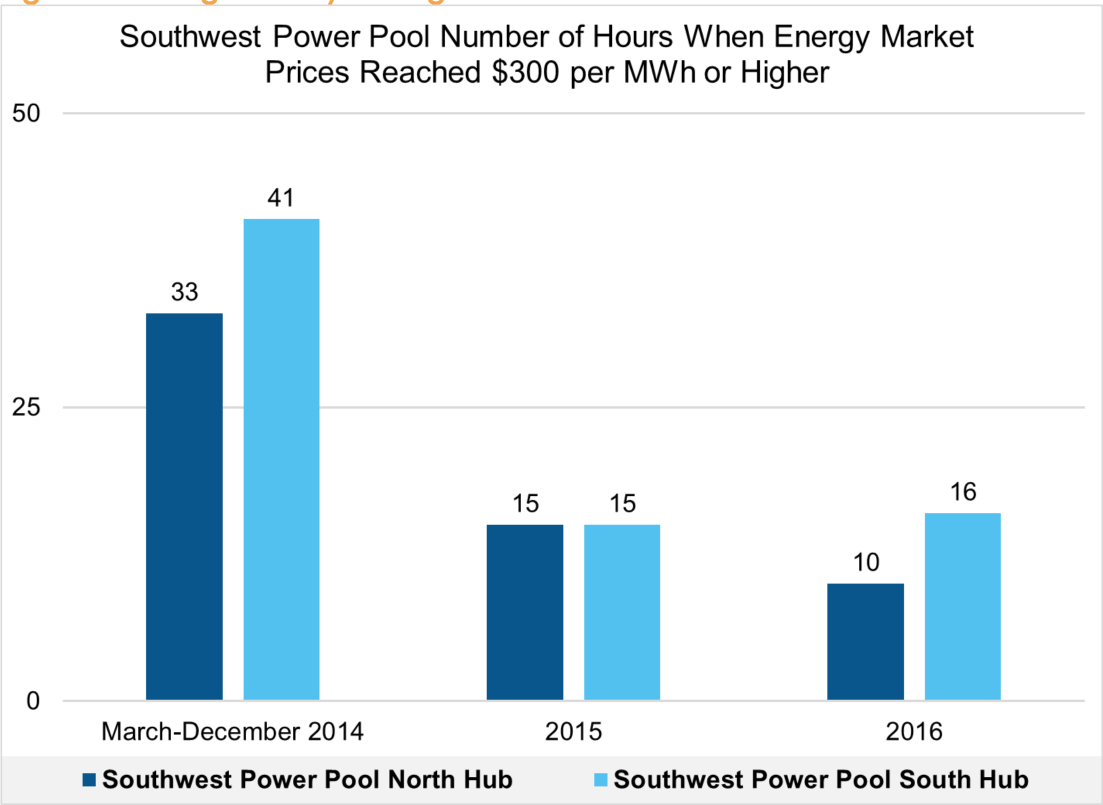
At the same time that U.S. competitive markets have been handling the transition from coal to renewables, the number of scarcity hours when energy market prices spiked to $500/MWh or higher has decreased dramatically. For example, in ERCOT, the number of hours with energy market prices above $500/MWh declined from 57 in 2011 to five in 2016 (see Figure 8). The number of scarcity hours with market prices above $1,000/MWh dropped from 32 in 2011 to zero in both 2015 and 2016. The addition of large amounts of new wind capacity (17,000MW by November 2016) surely contributed to this decline.

Figure 8. As Wind Power Climbs, Scarcity Pricing Falls



The number of scarcity hours in SPP has also fallen as the number of installed megawatts of wind has climbed. For example, the number of hours in which energy market prices at SPP's South Hub rose above $300/MWh, declined from 41 in the last 10 months of 2014 to 16 during all of 2016 (see Figure 9). The number of hours in which energy market prices at SPP's South Hub spiked above $1,000/MWh fell from nine in the last ten months of 2014 to one in 2015 and to two in 2016. This also reflects improved regional grid interconnectivity.

Figure 9. Falling Scarcity Pricing in SPP



U.K. Balancing Market Reform

One way to boost price signals in U.K. energy markets would be through sharper pass-through of the costs National Grid incurs in matching demand and supply in real time balancing markets. Higher imbalance charges ("cash-out prices") in the balancing market could do the same job as the capacity market, but through the energy market instead of regulatory intervention. The U.K. government itself accepts that higher imbalance charges would make the grid more resilient, and the capacity market less relevant: "In theory, as cash-out is fully reformed and the market has confidence to invest on the basis of scarcity rents the capacity price should tend towards zero under a capacity market."

In this section, we review the prospect for such reform. As described above, National Grid has various options for balancing demand and supply. These options include: competitive tenders for offers and bids to increase or decrease the supply of electricity; reserve generation under pre-arranged bilateral contracts (using the STOR, SBR and DSBR); and, in extremis, forced load-shedding.

National Grid passes some of the cost of these tools to market participants responsible for causing the imbalance. National Grid subsidiary Elexon calculates the imbalance charges in each half-hour settlement period from the accepted bids and offers, as well as from any use of reserve generation and demand control. If a generator produces less electricity in real time than its contracted volume, perhaps because of a power plant outage, it buys the shortfall at the rate set by this imbalance charge. The higher the charge, the more generators and suppliers will strive to meet their contracted generation or consumption.

If as a result electricity generators and suppliers invest more in flexible generation and demand-response contracts with customers, it would be to the benefit of ratepayers and the larger economy in general. The result would be a more efficient grid, governed by market supply and demand, rather than subsidized capacity markets.

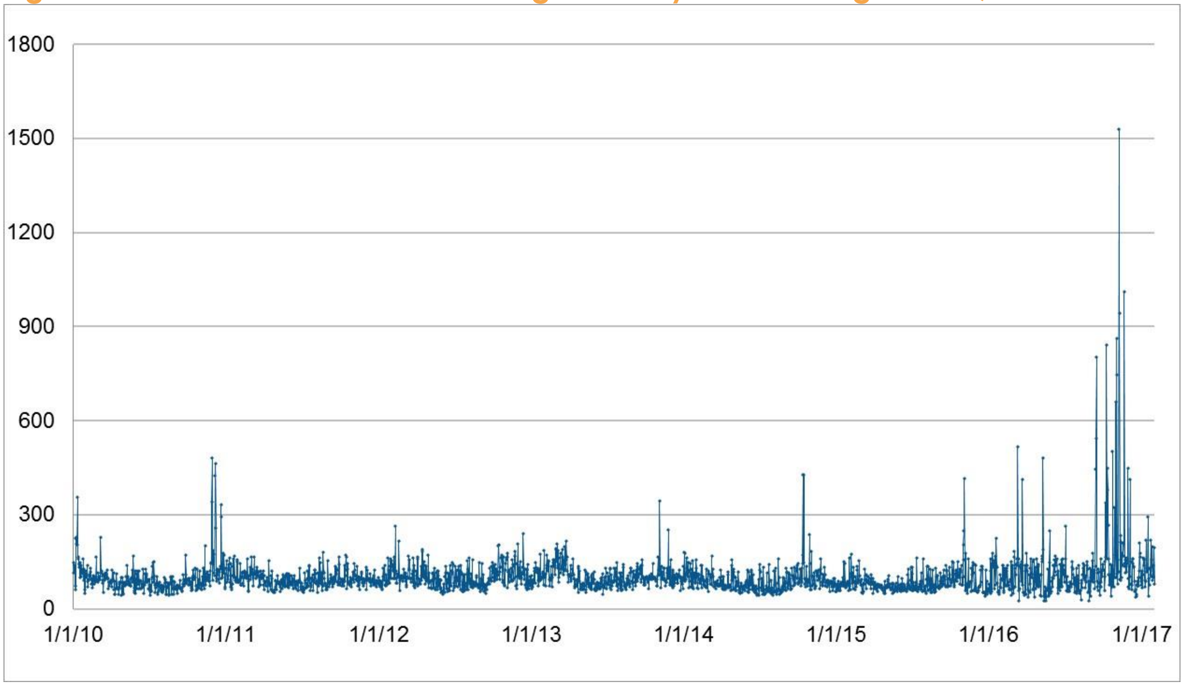
The method used for calculating imbalance charges would of course have a big impact on the cost to market participants of being imbalanced. At present, the charges do not include the full cost of balancing the system because of the way these charges are calculated:

1. In many settlement periods, National Grid will accept both bids and offers, to reduce or increase generation over the period. When calculating the imbalance charge, Elexon balances the bids and offers against each other, starting with the highest priced, until it reaches a net imbalance volume (NIV). Because the most expensive bids and offers are netted out first, the imbalance charge does not reflect the full cost of balancing the system.
2. Elexon then calculates the imbalance charge from the most expensive 50MWh of the remaining net bids or offers (called the Price Average Reference Volume, or PAR). Where the most expensive volume is smaller than 50MWh, it is averaged alongside other, lower priced bids or offers.
3. Where SBR or demand control is used, volume is priced at the value of loss load (VoLL). This is an estimate of the cost of disconnecting consumers, presently set at £3,000/MWh. If STOR is used, the price of this volume will reflect either a pre-agreed fee, or a scarcity price also related to VoLL. A VoLL of £3,000/MWh may fail to capture the true cost of electricity disconnection to consumers.

Balancing market reforms are already happening. In November 2015, PAR was cut to 50MWh from 500MWh and VoLL was introduced in the pricing of reserve power. Figure 10 shows how imbalance charges have started to rise, partly in response to these reforms, and partly as a result of tighter margins, as shown in Figure 4.[21]

[21] https://www.elexon.co.uk/wp-content/uploads/2011/10/P305-Post-Implementation-Review-Summary-and-Key-Points.pdf

Figure 10. Maximum Imbalance Charge Per Day in Balancing Market, Jan 2010 to Feb 2017



Ofgem has proposed additional balancing-market reforms in 2018. PAR will drop further, to 1MWh and the value of VoLL will rise to £6,000/MWh. If these reforms were already in play, Elexon calculates that imbalance charges would on average be £3.73/MWh higher when the system is short, illustrating the potential for a stronger price signal.

Ofgem can now go even further in its cash-out price reforms. There are various options to increase imbalance charging and incentivise generators and suppliers to balance the system themselves, rather than relying on the capacity market. These additional reforms include increasing the value of VoLL further. Other potential balancing market reforms include shorter settlement periods from 30 minutes to 15 minutes, in line with the trend in continental Europe. More frequent scheduling of wholesale power and balancing markets would allow generators to reduce forecasting errors and make despatch decisions closer to real time, reducing the need to call upon fast response, back-up capacity.

Conclusion

In its original support for a capacity market, the U.K. government hinted at how energy markets could make the capacity market redundant: "Given the scale of investment in new capacity needed it is unlikely that greater interconnection alone would enable an exit from the capacity market. However, coupled with more effective energy price signals and/or greater DSR, further investment in interconnection should reduce the level of support needed in the capacity market to achieve security of supply."[22]

IEEFA agrees with this assessment, and suggests the following alternatives to the present approach.

A strong first step would be for the U.K. to honor its commitment to fulfilling a project pipeline of renewable and especially offshore wind development, combined with its commitments to better interconnection. Such projects would create a backbone for a new energy grid, and — supported by flexible generation, could replace a large portion of present baseload coal and nuclear generation.

Second, the U.K. can repurpose its general capacity market to target new-build, flexible generation. The capacity market almost entirely supports existing generation at present, including inflexible nuclear and dirty, ageing coal-fired plants. Instead, targeted auctions could support new-build gas peakers, storage and DSR. Storage especially, may help solve the present conundrum of how to deliver unsubsidised renewables through energy markets. Brexit may provide an opportunity to reform the market in this way, given there will be less need to achieve EU state approval for auctions that support particular technologies, such as storage, or that aim to eliminate others, such as coal. A strategic reserve of ageing power plants, which would otherwise be mothballed, could be retained in place of the last resort buffer currently supplied by the SBR.

Third, continued reforms of the balancing market that pass on the full cost of matching demand and supply to market participants could strengthen price signals and support the energy only market. Reforms to the balancing market could extend to shortened settlement periods from 30 minutes to 15 minutes, following a trend already established in continental Europe.

[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324430/Final_Capacity_Market_Impact_Assessment.pdf

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Important Information