The Impact of Tightening Margins on Plant Availability

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BIEE Oxford 2016 Research Conference, 21st–22nd September 2016
Category: Energy Economics, Energy Security, Electricity and Nuclear
Keywords: Power system operation, energy economics

Abstract

The transition to a low-carbon energy future will inevitably pose challenges to the operation of power systems across the globe. A key strategy for governments seeking to meet their legally binding emissions reduction targets is to reform their energy systems to rely heavily on low-carbon sources of energy generation. This has resulted in a shift in the generation mix of many electricity markets worldwide, moving away from the traditional reliance on conventional sources of electricity generation (such as coal and gas), and towards an increasing use of renewable electricity generation (mainly wind and solar).

The increasing use of renewable energy sources has made system operation an increasingly complex task. The intermittent nature of renewables means that an increasing amount of operational flexibility is needed in the power system. There is a general agreement within the academic literature on the relationship between conventional and renewable plant operation that the growth of wind and solar generation has caused conventional plant, such as CCGTs, to operate differently than originally intended. However, what remains underexplored in academic literature on the relationship between conventional and renewable generation is how power plants respond during periods of system tightness.

The purpose of this research project is to assess what happens to CCGT availability at periods of tightness. We define availability as the proportion of a plant's maximum output level that is available. We expect our analysis to show that CCGT availability increases in tighter periods when demand is higher and less sources of alternative generation are available. Our research focuses specifically on CCGT availability in Great Britain (GB), as margins have been falling here over the past number of years. We expect that prices would increase during periods of system tightness, which should act as an incentive for CCGT plant to increase their availability.

If the hypothesis of this research project is correct, then CCGT potential in GB may currently be underestimated. Moreover, as availabilities are used in the GB Capacity Market to determine the necessary volume of capacity to procure, increased availabilities may impact the amount of procurement required in future analysis.

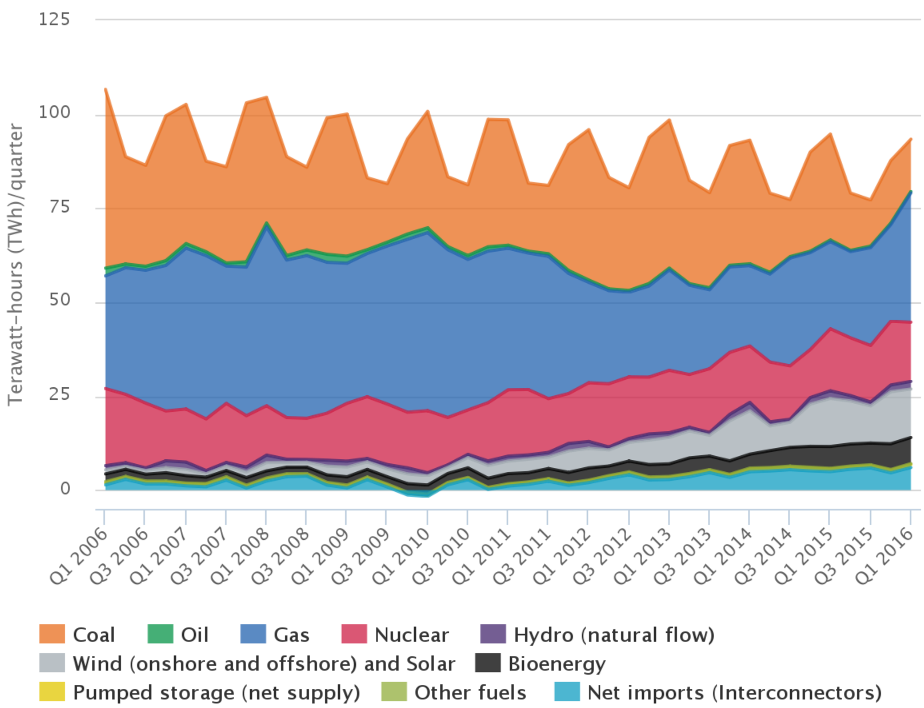
[1] The views expressed in this paper are those of the authors and do not necessarily represent the views of, and should not be attributed to, Ofgem or the Gas and Electricity Markets Authority.

Introduction

The transition to a low-carbon energy future is posing challenges to the operation of power systems across the globe. A key strategy for governments seeking to meet their legally binding emissions reduction targets is to reform their energy systems to one which relies heavily on low-carbon sources of energy generation. This has resulted in a shift in the generation mix of many electricity markets worldwide, moving away from the traditional reliance on conventional sources of electricity generation (such as coal and gas), and towards an increasing use of renewable electricity generation (mainly wind and solar).

Great Britain (GB) is no exception to this. Over the past decade, the share of high carbon-emitting energy sources in the generation mix has declined significantly, while the share of renewable generation has continued to rise. This shift is evident in Figure 1 below, which illustrates changes in the GB electricity generation mix by quarter and fuel type from 2006 to the first quarter of 2016. Coal's share in the electricity mix has fallen from almost half of the generation mix in Q1 2006 (at 48%) to only 14% in Q1 2016. By contrast, the share of wind (onshore and offshore) and solar in the generation mix has increased from 1% in Q1 2006 to 13% in Q1 2016.

Figure 1: Electricity generation mix by quarter and fuel source (GB), 2006-2016



(Ofgem 2016)

The growing proportion of renewables in the generation mix means that system operation is becoming an increasingly complex task. In particular, the variable nature of wind and solar generation may cause problems for the reliability of the overall electricity supply (Traber and Kemfert 2011). An existing body of literature has investigated the impacts of increased intermittent and renewable output on conventional generation, market operation and the challenges for system operation (see, for example, Meibom et al. 2008; Ketterer 2012; Nicolosi 2010; Green and Vasilakos

2010; Jacobsen and Zvingilaite 2010; Troy et al. 2010). This literature illustrates that the increasing penetration of renewable energy into the generation mix is likely to impact the technical and economic workings of the power system in a number of ways. The variable nature of wind output, and the difficulty in predicting this, means that conventional plant usage patterns and the prices they will receive are likely to become increasingly uncertain (Steggals et al. 2011). Moreover, intermittent generation is not always capable of delivering in periods of tight margins, and provides considerably less of a contribution to meeting peak demand. Solar, for example, is unavailable in evening peaks in winter when demand is at its highest. As a result, a key impact of the growing penetration of intermittent renewable output in the generation mix is the need for operational flexibility in order to be able to mitigate potential disturbances in the energy system.

As this need has grown, thermal plants are increasingly operating in a different way than originally intended, with increased 'cycling' of existing units (Troy et al. 2010). That is, generating units which were originally intended to operate at baseload, primarily CCGTs, are increasingly required to operate at the margin. This means that thermal plants are undertaking additional start-ups, shut-downs and variation of their output in order to meet fluctuating electricity demands (Denny and O'Malley 2009).

Market conditions for thermal generation have also changed significantly over the past decade. The growth of renewables has pushed thermal generation further out the merit order, while also helping to reduce transmission demand. This has put downward pressure on power prices, damaging the profitability of other plant types. The challenging economic environment has resulted in the closure of many coal plants in GB, and means that CCGTs have an increasingly important role in the generation mix.

Moreover, the growing number of coal plant closures in GB has contributed to increasingly tight margins over the winter period. As displayed in Figure 2 below, spare electricity capacity in the GB market during winter has decreased each year from 2011-12 through to 2015-16.

Figure 2: Spare electricity capacity in the market during winter

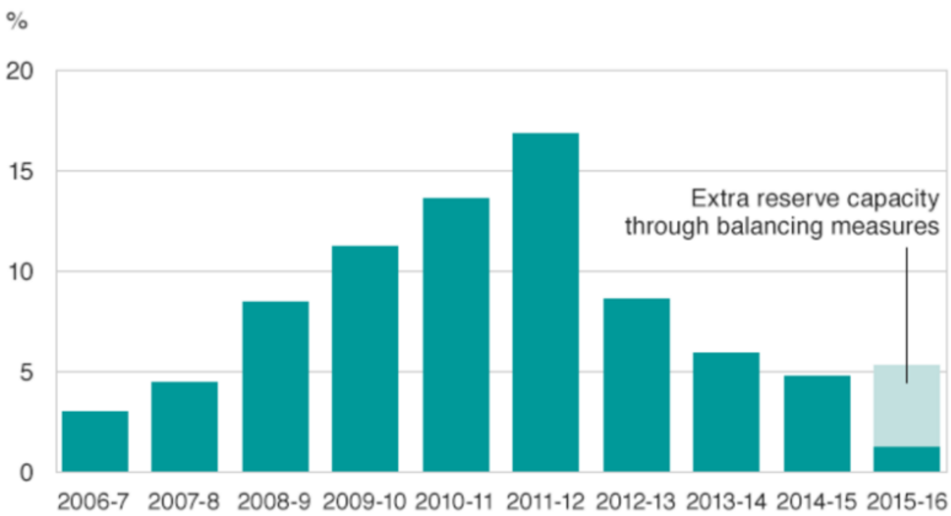


Chart constructed by BBC (2015) drawing on data provided by National Grid

Further, the design of the economic incentives for generation has also changed in recent years, with the sharpening of imbalance (cash-out) charges through BSC modification P305.[2] The changes included reducing the volume of actions included in setting the system price, making the price parties pay or receive for being out of balance more marginal and therefore incentivising flexibility. These changes have altered the market, and participants behaviour (including their availability) may be affected. We think assessments of availability using historical averages alone could have their limitations. However, there has been little academic research to date which has explored the relationship between these changes to market conditions and the behaviour and availability of power plants.

Research Purpose and Justification

The purpose of this research project is to assess what happens to CCGT availability when low capacity of other fuel types drives tightness. For example, what happens to CCGT availability during periods of low wind or low nuclear availability? We focus on CCGT availability due to the fact that these units are better able to respond to short term changes to supply and demand than less flexible dispatchable plant such as coal or nuclear.

We expect our analysis to show that CCGT availability responds to tighter periods when less alternative sources of generation are available. Just as we would expect CCGT availabilities to decrease during periods of high renewable availability (and therefore, lower prices), it is expected that CCGT availabilities will *increase* during periods of *low* RES (or non-CCGT) availability (and therefore, *higher* prices).

Our research focuses specifically on availability within GB, as margins have been falling here over the past number of years. We expect that prices would increase during periods of system tightness, which would further support CCGT plant economics. The expectation that gas power plants should respond to market price signals has already been established in the academic literature. For example, Roques (2011: 43) argues that the operational patterns of gas plants "can be expected to respond to market price signals, decreasing gas consumption when the cost of generating from other fuels is lower than the price of burning gas". Put simply, CCGTs are expected to respond to the ability to make money.

Research Implications

If the hypothesis of this research project is correct, then CCGT potential in GB may currently be slightly underestimated. This could have implications for GB consumers, as Ofgem, National Grid and the Department for Business, Energy & Industrial Strategy (BEIS) all use de-rated generation capacities as part of their electricity security of supply assessments. These are percentage values used to adjust the installed capacity to reflect when actual available capacity in peak periods. The de-rated values take into account factors such as planned maintenance, breakdowns and commercial availability.

Having an accurate de-rating value for each generation technology can have significant consequences on the assessments of security of supply in the outlook. For example, if the de-rating

[2] https://www.elexon.co.uk/mod-proposal/p305/

factor it is too low, it can lead to over procurement in policy areas such as the Capacity Market. This can drive up costs for consumers and dampen market signals. If it is too high, this can result in under procurement and lead to increased risks to security of supply.

The current assessments of de-rating values are based on historical assessments of availabilities. While we recognise the value of this approach, this method may not capture the changing nature of the market in the outlook. For example, the anticipated tighter electricity margins and sharper imbalance prices could increase the availability of some flexible generators at peak. This makes it an important time to re-assess the analytical approach to derive accurate de-rating values.

Moreover, as availabilities are used in the CM to determine the necessary volume of capacity to procure, increased availabilities may reduce the amount of procurement required in future analysis. They also have implications for system planning and, from a commercial perspective, can impact on the economics of CCGT plant financing. As such, we think that this gap in the current literature needs to be further investigated.

Data Collection and Analysis

We use four years of half-hourly time series plant level data from National Grid, from April 2013 to March 2016. We aggregate the plant level data to fuel type in order to see if there is a change on the whole in the running of different plant types over the period. This smooths the impact of any individual unit going on outage, reducing the impact of individual plants on the overall results. We use demand and wind output data for the same period from Ofgem's proprietary database, which sources data from BM Reports (Elexon)[3]. We create dummies for weekdays and peak hours (5-8pm) to allow us to identify if plants behave differently in these peak demand periods. We also consider times such as winter (November – March), and periods where different types of plant have low availability e.g. nuclear outages in 2014. We define the availability of a plant as being the ratio of the output each unit is willing to provide in a given period relative to the maximum output they have been willing to provide over the entire time period.

We present the summary statistics for the key variables in our trial data in Table 1 below.

Table 1: Summary Statistics

Variable	Unit	Obs	Mean	Std. Dev	Min	Max
totalavail	%	46,512	61.5	6.8	45.1	79.1
nucavail	%	46,512	72.4	9.4	41.3	94.2
coalavail	%	46,512	60.9	11.2	28.9	86.3
ccgtavail	%	46,512	63.3	8.2	41.0	84.6
demand	MW	46,512	34130	6776	19797	53693
wind	MW	46,512	2360	1576	0	6803

[3] BM reports can be accessed via the website http://www.bmreports.com/.

Table 1 shows that, on average, total system availability is 61.5% of the total capability of the system. Nuclear availability is much higher than this, at 72.4%, while CCGT availability is only slightly higher than the system average at 63.3%. We do not believe that this represents the individual fuel levels accurately and therefore believe that our dataset is missing some observations which is driving down the true availability of fuels.

Preliminary Findings

Our initial results suggest that our dataset may be incomplete. While the results produced from our data analysis broadly reflect the patterns and trends that we expected to find, the values of the availabilities are significantly lower than we know them to have been in the last number of years. As such, we suspect that our original dataset doesn't capture all generating units and therefore we wish to investigate further.

Due to the data limitations, we do not present the completed results of our regression analysis here. Instead, the following figures display key summary statistics which indicate that we can expect a larger response from CCGT plant in periods of system tightness.

Figure 3 below compares the availabilities for all dispatchable plant (in blue) and all CCGT plant (in red). While we are not convinced that the values on the y-axis are accurate in our trial data, it is interesting to note that the response we expected remains. Looking specifically at weekdays, we see very little difference in the total availability numbers between peak and offpeak hours. CCGT availability appears to respond by about a percent (though actual values tell us very little here). The same response can be seen across both availability when focusing on weekend periods and the difference between peak and offpeak hours.

Figure 3: Availabilities on Peak Days and Hours

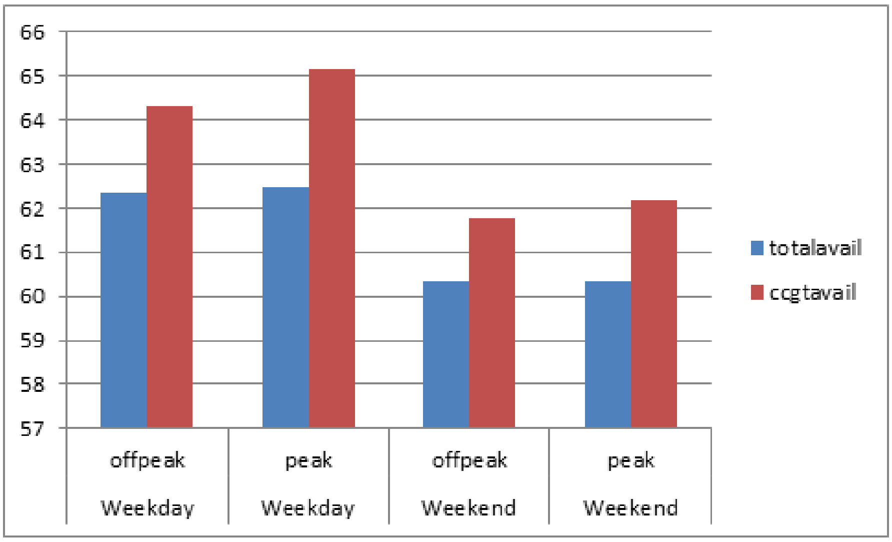
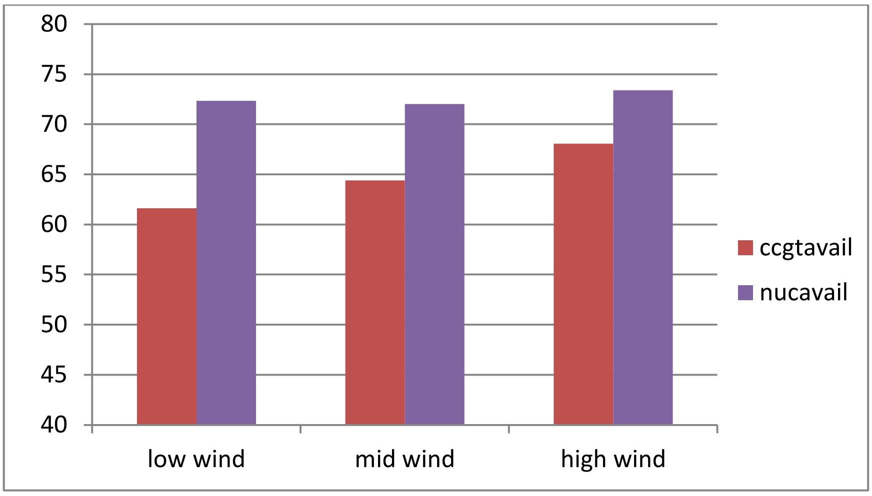


Figure 4 compares the availability of CCGT and nuclear plant over the total time period at different levels of wind. In our sample, wind output ranges from 0-6.8 GW. Low wind refers to wind output ranging from 0-2.3 GW, mid wind is 2.3-4.6 GW and high wind is 4.6-6.8 GW. Changes to wind levels on a minute by minute basis can require dispatching other types of plant in order to balance the system. This is particularly likely in the "mid wind" scenario, as at mid wind levels there is a greater risk of wind output changing quickly in either direction as opposed to just increasing quickly in the "low wind" scenario, or dropping off in the "high wind" scenario. Over the three wind scenarios, nuclear availability remains largely constant. This finding is as expected, given that nuclear plant cannot be dispatched quickly enough to respond to changes to wind output, and as baseload its output remains very constant over time. CCGT output can respond to short term changes to the system however, and changes by about 7% based on wind output in the current dataset.

Figure 4: Availability at different wind levels



While these two examples do not confirm that CCGT availability can continue to increase in periods of system tightness, they imply that it is possible and that further investigation is warranted.

Conclusion and Next Steps

This paper has identified a gap in the existing literature on energy economics regarding the relationship between recent changes in market conditions and the behaviour and availability of power plants. Establishing an empirically-grounded understanding of this relationship is important as plant availability is used in the GB Capacity Market as a measure to help determine the necessary volume of capacity to procure.

The preliminary findings detailed in this paper lend support for our hypothesis that CCGT availability increases in tighter periods when demand is higher and less alternative sources of generation are available. This suggests that historic lower CCGT availability is a result of market conditions, and as a result, that CCGT potential in GB is currently underestimated. It is important to note, however, that the preliminary findings in this paper are drawn from a dataset that we assume to be currently incomplete. While the broad trends seen in our data analysis conducted thus far reflect the trends that we would expect to see in terms of plant availability and market conditions, the values calculated in our analysis seem much lower than expected – indicating that our dataset is not capturing all plant present in GB.

Our next step is to clean the data and ensure that we have a completed dataset for analysis. This will allow us to rerun our regression analysis including all plant availability, rather than those limited to our current dataset. We expect that re-running this analysis with a completed dataset will lend further support for the hypothesis of this paper. We are also very eager to receive feedback on both our approach and hypothesis, and welcome any feedback which would allow us to improve our analysis.

We propose using a time series econometrics approach to identify how much of an effect the different variables have over time in affecting the availability of both dispatchable plant as a whole, and CCGT availability in particular. As noted above, we expect to see a greater response from CCGT plant due to their flexibility of operations.

Equation 1:

$$Total\ avail_t = \alpha + \beta_1 Demand_t + \beta_2 Wind_t + \beta_3\ PkDay + \beta_4 PkHour + \beta_5 Winter + \beta_6 LowNuc + \varepsilon$$

$$CCGT\ avail_t = \alpha + \beta_1 Demand_t + \beta_2 Wind_t + \beta_3\ PkDay + \beta_4 PkHour + \beta_5 Winter + \beta_6 LowNuc + \varepsilon$$

Our hypothesis is that the total availability values should increase as a result of periods of system tightness and CCGT availability should respond to a greater degree to short term events. We anticipate that demand will have a positive effect on availabilities, as plant aim to be available during periods of high demand. Wind may have a positive effect, and we expect that all of our dummies will have a positive impact on availabilities.

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