When the wind blows, constraint costs will ROC

Trident Economics

August 2020

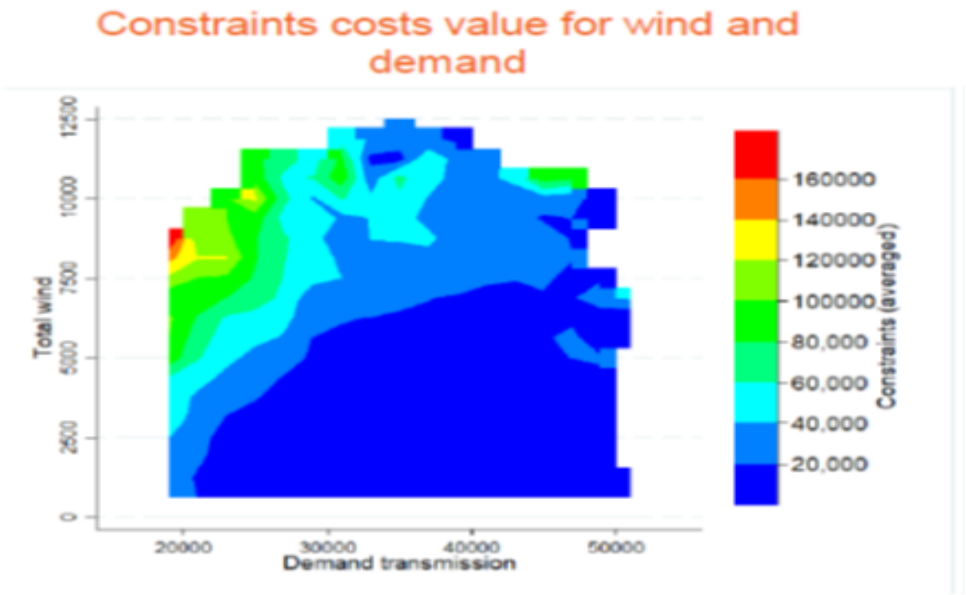
In 2019, a GB electricity industry task force decided that the balancing costs of the GB electricity market could not be effectively charged to the users of the system who caused them. The reasons given seem strong, it is hard to predict balancing costs in advance in order to provide an ex-ante signal for users to change their behaviour and it is also hard to associate general system costs with specific users actions.

The strongest case for locationally varying balancing market charges was in respect of transmission constraint costs. However, the task force report notes that some form of market splitting would be required to provide appropriate marginal price signals each side of transmission boundaries when constraints are active, which is outside the scope of the task force terms of reference. It also, correctly, points out that the GB use of system charges for the high voltage transmission system are supposed to provide locational economic signals and charging locationally varying constraint costs risks double counting these costs.

In this note, we look at the locational signals that are provided by the current transmission charging methodology, with a specific focus on wind generation. The note does not address the potential for locationally varying power prices, despite the clear advantages to such a system as demand grows from users with complex demand optionality, for instance electric vehicles.

There is a strong relationship between constraint costs and relative wind and demand conditions

The below chart was provided as part of the task force publications:



This shows a strong relationship between constraint costs and relative wind output and demand conditions as wind generators unable to generate are compensated for the loss of income from both electricity sales and lost Renewable Obligation Certificates. A weaker or no relationship was discernible for single variable correlation tests, for instance demand versus constraint costs, however this is not a surprise given that it is the relative wind output and demand conditions that the above chart suggests drive the highest constraint costs.

A material portion of the constraint costs would arise over the England-Scotland transmission boundary, raising the possibility of charging specific generators, for instance wind generation in Scotland, these costs.

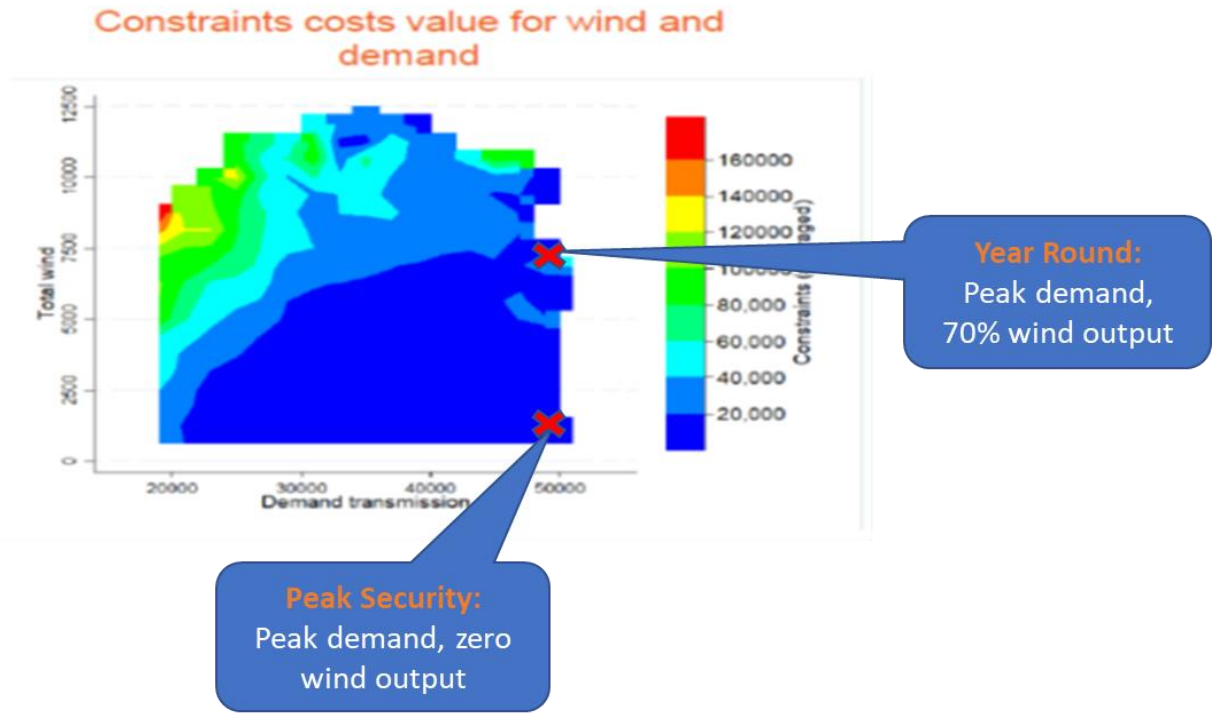
Is the double-counting risk real ?

The GB transmission charging methodology charges users based on an estimation of the network investment costs triggered by the location of their generation or demand. This is estimated by a theoretical rebuild of the UK transmission system to optimise power flows under two sets of system conditions, one reflecting the period of peak demand, 'peak', and one representing more average conditions, 'year-round'. Charges at each point on the transmission system are based on the case under which the local transmission flows are greatest. Whether or not constraint costs are captured by the transmission charging methodology will depend on the extent to which the defined cases capture the circumstances that cause constraint costs and hence trigger network investment (network investment is optimised through the Network Options Assessment process which explicitly assesses the trade-off between constraint costs and network investment options).

From the perspective of the relationship between demand, wind generation and network investment, the key parameters for each case are:

	Peak Security background	**Year Round background**
Demand	Average cold spell peak annual demand	Average cold spell peak annual demand
Wind output (intermittent)	0%	70%

Considering these parameters, the approximate position of the transmission cases relative to system conditions that cause constraint costs is therefore as below:



The conditions considered in the transmission charging methodology do not therefore seem to bear any relation to the system conditions which generate the highest constraint costs and which therefore presumably trigger network investment through the Network Options Assessment process. This raises significant questions regarding the accuracy of the transmission price signals provided for generation and demand on the GB power system.