nationalgrid

Dispatch Model

July 2013

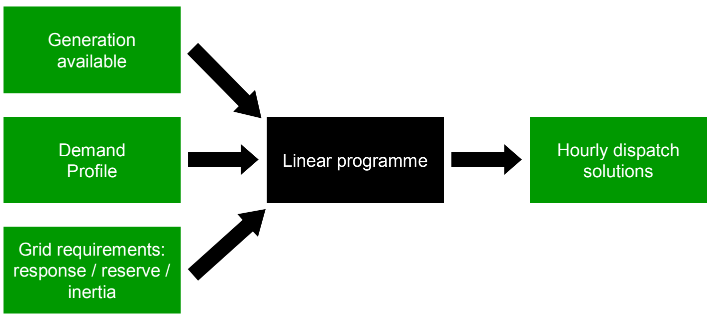
We have undertaken new analysis to investigate the operational issues regarding the electricity transmission network and the generation mixes within our Gone Green and Slow Progression scenarios. We have developed a new model that produces an electricity generation dispatch solution for every hour for any chosen year within our scenarios. The model enables us to investigate whether the electricity system is able to maintain appropriate levels of reserve, frequency response and inertia for the modelled levels of generation capacity within our scenarios. For an explanation of these terms please see the break-out box 'system inertia, frequency response and reserve' at the end of this paper.

Key findings:

- **The impact of increasing levels of non-synchronous sources (e.g wind generation) on system inertia.** A relaxation in Rate of Change of Frequency (RoCoF) constraints results in a lower requirement for large volumes of synchronous generation such as gas or coal fired generation to run, leaving more room for asynchronous generation such as wind.
- **Plant with low load factor is important for security of supply.** Gas, coal generation and imports are important to providing additional generation when there is little generation available from wind or solar.
- **The value of flexibility as provided by pumped storage and/or interconnectors.** Pumped storage plant provides frequency response and interconnectors provide additional reserve.

Figure 1 shows a high level schematic of how the model works.

Figure 1: The Dispatch Model



The model produces a supply demand match at the GB national level based on short run marginal cost and providing the appropriate levels of reserve, frequency response and inertia. It uses the wind output and solar radiation profiles from 2012 scaled to reflect the volume of plant available. Generation capacity is modelled at the fuel type level, with inputs for capacity, annual availability, prices, minimum stable generation, frequency response and inertia. The demand profile is based on the data for 2012 and scaled to provide the correct annual energy accounting for changes in levels of resistive heating, heat pump load, levels of electric vehicle usage and levels of overnight thermal storage, for example via a hot water tank. The model minimises generation costs for each hourly snapshot while ensuring that supply meets demand and providing the appropriate levels of reserve, frequency response and inertia.

We have presented only Gone Green here on the basis that Slow Progression is closer to the present day system and hence exhibits similar issues, but to a lesser extent. The analysis provides an indication of the potential benefits of allowing maximum system rate of change to increase by raising the minimum protection settings on distributed generation. The value of flexibility was also evident as provided by pumped storage and/ or interconnectors.

It should be noted that the model produces different results for generation utilisation to those shown in our 2013 Future Energy Scenarios, but this is to be expected, as the model focuses on operational issues and models generation at the fuel type level, and not at the station level. In addition the model does not include a network model; hence there are no network flow constraints and does not attempt to account for plant dynamics and hence tends to underestimate costs. All references to constraints within this section are in the context of supply and demand (energy) balancing, not network constraints.

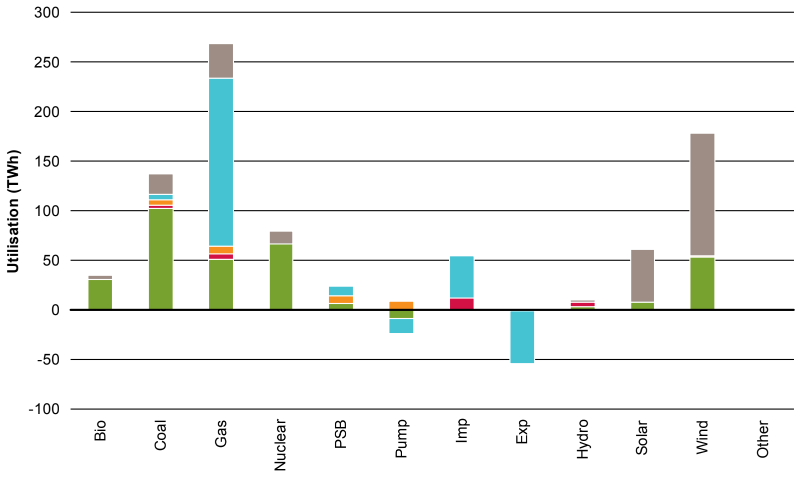
Figure 2 shows annual utilisation of generation by type for 2020/21 using our Gone Green scenario assumptions for generation capacity, with coal generation cheaper than gas generation. This represents our Base Case, and is subsequently referred to as Run A.

The output is shown by fuel type broken down by whether the plant is generating, providing frequency response or reserve, constrained off (for energy), not required or not available. The "other" category contains tidal generation, demand side response and the potential for schedulable demand such as electric vehicle charging. There are a number of points to be highlighted from the chart:

- Low utilisation of gas plant
- Wind is virtually unconstrained in terms of energy balancing. The model does not forecast potential transmission network issues, which will cause a level of constraint
- High levels of frequency response coming from pumped storage plant.

The subsequent analysis highlighted a number of high level issues:
- The impact of increasing levels of non-synchronous generation on system inertia. For an explanation of system inertia see the break-out box entitled 'System Inertia, Frequency Response and Reserve' at the end of this paper

Figure 2: Run A*: Base Case - Gone Green 2020. Coal generation cheaper than gas generation



*Gone Green is designed to hit 2020 renewable and carbon target. The model tests dispatch-ability of that scenario using the wind load factor hourly profile for 2012, this has not be adjusted for increased load factor anticipated in 2020 due to increased levels of offshore wind capacity.

Background to Assumptions in Base Case

In the base case study for 2020 we have assumed that distributed generators are able to modify the RoCoF protection settings to allow their plant to continue operating safely with a higher rate of change of frequency and that the National Electricity Transmission System Operator (NETSO) is able to access reserve in Europe via the inter-connectors in real time. We are working on both of these issues with the other parties who will be affected.

On the relaxation of RoCoF settings we are in discussion with DNOs and the industry with a view of obtaining agreement to adjust the RoCoF protection settings on all generation with a capacity of 5MW or above from the current 0.125Hz/s to a level between 0.5Hz/s and 1.0Hz/s so as to mitigate for the effects of reduced inertia on the system caused by high penetration of renewable generation and interconnection imports. The dispatch model has been applied to 2020 when we anticipate that the largest loss on the system will be 1800MW.

- Criticality of relative prices of coal and gas generation
- The need to retain plant with low load factor on the system for security of supply.

These (and others) are discussed in the analysis that follows comparing Run A, the Gone Green Base Case, with alternative sensitivity runs. Note that the Base Case and all the sensitivities refer to year 2020/21 in our 2013 Gone Green scenario.

Assumptions Made in the Base Case

1. Inertia

Figure 3 shows Run A being the Base Case, having RoCoF set above 0.5 Hz/s, and Run B having RoCoF set at 0.125 Hz/s, the current setting.

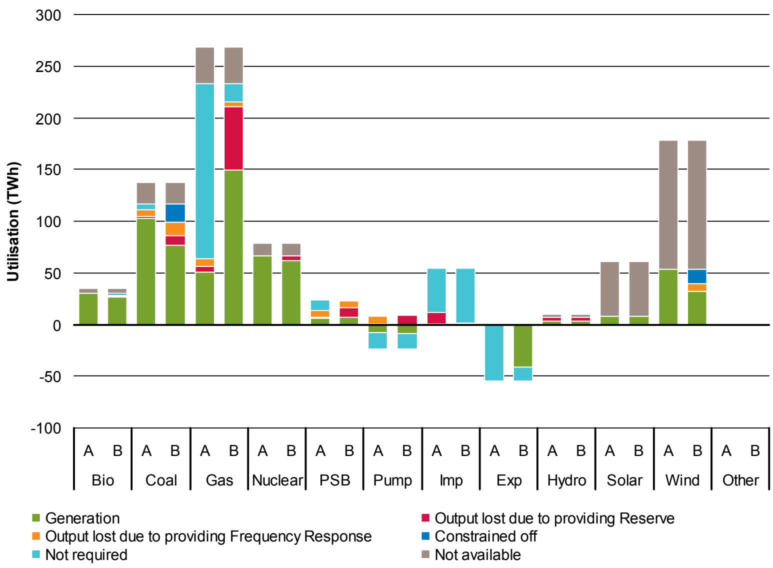
This chart highlights the benefits of relaxing RoCoF limits.
In Run B:

- Gas is running and being part-loaded to maximise system inertia
- Coal is running less as gas fired plants provide more inertia per MW
- There is significant wind constrained off and use of interconnectors to export. The need for inertia on the system requires large volumes of synchronous plant to run, leaving little room for asynchronous generation such as wind. For 859 hours (~10% of the year) the model is unable to maintain adequate levels of system inertia. This would require alternative operational actions, not included in the model, for example reducing the largest loss of generation on the system.

2. Access to European Reserve via the Interconnectors

The base case makes an assumption that the interconnectors can be flexed by NETSO in real time to access reserves from Europe. Whilst this flexibility would be valuable, the implications on the load factor of other plant are relatively modest. This assumes a high level of co-operation between NETSO, interconnector owners and other System Operators in Europe.

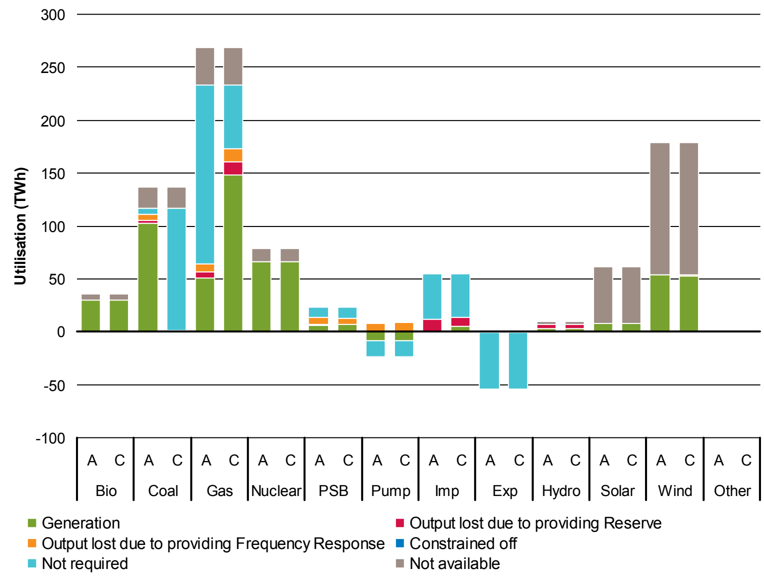
Figure 3: Run A: Base Case (RoCoF > 0.5 Hz/s) and Run B: RoCoF 0.125 Hz/s



Relative Price of gas and coal generation

The modelling by fuel type, rather than station, means a single price for each type of generation is used, leading to very sharp changes in utilisation as the prices vary. This can be seen in Figure 4 which compares Run A with RunC: gas generation cheaper

Figure 4: Run A: Base Case (coal generation cheaper than gas generation) and Run C: gas generation cheaper than coal generation



than coal generation.

Run A is the Base Case, with coal generation cheaper than gas, and Run B is gas generation cheaper than coal.

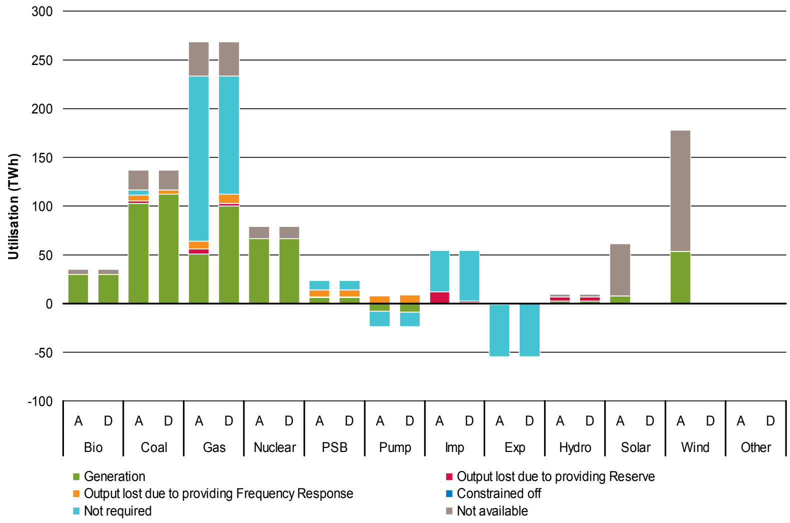
- The chart highlights the impact of changing merit order in the two runs. In Run A, the ascending cost order is coal, gas, then imports: in Run C the order is gas, imports, then coal
- Apart from the impact on utilisation of coal and gas the two runs are very similar

Security Requirement for Plant with Low Load Factor

Figure 5 shows the importance of gas, imports and coal in providing additional generation when there is little generation available from wind or solar.

- Run D shows the impact of no generation from wind or solar. This leads to significantly higher generation from gas and some from coal.
- The additional reserve needed when wind is operating is largely provided by the interconnectors in Run A.

Figure 5: Run A: Base Case (with wind and solar available) and Run D: without wind and solar available



Commercial, Technical and Operational Developments

Developing Balancing Services

We are working with GB market participants, interconnectors and the respective TSOs that they connect to in order to maximise the value to consumers. This mainly concerns reduced costs of managing constraints and balancing actions. These include the development of frequency response services, Commercial Balancing Arrangements and participation in a European Network of Transmission System Operators for Electricity (ENTSO-E) pilot scheme that aims to explore how the future European Balancing Code proposals may work in practice.

Within Great Britain we are developing new frequency response services which will be more rapid than those available to us now. These are needed to ensure that frequency can be contained even though the initial rate of change is higher.

We are also developing a suite of services which will ensure we can manage periods of low demand efficiently. We have run two tender rounds this summer to procure services for frequency response and regulating capability where there is limited scope to reduce plant output, for inertia and for voltage control and reactive power. The results from these tenders will inform our next steps in developing these services.

ENTSO-E Network Code on balancing envisages a common merit order between TSOs for standard Energy and Reserve products which will require the interconnectors between TSOs to be flexible within balancing timescales. The code also envisages Replacement Reserves (RR) and Frequency Restoration Reserves (FRR) being shared between TSOs so as to facilitate harmonisation of balancing arrangements between TSOs. It also requires the GB and Irish synchronous areas, along with GB and Continental Europe synchronous areas (and eventually GB and the Nordic synchronous areas) to exchange and share Frequency Containment Reserves, and Replacement Reserves.

A pilot project is being led by National Grid to competitively exchange Replacement Reserves through both NorNed and BritNed interconnectors in partnership with Statnett, Tennet and National Grid.

A second pilot project, also led by National Grid, is extending the current Cross Border Balancing arrangements to Italy, Portugal and Spain from the current cooperation with France and GB. This will involve a trial implementation of the Balancing Code principles, and development of a Common Merit Order with Marginal Pricing by 2016.

Operational Innovation

Both commercial and technical innovative solutions are also being considered to limit the effects of rapid ramping of HVDC interconnectors on the frequency to the synchronous areas. One technical concept which is being explored is enabling HVDC interconnectors to operate in a pseudo "ac" mode (as between Australia and Tasmania) so as to enable synchronous areas to be coupled to form "virtual" larger synchronous areas so as to increase the inertia of all systems and enable total levels of Frequency Restoration Reserve to be reduced across all TSOs.

Finally, we are investigating the case for using Automatic Generator Control (AGC) on some of the plant on the GB system. Initial studies indicate that AGC may be an economic way to improve the management of the high ramp rates that we are currently experiencing on wind generation, and expect to be a feature of high levels of solar penetration. AGC would also bring the standard deviation of the frequency trace in line with that on the continent therefore making it easier to share dynamic Frequency Containment Response and Frequency Restoration Reserve over the interconnectors if operation in pseudo "ac" mode was adopted.

The results can also be shown in the form of generation duration curves, shown in Figures 6 and 7.

Figure 7 shows that significantly more gas generation is required for energy balancing.

- Figure 6 and 7 show that it is mainly gas generation as the marginal fuel that is replaced as a result of renewable generation
- The risk of low renewables at peak requires that conventional plant must still be available.

Note: The dispatch model does not include a network model, hence it does not model locational effects and only looks at the GB as a whole. Locational effects could have significant impacts on capacity adequacy, the cost of managing the system and potentially inertia and voltage requirements. In addition the model does not consider generation dynamics and this could lead to an underestimate of constrained energy.

Figure 6: Run A: Base Case - generation from coal, gas and imports, with wind and solar available

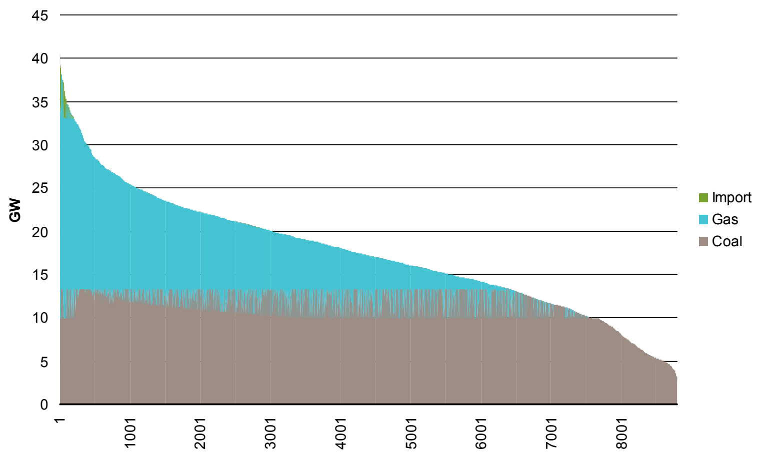
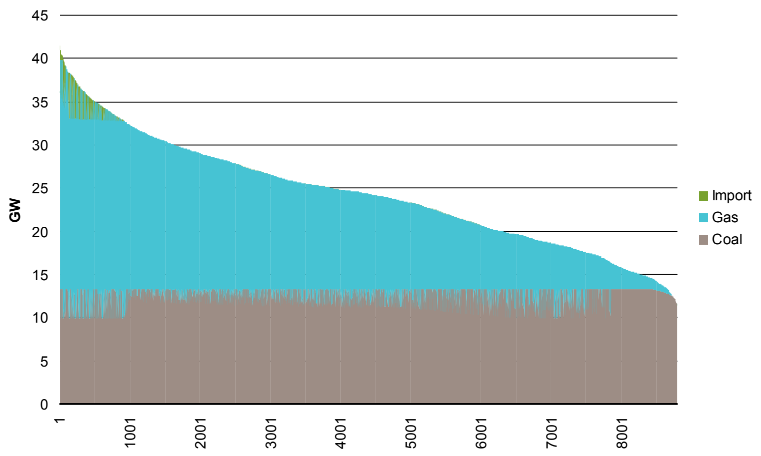


Figure 7: Run D - generation from coal, gas and imports, without wind and solar available



System Inertia, Frequency Response and Reserve

On an AC system the voltage continuously changes its polarity. The system frequency is a count of the number of cycles of voltage reversal completed in a second. The nominal system frequency is 50Hz, but it varies within a tightly controlled range in response to the overall energy balance on the system. If the total power station output exceeds the demand, then the surplus energy will accelerate the generators and the frequency will rise. Conversely, if the total power station output is less than demand, then the shortfall will be made up by the kinetic energy of the generators being released and the frequency will fall.

The generators connected to the system can be either synchronous or asynchronous. Synchronous generators are directly coupled to the system and, as suggested by the name, must rotate at the same speed as the system frequency. On the other hand asynchronous generators are linked to the system via power electronics and the speed of rotation is not tied to the system frequency. Asynchronous sources of generation on the system include wind power, solar power and imports via the interconnectors.

This difference is important immediately after the loss of a large generator from the system. At this point there is a large mismatch between the power entering the system and the demand so the frequency starts to fall. Before any governor valves have had time to respond the power mismatch has to be drawn from the kinetic energy of the generators. However, the asynchronous generators do not contribute as their speed of rotation is independent of the system frequency. Hence the initial Rate of Change of Frequency (RoCoF) is determined by the size of the generation loss and the rotating mass of synchronous generators on the system, also known as system inertia. It is important to manage RoCoF because many embedded generators are fitted with RoCoF protection to shut the generator down safely if it is isolated from the main system. When a generator is "islanded", i.e. disconnected from the main system but still connected to local demand, there is almost inevitably a power mismatch within the island leading to a rapid change of frequency. The RoCoF protection detects this and trips the generator to protect both the generator and the local demand. However, if the RoCoF on the main system exceeds the setting on this protection then there is likely to be a cascade with a single large loss of generation triggering other generators to trip and thus increasing the RoCoF still further. It can be seen that this risk is a function of the largest generation loss on the system, the system inertia and the RoCoF protection settings applied to embedded generators. With the forthcoming increase in the largest loss on the system from 1320MW to 1800MW and increasing volumes of asynchronous generation, we are working with the industry to ensure the continues safe operation of the networks with higher settings and allow the system to operate with lower levels of inertia.

Whilst system inertia limits the RoCoF, it does not arrest the fall in frequency. This is achieved by carrying frequency response – part loaded plant that responds to the fall in frequency by automatically increasing its output. It is essential that at all times the system has the appropriate level of both inertia and frequency response and that frequency response acts quickly and reliably enough to contain the frequency change.

Operating a power system is inherently uncertain as neither the demand nor the output of each generator is entirely predictable. If there is a deficit of generation compared to demand, the frequency will start to fall. If no action is taken this mismatch will be made up by the frequency response on the system, with the risk that the level of response is eroded to the point where it is no longer sufficient to contain a large loss of generation. To avoid this situation the system is operated with a level of reserve. Reserve can either be generation that can increase output quickly or demand that can be reduced in a similar time scale. Reserve is dispatched continuously to make good any mismatch between generation and demand to maintain the frequency at 50Hz and ensure that the frequency response is available at all times. Some generation sources, for example wind, are inherently less predictable than others. The level of reserve carried on the system is varied to reflect the potential scale of the mismatch between supply and demand.

For further information or to discuss the analysis please contact us at:

transmission.UKFES@nationalgrid.com