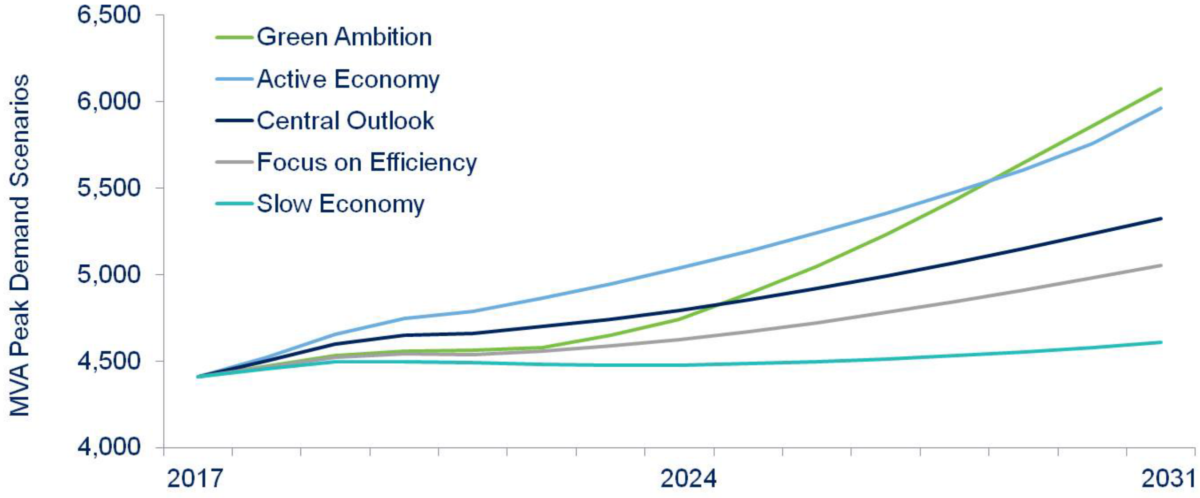
Overview of our ‘central outlook’ demand forecast

For 2017, we have introduced new methodologies and tools to analyse historic demand on our major substations and to produce demand forecasts. This has been developed as part of our ATLAS innovation project.

There remains significant uncertainty around the future for demand, generation and storage in the decades ahead. So we have developed a range of scenarios for our network – we can use these to inform our decisions about efficient development of the network for the long term, so there is sufficient capacity to meet our customers’ needs.

Scenarios for winter peaks



The 33kV and 132kV substation load tables in the 2017 Long Term Development Statement (LTDS) present our ‘central outlook’ scenario for annual peak demand using our new ATLAS approach. This document is an overview of the assumptions behind central outlook demand for 2017.

New connections projects in certain areas of our network, such as central Manchester, are leading to a predicted increase in demand over the next three years. This is not uniform across our region, and justifies our bespoke approach to load forecasting and investment planning. The longer-term trend in expected peak demand growth is more modest. Demand growth from demographic and economic factors is compensated by demand reduction from energy efficiency, to maintain current underlying demand levels, with an increasing contribution from electric vehicles and heat pumps driving the further increase in electricity demand by 2030. Apart from areas of new connections growth, total electrical energy (units) distributed to our customers is not expected to increase until the mid 2020s.

The peak demands in the LTDS tables are based on the normal configuration of our network, so the load will be higher during faults or maintenance conditions. For comparability, they reflect the peak demand of each substation under typical historic regional weather conditions – so the load may be higher in extreme cold weather and lower in warm weather. They also reflect underlying or true demand from our customers; when there is local electricity generation the measured peak demand will be lower than this true demand. Our new methodologies are now able to quantify the contribution of local generation to meeting customer demand.

Key assumptions behind the central outlook forecast of winter peak substation 'true' demand

1. The baseline demand and customer mix per substation reflect the year 1 April 2016 to 31 March 2017.

2. Additional demand from new connections is based on a snapshot of connections activity in June 2017, and interim confidence factors suggesting what proportion of requested demand will be realised.

3. The number of households per local authority changes based on the official scenario from the Department for Communities and local government – initially 0.7% annual growth, reducing to 0.4% by 2039. But wide variations across region; more than 10% cumulative increase in Manchester by the end of ED2, but less than 3% cumulative increase in Cumbria.

4. Domestic energy efficiency improvements occur consistently with current policies such as DEFRA's Market Transformation Programme.

5. National GDP grows based on the Office for Budget responsibility's central view at March 2017 of 2% per year on average, with differences per local authority based on historic trends. This links to growth in non-domestic electricity demand.

6. Non-domestic energy efficiency improvements are consistent with implementation of EU energy efficiency targets.

7. The number of electric vehicles is based on the uptake models developed by Element Energy for the Department for Transport (380,000 by 2030), with the baseline set consistently with data on uptake of electric cars to date, and their electricity demand based on trial data.

8. The numbers of domestic heat pumps (190,000 by 2030) and air conditioning (2.9% of domestic homes by 2030) are based on work done for Electricity North West in 2016 by Delta EE and by the University of Manchester in our Demand Scenarios Network Innovation Allowance project.

9. Non-domestic heat pumps (11,500 by FY31) are based on figures from the Department on Energy and Climate Change in 2014.

The baseline loading data and the scenario assumptions will be updated again in 2018, to produce a new set of scenarios and a new 2018 central outlook for use in network planning and regulatory reporting next year.

About the new ATLAS load models

Our capacity strategy team has introduced new methodologies and tools this year to analyse historic demand on our major substations and to produce demand forecasts. This has been developed as part of our ATLAS innovation project.

These tools can be used to indicate seasonal maximum, minimum and average demand on a half-hourly basis for each major substation in each scenario, out to 2050. The models can also be used to show how these results are affected by changes in the detailed scenario assumptions.

The demand scenario methodology focuses on long-term trends per substation.

1. Our view of true demand through the year is more comprehensive than ever before. First we combine measured demand (from measurements at a substation) with metering data from our generation customers. This half-hourly data is processed to represent normal

system conditions, correcting for data spikes, zeroes and switching actions. To this processed metered demand, we add an estimated output of non-metered generation per substation (eg PV) and an estimate of how much CHP is offsetting customer demand. This half-hourly true demand is then weather-corrected with a regional 30-year weather dataset, based on that particular substation's temperature dependence, to give the half-hourly baseline for the forecast. This work represents a significant advance in our analysis, relative to our previous approach focused only on peak demand and using a national scaling-factor for weather-correction.

2. Our long-term forecasting of active power demand (P, in MW) is based on our work in ATLAS with Element Energy, extending and building on our and their previous methods to develop with them a bespoke scenario model for our network. The electrical energy demand of each of 35 defined customer types is matched to each substation based on geographical datasets from the Office of National Statistics (domestic) and Valuation Office Agency (non-domestic). Their demand then varies over future years based on modelling developed by Element Energy in previous work for the Energy Saving Trust, the Department of Energy and Climate Change, the Committee on Climate Change and the Energy Technologies Institute.

3. Our forecasting of reactive power demand (Q, in MVAr) is a new approach we have developed in ATLAS. The previous REACT innovation project (all DNOs with National Grid, 2013-2015) identified how the interaction of falling power demand at primary substations with the DNOs' 33kV and 132kV networks was leading to increased reactive power exports to the transmission network. ATLAS has built on to this to develop a Q forecasting methodology for a whole DNO network throughout the year, combining the detailed P forecast with seasonal trends in Q/P ratios and time-series modelling of the 33kV and 132kV networks.

4. The peak demands shown in the LTDS tables for the year 2016/17 represent the historic peak true apparent power demands in MVA, adjusted for normal network configuration, normal regional weather conditions at peak demand and local generation output.

5. The peak demands shown in the LTDS tables for future years combine the P and Q scenario results to indicate apparent power demand in MVA.

Last updated 17 November 2017, Rita Shaw, model development lead