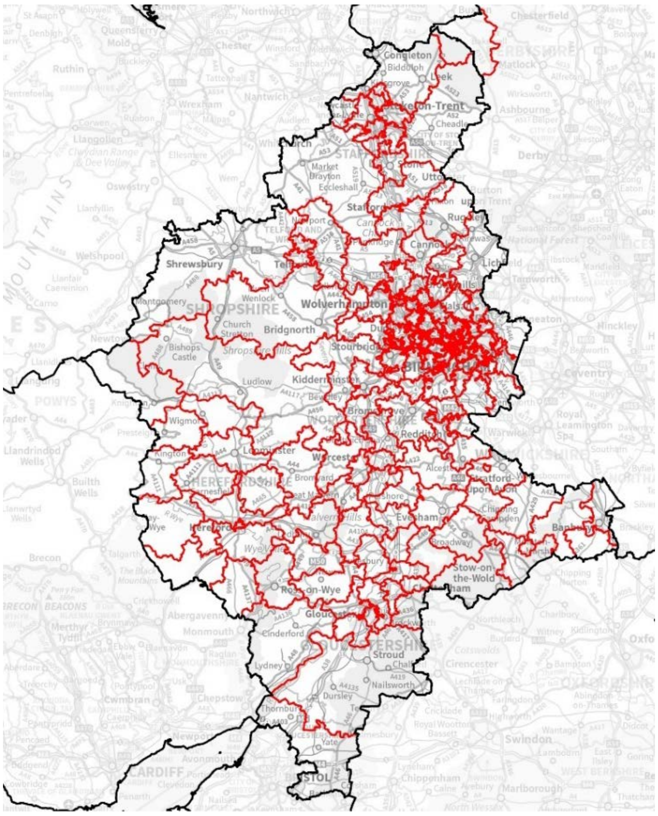
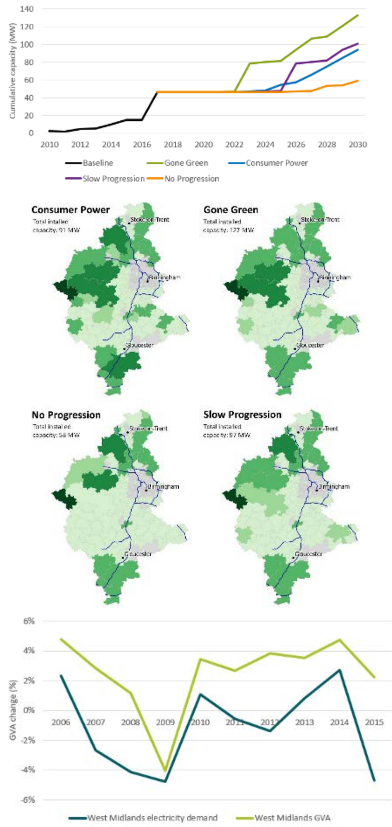
Distributed generation and demand study

Technology growth scenarios to 2030





West Midlands licence area

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Acronym list

Acronym	Definition
ADBA	Anaerobic Digestion & Bioresources Association
AONB	Area of Outstanding Natural Beauty
BEV	Battery Electric Vehicle
CCGT	Combined Cycle Gas Turbines
CCC	Committee on Climate Change
CfD	Contract for Difference
CHP	Combined Heat and Power
DNO	Distribution Network Operator
DSR	Demand Side Response
Duos	Distribution Use of System
EFR	Enhanced Frequency Response
EfW	Energy from Waste
EPN	Eastern Power Networks
ERF	Energy Recovery Facility
ESA	Electricity Supply Area
EV	Electric Vehicle
FFR	Firm Frequency Response
FIT	Feed in Tariff
GIS	Geographic Information System
LCOE	Levelised cost of electricity
NO_x	Nitrogen Oxides
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PPP	Public–Private Partnership
R&D	Research and Development
RDF	Refuse-derived fuel
RHI	Renewable Heat Incentive
RO	Renewables Obligation
SAC	Special Area of Conservation
SRF	Solid Recovered Fuel
SSSI	Site of Special Scientific Interest
STOR	Short Term Operating Reserve
TDR	Transmission Demand Residual
ToUT	Time of Use Tariff
WMS	Written Ministerial Statement

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Introduction and methodology

Background and methodology for a scenario based approach to the forecasting of energy generation, demand and storage on the West Midlands distribution network to 2030.

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1 Introduction

This report focuses on Western Power Distribution's West Midlands licence area.

1.1 "A revolution in the provision of our energy"

"What we see going forward is nothing less than a revolution in the provision of our energy."
Cordi O'Hara, Director of the UK System Operator, National Grid

The UK has experienced unprecedented growth in distributed generation in the last six years. On 7 June 2017, more than 50 per cent of midday electrical power came from renewable sources, a record high[1]. Similarly, in quarter one of 2017, 26.6 per cent of electrical power in the UK came from renewable sources[2]. This represents a huge shift, from a centralised electricity system powered almost entirely by a small number of large scale power plants to a system that includes over 800,000 renewable electricity generators in the UK, mostly connected to the distribution network.

Although current deployment rates for renewable energy have slowed significantly for most technologies due to subsidy reductions and policy change, it is widely accepted that continued rapid change in the way electricity is generated, stored and distributed is inevitable. Distributed generation costs are falling and storage technologies are becoming viable. Electricity demand could change dramatically as electric vehicles are rolled out, heat is electrified and as smart and storage technologies enable users to shift their usage patterns away from peaks.

1.2 Implications for Western Power Distribution

Western Power Distribution and the other Distribution Network Operators (DNOs) have had to adapt to high levels of distributed generation capacity connecting to their network. In the West Midlands, there are over 1,600 MVA of projects connected to the distribution network, with double that holding connection agreements, either accepted-not-yet-connected or offered-not-yet-accepted.

Table 1: WPD's July 2017 connections by technology in the West Midlands licence area

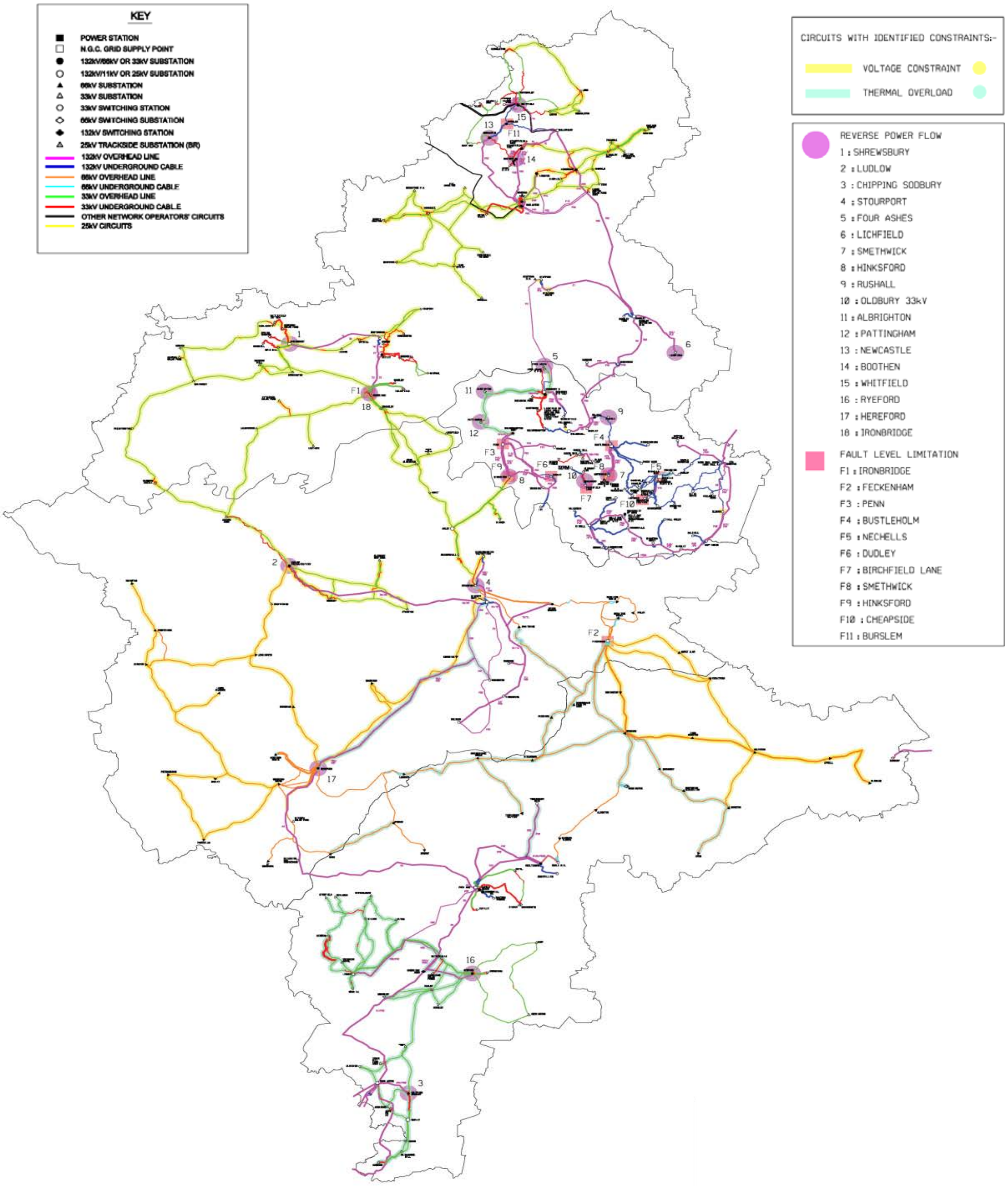
Generator type	Connected [MVA]	Accepted-not-yet-connected [MVA]	Offered [MVA]	Total [MVA]
Photovoltaic	591.4	282.4	22.1	895.9
Wind	48.1	4.0	4.0	56.1
Landfill gas, sewage gas, biogas and waste Incineration	202.0	64.0	5.6	271.5
CHP	13.8	32.8	303.0	349.5
Biomass and energy crops	32.9	16.5	-	49.3
Hydro, tidal and wave power	0.6	0.5	-	1.1
Storage	2.9	704.0	298.6	1,005.4

[1] www.bbc.co.uk/news/business-40198567
[2] www.gov.uk/government/uploads/system/uploads/attachment_data/file/622799/Renewables.pdf

All ‘other generation’ (inc mixed technology sites)	745.4	934.6	553.2	2,233.16
Total	**1,637**	**2,039**	**1,186**	**4,862**

Across the UK, the increased pressure on the distribution networks has led to constraints on the network.

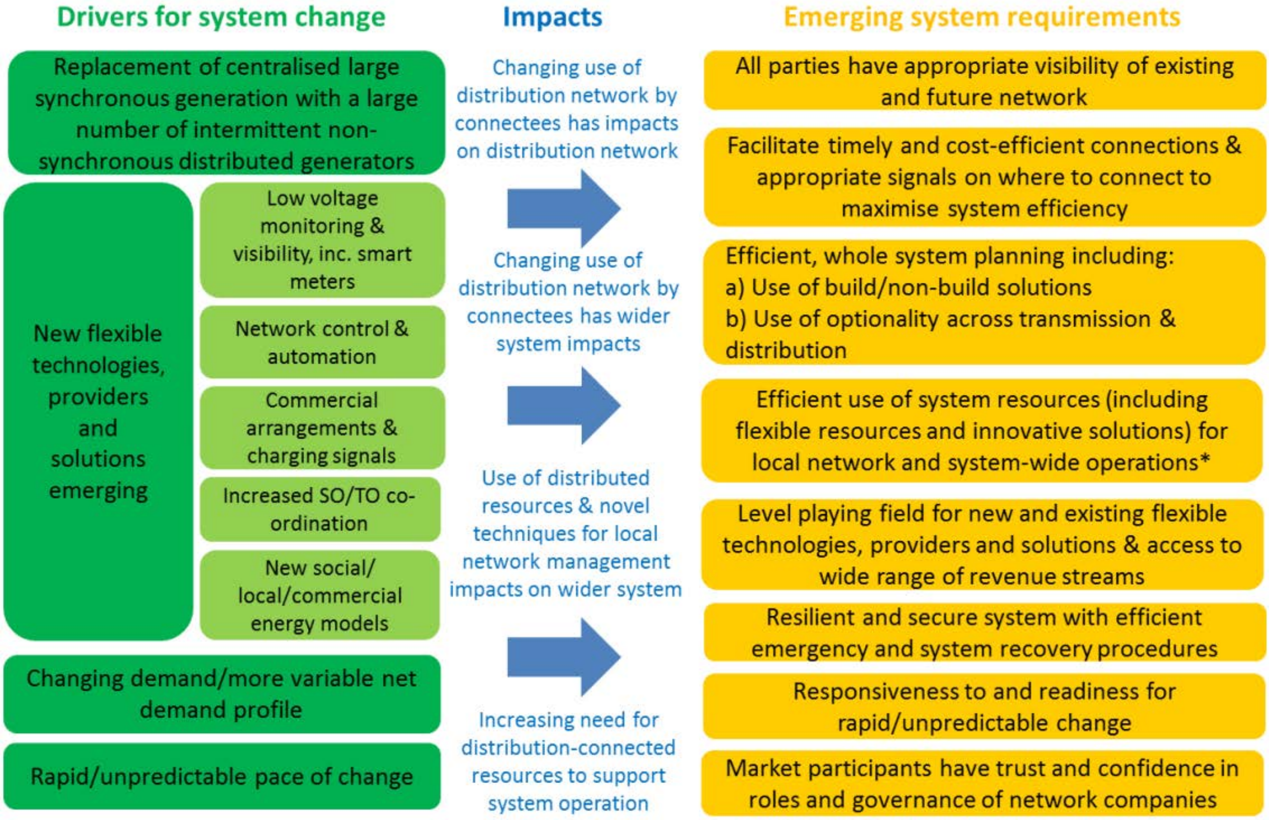
Figure 1: Map of current network constraints in WPD West Midlands licence area (as at May 2017)



Current regulations require network reinforcement costs caused by generators to be borne directly by those generators. DNOs are limited in the strategic network reinforcement they can undertake. While this approach has limited the potential cost to consumers, it has also arguably inhibited long term strategic investment.

Ofgem has recognised that there needs to be changes made to enable our electricity system to adapt to changes in the way electricity is generated, used and stored. Ofgem and the Department for Business, Energy and Industrial Strategy (BEIS) issued a call for evidence in November 2016 on the creation of a "smart, flexible energy system". It included confirmation that the role of DNOs needs to change to enable them to play a stronger role in the energy market, becoming Distribution System Operators (DSOs).

Figure 2: Drivers for change and system requirements (BEIS, 2016, A Smart, Flexible Energy System)



To address constraints on their networks, and in preparation for taking on a DSO role, Ofgem has asked DNOs[3] to undertake "enhanced forecasting and planning" to inform their strategies to address the potential impacts that distributed generation, demand and storage growth will have on their networks.

WPD has recognised that, to develop a robust investment strategy, it needs to have a clear understanding of the different scenarios for potential growth of distributed generation, electricity demand growth and electricity storage in its licence areas; this assessment is the first stage in the process of developing an investment strategy.

WPD have now published their DSO transition strategy, on which topic they discuss:

[3]www.Ofgem.gov.uk/system/files/docs/2017/02/unlocking-the-capacity-of-the-electricity-networks-associated-document.pdf

"Responding to the Government's call for industry to lead these changes, in June 2017, we published the first costed DSO Transition Strategy which outlined our core priorities. During the summer, we invited feedback on our strategy and plans. Our stakeholders told us that our DSO Transition Strategy laid a valuable foundation for the future of energy across all of our licence areas.

With DSOs managing the co-ordination of transmission and distribution services at a local level, it enables the National Transmission System Operator (NETSO) to concentrate on balancing the national network using un-conflicted services competitively made available.

We will continue to review our proposed actions and workplan in line with views received from our customers, other stakeholders, BEIS and Ofgem."

1.3 Building a case for strategic network reinforcement

WPD has developed an approach to identify, assess and provide a business case justification for future strategic reinforcement.

While network reinforcement decisions will need to be justified on a case-by-case basis, it is likely that the starting point to identify strategic investment options will be to identify the network areas with:

- Low or no spare capacity
- A viable network reinforcement opportunity
- High potential for growth of future distributed generation
- Least risk of investment regret or stranded assets
- A strong supporting business case for investment, potentially backed by local stakeholders
- A clear model for cost recovery

To identify and provide an evidence base to support strategic investment options, WPD has set out a 5 step methodology.

Table 2: Strategic investment methodology

Strategic network investment business case development	
Step 1. Distributed generation, electricity growth and demand growth scenarios ***(this assessment)***	Assessing the potential growth in distributed generation, electricity storage and demand by technology type, Electricity Supply Area (ESA) location and year, by scenario
Step 2. Network constraint modelling	Identifying thermal, voltage and fault level constraints that result from scenario modelling
Step 3. Identify and assess options • Estimate the capacity provided by these solutions • Assess cost/timescale of these solutions	Identify and cost a small number of potential network reinforcement strategic investments Identify future network solutions (including required National Grid electricity transmission upgrades)
Step 4. Assess alternative options	Assess the potential for demand side response (DSR), energy storage or generation constraint take up, given the cost of network solutions
Step 5. Present business case and options	Present business case and recommended investment options

The analysis documented in this report is focused on the first step. It is intended to enable WPD to assess future potential growth of distributed generation and demand, providing the key inputs to help WPD identify areas of the network, at Electricity Supply Area (ESA) level, that may require network reinforcement and to make a business case for 'least risk' investment.

2 Methodology

2.1 Objectives and output

The overall objective of this report is to produce an assessment of the potential growth of distributed generation, electricity storage, disruptive demand technologies (electric vehicles and heat pumps) and demand from new development in the West Midlands licence area, under four future scenarios from 2017 to 2030. The approach uses the 2016 Future Energy Scenarios (FES) developed by the National Grid as a starting point.

The main output of the assessment is a data set, which gives an annual capacity growth projection from 2017-2030 by technology type for each ESA, including:

- Current 2017 distributed generation capacity connected
- A pipeline analysis of distributed generation capacity (up to 2020 where possible)
- Scenario analysis of distributed generation technology capacity growth to 2030, building on the FES
- Scenario analysis of potential future demand resulting from new residential and commercial development, heat pumps and electric vehicles from 2016 to 2030, building on the FES
- Scenario analysis of the development of storage

Where appropriate, Geographic Information System (GIS) based maps have been provided to illustrate the spatial distribution of technology deployment growth.

This report accompanies the dataset, documenting the key market insights and assumptions used. The report's aim is to set out the thinking and logic applied, so that, as more data becomes available, the scenarios can be reviewed and updated.

2.2 Assessment scope

2.2.1 Technology scope

Distributed generation technologies

The definition of distributed generation for this report is all electricity generating projects connected to the distribution network in the West Midlands licence area. We have examined potential growth in:

- Solar PV
- Onshore wind
- Hydropower
- Energy from waste
- Anaerobic digestion
- Gas and diesel peaking plant

We have included a more detailed analysis of the potential growth of gas and diesel 'peaking' plant in the West Midlands due to significant growth in the last 18 months of the number of network connection applications for these plants.

Offshore generation is not covered in this licence area as there are no opportunities for the technology in the landlocked West Midlands.

We have included other technologies in the baseline data, but have not considered growth of these technologies either as we conclude they are unlikely to have a material effect on the West Midlands distribution network or because the data available is limited. This should be kept under review as these scenarios are updated. These technologies are:

- Landfill gas
- Sewage gas and combined heat and power (CHP)
- Biomass fuelled distribution connected CHP and electricity only plants

We have not considered any projects that connect directly to the National Grid electricity transmission network, including large scale biomass electricity generation or CHP, large scale gas powered turbines, and nuclear.

Demand

We have reviewed overall trends in power demand in the UK and their implications for the West Midlands. This analysis identified a general downward trend in demand but noted that electric vehicles and heat pumps could have potentially disruptive and regionally specific impact on demand on the electricity network. More detailed analysis of heat pumps and electric vehicles potential growth in the West Midlands was, therefore, carried out.

We have also undertaken a detailed study of potential commercial and residential development growth in the West Midlands to assess where there may be demand growth at a local network level.

Electricity storage

Electricity storage is identified by BEIS and Ofgem as having a key role in the development of a smart, flexible energy system. WPD has received a higher number of network connection applications in the West Midlands than any of its other licence areas. In the West Midlands, in May 2017 there was one connected battery storage project, a further 41 projects totalling 704 MVA with a connection agreement that was accepted-not-yet-connected and 17 projects with a connection agreement that was offered-not-yet-accepted. We have analysed the factors contributing to this high level of activity in the area in order to understand the future growth potential, making comparisons in particular with the neighbouring East Midlands licence area.

We have refined our approach to scenarios for the development of electricity storage and considered six emerging business models, building on the analysis in our paper “Storage: Towards a Commercial Model” and further work on the operation of energy storage assets for WPD. These models are:

- Response services
- Reserve services
- Commercial and industrial (C&I) high energy user behind the meter high energy ‘prosumer’
- Domestic and community scale own use
- Generation co-location
- Energy trader

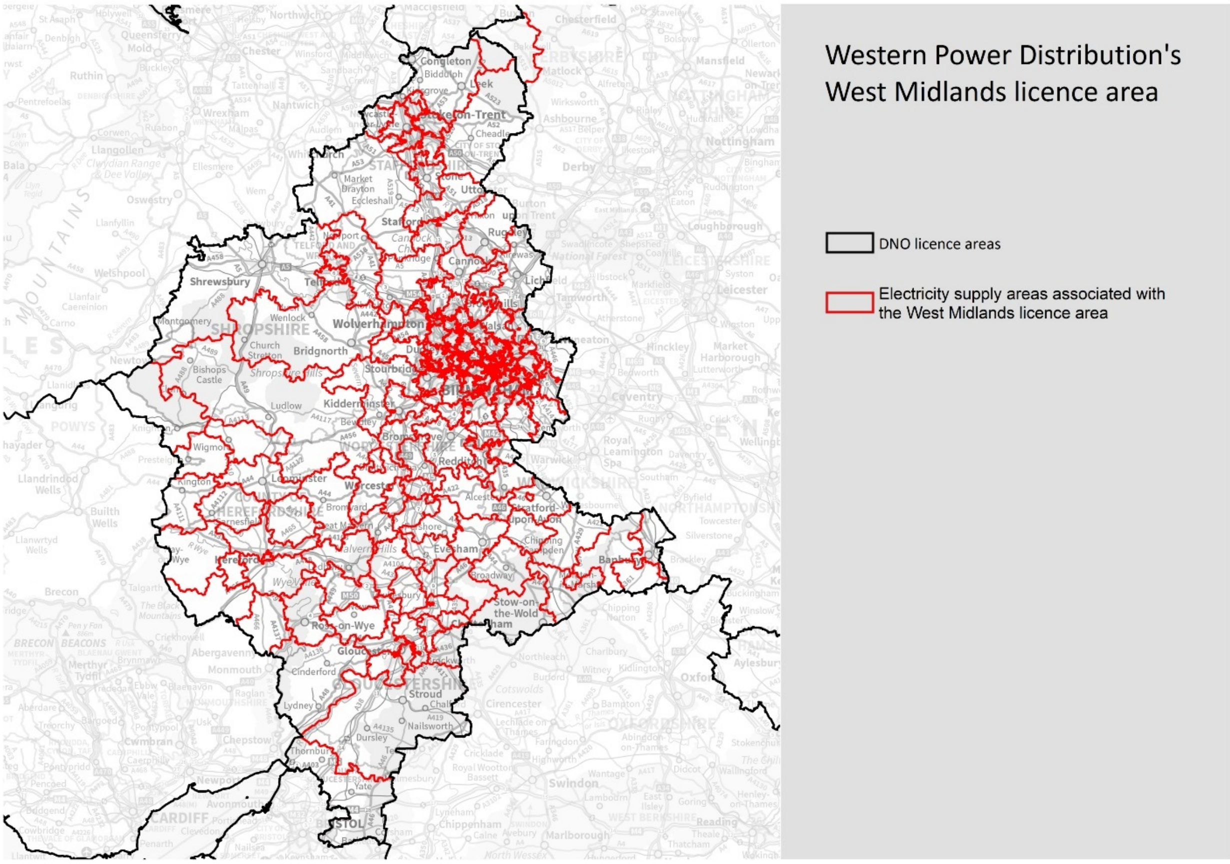
2.2.2 Geographic scope and ESA mapping

The assessment scope is the West Midlands licence area, building on the methodology applied in WPD's East Midlands, South West and South Wales licence areas.

To inform business planning and investment decisions on the distribution network, we have analysed growth of distributed generation (and other technologies) at a local network level. To enable this localised assessment, ESAs have been created. These can be defined as geographic areas served by the same upstream network infrastructure.

Regen and WPD have created the ESAs by mapping data on individual substations and the upstream network point that they are attributed to using GIS software; 141 ESAs have been created.

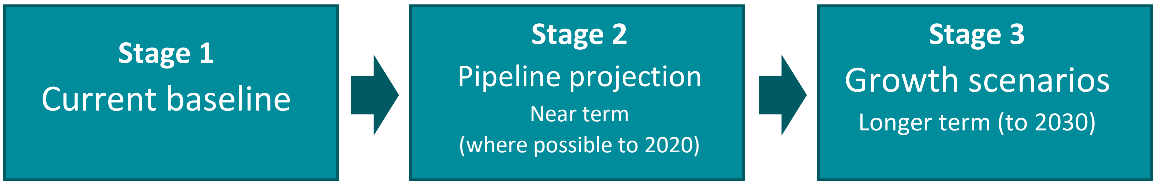
Figure 3: Electricity supply areas in the West Midlands licence area



2.3 Summary of methodology

The methodology to assess potential distributed generation, electricity storage and demand is broken down into three distinct pieces of analysis:

Figure 4: This study's methodology in stages



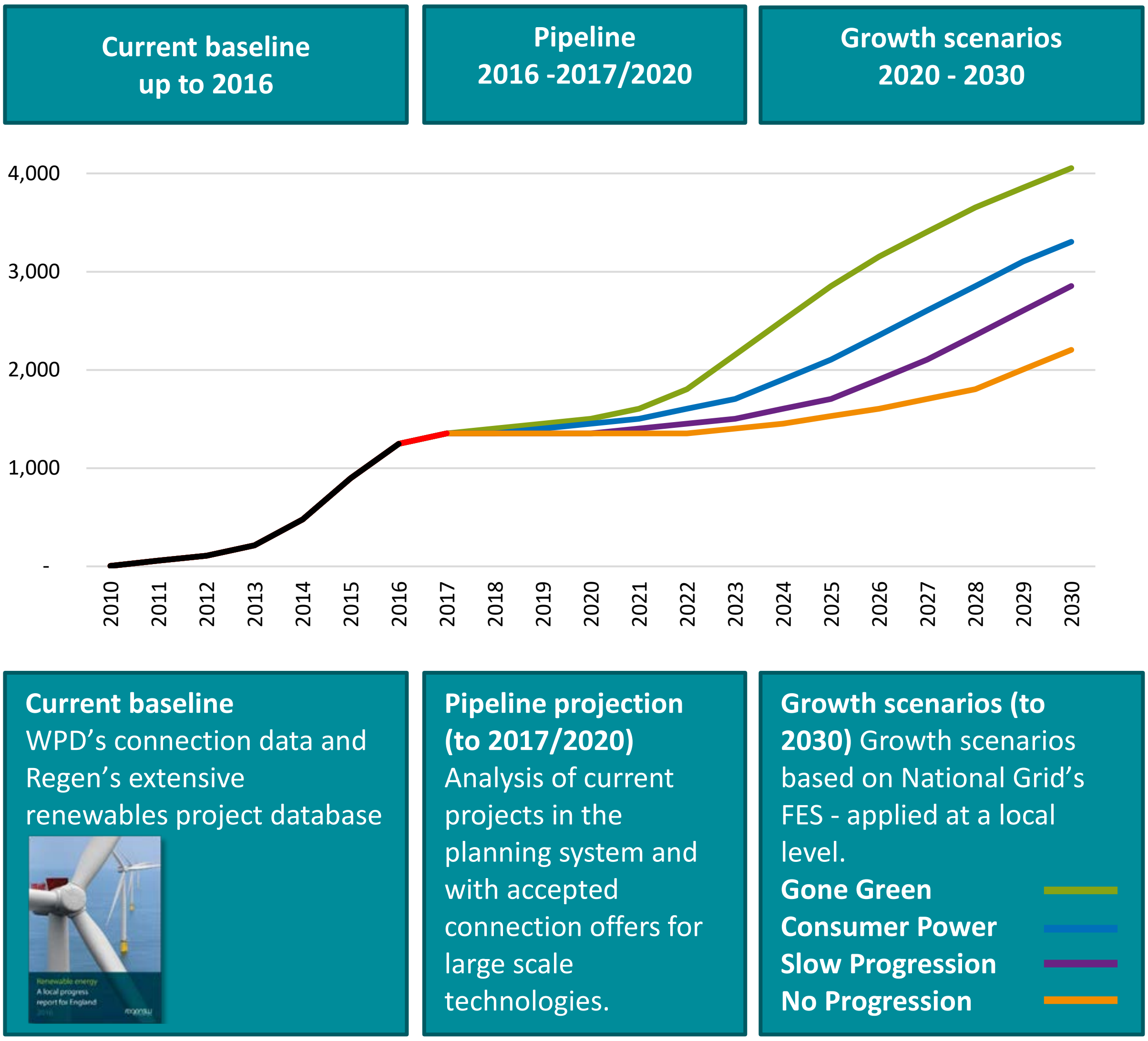
- Stage 1 - A baseline assessment – taken at the end of May 2017. The baseline has a high degree of accuracy as it is based on WPD's database of connected generation, reconciled with Regen's project database and further desktop research to address errors and inconsistencies.

- Stage 2 - A pipeline assessment – looking out to 2020 where possible. The pipeline has a reasonable degree of accuracy since it is based on WPD's database of accepted-not-yet-connected customers reconciled with the BEIS planning database, telephone and internet research and understanding of the current market conditions. For most technologies for this West Midlands assessment, there is no pipeline given the current stalling of the market and/or uncertainties about near term growth rates.

- Stage 3 - A scenario projection – out to 2030. The scenarios are based on the FES, assessed and interpreted to take into consideration the specific local resources, constraints and market conditions. To inform our market insights for each technology, we have undertaken detailed interviews with renewable energy developers and investors, analysed current market reports and applied our own knowledge from over 14 years of supporting the industry. We also ran a consultation event to gather local specific views and information; one event covered distributed generation and storage and the other one covered demand.

To build the baseline and scenarios for demand from new development, we undertook a different methodology which is detailed in section 14.

Figure 5: Illustrative graphical representation of methodology



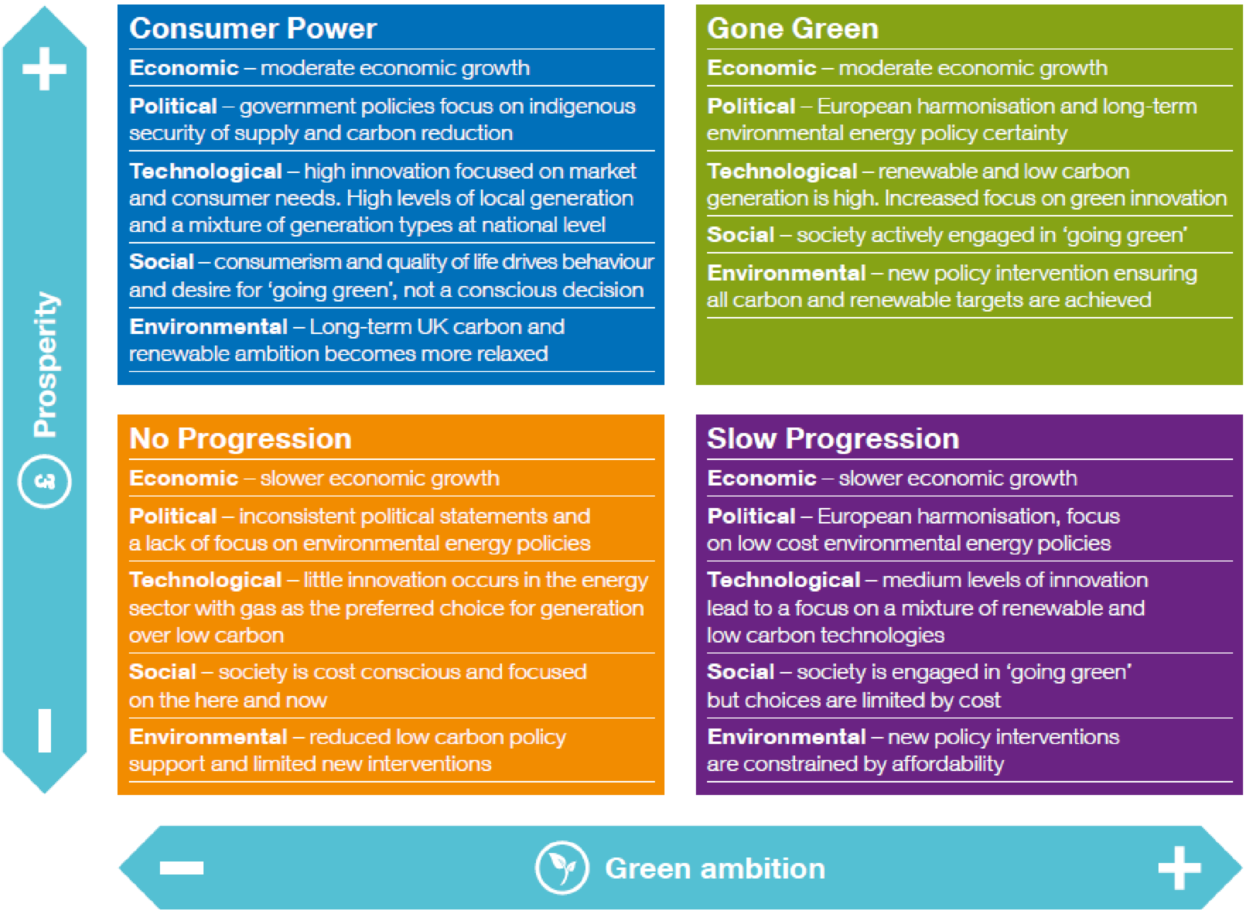
2.4 The scenarios

The assessment estimates potential growth of distributed generation, electricity storage and demand technologies under four scenarios. Based on the FES, these are:

- Gone Green
- Consumer Power
- Slow Progression
- No Progression

The following graphic is reproduced from the FES to illustrate the scenarios that we have based the assessment on.

Figure 6: National Grid 2016 Future Energy Scenarios



In applying the scenarios, we have interpreted the scenarios for the West Midlands licence area, assuming the following general features.

Under the Gone Green scenario, it is assumed that future government policies take a strategic approach to the energy system, consistent with the decarbonisation targets set for 2030 and 2050, and reinforced by the commitments made at the Paris COP. It is assumed that market conditions, financial support and technology development is conducive to the strategic growth of distributed generation, allied to the growth of electricity storage solutions and electricity demand technologies, such as electric vehicles and heat pumps. As a result, overall renewable energy and disruptive demand growth is strongest under this scenario.

The Consumer Power scenario has features that lead to an emphasis on deployment of smaller scale generation and local supply through individuals, communities and other organisations, including technology development and consumers interested in green technologies. Government intervention is more limited under this scenario, with policies supporting deployment where there is demand for it from consumers and communities. The result is widespread, dispersed growth of small and medium scale renewable energy and demand technologies.

The Slow Progression scenario features a strategic approach to renewable energy by government, but in a poor economic environment which means there is a lower government budget for support, less investment capital available and fewer technological innovations. Government policy is focused on the lowest cost actions, unlocking regulation and barriers where it is cost-effective to do so. The result is a medium growth scenario, with a focus on the lowest cost technologies.

Under the No Progression scenario, there is a continued dependence on fossil fuels that would not be consistent with the UK's stated decarbonisation and climate change commitments. The poor economic climate is coupled with a lack of green ambition across society. Growth of renewable distributed generation is slow for all scales and technologies under this scenario.

Section 2

Electricity generation technologies growth scenarios

Analysis, assumptions and market insight behind the future growth scenarios for different electricity generation technologies.

Section contents

3 Electricity generation technology growth scenarios

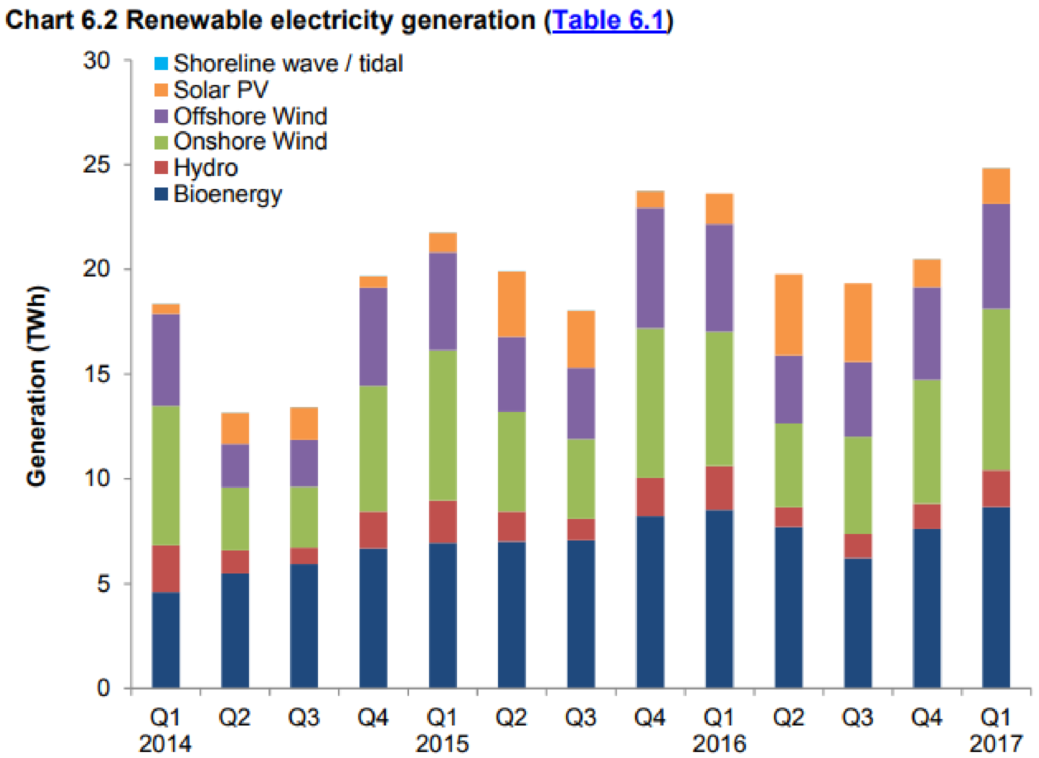
This section of the report sets out our analysis, assumptions and market insights behind the future growth scenarios of the following electricity generation technologies in the West Midlands licence area:

- Solar PV
- Onshore wind
- Hydropower
- Energy from waste
- Anaerobic digestion
- Gas and diesel peaking plant

3.1 UK trends in renewable electricity deployment

Renewable energy deployment has increased dramatically across England and the UK since 2011 and now provides over a quarter of our electricity. According to government statistics, the UK's renewable electricity capacity totalled 36.9 GW at the end of March 2017[4]. Figure 7 illustrates the generation that each renewable technology provides on a quarterly basis.

Figure 7: Renewable electricity generation in the UK, 2014 to 2017[5]



[4] www.gov.uk/government/uploads/system/uploads/attachment_data/file/622799/Renewables.pdf
[5] www.gov.uk/government/uploads/system/uploads/attachment_data/file/622799/Renewables.pdf

Figure 8: Renewable energy capacity growth in England

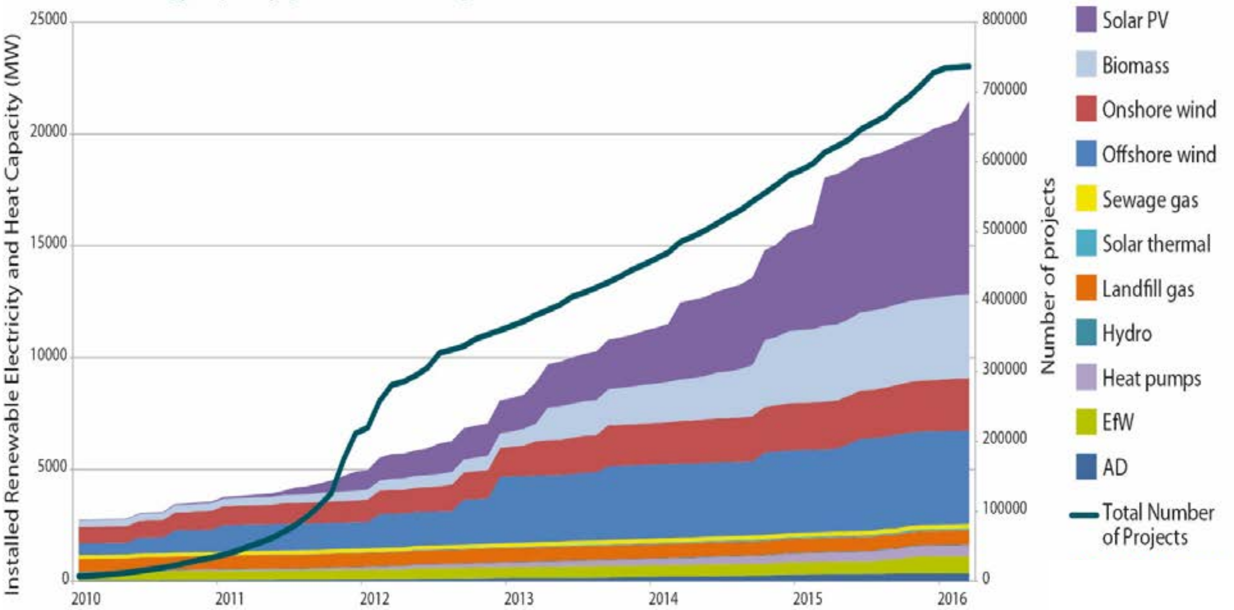


Figure 8 presents the growth of renewable capacity in England to 2016.

A third of installed renewable energy capacity in the UK is now solar PV, a further 32 per cent is onshore wind, bioenergy projects is 16 per cent and offshore wind is 15 per cent. Figure 8 shows the dominance of these four generation types in the English renewable energy mix.

Solar PV has seen rapid growth thanks to the introduction of the FIT, support through the RO, a relatively supportive planning environment and falling costs. Onshore wind has seen much slower, but steady growth across the same period in the UK. Generation from biomass is dominated by co-firing at Drax, with little growth in distributed generation from biomass electricity plants. Offshore wind has grown substantially since 2011, with 160 MW of new schemes commissioned in the UK in the first quarter of the year.

Other renewable technologies have, to date, played a far smaller role in energy generation in England, although they can have significant impacts on the local distribution network where they are deployed.

3.2 Key factors having an influence

Several factors have contributed to the growth of renewables in England to date and will have an impact on future growth. These are discussed in more detail on a technology by technology basis in the relevant chapters:

3.2.1 Government environmental commitments

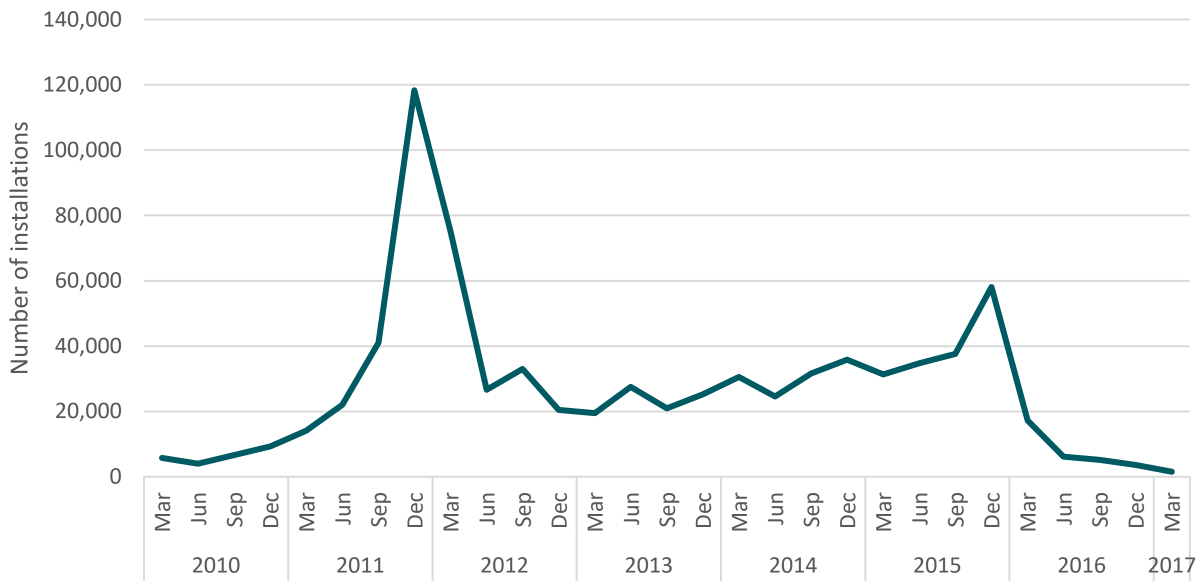
The Climate Change Act commits the government to an 80 per cent reduction in greenhouse gas emissions against 1990 levels by 2050. The target has been broken down into five year portions with a carbon budget setting out how emissions reductions are to be achieved. The UK also subscribed to the Paris Agreement to take action to limit global temperature rise this century to well below 2 degrees Celsius. Decarbonisation of the power sector has a major role to play in the government's plan to achieve our carbon target and to meeting our obligations under the Paris Agreement.

The UK has also agreed to an EU target of meeting 15 per cent of its 2020 total energy demand (heat, electricity and transport) from renewables. Under current predictions, the UK is set to miss this target. Sanctions for missing the target are uncertain, especially given the UK is leaving the EU.

3.2.2 Revenue support

As a result of the UK's carbon and renewable commitments and to support economic development through the growth of new renewables industries, the government provides revenue support for renewable technologies through subsidies. The FIT, introduced in 2009, has had a dramatic impact on the growth of solar PV and to a lesser extent other small scale generation technologies. However, recent cuts to the FIT have all but stopped deployment from 2016, as shown by Figure 9.

Figure 9: FIT installation rates for all technologies, by quarter, showing the impact of subsidy cuts (BEIS, Solar Photovoltaics Deployment in the UK, May 2017)



The Renewables Obligation (RO) offered subsidy support to a range of renewables technology. Its closure on 31 March 2017 has had significant impacts for ground-mounted PV, onshore wind and energy from waste (EfW) deployment. Contracts for Difference, which replace the RO, are not available for all technology types and many technologies are unable to compete on a cost basis for the available support.

3.2.3 Planning environment

Planning applications in England for energy generation plants up to 50 MW and (since 2016) for all scales of onshore wind are determined by local authorities under the Town and Country Planning Act. As a result, the planning environment in England varies depending on the political leanings of the local authority area and the opinions of those on the planning committee. Some areas have seen very high rates of refusal at committee, whereas others have a more positive stance on renewable energy, permitting a higher proportion of applications. As a result, developers have tended to focus their efforts in areas with a reputation for a more benign planning environment.

In 2015, the government announced new rules for onshore wind planning, which have effectively closed England to new planning applications (see section 4.3). As a result, developers are focussing their efforts on Wales, Scotland or overseas. Planning policy for other technologies has not changed, but the planning environment remains a significant factor in determining where developers look for sites. Any further changes will impact on deployment rates.

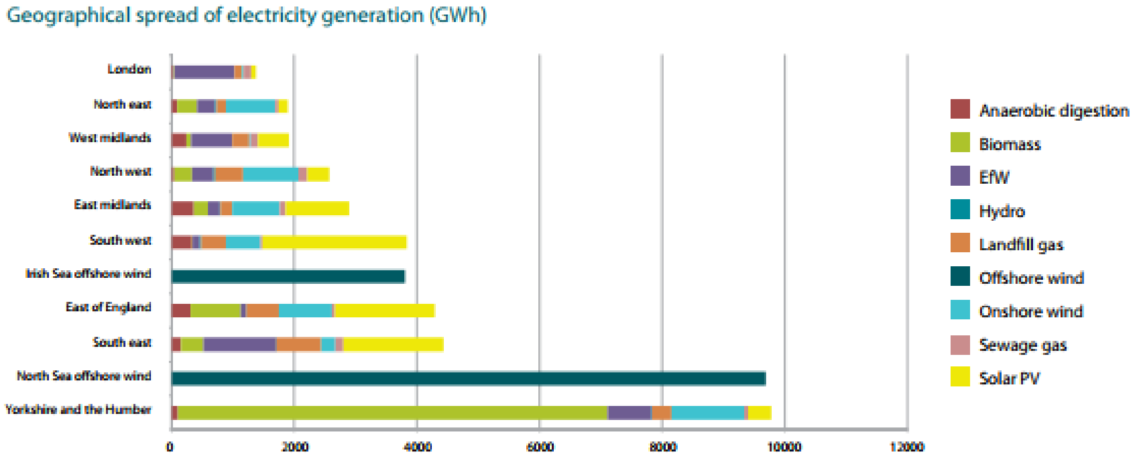
3.2.4 Global market

Falling costs have had a significant impact on the deployment rate of renewable energy, particularly in relation to onshore and offshore wind and solar PV where a growing global market has driven down costs at a remarkable rate. Looking forward, global cost reductions are likely to have a significant impact for the UK's solar PV and wind markets. Other technologies such as AD and hydropower are more mature and not expected to see significant cost reductions. The deployment rate of Advanced Thermal Treatment (ATT) technologies which produce energy by gasifying waste will also be linked in part to innovation and cost reductions from the global market.

3.3 Baseline in the West Midlands

Data from Regen's 2016 progress report shows that the West Midlands region has a relatively low uptake of renewable generation compared to other areas of England, ahead of just the North East and London.

Figure 10: Renewable electricity generation by English region (GWh)[6]



Deployment of renewable electricity capacity in the West Midlands has grown at a slower rate than other areas, with the exception of anaerobic digestion and energy from waste. In particular, ground-mounted solar PV has been slower to take off in the West Midlands than in other more southerly and easterly areas with higher irradiance levels. Despite this, solar PV dominates renewable electricity capacity in the licence area, with ground-mounted PV making up 44 per cent and rooftop an additional 31 per cent of total installed capacity. In terms of generation within the licence area, energy from waste with its higher capacity factor has the most significant impact, supplying around a third of renewable electricity in the area.

We analyse the reasons for the slow growth of renewables in relation to each technology in the following chapters. The overriding factor that has contributed to slow growth in the West Midlands tends to be that the area has a lower resource than other areas in England. In addition, the middle section of the licence area has a 66 kV network, making it more expensive for smaller scale renewable projects to connect to.

[6] Regen's 2016 Progress Report. Note the West Midlands region covers a slightly different area to Western Power Distribution's West Midlands licence area.

Figure 11: Historic growth of renewable electricity capacity in the West Midlands licence area

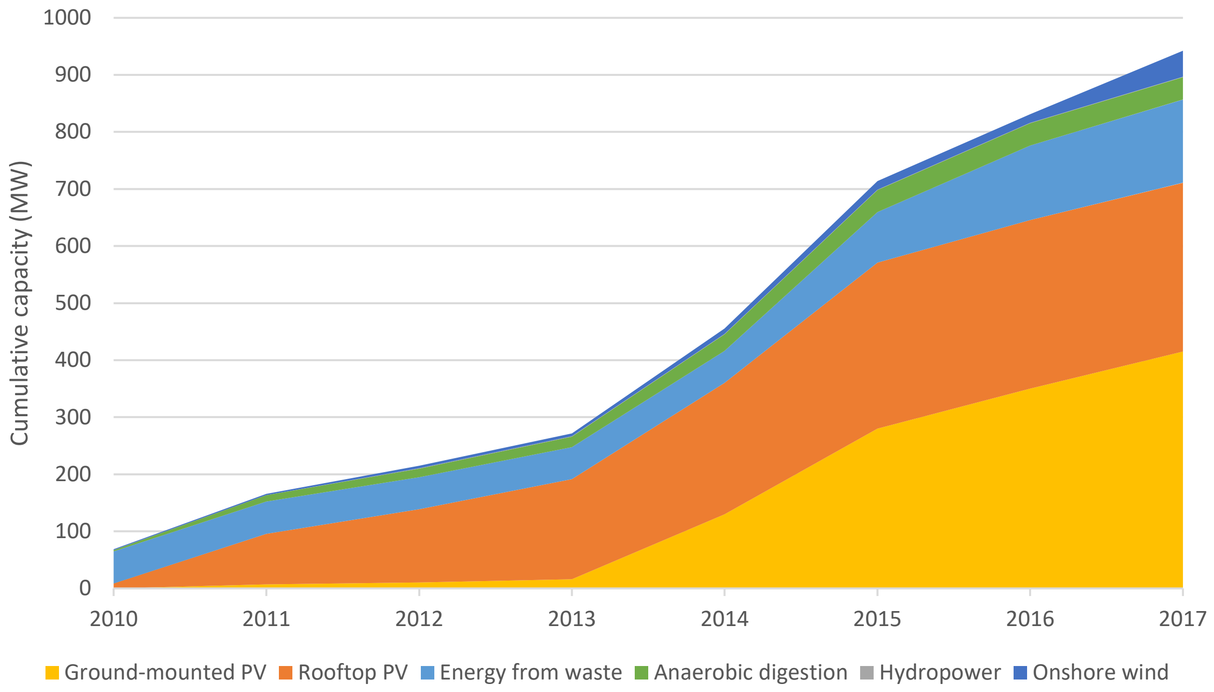


Figure 12 compares the connected and accepted-not-yet-connected generation capacity and system demand in each of WPD's licence areas. The West Midlands has the lowest connection generation capacity of the four areas, but a relatively high level of accepted-not-yet-connected connection offers. Despite these offers being in place, our analysis shows the pipeline of projects expected to be built by 2020 is relatively empty, largely due to changes to the subsidy regime.

Figure 12: Generation capacity and system demand by licence area (WPD, 2017)

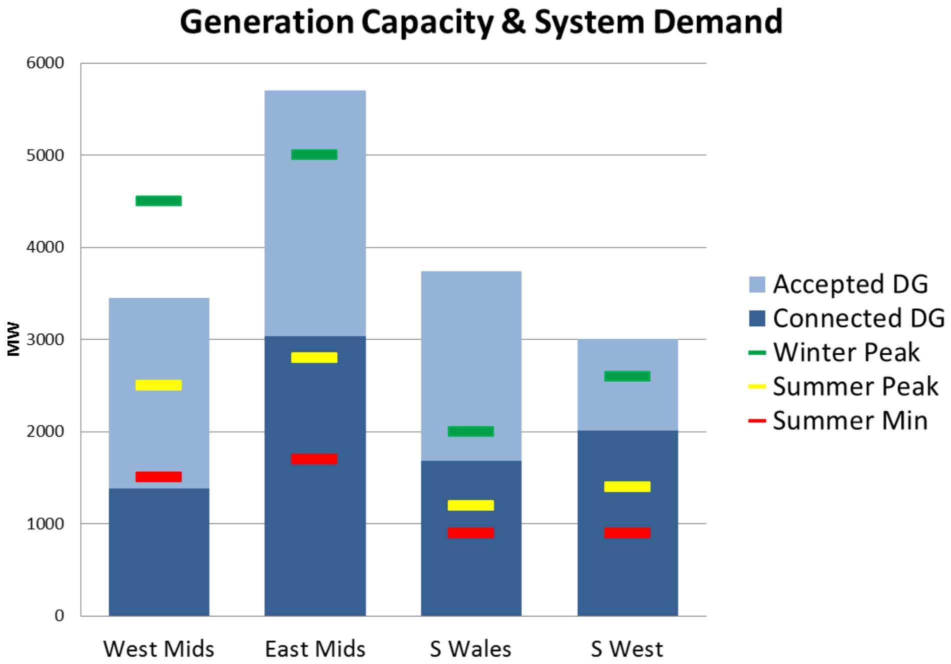
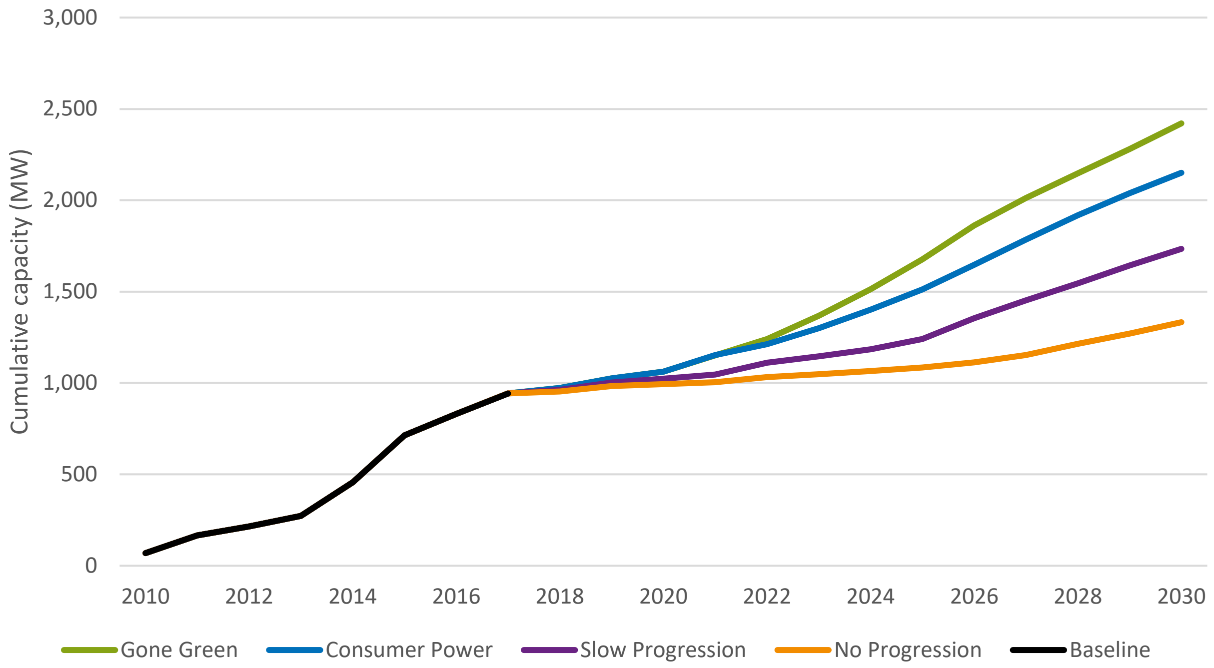


Figure 13 shows the combined results of the scenarios' analysis for all renewable electricity technologies. After 2020, our scenarios show substantial potential for growth in renewable electricity capacity in the licence area, although due to lower resource availability and low historic deployment rates, this is lower than predicted growth in other licence areas. Under a Gone Green scenario, renewable electricity deployment in the licence area could reach almost two and a half times current installed capacity. However, a No Progression scenario would see very little growth within the licence area.

Figure 13: Renewable electricity capacity projections by scenario in the West Midlands



4 Onshore wind power

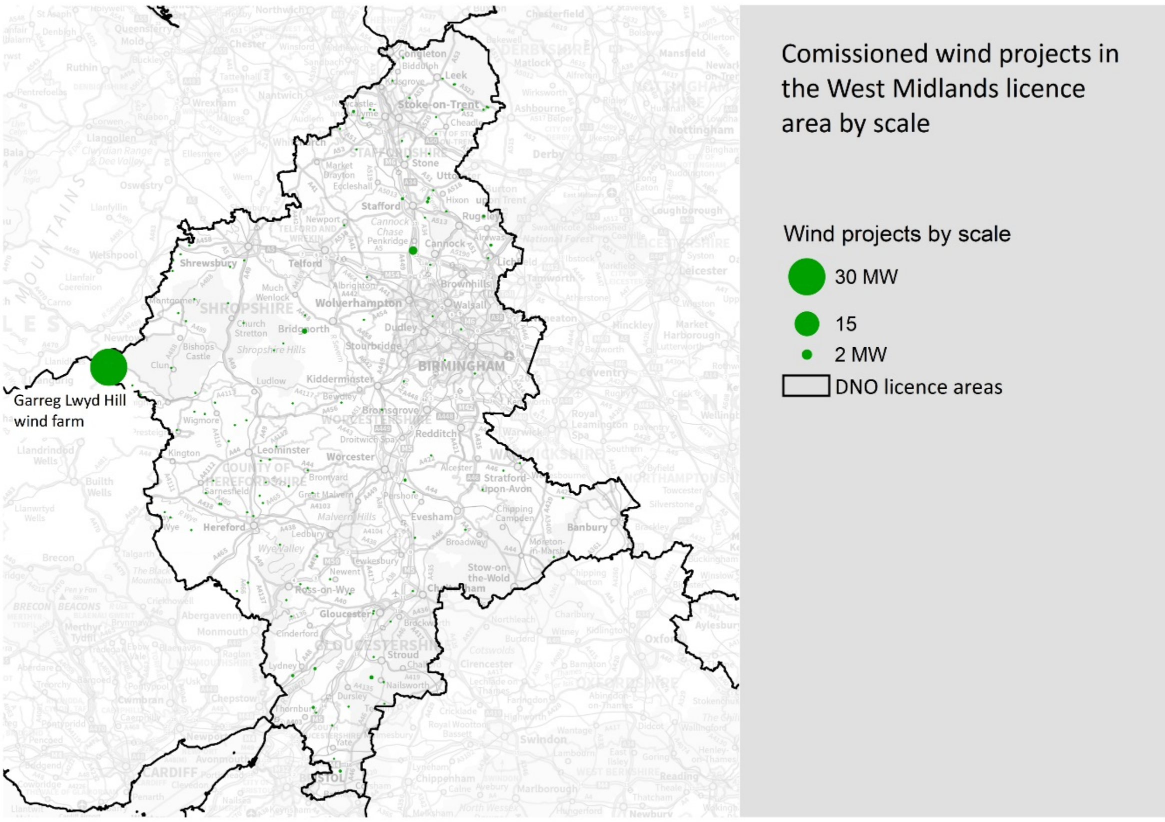
4.1 Baseline: onshore wind growth to 2016

4.1.1 Large scale wind baseline

The West Midlands licence has 17 large scale wind projects in the licence area (500 kW and above), totalling 45.1 MW, compared with 72 large scale projects totalling 352 MW in WPD's East Midlands licence area. Wind power capacity is dominated by RES's 30.6 MW Garreg Lwyd Hill Farm commissioned in February 2017, which lies to the very west of the licence area in Powys, Wales. This wind farm was refused at committee by Powys County Council, approved at appeal by the Planning Inspectorate and upheld by the Welsh Minister for Natural Resources.

At South Staffordshire College in Penkridge, REG Windpower installed two 2 MW turbines in November 2016. There is one further turbine over 1 MW at Sharpness Docks in Gloucestershire and a further 900 kW turbine in the licence area.

Figure 14: Commissioned wind projects in the West Midlands licence area by scale

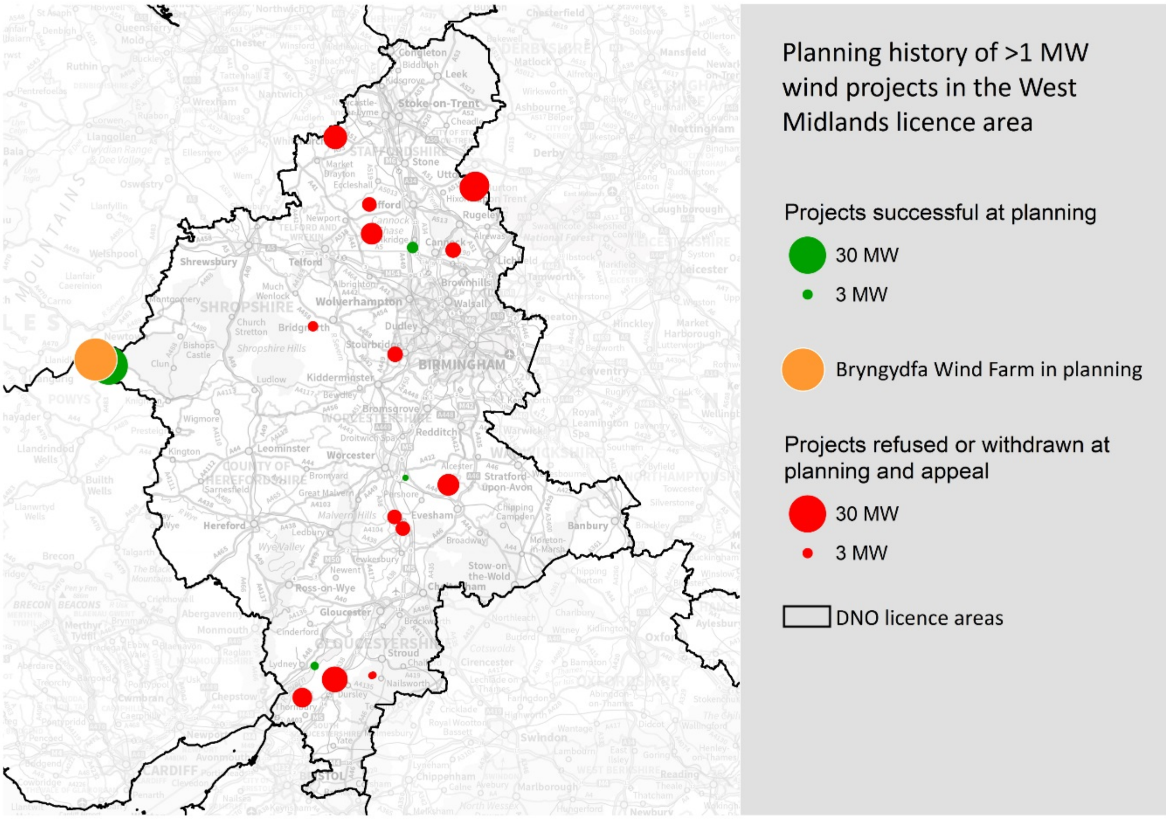


The remaining 12 large projects are single or double 500 kW turbine projects. One of these, Lynch Knoll is Ecotricity's first installed wind project, dating back to 1996. The remainder are predominately owned by farmers or by the local community. Resilient Energy is a community focused renewable developer based in Lydney in the licence area, and responsible for several of the schemes.

The wind resource is limited in the West Midlands compared with other areas of England due to large areas of designated landscapes and a relatively dense population. Pockets of wind resource are available, however, there have been few wind planning applications and these have had a poor success rate, with 15 projects over 1 MW refused or withdrawn and just 4 successful projects. Fewer projects have been proposed in the central/lower central horizontal band of the licence area as the network is 66 kV, making it more expensive to connect to.

Bryngydfa, a 30 MW wind project adjacent to the Garreg Lwyd wind farm in Powys, was submitted for planning permission in 2009. The application is still being processed and the developer is currently updating their Environmental Statement. As the project is in Wales, there is more likelihood that it will get planning permission than if it were in England due to a more positive stance on wind by the Welsh Government.

Figure 15: Planning history of projects over 1 MW wind projects in the West Midlands licence area



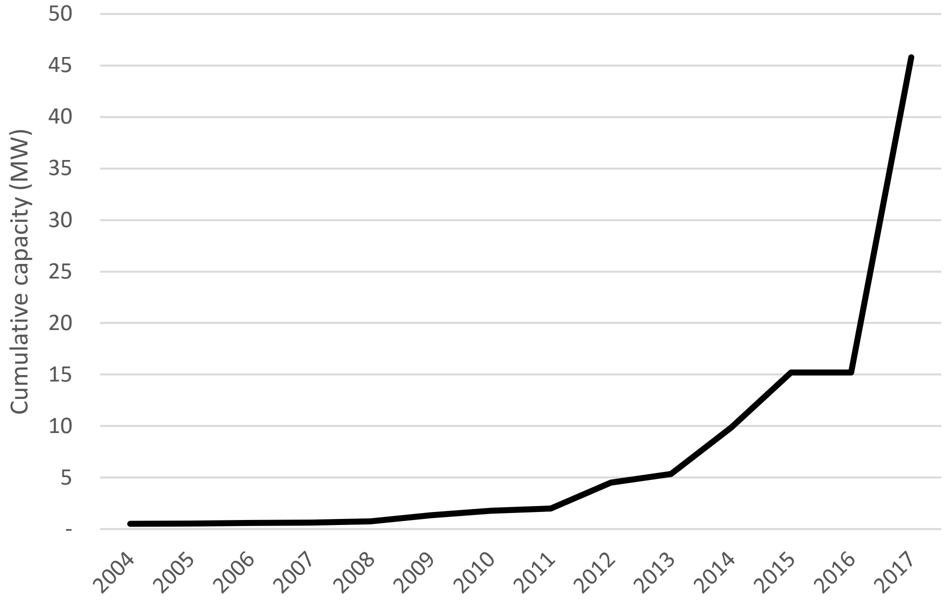
4.1.2 Small and medium wind baseline (under 500 kW)

There are a limited number of small and medium scale projects in the West Midlands with 106 turbines under 500 kW, totalling less than 1 MW. This is significantly fewer than other areas of the UK, such as the South West where there are over 700 projects of this scale. Most projects in the West Midlands are towards the smaller end of the scale, with 85 per cent of projects under 15 kW representing less than 2 per cent of the licence area's total wind capacity.

4.1.3 Historic growth rates for onshore wind

With a limited number of projects within the licence area, growth was slow before Garreg Lwyd was commissioned in 2017. In other areas of the UK, onshore wind's growth curve has been fairly steady since the first onshore wind turbines were installed in the 1990s. In the West Midlands, growth prior to 2010 was very limited.

Figure 16: Growth of onshore wind in the West Midlands licence area



4.2 Pipeline: onshore wind, 2017 to 2020

There are no large wind projects within the licence area with planning permission that are yet to constructed and so no pipeline of projects that could be built by 2020.

For small and medium scale projects (sub-500 kW), we have analysed WPD's connection agreement data, taking out duplicates, commissioned projects and those that have failed in planning. This analysis shows there are also no sub-500 kW projects in the pipeline.

4.3 Regen's market insights: onshore wind

4.3.1 Onshore wind project economics

Onshore wind subsidies have been significantly reduced:

- the RO closed a year early for onshore wind (March 2016).
- the FIT (for schemes up to 5 MW) has been reduced dramatically for all scales
- Contracts for Difference (the scheme which is replacing the RO) are unlikely to be available for onshore wind.

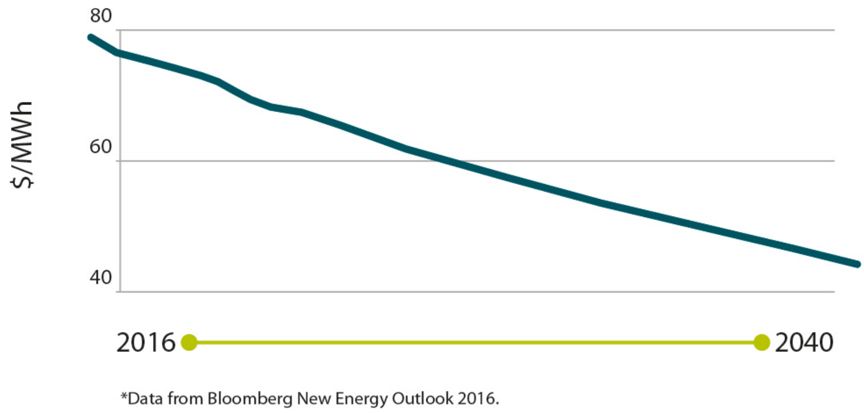
Projects currently being constructed are, in general:

- large scale projects that are eligible for one of the RO grace periods (which extend out to January 2019 depending on project circumstances)
- or single or double turbine schemes of all scales where the energy can be used on or near site through a private wire arrangement.

Global onshore wind costs have fallen dramatically in recent years and are expected to continue to fall. Developers are beginning to bring forward projects that are viable based on the wholesale price of power without any subsidy – such as Good Energy's proposals for the Big Field Wind Farm in Cornwall.

Bloomberg New Energy put the 2030 cost of onshore wind at around \$60/MWh (around £48/MWh).

Figure 17: Bloomberg onshore wind cost forecast



BEIS's 2016 report on the Levelised Cost of Energy (LCOE) puts new onshore wind projects commissioning in 2025 at a lower cost per MWh than the next generation of Combined Cycle Gas Turbine (CCGT) projects.

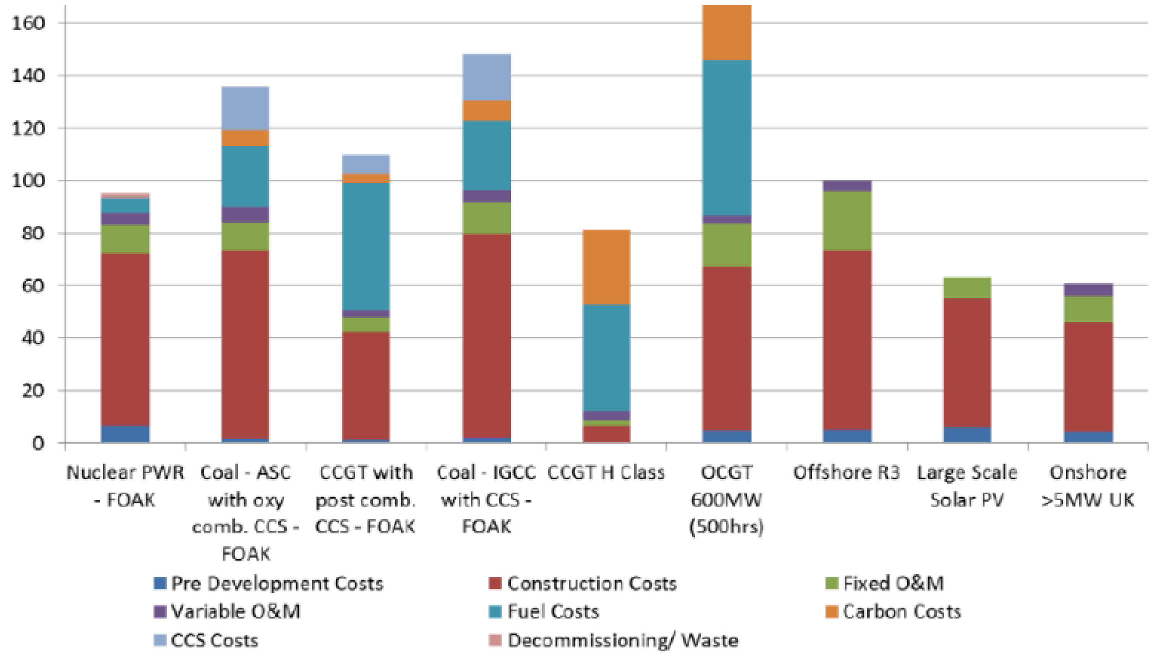
Current costs have also decreased, with DECC's previous 2013 report putting a central estimate of the cost of onshore wind in 2016 at £88/MWh, compared with £64/MWh for 2016 in the latest BEIS report.

In general, developers are moving towards installing larger turbines; planning and installation costs do not increase in proportion to size, whilst electricity output and, therefore, income increase disproportionately as the turbine's height and swept area increases.

Small scale stand-alone wind economics should improve as a result of the global market; however, without a subsidy, we consider they are unlikely to be widely economically viable outside of private wire applications until the late 2020s. In particular, planning costs tend to be similar regardless of turbine scale, meaning that they are proportionally higher for small scale projects. For example, since 17 December 2013 community consultation has been required for:

- the installation of one or more turbines over 15 m hub height (nearly all turbines exceed this height);
- any installations of more than two turbines whatever the hub height.

Figure 18: BEIS's 2016 LCOE: Levelised cost estimates for projects commissioning in 2025, technology-specific hurdle rates, £/MWh



Certainty, not subsidy, is needed to support onshore wind

A key challenge for wind developers operating without subsidy is the uncertainty around the market price of power, which creates risk, increasing the cost of capital. Making Contracts for Difference accessible to onshore wind (even if the price offered was at the wholesale price of power), the provision of government backed PPAs or of other price guarantee mechanisms would offer certainty to the market, reducing risk and the cost of capital.

4.3.2 Planning is the key issue for onshore wind

Despite falling costs, the market for all scales of onshore wind in England has stalled as a result of changes to the planning regime. On 15 June 2015, the Secretary of State published a Written Ministerial Statement (WMS) that states:

When determining planning applications for wind energy development involving one or more wind turbines, local planning authorities should only grant planning permission if:

- the development site is in an area identified as suitable for wind energy development in a Local or Neighbourhood Plan; and
- following consultation, it can be demonstrated that the planning impacts identified by affected local communities have been fully addressed and therefore the proposal has their backing.

The majority of local and neighbourhood plans do not identify areas for wind development, meaning that in effect, according to national policy, wind cannot be developed in England.

Developers that we have spoken to have cited this heightened planning risk as a major barrier to further development and there are very few applications currently being prepared for projects in England. Whereas previously developers and investors were prepared to risk the £500,000 or more to take projects through planning on the basis that across their portfolio some would succeed, the low likelihood of success means that the risk is now too great. Developers are building out projects that have planning permission and consolidating their portfolios.

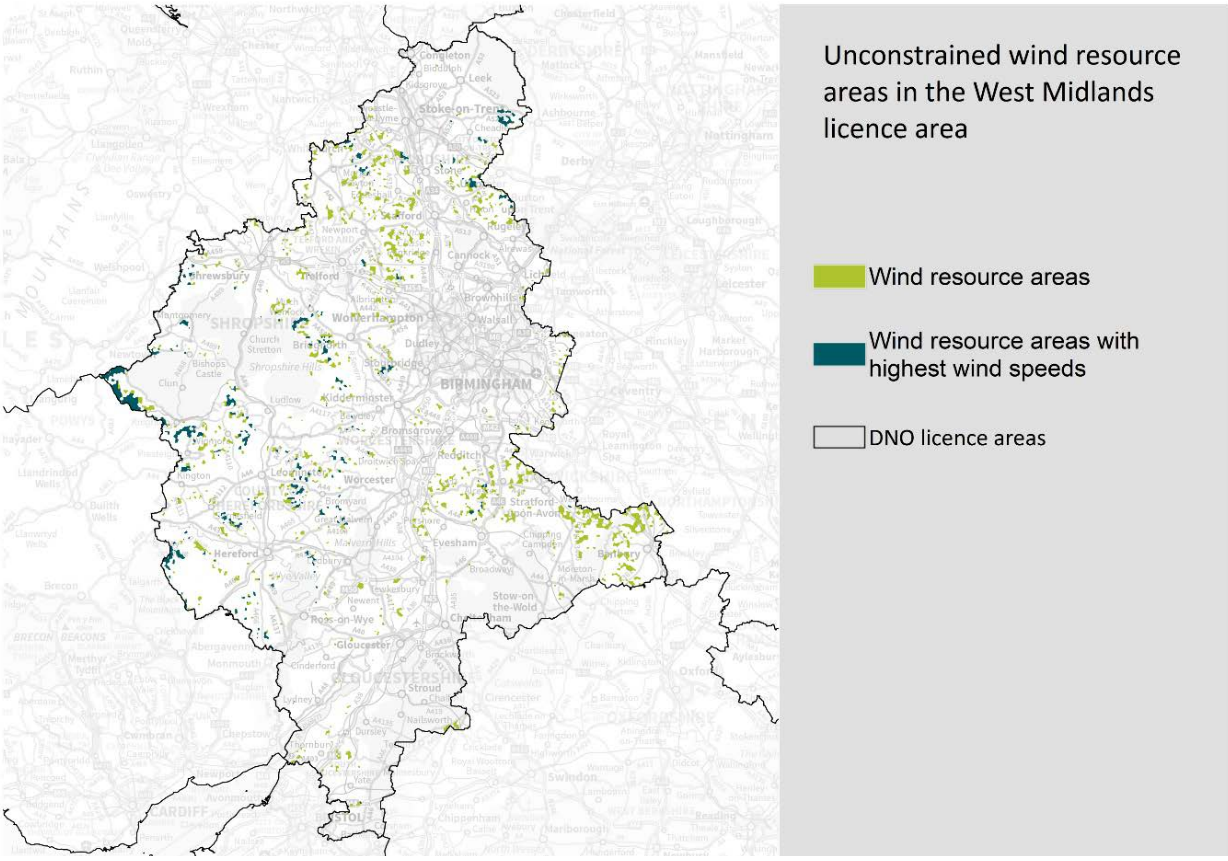
If the government changes the current very restrictive planning policy, either back to the previous difficult but possible approach, or to an approach which is favourable, onshore wind deployment will pick up relatively swiftly. Developers have sites that are "on ice" waiting for a change in policy. In the meantime, developers are focussing on wind sites in Wales and Scotland (or abroad) or shifting towards deploying other technologies.

The 2017 election result means that, at least in the short term, there is unlikely to be any change to the current policy situation. The Conservative Manifesto stated "we do not believe that more large-scale onshore wind power is right for England."

A small corner of the West Midlands licence area is in Powys, Wales. The existing 30 MW Garegg Lywd wind farm falls in this area and a planning application for a further large scale project on adjacent land is being prepared. If submitted, this project will be determined under the Welsh planning system, which is more positive in relation to large scale wind.

4.4 Resource assessment: onshore wind potential

Figure 19:Onshore wind technically unconstrained resource areas in the West Midlands



In order to understand the potential for onshore wind and the geographic distribution of projects under each scenario, we have undertaken a resource assessment. Areas with environmental, heritage and physical constraints, areas too far from the network and areas with low wind speeds were excluded from the analysis. Figure 19 shows the remaining areas with potential for onshore wind.

There are 200 km^2 of technically developable space, representing 1.5 per cent of the total land area. This is significantly less than the neighbouring East Midlands area, where there is 1,500 km^2 of technically developable space. In the West Midlands, just 4 km^2 is considered to have a currently economically viable wind speed. Areas with the best wind resource are to the west and north of the region.

4.5 Scenarios: onshore wind, 2020 to 2030

4.5.1 Factors affecting the scenarios: onshore wind

Most of the factors only have a small part to play; it is the current planning environment that is holding back all scales of onshore wind development.

Table 3: Potential factors enabling onshore wind deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Price guarantee mechanism introduced for large scale wind e.g. CfD or government backed PPA	●			
Government re-introduces limited revenue support for small and medium scale turbines		●		
Planning environment changes to enable commercial wind development, with a strategic approach favouring large scale projects over small scale	●		●	
Planning environment changes to enable community scale wind development	●	●		
Technology costs				
Global prices continue to fall rapidly	●	●		
Technological innovation – turbine efficiencies improve rapidly	●	●		
Negative medium and long term impact of Brexit on import costs				●
Electricity network connection costs				
Lower network reinforcement costs – enabled by strategic investment	●		●	
Lower network reinforcement costs – enabled by ‘smart’ solutions, active network management and demand response solutions etc.	●	●		
Wholesale price of power				
Rising electricity wholesale price – potentially driven by economic growth, increased demand and/or falling supply	●	●		
Availability of finance				
Strong economy or government backing means investment capital is available	●	●	●	

Under all scenarios, onshore wind growth is limited in the West Midlands licence area due to the relative lack of available resource and difficult local planning environment, both of which have contributed to the historically low growth rate.

Beyond one 500 kW turbine, currently installed large scale projects are not due to repower within the timeframe. We have assumed that the 500 kW project would repower under Gone Green and Slow Progression as a 1 MW turbine after 25 years.

As noted above, the planning regime is currently the main brake on onshore wind deployment. We have assumed this restriction is removed under Gone Green and Slow Progression, resulting in deployment of one additional 30 MW wind site (at a site which has been proposed previously), a small number of 5 or 10 MW sites and a limited number of 500 kW turbines. Small/medium scale deployment remains low under both Gone Green and Slow Progression, as the government takes a strategic approach to onshore wind, favouring larger scale projects.

Under the Consumer Power scenario, small/medium scale deployment is highest, but large scale deployment is limited to a small number of double turbine projects. Under this scenario, the government favours "consumer-led" projects including projects by farmers, small businesses and community groups, with 500 kW turbines dominating in this licence area. The government offers support to enable this scale of project by offering limited revenue support and a favourable planning environment.

The No Progression scenario reflects the status quo; ongoing planning restrictions affect all but the very best sited projects for all scales.

Table 4: Scenarios summary for onshore wind in the West Midlands licence area

Consumer Power	Gone Green
• Low growth scenario for large scale projects, which are limited to a small number of double turbine projects with community support due to planning regime • Highest scenario for the deployment of small and medium scale turbines for private wire, community and network-connected on farm projects, supported by the re-introduction of limited revenue support for this scale and changes to the planning regime • The deployment of small and medium scale turbines exceeds its previous peak as a result of global cost reductions over the course of the decade.	• Highest overall growth scenario with wind cost parity reached imminently for large scale turbines, potentially backed by a price guarantee mechanism • Changes are made to create a positive planning environment that prioritises large and medium scale projects; commercial scale are limited by West Midlands geography to one 30 MW project and a small number of multi-turbine projects. • Community scale projects around 500 kW continue to be the dominate project type in terms of numbers in this licence area, (although deployment is at a lower rate than under Consumer Power.) • **Small scale:** Planning favours strategic larger scale projects. Small scale deployment remains restricted to private wire projects until technology costs fall late in the decade.

No Progression	Slow Progression
• Lowest growth scenario • Poor planning environment restricts most schemes, with poor economic situation also having an impact • Growth is very slow – only schemes with strong community support would be built in the most favourable areas.	• Medium growth scenario • A positive planning environment is created for large and medium scale, unlocking the potential for deployment from 2023. Large scale projects are limited in West Midlands due to resource availability. • Growth is at a slower and lower rate than under Gone Green due to the lack of price guarantee mechanism and poorer economic environment • Projects are focused in high resources areas in most attractive ESAs • **Small scale:** As under Gone Green, deployment is limited both by a strategic planning approach to wind and a lack of revenue support provision. The poor economic situation further limits deployment.

4.6 Scenario results: onshore wind

Figure 20: Scenario growth of onshore wind in the West Midlands licence area

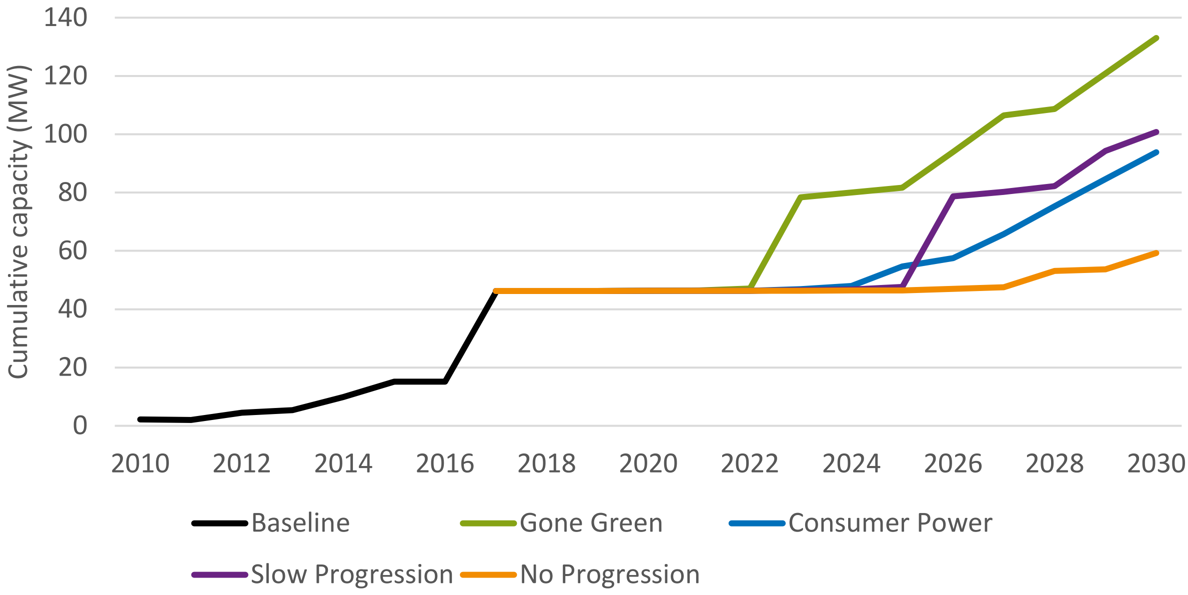


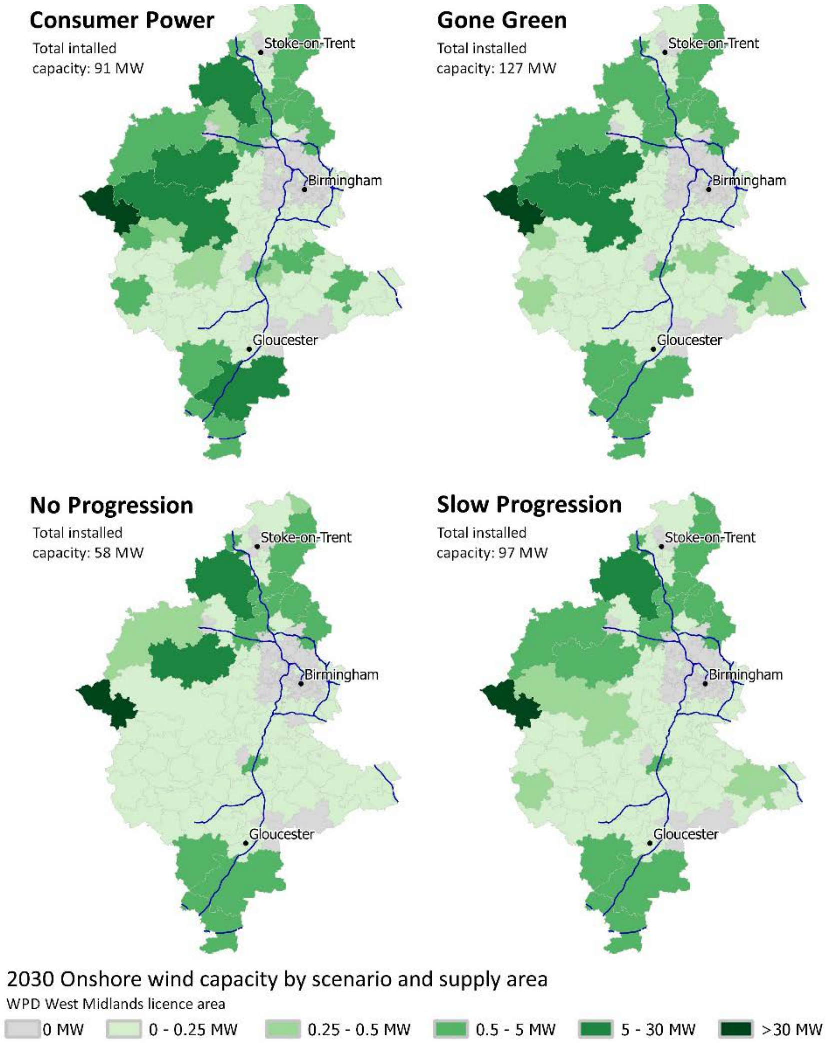
Table 5: Cumulative capacity breakdown of onshore wind in the West Midlands licence area (MW)

	Baseline (MW)	2020 capacity (MW)	2025 capacity (MW)	2030 capacity (MW)
Gone Green	46	46	82	133
Consumer Power	46	46	55	94
Slow Progression	46	46	48	101
No Progression	46	46	46	59

4.7 Geographic distribution of the scenarios: onshore wind

The geographic distribution of wind development varies under the different scenarios. The spatial allocation is determined by the area's planning history, current installed capacity and the resource potential. These factors have been weighted differently under the different scenarios. In this licence area, there is a greater weighting towards resource availability as a factor than in other licence areas due to a lack of projects installed or planning history.

Figure 21: Geographic distribution of onshore wind capacity by scenario in 2030



5 Solar

5.1 Baseline: solar PV growth to 2016

To assess the baseline solar PV capacity in the West Midlands, we used WPD Database of connected generation and validated this against data from the RO, the BEIS Renewable Energy Planning Database (REPD) and Regen's in house project data.

There are 715 MW of solar PV in the licence area made up of 65,600 projects. For comparison, this is around half of the neighbouring East Midlands licence area's installed capacity and around a quarter of that of the South West of England.

5.1.1 Ground-mounted baseline

Ground-mounted solar deployment expanded rapidly in the UK in 2010, following the introduction of the FIT with subsidies for ground-mounted schemes up to 5 MW and the RO for larger schemes.

However, this rapid growth was concentrated in more southerly and easterly regions initially, as developers focused on areas with the greatest irradiance levels and open space. As network and other constraints began to impact in these areas, developers looked to the next available area of solar resource, with the wave of deployment moving up the country. As a result, the West Midlands has the fifth highest level of ground-mounted solar deployment in the UK, with 415 MW installed through 73 projects in April 2017.

In the West Midlands licence area, there have been distinct stages to ground-mounted solar deployment:

- Growth was limited in the licence area until 2014, with just five sub-5 MW projects built.
- 2014 and 2015 saw the highest deployment rates in the licence area, with new installed capacity of 114 MW in 2014 and 150 MW in 2015. The first projects over 5 MW were installed in these years, although the predominant size was 5 MW or below.
- From April 2015 to April 2016, around a further 70 MW of projects commissioned, with the majority sub-5 MW to meet the deadline for the end of the sub-5 MW RO, and a few larger projects that were eligible for the grace period for the RO for projects over 5 MW.
- Another 75 MW of projects were built to April 2017, these were schemes that were eligible for the sub-5 MW grace period being building out.

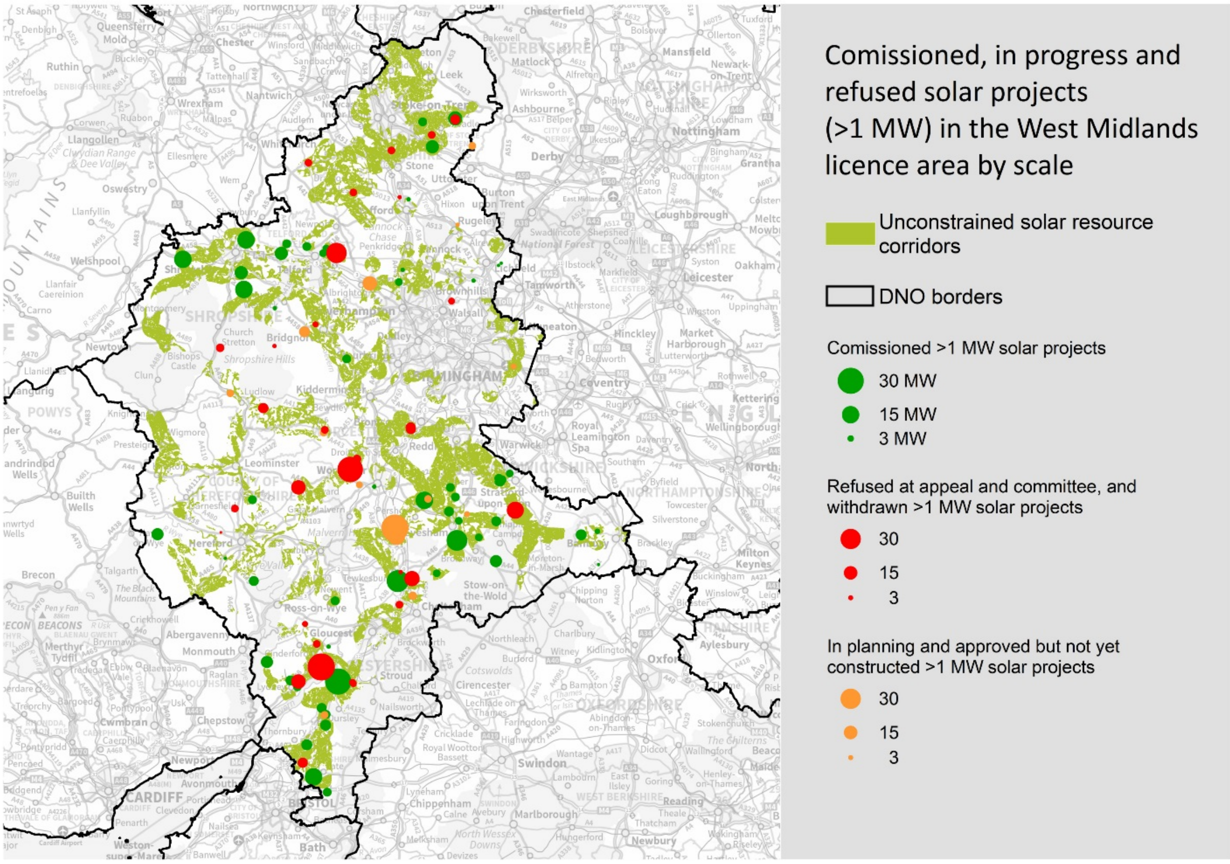
As in other licence areas, ground-mounted solar projects are concentrated in areas with good access to the 33kV network. Projects have tended to cluster to the north and the south of the licence area, with the top four local authorities having over 50 per cent of the installed capacity. The central belt of the area has had fewer applications and a higher rate of refusals. The Shropshire Hills AONB, Greater Birmingham conurbation and the fact that the network is 66 kV rather than 33 kV are three factors leading to lower resource availability in the centre of the licence area.

Table 6: Top ten local authorities in the West Midlands licence area for ground-mounted solar PV capacity

Local authority	Installed capacity (MW)	Number of projects
Shropshire	91.4	13
Wychavon	49.6	6
Stroud	48.8	5
Stratford-on-Avon	42.3	12
Forest of Dean	30.1	7
Tewkesbury	29.7	3
South Gloucestershire	25.5	3
Telford and Wrekin	24.7	5
Staffordshire Moorlands	23.3	3
Herefordshire, County of	17.9	4
(Others)	(31.9)	(12)
Total	**415**	**73**

There are a reasonably large number of projects, particularly in the centre of the licence area, that have been refused planning permission. This area tends to have a higher grade of agricultural land classifcation which may be an issue contributing to higher refusal rates and lower numbers of applications. Authorities in the north/north west and south/south east of the licence area have seen a lower rate of refusal and a higher number of applications.

Figure 22: Commissioned and refused at planning ground-mounted solar PV in the West Midlands



5.1.2 Rooftop baseline

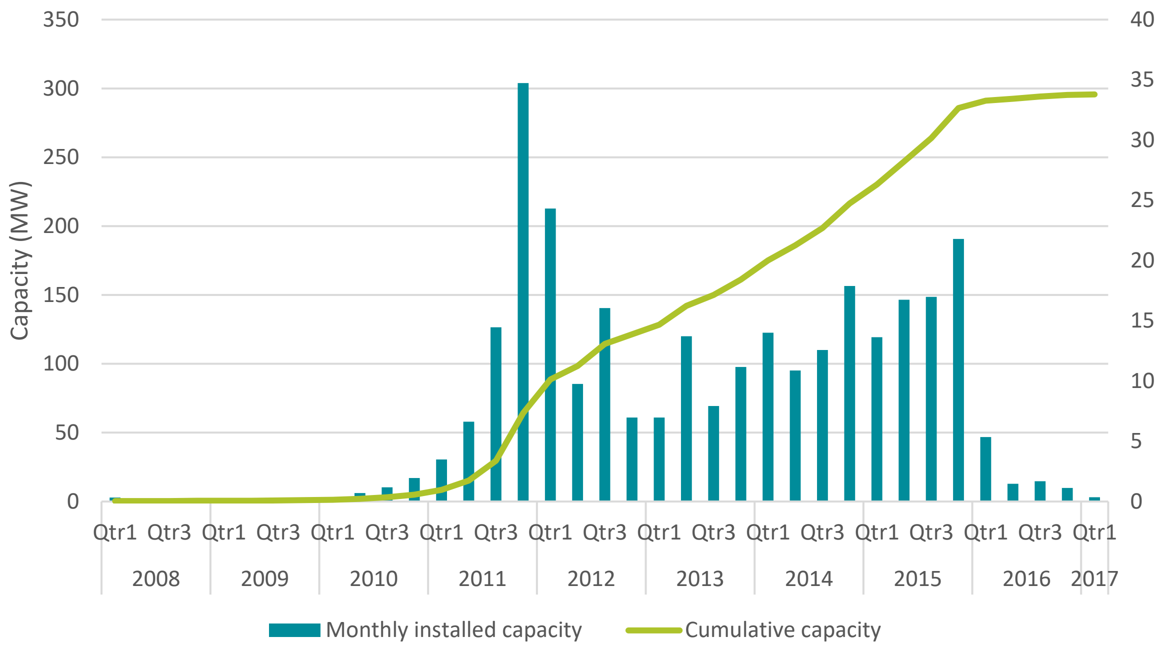
There are over 65,500 rooftop projects, totalling 296 MW. These are concentrated in populated areas, with the greatest numbers of suitable roofs.

Table 7: Top ten local authorities in the West Midlands for rooftop solar PV installations

Local authority	Installed capacity (MW)	Number of installations	Proportion of homes with PV
Herefordshire	36	4,541	6%
Shropshire	27	4,243	3%
Birmingham	23	6,717	2%
Stroud	12	2,763	6%
Wychavon	11	2,451	5%
Telford and Wrekin	11	2,393	4%
Stoke-on-Trent	11	3,186	4%
Stafford	10	2,299	4%
Dudley	10	2,579	2%
Forest of Dean	10	1,942	6%
(Other local authorities)	(136)	(32,413)	-
Total	**296**	**65,527**	**1% (average for licence area)**

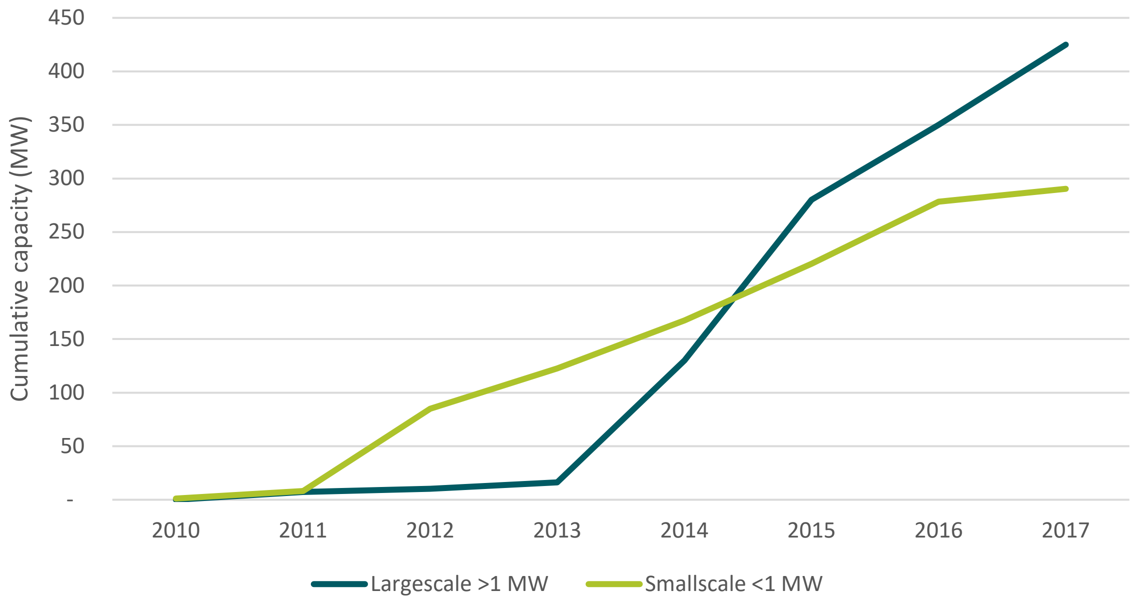
With the introduction of the Feed-in Tariff (FIT) in 2009, rooftop solar deployment grew steadily in the licence area from a very low base. Installation rates have all but stopped since April 2016 as a result of cuts to the FIT.

Figure 23: Monthly rate of rooftop solar PV deployment in the West Midlands licence area



Whereas in other licence areas ground-mounted solar installed capacity dwarfs rooftop, in the West Midlands the lower deployment of ground-mounted solar means that the difference between the two totals is much smaller.

Figure 24: Growth of rooftop and ground-mounted solar PV capacity in the West Midlands licence area



5.2 Pipeline: solar PV

5.2.1 Ground-mounted pipeline

Subsidies for large scale solar PV have been cut or ended, meaning that PV projects over 5 MW have to be built without subsidy and smaller ground-mounted projects have to be viable with a very low FIT.

WPD have a database of connected generation of over 517 MW of projects with agreements in place. However, we have not included a pipeline for ground-mounted projects for this licence area, as project economics have stalled deployment at present even for sites with connection agreements and planning in place. The scenarios begin immediately.

The projects in the network connection database form the basis of the scenarios as these are likely to be the first projects built once project economics improve.

5.2.2 Rooftop pipeline

The FIT is scheduled to be available for new solar installations until March 2019 (unless the budget is exceeded at an earlier date), but the rate is much lower than previous years and there are quarterly degressions (dependent on deployment levels). There is no pipeline data available for rooftop solar and so the scenarios begin immediately.

5.3 Regen's market insights: solar PV

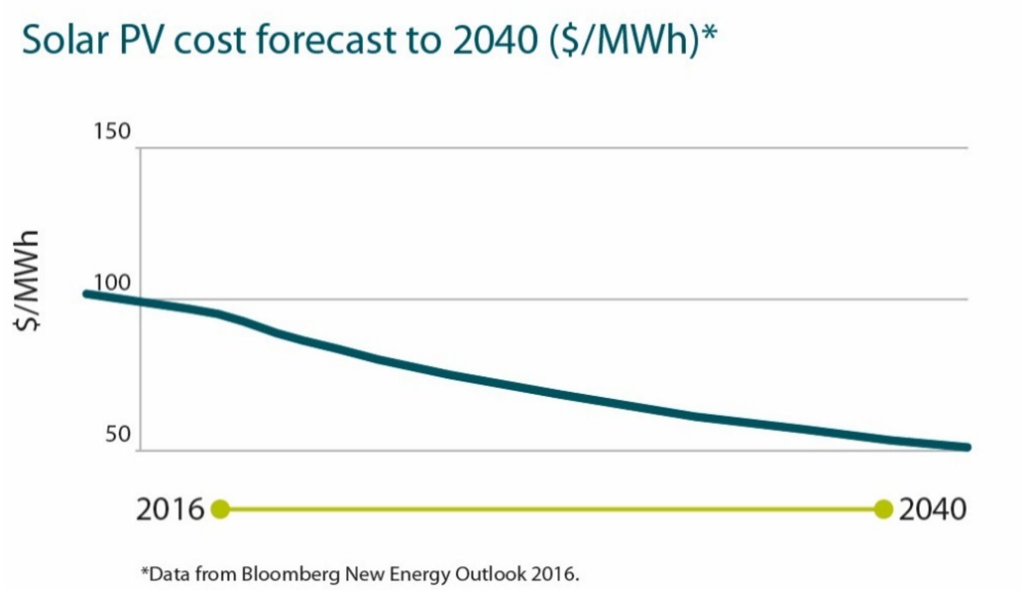
5.3.1 Rapidly reducing solar PV costs

Thanks largely to falling module prices due to increases in global supply and innovation, the installed cost of solar PV has dropped by 62 per cent since 2009 according to Bloomberg. This trend is continuing. A recent World Bank-backed auction by Madhya Pradesh state in India for 750 megawatts of solar cleared at 3.30 rupees (40p) per kWh. This was closely followed by a Solar Energy Corporation of India tender for a 500MW section of the Bhadla Solar Park in Rajasthan being won at 2.44 rupees (29p) per kWh. In Italy, Octopus has recently installed five new large scale solar farms on a subsidy free basis with two-year fixed power price agreements.

Bloomberg New Energy Finance predicts continued price falls, with installed costs in the EU reaching $50 per MW by 2040. The recent prices in India and elsewhere suggest price drops could be even faster.

The impact of leaving the EU introduces some uncertainty. There is potential for it to unlock trade deals for the UK with China, for example, or for ongoing currency and trade issues to keep UK prices above the Eurozone. However, none of this is likely to affect the long-term trend.

Figure 25: Bloomberg New Energy Outlook 2016 solar PV cost forecast to 2040 ($/MWh)



5.3.2 Rooftop solar and price parity

Solar on roofs where the power can be used on site – and thus offset the retail price of power – has already reached price parity. Installers are reporting attractive rates of return with payback periods around six years achievable with the right site. With subsidies at very low levels, the market is changing. Solar is more likely to be part of a broader approach to cutting energy bills in commercial properties alongside, for example, LED lighting. Despite the attractive returns, installation rates are much lower than the peak reached recently.

In the domestic market, falling costs mean that payback periods can be as low as eight years for the right property, particularly where the customer is able to maximise onsite use. As a result, there are continued installations in the domestic market, albeit at a greatly reduced level compared with the period when high FIT payments were available. Further cost reductions will continue to improve the financial case and the rooftop market is expected to steadily pick up.

5.3.3 Large scale solar and price parity

Industry sources indicate that Engineering, Procurement and Construction (EPC) contractors are quoting installed costs of £550k per MW for solar farms – down from £850k a couple of years ago. At these prices the best sites for solar farms, particularly those where development work has already taken place, are close to viability at the current price of power. Evidence of this is the planning application recently submitted for a post-subsidy project in South Hams, Devon – the 7.3 MW Creacombe Solar Farm.

The major barrier now to post-subsidy solar farms is that the loss of the RO and the FIT removes certainty of income for developers. Projects will be subject to power price risk which pushes up the cost of capital. To address this barrier, developers will need to find private wire customers or corporate customers who will agree a long-term PPA. Alternatively, developers will need to identify sources of affordable finance that are willing to take power price risk.

We expect that the first post-subsidy projects will start to come forward in the next couple of years. NextEnergy for example are purchasing consented assets on the basis that they will be viable within 12 to 24 months. Solar Media has identified an increase in the number of EIA screening requests for large scale solar in the last few months, indicating the industry is preparing for post-subsidy viability.

The first commercial post-subsidy projects are likely to be very large to take advantage of economies of scale, have low network costs and to be multi-technology with storage and gas peaking plants co-located to take advantage of the network connection. Creacombe Solar Farm indicates that there may also be some smaller landowner or community projects with access to different sources of finance.

Without any subsidy or price guarantee, it is likely that large scale solar will develop at a steadier pace than the "subsidy deadline" driven market of recent years.

The industry has pressed for solar to be able to bid for Contracts for Difference to reduce risk and the cost of capital. However, there was no indication in the Conservative manifesto of any price guarantee mechanism. The introduction of a price guarantee would greatly accelerate the pace of project development.

5.3.4 The role of solar in the UK power system

As increasing levels of solar (and renewables with intermittent generation in general) are deployed, the fact that solar generation is concentrated during certain times could affect its viability in a number of ways:

- As discussed in this report, significant network constraints in some areas of the country have essentially stopped further solar projects.
- The wholesale price of power could reduce when there are substantial amounts of solar on the system – reducing the income.
- The government has indicated it is keeping under review if there are system costs, that is the cost of backup and network balancing due to the variability of renewables, that should be borne by variable generators.

Solar is still relatively small as an overall contributor to the UK power system. Research from Aurora Energy Research shows that more than tripling solar generation capacity to 40 GW (a level that would provide over 10 per cent of annual UK electricity production) would increase the costs of managing variability by only a relatively modest amount, to a maximum of £6-£7 per MWh.

However, it is clear that growth of solar beyond a certain point will rely on much more flexibility, such as storage, on the system. Aurora's research concluded:

"*When solar is integrated into a decentralised, flexible, 'smarter' power system, including batteries, it actually delivers more benefits than costs to the system. High battery penetration combined with high solar penetration reduces the cost of variability by £10.50 per MWh, resulting in a net £3.70 per MWh benefit. This is because solar combined with batteries allows output to match demand requirements exceptionally closely and requires only a small amount of back up.*"

The viability of solar plus storage business models will, therefore, be a key factor in the future growth of solar.

5.4 Scenarios: solar PV, 2017 to 2030

5.4.1 Factors affecting the scenarios: solar PV

Under no scenario is it expected that subsidy levels will be increased – growth will therefore be predicated on PV achieving energy price parity. The following table sets out a summary of the potential factors that affect the level of deployment of ground-mounted solar PV in the West Midlands licence area.

Table 8: Potential factors enabling ground-mounted solar PV deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Introduction of a price guarantee mechanism, such as a CfD or government backed PPA	●			
Planning environment is straight-forward, reducing planning risk	●		●	
Technology costs				
Falling UK solar PV panel and inverter costs – potentially due to reduction in import duties, manufacturing innovation and economies of scale	●	●	●	●
Technological innovation – especially for rooftop and building fabric technologies	●	●		
Innovative integrated systems – PV linked to electric vehicle charging for example	●	●		
Negative medium and long term impact of Brexit on import costs				●
Impact of storage				
New business models – 'own use' enabled by energy storage	●	●	●	
New business models – 'capacity utilisation' enabled by energy storage	●	●	●	
New business models – 'energy market' enabled by energy storage	●	●		
Electricity network connection costs				
Lower network reinforcement costs – enabled by strategic investment	●		●	
Lower network reinforcement costs – enabled by 'smart' solutions, active network management and demand response solutions etc.	●	●		
Wholesale price of power				
Rising electricity wholesale price – potentially driven by economic growth, increased demand and/or falling supply	●	●		
Availability of finance				
Strong economy or government backing means investment capital is available	●	●	●	

Many of the factors in Table 8 also apply to rooftop installations. An additional factor considered for rooftop schemes is whether higher energy standards are introduced for new build properties through national building regulation improvements or local planning policies. We have assumed these requirements are introduced under the Gone Green and Slow Progression scenarios.

In all scenarios, it is anticipated that there will be continued slow growth in PV in 2017 due to the lack of available subsidy. The key uncertainty is how quickly growth would recover under the four future energy scenarios. For all the scenarios, growth is affected by other areas of the UK being more attractive to solar developers. The first viable schemes are expected to be in licence areas with higher irradiance and more positive planning policy than the West Midlands. We have, therefore, concluded that schemes will start to be installed without subsidy later in the West Midlands compared with other licence areas.

The Gone Green scenario produces the quickest recovery in growth rates with installations viable in the near term under this scenario, resulting in the highest level of solar PV installation. Even under this most optimistic scenario, growth rates for ground-mounted solar PV remain below the historic peak, under half of the peak seen during 2014-15. This is due to both a lack of subsidy, network constraints and system issues limiting overall solar deployment.

The Consumer Power scenario closely follows the Gone Green scenario, with lower large scale deployment due to a lack of strategic network investment and no price guarantee mechanism. For domestic projects, Consumer Power shows lower deployment than Gone Green due to a lack of policy requirements for new homes to include solar.

Overall, the poorer economic situation in both Slow Progression and No Progression lead to price parity being achieved later, resulting in lower deployment.

Consumer Power

- High growth scenario
- For ground-mounted sites, some sites are viable from around 2022 in West Midlands, wide-spread parity achieved from middle of decade – slightly later than under Gone Green as less government support.
- Private wires and industrial roofs viable now, tailing off from 2023 as best sites taken.
- Retrofit rooftop installation rates rise at the same rate as Gone Green as costs fall, with the proportion of solar PV installations with storage increasing.
- For new homes, the impetus for installations is driven by consumer demand for high tech properties; this leads to growth through the decade, with high installation rates achieved by the end of the decade.

Gone Green

- Highest growth scenario
- Price parity for ground-mounted achieved 2018/19 in other licence areas, first projects around 2021 in West Midlands due to focus on better sites elsewhere.
- The business models for storage and solar work together, thanks to technology and regulatory changes, reducing intermittency issues.
- Private wires and industrial roofs projects are viable now, tailing off from 2023 as best sites taken
- Retrofit rooftop installation rates rise through the decade as costs fall, with the proportion of PV installations with storage increasing.
- Around 9.3 per cent of all homes in the licence area have solar by 2030, up from 2.5 per cent now
- Large proportion of new homes include PV due to planning requirements

No Progression	Slow Progression
• Lowest growth scenario • Poor planning and economic environment • Growth would be slow 2020-25 with an increase post 2025 as costs fall and power prices rise and more large scale sites are viable in the West Midlands. • Limited growth would be more weighted to economically viable projects – very large or 'own use'. • Some municipal and community schemes installed but otherwise rooftop schemes are relatively limited.	• Low/medium growth scenario • Subsidy free sites start to be installed around 2024 in West Midlands, at a relatively steady rate. • Overall around 30 per cent fewer rooftop projects than under Gone Green. • Private wires and industrial rooftops installed at a lower rate than Gone Green due to economic situation and lack of price guarantee. • Large proportion of new homes include PV due to planning requirements

5.5 Scenario results: solar PV

5.5.1 Ground-mounted results

Figure 26: Scenario growth of ground-mounted solar PV in the West Midlands licence area

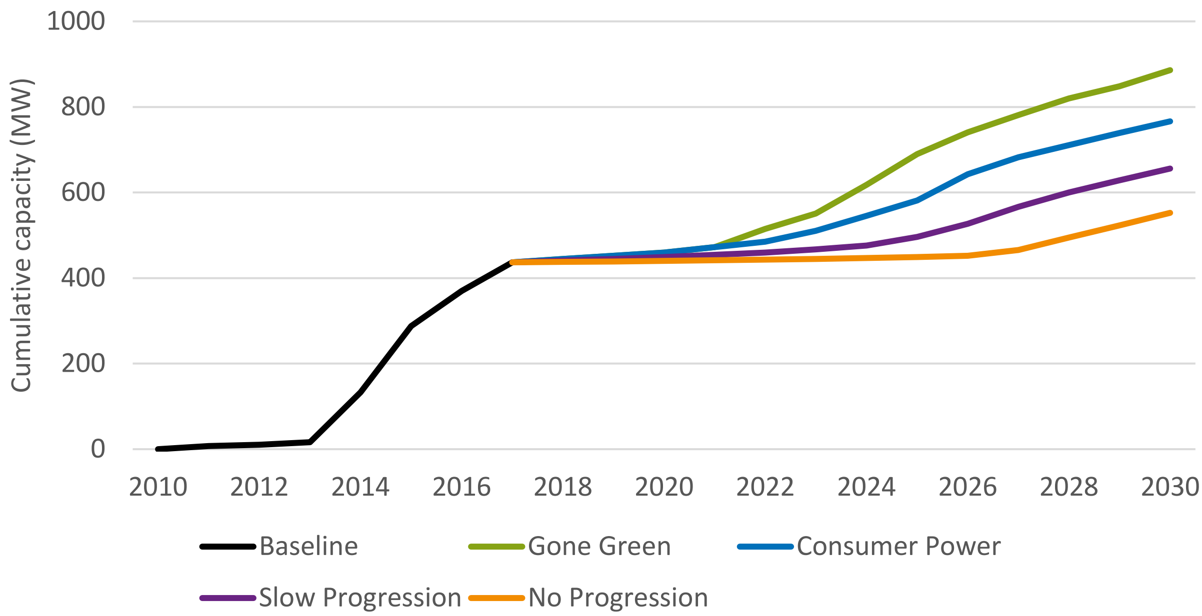


Table 9: Cumulative capacity breakdown of ground-mounted solar in the West Midlands licence area (MW)

	Baseline (MW)	2020 capacity (MW)	2025 capacity (MW)	2030 capacity (MW)
Gone Green	437	460	690	886
Consumer Power	437	460	582	766
Slow Progression	437	449	496	656
No Progression	437	440	449	552

5.5.2 Rooftop results

Figure 27: Scenario growth of rooftop solar PV in the West Midlands licence area

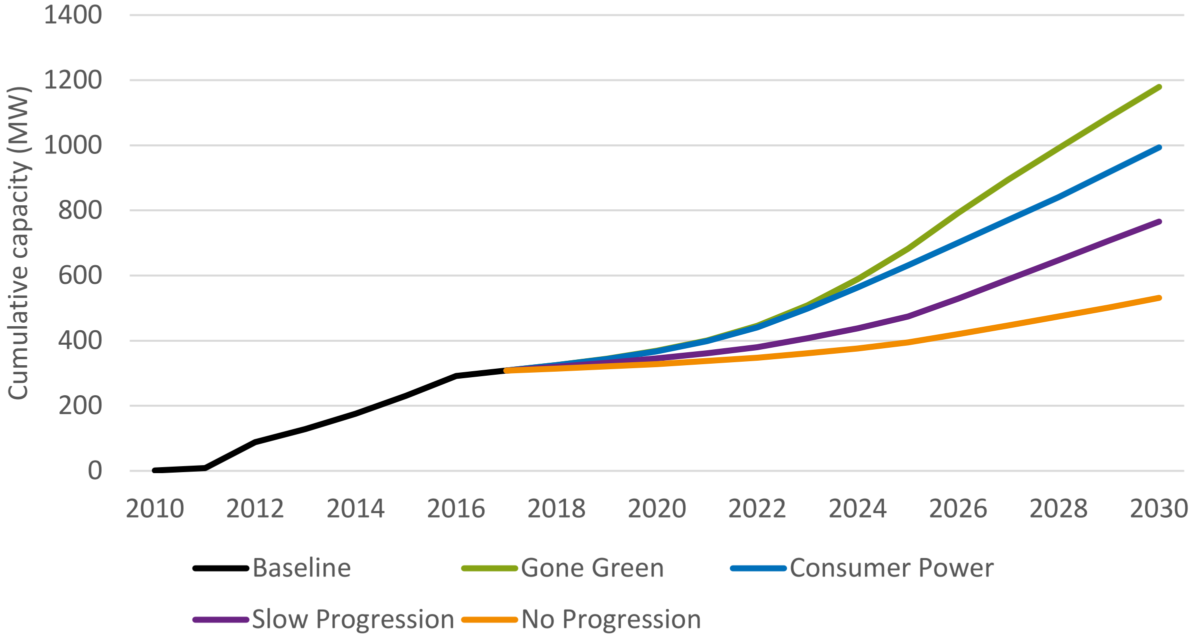


Table 10: Cumulative capacity breakdown of rooftop solar in the West Midlands licence area (MW)

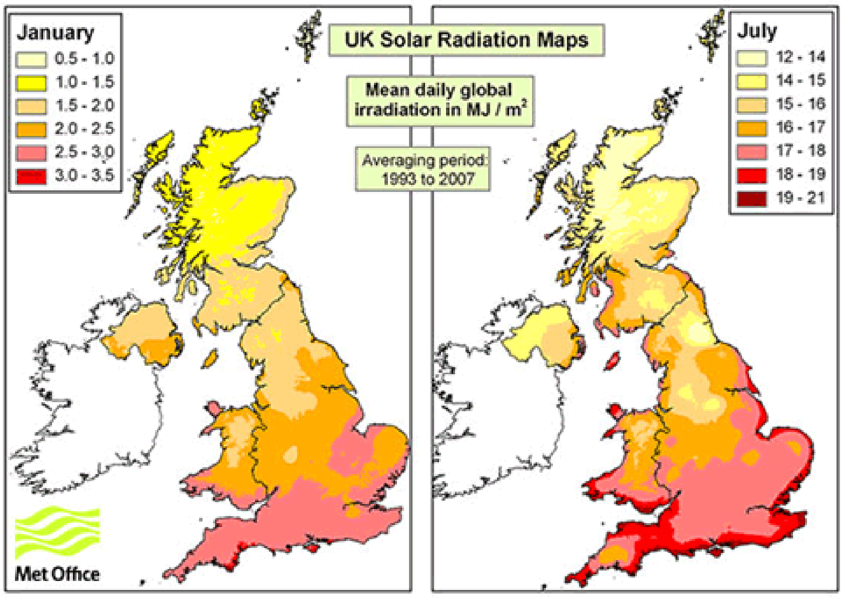
	Baseline (MW)	2020 capacity (MW)	2025 capacity (MW)	2030 capacity (MW)
Gone Green	308	369	682	1,179
Consumer Power	308	367	631	994
Slow Progression	308	346	474	766
No Progression	308	328	394	531

5.6 Geographic distribution

5.6.1 Technical resource assessment methodology for ground-mounted

To assess the potential locations for growth, it is important to have an idea of the total developable resource in the licence area.

Figure 28: UK solar irradiation (MJ/m²)



Given the largely undifferentiated solar irradiation levels across the licence area, network connection cost is the key driver for developers seeking sites. As a result, in assessing the potential for ground-mounted solar the main consideration is the amount of land space (non-designated, brownfield or low grade agricultural land, flat/unshaded or south facing) that is close enough to an unconstrained area of the network to enable a reasonable connection cost.

Additional considerations for developers may include:

- Coastal areas and areas with higher average wind speeds, which have greater potential to cool the panels and therefore create slightly higher generation efficiency
- South facing land would be an advantage in terms of energy generation; however, from a visual impact consideration lower lying flat land, not shaded by trees but potentially 'nestled' into the landscape is more developable
- Ground-mounted PV adjacent to major roads in rural areas is also attractive both from the perspective of vehicle access and also because these tend to correspond to lower grade agricultural areas, less sensitive landscapes and lower housing density. "A" roads for example, also tend to follow the major infrastructure/transport routes including network.

These detailed site finding points do not have a significant impact at network area level and therefore are not included in the analysis. Deployment trends should be monitored in the future to see if these factors become more important. Planning policy, guidance and local authority engagement can have a significant effect on planning success and we have included consideration of that below.

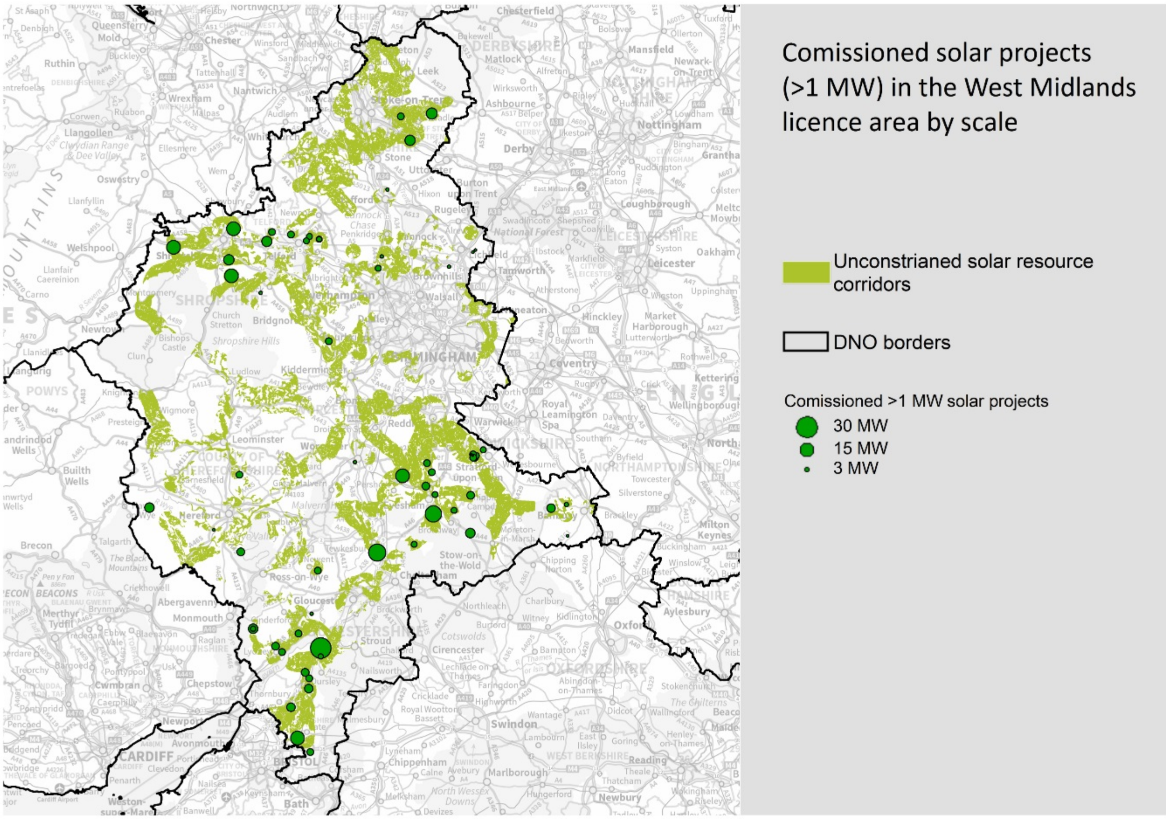
We have estimated the area of developable land by removing areas with the following constraints:

- Designated land areas – National Parks, AONB, SAC, SPA, RAMSAR, SSSI, Heritage Coasts, local nature reserves, country parks, etc.
- Physical constraints – houses, roads, woodland, rivers, rural heathlands, water bodies, etc.
- Historic assets
- Agricultural land classification grade 3b or above

- Within 50 m of residential properties
- Over 2.5 km distance from 33 kV (or higher) network as a proxy for network connection costs.

5.6.2 Results of resource assessment

Figure 29: Technically unconstrained solar PV resource in the West Midlands licence area



The occurrence of existing ground-mounted PV farms, shown as green circles, indicates a very strong correlation between the location of PV farms and the developable resource areas when a 2.5 km from 33 kV network proximity criteria is included.

The resource assessment suggests that there is over 2,600 km² of land space within the potential PV development corridors in the West Midlands licence area. For the East Midlands licence area, this figure was 4,000 km². Only 0.4 per cent of the total developable resource area has so far been developed. This is equivalent to less than 0.1 per cent of the total land in the West Midlands licence area. The West Midlands has a higher proportion of agricultural land that is grade two and above than neighbouring areas, which is one of the factors contributing to a smaller overall resource area. Other factors are the large urban areas, the AONB to the west of the licence area and the centre of the licence area having a 66 kV network rather than 33 kV.

5.6.3 The impact of planning constraints on solar PV resource potential

We have reviewed the potential for cumulative impact to be a factor limiting PV deployment in the licence area. In other licence areas, we have capped deployment at four per cent of the developable resource area in any network supply area, unless there is a good reason to support higher deployment in that area, e.g.

co-location of solar and wind, or high levels of existing capacity, or the land area is very small. In those areas, we have also limited the number of solar farms to three PV farms within a 10 km² area.

For the West Midlands, we reviewed whether these limits would have an impact on deployment. Given the relatively low predictions under each scenario, it has not been necessary to include these deployment caps in considering the geographic distribution of the scenarios.

For other licence areas, we considered the impact of the planning environment on future deployment rates. For the West Midlands, there have been fewer applications over all and it is difficult to robustly identify areas with a positive planning environment as a result. We have therefore not included this as a factor in distributing the scenarios.

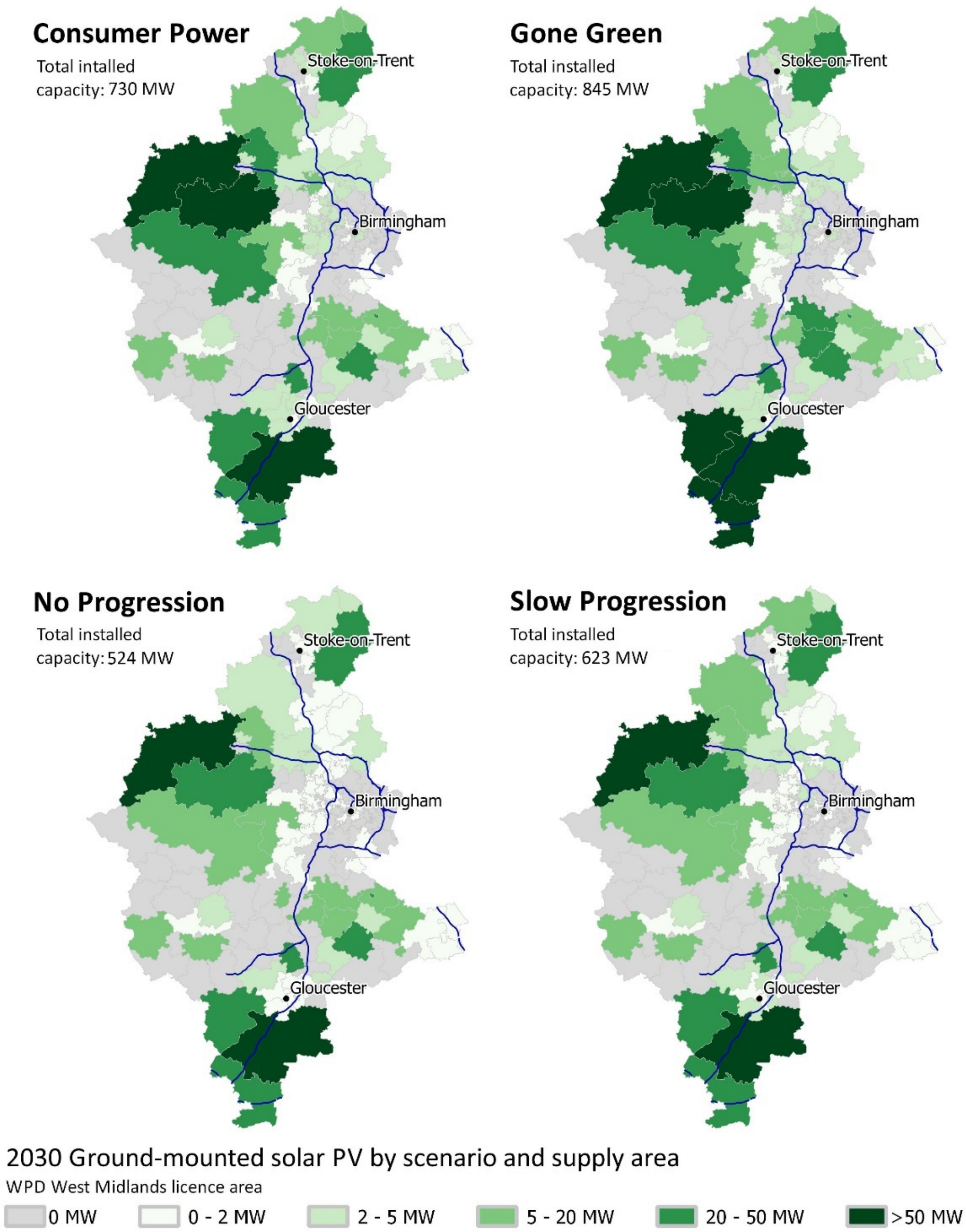
5.6.4 Private wire and industrial/commercial rooftop opportunities

To identify potential commercial and industrial companies that might present private wire/rooftop opportunities, we have identified users with a 33kV connection and examined address based data. We have made assumptions about the percentage of sites that could be suitable for PV. This has enabled us to identify the potential scope of the private wire and industrial/commercial rooftop market for PV in the region and in each ESA.

5.7 Geographic distribution of scenarios: solar PV

5.7.1 Results of geographic distribution: ground-mounted PV

Figure 30: Geographic distribution of ground-mounted solar PV capacity by scenario in 2030

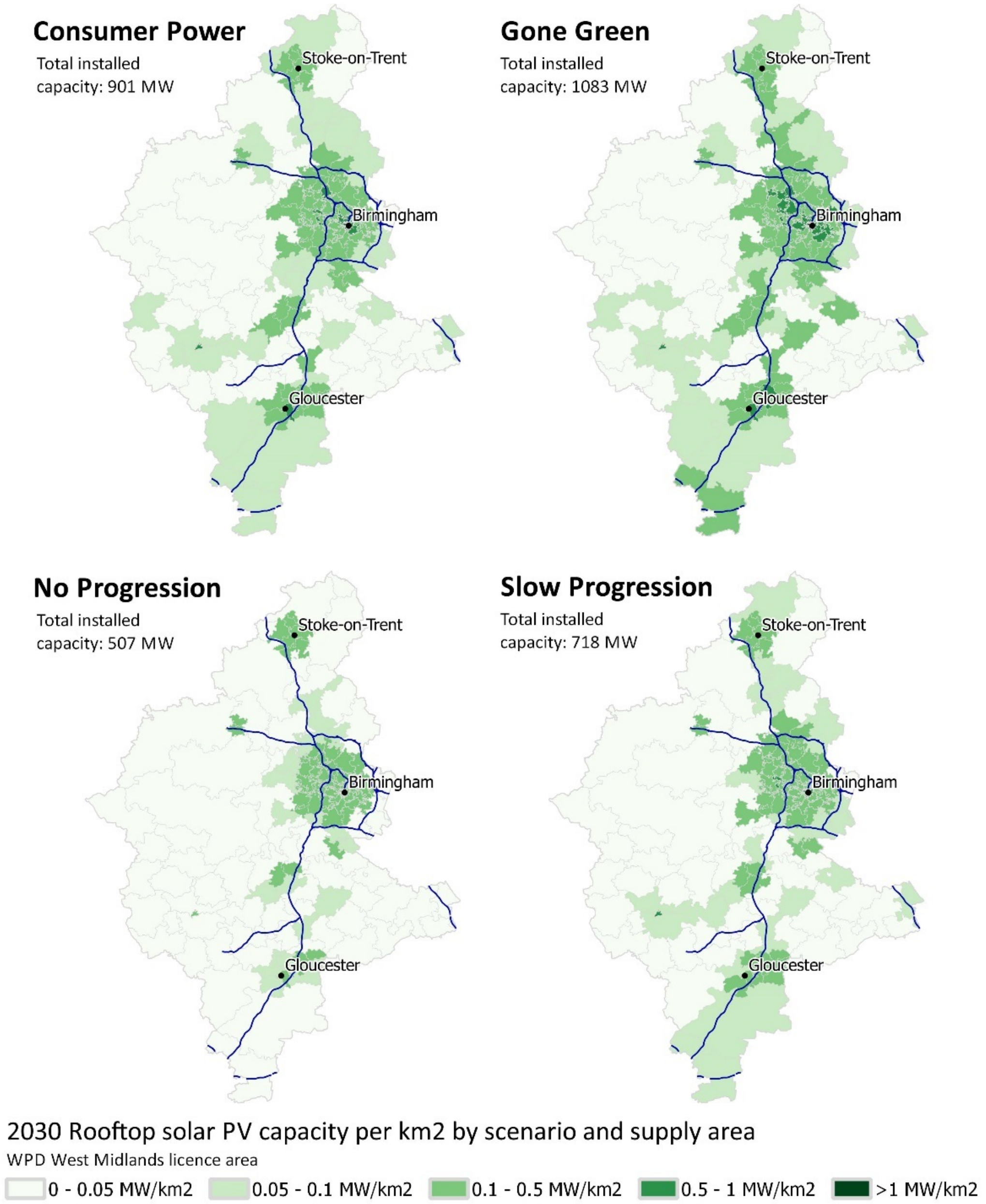


5.7.2 Results of geographic distribution: rooftop PV

We have distributed the scenarios geographically according to the number of existing homes, the number of new homes, the existing baseline, and affluence of householders.

We have considered the correlation between deployment of solar PV and affluence in the area. In the early years of PV installations, there was a strong correlation, with PV predominantly installed by wealthier households. By 2015, this correlation was far weaker. Having investigated the relationship, we conclude that this is due to a high proportion of social housing providers undertaking mass installation programmes and people across the economic spectrum installing PV on their own homes. Under Gone Green and Consumer Power, it is assumed that the current trend continues, so there is a smaller weighting given to affluence. Under Slow Progression, areas of deprivation see higher deployment due to social landlord programmes. Under No Progression, high deployment is not seen in less affluent areas.

Figure 31: Geographic distribution of rooftop solar PV capacity per km^2 by scenario in 2030



6 Anaerobic digestion

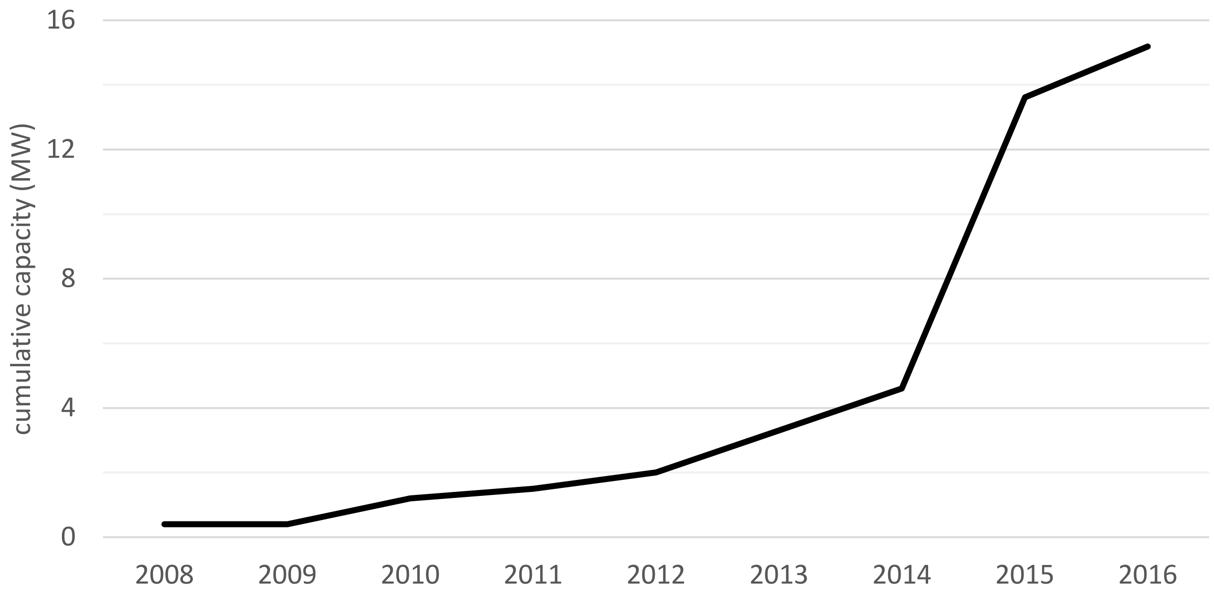
6.1 Baseline: anaerobic growth to 2017

There are 56 anaerobic digestion projects in the licence area, totalling 39 MWe in installed capacity. 8 projects are listed by the Anaerobic Digestion and Bioresources Association (ADBA) as biomethane producing projects.

Shropshire and Herefordshire are the leading local authority areas in England for the number of projects installed. The majority of these are on farm electricity generation projects. There are local installers in these areas installing multiple projects. This reflects a trend in the anaerobic digestion market; companies tend to focus on a local, rather than national market for farm scale installations.

Outside of Shropshire and Herefordshire projects are relatively dispersed, with food waste plants tending to be closer to urban/industrial areas. There are 12 projects over 1 MW in size in the licence area, mainly processing food waste. The largest site is a 6 MWe project owned by Biffa in Staffordshire.

Figure 32: Growth of anaerobic digestion in the West Midlands licence area



Anaerobic digestion planning applications tend to be approved at committee; out of 16 planning applications listed on the BEIS planning database for the region (over 1 MW), only one was refused at committee.

AD has grown from a low base, with the start of the FIT in 2009 resulting in slow, steady growth in the area until 2014. 2014 saw the peak installation rate with 21 projections commissioned; since then deployment has tailed off in the licence area, in line with the national picture, with just one project commissioned in 2016.

Table 11: Baseline anaerobic digestion projects by local authority in West Midlands

Local authority area	Number of projects	Installed capacity (MWe)
Herefordshire, County of	21	11.0
Shropshire	19	8.2
Telford and Wrekin	4	1.4
North Warwickshire	2	5.8
Stafford	2	1.4
Wychavon	2	1.0
Birmingham	1	0.9
Cannock Chase	1	6.0
Cotswold	1	0.3
Forest of Dean	1	1.2
Redditch	1	0.0
Tewkesbury	1	2.1
Total	**56**	**39.3**

6.2 Pipeline: anaerobic digestion, 2016 to 2017

There is no pipeline for anaerobic digestion due to the lack of suitable data and so the scenarios begin immediately.

6.3 Regen's market insights: anaerobic digestion

AD offers significant potential for growth. Given the right conditions, there is good potential for the development of AD in the area.

The West Midlands has a relatively strong local AD supply chain, an abundance of potential AD sites and a plentiful organic waste resource for the development of both on farm and larger scale AD, as well as the potential for growing energy crops. There are increasingly variable and diverse fuel sources for AD and it is suitable for a variety of different uses at different scales: processing food waste and manure; producing biomethane for the gas grid and transport; producing onsite electricity and heat; and generating electricity for export. AD can offer benefits to many different stakeholders, including farmers, industry, communities and local authorities.

In addition, AD export generation can be controlled, with gas stored ready for generating electricity through a CHP unit when required. Most network connected plants currently aim to generate a steady load to maximise output and therefore income, however, if incentivised to do so, AD has the ability to provide balancing services to the local network, for example, generating at times of peak demand. Similarly, flexible connection offers are more likely to be viable for AD in comparison with other renewable energy technologies.

AD plants that produce biomethane have access to additional potential income streams from the RHI for gas to grid, from the Renewable Transport Fuel Obligation (RTFO) for transport fuel and by processing food waste. As a result, these are more likely to economically viable in the current climate and going forwards. The ADBA announced in June 2017 that the 200th on farm biogas plant for the UK had been permitted. Projects exporting gas to grid generally only generate electricity to meet the parasitic load, as more can be earned exporting the gas, than burning it for electricity generation. The impact on the electricity network of biomethane plants is therefore reduced compared with electricity producing plants. Biomethane plants tend to be larger (around 4 MWth), but with a grid connection requirement that is much reduced compared to their size (around 500 kW on average).

6.3.1 On farm small scale market limited by lack of subsidy and lack of potential for cost reduction

Despite significant potential, at present the AD market for on farm electricity producing plants is severely restricted at all scales, due to subsidy cuts. The RO has now ended and the FIT has been cut to the point that it no longer sufficiently incentivises investment in most cases. In addition, sustainability requirements have been introduced that plants must comply with to access the FIT (similar to those for the RHI).

Unlike solar PV, there are unlikely to be significant cost reductions for AD that would make it widely viable without subsidy/with a low subsidy. The ADBA state in their 2016 AD market report that the fundamental elements of the AD process are not likely to change in the next 20 years, as "the materials used and the processes followed are relatively mature." The technology cost is, therefore, unlikely to reduce significantly. Similarly, installation costs are likely to remain relatively constant, given the small size of the current market and the site specific nature of installations. Achievable improvements to the economics of small scale AD are likely to be relatively small, based on improved quality of feedstock and some potential for innovative improvements to the micro-biology processes. Widespread deployment without subsidy is unlikely to be achieved before 2030.

Other issues for on farm AD include:

- AD's role in processing manure is under-recognised, with regulation hindering this application.
- Some AD digestates are classified as waste, meaning that their use as fertiliser has to be permitted. Good quality digestate, particularly from food waste plants, has high nutrient value, but the value is not currently recognised by farmers and plants often have to pay for its disposal as a waste product.
- The current low return on investment that is available is only sufficient to attract project owners with available capital i.e. it is not high enough to allow for the cost of borrowing, reducing the pool of potential farmers able to develop schemes.

6.3.2 Biomethane market limited by uncertainty around RHI and lack of food waste availability

Despite ambitious statements from the industry, there are a number of limitations at present on widespread deployment of biomethane producing plants.

Uncertainty around the RHI

The government announced a reset of RHI tariffs for biomethane (gas to grid) plants in December 2016, which should lead to higher levels of deployment in the short term. However, due to Brexit and the general election the reforms have not taken place, meaning there is a great deal of uncertainty in the industry. The ADBA has written to the minister urging him to undertake the reforms, writing:

> *Due to the delay, there is more than £100m of investment across 15 biomethane-to-grid projects across the UK currently on hold. We look to government to take action before the delays lead to projects being abandoned and redundancies.*

In addition, the government introduced an overall budget cap for the RHI in 2015 that could close the RHI to new projects in the near future, although it is due to remain open to new applicants until April 2021.

Availability of food waste

The government has introduced a requirement for at least 50 per cent of feedstock to be from waste (or residues) in order to receive RHI support, limiting the potential for energy crop use. Plants over 1 MWth will have to produce an independent sustainability audit report. Biomethane projects may struggle to meet this criteria as it is difficult to secure sufficient feedstock due to limited availability of food waste.

In England, unlike Scotland and Wales, there is no requirement for local authorities to collect food waste and just under half of English local authorities do not collect food waste. As a result, digestion capacity currently exceeds food waste availability. A change in policy for England would drive up food waste availability and gate fees. At present, lack of food waste availability means AD plants often have to pay to access food waste, rather than processing it to generate an additional revenue stream.

Other factors

Other factors limiting biomethane plant deployment include:

- It is currently only viable for larger AD projects to buy the equipment required to export gas. Technology development could change that.
- Low wholesale gas prices and the lack of a significant carbon price mean that biomethane prices remain low.
- The RTFO is not currently sufficient to incentivise significant biomethane use. The government consulted on the future of the RTFO in late 2016 and is due to issue its response.

6.4 Scenarios: anaerobic digestion, 2017 to 2030

6.4.1 Factors affecting anaerobic digestion scenarios

We have considered the following factors in producing the scenarios.

Table 12: Factors enabling potential anaerobic digestion deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Government extends the FIT or introduces new subsidies for electricity production from large scale AD	•	•		
Government extends the FIT for farm scale AD plants	•	•		
RHI and RFTO effectively incentivise biomethane production	•			
Extensions to current plants become eligible for subsidy support	•			
Technology costs				
Technological innovation – improvements to micro-biology processes could increase the output of plants at low additional cost	•	•		
Feedstock				
Greater level of household food waste collections and higher gate fees for food waste	•			

Cost of disposal of indigestible elements present in feedstocks is reduced	●			
AD is recognised and incentivised as an approach for manure management	●	●		
Digestate				
Development of a market for digestate due to awareness of its benefits and reduced permitting requirements where appropriate	●	●		
Wholesale price of power and gas				
Rising electricity and gas wholesale price – potentially driven by economic growth, increased demand and/or falling supply	●	●		
Availability of finance				
Strong economy means investment capital is available	●	●		

6.4.2 Scenario results: anaerobic digestion

The Consumer Power scenario has the highest growth for network connected anaerobic digestion projects, with the installed electrical capacity by 2030 reaching around 2.5 times the baseline. Growth of AD projects is actually greatest under Gone Green, but there is a greater focus on biomethane production, and lower electrical capacities as a result. In all scenarios, the overall potential total installed capacity in 2030 remains relatively low compared with other renewable technologies due to relatively high technology costs.

Table 13: Scenarios summary for anaerobic digestion in the West Midlands

Consumer Power	Gone Green
• Highest growth scenario for network connected capacity . • Large number of small scale network connected farm scale plants are developed, dispersed across the area, due to availability of the FIT and development of digestate and manure processing markets. • Deployment of biomethane producing plants is limited until the end of the decade, when R&D leads to cost reductions. • Food waste collections remain limited without strong government policy drivers, limiting the deployment of food waste projects.	• Medium growth scenario for network connected sites (strong growth for plants producing biomethane) • Through incentives, government prioritises strategic use of anaerobic digestion for gas to grid and transport, resulting in lower numbers/capacities of network connected projects. • Capacities of existing sites are expanded due to availability of FIT for extensions • Increase in food waste collections, enabling larger food waste projects, but these focus on biomethane. • Network connected projects developed are on farm projects, as manure processing and digestate markets are unlocked.

No Progression	Slow Progression
• Very low deployment • No increase to subsidies • The only projects installed are on farm waste management projects with very low export capabilities. • A lack of available investment in R & D means that high technology costs and performance issues remain prohibitive to widespread roll-out and to large scale projects.	• Low growth scenario • Available subsidies are insufficient to incentivise widespread deployment. • Technology costs remain high due to a lack of R&D investment. • The markets for digestate and for manure processing are enabled by government action, with a small increase in the number of on farm sites as a result. • Food waste processing fees also increase, with a handful of these projects becoming viable.

6.5 Scenario results: anaerobic digestion

Figure 33: Scenario growth for anaerobic digestion electrical capacity in the West Midlands licence area

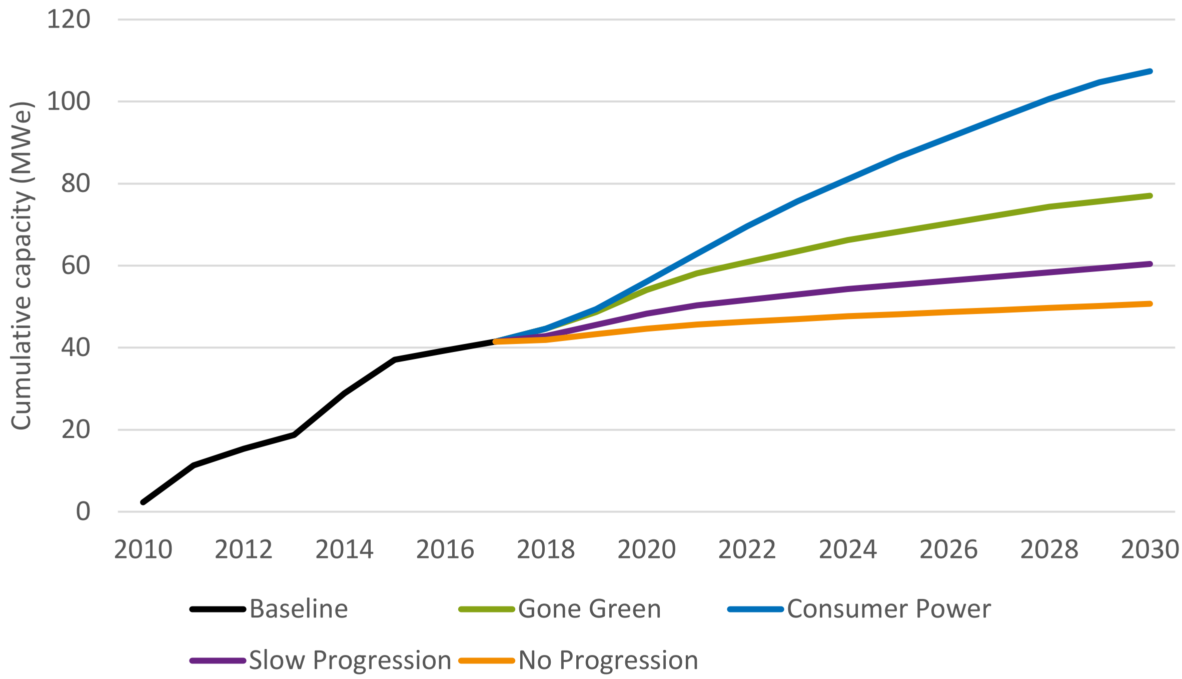


Table 14: Non-cumulative scenario capacity growth of network connected anaerobic digestion in the West Midlands licence area (MWe)

Scenario	Baseline (MWe)	2020 capacity (MWe)	2025 capacity (MWe)	2030 capacity (MWe)
Gone Green	41	54	68	77
Consumer Power	41	56	86	107
Slow Progression	41	48	55	60
No Progression	41	45	48	51

6.6 Geographic distribution of the anaerobic digestion scenarios

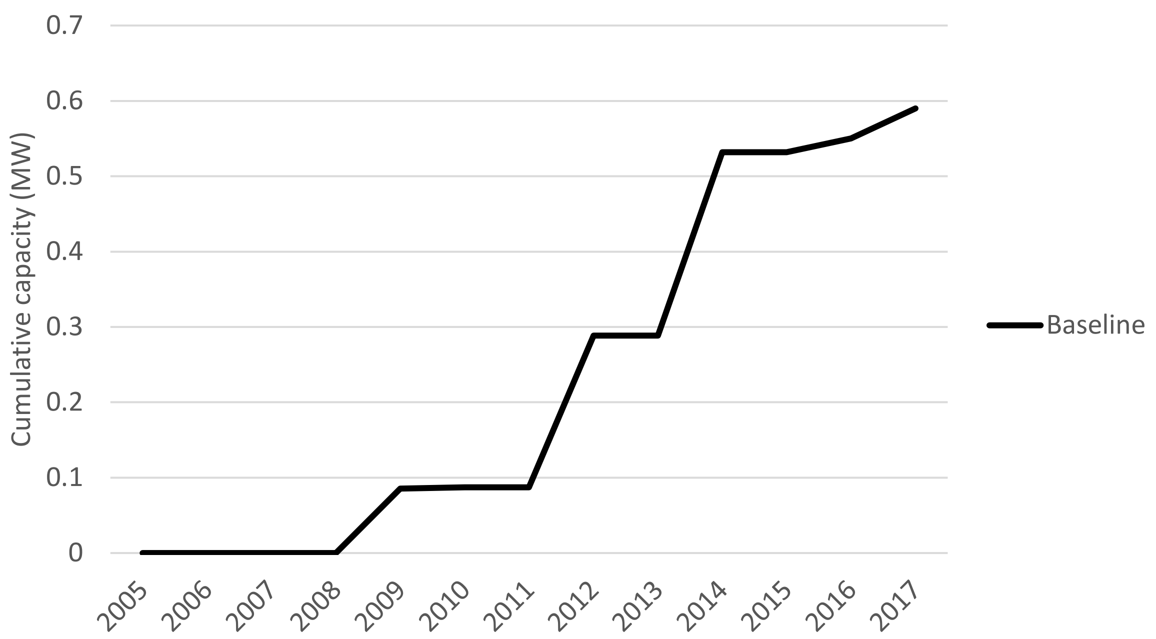
We have distributed the scenarios using the factors of total land area, proportion of farm land and the current installed capacity. For Gone Green, we have weighted the distribution towards the location of current installed capacity, as there are likely to be a greater number of extensions of existing sites under this scenario.

7 Hydropower

7.1 Baseline: hydropower growth to 2017

Despite resource maps showing a greater resource in the West Midlands than some other English regions, hydropower deployment in the West Midlands licence area has been limited, the total installed capacity is one of the lowest in the country. There are currently 30 projects totalling just less than 600kW in installed capacity. Wychavon and Shropshire are the only local authority areas with over 100kW of installed capacity. Outside of these areas small/micro hydro sites are scattered across the licence areas, with slow growth since 2009.

Figure 34: Baseline capacity growth for hydropower



This low deployment reflects the trend across other renewable technologies in the West Midlands – despite seeming resource availability, deployment is low. Contributing factors may be:

- In other regions, hydropower projects have tended to cluster, as project owners are inspired by or learn from nearby installations; the West Midlands has not seen this effect.
- Difficulties in connecting to the electricity network.
- Other river features and ecology having an impact.

7.2 Pipeline: hydropower, 2017 to 2020

Hydropower across the UK is suffering from the closure of the RO and significant cuts to the FIT in February 2016. As a result, only a few new schemes are being developed, as the subsidy is not sufficient to make schemes economically viable. Developers are focusing on: higher head sites, particularly in North Wales and Scotland; sites with onsite electricity usage; and the refurbishment or improvement of existing sites.

Shrewsbury Hydro CIC developing the only hydropower project in WPD's connection database with a connection agreement in place have announced that it will not go ahead. The pipeline is, therefore, empty.

7.3 Regen's market insights: hydropower

Hydropower is particularly appealing to community energy groups and landowners who are attracted to generating energy from this very visible resource in their area. Hydropower is a well-developed technology, with an established supply chain and high public approval. It is a predictable and reliable renewable energy resource and is expected to play a role, albeit relatively small in terms of generation capacity, across all the future growth scenarios for the UK.

There are, however, obstacles to current and future development of hydropower which mean that growth is very limited under all scenarios. Issues affecting deployment include:

- Hydropower is a relatively expensive technology to deploy, given the need for detailed technical feasibility studies, permitting requirements and high upfront capital costs. The technology is relatively mature, with limited market scale and so unlikely to see the type of cost reductions that other renewable technologies are expected to achieve. In addition, civil engineering costs make up a large proportion of installation costs and, if anything have increased since the introduction of the FIT, as regulators' expectations have been raised. Current FIT levels are too low for most run-of-river sites to be economically viable.
- Eel regulations were introduced in 2009. The current interpretation of screening requirements can cause major difficulties for some low head schemes.
- In March 2016, the UK Government proposed new legislation requiring the removal of river obstructions or the building of fish passes to provide a route around or through these hurdles. If enacted, this would pose a new regulatory challenge for some new hydro projects.
- There are a limited number of viable sites and those with optimal conditions tend to have already been developed.
- Unlike wind and solar, third party development models are more unusual, outside of the community sector, and as a result, good site conditions have to be aligned with an owner who is keen to develop a hydro project and who has the necessary finances.

7.4 Scenarios: hydropower, 2020 to 2030

7.4.1 Factors affecting the scenarios: hydropower

We have considered the factors in the table when developing the scenarios.

Table 15: Factors enabling potential hydropower deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Government extends and increases FIT or subsidy for hydropower	●	●		
Government increases permitting and ecological requirements (e.g. fish pass legislation is introduced)				●
Electricity network connection costs				
Lower network reinforcement costs – enabled by strategic investment	●		●	

Lower network reinforcement costs – enabled by 'smart' solutions, active network management and demand response solutions etc.	●	●		
Wholesale price of power				
Rising electricity wholesale price – potentially driven by economic growth, increased demand and/or falling supply	●	●		
Availability of finance				
Strong economy means investment capital is available	●	●		

7.4.2 Scenario results: hydropower

According to the Environment Agency hydropower resource assessment, there is resource available in the West Midlands for small scale hydropower. However, historic development has been low. Further opportunities are low head, which means that current conditions are not favourable to development, and there is unlikely to be a major change to this before 2030. Areas with high head opportunities (North Wales, Scotland) are more likely to develop significant amounts of hydropower.

Overall growth is low under all scenarios. However, given the low baseline, the Gone Green scenario shows an approximate tripling of installed capacity.

Table 16: Summary of scenarios for hydropower in the West Midlands

Consumer Power	**Gone Green**
• Deployment is marginally lower than under Gone Green. • Subsidy is made available for small and medium scale hydropower, to enable projects by farmers, landowners and consumer groups. • Lack of strategic network investments means that deployment is below Gone Green scenario. • Deployment rate falls slightly towards 2030 as the subsidy begins to run out and the best sites have been developed.	• Highest deployment rate, though this is still limited • Subsidy / increased FIT is made available for all scales of hydropower, meaning that deployment rates rise to marginally above previous peak. • Nationally, deployment remains focused on areas with the best resource and these are largely outside of the licence area, meaning West Midlands deployment remains limited. • Deployment rate falls slightly towards 2030 as the subsidy begins to run out and the best sites have been developed.
No Progression	**Slow Progression**
• Very low deployment • No increase to subsidies • Permitting and ecological requirements are increased, increasing development costs	• Low deployment • Installation rate drops below current rate focused on sites with owners with green ambition and onsite demand. • The availability of investment capital amongst landowners is limited. • No increase to FIT or other subsidies available.

Figure 35: Scenario growth for hydropower in the West Midlands licence area

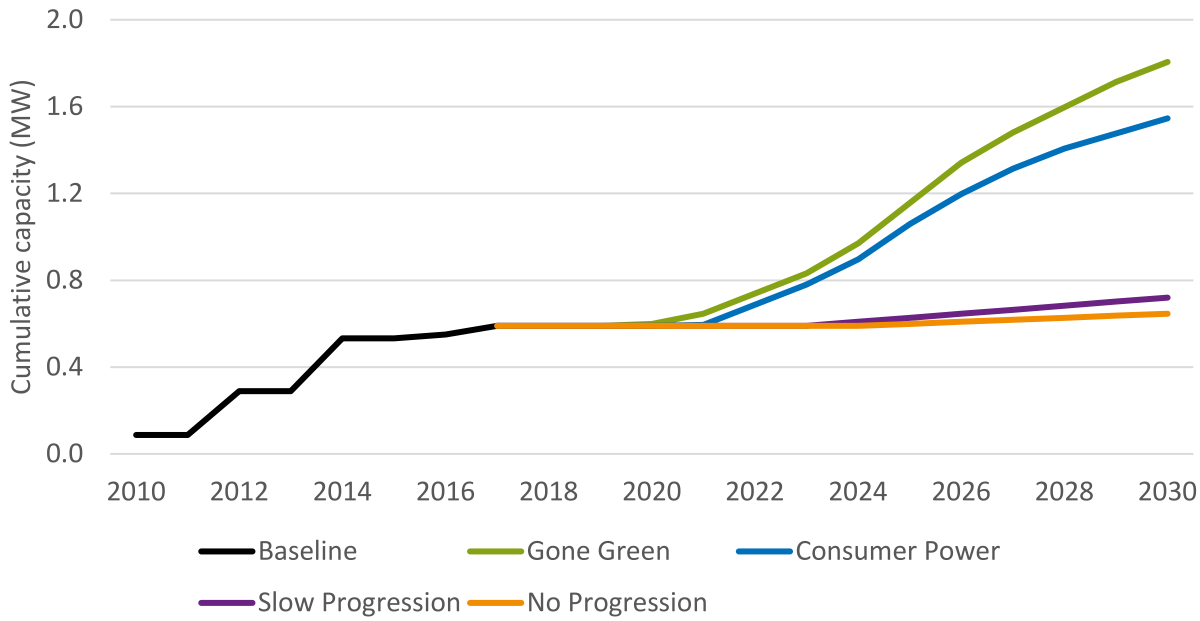


Table 17: Non-cumulative capacity breakdown of hydropower in the West Midlands licence area (MW)

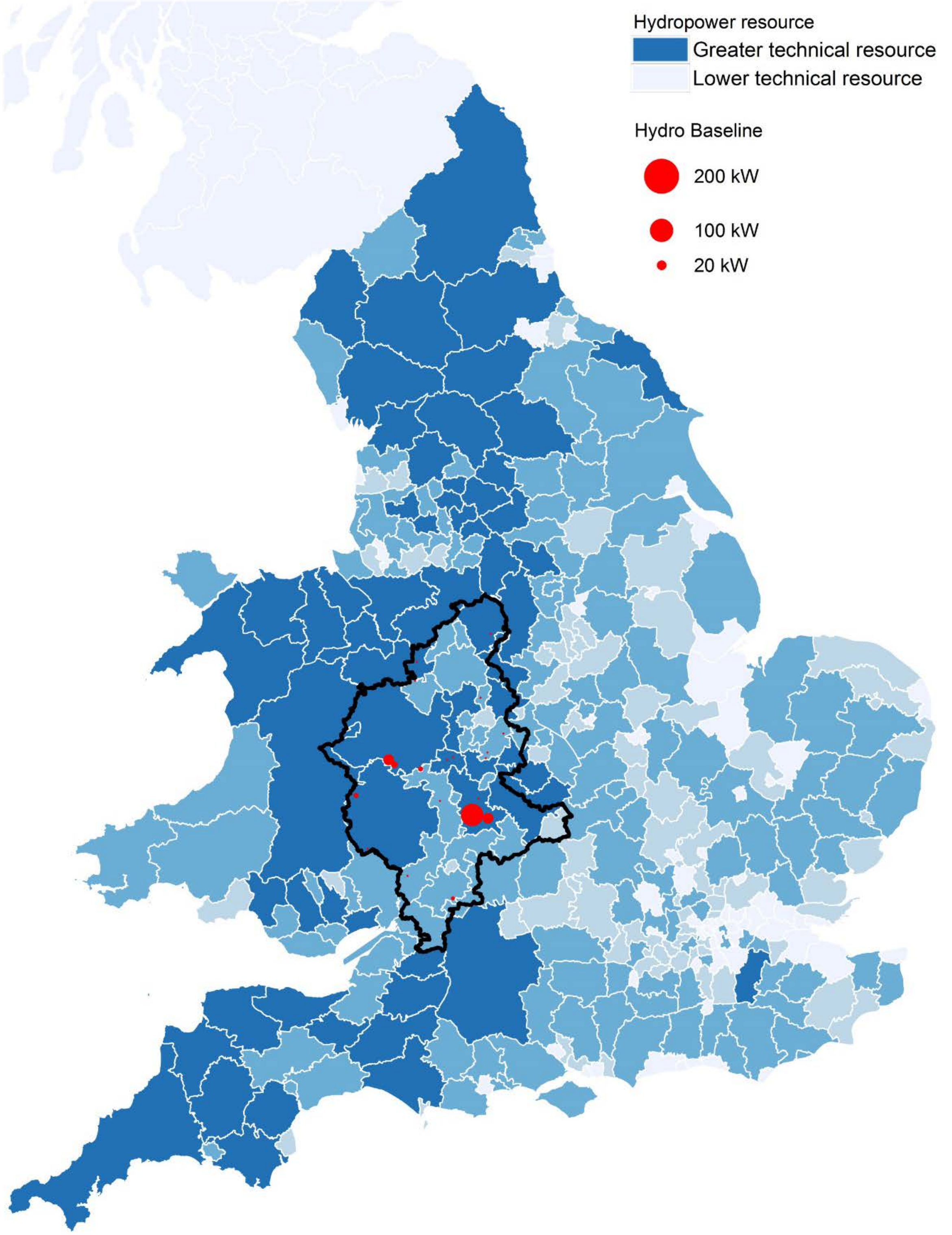
Scenario	Baseline (MW)	Pipeline (MW)	Scenarios (MW)
Gone Green	0.6	-	1.2
Consumer Power	0.6	-	1.0
Slow Progression	0.6	-	0.1
No Progression	0.6	-	0.1

7.5 Geographic distribution of the scenarios: hydropower

Figure 36 shows the distribution of the hydropower resource by local authority across England and Wales. The resource is higher in hilly areas of the licence area, and the larger existing projects are in these areas. In general, hydro projects in the UK tend to cluster around existing sites due to resource availability and a learning/inspirational effect.

The installed capacity under each scenario is, therefore, distributed according to the available resource and existing projects in the ESAs.

Figure 36: Hydropower resource map



8 Energy from waste

8.1 Baseline: energy from waste growth to 2017

There are seven energy from waste plants in the licence area that incinerate municipal waste:

- Battlefield EfW, Shrewsbury, 9 MW
- Stoke EfW, 15.2 MW
- Wolverhampton EfW, 8.7 MW
- Dudley EfW, 7.4 MW
- Hartlebury EfW, near Kidderminster 15.5 MW
- Staffordshire EfW, near Cannock 23 MW
- Tyseley EfW, Birmingham 25 MW

These EfW plants can process around 1.3 million tonnes of waste annually, largely through contracts with the local authorities in the area to process municipal solid waste (MSW). These plants were built in two waves with four plants commissioned in the late 1990s and three between 2014 and 2017.

In addition, there are two operational gasification plants in the licence area, one at Oldbury, commissioned in 2015 with an installed capacity of 42 MW and one adjacent to the Tyseley EfW incineration site, a 9 MWe waste timber gasification plant which is in the process of commissioning in June 2017.

8.2 Pipeline: energy from waste, 2016 to 2020

There is one further incineration plant under construction in the licence area in Gloucestershire, which will add a further 190,000 tonnes of MSW processing capacity in the licence area.

There are two gasification plants due to be constructed/under construction in the licence area. Current trends show that advanced thermal treatment (ATT)[7] plants have a low success rate, even at the construction stage. However, we have assumed that these two plants will go ahead, depending on the scenario.

There is one further site within the licence area with planning permission for an energy from waste plant in Worcestershire. It has been granted permission at appeal for a small scale EfW plant, though there is not a developer or technology in place. We have assumed this is the site of an EfW plant in the Consumer Power scenario.

8.3 Regen's market insights: energy from waste

8.3.1 Limited availability of waste resource

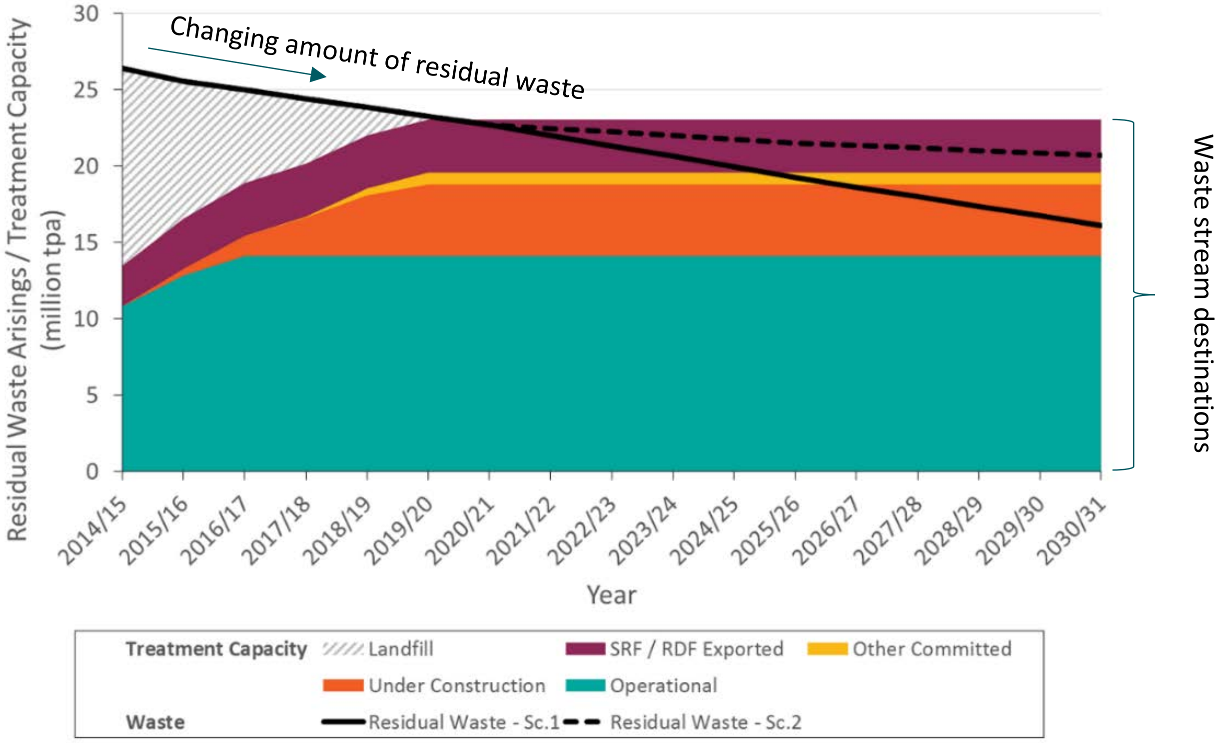
There is significant debate in the waste industry about the availability of the waste resource for energy production going forwards.

[7] ATT is second generation thermal treatment and can be applied to a range of processes including gasification and pyrolysis.

Research by Eunomia estimates that, based on currently operational plants and those in the pipeline (under construction or at financial close), the UK's residual waste treatment capacity will exceed supply around 2021, taking into account export commitments. If no waste is exported, capacity will exceed supply around 2025 if recycling targets are met and shortly after 2030 in a low recycling scenario. This is the point on the graph at which the residual waste line falls below the level at which any Solid Recovered Fuel (SRF) or Refuse Derived Fuel (RDF) is exported. These findings have been questioned by the industry, with companies such as Biffa claiming there will remain areas with unused resource.

Export remains an attractive option for the UK waste industry at present; there is significant over-capacity in European energy from waste facilities, which is likely to grow further as each country's domestic waste resource shrinks. Gate fees for these EU plants will have a significant impact on investment in the energy from waste market. The impact of Brexit on this market is uncertain, but it may increase export costs.

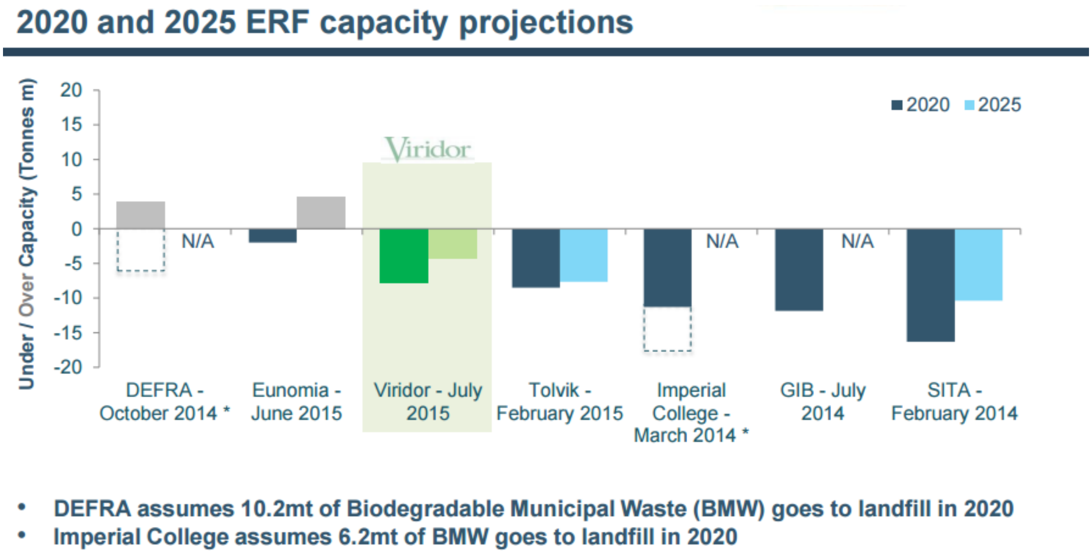
Figure 37: Changing waste stream destinations (2014 to 2030)



Source: Eunomia, A reality check (2015), http://www.eunomia.co.uk/a-reality-check/

Eunomia's analysis has been questioned by others in the industry with Viridor publishing a comparison of the various industry analyses, showing the differences in projections. Eunomia and Defra are the only two pointing towards oversupply of energy from waste by 2025 at present.

Figure 38: Energy Recovery Facility capacity projections



Source: Pennon Group UK Waste Market Analyst Briefing, July 2015, http://www.pennon-group.co.uk/system/files/uploads/financialdocs/uk-waste-market-analyst-briefing-v2.pdf

Despite these differing assessments, it is certain that the UK's municipal resource is shrinking due to recycling imperatives and, with planned increases to supply in the energy from waste market and export a viable option, the remaining resource is limited in any geographic area.

The availability of the waste resource in the area from 2020 to 2030 is one of the key factors we have considered in assessing the potential for energy from waste in the area under the scenarios.

8.3.2 Current technology trends for energy from waste

There has been a move towards treating residual household waste through energy from waste plants, as the landfill tax has made landfill prohibitively expensive and as landfill sites fill up.

This shift was initially led by investment in energy from waste incineration plants enabled by long-term Private Finance Initiative Contracts let by local authorities to treat and dispose of municipal waste. However, the removal of Public Private Partnership (PPP) credits in 2013 means there are currently a very limited number of PPP projects in procurement in the UK, and a resulting decrease in the number of large scale energy from waste plants being proposed.

The government has now withdrawn financial support for new incineration facilities believing that sufficient municipal waste treatment capacity exists for the UK to meet the 2020 landfill diversion target set by Europe. This is reflected in the withdrawal of PPP credits, the ending of the RO and restrictions for energy from waste on accessing Contracts for Difference. Although two energy from waste incineration with CHP projects won CfDs in the first auction, the technology was not eligible for the second round. There is no subsidy currently available for new incineration plants. Large scale energy from waste incineration plants are therefore dependent on other revenue streams. Viridor estimates that the revenue mix for its new plants will be approximately 70 per cent gate fees, 25 per cent power price, and 5 per cent recovered metals[8].

[8] www.pennon-group.co.uk/system/files/uploads/financialdocs/uk-waste-market-analyst-briefing-v2.pdf

The major waste companies continue to predict steady growth in their energy from waste incineration portfolios. However, we believe deployment of this technology is likely to be relatively limited outside of the current pipeline, which is limited in itself. Analysis by Ricardo-AEA shows a decline in the number of energy from waste incineration and CHP projects in planning and proposed between 2011 and 2014.

8.3.3 Advanced Thermal Treatment (ATT) Technologies currently struggling

Despite a move away from supporting incineration technology, the government is continuing to support Advanced Thermal Treatment (ATT), such as gasification and pyrolysis, allowing these projects to apply for Round 2 of the CfDs. Contracts were awarded to three ATT projects in Round 1.

ATT remains in its infancy in the UK market; in England, the IES Oldbury plant and Birmingham Bio Power plant at Tyseley in the West Midlands are two of only a handful of ATT plants generating electricity. At present, there is a high failure rate for ATT projects, with technology issues resulting in investors withdrawing; for example, two 50 MW gasification plants on Teeside halted construction midway in November 2015, others such as Energos have gone into administration with four plants in the development phase (Derby, Milton Keynes, Isle of Wight and Glasgow).

Despite these technology issues, there remain a high number of pipeline ATT projects under construction in the UK, including two in the licence area.

8.3.4 Future potential for ATT

ATT produces syngas, which can be used both for heat production and as a transport fuel, both more efficient uses of the syngas than using it to drive a turbine to generate electricity. A waste to gas plant that produces gas for homes and heavy goods vehicles opened in 2016 in Swindon. As well as output flexibility, ATT has several other advantages over incineration as outlined by the Energy Technologies Institute:

- Feedstock flexibility – ATT can process a range of waste and biomass feedstocks
- Greater efficiency than incineration and the potential for this to develop further through innovation
- The ability to be deployed at a range of scales, including sized to process the waste resource of a small town. By operating at smaller scales, waste miles can be reduced and integration with local heat networks can be facilitated.
- The potential to be integrated with carbon capture and storage infrastructure if this is developed

The use of ATT to produce syngas seems to be where the key remaining opportunity for energy from waste lies, but only if there is sufficient research and development. If the technology matures, the impact of energy from waste on the network will change; ATT will be used to produce gas for heat and transport, rather than electricity and so network connection requirements will be reduced or even eliminated.

With the market for municipal waste management stalling, the focus for many new projects is on treating commercial and industrial (C&I) waste. This waste stream represents a largely underused resource in the UK. There is now an increase in the number of merchant facilities being proposed to treat C&I waste. These facilities tend to be smaller scale and more dispersed and ATT seems to be the right technology FIT for this type of plant – if it can be shown to work.

8.4 Resource assessment: energy from waste

We mapped and reviewed the location of baseline and pipeline projects (including those in neighbouring areas) against population centres. We looked for current gaps in the provision of MSW treatment plants. We identified that the majority of population centres are or will be served by current or under construction MSW energy from waste plants. We identified a potential gap in provision in southern Worcestershire.

In some areas of the UK an import model has developed, where multiple projects are co-located, forming a hub. We consider that if ATT matures sufficiently this type of model could occur more widely, with ATT plants processing C&I waste located close to existing municipal waste incineration plants in areas designated in local plans as suitable; the Tyseley Energy Park is an example of this model in the West Midlands. ATT plants are more likely to produce gas for heat or transport than electricity and so their impact on the network will be reduced. The scenarios consider the factors that would lead to construction of plants.

8.5 Scenarios: energy from waste, 2020 to 2030

8.5.1 Factors affecting the energy from waste scenarios

Table 18: Potential factors affecting energy from waste deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Government extends and increases support for energy from waste incineration with CHP	●			
Subsidy available for ATT technologies	●	●		
Technology costs/innovation				
Advanced thermal treatment technologies develop to become a more mature technology later in the decade	●	●		
Resource availability				
Low rates of recycling means more resource		●		●
Higher rates of consumption means more resource	●	●		
Availability of finance				
Strong economy means investment capital is available	●	●		

8.6 Scenario results: energy from waste

Conditions are most favourable to energy from waste incineration plants under the Gone Green scenario where useable heat can be produced, as government provides revenue support for EfW with CHP. Under Consumer Power, there is potential for new energy from waste incineration plants without CHP where there is sufficient resource availability, as under Consumer Power gate fees are higher due to a higher availability of MSW. On this basis and our analysis of current MSW treatment provision in the licence area, we have included a new plant at Hanley Castle in Worcestershire under Consumer Power. This is a rural site with little potential to provide usable heat and therefore is not included under a Gone Green scenario. Under

Gone Green, we have included a new EfW plant with CHP to the south of Worcester, on the basis that there could be potential for heat to be supplied to industrial units in that area.

New ATT merchant plants could be developed in the area under both Gone Green and Consumer Power to treat commercial and industrial waste, with Consumer Power the most favourable scenario for the deployment of this technology.

The most likely location for these plants would be in proximity to existing incineration plants as key factors in determining locations tend to be access to a waste resource, access to the road network and obtaining planning permission, which tends to be easier in areas already designated for waste treatment. We have assumed therefore that these plants would be built in four locations where there are existing or under construction projects. We selected the four locations with the largest commercial/industrial land use surrounding them, on the basis that these would be the most likely to produce significant commercial and industrial waste arisings.

Under the Gone Green scenario, we have also assumed that these new plants would focus on producing gas for heat and transport, exporting less electricity to the network, as this is the greenest, more efficient option. Under the Consumer Power scenario, we have assumed these new plants would focus more heavily on exporting electricity to the network.

Table 19: Scenarios summary for energy from waste in the West Midlands

Consumer Power	Gone Green
• One new municipal waste incineration projects in the area built late 2020s • 4 new ATT projects treating C&I waste built towards the end of the decade. • R&D investment makes ATT more reliable and cheaper to deploy. • Government subsidy is available for ATT.	• One new municipal waste incineration project with CHP in the area built mid to late 2020s • 4 new ATT projects treating C&I waste built mid/end of the decade. • R&D investment makes ATT more reliable and cheaper to deploy. • Government subsidy is available for syngas production from ATT. • Impact on network is more limited as focus in on producing syngas for grid and transport.
No Progression	**Slow Progression**
• No new municipal waste incineration projects in the area due to poor project and market economics. • No new ATT projects as technology development is limited and there is a lack of subsidy. • Waste continues to be landfilled until 2026 and then exported.	• No new municipal waste incineration projects in the area due to poor project and market economics. • No new ATT projects as technology development is limited and there is a lack of subsidy. • Excess waste is exported.

Figure 39: West Midlands energy from waste scenarios

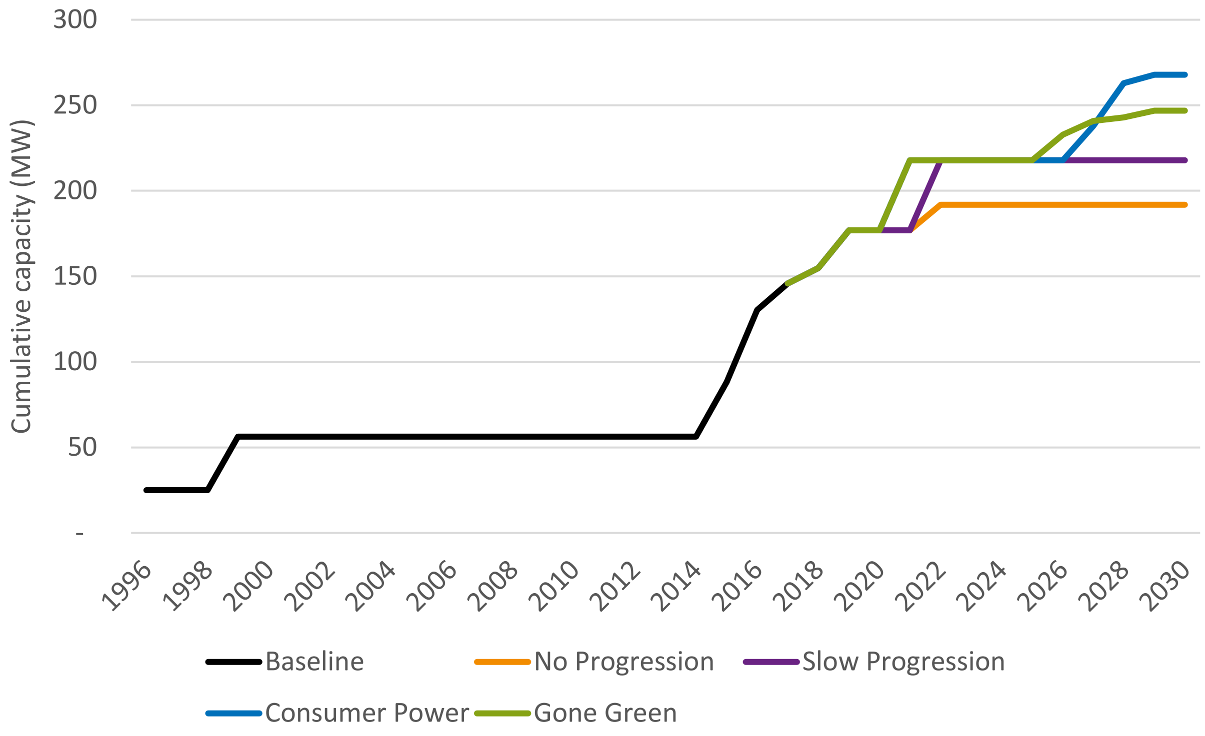


Table 20: Non-cumulative capacity breakdown of energy from waste in the West Midlands licence area (MWe)

	Baseline (MWe)	Pipeline (2017 to 2022) (MWe)	Scenarios (2022 to 2030) (MWe)
Gone Green	146	31	70
Consumer Power	146	31	91
Slow Progression	146	31	41
No Progression	146	31	15

9 Diesel and gas generation technologies

9.1 Introduction

The diesel and small scale gas generation technologies analysis has focused on smaller scale fossil fuel generators connected to the distribution network which are currently registered under CHP, STOR, Mixed and 'other generation' categories within the WPD connection register. This includes:

- Diesel reciprocating engines generators
- Gas reciprocating engines
- Gas CHP plants
- Other fossil fuel generators

For the West Midlands study, we have undertaken a greater level of research and analysis to better understand the structure of the diesel and gas small scale generation market, the technologies within these broad categories and their potential growth scenarios.

The analysis has been made more complex because the 'other generation' category in the connection register has historically been used as a catch-all category for a range of technologies, and the detail needed to identify specific technologies and fuel types has not been recorded centrally. It is understood that this issue is common across all UK DNOs.

To address this data issue, Regen has conducted a further level of research to identify the technology and fuel type of each diesel and gas generating sites that is either connected to the WPD West Midlands network or holding an accepted-not-yet-connected connection agreement. While this research has been successful in identifying most connected sites (by capacity), it has not been possible to categorise every site. This means the analysis presented below is based on several assumptions.

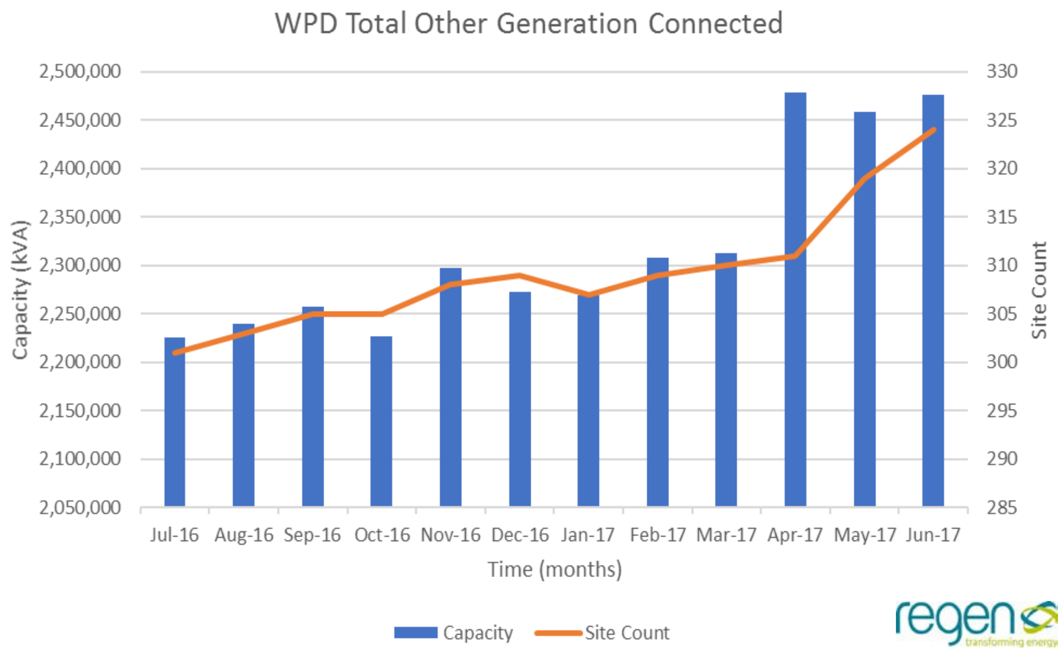
To improve the analysis further work is needed to identify and categorise all fossil fuel generators on the connection register, which would involve contacting individual asset owners and project developers.

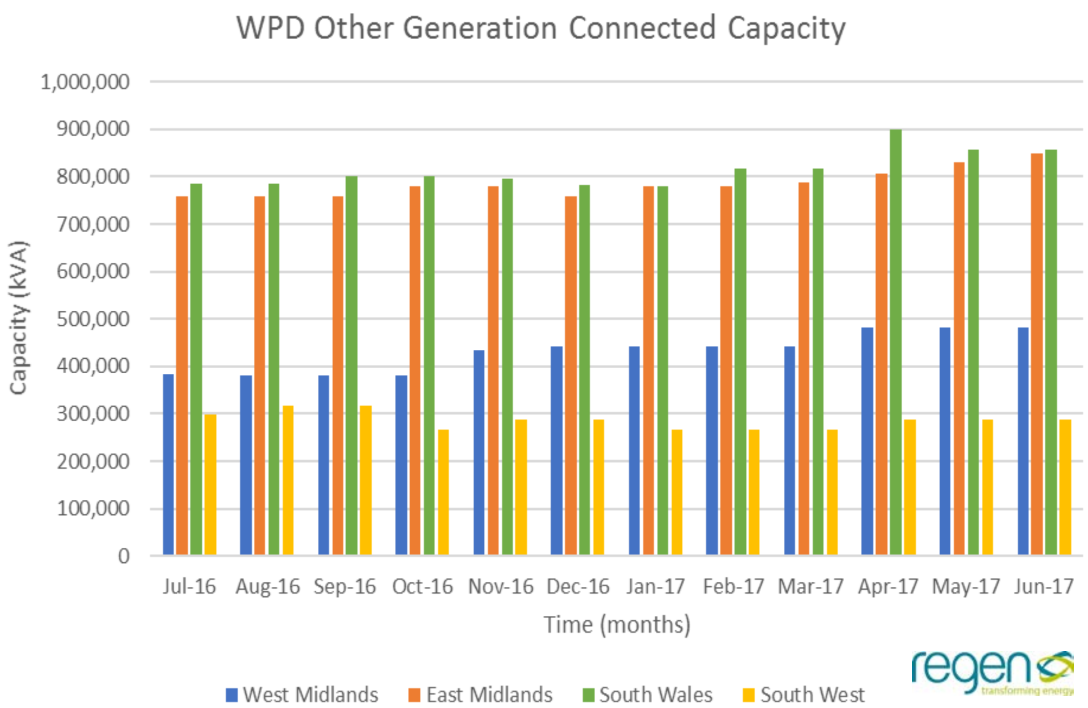
9.2 Growth of diesel generators, gas CHP and gas reciprocating engines

9.2.1 Diesel and gas technology connected and with accepted-not-yet-connected connection agreements

Along with other UK DNO's, WPD has seen a significant growth in both the capacity connected and the number of network connection applications for diesel generators and small scale gas reciprocating engines. The growth of these technologies over the past year is shown in chart data below.

Figure 40: Other generation assets connected to the WPD networks - source connection register data June 2016 - July 2017





Overall the growth in 'other' generation connections across all WPD licence areas between July 2016 and June 2017 has been just over 250 MW or 11%. This has taken the connected capacity recorded under the 'other' generation category to just over 2.4 GW, comprising 324 connection sites.

Without a full data analysis, it is not possible to say categorically that all these sites are in fact diesel, gas CHP, gas reciprocating engines or other fossil fuel generators. Generation assets categorised under 'other generation' could also include biomass, energy from waste, energy storage, biomass, mixed fuel type or were unknown at the time the network connection application was made.

The analysis undertaken for the West Midlands, however, suggests that gas or diesel generation makes up circa 80-90% of the 'other generation' category.

The network connection register data suggests that there has been a substantial increase in diesel and gas reciprocating engines connected across the WPD licence areas.

Table 21: Increase in network connected assets categorised as Other Generation – source WPD connection register June 2016-July 2017

Growth in "Other Generation" connected			
	Connected	Growth June 2016 - July 2017	
Licence Area	June 2017 MW	MW Increase	% Increase
West Midlands	483	99	25.83%
East Midlands	848	89	11.78%
South Wales	856	72	9.22%
South West	289	-10	-3.28%
Total	**2476**	**251**	**11.28%**

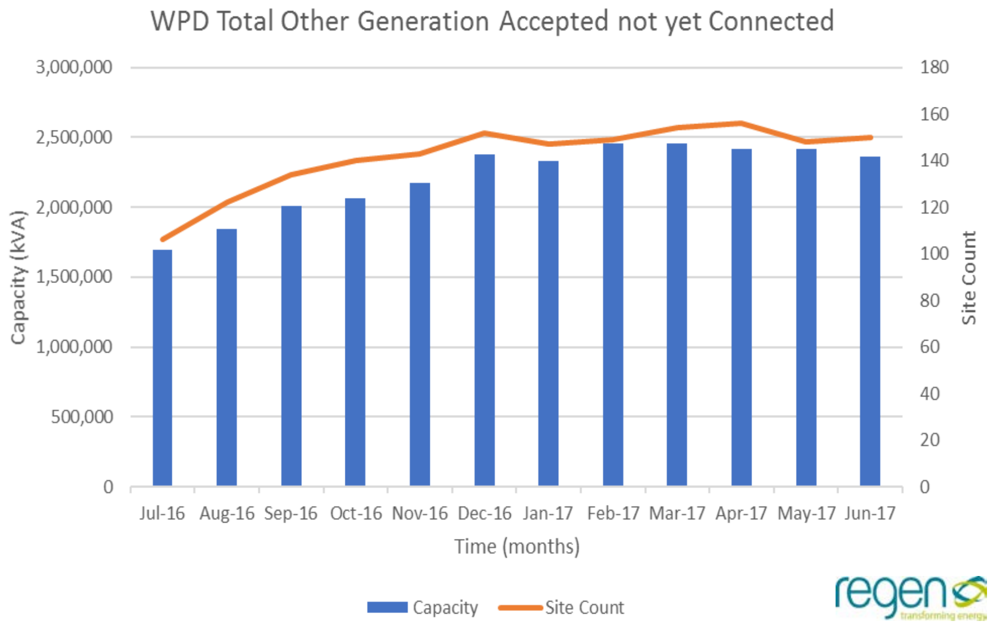
The growth in connections has not been evenly spread. The South West has seen a slight reduction in 'other generation' connections over the past 12 months, while the greatest increase has been in the West Midlands and the East Midlands. The difference in growth probably reflects the relative ease and cost of securing a network connection, plus the availability of cheap industrial brownfield land-space proximate to the network.

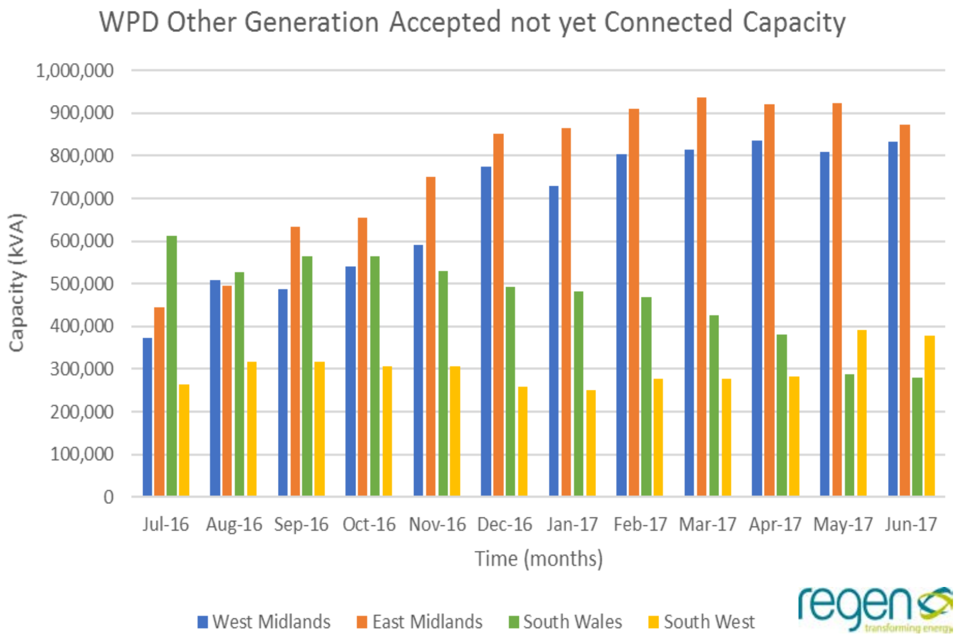
9.2.2 Pipeline of 'other generation' projects with Offered or Accepted network connections

The pipeline connection register data for accepted-not-yet-connected and offered-not-yet-accepted network connections presents a similar picture. Overall, across WPD's network there has been a steady increase in 'other generation' projects with an accepted-not-yet-connected network connection reaching a peak in February 2017 at 2.45 GW. Since then the capacity of accepted-not-yet-connected agreements has fallen slightly to 2.36 GW in June 2017. If all these projects were now deployed the capacity of 'other generation' assets connected to the West Midlands licence area networks would almost double to 4.8 GW.

The spread of accepted-not-yet-connected agreements has, however, been uneven with a more rapid and earlier fall occurring in the South West and South Wales.

Figure 41: Other Generation Assets with an accepted network connection but not yet connected

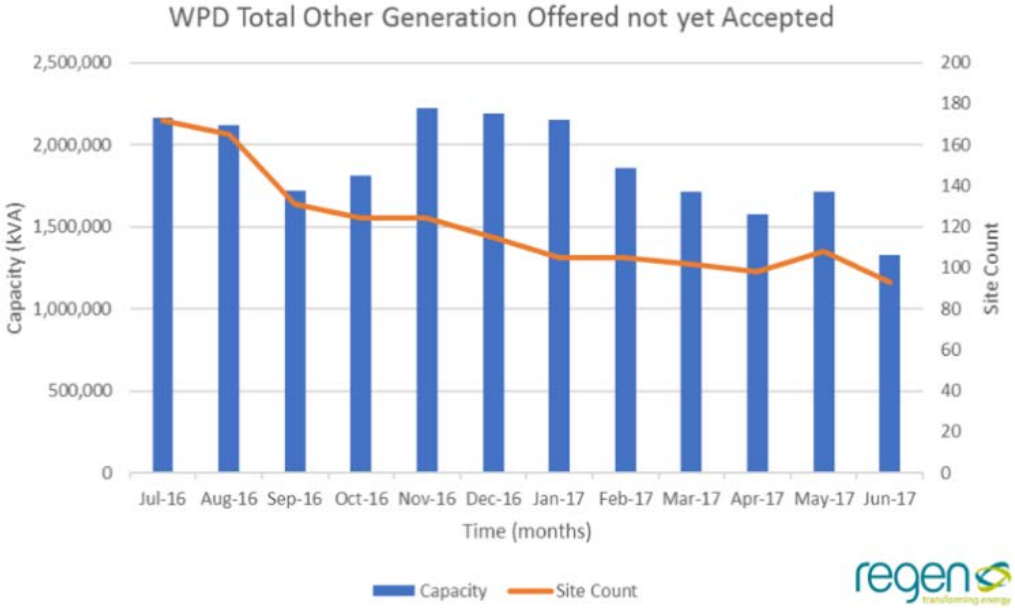


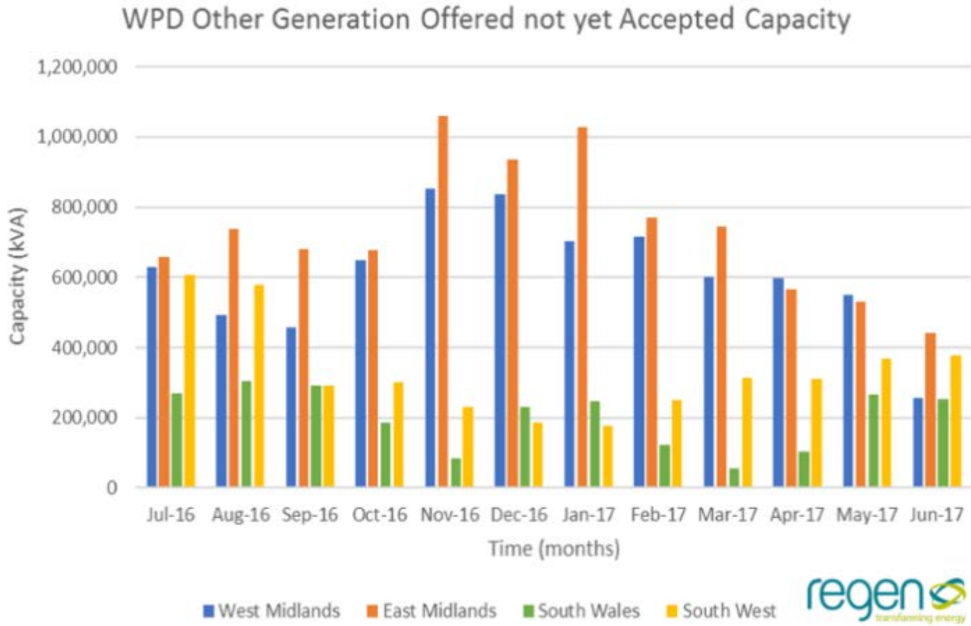


Looking further into the pipeline, the register of those projects with a connection offer that has not yet been accepted shows there has been a significant fall in the number of new projects coming forward since the beginning of 2017. The pattern is uneven across the licence areas, with even a small uplift in new offers now seen in the South West and South Wales.

Looking at the Connected, Accepted and Offered 'other generation' assets together suggests that the rate of growth of new projects coming forward has peaked and is now reducing significantly. The slowdown in

Figure 42: Other generation assets with a connection offer that has not yet been accepted





growth of new completed connections, compared to the very high volume of accepted-not-yet-connected connections in the pipeline, also suggests that there is now a relatively low deployment conversion rate and that more projects are being shelved or cancelled.

The cost of holding an accepted-not-yet-connected agreement is not prohibitive and many developers treat accepted-not-yet-connected agreements as an option rather than a firm commitment. WPD typically requires that projects holding an accepted-not-yet-connected connection agreement demonstrate progress within a 6 month timeframe, so, if the market is softening, it is expected that the rate of project fallout will increase significantly over the next 6 months as more projects forego their connection agreement.

Nevertheless, there is still a very significant capacity of 'other generation' assets in the connection pipeline, and assuming that the majority of these are gas reciprocating engines and diesel generators, there is the potential for the capacity of small scale fossil fuel generators to rise.

Whether this growth does in fact happen will depend very much on the economics of diesel and gas reciprocating engines and the changes to policies and regulations regarding embedded benefits and NOx emissions. These issues are discussed in more detail the sections below.

9.2.3 Factors driving the growth in diesel and gas reciprocating engines

There are several factors that have driven the growth of diesel and gas reciprocating engines. These include:

- The dramatic fall in the cost of diesel generators and gas reciprocating engines. It is now possible to buy a high spec 1 MW diesel generator for under £600k with cheaper models available at £250k. Gas reciprocating engines have higher capital costs ranging from £650k to £950k for a high spec 1 MW engine. Cheaper models and cheaper second-hand assets are also available.
- The rise, and anticipated future rise, in the level of grid and network charges based on peak time consumption. Especially the Triad based transmission network use of system charges (TNUoS).
- Access to Triad prediction services enabling companies to confidently predict when Triad charge periods will occur – although ironically, the more companies that do this the more difficult the prediction is becoming.
- Additional revenue opportunities through the Capacity Market (and the existing STOR market), although as the West Midlands analysis shows a significant number of diesel and gas reciprocating engine asset owners are not bidding into the capacity or STOR market.

The business model backing diesel projects is not about generating energy per se. The cost of diesel (circa 90p per litre) means that, except in exceptional high wholesale price and balancing market periods, the marginal cost of generation per kWh exceeds the marginal revenue and cost savings that could be earnt.

Gas reciprocating engines typically have a higher capital cost (compared to diesel) but a lower marginal cost of generation (lower fuel costs and greater electrical generation efficiency) which means that they could be used as peaking generation plants to avoid peak commodity (electricity) costs and peak network charges (DUOS), although the marginal profit generated would not be enough to create a viable business case without additional revenue streams.

The diesel/gas reciprocating engine business model is therefore primarily based on:

- Avoiding transmission network charges or earning embedded benefit credits (Triads) which under the current charging regime can be worth £45 per kW and is expected to rise £70-80 per kW by 2020.
- Potentially bidding into the Capacity Market or providing Short Term Operating Reserve (STOR) balancing services which can be worth circa £20-24 per kW depending on auction outcomes.
- Avoiding peak electricity price and network charges (DUOS) during peak time Red Zone periods. However, note that for diesel this will typically be less than the marginal fuel costs of generation.
- Providing backup (UPS Uninterruptable Power solution) for those organisations that require it.

Given this model a typical diesel generator may only run for a minimal number of days to secure Triad revenues and meet any Capacity Market or STOR obligations.

A gas reciprocating engine may be expected to run more regularly during peak price and network cost periods (5-7pm during winter months) and to be on standby to target exceptional peak wholesale and Balancing Market price periods.

The market for gas CHP plant has also grown and, in addition to the business model described above, has the added advantage of a potential heat revenue stream if there is nearby heat demand.

The business model for gas reciprocating engines and gas CHP is complicated by the availability of a gas network connection. If a gas network connection is not readily available then more expensive bulk LPG can be used and is becoming more commonplace.

9.3 Market outlook

9.3.1 Impact of the growth of diesel and gas reciprocating engines

The growth of peaking fossil fuel plants is having a significant impact on the UK energy system. Unfortunately, because of the lack of data available about what assets are connected and how they are being used it is very difficult to quantify what that impact has been. It is possible that, because these assets are being used infrequently the actual impact on the energy system and carbon emissions is small compared to the capacity that is connected.

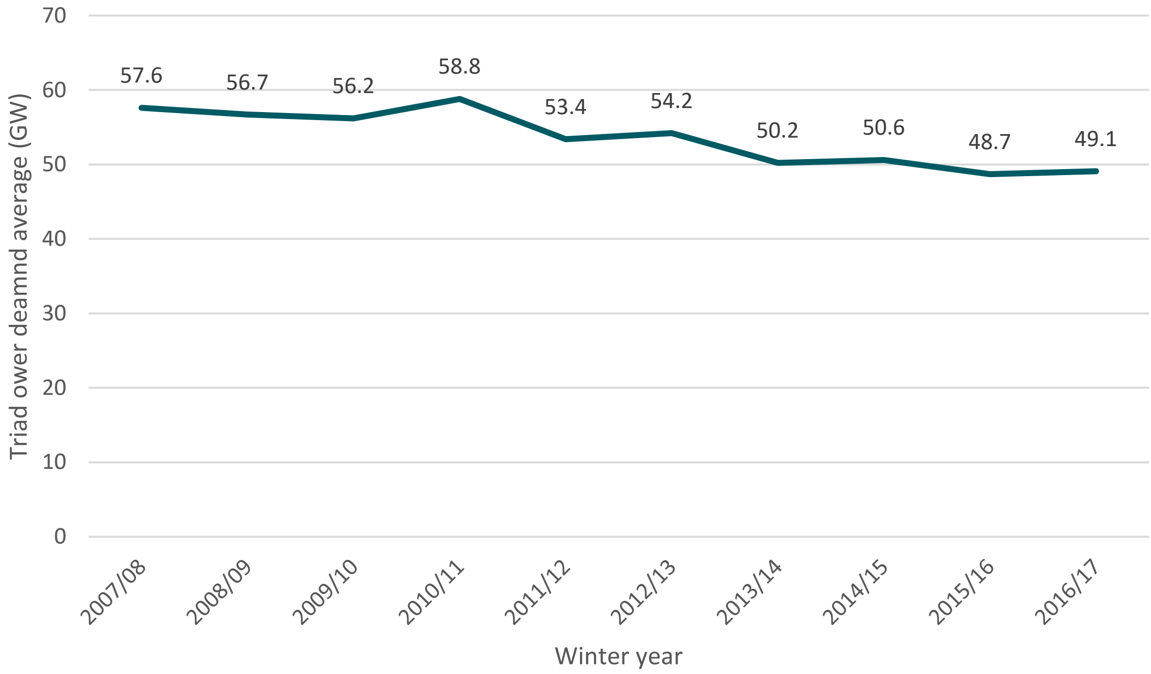
One area where diesel and gas reciprocating engines are having a direct impact is in the Capacity Market.

- **2015 T4 Capacity Market Auction**. Over 650 MW of diesel generators picked up Capacity Market contracts helping to push the final auction price down to £18-19 per kW.
- **2016 T4 auction**. Over 4 GW of diesel generation pre-qualify for the bidding but in the end only 680 MW received contracts. Gas reciprocating engines however picked up 2.29 GW of contracts.
- Existing gas and diesel generators are also bidding into the T1 – year ahead – capacity market auctions.

Less easy to quantify has been the impact of diesel generators and gas reciprocating engines on overall peak demand. It is noticeable that the peak demand, as measured during the three peak Triad periods, has been dropping in Great Britain over the last decade from an average winter Triad peak of 57.6 GW in 2017/18 to 49.1 GW in 2016/17. This fall could be due to a variety of reasons – deindustrialisation, energy efficiency, milder winters – but one factor has been the increase in high energy users who are reducing peak demand on the network by switching to on-site generation. [9]

[9]National Grid estimates that around 7.5 GW of embedded generation currently runs at peak. The addition of 7.5 GW to the demand charging base would reduce the size of the Transmission Demand Residual (TDR) from circa 47.50 per GW in 2017/18 to circa £42.50 per kW, by spreading the required revenue over a greater number of users. Source: Ofgem Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators Une 2017.

Figure 43: Falling peak winter demand – Triad average



9.3.2 Concerns raised over the growth of diesel generators

While it can be argued that, in an open market, diesel generators are providing a valuable service both to their asset owners and to the network, a number of concerns have been raised that the growth of diesel generators has distorted the market and may be unfairly competing against other forms of generation and in particular larger (more efficient) Combined Cycle Gas Turbine (CCGT) generators.

The specific concerns raised regarding the widespread use of diesel generators (and to an extent gas reciprocating engines) include:

- Distorting 'out of merit' despatch during winter peak network cost periods which is reducing the wholesale price
- Displacement (out bidding) of new CCGT plant from the Capacity Market – without necessarily providing the same duration and resilience to contribute to energy security
- Avoidance of network charges for high energy users pushes up the charges for other network users – the 'death spiral of the grid' syndrome[10]
- Use of on-site generation behind the meter effectively masks the real underlying demand making it more difficult to fully assess the UK's demand
- NOx and other particulate emissions associated with diesel generation

[10]National Grid estimates that around 7.5 GW of embedded generation currently runs at peak. The addition of 7.5 GW to the demand charging base would reduce the size of the Transmission Demand Residual (TDR) from circa 47.50 per GW in 2017/18 to circa £42.50 per kW, by spreading the required revenue over a greater number of users. Source: Ofgem Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators Une 2017.

The extent to which these concerns are real and valid has been the subject of much debate. As has the counter argument that diesel generators and gas reciprocating engines are providing high energy users a cost effective means to reduce peak demand.

9.3.3 Impact of recent policy changes

Embedded benefits charge review

To address what Ofgem believed were 'excessive revenues' from some distribution generation, in 2017 Ofgem confirmed that it will reduce the embedded benefits related to Triad avoidance from circa £45 per kW to £3-5 per kW, implemented in 2018.

Note, the proposed changes would greatly reduce TNUoS credit for embedded generators exporting to the grid but would not affect the equivalent TNUoS cost savings of using behind the meter generation to meet onsite demand. Ofgem has stated that it will look at the impact of behind the meter embedded generation as part of its review of residuals as part of the Targeted Charging Review.

> 5.8. We recognise that a reduction in payments to smaller EG may increase the incentive to move generation behind the meter (BTM) to net off consumption and reduce charges. We are proposing to consider the collection of residuals as a priority area for the TCR. Some respondents to our consultation have suggested that changes to the payment of the TDR to EG, but not to BTM and DSR, constitutes an end to the equivalence of demand-side response and generation. This is not necessarily the case, as the cost-reflective elements will retain equivalence. The residual, cost-recovery elements will be considered as part of the TCR.

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Network banding (DUOS) charge calculation

Ofgem has also agreed to implement a change (CDP228) to the way in which distribution network (DUoS) charges are calculated. While the effect of this change varies across licence, the overall impact has been to significantly reduce the peak 'red band' charges made between 5 and 7pm, thus reducing the business case of using diesel and gas generators during peak periods. In an extreme case, in the South West for example, the red band charge for half hourly settled meters will be reduced from 23.3p to 9.75p per kWh. For a 1 MW diesel or gas engine planning to operate from 5-7pm throughout the winter this change represents a lost benefit of just over £30k per annum.

Tighter NOx emissions controls

The Government is also looking to implement of tighter NOx emissions controls from small scale generation (i.e. with a capacity of 1-50MWth). Any new build generator winning an agreement in the 2016 Capacity Market auction, may need to comply with a limit of 190mg/Nm^3 from 1 January 2019. For existing generators, this limit will apply from 2025 or 2030, depending on its capacity.

9.3.4 Market outlook and growth scenarios

There is a consensus that gas will continue to play a major role in the energy system into to 2040's and there has been a lot of debate about the impact of the policy changes on small scale peaking fossil fuel assets.

At one extreme, industry commentators have said that the change to the way in which TNUoS charges are applied will damage the business case for smaller peaking plants, and especially diesel generators to the point where even those who have previously won contracts in the Capacity Market may not now be built. This scenario would lead to the rapid reverse in the trend towards diesel generators and a slow-down in the build out of distribution connected gas reciprocating engines and instead, a return to larger CCGT gas capacity connected to the transmission network.

Others believe the market for peaking plant will remain strong into the next decade and that the flexibility they deliver at a local level will increasingly command a higher market value (greater than baseload) as the UK moves towards more variable decarbonised generation coupled with relatively inflexible nuclear.

Peaking plants, such as gas reciprocating engines, with lower capital costs and more flexibility to operate at lower load levels could therefore continue to have a major role in the UK energy system. In a high peaking plant scenario, the reduction of network cost avoidance revenues would be replaced by targeting wholesale peak price periods, Capacity Market and balancing mechanism and auxiliary services.

9.3.5 Future UK energy system scenarios

The National Grid FES 2016[11] provides an overall scenario projection for gas fired capacity and generation ranging from 24 GW by 2030 under a Gone Green scenario to 37 GW under a No Progression scenario.

The FES 2016 also provides a breakdown projection of gas and diesel reciprocating engines connected at the distribution network level. In summary, this shows gas and diesel reciprocating engines under the Consumer Power and No Progression scenarios growing to 4.8 GW by 2030 and a lower growth under a Gone Green Scenario to 2.3 GW.

The FES 2016 baseline numbers of 250 MW of gas reciprocating engines and 438 MW of diesel generators looks to be significantly lower than the capacity that is connected to the DNO networks.

Figure 44: Extract from National Grid FES 2016

National Grid Future Energy Scenario 2016		MW	MW	MW	MW
Scenario	**Technology**	**2015**	**2020**	**2025**	**2030**
Gone Green	Gas Reciporating Engines	250	798	812	841
Consumer Power	Gas Reciporating Engines	250	962	1514	2123
Slow Progression	Gas Reciporating Engines	250	868	1056	1254
No Progression	Gas Reciporating Engines	250	962	1514	2123
Gone Green	Diesel Reciporating Engines	438	1402	1452	1485
Consumer Power	Diesel Reciporating Engines	438	1536	2154	2683
Slow Progression	Diesel Reciporating Engines	438	1500	1781	1991
No Progression	Diesel Reciporating Engines	438	1536	2154	2683

The FES 2016 numbers are used as a basis for the recently published Ofgem Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change the electricity transmission charging arrangements for embedded generators. This identifies that there may be 1.5 GW of diesel reciprocating engines and 867 MW of gas reciprocating engines providing peaking plant capacity by 2020/21.

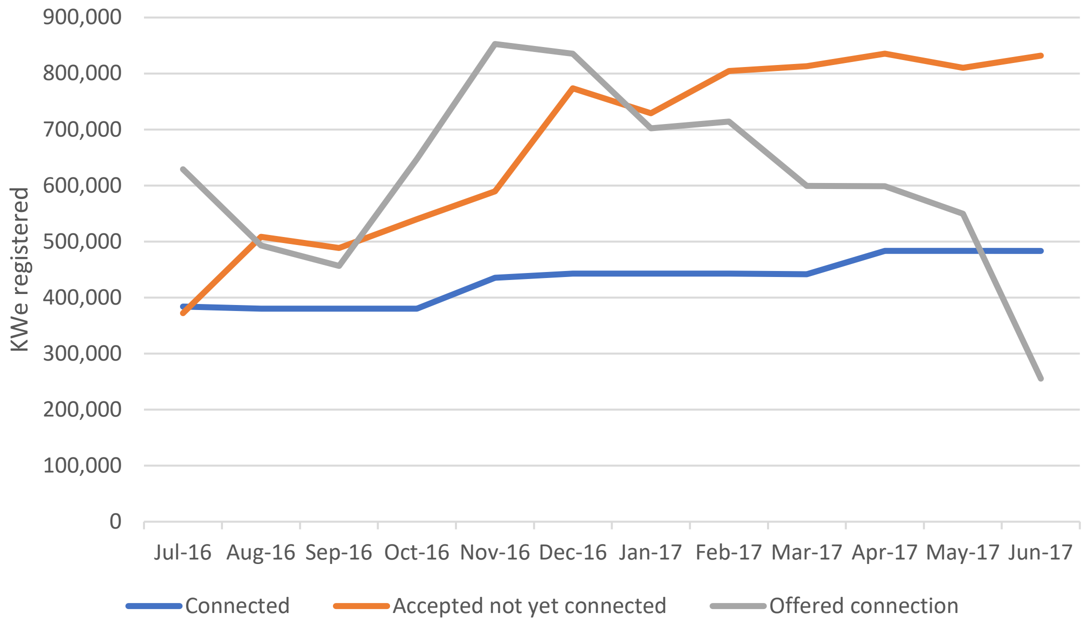
[11] National Grid Future Energy Scenarios 2016 Charts Workbook PS14

West Midlands connection register

In common with other WPD licence areas and the experience of other DNOs, the West Midlands has seen a surge in network connection applications recorded under the 'Other' generation category which are mainly diesel and small scale gas reciprocating engine technologies.

The rate of new offers reached a peak in Autumn 2016 and has since fallen off significantly. The rate of new projects actually connected has been less dramatic rising from 384 MW to 483 MW over the past 12 months, this nevertheless represents a 25% increase in connected capacity. There are currently over 800 MW of projects within the 'other generation' category holding a connection offer, but have not yet connected to the network.

Figure 45: West Midlands - 'other generation' connection register



9.3.6 West Midlands 'other generation', Mixed and STOR data analysis

In order to get a better understanding of the diesel and gas technologies connected to the WPD network in the West Midlands, Regen has conducted a more in-depth analysis of the those projects connected or with an accepted-not-yet-connected connection agreement as recorded in the connection register database. In total there are 136 sites, comprising 1.25 GW of export capacity registered under the Other, STOR, Mixed or CHP categories.

Table 22: West Midlands – other, STOR, mixed and CHP categories.

WPD West Midlands	Connected		Accepted and not Yet Connected		Total Register	
Register	Sites	Export Cap. kW	Sites	Export Cap. kW	Sites	Export Cap. kW
Other Generation	38	355,509	37	594,919	75	950,428
STOR	1	-	6	224,800	7	224,800
Mixed	43	63,591	-	-	43	63,591
CHP (med, Micro, Mini, Small)	4	5,887	7	6,220	11	12,107
Total Categories	86	424,987	50	825,939	136	1,250,926

As discussed above this process is made more complicated by the fact that most gas and diesel projects are recoded under the 'other generation' or CHP asset categories. It is not therefore easy to extract accurate data by technology type and fuel source. The export capacity figure has been used from the register dataset except in cases where there is an identified installed capacity.

To identify the technology type and fuel usage Regen has conducted an enhanced analysis:

1. Cross referenced the Connected and Accepted-not-yet-connected offers to the recent Capacity Market Auctions (T4 auction in 2014, 2015 and 2016, and the 2015 TR auction)
2. Cross referenced to available Elexon and Dukes data which is mainly for larger balancing market plant
3. Conducted a planning database and internet search to identify technologies used – focusing on the larger sites
4. Made an informed judgement on those sites (hospitals and water companies) and scale of assets where possible

As a result of the enhanced data analysis we have been able to identify (or confidently assume) the technology type for the majority (77% by capacity) of the 1.42 GW of 'other generation', CHP, STOR and mixed technology categories that are connected or have an Accepted-not-yet-connected network connection agreement.

However, 71 sites, comprising 291 MW, remain unidentified in terms of technology and fuel type and although we could assume, given their size and location that the majority are diesel or gas generators it is not possible to be certain of their technology type.

Table 23: West Midlands – other, STOR, Mixed and CHP generation sites identified by Regen's analysis.

Results of enhanced analysis of the connection register			
	Export capacity (kW)	Tech identified (kW)	Percentage identified
Register capacity	1,498	0	0 %
Medium CHP (>5 MW,< 50 MW	52	0	0 %
Micro CHP (<1MW)	1,875	14,000	74 %
Mixed	63,591	34,483	54 %
Other generation	950,428	807,133	85 %
Smalla CHP (<5 MW, >1 MW	8,682	4,486	45 %

STOR	224,800	99,800	44 %
Total	**1,250,926**	**959,902**	**77 %**

9.3.7 Cross reference of register to the Capacity Market auction data

It was hoped that a sizable number of the unidentified assets would be found in a cross reference (based on post code) to the recent Capacity Market auctions. In fact, only 28 sites, out of a total of 136 connected or Accepted-not-yet-connected sites, were found to have a positive match to the Capacity Market. Although the per cent match was higher for those assets identified as gas and diesel reciprocating engines and by capacity, suggesting that larger assets are more likely to have bid into the Capacity market auctions.

Table 24: West Midlands –generation sites identified by Regen's analysis.

OTHER, STOR, Mixed sites Matched to the Capacity Market				
Matched to Capacit	Sites	Matched Sites	% Sites matched	% of Capacity
All Sites	136	28	21%	32%
Connected	86	10	12%	20%
Accepted not yet c	50	18	36%	37%
Diesel and Gas Rec	35	9	26%	40%
Sites matched by post code in the T4 2014, 2015, 2016 and 2015 TR Auction				

It would be wrong to read too much into these figures as the cross-referencing to the Capacity Market by post code was imperfect (especially for the T4 2014 auction). It is also the case that the technology description data within the available Capacity Market datasets is also imperfect with a high proportion of imprecise entries. The overall numbers do however suggest that a relatively high proportion of the peaking plant assets connected or Accepted-not-yet-connected on the WPD network have not bid into the Capacity Market. This could be because they:

- Will do so in the future especially targeting the year ahead T1 auctions
- Intend to bid into STOR or another balancing mechanism scheme
- Are too small – behind the meter – assets
- Their business case is based on network and commodity peak cost avoidance

Further analysis would be required to confirm the above hypothesis which would reveal more about the business models of peaking plant and their likely mode of operation.

9.3.8 Baseline and pipeline analysis to 2020

It has been very challenging to make a precise estimate for the baseline of connected and the pipeline of Accepted-not-yet-connected gas and diesel peaking plant assets in the West Midlands.

The estimates given in the tables below should therefore be treated with some caution but based on the more detailed analysis of sites, the following tables show a breakdown and allocation of the diesel and gas reciprocating sites and capacities that are estimated to be connected (baseline) and Accepted-not-yet-connected (in the pipeline).

Step 1 – The total connected sites and capacities within the West Midlands register are given in the table below

WPD West Midlands Register	Connected		Accepted and not Yet Connected		Total Register	
	Sites	Export Cap. kW	Sites	Export Cap. kW	Sites	Export Cap. kW
Other Generation	38	355,509	37	594,919	75	950,428
STOR	1	-	6	224,800	7	224,800
Mixed	43	63,591			43	63,591
CHP (med, Micro, Mini, Small)	4	5,887	7	6,220	11	12,107
Total Categories	86	424,987	50	825,939	136	1,250,926

Step 2 - **Connected sites by fuel analysis** – based on the enhanced analysis and dataset mapping we have been able to positively identify the technology and fuel types associated with the majority (by capacity) of connected sites. This analysis shows 16 sites associated with diesel comprising 78 MW of capacity and eight sites associated with gas comprising 197 MW capacity. Unidentified connected sites comprise only 15 MW.

Step 3 – Accepted-not-yet-connected by fuel – the enhanced analysis of the Accepted-not-yet-connected sites also managed to identify almost half of the site technology fuel types (by capacity) but there were a higher proportion of unidentified technology sites comprising 34 sites and 420 MW of capacity.

There are therefore still a significant number of sites and MW in the pipeline register that are not fully understood in terms of technology and fuel type.

Step 4 Allocation of unidentified sites to diesel and gas – in order to give some overall estimate of the capacity of gas and diesel reciprocating engines connected, and in the Accepted-not-yet-connected pipeline, we have allocated the unidentified sites and capacity on a pro-rata basis based on those sites that have been positively identified.

In the case of the connected sites the allocation process makes only a marginal difference (since the majority of sites were already identified) but for the Accepted-not-yet-connected sites the allocation of unidentified sites comprises over 230 MW of unidentified capacity.

It is likely that this allocation process, although logical, has probably under allocated the amount of diesel and gas reciprocating engines in the pipeline. This is because it is normally easier to identify non-fossil fuels plant in the pipeline because of the associated publicity and corroborating datasets.

Step 5 Estimates for gas and diesel capacity connected and in the Accepted-not-yet-connected pipeline – combining those sites which have been positively identified with the allocation of unidentified technology type sites give and overall estimate of the baseline and pipeline for diesel and gas reciprocating engines in the West Midlands.

Based on this analysis it is therefore estimated that as of April 2017:

- As a baseline there are circa 282 MW of gas and diesel reciprocating engines connected to the West Midlands network.
- There is potentially another 490 MW in the near-term pipeline with an Accepted-not-yet-connected network connection agreement. This number is however less certain owing to the high number of sites those technology and fuel type has not been positively identified.

9.3.9 Geographic spread of gas and diesel engine assets

GIS analysis of those sites that have been positively identified reveal a very similar geographic spread to that seen for energy storage with a high concentration of sites in industrial and brownfield site areas proximate to the 66 and 132 kW network.

9.3.10 West Midlands licence area diesel and gas generation growth scenarios to 2030

Given the policy uncertainty around the use of diesel and gas reciprocating engines, including the curtailment of embedded benefits, possible review of behind the meter assets, pollution controls and participation in future Capacity Market and balancing mechanisms, it is difficult to project the future growth or reduction in gas and diesel peaking plant connected at the distribution level.

A great deal more will be known in the next 18 months as the impact of recent policy changes work their way through the market.

Table 25: Scenario assumptions

Scenario	Pipeline / near term	Longer Term Growth Assumptions
Gone Green Lowest growth scenario for gas and diesel engine technology	Owing to network charge changes and emission regulations, a high proportion of projects in the pipeline and those that have bid into the Capacity Market but have not yet connected fall away. Pipeline of Accepted-not-yet-connected - only 10% of diesel pipeline projects and 15% of gas reciprocating engine projects are in fact connected. Annual decommissioning rate of plants 10%.	Growth of renewables and variable generation adds value to flexibility and the need for peaking plants. But growth is focused on energy storage, coupled with interconnectors and new CCGT and OCGT technology with greater responsiveness and lower cycling costs. Regulatory and planning pressure around emissions and energy efficiency continues to push out diesel technology. Market shrinks and as older plants come to their decommissioning date they are replaced by other technologies. Gas reciprocating engines fare slightly better than diesel owing to lower operating costs and energy conversion efficiency.
Consumer Power Low growth scenario for gas and diesel engine technology	Only 15% of diesel pipeline projects and 25% of gas reciprocating engine projects are in fact connected. Annual decommissioning rate of plants 7%.	As above but there is more opportunity for decentralised energy and less regulatory pressure leading to a slighter high growth projection. Consumer pressure on emissions supports higher gas growth over diesel
Slow Progression Low growth scenario	Only 15% of diesel pipeline projects and 20% of gas reciprocating engine projects are in fact connected.	Slower growth of renewables reduces the market and value for flexibility.

	Annual decommissioning rate of plants 8%.	However new technologies – such as storage and interconnectors – are slower to develop and therefore the role of gas and diesel generators continues, with modest growth.
No Progression Higher growth scenario	Only 20% of diesel pipeline projects and 25% of gas reciprocating engine projects are in fact connected Decommissioning rate of plants 5%.	Low growth of renewables reduces the market for peaking plants. UK reverts to larger scale gas generation. On the other hand new technologies do not develop and so diesel and gas plants continues to be deployed.

Based on the baseline and pipeline estimate and the assumptions above the growth scenarios are given in the table and chart below.

The higher growth prospects for gas reciprocating engines compared to diesel reflects

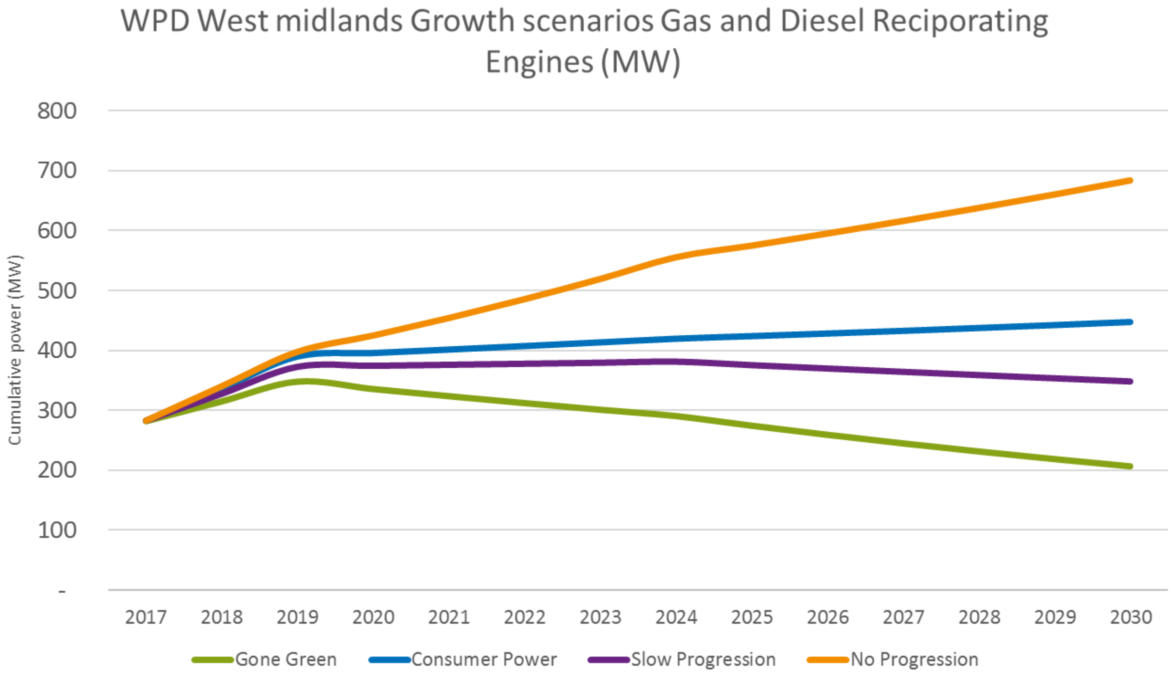
- the greater energy generation efficiency and potential as peaking plant
- Likely UK strategy to support gas
- Relative lower NoX emissions

Table 26: West Midlands gas and diesel growth scenarios

WPD West Midlands Licence Area - Gas and Diesel Growth Scenarios

		Reciporating Engines Power (MW)			
		2017	2020	2025	2030
Gone Green	**Diesel Engine**	80	91	69	48
	Gas Engine	202	244	205	159
	Total power (MW)	282	336	275	207
			-	-	-
Consumer Power	**Diesel Engine**	80	104	102	92
	Gas Engine	202	291	321	354
	Total power (MW)	282	395	423	447
Slow Progression	**Diesel Engine**	80	103	96	83
	Gas Engine	202	271	279	265
		-	-	-	-
	Total power (MW)	282	374	375	348
			-	-	-
No Progression	**Diesel Engine**	80	117	139	154
	Gas Engine	202	308	435	530
	Total power (MW)	282	424	575	683

Figure 46: Gas and diesel reciprocating engine growth scenarios for West Midlands licence area



9.3.11 Geographic distribution of electricity storage across ESAs

It is difficult to give an accurate assessment of the likely geographic distribution of future gas and diesel reciprocating engine projects across the West Midlands licence area.

The evidence based on the existing connections and the pipeline of Accepted-not-yet-connected projects suggest that the deployment of gas and diesel technologies will continue to focus in the more heavily industrialised area in the east of the licence area, around Birmingham, Stoke-on-Trent, Wolverhampton, Dudley and in the south around Gloucester, and that proximity to available capacity on the 132 kV or 66 kV network is the overriding locational factor.

9.3.12 Further work – data analysis and operating models

The data analysis of diesel and gas generators has been difficult and remains imprecise. Further work is needed, potentially contacting individual asset owners to confirm the capacity, technology and fuel usage.

A secondary piece of work would be to then consider the likely different operating modes of diesel and gas generators based on their different business models.

Section 3

Electricity storage technology growth scenarios

Analysis, assumptions and market insight behind the future growth scenarios for battery storage.

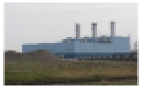
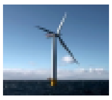
Section contents

10 Electricity Storage

10.1 Introduction to the electricity storage market

The UK energy system is undergoing significant change including, the closure of legacy generating plant, the growth of distributed generation and the shift towards more variable sources of low carbon energy.

Figure 47: Changing GB electricity capacity

	Capacity 2010/11	Closed* since 2010	New Cap added	Current 2015/16	Closed by 2030 ???
	Coal 26 GW	13.3 GW		12.8GW	12.8 GW
	Gas 30.2 GW	4.5 GW	8.5GW	33.7 GW	16.5 GW
	Renewables 8.6 GW		24.8 GW	33.3 GW	3.5 GW
	Nuclear 10.7 GW	1.4 GW		8.9 GW	7.7.GW
	77.8 GW	22.9 GW	33.2 GW	90 GW	41.4 GW

* Closed, partially closed, converted to biomass or mothballed

An overall impact of this change has been to increase need for greater flexibility within the energy system in order to; improve the balancing of generation and consumption, maximise the use of low carbon energy generation and optimise the investment in infrastructure. Flexibility can come from a number of sources including peaking plant, energy storage, demand side response, interconnection, active network management and other forms of flexibility such as local supply and balancing.

As well as enabling greater levels of system flexibility, electricity storage assets (especially batteries) can also be used to provide additional high value grid (auxiliary) services such as frequency response and voltage support.

The future market for energy storage, therefore, looks to be very positive and this is reflected in the high levels of project development activity and number of network connection applications during the last 18 months.

How quickly and to what scale the market will grow is still uncertain. Developing robust future growth scenarios for electrical storage is challenging. Except for existing hydro pumped storage, the market is still relatively immature and, although there has been a growth, there are still relatively few new storage projects in operation.

The analysis and projection of energy storage is made more difficult by the multi-faceted nature of storage; with multiple technologies, supporting many different applications and business models. In Regen's 2016 paper Energy Storage : Towards a commercial model, we described the storage market as a Rubik's Cube with many elements that need to be brought together in order for the market to reach its full potential.

In the absence of a baseline of deployment and firm pipeline of future projects from which to make a future growth projection, our analysis methodology for energy storage has focused on understanding four key areas:

1) **Role of storage and resulting business models:** The role of energy storage on the network, identification of the business models that are likely to underpin growth and the mode of operation of energy storage assets.

2) **Long term market potential:** Assessing the long-term market for energy storage as one, of several, sources of flexibility and responsiveness services within the energy system to understand the potential size of the market in terms of both power (MW) and capacity (MWh).

3) **Near term pipeline:** Analysing those energy storage projects that are currently active to understand the near-term pipeline of projects which could be deployed in the next 2-3 years. Including those projects that have bid into the recent Enhanced Frequency Response(EFR) and Capacity Market auctions and/or have accepted network connection agreements.

4) **Geographic distribution of assets:** Looking in detail at the geographic distribution of energy storage projects to better understand the locational drivers that will influence where storage assets are likely to be located on the network.

In a separate piece of work Regen has worked with WPD to better understand the operation of energy storage assets and how these are likely to impact on the distribution network.

10.2 The role of energy storage and emerging business models

The use of energy storage to provide flexibility and to improve system balancing and security of supply, is expected to become an increasingly important part of the changing UK energy system. Although energy storage is not new, technologies such as pumped hydro, flywheels, heated water tanks and other storage technology have been in use for a long time, the role of energy storage is changing rapidly. This change has in part been due to the changing market, technology costs, the need for flexibility services and the development of more sophisticated control systems to integrate, aggregate and manage storage assets.

At a high-level energy storage performs three main roles within the electricity network:

- ***Response:*** The ability to respond quickly (milliseconds – minutes) to network, frequency and/or price signals. Potential applications include the provision of ancillary network services such as frequency response and voltage support.
- ***Reserve:*** The fundamental property of energy storage that enables the storage of energy to be used at a time when it is required. This ranges from a simple back-up capability for use as an alternative source of energy, to large scale capacity reserve and Short Term Operating Reserve (STOR).

- ***Price and time shift:*** The capability to shift energy from lower to higher price/cost periods. A more sophisticated application of both reserve and response functions, allowing energy users and suppliers to take advantage of price variance (price arbitrage), avoid peak transmission and distribution costs and/or to recover energy that would be lost due to network or other constraints.

The variation in business models will determine how electricity storage solutions are designed and the operating mode of how they are used. This includes the ratio between MW power and MWh storage capacity, the depth of discharge and the periods of charge/import and discharge/export. Since the business models and their variations will determine how storage interacts with the network, understanding the business model operating modes is a key prerequisite to model network impacts.

The Regen future growth scenarios for electricity storage have been developed using what we currently consider to be the most likely future or emerging business models.

1. **Response service -** Providing higher value ancillary services to transmission and distribution network operators, including frequency response
2. **Reserve service -** Specifically aiming to provide short/medium term reserve capacity for network balancing services
3. **Commercial and industrial -** Located with a higher energy user (with or without on-site generation) to avoid peak energy costs and peak transmission and distribution network charges, while providing energy continuity
4. **Domestic and community -** Domestic, community or small commercial scale storage designed to maximise own use of generated electricity and avoid peak electricity costs
5. **Generation co-location -** Storage co-located with variable energy generation in order to a) price/time shift or b) peak shave to avoid network curtailment or reinforcement costs
6. **Energy trader -** The business model that references the potential for energy supply companies, local supply markets and/or generators using storage as a means of arbitrage between low and high price periods - likely aggregated - and peak shaving.

A summary of the electricity storage business models used in the growth scenario analysis, together with the key growth and geographic locational factors, is shown in Table 27.

10.3 Growth of the energy storage market to 2030

Many industry analysts are predicting a rapid market growth for electricity storage and other forms of flexibility in the next decade. For this rapid growth to materialise, there is a need for steps to be taken to facilitate market innovation, with an early focus on battery storage.

Several market analyst's reports have projected energy storage growth scenarios, these include National Grid *Future Energy Scenarios*, the Committee on Climate Change, Carbon Trust and UK Government.

The scenario analysis has considered a high growth scenario of 10-12 GW and 24-44 GWh of energy storage capacity installed across Great Britain by 2030 and a lower growth lower growth scenario of 4-5 GW and 6-15 GWh across GB by 2030.
Note: these figures include 2.7GW of existing pumped hydro storage.

Table 27: Great Britain market scenario growth assumptions to 2030

Business model	Gone Green and Consumer Power	No and Slow Progression	Possible upside very high growth scenario
	Great Britain market scenario growth assumptions to 2030* **Used to underpin West Midlands licence area scenarios**		
Response service	2 GW 2 GWh	0.5 - 1 GW 0.5 - 1 GWh	2 - 3 GW 4 - 5 GWh
Reserve Services*	3-4 GW	2-3 GW	4 GW
C&I high energy user & behind the meter	2.5 - 4 GW 10 - 16 GWh	0.6 - 1.2 GW 2.5 - 5 GWh	5 GW 20 GWh
Domestic and community own use with PV***	1.5 - 2 GW 6 - 8 GWh	0.37 - 0.75 GW 1.2 - 3 GWh	3 GW 12 GWh
Generation co-location	2 GW 6 - 8 GWh	0.5 - 1GW 2-4 GWh	4 GW 16 GWh
Total Great Britain market	10 - 12 GW 24 - 44 GWh	4 - 5 GW 6 - 13 GWh	15 GW** 50 GWh

* includes existing 2.7 GW of storage – mainly pumped hydro reserve services

** A very high growth scenario for all business models would probably imply some degree of revenue cannibalisation between business models and is therefore less likely by 2030.

*** Would include EV vehicle-to-house storage discharge although this has not been modelled separately.

10.3.1 Development of the energy storage market

Following the National Infrastructure Commission's Smart Power report, which concluded that a smart and flexible energy system could save UK consumers over £8 billion per year by 2030 when compared to a system relying on over capacity, many industry analysts are predicting a rapid market growth for electricity storage and other forms of flexibility in the next decade.

The 2016 EFR and T4 Capacity Market auctions jump-started the electricity storage market development in the UK. WPD, along with other DNO's, has received unprecedented interest in connecting storage assets.

In November 2016, the UK government and BEIS issued a call for evidence consultation on the future for a Smart and Flexible Energy system.

Based on signals that the UK government response to the consultation will be positive, and that steps will be taken to facilitate market innovation and put in place a policy framework that encourages flexibility and smarter energy solutions, industry analysts are predicting a very rapid growth in the energy storage market, with an early focus on battery storage for electricity.

The first 'wave' of connected storage assets appear to be focussing on frequency response, Capacity Market, demand side response (DSR) and potentially other grid and network services. In a high growth scenario, Regen's analysis anticipates that future waves of energy storage projects will target commercial and industrial (C&I) applications, domestic and small scale energy storage and also co-location with generation and aggregation.

Wave 1 - Led by response services (Now-2020)

- Focus on grid and network services (including frequency response & DSR)
- First applications for C&I 'behind the meter' models and co-location
- Domestic and community scale early adopters.

Wave 2 - Co-location business models become viable (Early 2020's)

- Market for C&I high energy users/generators grows rapidly
- Co-location projects with solar PV and wind become viable
- The domestic and community storage market expands.

Wave 3 – Market expansion and new business models (Mid/Late 2020's)

- Price arbitrage and new trading platforms develop
- Storage enables local supply markets, private wire and virtual markets
- Domestic electricity storage becomes common
- Most new solar and wind farms now include electricity storage to harness low marginal cost energy and price arbitrage
- Heat storage and electricity storage are increasingly integrated.

The overall storage deployment outcome for the higher growth Gone Green and Consumer Power scenarios are similar, although the mix of storage assets deployed across business models is different.

A lower growth scenarios could occur if, after the initial enthusiasm for electricity storage as a result of the EFR and Capacity Market auctions, future growth stalls. However, given the UK's legally binding commitment[12] to decarbonisation, and the fundamental need to increase energy flexibility, it seems increasing unlikely that a very low or no growth scenario for electricity storage is realistic.

10.3.2 Cost reduction as a major growth driver for the storage market

The anticipated continued fall in electricity storage costs will be a key growth driver for the storage market.

There have been several reports produced by market analysts pointing to a step change in cost reduction in battery costs through innovation, supply chain efficiency, new competition and investment in large scale manufacturing facilities.

Several reports and analysts[13] have projected that storage costs could fall from circa $400-500 per kWh today to under $150 per kWh in the early 2020s.

[12] UK 5th Carbon Budget enacted July 2016

[13] For example: Saudi Aramco comparative analysis presented MENASoL 2016, Navigant Research (Jaffe and Adamson 2014) cited in IRENA Battery Storage for Renewables

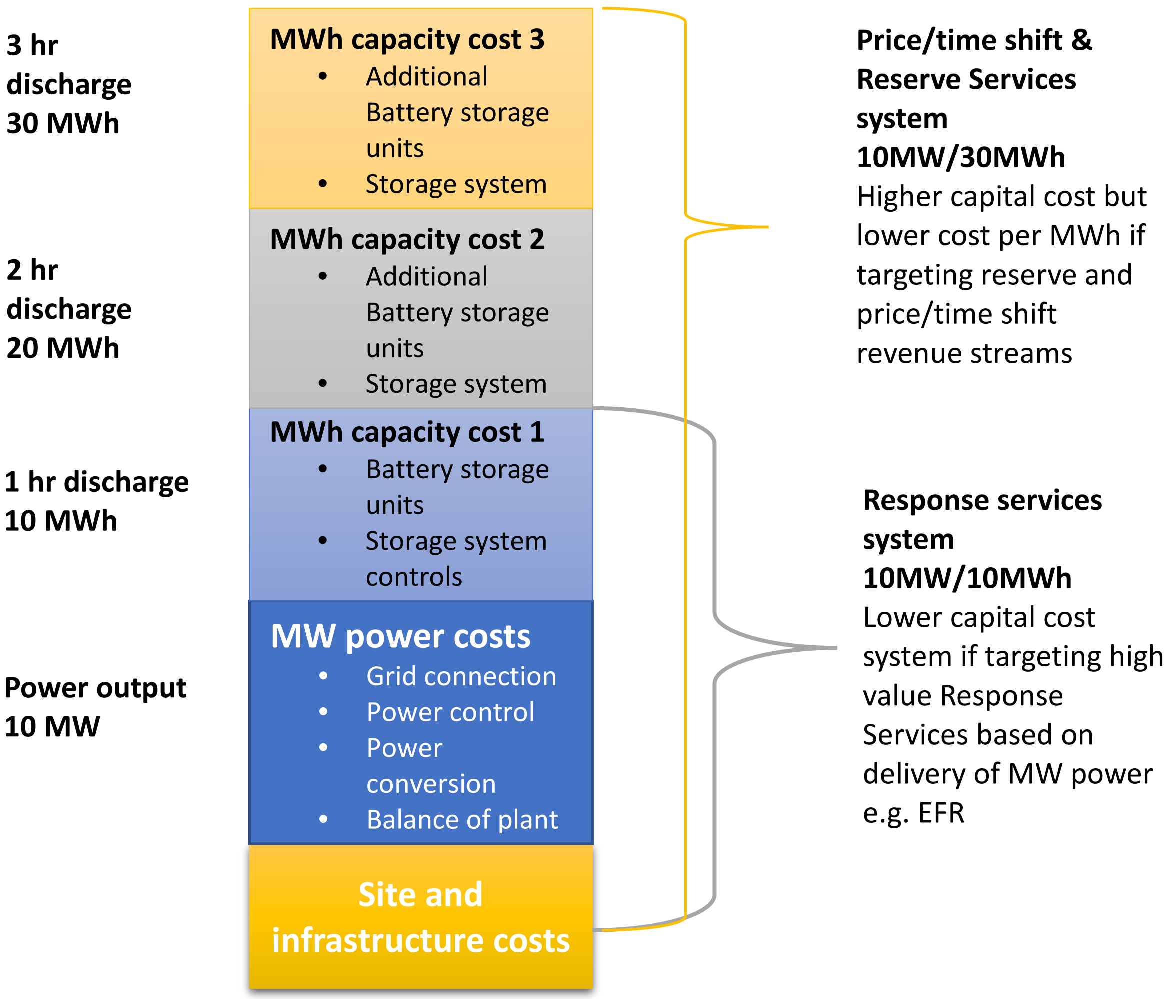
Anecdotal evidence from the 2016 EFR and Capacity Market auctions, as well as the lower than expected auction clearing prices, suggests that battery storage costs have already fallen and that commercial prices are already below previous market benchmarks.

Electricity storage cost is not, however, a simple linear function. A key consideration to assess the potential cost of battery storage is to understand the relationship between the MW power requirement, MWh storage capacity and the overall system specification. This relationship is discussed in more detail in Regen's storage paper "Energy Storage – Towards a commercial model".

A key factor in relation to the analysis of future capacity growth is the techno/economic relationship between the economies of scale related to MW power output and MWh electricity storage. This impacts the core commercial decision about the business model being targeted, the size of electricity storage to be deployed and the ratio between the power MW and storage period MWh elements of the storage system. In simple terms:

- If a developer is targeting higher value response services whose revenue is based on MW then it makes sense to commission a system with relatively high MW power capability and the minimum MWh capacity storage required to deliver the service.
- However, if a developer is targeting price/time shift revenue streams, including high network cost avoidance and reserve balancing services (e.g. STOR), there are increasing economies of scale and lower costs per MWh from larger capacity systems.

Figure 48: Electricity storage system economies of scale

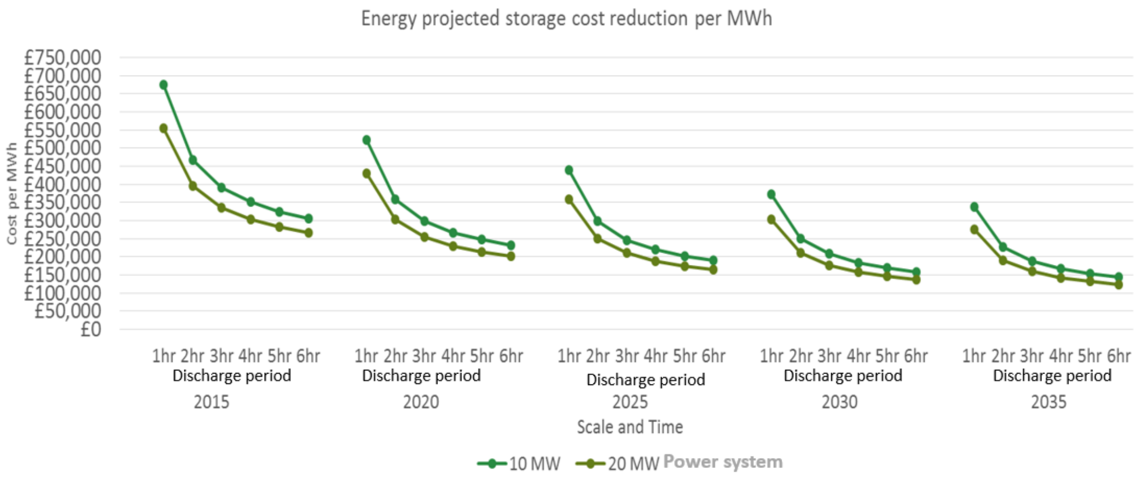


Over time, as electricity storage capacity costs reduce, it is expected that price/time shift and reserve based business models, including renewable energy co-location and C&I, will become more attractive. We therefore expect to see a progression from relatively high power output systems, with perhaps a 1:1 ratio between MW power and MWh storage capacity, to much higher storage capacity systems with perhaps a 1:3 or 1:4 ratio between MW power and MWh storage capacity[14].

We are already seeing this trend in the domestic and small scale battery system. Installers are reporting that the older 2 kW/2 kWh systems are now virtually unsellable and that most new installations are of a 2 kW/6 kWh or indeed a 4 kW/12 kWh system.

[14] This analysis ignores the additional complication of the 'depth of discharge' and the residual charge that batteries ought to maintain in order to prolong their battery life and may also be required by their warranty.

Figure 49: Electricity storage cost reduction



Gone Green and Consumer Power scenarios assume rapidly falling storage costs in the next ten years

For the West Midlands licence area scenario analysis, we have assumed that the ratio of MWh to MW storage varies by business model and will also increase through the decade.

10.4 Near term pipeline and current market overview

10.4.1 Pipeline of Accepted-not-yet-connected sites

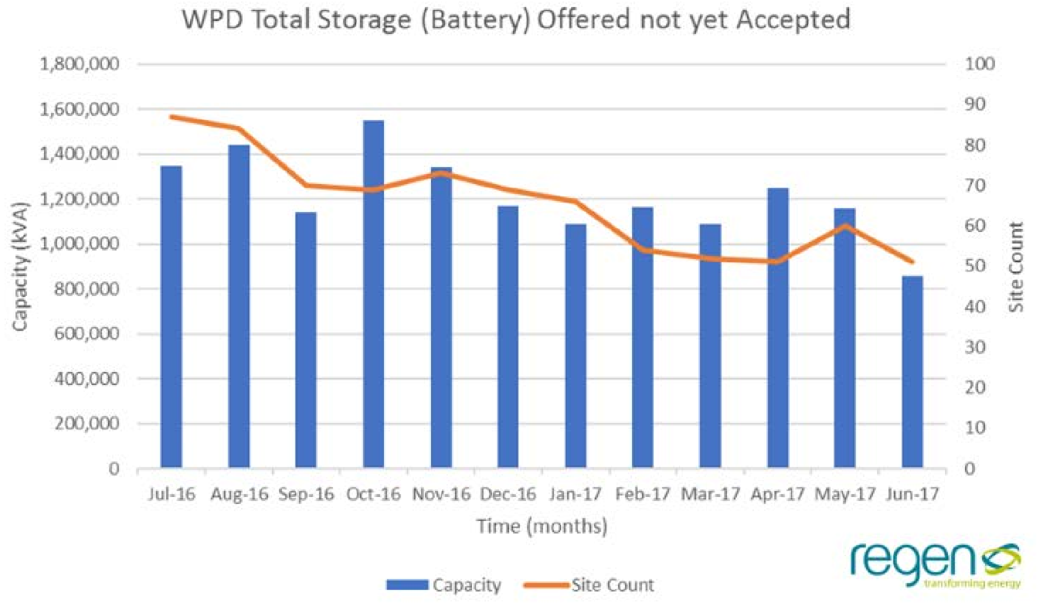
WPD has received unprecedented interest in connecting storage assets. The volume of network connection applications has significantly increased over recent years. As shown in

Table 28, a total of 2,580 MVA (across 141 sites) of connected, accepted-not-yet-connected and offered-not-yet-accepted storage capacity is on the WPD network.

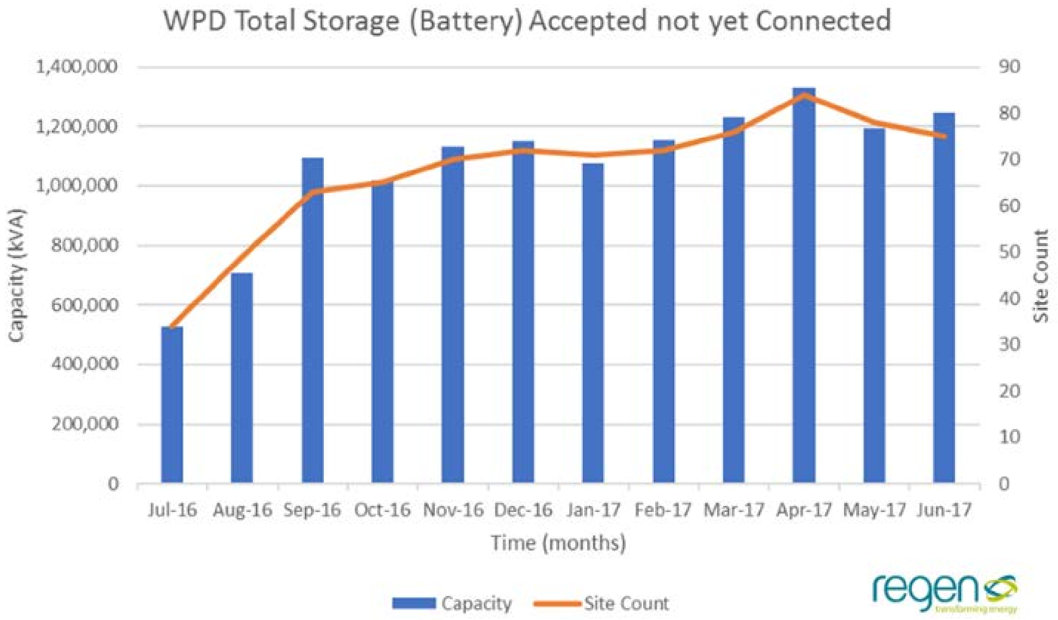
Table 28: WPD Generation Capacity Register data for storage, dated 3rd May 2017

	Battery Storage Capacity					
	Connected		Accepted-not-yet-connected		Offered	
WPD Supply Area	**Number of Sites**	**Capacity (MVA)**	**Number of Sites**	**Capacity (MVA)**	**Number of Sites**	**Capacity (MVA)**
West Midlands	1	3	41	704	17	299
East Midlands	0	0	20	229	20	399
South Wales	0	0	4	60	3	50
South West	0	0	15	201	20	410
TOTAL	**1**	**3**	**78**	**1,194**	**60**	**1,157**

Figure 50: WPD energy storage network application status July 2016 - June 2017



Connection agreements offered but not yet accepted



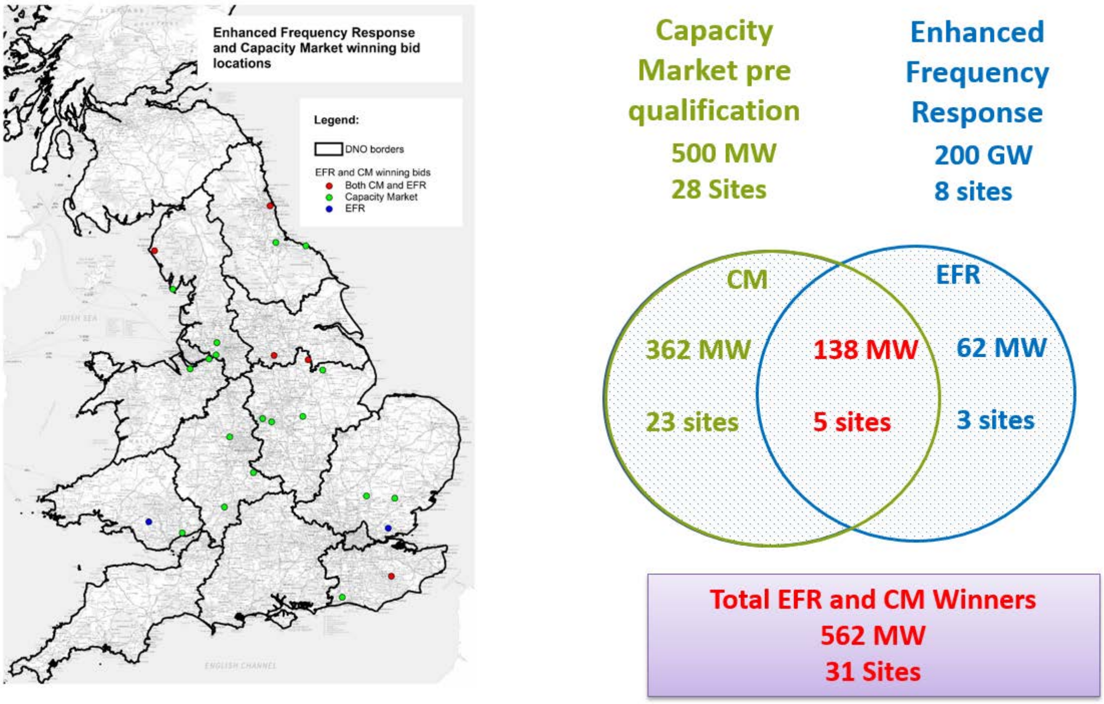
Connection agreements accepted but not yet connected

Over the past year, the pipeline of energy storage network applications has risen dramatically reaching a peak of around 2.5 GW of applications offered-not-yet-accepted or accepted-not-yet-connected. The number of new applications offered-not-yet-accepted has begun to reduce in Q1 2017, and the number of accepted-not-yet-connected applications has also fallen slightly as some projects have fallen away. It is known that there is still a significant amount of speculation and network "land-grabbing" in the market and so it is possible that several projects with accepted-not-yet-connected connection offers will be withdrawn over the next 6-12 months. This will depend in part on the success of storage technology in the 2017 T4 Capacity Market and future response service auctions.

10.4.2 Analysis of 2016 EFR and Capacity Market auction bids

The results of the 2016 EFR and T4 Capacity Market Auction were published in July. Together the winners represent a total of 31 sites with a combined capacity of circa 562 MW when the overlap between auctions is taken into consideration.

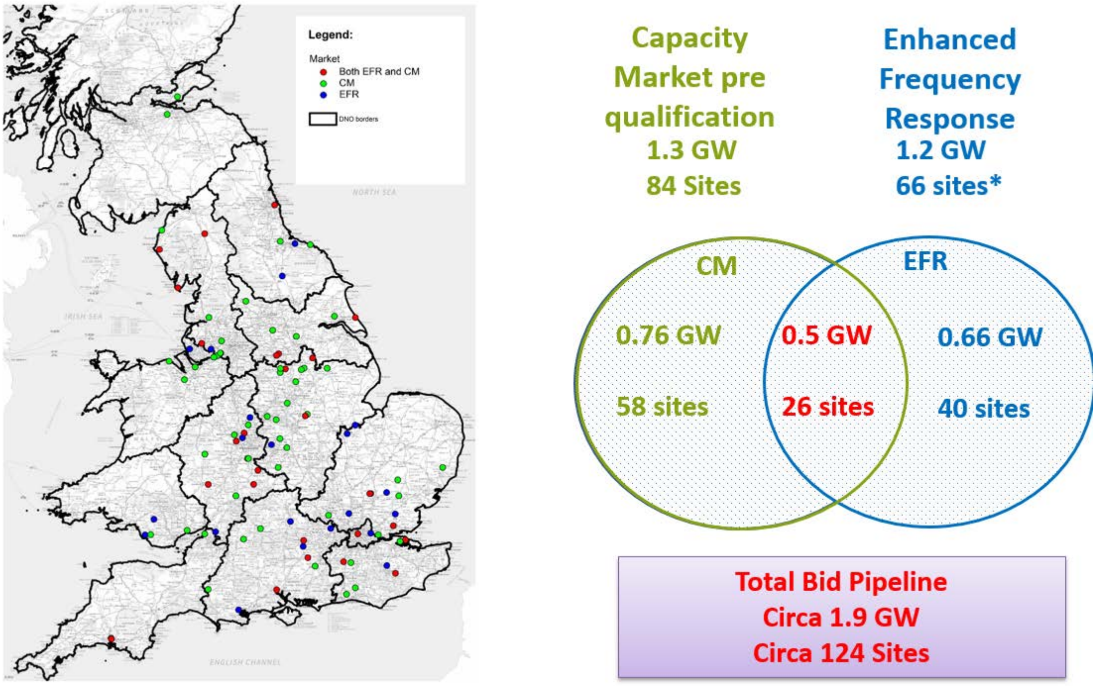
Figure 51: 2016 EFR and T4 Capacity Market auction winners - new battery storage



Analysis of all the bids that took part in the EFR auction and pre-qualified for the Capacity Market auction suggests that there is a bigger pipeline of projects which could be brought forward in the next few years. In fact, on the basis that those that took part in the EFR and Capacity Market auctions represent the most likely development sites, the active pipeline of projects across Great Britain could be as large as 124 sites with a total capacity of just under 2 GW[15].

[15] Note: Source Regen analysis - This is an approximate (but fairly accurate) figure taking into consideration the high number of duplicate site bids, the overlap between auction schemes and with some margin of error due to inaccurate or missing site address data

Figure 52: All EFR and T4 Capacity Market auction bidders, pre-qualification



* National Grid reports a lower figure @ 62

Analysis of the geographic distribution of the EFR and Capacity Market bids reveals a number of points of interest:

- The overwhelming majority of sites are distribution network connected, although a number of larger capacity sites are connected to the transmission network, co-located with existing generating plant such as West Burton.
- Geographically the majority of bids are concentrated in an arc running from the south east, through the midlands to the north of England. In other words, they follow the main industrial centres of Great Britain and the main spine of the network.
- Proximity to the 132 kV network has been the overriding geographic factor that correlates with bid locations. With only a few exceptions, the vast majority of sites are close to a substation or network lines.
- Aside from a correlation with network connections, sites tend to fall into four categories of sites:
    - Standalone sites which are close to a substation
    - Located with existing generating power stations
    - Located in, or proximate to, industrial areas of high demand
    - Proximate to existing or, more often, planned solar PV farms.

10.5 Recent regulatory and market changes

The GB energy storage market is relatively immature and there are several areas where the regulatory and policy environment is not yet aligned to support a high growth scenario. Developers and investors in energy storage are therefore extremely sensitive to changes in energy policy and any perceived uncertainty that could add further risk to investment returns.

In the last six months, several policy and regulatory changes (or proposed changes) have impacted the storage market.

These changes and developments are outlined in the table below:

Table 29: Recent policy and regulatory changes impacting the storage market

Recent policy and regulatory developments	Potential impact on energy storage
BEIS and Ofgem call for Evidence: A Smart and Flexible Energy System	Positive – The call for evidence document shows that both government and regulatory are looking for ways to encourage greater flexibility in the UK energy system. "*we want to create a system that allows disruptive innovation…New business models could challenge incumbents… Where these could bring overall benefits to consumers, we should allow them to do so*". The outcome of the call for evidence was expected in the spring but has been delayed by the 2017 election.
Approval of code modification to the Common Distribution Charging Methodology (CDP228), to be introduced in 2018, which will reduce the level of peak Red Band charging in favour of higher off-peak charges.	**Somewhat negative** – the change to the way distribution network charges are calculated will vary across licence areas but the general direction has been to reduce the highest red band changes with an increase in green and amber (off peak) charges. The effect for storage is to reduce the relative value of discharging during peak time periods. Combined with the transmission charge changes below this reduces the business case for distribution connected storage.
Proposal to remove the residual demand embedded benefit for distributed connected generation – effectively removing the main Triad/transmission cost avoidance benefit for generators and energy storage providers. **Implementation of CUSC code modifications CMP264 and CMP 265** Note: as yet this would not affect the behind the meter element of energy storage Triad	**Negative** – although the measure is intended to discourage diesel and gas reciprocating generators it will have a direct impact on energy storage revenue streams removing a potential £45 per kw revenue stream which was expected to grow as Triad based transmission costs increase over time. Although this decision was widely publicised last year, the decision and the governance process by which the decision was reached, has had a negative impact for storage investors. It could even mean that some of those

avoidance by demand reduction, although Ofgem has strongly hinted that they will also consider this issue in future.	projects that successfully bid into the 2016 EFR and Capacity Market may not now go ahead. Although the proposed change will not directly affect the behind the meter element of transmission cost avoidance, Commercial and Industrial storage projects will be impacted as many (perhaps most) of these storage projects would also be designed to export to network during Triad periods
"Minded to" decision on energy storage "double charging" which would remove the double charge element of grid and network charges by treated storage, for the purpose of charging as generation.	Positive - If implemented this would be positive and would remove a source of additional Electricity network connection costs for energy storage providers. It may also help to further clarify how storage is treated within the regulatory framework
Ofgems announcement of a targeted charging review May 2017	Positive – the industry has been calling for a more holistic review of network charging although it is unclear whether this review will in fact look at all aspects of the charging regime and whether it will also deal with the governance and transparency issues which will continue to hamper future investment.
DNO to DSO transition	Largely positive – the process of transition continues but it is not yet clear what the future model will be. Nevertheless, as a direction of travel, enabling DSO's to procure a wider range of services and to consider other solutions, including storage, to defer capital investment is positive and will create a new market for storage.
Brexit, election, minority government	**Uncertain:** Very hard to tell but obviously the recent political uncertainty has had an impact on the market and has had a direct impact in terms of delays to policy decisions. One possible positive is that the DUP in coalition may be able to influence the UK government to support storage. Northern Ireland has identified energy storage as a key part of its future energy strategy and has taken a leadership position in this sector.

In addition to the regulatory and policy changes announced above, two other significant changes (or directions of change) are impacting the market:

1) The ongoing shift from a wholly TSO to a combined TSO/DSO model.

This could potentially open up new opportunities for energy storage assets to provide a range of additional services at the distribution network level including supply balancing, constraint management and capital expenditure investment deferment.

2) Changes to the way National Grid defines and procures its services. National Grid has recently published a report and consultation on its Service Needs and Product Strategy which sets out the TSO's current thinking on the type of grid services that will be required and how they will be procured.

The highlights of this paper include:

- Combining Enhanced, Firm and Mandatory Frequency Response into a new Response Service
- Simplifying the range of Reserve Services
- A general trend towards more flexible and near-time service provision
- Potentially new services for reactive power and voltage management

10.5.1 Regulatory and market change conclusions

Overall it is difficult to assess the impact of recent policy and regulatory changes. Judging by the level of activity, market interest remains high, but Regen is hearing from developers, battery providers and supply chain companies that the expected wave of storage project installations has been slow to materialise.

The change to the way network charges are applied and the impact this has had on embedded benefits has had a significant impact on investor confidence. This is partly because network charge avoidance was viewed as a core, or backstop, revenue stream.

A lot will now depend on the outcome of the Smart and Flexible Energy System consultation and whether BEIS and Ofgem come forward with progressive policies to support new technologies including storage.

Looking to the longer term, there is still a high probability that storage will play a significant role in the future UK energy system leading to a high growth scenario outcome. The anticipated Clean Growth Plan, which should articulate the government's long term energy strategy to meet its 5th Carbon Budget, should also set a high-level strategy and target for energy storage within the UK energy system.

10.6 WPD West Midlands licence area storage analysis

10.6.1 West Midlands pipeline analysis to 2020

A number of factors would suggest that the West Midlands ought to have a lower storage growth potential than the East Midlands but in fact, in the near term at least, the West Midlands appears to be an attractive location for energy storage projects.

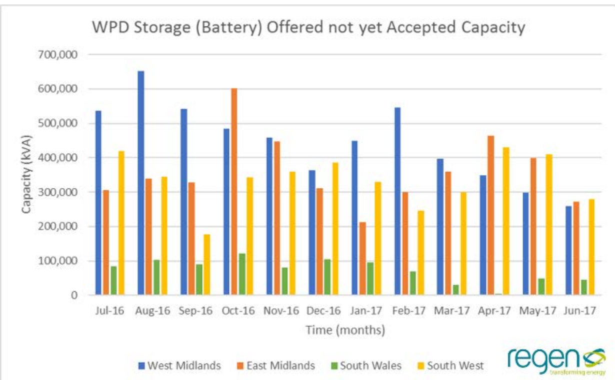
The table below gives a high-level comparison of key storage growth factors, comparing the East and West Midlands against the total GB.

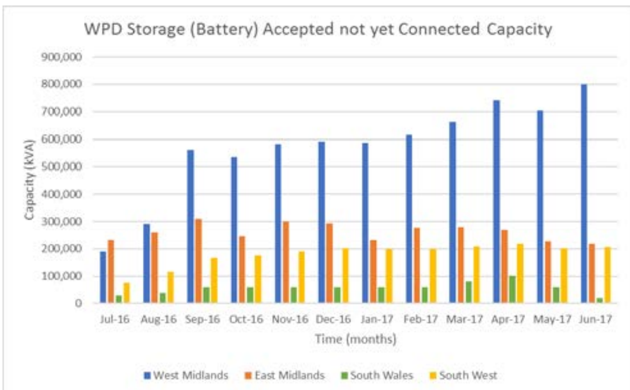
Table 30: Battery storage growth factors comparison

Comparison of East and West Midlands Key Metrics				% of GB Total	
Storage Growth Scenario Factor	**East Midlands**	**West Midlands**	**GB circa**	**East Midlands**	**West Midlands**
2016 CM and EFR Bids MW's	215	338	1,986	10.82%	17.02%
2016 CM and EFR Bids Sites	17	16	125	13.60%	12.80%
Number of houses	2,579,000	2,668,000	26,680,000	9.67%	10.00%
Industrial demand GWh	23,512	13,722	184,588	12.74%	7.43%
Onshore Wind MW	381	47	10,000	3.81%	0.47%
Rooftop PV MW	383	296	3,294	11.63%	8.99%
Ground mounted PV	938	426	8,400	11.17%	5.07%

The East Midlands has more installed rooftop and ground-mounted PV, onshore wind and a much higher level of industrial demand. The number of households is similar. All other factors being equal, therefore, we would expect that the potential storage growth in the West Midlands would be lower than the East Midlands.

In fact, however WPD has received a higher number of network connection applications in the West Midlands, and a significantly higher proportion of West Midlands applications that been accepted and are accepted-not-yet-connected. The West Midlands has also featured strongly in the bids to the 2016 Capacity Market and EFR auctions and has a higher level of bid activity (by MW capacity) than the East Midlands.

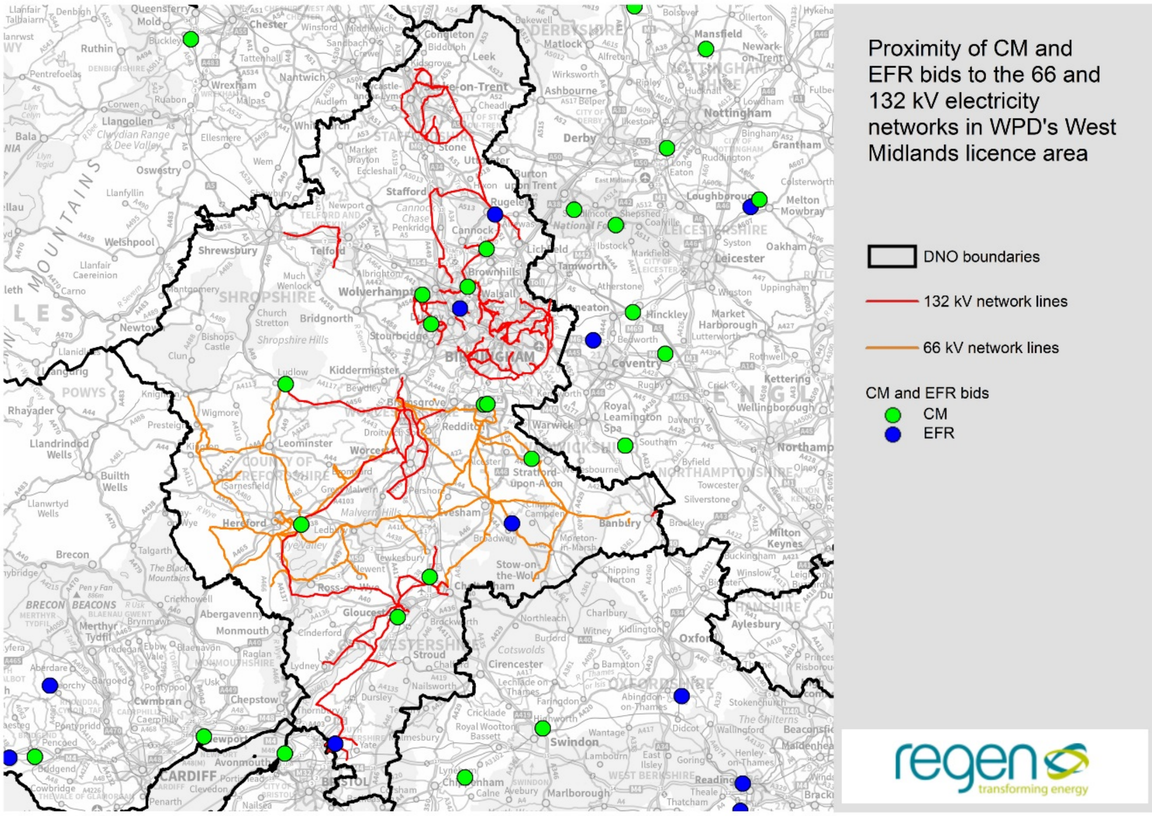




The reason for this, we believe, is largely down to the relative availability and lower cost of network connections in the West Midlands (hence a higher offer acceptance rate) and, very likely, the availability of cheap brownfield land space close to the 132 and 66 kV network. It would require more analysis to quantify these factors but both are probably due to the deindustrialisation of the West Midlands particularly in the areas around Birmingham, Wolverhampton and Walsall. In addition to deindustrialisation, the fact that the West Midlands has seen less deployment of wind and solar PV (because resource levels are lower) has reduced the level of network constraint compared to other parts of the WPD network.

The trend to locate energy storage proximate to the 66 kV and 132 kV network is shown very clearly in the pattern of bids for the 2016 EFR and Capacity Market auctions.

Figure 53: Capacity Market and Enhanced Frequency Response bids in the West Midlands licence area and their proximity to the 132 kV and 66 kV distribution networks



Analysis of the EFR and Capacity Market auctions' bids plus the WPD network connection agreement dataset (April) suggest that there are circa 45 storage sites in active development in the West Midlands licence area with a combined capacity of circa 800 MW[16] . Of the 45 sites identified it appears that 39 have an accepted-not-yet-connected network connection agreement offer from WPD. Analysis of this pipeline is given in Table 31.

[16] This estimate has been developed by looking at the EFR and Capacity Market bids in some detail to remove duplicate sites, overlapping bids and in some cases erroneous address data. The estimate is approximate, however, as there may still be duplication especially were multiple SPVs have established. The link between sites and accepted grid connection agreements has also been made based on post codes which can be inaccurate.

Table 31: Breakdown of visible electricity storage pipeline sites West Midlands (July 2017)

Category	Number of sites	Capacity (MW)	With connection agreement*
Capacity Market	13	258	10
(Of which Capacity Market winning bids)	4	72	2
Both EFR and Capacity Market Bids**	5	114	5
EFR Bid Only	3	90	0
Other sites with agreement accepted	29	452	29
Total	**45**	**800**	**39**

* As of the April 2017 WPD network connection agreement dataset.
** Identified by Regen through GIS analysis of project locations

Table 31 includes WPD's accepted-not-yet-connected connection agreements only and not those that have offered-not-yet-accepted. It also does not include other sites (e.g. behind the meter sites) that may be in development, but have not yet have made a network connection application.

The pipeline also contains four sites which have been successful in the 2016 T4 Capacity Market auctions. These are[17]:

- Limejump Ltd – 4.6 MW
- Langley Storage Limited 48.0 MW
- UK Energy Reserve Limited 9.6 MW
- UK Energy Reserve Limited 9.6 MW

For the short term pipeline for the higher growth Consumer Power and Gone Green scenarios, we have assumed that the four winning Capacity Market sites are built by 2020 and that an additional 180 MW of capacity is added from the other pipeline sites, C&I behind the meter and domestic electricity storage. This would give a total installed capacity of circa 250 MW by 2020.

For the Slow Progression scenario, Regen has also assumed that three of the four winning bids will be constructed. This seems a likely outcome given that these projects have Capacity Market contracts, but there is the potential in a No Progression scenario for winning bid projects to not proceed.

10.6.2 Future West Midlands licence area storage growth scenarios to 2030

The electricity growth scenarios for the licence area are shown in the table below.

Under a Gone Green or Consumer Power scenario, the projection is that electricity storage could reach over 1GW storage power and 2.5 GWh of energy capacity in the West Midlands licence area by 2030. This would be consistent with the West Midlands providing around 12 per cent of the GB distribution connected energy storage capacity.

[17] Taken from published National Grid EFR and Capacity Market results

Gone Green and Consumer Power reach a similar MW and MWh figure although the breakdown of capacity by business model type is different with Consumer Power having a higher proportion of domestic and community scale installations compared to the Gone Green scenario's higher proportion of co-location with renewable energy.

The West Midlands storage power figure of 1 GW by 2030 is similar to the high scenario outcome for the East Midlands however the energy capacity figure of 2.5 GWh is less than the 3 GWh that would be installed in the East Midlands. The reason for this that the West Midlands has a higher proportion of response service storage which has a lower capacity ratio, and correspondingly less co-location and C&I based energy storage.

Table 32: Electricity storage scenarios results for the West Midlands licence area

		Storage power (MW)				Storage energy capacity (MWh)			
		2017	2020	2025	2030	2017	2020	2025	2030
Gone Green	Response service	2	145	215	266	1	145	215	266
	Reserve service	0	20	122	182	0	60	367	547
	High Energy Commercial and Industrial	2	41	106	190	1	123	337	668
	Domestic and community own use	0	9	63	192	0	13	116	477
	Generation co-location	0	4	51	95	0	13	171	326
	Energy trader	0	20	70	120	0	60	210	360
	Total	4	238	628	1045	4	423	1406	2629
Consumer Power	Response service	2	101	181	231	0	101	181	231
	Reserve service	0	0	80	152	0	0	240	455
	High Energy Commercial and Industrial	2	21	164	274	1	62	538	965
	Domestic and community own use	0	10	85	239	0	15	156	590
	Generation co-location	0	0	18	35	0	0	61	122
	Energy trader	0	20	70	120	0	60	210	360
	Total	4	152	599	1051	4	240	1379	2712
Slow Progression	Response service	2	100	130	155	0	100	130	155
	Reserve service	0	0	50	102	0	0	150	305
	High Energy Commercial and Industrial	0	21	56	94	0	62	179	315
	Domestic and community own use	0	1	18	71	0	1	35	185
	Generation co-location	0	0	5	24	0	0	18	85
	Energy trader	0	10	35	60	0	30	105	180
	Total	2	131	295	505	2	192	612	1197
No Progression	Response service	2	9	64	78	0	9	64	78
	Reserve service	0	0	0	0	0	0	0	0
	High Energy Commercial and Industrial	0	21	28	47	0	62	86	153
	Domestic and community own use	0	0	6	21	0	0	12	54
	Generation co-location	0	0	0	18	0	0	0	61
	Energy trader	0	5	18	30	0	15	53	90
	Total	2	35	116	193	0	64	213	423

Figure 54: West Midlands Growth scenarios electricity storage power (MW)

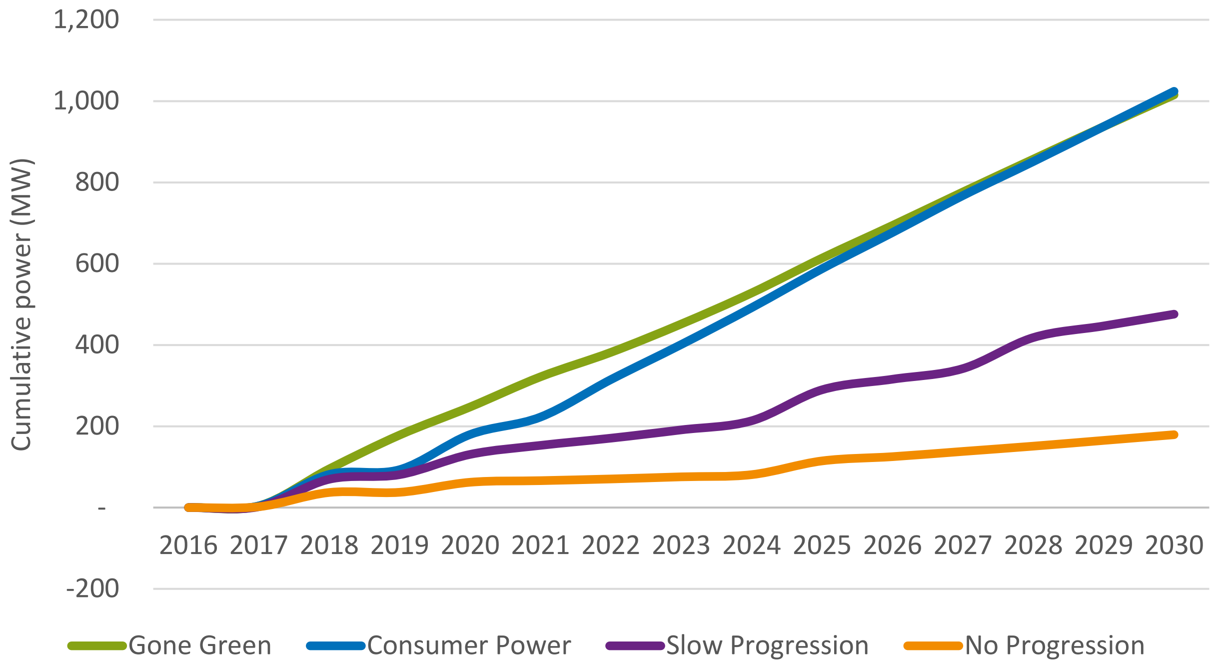
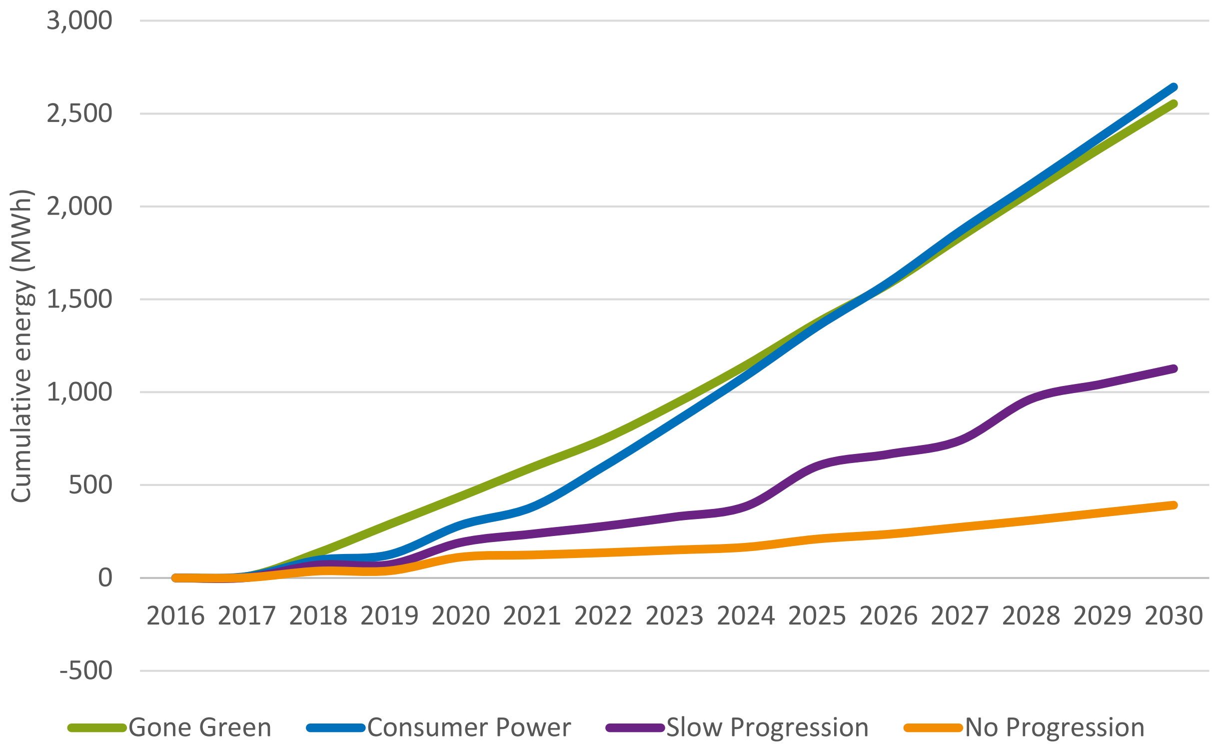


Figure 55: West Midlands growth scenarios electricity storage capacity (MWh)



10.6.3 Geographic distribution of electricity storage across ESAs

It is extremely difficult to give an accurate assessment of the likely geographic distribution of electricity storage across the West Midlands licence area.

The evidence based on the visible pipeline of Capacity Market and EFR auction bids and current accepted-not-yet-connected network connection agreements would suggest that the bulk of early projects are likely to be in the more heavily industrialised east and south of the licence area and that proximity to available capacity on the 132 kV 66 kV network is the overriding locational factor.

Analysis of the 45 sites identified in the pipeline suggests that a significant of sites are located on brownfield industrial land close to the 132 kV or 66 kV network in the areas around Birmingham, Wolverhampton, Dudley and in the south around Gloucester.

It is also notable that the majority of Capacity Market bids already have an accepted-not-yet-connected network connection agreement.

Looking to the future, under a Gone Green or Consumer Power scenario, the analysis would suggest more even distribution of electricity storage across the West Midlands licence area as co-location with energy generation becomes a larger factor, but the overall weighting of projects will still be towards the more industrial East band South East of the region.

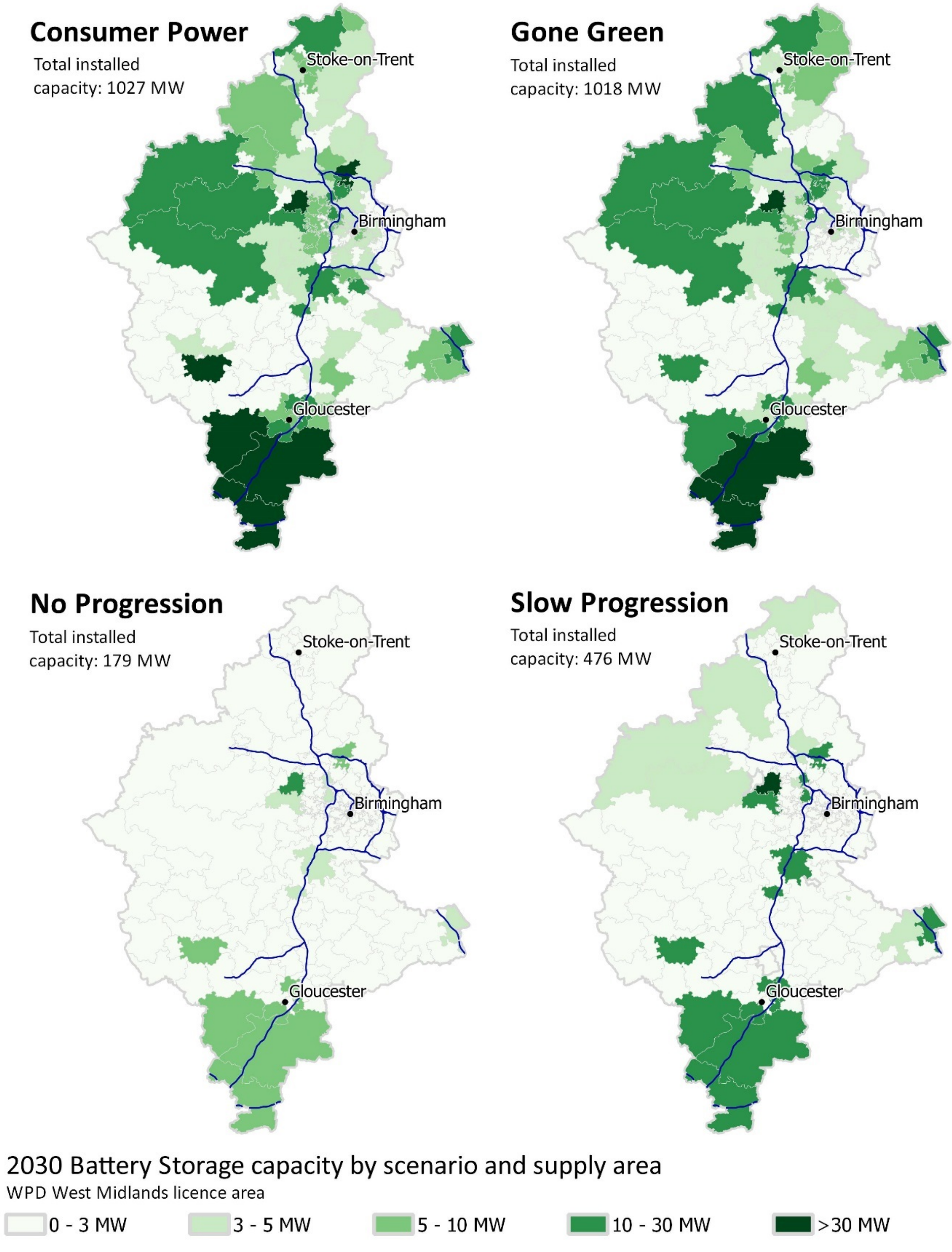
In the case of Consumer Power, the higher deployment of small scale storage would imply a greater correlation with domestic households and areas with high levels of rooftop PV installation.

For both Consumer Power and Gone Green we would expect to see a correlation with industrial and commercial high energy users.

Table 33: Factors used for distribution across the licence area

Business model	Distribution factors used
Response service	Proximity to 132 kV network with weighting to ESAs with EFR bids
Reserve services	Not distributed to individual ESAs
C&I high energy user & behind the meter	Proportion of C&I land space
Domestic and community own use with solar PV	Distribution of rooftop solar PV
Generation co-location	Distribution of ground-mounted solar PV (will potentially underestimate correlation with wind)

Figure 56: Geographic distribution of battery storage capacity by scenario in 2030



10.6.4 Further work - energy storage operating models

In order to model the potential network impact of energy storage, as well as an estimate of energy storage power output (MW) and generation capacity (MWh), it will be necessary to model the operating mode of storage technology under different business models. Operating mode means the anticipated daily and seasonal profile of charging and discharging.

In the next stage of analysis, Regen, working with WPD, has been developing a Standard Operating Mode for each of the five business models and their main variants.

This will provide, for each business model, a standard daily and seasonal profile for battery usage, giving the expected periods of charge and discharge in much the same way as WPD has a standard generation profile for solar PV. This will enable the storage scenario growth figures to then be networked modelled.

So, for example, a number of companies bidding into EFR to offer response services have also carved out time from their contract in order to utilise their storage capacity to target Triad and peak price periods during the winter season.

Similarly a domestic/consumer own use business model which was only concerned with maximising the consumers' own use of PV generation would have a different standard operating mode to the same consumer business model with a price sensitive time of use tariff or variable export tariff.

Examples of potential business model variations are show in the graphic below.

Figure 57: Examples of potential business model variations

Response service	EFR and/or FFR	Combined with Embedded benefits (mainly TRIAD)	Combined with Capacity Market
Response service	STOR Peak Generation		
High energy user "behind the meter"	With generation maximise own consumption	Peak Demand reduction appears as DSR	Sized for export for embedded benefits TRIAD and DNuOS
Domestic and community "own use" with PV	"Simple" maximise own consumption	Price sensitive Time of Use / variable Export Tariff	Peer-to-peer, virtual or private wire – micro grid
Generation co-location	Generation Time/price transfer	With grid curtailment	Winter use CM stress and Embedded
Energy trader	Arbitrage Time/price transfer	Aggregation	Market platform trader

Section 4

Electricity demand growth scenarios

Analysis, assumptions and market insight behind the future growth scenarios for key demand technologies and new demand arising from future residential and non-residential developments.

Section contents

11 Demand

For WPD to develop a robust investment strategy for their network, they need not only to plan for potential changes in generation and storage technologies, but also to understand the potential changes in demand that may occur. This section analyses the key drivers underpinning changing demand in Great Britain and specifically in the West Midlands licence area to provide insight into future energy demand.

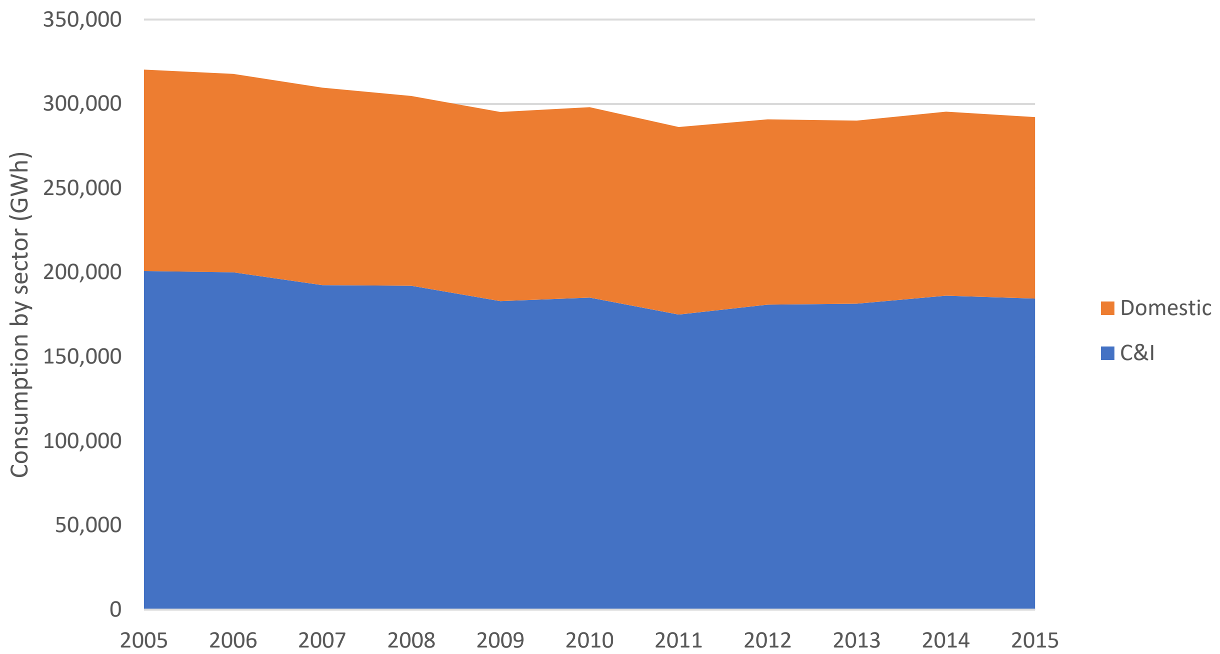
The report then looks in detail at three potentially disruptive factors on energy demand in the West Midlands: heat pumps, electric vehicles and residential and commercial development.

11.1 Baseline

11.1.1 Baseline GB demand

Electricity demand in Great Britain declined from a peak in 2005. Figure 58 shows electricity consumption from 2005 to 2015[18].

Figure 58: Great Britain electricity consumption by sector (2005 to 2015)



Since 2005, overall demand has fallen by around 9 per cent in Great Britain to 292 TWh in 2015, with a 10 per cent drop in domestic demand and an 8 per cent drop in industrial and commercial demand[19]. There was an overall increase in electricity demand in the years 2010, 2012 and 2014. Domestic demand has fallen year on year from 2005, with the exceptions of 2010 and 2014, which both recorded small increases.

[18]Figures from Sub-national gas and electricity consumption statistics and Energy Trends: Electricity
[19]Figures for electricity sales (GWh) from Subnational electricity consumption statistics 2005 to 2015 www.gov.uk/government/statistical-data-sets/regional-and-local-authority-electricity-consumption-statistics-2005-to-2011

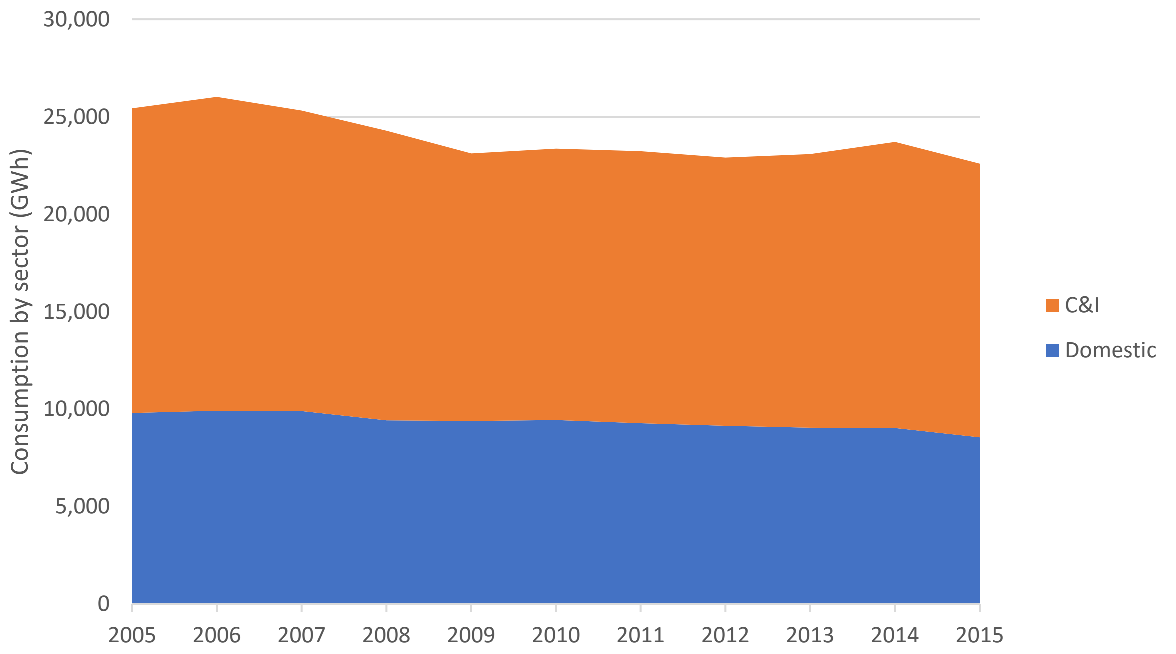
In 2016, domestic demand made up 35 per cent of total demand in Great Britain, with the remaining 65 per cent of consumption from commercial and industrial users.

11.1.2 Baseline demand in the West Midlands[20]

Electricity demand in the West Midlands licence area represents 7 per cent of electricity demand from Great Britain.

Overall demand in the licence area totalled 22.6 TWh in 2015, a decrease of 11 per cent from 2005. This is slightly more than the national reduction for the same period. Domestic demand fell by 13 per cent in the West Midlands, compared with a 10 per cent fall nationally. Commercial and industrial demand fell by 10 per cent in the licence area, compared with an 8 per cent drop nationally.

Figure 59: Electricity demand in the West Midlands from (2005 to 2015)



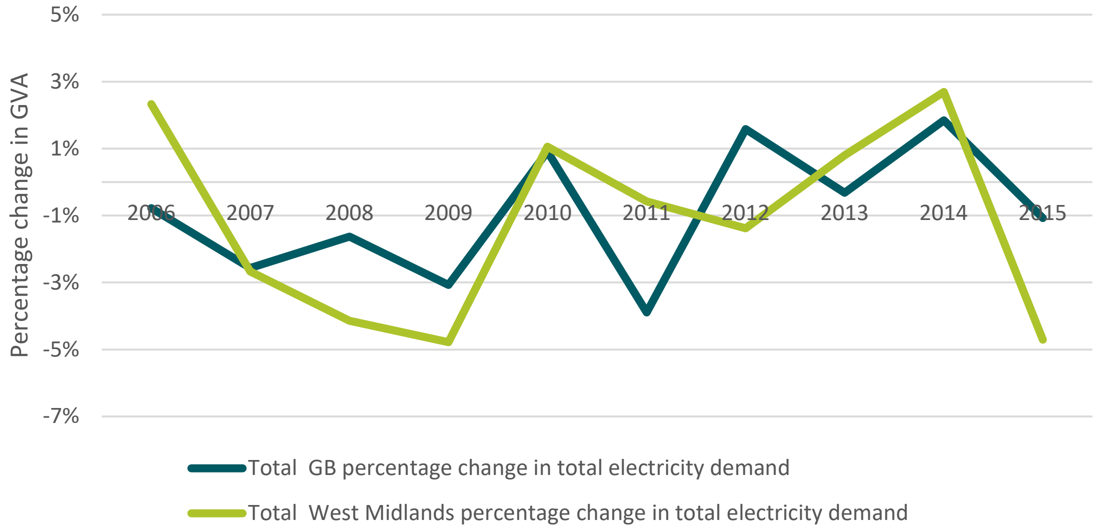
In 2015, 38 per cent of demand in the West Midlands was from domestic consumption compared to 35 per cent nationally.

We have compared trends in the West Midlands demand with national trends to aid understanding of local demand and its drivers. Figure 60 shows the differences between Great Britain and West Midlands total consumption trends, with 2011, 2012 and 2015 showing particularly notable differences.

For example, in 2015, demand in the West Midlands decreased by 5 per cent whereas nationally demand decreased by 1 per cent. Looking in more detail at these figures domestic demand decreased by 5 per cent, compared with a one per cent national decrease. Commercial and industrial demand decreased by 4 per cent, compared with a 1 per cent national decrease. The reasons behind this difference require further analysis – however, we can conclude that national trends cannot simply be assumed when considering demand at licence area level.

[20]Demand figures are for the WPD licence area, constructed from local authority/LSOA data – note this differs from the West Midlands region which government statistics report on.

Figure 60: Annual percentage change in total electricity demand for GB and West Midlands licence area from 2006 to 2015



11.1.3 West Midlands demand by local authority area

As might be expected the areas in the West Midlands with higher populations have higher domestic electricity demand. Similarly, higher commercial and industrial electricity consumption is found in areas that are either larger or have urban centres. Rural areas such as Malvern Hills and Cannock Chase have the lowest total electricity demand.

Figure 61: Domestic and commercial and industrial electricity sales by local authority for the West Midlands

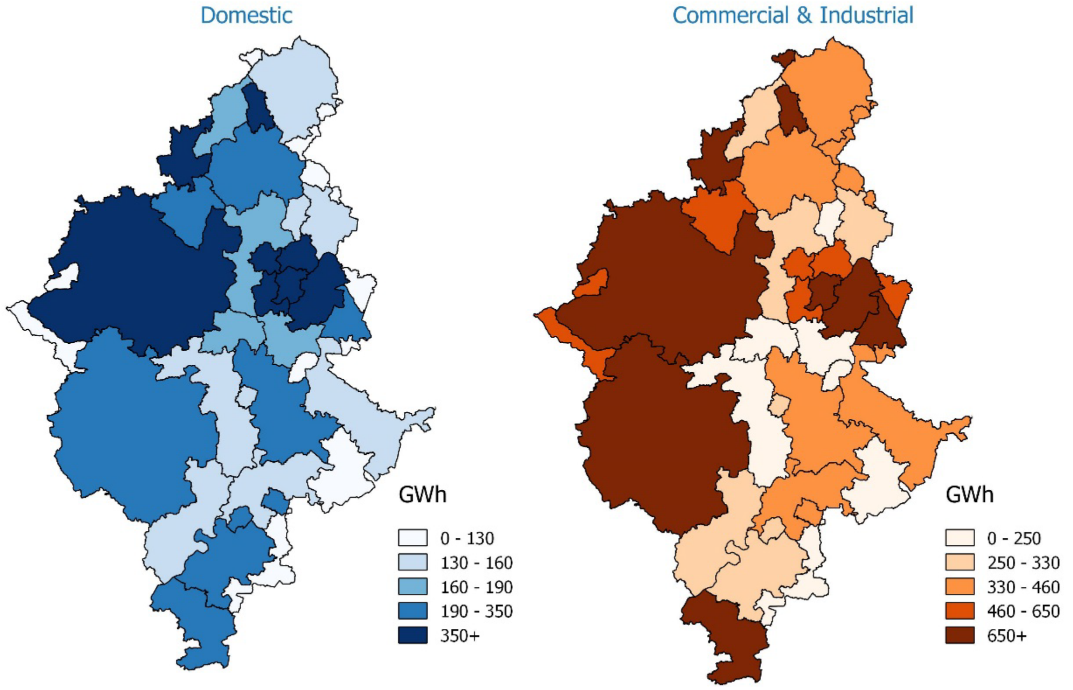
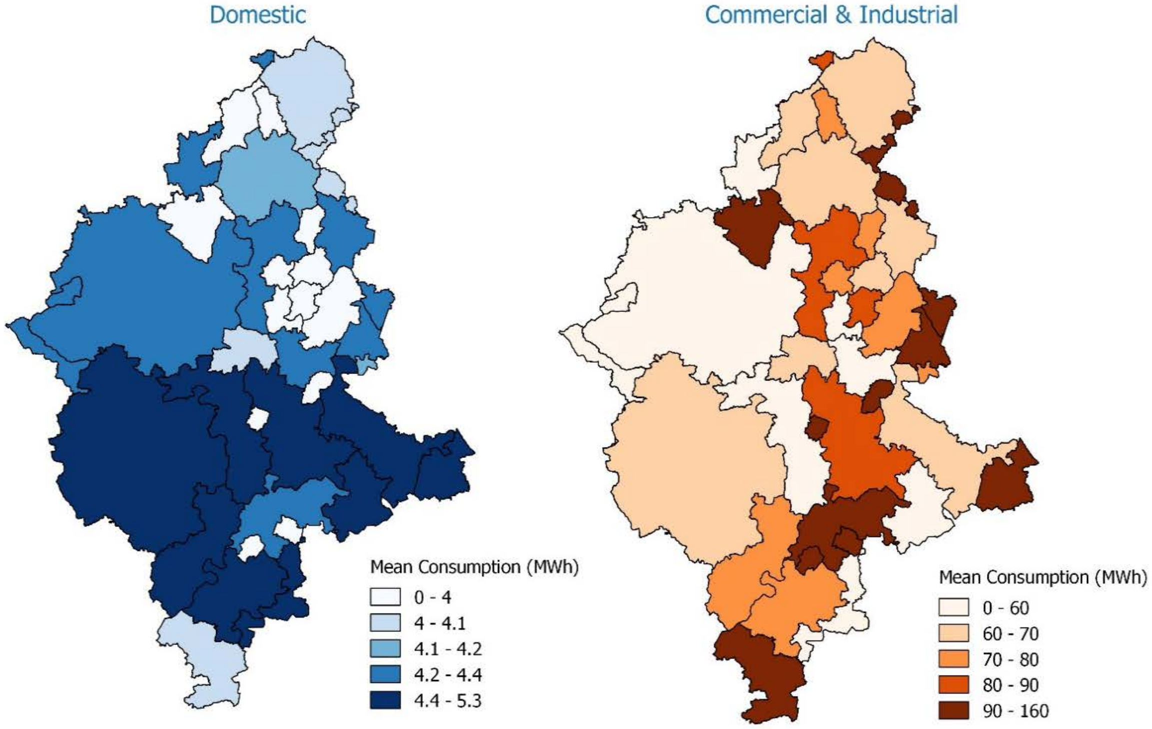


Figure 62 shows electricity sales per meter by local authority. For domestic properties, the map shows that rural areas tend to have higher use per household. These areas tend to have larger and less efficient housing. For commercial and industrial consumption, the map identifies areas with higher intensity commercial and industrial users.

Figure 62: Mean electricity sales per meter by local authority



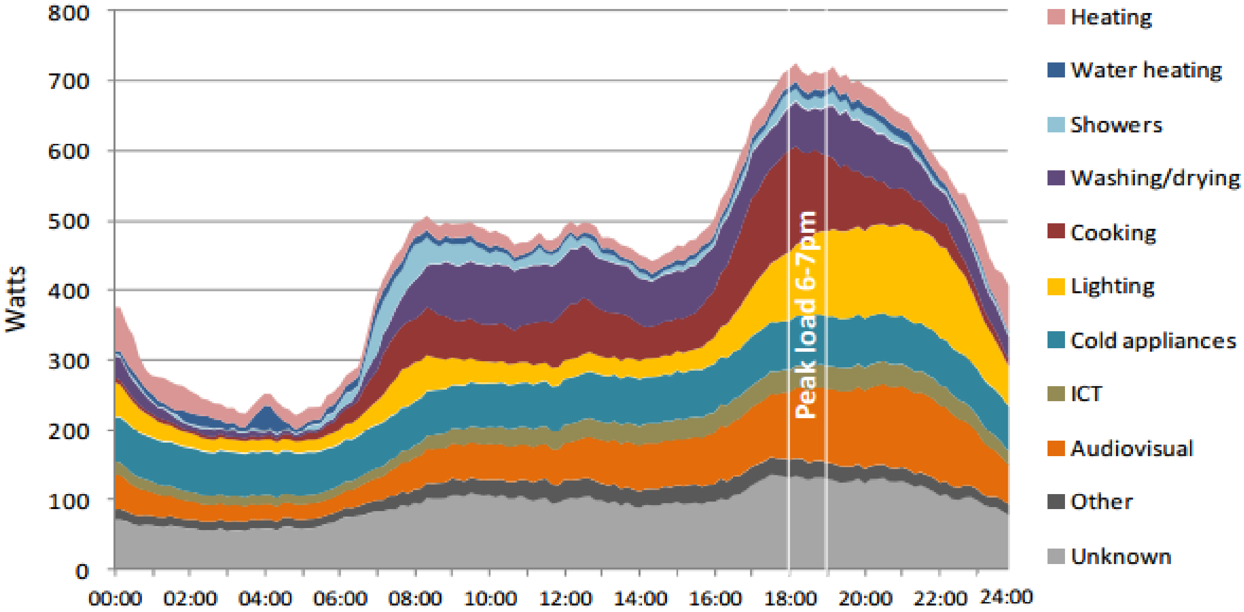
11.1.4 Peak electricity demand in Great Britain

From a network point of view the profile of demand is critical. Peak demand in the UK usually occurs between 5:30 and 6 pm on a cold winter's day, when demand for lighting and heat is greatest and commercial/industrial and domestic customers are using electricity[21]. Summer demand is both lower and smoother, with lower daytime demand spread more evenly across daytime hours.

Figure 63 illustrates why domestic demand peaks in the evening. It shows the mean domestic demand profile for a sample of 250 homes that were involved in a government study in London. The evening peak is made up of increased demand for a range of uses, notably lighting, audiovisual and cooking.

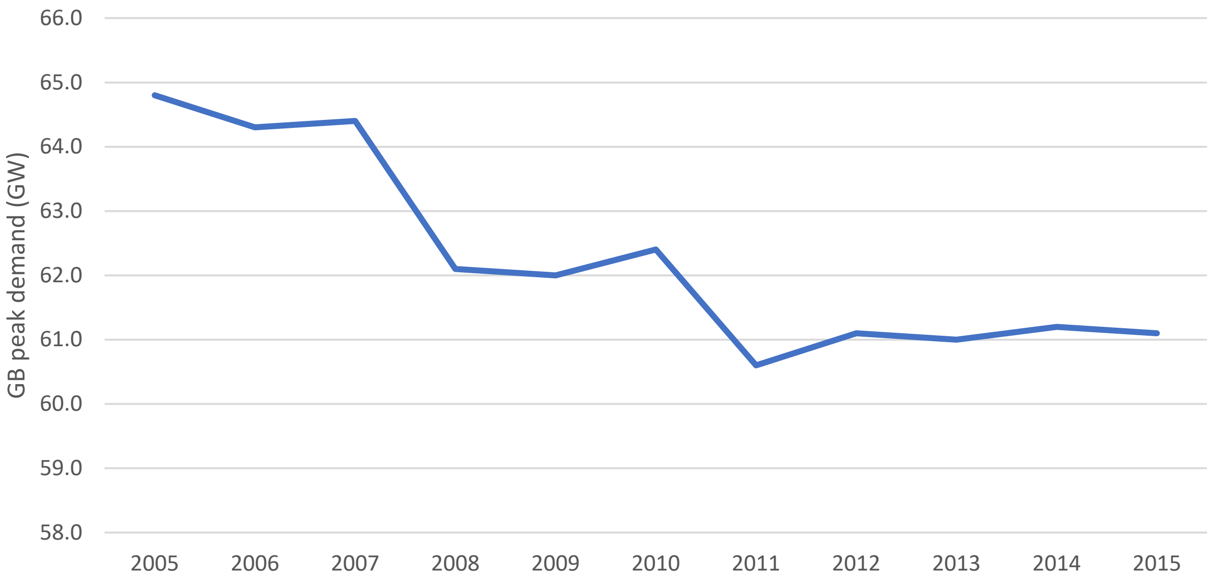
[21] www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Figure 63: Mean 24 hour profile for 250 homes by type of usage[22]



Since 2005, there has been a 5.7 per cent decrease in average cold spell peak demand in Great Britain, as shown in Figure 64. This trend levelled out between 2012 and 2015.

Figure 64: Changing GB peak demand[23]



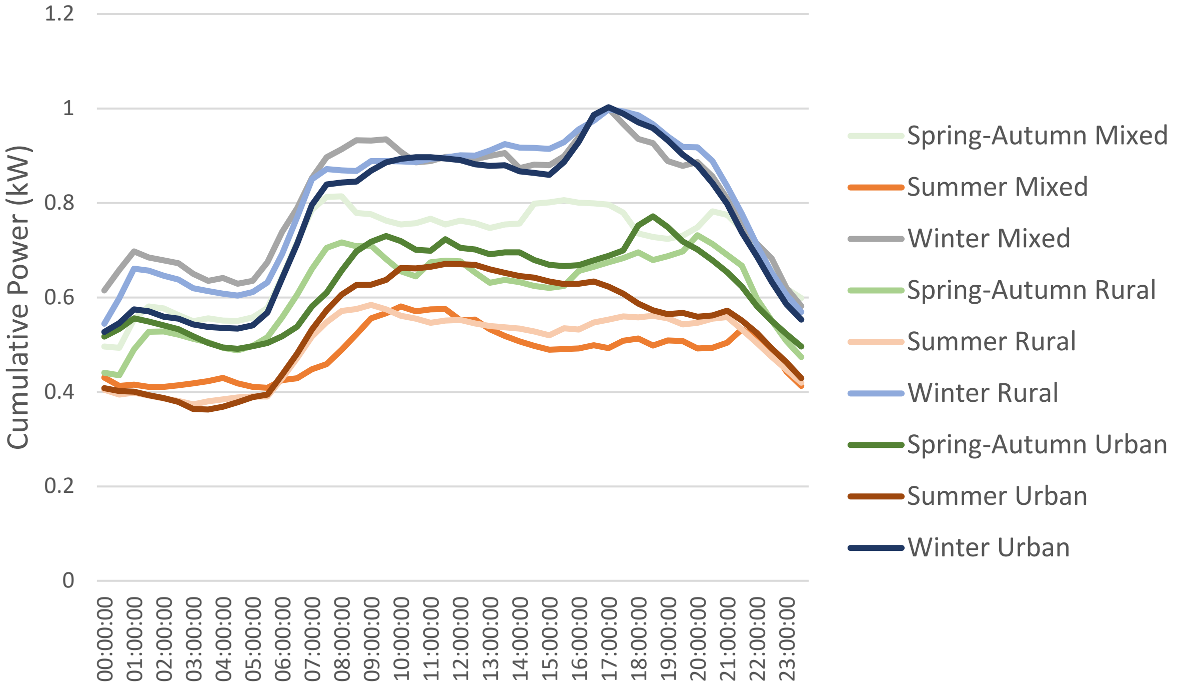
11.1.5 Peak electricity demand in the West Midlands licence area

Figure 65 shows the average daily domestic demand profiles for domestic properties in the West Midlands. Average demand in the West Midlands appears to be more evenly spread across the daytime hours with a lower evening peak (in all the seasons) than is seen in typical demand profiles such as Figure 63. Further

[22] www.gov.uk/government/uploads/system/uploads/attachment_data/file/275483/early_findings_revised.pdf
[23] National Grid 2016 Future Energy Scenarios

analysis is required to understand if the demand profile is significantly different in the West Midlands than nationally.

Figure 65: Daily average domestic demand profiles in the West Midlands[24]



11.2 Factors affecting electricity demand

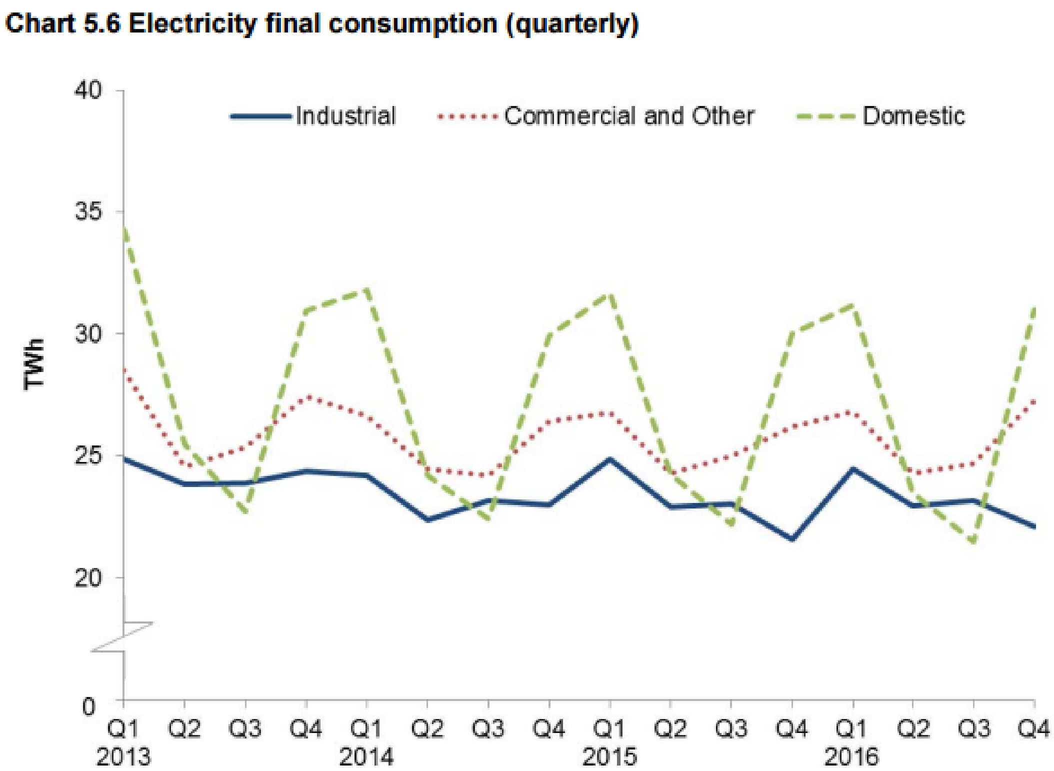
There are several underlying factors that have affected electricity demand in Great Britain.

11.2.1 Seasonal and weather effects

Electricity demand is affected by the season, with peak demand occurring on the coldest days in winter in the evenings. These peaks are due to an increased need for heating, alongside lighting and to a lesser extent entertainment. Winter peaks are particularly prominent for domestic demand. Figure 66 illustrates the seasonal nature of electricity demand, broken down by sector.

[24] Data from WPD datasets

Figure 66: Seasonality of electricity demand[25]

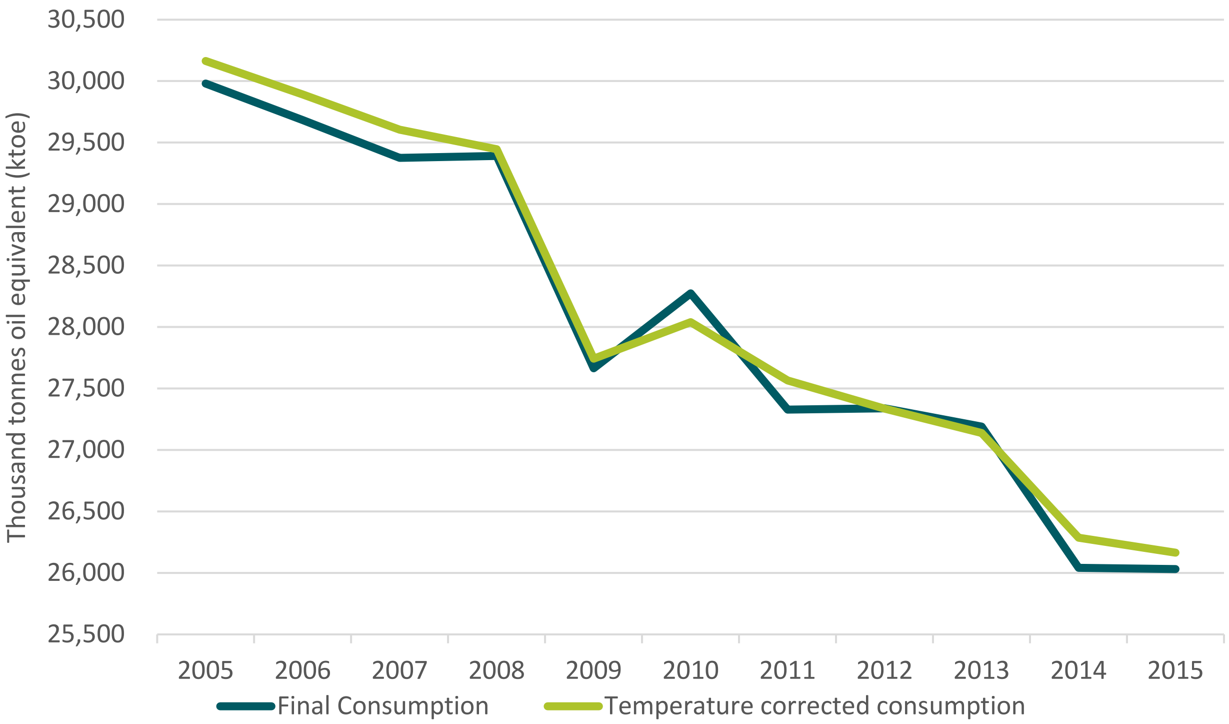


An inter-year comparison demonstrates the impact of weather on electricity demand. Final consumption of electricity increased by 3.3 per cent in 2016 Q4 compared to 2015 Q4. The average temperature was 2.2 degrees Celsius colder in the fourth quarter of 2016 compared to the same period a year earlier.[26]

Figure 67 shows temperature corrected annual electricity demand data against actual demand. As the graph shows, increased annual electricity demand for Great Britain in 2010 can be partially explained by temperatures in quarter 1 and quarter 4 of that year which fell below the long term mean[27]. 2011, when electricity demand in the UK fell by 4 per cent, had warmer quarters 1, 2 and 4 than the long term mean.

[25] www.gov.uk/government/uploads/system/uploads/attachment_data/file/604090/Electricity.pdf
[26] www.gov.uk/government/uploads/system/uploads/attachment_data/file/604090/Electricity.pdf
[27] www.gov.uk/government/statistics/energy-trends-section-7-weather

Figure 67: Temperature corrected figures against final electricity consumption (ktoe – Thousand tonnes of oil equivalent)[28]



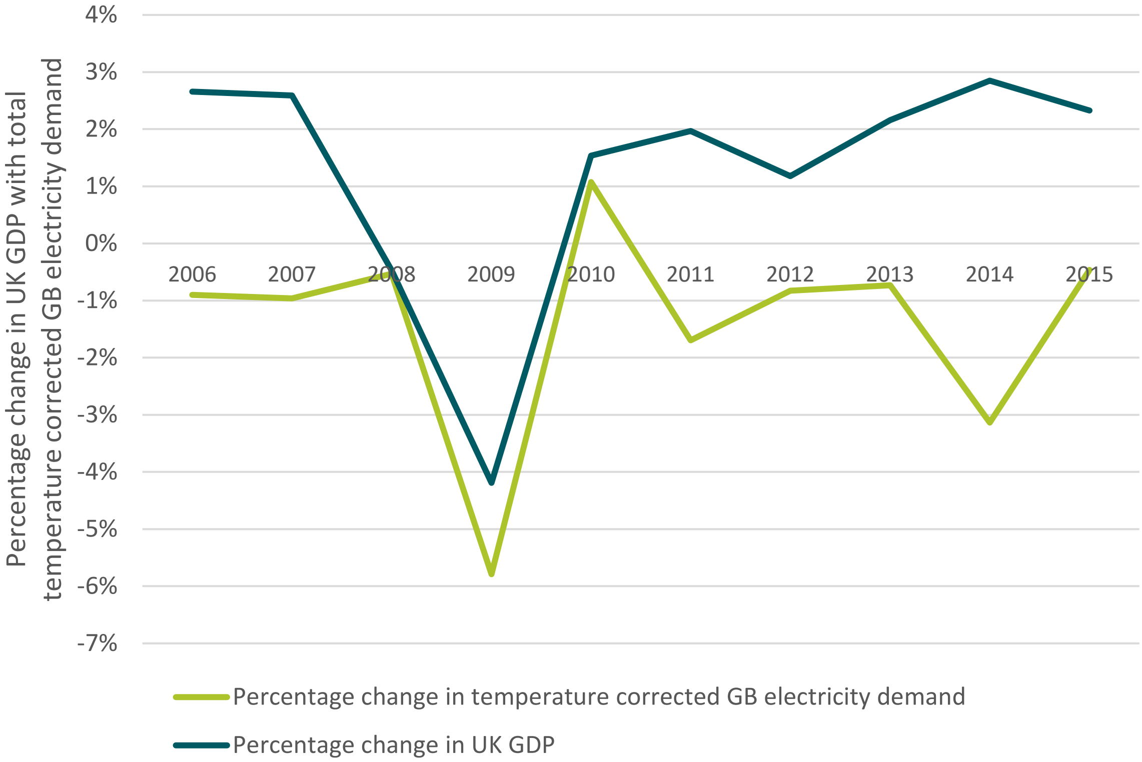
This link between external temperature and electricity demand peaks could grow if more heating is electrified, for example through widespread installation of heat pumps. Similarly, as summer temperatures rise due to climate change, demand for electrically powered cooling (fans and air conditioning) could rise, increasing summer demand and summer peaks. National Grid's 2016 Future Energy Scenarios predict that this effect will be fairly limited under all scenarios to 2030 (up to 1.6 TWh of additional demand under Consumer Power), but that increases could be dramatic after 2040[29]. The impact will be to create summer peaks, which should be met by increased solar generation but may cause issues for essential routine maintenance which is usually scheduled for the summer period[30].

11.2.2 Economic growth

Figure 68 shows the relationship between percentage change in Gross Domestic Product (GDP) for the UK and total temperature corrected electricity demand. The 2008/9 recession seems to correlate with reduced electricity demand but since then it is difficult to discern a relationship.

[28] Data from Energy Consumption in the UK 2016
www.gov.uk/government/uploads/system/uploads/attachment_data/file/586245/ECUK_Tables_2016.xlsx
[29] National Grid 2016 Future Energy Scenarios
[30] fes.nationalgrid.com/media/1231/ac-2050-v23.pdf

Figure 68: Comparing percentage change in UK GDP with total temperature corrected GB electricity demand[31]



11.2.3 Reduced energy intensity

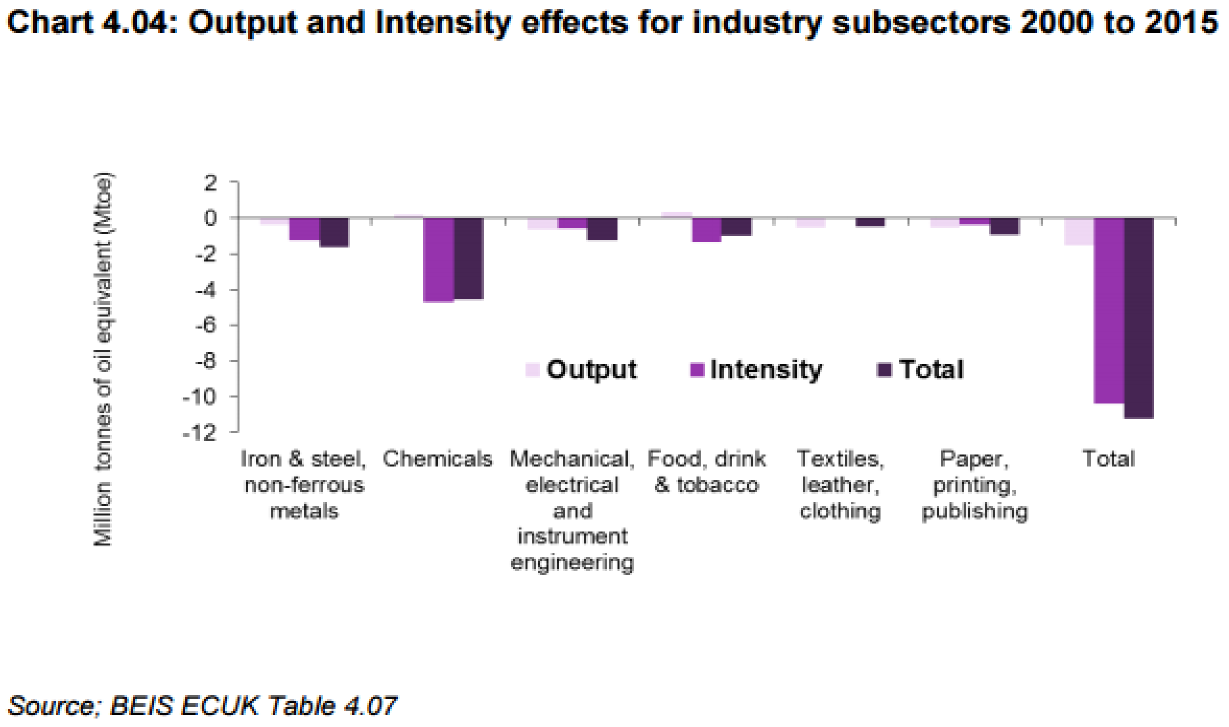
The broken link between increased GDP and electricity demand is a result of the decoupling of economic growth from energy demand. This is partially attributed to a shift in developed economies, such as the UK, from energy intensive industries to service-led businesses. Alongside this, energy intensive industries have become far more efficient in their use of energy, due to more efficient processes and machinery[32]. According to government figures, energy intensity (energy consumed per unit output) for the UK's industrial sector decreased by 38 per cent between 1990 and 2015[33]. Figure 69 highlights the extent to which the reduction in energy demand from the UK's industrial sector is attributable to decreased energy intensity, compared with the influence of reductions in output from the sector.

[31] GDP stats calculated from Office for National Statistics, Temperature corrected stats calculated from Energy Consumption in the UK 2016
www.gov.uk/government/uploads/system/uploads/attachment_data/file/586245/ECUK_Tables_2016.xlsx

[32] www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2015/reports-and-publications-economic-development-demand-for-energy.pdf

[33] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf

Figure 69: Output and intensity effects for industry subsectors 2000 to 2015[34]



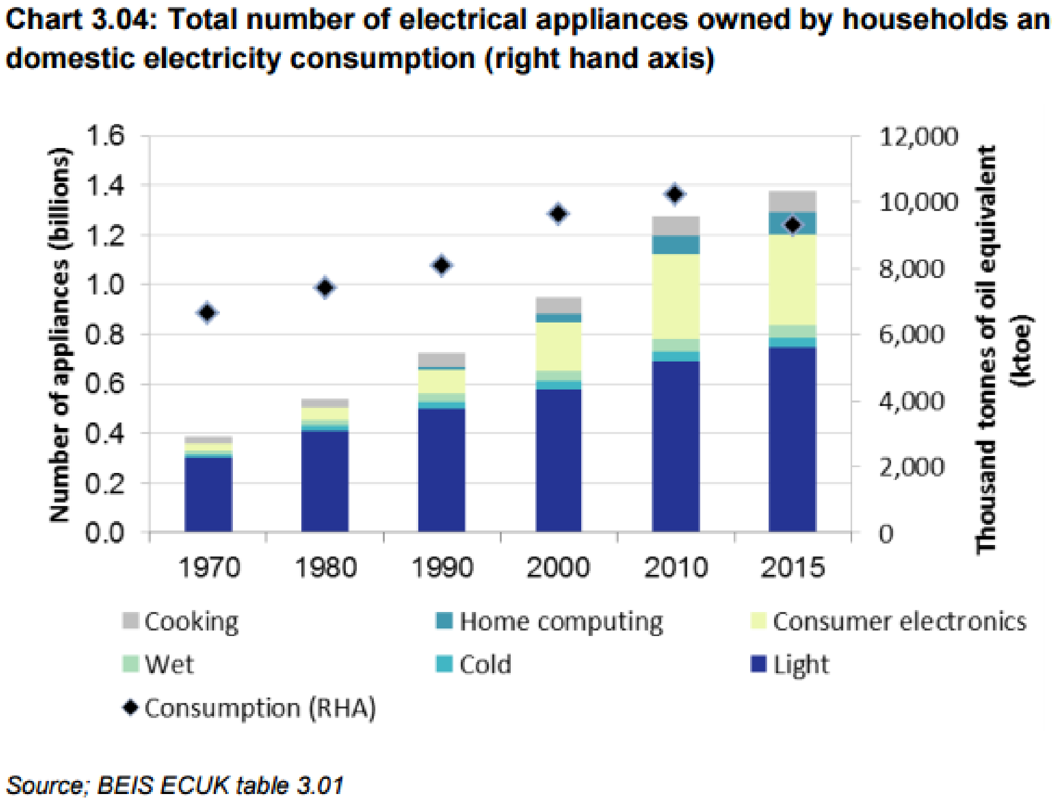
11.2.4 Energy efficiency improvements

The number of households in the UK has grown steadily since 1970 from 18.8 million to 27.5 million in 2015, an increase of 46 per cent[35]. There has also been an increase in the number of appliances. Despite this, domestic demand has fallen by around 10 per cent in GB since 2005.

Lighting and appliances account for approximately two thirds of domestic electricity consumption. Since 2005, domestic electricity consumption has declined due to greater efficiency despite an increase in the amount of appliances in use.

[34] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf
[35] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf

Figure 70: Total number of electrical appliances owned by households and total domestic electricity consumption[36]



The EU introduced energy efficiency labelling requirements for many household appliances in 1995, requiring manufacturers to label their products with a rating from A to G depending on its performance. Since 1995, the performance of the appliances has improved to the point that many of the appliances are now in the top category and the EU is considering re-calibrating the scale[37].

The increased roll out of energy efficiency measures for houses will also have had an impact on reducing electricity demand for Great Britain's 2.2 million electrically heated homes[38]. Electrically heated homes have been targeted for support with energy efficiency measures through the Energy Company Obligation (ECO), with around 6 per cent of the first wave of ECO benefiting electrically heated homes[39].

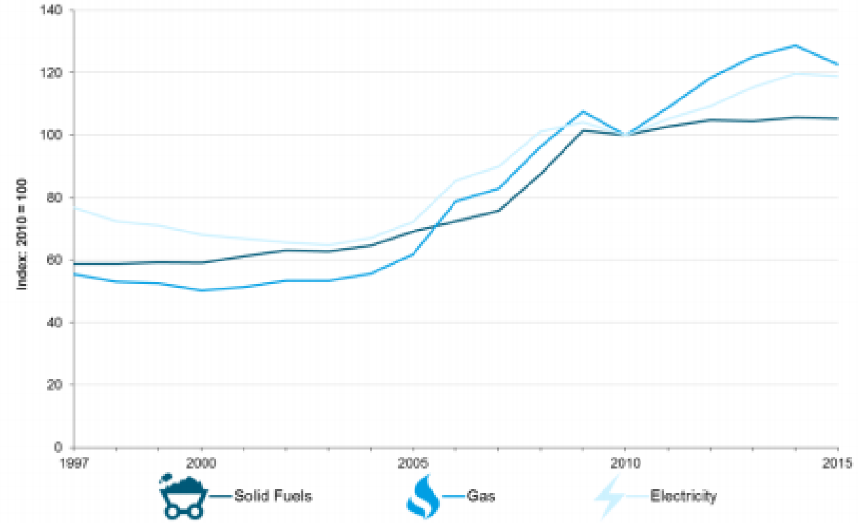
11.2.5 Behavioural change

Domestic electricity bills approximately doubled between 2005 and 2015 (see Figure 71). The Public Attitudes Tracker from May 2017 found that 30 per cent of households were worried or very worried about paying for their energy bills, more than for any other household bill; food, transport and housing costs[40].

[36] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf
[37] ec.europa.eu/energy/en/topics/energy-efficiency/energy-efficient-products
[38] www.Ofgem.gov.uk/Ofgem-publications/98027/insightspaperonhouseholdswithelectricandothernon-gasheating-pdf
[39] www.Ofgem.gov.uk/Ofgem-publications/98027/insightspaperonhouseholdswithelectricandothernon-gasheating-pdf
[40] www.gov.uk/government/statistics/energy-and-climate-change-public-attitude-tracking-survey-wave-21

The government points to the likelihood of a significant link between rising electricity bills and decreased domestic consumption in their Energy Consumption in the UK November 2016 update[41].

Figure 71: Consumer price index for gas and electricity[42]



Source; BEIS Domestic energy price indices, QEP 2.1.1 and 2.1.2
https://www.gov.uk/government/statistical-data-sets/monthly-domestic-energy-price-stastics

11.2.6 Reduced peak demand

The Triad charging mechanism (three highest demand peaks separated by 10 days across the winter Nov-Feb) incentivises major energy users to avoid peak demand periods, which has led to the UK becoming better at reducing peak (i.e. flattening them off). Similarly, high energy users are taking steps to shift their demand away from Red Band DUoS charging.

Much of this reduced peak demand on the network could be the result of 'behind the meter' generation rather than actual demand shifting or reduction.

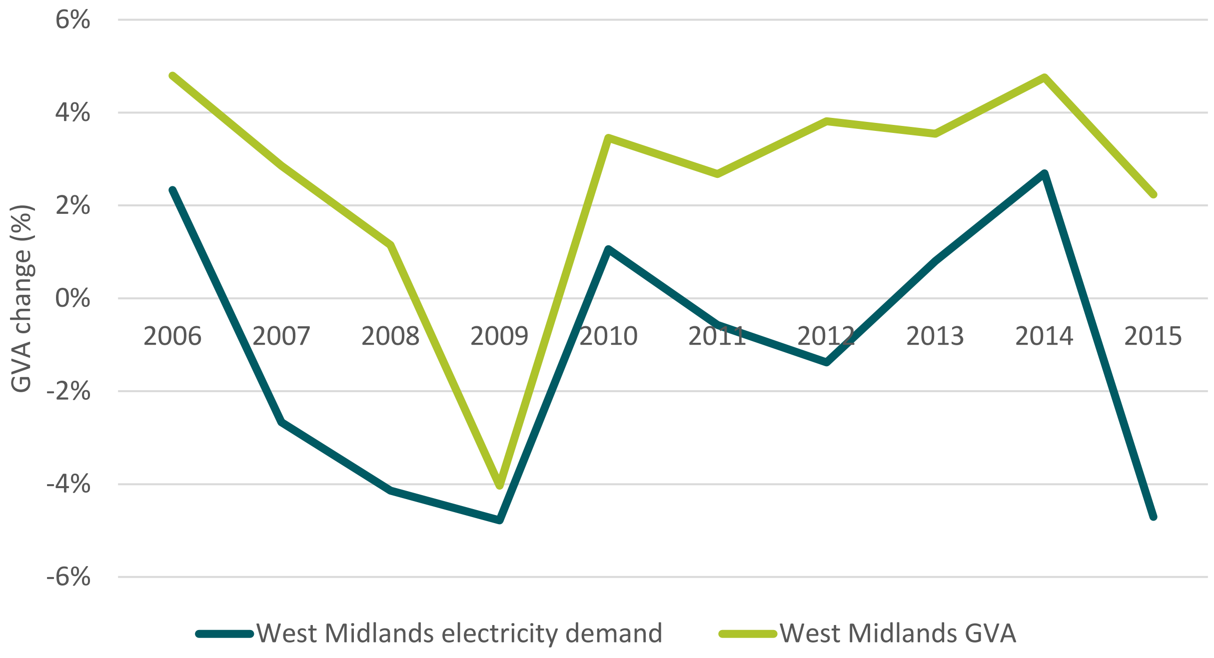
11.3 How these factors have affected West Midlands licence area electricity demand

As discussed above electricity demand in the West Midlands has seen a similar but slightly higher trend of falling demand than the national average since 2005 for both commercial and domestic properties.

Figure 72: Comparison of West Midlands electricity demand change and GVA change indicates there may be a closer correlation between West Midlands Gross Value Added (GVA) and electricity demand than a national link between GDP and demand, although more investigation of the data would be required to confirm this and to analyse the causes. We have used GVA as a proxy for economic growth in the licence area as GDP is a national statistic.

[41] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf
[42] www.gov.uk/government/uploads/system/uploads/attachment_data/file/573269/ECUK_November_2016.pdf

Figure 72: Comparison of West Midlands electricity demand change and GVA change



11.4 Factors affecting future energy demand

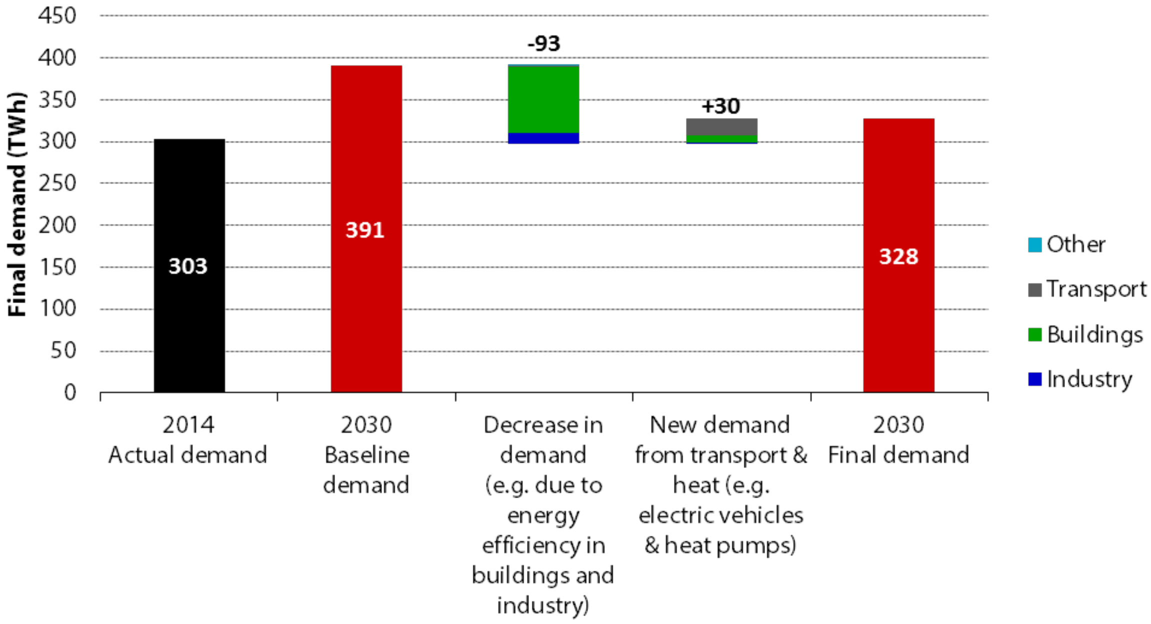
11.4.1 New disruptive demand

The CCC's Fifth Carbon Budget report estimates that electricity demand will increase by around 8 per cent to 2030, from 303 TWh in 2014 to 328 TWh.

The prediction considers that the historic factors reviewed here will continue to have an effect. Baseline demand would grow by around 88 TWh due to economic and population growth. However, this will be more than offset by 93 TWh of efficiency savings across the domestic and commercial/industrial sectors.

Growth in demand from 2020 to 2030 will be dominated by two new factors: electric vehicles and the electrification of heat, through heat pumps. The CCC estimate that electric vehicles will account for around 6 per cent of 2030 electricity demand (21 TWh) and heat pumps will add around a further 8 TWh of demand.

Figure 73: The Committee on Climate Change Fifth Carbon Budget electricity demand in 2030[43]

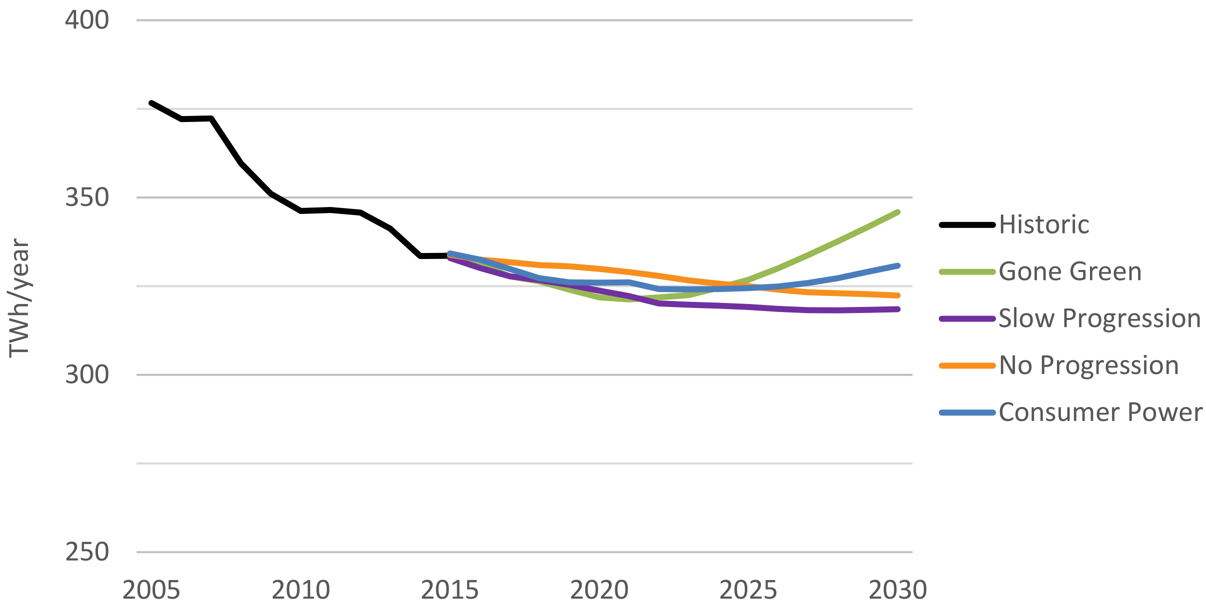


The Gone Green scenario of National Grid's FES in 2030 also predicts that electricity demand (with losses deducted) will reach 328 TWh. Again, increased baseline demand is more than offset by efficiency savings and demand reduction, dropping to 287.6 TWh in 2030. The Gone Green scenario allows for a greater penetration of heat pump technology by 2030 than the CCC scenario, with 27.5 TWh of additional domestic demand as a result. However, the 2016 FES prediction for maximum electric vehicle demand is lower than the CCC, with an additional 12 TWh of demand created under the FES scenario. Prior to 2027, efficiency savings and demand reduction outstrip new demand; after 2027, increased cumulative roll out of heat pumps and electric vehicles leads to demand growth beyond the 2016 level.

Under the remaining 2016 FES scenarios overall electricity demand falls to 2030, continuing the historic trend. From 2030 to 2040 the Consumer Power scenario sees increased demand as electric vehicles and heat pumps become more widespread.

[43] www.theccc.org.uk/publication/fifth-carbon-budget-dataset/

Figure 74: 2016 FES scenarios for annual electricity demand including losses



Source: National Grid 2016 Future Energy Scenarios

11.4.2 Continuing demand shift and demand side response

Some reductions in winter peak demand have already occurred, with heavy users trying to avoid Triad charges. In 2017, Ofgem consulted on changes to the network charging system and we expect to see changes to the mechanism to incentivise users to reduce winter peak demand. The design of a new charging mechanism for heavy users could have a significant impact on winter peaks.

Demand side response mechanisms, which enable electricity users to turn their demand up or down in response to a signal, could have a significant impact on peak demand. National Grid's Power Responsive Programme currently provides revenue streams to incentivise demand side response and aggregator companies are bidding in to provide services to the National Grid. WPD is trialling providing a similar revenue stream to businesses through its Flexible Power programme in the East Midlands.

Ofgem estimates that far greater untapped potential for DSR exists (circa 3 GW for reducing demand and circa 2 GW for increasing demand as a rough estimate)[44].

Time of use tariffs could have an impact on the demand profiles of both domestic and commercial/industrial customers by incentivising customers to shift their demand away from peak times by offering lower prices during lower demand periods. Time of use tariffs are available to customers now, particularly larger users with half-hourly metered sites.

With the introduction of smart meters, time of use tariffs are likely to become more common for electricity customers. In combination with a time of use tariff, smart meters will enable customers to review their electricity demand and shift away from the more expensive periods where they can.

[44] www.Ofgem.gov.uk/system/files/docs/2016/10/industrial_and_commercial_demand-side_response_in_gb_barriers_and_potential.pdf

Regen worked with Western Power Distribution on the Sunshine Tariff Trial, which investigated the potential for customers to shift demand in response to a time of use tariff. The tariff incentivised customers to use electricity in the middle of the day when the local solar farm is generating electricity,

A key finding was that automation has a strong role to play in enabling customers to take advantage of time of use tariffs. On average, Sunshine Tariff customers were able to shift around 10 per cent of their demand into the required 10am to 4pm period. However, customers with automation (a timer on hot water immersion or on appliances such as washing machines) were able to shift an average of 13 per cent of their consumption, compared with 5 per cent for those without automation.

As part of its DSO strategy, WPD is working on the potential for DSR potential for energy users to shift their demand profile to reduce peak pressure on the network.

Figure 75: Average weekday demand during the Sunshine Tariff for customers with and without automation[45]

11.5 Scenarios for electricity demand in the West Midlands

To assist WPD in modelling future demands on the network, the rest of this section looks in more detail at the effect in the West Midlands of three factors that could significantly change electricity demand: electric vehicles, heat pump deployment and housing/commercial development.

[45] Sunshine Tariff Summary Report, Western Power Distribution and Regen, February 2017

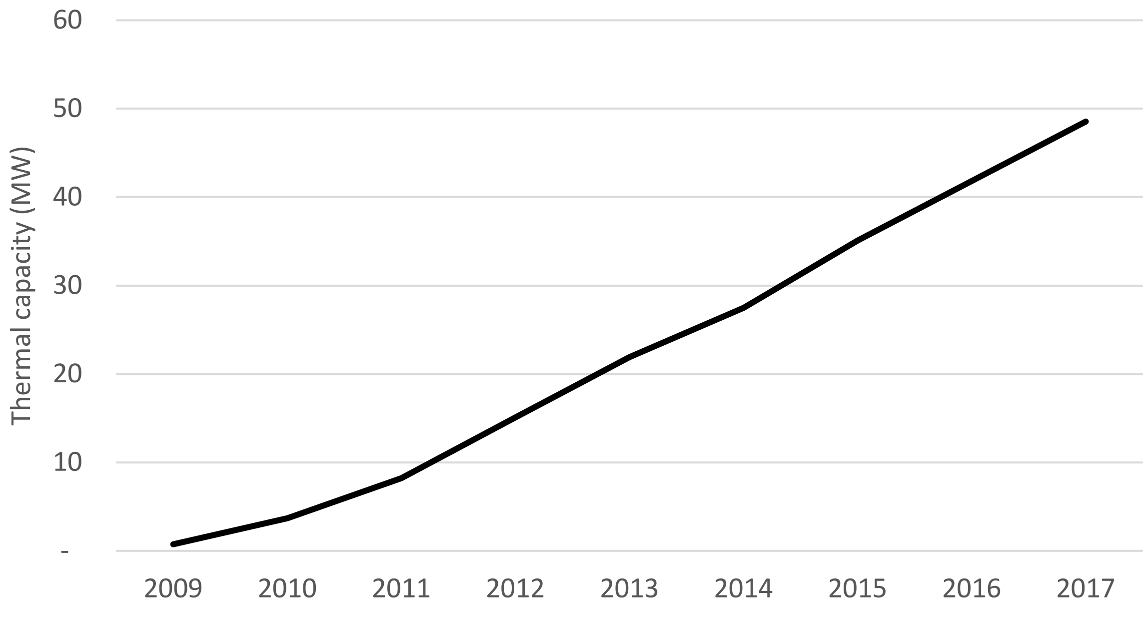
12 Heat pumps

12.1 Baseline: heat pumps growth to 2017

There were approximately 4,800 heat pumps in the licence area by June 2017, totalling around 48.5 MW_{th}. Growth has been steady, but relatively low in the West Midlands since 2009. This is consistent with the national picture; the announcement of the Renewable Heat Incentive and the introduction of the Renewable Heat Premium Payment scheme in 2009 led to consistent but slow growth in most areas of the UK. Despite relatively short payback periods created by the RHI, there are several barriers limiting widespread deployment (see our market insights below).

The West Midlands has some of the lowest rates of heat pump installation in the UK, with around 40 per cent of the number installed in the South West, the leading region. However, going against this trend, Stroud District Council has the highest level of heat pumps per household (1.4% of homes) in England due to successful social landlord installation programmes. This reflects the national picture where off-gas areas where social landlords have put in place investment programmes have seen the highest levels of heat pump deployment.

Figure 76: Heat pump thermal capacity growth in the West Midlands licence area



Other licence areas have a relatively strong correlation between off gas areas and heat pumps installations. In the West Midlands, this correlation is weaker. Figure 77 shows the relationship between the number of off gas homes in each ESA and the installed capacity of heat pumps. When compared with Figure 78, which shows the total number of all homes and the installed capacity of heat pumps, there is a weak correlation between off-gas homes and heat pumps.

Figure 77: Correlation between the number of off gas houses and the thermal capacity of heat pumps in each of the West Midlands licence area's ESAs

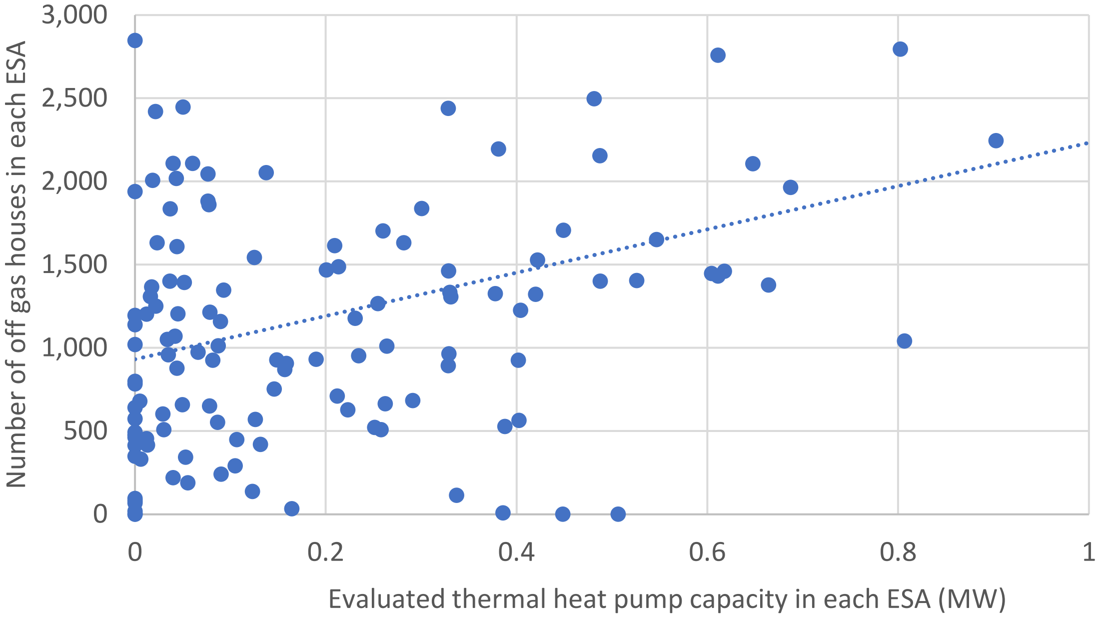
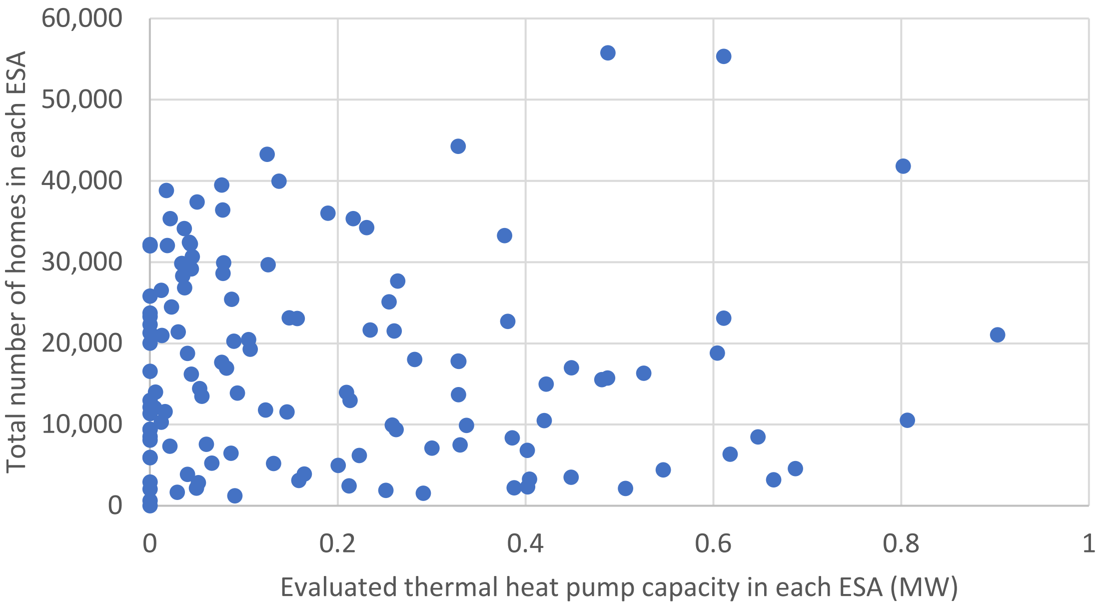


Figure 78: Correlation between total number of homes and the thermal capacity of heat pumps in each of the West Midlands licence area's ESAs



12.2 Pipeline: heat pumps

Heat pumps are permitted development in most cases so there is no pipeline of projects with planning applications and/or network connection agreements. We have, therefore, started the scenarios assessment immediately.

12.3 Regen's market insight: heat pumps

If deployed in significant numbers, conventional heat pumps would place a significant additional demand on the network, especially at peak times, when electricity is used to augment the heat energy extracted from ground and air sources.

12.3.1 Heat pumps growth forecasts have proved highly optimistic

The 2013 DECC strategy, the Future of Heating, estimated there would be 700,000 heat pump installations by 2020 and predicted that heat pumps will be the main heat source for off-gas rural and suburban areas in the future.

However, deployment rates are falling well short of that aspiration, less than 44,000 heat pumps were installed in England by April 2016. The Committee on Climate Change's Fifth Carbon Budget report has decreased its target for the number of heat pumps in UK homes by 2030 from 4 million to 2.3 million – a figure that remains challenging.

The 2016 consultation on reforming the RHI significantly reduced the government's predictions on the installation rate, estimating 19,400 domestic and commercial installations per year to 2021 – an additional 97,700 on the 44,000 installed by 2016.

BEIS is currently considering its long term policy on decarbonising heat. Reports from think-tanks such as the Policy Exchange have called for the government to recognise that high levels of heat pump deployment are unlikely to be achieved and that a new approach to heat is needed.

12.3.2 Barriers to current and future heat pump deployment

The heat pump market faces significant barriers to growth, including:

- The disruption involved for consumers to replace their current heating systems with a heat pump; it is more straightforward to replace like with like, in terms of the space required, the heating distribution system and consumers' current knowledge base.
- Higher upfront capital costs than conventional heating systems, which have not been overcome by grant and RHI schemes, alongside low gas and oil costs.
- Practical constraints, e.g. land space and bore holes for ground source heat pumps.
- The need for well insulated homes and ideally underfloor heating solutions. Heat pumps work best providing low-grade heating that requires relatively air-tight, well insulated properties to achieve cost effectiveness
- Public awareness of heat pumps remains low. Wave 20 of DECC's Public Attitudes Tracker found in 2016 that 47 per cent of those surveyed had never heard of air source heat pumps and 38 per cent were unaware of ground source heat pumps.
- Doubts and concerns about heat pump performance, partly driven by some poor installations but also some critical studies, and their reliance on electricity as the main backup and augmentation energy source. Reports from the Energy Saving Trust showed that installations can fail to live up to expectations, with co-efficients of performance (a measure of heat pump efficiency) below the level required for the technology to be deemed renewable. A second phase of investigation led to more positive results and learning about the factors that need to be in place to ensure more efficient performance, in particular about householder education of how best to use the technology. These findings are backed up by analysis published by government in 2017 showing that from a sample of heat pumps installed via the Renewable Heat Premium Payment scheme a third of installations could not be classed as renewable.

12.3.3 RHI decisions important to heat pumps' deployment

In December 2016, the government announced changes to the RHI, increasing domestic heat pump tariffs and maintaining the current tariffs for non-domestic projects. They have also set limits on the amount of heat production that can be claimed under the domestic RHI; this will have a limiting effect on deployment, as it will have an impact on the economic viability of larger domestic installations. A further change is the requirement to fit an electricity meter to monitor the usage of the heat pump. This is an attempt to improve the visibility of heat pump performance and will not be used to assess payments. These changes have been delayed by the Brexit vote and the general election, causing uncertainty in the market. They are expected to be implemented in summer 2017.

There remains uncertainty surrounding the future of the RHI, with current budget limits having the potential to stop the scheme early at short notice, although the scheme is officially planned to be open to new applicants until April 2021. The future of the RHI will have the greatest impact on the level of heat pump deployment; if we are to see significant deployment in the retrofit domestic market, high tariff levels will be needed to overcome the significant barriers.

12.3.4 Emerging heat pump technologies

Recent government reports analyse the market for gas heat pumps (including gas driven, adsorption and absorption heat pumps), high temperature heat pumps and hybrid solutions combining heat pumps with gas boilers. Deployment of these technologies will have a different impact on the electricity network depending on the technology, with gas heat pumps not using electricity and hybrid solutions having a lesser electricity demand than conventional and high temperature heat pumps.

These emerging products have features that may help to mitigate some of the barriers to widespread uptake, as they can provide the high temperature space heating that customers are used to and also supply hot water and use gas, which customers are familiar with. They have the potential to offer considerable carbon savings against conventional heating options.

However, the upfront costs are high and there is low customer awareness, a lack of trial information to prove performance claims and, for some products, a relatively low running cost saving. Improvements to the technology may lead to a wider range of appropriate applications and greater deployment.

Heat pumps may also be used to supply heat networks, for example, there is a pilot in construction at EON's Cranbrook network, near Exeter, Devon.

12.3.5 Impact on the network

Heat pumps could have a significant impact on domestic demand peaks, creating an additional morning peak, as well as adding to the existing UK evening peak, as shown for average users in Figure 79.

Figure 79: Average winter demand from an air source heat pump in addition to underlying baseline demand[46]

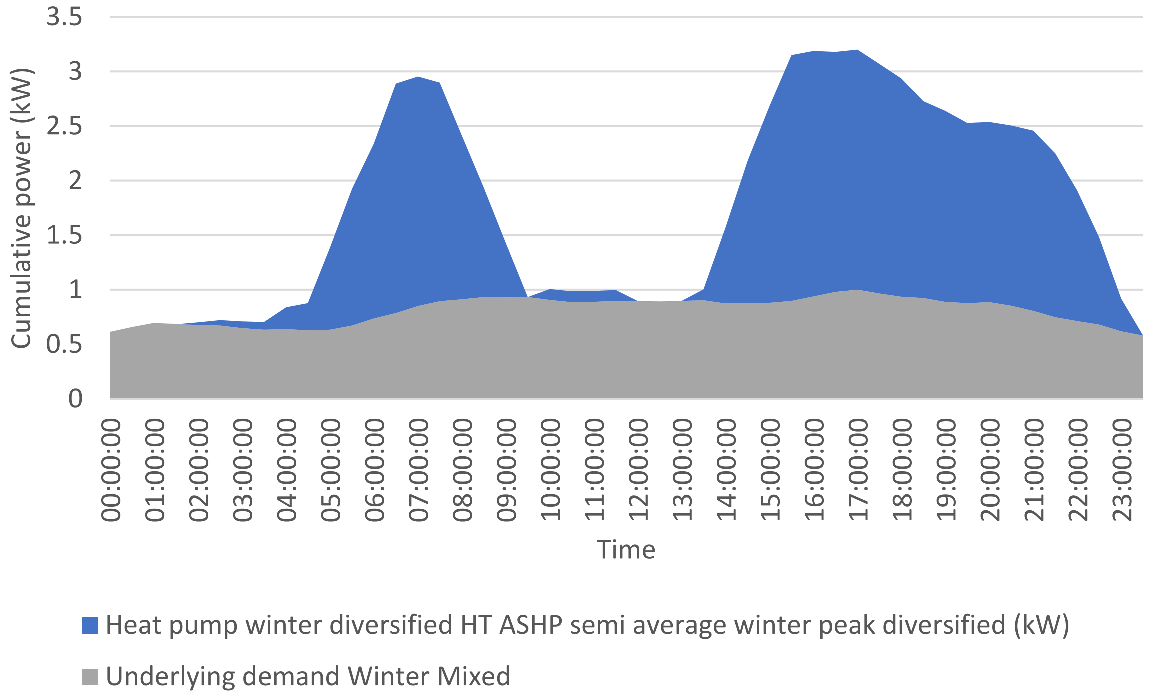
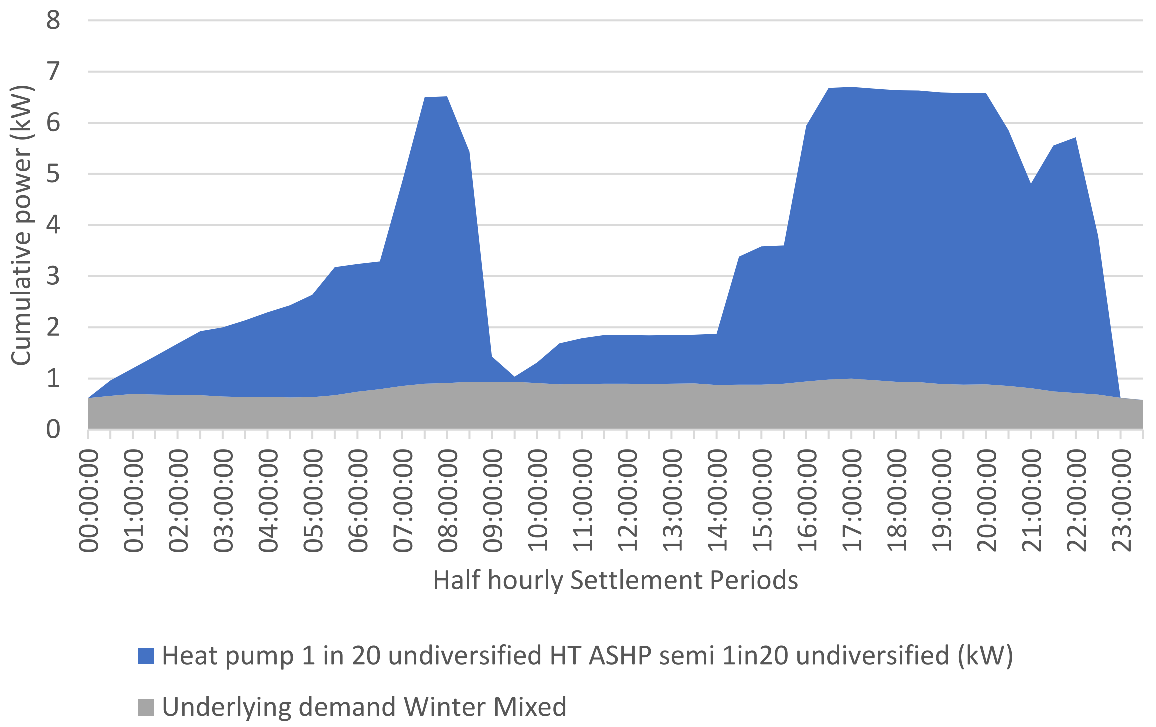


Figure 80:Worst case scenario for air source heat pump use in an average home[47]



46 Data from Western Power Distribution
47 Data from WPD

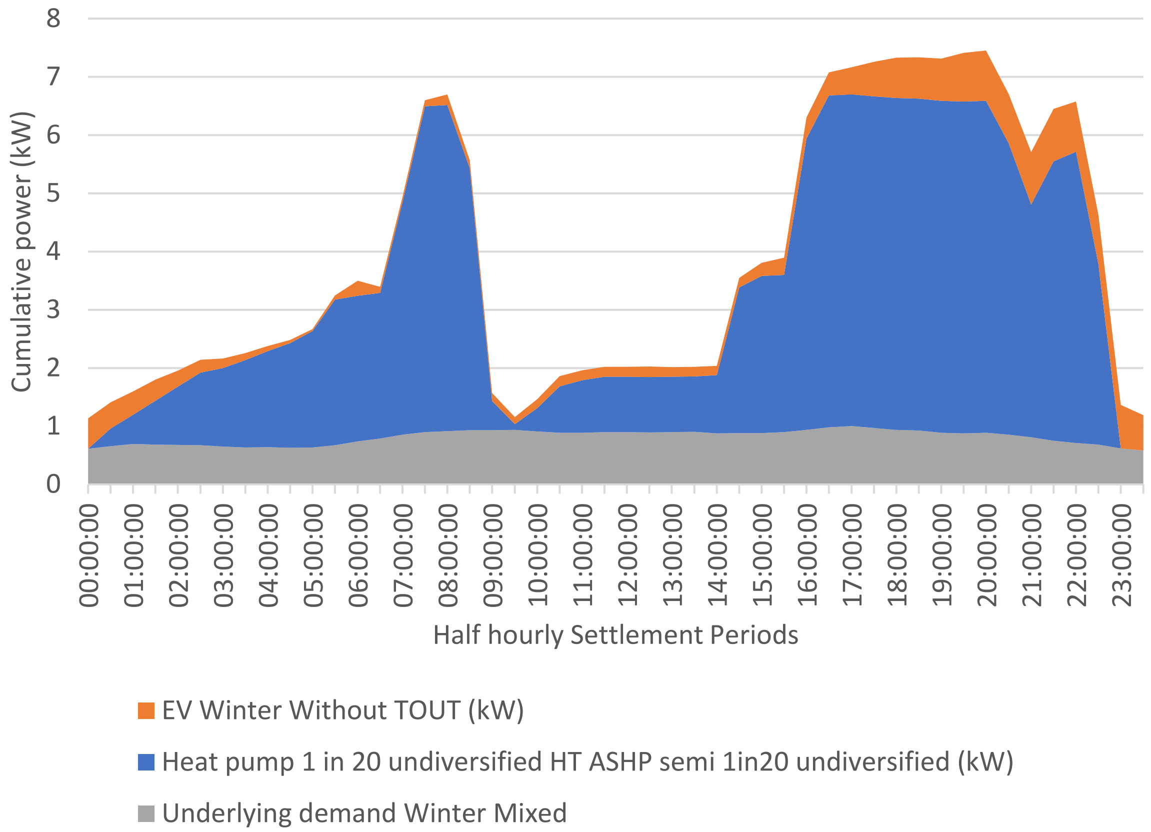
Figure 80 shows the potential peaks created in an average home where an air source heat pump is either poorly installed or poorly used, with demand peaking at double that of an average heat pump user.

12.3.6 Combined effects of heat pumps and electric vehicles

Together electric vehicles and heat pumps could have a very significant impact on the local network.

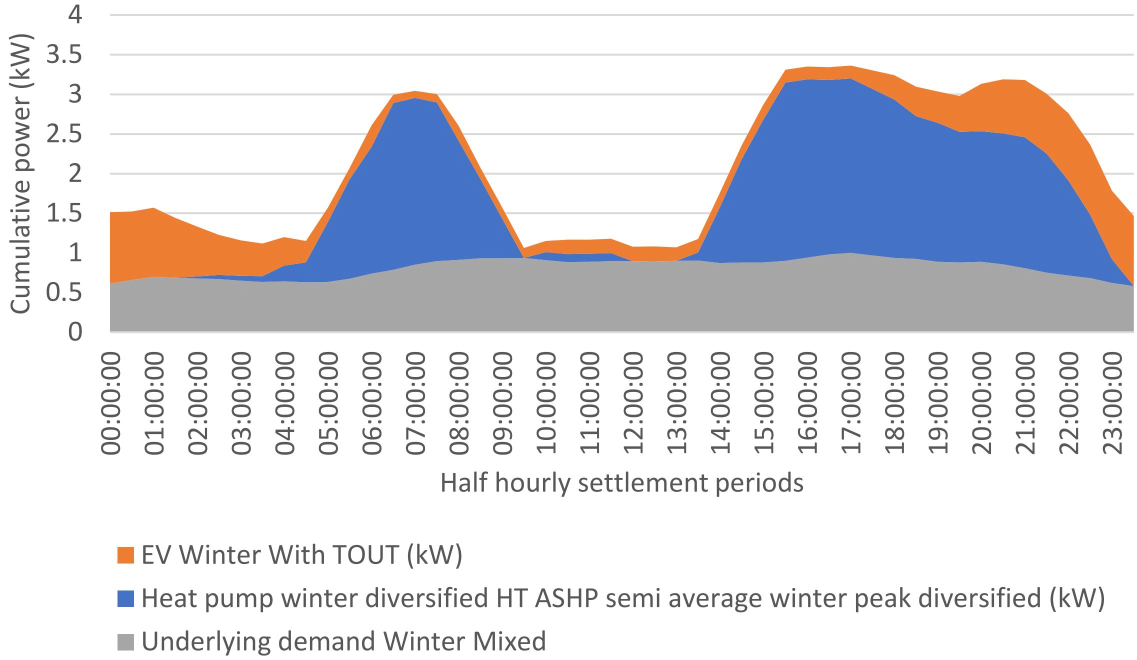
Figure 81 shows the potential worst case scenario for demand in a domestic property where a heat pump is poorly used and an electric vehicle is used without a time of use tariff. This can be compared with Figure 82 where a properly used air source heat pump is used in conjunction with an electric vehicle and a time of use tariff. The time of use tariff shifts the EV charging demand away from the peak.

Figure 81: Worst case scenario: a household's average daily winter peak demand with a poorly used heat pump and EV without a time of use tariff[48]



[48] Data from WPD

Figure 82: Average daily winter peak demand for a household that is an average ASHP user with an electric vehicle and time of use tariff



12.4 Scenarios: heat pumps, 2017 to 2030

12.4.1 Factors affecting the scenarios: heat pumps

We have considered the following factors in producing the scenarios.

Table 34: Potential factors affecting heat pump deployment

Factors	GG	CP	SP	NP
Government influenced factors				
Government heat policy includes drivers for heat pumps, including continued/expanded RHI	●		●	
Energy efficiency standards for new properties are tightened, either through national building regulations or widespread local planning policies	●		●	
Technology costs				
Upfront costs of conventional heat pumps falls due to strong global market and R&D	●	●		
Technological innovation – emerging technologies become more established enabling new applications and cost reductions	●	●		
Wholesale price of power and gas				
Rising electricity and gas wholesale price – potentially driven by economic growth	●	●		
Availability of finance				
Strong economy means individuals, communities and small businesses have capital available to invest	●	●		
Other factors				
Consumer appetite for heat pump technology increases	●			
Public sector investment programmes drive installations in local areas	●		●	

12.4.2 Scenario results: heat pumps

In total, our Gone Green scenario would see over 70,000 heat pumps installed by 2030 in the licence area, totalling 601 MW_{th} – equivalent to approximately 2.5 per cent of all homes having a heat pump. The growth rate of houses fitting heat pumps in this scenario would greatly increase from the historical trend to almost reach the level of the number of houses fitting the technology to the growth of solar PV during the 2011/12 boom.

Our Gone Green prediction is significantly lower than that implied by the 2016 FES prediction for Great Britain. The FES estimates 5.7 million heat pumps by 2030 in Great Britain under Gone Green, which is equivalent to approximately 23 per cent of homes.

The difference in our Gone Green scenario for the West Midlands from the FES national prediction is partly explained by the lower historic roll out of heat pumps and the lower number of off gas homes in the West Midlands than nationally. There are also significantly lower numbers of new homes planned in the West Midlands compared to the East Midlands.

However, the main difference results from basing our predictions on historic trends of heat pump installation which have remained slow and steady at a time of significant subsidy. This evidence indicates that whilst technological development and further support for heat pumps could see a much more rapid take up, the level of deployment in the FES is impractical.

Table 35: Scenarios summary for heat pumps in the West Midlands

Consumer Power	**Gone Green**
• Medium growth scenario • Technology improvements lead to a greater range of applications, for cooling, on gas properties, network stabilisation and co-deployment with solar PV. • However, the government's heat strategy focuses on microCHP and fuel cell technology. • Private sector retrofit demand is limited by both the high upfront costs and disruptive nature of switching to a heat pump. • Building regulations are not tightened significantly, meaning that the rate of deployment in new build properties is driven by consumer demand for low carbon buildings, which takes longer to have a significant impact on deployment rates.	• Highest overall growth scenario • Government programme of incentives and awareness raising leads to high levels of private sector retrofit installations. • Public sector and housing associations roll out investment programmes. • New build install rates are high from the middle of the decade, due to the re-introduction of zero carbon homes legislation. • R&D leads to development of cost competitive gas driven heat pumps and integrated solutions combined with storage and smart technologies, leading to higher on and off gas deployment rates. • Heat pump driven heat network market develops.
No Progression	**Slow Progression**
• Lowest growth scenario • In the retrofit market, there is a lack of incentives, investment capital and consumer awareness.	• Medium growth scenario • The retrofit market grows slowly under this scenario as: the incentives available are lower than under Gone Green; there are fewer individuals and organisations with

- Building regulations are not tightened significantly, consumer appetite for high tech new homes is reduced and fewer homes are built.
- Costs remain high and technology development is limited.

investment capital available; fossil fuel prices remain lower; and technology development and cost reductions are limited.

- Public sector investment programmes are more limited.
- Zero carbon homes legislation is enacted, leading to high levels of new build deployment from the middle of the decade; but fewer new homes are built under this scenario than under Gone Green.

Figure 83: Scenarios for the number of heat pumps in the West Midlands licence area to 2030

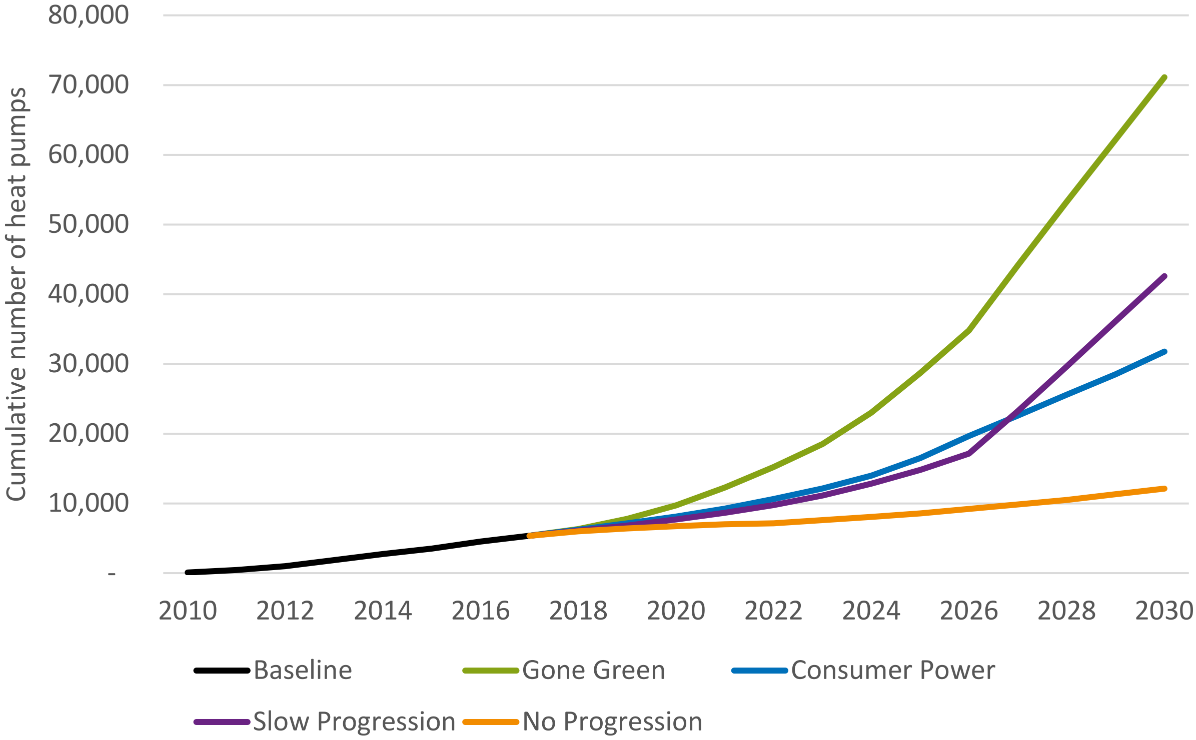


Table 36: Cumulative numbers of heat pumps in the West Midlands licence area

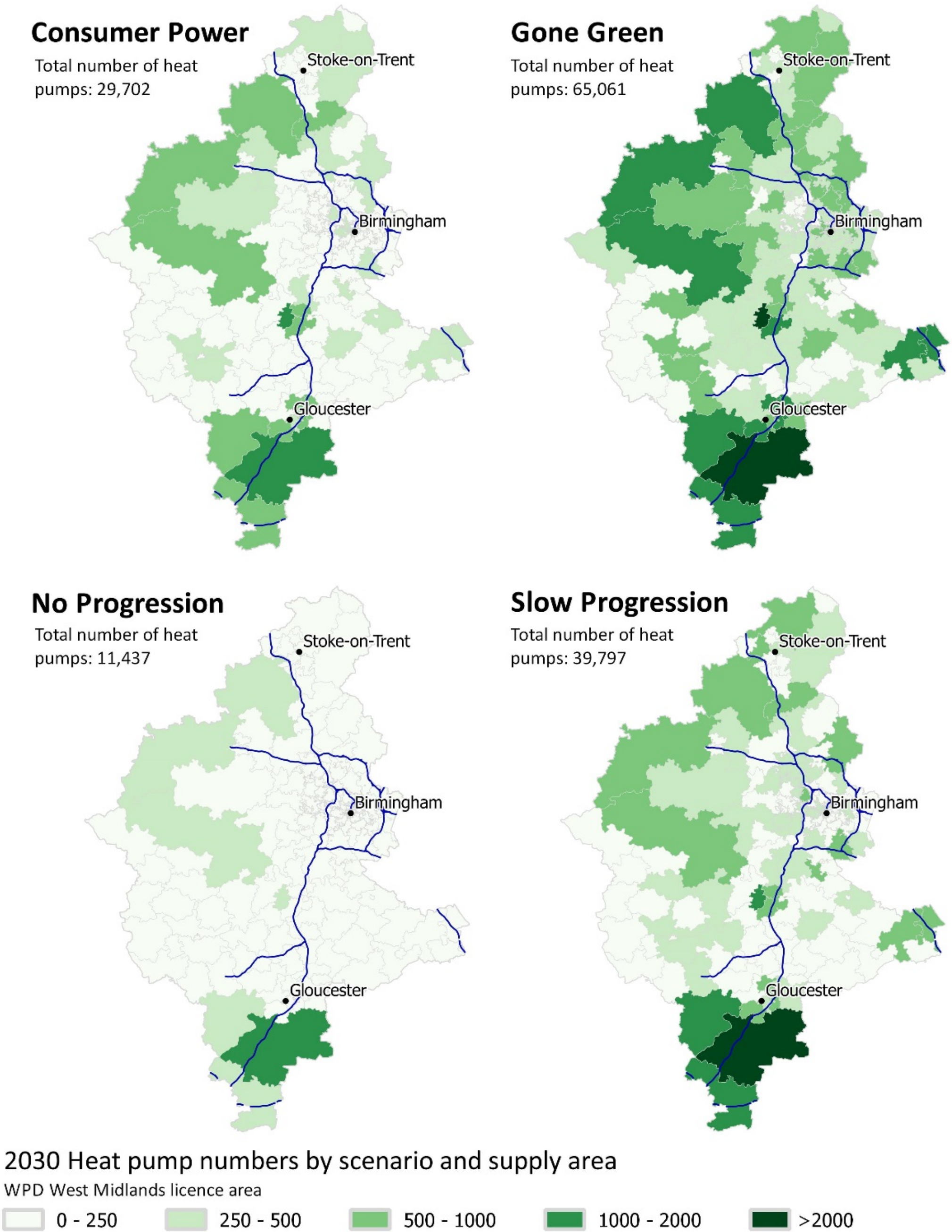
	Baseline (numbers)	2020 capacity (numbers)	2025 capacity (numbers)	2030 capacity (numbers)
Gone Green	5,364	9,728	28,712	71,120
Consumer Power	5,360	8,112	16,514	31,776
Slow Progression	5,359	7,712	14,818	42,594
No Progression	5,354	6,737	8,556	12,120

12.5 Geographic distribution of heat pumps by ESA

We have distributed the projected heat pump growth across the West Midlands' ESAs based on the following factors:

- The distribution of off-gas houses
- The distribution of on-gas households
- Past trends
- Numbers of new homes that will be built

Figure 84: Geographic distribution of heat pumps by scenario in 2030



The projected number of new build houses to be built by 2030 in each ESA was determined as set out in section 14. Under the Gone Green and Consumer Power scenarios, we have assumed high growth rates of new homes due to a better economic environment, with a lower growth rate under Slow Progression and No Progression.

Under the poor economic scenarios (Slow and No Progression), a greater proportion of homes predicted to install heat pumps are off-gas, than under the better economic scenarios (Gone Green and Consumer Power), which see a comparatively greater proportion of on-gas homes with heat pumps. We have weighted the geographic distribution accordingly, with the resulting impact depending on the degree to which each ESA is off or on the gas network.

12.6 Heat pump capacity and performance

12.6.1 Coefficient of performance

Heat pump installation data is given in installed thermal capacity. To estimate the impact of heat pumps on the electricity network in the licence area, we have calculated figures for electrical demand based on installed thermal capacity. To undertake the conversion, a suitable Coefficient of Performance (COP) needed to be established. We have used a current COP of 2.5 for the baseline; although ground source heat pumps can regularly be found to have a COP of 4, the majority of heat pumps are air source heat pumps, for which a COP of over 3 is unusual.

Looking forward, we have varied the COP for each scenario. In the Gone Green and Consumer Power scenarios, more new, well-insulated homes are projected to install heat pumps and there will be technology developments. The COP is projected to rise under these scenarios by 2030 to 3.4 and 3.3 respectively.

In the Slow Progression scenario, there is still some investment and technology development, but this is slower. Also, there are slighter fewer new homes with heat pumps installed than Gone Green. As a result, we have projected that there is an average COP of 2.9 reached by 2030 under Slow Progression. In the No Progression scenario, heat pump improvements are hindered by poorly insulated homes and a lack of technology development. Therefore, the COP is not expected to increase, remaining at 2.5.

12.6.2 Size of installed heat pump

We have assumed that the average heat pump thermal capacity reduces from 10 kW in 2017 to 9 kW by 2030 as technology improvements are made and smaller scale domestic retrofit heat pumps are installed.

13 Electric vehicles

13.1 Baseline: electric vehicles growth to 2017

The baseline for the West Midlands licence area is drawn from anonymised registered keeper data from the Department for Transport (VEH0131). The issue with this dataset is that where cars are leased, the registered keeper is the leasing firm rather than the user. We have, therefore, distributed the West Midlands's electric vehicle's baseline to individual ESAs through a combination of factors. These factors have been evaluated as the key spatial datasets affecting electric vehicles. These factors are:

- Numbers of houses within an ESA
- Domestic rooftop PV baseline distribution, particularly in more affluent areas
- Urban density of ESA

There were 12,605 registered keepers of electric vehicles in the licence area at the end of March 2017.

The West Midlands is one of the leading regions in the UK for electric vehicles, following the East of England and the South East.

Sales growth of electric vehicles in the West Midlands has been exponential, reflecting the national picture – growing from 0.1 per cent of total vehicle purchases in 2012, to approximately 1.5 per cent of purchases in 2016.

Electric vehicle ownership in the West Midlands is concentrated in the Birmingham conglomeration, which is the local authority area with the highest number of registered keepers in the UK. However, Birmingham is the location for a number of large leasing firms; as a result, it is unclear the extent to which Birmingham has a high number of electric vehicle users in its area.

Several projects have aimed to facilitate electric vehicle use in the licence area:

- the CABLED project demonstrated electric vehicles and gather data on their use in Birmingham (and Coventry),
- Plugged-In Midlands invested in the charging network across the East and West Midlands
- Funding from the Office for Low Emission Vehicles to support the provision of fast/rapid charging facilities for electric taxis in Birmingham

Outside of Birmingham and its urban outskirts, electric vehicle ownership is relatively low in the West Midlands. The remainder of the licence area is relatively rural, which is less suited to current electric vehicles

13.2 Pipeline: electric vehicles

There is no pipeline for electric vehicles.

13.3 Regen's market insights: electric vehicles

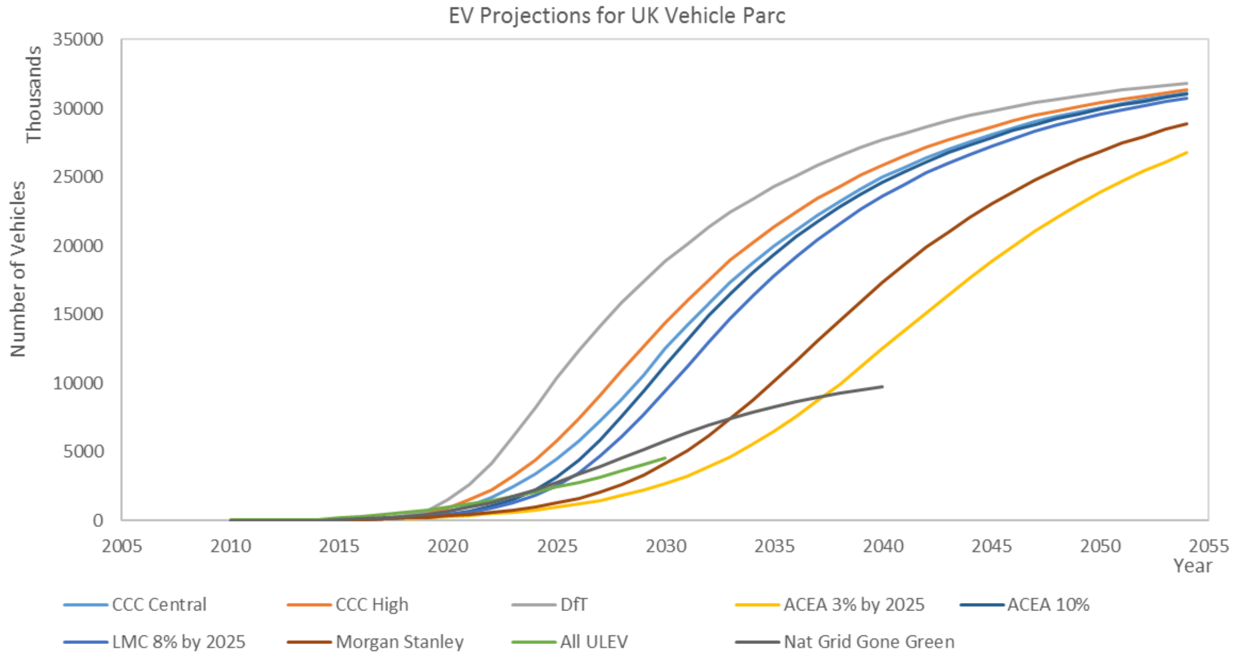
Growth in electric vehicle purchases has been exponential in the UK. Registrations through the national plug-in grant scheme increased from 3,500 in 2013 to nearly 95,000 by the end of March 2017. Over 12,200 electric cars were registered in the UK from January 2017 to March 2017, an increase of 11 per cent on the same period in 2016.

National Grid's 2016 Future Energy Scenarios predicts the number of electric vehicles in Great Britain will grow to approximately 5,814,000 (Gone Green) in 2030. We believe this is an underestimate of the national growth potential[49].

Figure 85 provided by Cenex sets out the range of current predictions for EV growth, with forecasters tending to agree on the level reached by 2055 but disagreeing about the speed at which growth occurs. As a result, there are significant differences between the highest and lowest 2030 predictions.

Car manufacturers are investing heavily in electrification and are bullish in their targets. Volkswagen for example is targeting 25 per cent of its sales to be electric by 2025[50]. Even oil companies are predicting a huge rise in EV sales, with total predicting they will make up a third of sales by 2030[51].

Figure 85: Comparison of projections for EVs in the UK to 2055



Source: Cenex

A number of factors are leading to heightened interest in electric vehicles. We predict that this interest is likely to tip over into major widespread uptake in the next couple of years – and that growth will therefore be strong across all of the potential scenarios.

[49] We note the FES is for Great Britain, whereas other forecasts are for the UK and so will be marginally higher on the basis of also including Northern Ireland.
[50] www.bloomberg.com/news/articles/2017-04-25/electric-car-boom-seen-triggering-peak-oil-demand-in-2030s
[51] www.bloomberg.com/news/articles/2017-04-25/electric-car-boom-seen-triggering-peak-oil-demand-in-2030s

13.3.1 High consumer awareness of electric vehicles

There were 55 different electric car models available in June 2017[52], with the majority of the top manufacturers in the UK now offering an electric vehicle as part of their range and investing heavily in development; so consumers can stick with their trusted brands when switching to electric. Car magazines and media programmes are reviewing electric vehicles regularly as a mainstream purchase.

In addition, people are used to buying cars. This means that compared with solar PV or other forms of microgeneration – which constitute a new type of purchase for most people – electric vehicle purchases do not require people to buy a product they would not normally buy.

13.3.2 Promoting electric vehicles is politically attractive

There is strong political backing for the roll-out of electric vehicles, which are a way of tackling carbon whilst promoting the UK car industry and economic growth. The UK government has committed to making nearly every vehicle in the country zero-emission by 2050 and has developed a multi-stranded funding and policy programme to enable the shift:

- The plug-in vehicle grant opened in 2011, with the aim of supporting the purchase of 50,000 electric vehicles by February 2016. Having achieved that aim, the government announced a £400 million extension to the scheme to fund a further 100,000 vehicles up to March 2018.
- A grant for 75 per cent of home charge point costs is currently available and there is a workplace charging scheme open.
- Nottingham, Bristol, London and Milton Keynes have been awarded shares of £40 million Go Ultra Low City funding to improve their electric vehicle infrastructure.
- The government announced a further £290 million for low emission vehicles in November 2016, including £2.9 million for cleaner taxis in Birmingham, further charging point investment and investment in the development of advanced renewable fuels. A further £109 million is being invested in the development of driverless and low carbon cars.
- Electric vehicles are free to tax, unless they cost over £40,000.

Meanwhile, there is increasing recognition of the polluting nature of diesel cars. ClientEarth won a legal case in November 2016 against the government over claims that current plans for action on air quality issues in our major cities are insufficient[53]. Revised plans are likely to include charges for using diesel vehicles in major cities or in some locations a ban on their use altogether. Diesel's share of the new car market fell from 46.4 per cent in March 2016 to 43.4 per cent in March 2017[54].

13.3.3 Falling costs, improved performance and increased availability of electric vehicle infrastructure

Electric vehicle costs have fallen and continue to fall considerably, as battery prices come down. In addition, Chinese vehicles are entering the global market, at very low costs, driving down prices. Going forward, their impact on the UK market will be determined in part by Brexit trade negotiations.

According to Bloomberg New Energy Finance, electric vehicles will be cheaper to own over their lifetime than conventional cars by 2022, based largely on falling battery prices. Meanwhile, research by Swiss investment house UBS identifies the potential for significant cost reductions for electric vehicles that could

[52] www.nextgreencar.com/electric-cars/statistics/
[53] www.clientearth.org/major-victory-health-uk-high-court-government-inaction-air-pollution/
[54] www.theguardian.com/business/2017/apr/05/uk-new-car-sales-record-tax-rates

be achieved in the short term and predicts lifetime cost parity for EVs as soon as 2018.[55] By 2025, Bloomberg predicts that the upfront costs of purchasing an EV will be lower than conventional vehicles[56].

There are several longer range electric vehicles due to hit the market in 2017, making electric vehicles a more viable option to many as range issues fall away.

The UK's EV charging network is improving. According to Zap-Map, there are over 12,800 connectors at over 4,470 public charging point locations across the UK, with their number growing consistently each month. An increasing proportion of these are rapid or fast chargers. The West Midlands has 772 connectors in June 2017, 6.3 per cent of the UK's total charge points.[57]

13.3.4 Impact of electric vehicles on the network

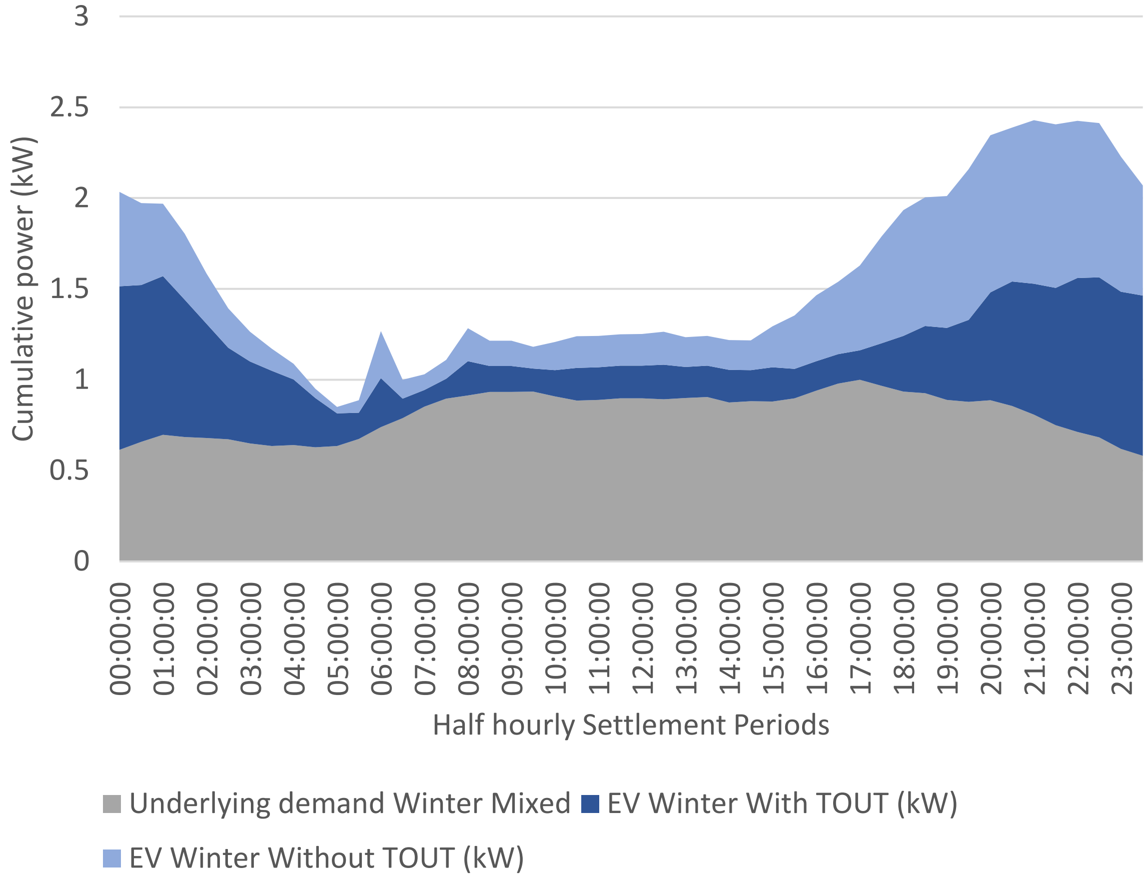
Electric vehicles could have a significant impact on the network. The scale of this impact will depend in part how fast we shift to electric vehicles and in part on whether time of use tariffs and smart chargers are successful in shifting demand for charging away from the evening peak.

A particular concern is that charging electric vehicles will lead to spikes in demand at both a local network level where clusters develop and at National Grid level. Trials are seeking ways to overcome this risk through smart charging approaches, such as Scottish and Southern Energy Power Distribution's project, My Electric Avenue. My Electric Avenue found that around a third of low voltage feeders will need upgrading when 40 to 70 per cent of customers have an electric vehicle at a cost of £2.2 billion. However, upgrades can be avoided by using smart charging technology that allows the DNO to interrupt charging at peak times. WPD's project, Electric Nation, is seeking to expand on the learning from My Electric Avenue.

Figure 86 highlights the potential winter peaks created by electric vehicle use in an average home. A time of use tariff with smart charging reduces the potential peak created by more than half, by spreading the charging period through the night.

[55] www.ft.com/content/6e475f18-3c85-11e7-ac89-b01cc67cfeec
[56] www.bloomberg.com/news/articles/2017-05-26/electric-cars-seen-cheaper-than-gasoline-models-within-a-decade
[57] Data from Zap Map www.zap-map.com/statistics/#region

Figure 86:Winter peaks from EV use with and without a time of use tariff for an average home[58]



Some analysts also predict that there is potential for electric vehicles to offer storage services to the network by charging or discharging when there is a need. We have not yet included this option in our storage chapter as there are significant barriers and we believe it is unlikely to be a standard model by 2030.

13.3.5 New ownership models for electric vehicles

In urban centres, new car ownership models have emerged in recent years, with increasing numbers of people joining car clubs or using Uber taxis rather than purchasing private vehicles. The introduction of driverless cars may further shift ownership models away from private ownership. The impact of new ownership models on electric vehicle sales is uncertain. This is an area for further work as WPD's scenarios develop and more data becomes available.

13.3.6 Low emission alternatives to electric vehicles likely to be more limited in their roll out

Hydrogen vehicles are also being supported by the government, for example through the £2 million Fuel Cell Electric Vehicle Fleet Support Scheme, announced in May 2016 to support investment in hydrogen-powered fleets and the £23 million fund announced in March 2017 to help build the necessary infrastructure.

However, these alternatives are likely to play a smaller role in the low emission vehicle market and tend to be focused on freight vehicles. Electric vehicles' infrastructure is a step ahead in its development and the

[58] Data from Western Power Distribution

technology is more established in both performance terms and in public perception. As a result, there is a degree of first mover advantage for electric vehicles against hydrogen and biomethane vehicles, coupled with technology advantages, such as the ability to re-fuel at home.

13.4 Scenarios: electric vehicles, 2016 to 2030

13.4.1 Factors affecting the scenarios: electric vehicles

We have assumed steady growth in uptake for electric vehicles to the end of March 2018, when the government's plug-in grants are due to end, with only slight variations in the scenarios to that point.

As well as considering the proportion of electric vehicles purchased under each scenario, the total number of new vehicles varies between the scenarios as a result of economic prosperity variations. For example, under Gone Green more cars are purchased in total each year, and a greater proportion of them are electric.

We have not included a detailed consideration of new ownership models or driverless cars in our projections; this is an area that would benefit from further consideration as part of the development of WPD scenarios.

Table 37: Potential factors affecting electric vehicle deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
Significant continued programme of grants for electric vehicle purchases post-2018	●			
Public sector led programme of investment in electric vehicle infrastructure	●		●	
Strengthened legislation restricting the use of diesel vehicles	●		●	
Electric vehicles continue to be exempt from road tax	●	●	●	
Technology costs and development				
Costs continue to fall rapidly due to investment in the UK market	●	●		
Performance of electric vehicles improves rapidly due to R&D investment	●	●		
Availability of finance				
Strong economy means individuals, communities and small businesses have capital available to buy new cars	●	●		
Other factors				
Consumer appetite for electric cars increases, with high profile endorsements	●	●	●	

13.4.2 Scenario summaries

National Grid's 2016 Future Energy Scenarios predicts the number of electric vehicles in Great Britain will grow to approximately 5,814,000 (Gone Green) in 2030. The WPD West Midlands licence area represents approximately ten per cent of UK car sales, which would mean that if a straightforward apportioning of the FES scenario is undertaken, over 580,000 electric cars would be sold in the West Midlands licence area by 2030 under Gone Green.

However, a number of industry predictions are higher than the FES estimates for GB under Gone Green. We estimate that a Gone Green scenario in the West Midlands licence area would result in 1.2 million EV purchases by 2030, 2.1 times higher than the FES estimate would imply.

Even under No Progression, we predict relatively high roll out levels for electric vehicles based on current growth trends. This is because the necessary puzzle pieces for widespread uptake of electric vehicles are already beginning to fall into place, especially as costs fall and the technology improves, as set out in our market insight section.

Table 38: Scenarios summary for electric vehicles in the West Midlands

Consumer Power	Gone Green
• High growth scenario (but lower than Gone Green) • 57 per cent of cars sold in 2030 are electric, with over 775,000 sold by the end of 2030. • R&D investment leads to technology improvements and lower costs • Strong consumer appetite for EVs and strong economy means greater proportion of population (than under NP and SP) has sufficient access to finance • But, no government incentives available and public sector infrastructure investments more limited than under Gone Green – purchases are restricted to more affluent customers, and focused in areas with off-road parking	• Highest overall growth scenario • 70 per cent of cars purchased in 2030 are electric, with over 1.2 million sold by the end of the decade • Significant continued programme of government incentives for EV purchases and ongoing use (e.g. road tax discounts) • High levels of public sector investment in supporting infrastructure, such as charge points in residential areas that enable householders without off-road parking to invest • Strong economy and green ambition drives consumers to invest • R&D investment leads to technology improvements and lower costs • Legislation restricts the purchase and use of diesel vehicles
No Progression	**Slow Progression**
• Lowest growth scenario • 26 per cent of cars sold in 2030 are electric, with just over 380,000 sales. • Growth continues at a steady rate based on historic trends. • The incentive programme is not continued after March 2018. • Fewer customers have the capital available to invest in new cars, and there is a lack of green ambition and so consumers take longer to discard older vehicles. • Costs fall more slowly under this scenario and there is not the added incentive of reduced road tax, or the stick of restrictions on diesel vehicles.	• Medium growth scenario • 48 per cent of cars sold in 2030 are electric, with around 650,000 sold in total over the decade. • Growth is maintained by falling costs, public sector investment, an ongoing government incentive programme and high levels of green ambition. • But, the weaker economy means fewer consumers have capital available to invest and in general they take longer to discard older vehicles • Similarly, the slow economy means there is less investment in R&D and costs are reduced more gradually. • Government incentives are also lower in this scenario than under Gone Green.

13.5 Summary of results: electric vehicles

Figure 87: Number of pure and plug-in hybrid electric vehicle scenarios in the West Midlands licence area

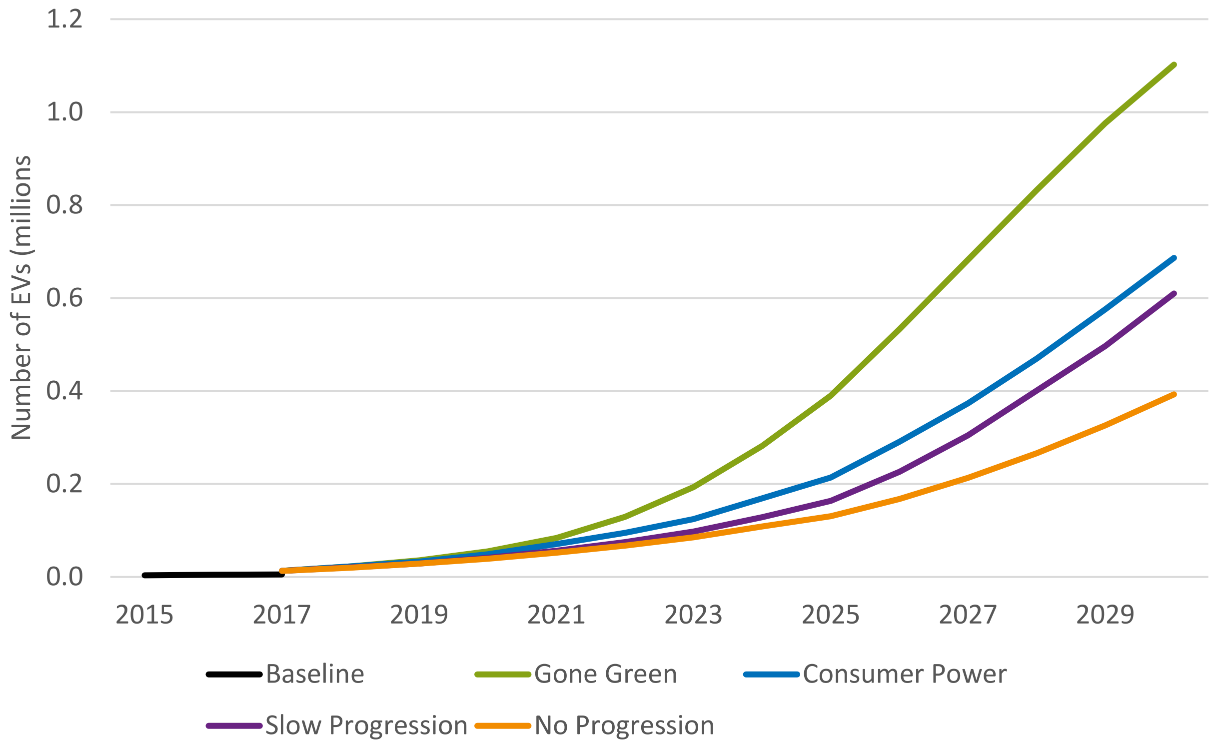


Table 39: Cumulative number of pure electric vehicles and plug-in electric vehicles in West Midlands licence area (thousands)

	Baseline (thousands)	2020 (thousands)	2025 (thousands)	2030 (thousands)
Gone Green	13	55	390	1,102
Consumer Power	13	49	214	686
Slow Progression	13	41	164	610
No Progression	13	39	131	393

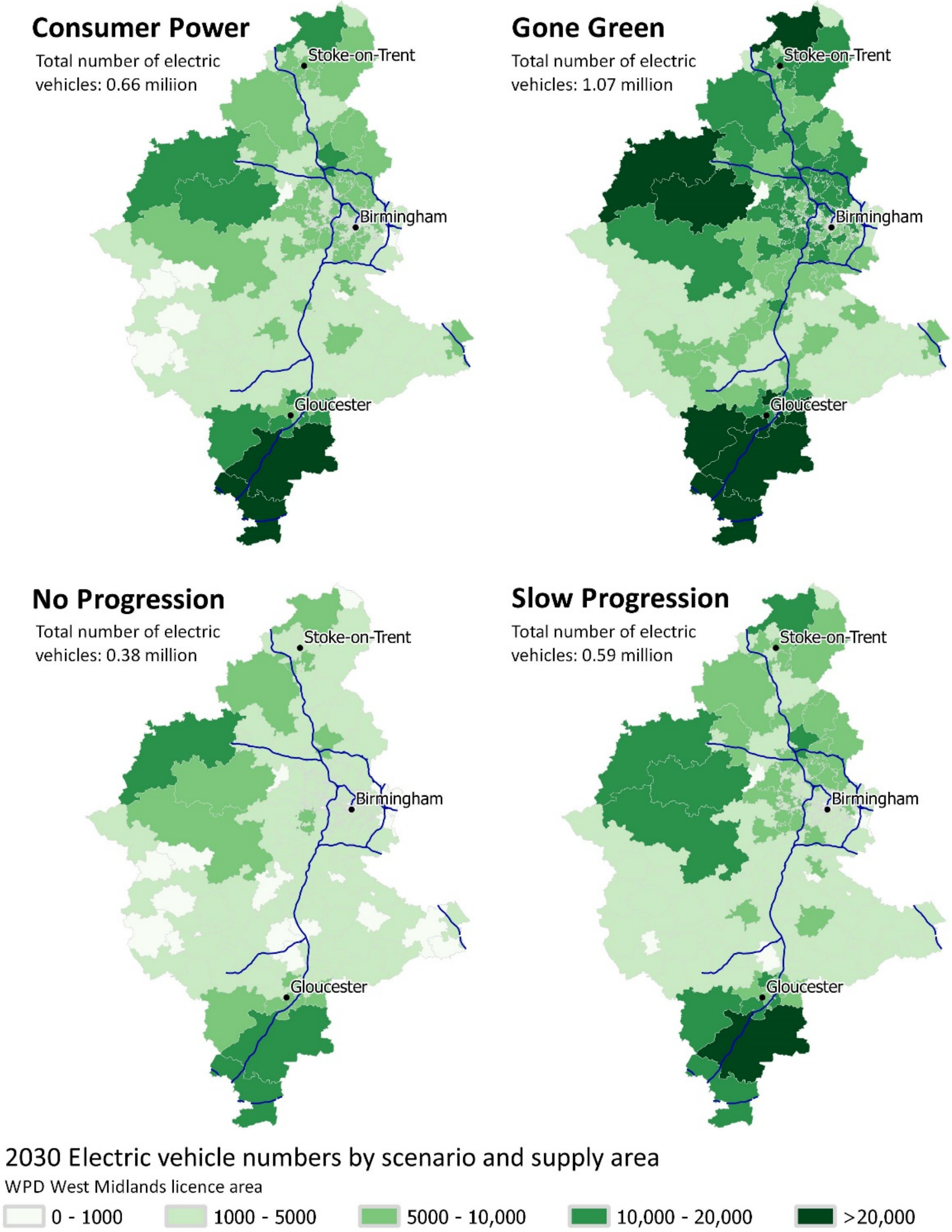
13.6 Geographic distribution by ESA for electric vehicles

As noted above, there is a correlation between current electric vehicle purchases and levels of affluence, although this is weaker than in other licence areas that we have analysed. In distributing the scenario predictions across the ESAs, we have taken this correlation into account.

For the two less prosperous scenarios, Slow Progression and No Progression, we have assumed electric vehicles will be less affordable and so the distribution has been more weighted towards uptake in affluent areas.

For Gone Green and Consumer Power, we have assumed that an electric vehicle is more widely affordable, and so the distribution under this scenario is weighted less towards affluent ESAs and is based on the number of homes in each area.

Figure 88: Geographic distribution of electric vehicles by scenario in 2030



14 Growth in residential and non-residential development

New housing or commercial developments can have a significant impact on demand on the distribution network at a local level. To develop scenarios for the impact of development on demand at an ESA level we undertook an assessment of what development is planned.

14.1 Methodology

The methodology we followed it set out in the diagram below. Based on feedback from local authorities to the East Midlands scenarios, we have added a process of reviewing the data in local plans with local authorities to ensure up to date information and local insight is captured.

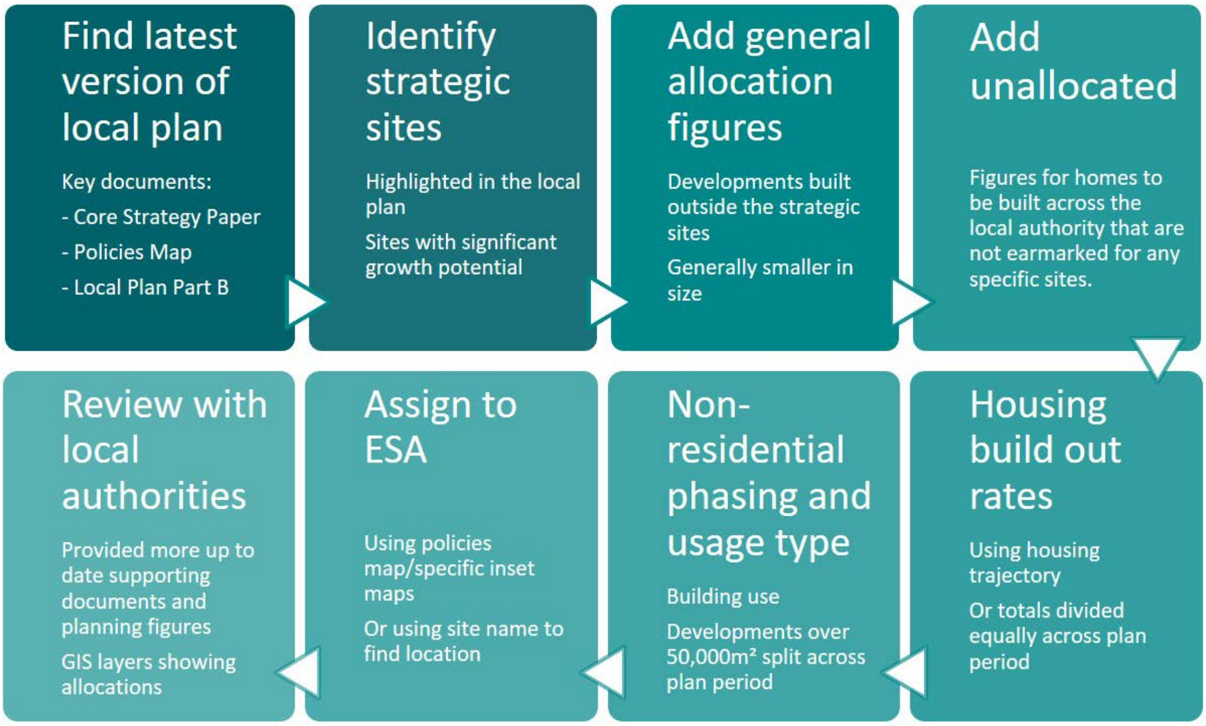


Figure 89: Summary of data collection methodology for residential and non-residential sites

14.1.1 Data sources

The primary data source used was the local plan. Produced by individual local authorities, each local plan typically provides a core strategy paper which is the main document in the local development framework (LDF) and additional supporting documents, such as annual monitoring reports and policies maps identifying potential sites. Some local authorities have produced Joint Core Strategy (JCS) papers with one local plan covering a wider area, such as the Black Country JCS and the Gloucester, Cheltenham, Tewkesbury JCS.

These documents normally provide an outline plan of where developments are likely to take place and varying levels of detail on the building type and end use.

If the documents were not available, outdated or too vague due to the stage of the local plan process, we used additional documents which provide the evidence base and monitor the local plan including, the strategic housing land availability assessment (SHLAA) and Employment land assessment (ELA), as well as annual monitoring reports. Such documents are updated regularly for each planning authority and identify available sites within a local authority area that have the potential for housing and non-residential development.

14.1.2 Types of development

14.1.3 Development sites

We have categorised development sites into two main types of development sites: strategic sites and general allocation sites.

Strategic sites are highlighted in local plans as areas of development with significant growth potential. Each site is given a specific location within the policies map. There is no established single definition for what constitutes a strategic site, however, generally these are large developments; either housing led or mixed-use regeneration projects.

General allocation covers additional housing or non-residential developments to be built outside of the strategic sites. These developments tend to be smaller sites with less specific location details.

14.1.4 Unallocated homes

Local plans generally contain targets for new homes to be achieved during the plan period. This target is made up of planned development sites and, in some cases, also includes 'unallocated' homes to be built across the local authority that are not earmarked for any specific sites.

Where unallocated housing was identified, the quota was distributed across the local authority's ESAs, based on geographic area and any additional information in the plan as to where it could be focused.

14.1.5 Information gathered about development sites

The available data for each development site was reviewed to where possible obtain:

- An estimate of the number of residential units to be built.
- The site area (m^2) of non-residential property to be built.
- Any indication of phasing, amount of property to be built per year etc.
- The site's location and the relevant ESA/ESAs it would connect to.
- Status of the local plan.
- The category of planned end-use for non-residential sites/areas of sites. The non-residential categories provided by WPD are listed in Table 40 and cover 15 different electricity profiles.

Table 40: Non-domestic profile categories

Non-domestic demand profile categories	Equivalent General-Use Classes Order
Factory and Warehouse	B8, B2
Government	D1
Hospital	C2
Hotel	C1
Hypermarket	A1
Medical	D1
Office	B1
Other	
Police	D1
Restaurant	A3
Retail	A1
School & College	D1
Shop	A1
Sport & Leisure	D2
University	C2

14.1.6 Notes on phasing

Where information on phasing of developments was not available, domestic build out figures were spread evenly across the plan period: assumed figures have been highlighted in the dataset provided to WPD.

For non-residential developments, phasing information was very limited. We estimated how the development would be phased by applying the following considerations:

- The detail about what non-residential amenities were proposed. For example, a single school must be built in one go, not phased.
- The size of the non-residential amenities being proposed. Large scale retail or offices are likely to be built in phases.
- For mixed use sites, the length of time the residential units would be built over. This was assumed to represent the total time available to build out the non-residential buildings.
- Any development over 50,000 m^2 was split into build slots, either two or three depending on the plan end date and the size of the development.

14.1.7 Notes on planned end-use categories for non-residential sites/areas of sites

Each non-residential site/area of a site was assigned usage category/categories. Where possible, this was based on details in each local authority's local plan.

Where usage information was not available, we made assumptions about site use based on other developments of a comparable size.

Where mixed developments are planned we split the area given evenly into the types of usage indicated. Where plans indicated numbers of buildings (e.g. 2 schools, 1 community hall) rather than site areas, we used information from other plans to estimate the likely site area in square metres.

Floorspace was given for some developments and where this was identified we have recorded the figure in the dataset notes. However, for the majority of developments identified by local authorities only a site area is given, usually in hectares at this stage of the planning process. Square meterage is only given once developers submit a site specific planning application. Conversion between site area and floor space can vary significantly depending on usage type and site location. For example, an office development in a high density city location would have a higher plot ratio compared with an industrial site on the outskirts of a town. Therefore, we have provided site area figures as these are the most accurate details currently available.

14.1.8 Notes on the site's location and the relevant ESA/ESAs

The location of each domestic and non-residential development was located spatially using Google maps, then assigned to the relevant ESA using the site name, alongside any specific strategic site maps or policies maps included in the local plan.

On several occasions, a development was either large enough to straddle two or more ESAs, or there was insufficient location data to be sure of its exact location where it was close to a boundary. Where this was the case, the development was proportionally allocated to each relevant ESA based on area.

14.1.9 Notes on the status of the local plan or SHLAA

We recorded whether the information about the site was taken from a draft, published or adopted local plan. For sites where the information was drawn from SHLAA documents or monitoring reports, if possible we noted whether they had planning permission in place or not.

14.2 Review with local authorities

To ensure we have gathered the most up to date information on future developments we sent the data collected to planning and economic development officers in the 36 local authorities across the West Midlands licence area.

From this process, several local authorities including Birmingham and Solihull sent back GIS shapefiles of allocated sites, this made identifying which ESA/s development will be located in a much quicker and more accurate process. Several planning officers also updated figures themselves or provided a spreadsheet version of housing planning monitoring data.

Contacting the local authorities individually also highlighted how in some areas the local plan core strategy can be out of date quite quickly, due to the lengthy examinations process. Although the current local plans remain useful for identifying large strategic sites, the detail of SHLAAs, 5-year supply documents, ELAs and annual monitoring reports is often necessary to capture the most up to date information and the full picture. In particular, these documents often include details on the smaller 'off plan' sites, which are not part of the larger allocations.

14.3 Limitations

Sites within adopted local plans are likely to go ahead. Adopted local plans have passed through the Examination in Public process, by which a Planning Inspector assesses whether the policies are sound (justified, effective and consistent with national policy). Sites that are in adopted plans and are, therefore, supported by the Local Authority, go through an extensive consultation process and have a detailed technical evidence base. They do still need developers to want to invest in them and to submit suitable planning applications and some elements of the proposed development are likely to vary from the plans set out in the local plan, e.g. building usage.

Table 41: Breakdown of the local plans analysed by stage their local plan was at when assessed

Stage of local plan	Number of local authorities
Draft plan	11
Adopted	25

The majority of local authorities had an adopted local plan, however, some were several years out of date and even those published recently did not represent the latest development plans, due to the lengthy consultation process. From the QA process with the 36 local authorities in the West Midlands, it became evident that the supporting documents or monitoring reports had often superseded local plan figures. This evidence based is updated annually and provided the necessary detail and latest information required.

Although the SHLAAs and ELAs offer the most up to date figures, many of the sites listed in these documents are less likely to go ahead than those allocated in local plans as they have not necessarily gone through an extensive consultation process with the public and subsequent examination by the planning inspectorate. Therefore, we have where available recorded the stage of planning for each development, as strategic sites with planning permission granted or sites which are part of an allocation in a local plan have the greatest likelihood of proceeding, whilst sites simply identified as available for development are less certain.

For non-residential developments the employment land assessment has often been the most up to date resource provided by local authorities, this is useful for capturing large sites consisting of office and industrial space. However, information on the growth of other non-residential usage such as retail and education in these documents is often quite limited.

14.4 Scenarios: domestic and non-residential demand, 2017 to 2030

14.4.1 Factors affecting the scenarios: housing and non-residential demand

The key factor affecting the growth rate of new developments is the economic environment. The level of green ambition will have little relevance to the number of developments – although it may change the energy demand of a property (the demand profile of housing and non-residential properties is outside the scope of this report). We have, therefore, combined Gone Green and Consumer Power into one scenario that assumes high growth rates for new homes and non-residential developments due to a better economic environment. We have combined Slow Progression and No Progression scenarios into a second scenario and applied a lower growth rate.

14.4.2 Scenario 1 - High economic growth: Consumer Power & Gone Green

Under this scenario, we assumed that build out rates for domestic and non-residential development matched the targets given in the local plan.

14.4.3 Scenario 2 - Slow economic growth: No Progression & Slow Progression

The following assumptions were made, setting out a slower pace of development:

- Strategic sites: we assumed that all strategic sites are likely to go ahead, regardless of economic climate, but are likely to suffer delays. The delay period was based on the development stage of the local plan:
  - Sites in adopted local plans or sites in a SHLAA, AMR with planning permission in place: delayed by 5 years
  - Sites in published local plans: delayed by 8 years
  - Sites in the draft local plans or sites in a SHLAA without planning permission in place, delayed by 10 years
- General allocation: for non-strategic sites, the planned target figure has been multiplied by 64 per cent, to reduce the total housing built in the slow economic growth scenario. This percentage reduction was calculated by assessing total completed build figures in the UK compared with anticipated figures for the years 2008 to 2010 (following the economic recession).
- Unallocated homes: as with general allocation, the planned target figure has been multiplied by 64 per cent.

14.5 Findings

14.5.1 Overall development

In total, the higher economic scenario would see 215,467 houses developed by 2030 in the licence area. An additional 1,827 ha of non-residential development is also anticipated up to 2030 using scenario 1.

The lower economic scenario (scenario 2) delivers 138,805 houses and a further 947 ha of non-residential development by 2030.

Table 42: Total figures for domestic and non-residential development up to 2030

	High economic scenario		Low economic scenario	
	Residential (number of homes)	Non-residential (ha)	Residential (number of homes)	Non-residential (ha)
2020	62,394	358	22,362	22
2025	158,112	1,309	74,388	301
2030	215,467	1,827	138,805	947

Across the 36 local authorities, 164 strategic mixed-use developments were identified. A further 85 strategic sites have been identified for office or industrial use only. General allocation sites total 86,178 for housing and 186 ha for non-residential development. The largest strategic sites identified across the licence area include the Langley Sustainable Urban Extension in Birmingham with up to 6,000 homes and the North West Cheltenham Urban Extension with 4,285 homes. There are 11,582 unallocated homes planned in the licence area up to 2030.

14.5.2 Domestic developments

Table 43 shows the 10 local authorities in the West Midlands licence area with the highest amount of new housing to be added by 2030. Housing development is concentrated around areas with high population density, such as: Birmingham, Worcester and Solihull. Other local authorities with high future housing growth are either close to existing large conurbations or have a considerable number of strategic sites allocated within the local plan.

Table 43: Top 10 local authorities for planned new homes in the West Midlands licence area

Local authority	Scenario 1 total number of homes (up to 2030)	Scenario 2 Total number of homes (up to 2030)
1. Birmingham	28,917	16,742
2. Worcester	24,074	15,241
3. Shropshire	13,569	8,982
4. Solihull	11,600	7,267
5. Herefordshire	11,242	8,070
6. Stroud	11,239	7,373
7. Tewkesbury	10,582	3,408
8. Sandwell	10,057	8,845
9. Stafford	7,990	5,133
10. Malvern Hills	6,783	4,742

The graph in Figure 90 shows a peak early on for the high economic scenario as strategic sites with more certainty of going ahead are often focused in the initial stages of the plan period. In addition, the data we have included from SHLAA or annual monitoring reports often only covers a 5-year trajectory, offering more certainty of what will happen in the near term. However, the further you project the amount of robust data available reduces, particularly for monitoring reports based on planning applications, hence the decline towards 2030. In a high growth scenario further development sites could be expected to come forward towards 2020 – however we have not included any assumptions about development that is not yet identified.

Scenario 2 shows the decreased level of growth once we have applied the percentage reduction figures to general allocation in a slower economic climate. The growth rate for scenario 2 gradually picks up later on due to the staggered rates of development applied to the strategic sites or sites with planning permission identified in supporting documents, delaying construction by 5 – 10 years.

Figure 90: Annual total for housing figures in the West Midlands licence area

14.5.3 Non-residential development

Table 44: Top 10 local authorities for planned non-residential development

	Local Authority	Scenario 1 total non-residential (ha) up to 2030	Scenario 2 total non-residential (ha) up to 2030
1	Birmingham	248	105
2	Solihull	188	120
3	Shropshire	143	33
4	Telford and Wrekin	112	46
5	Worcester	104	59
6	South Staffordshire	96	72
7	Tewkesbury	87	10
8	Newcastle-under-Lyme	79	49
9	Forest of Dean	67	56
10	Wychavon	65	45

The table above shows the local authority of Birmingham has the highest amount of planned non-residential development. This local authority has 15 strategic sites over 5 ha (50,000 m²), including Peddimore a 71 ha employment site, which aims to create up to 10,000 jobs and accommodate major national and international investment in the industrial and logistic sectors. This site links with the Langley Sustainable Urban Extension in Sutton Coldfield which aims to provide an additional 6,000 homes.

A significant proportion of the non-residential developments in Solihull are planned at the UK Central Hub site on the outskirts of Birmingham, near the airport and NEC. The Hub consists of an area surrounding the proposed HS2 station site and offers significant potential for economic growth and housing development. The existing site has significant land assets in a strategic location with large commercial and leisure sites already in operation.

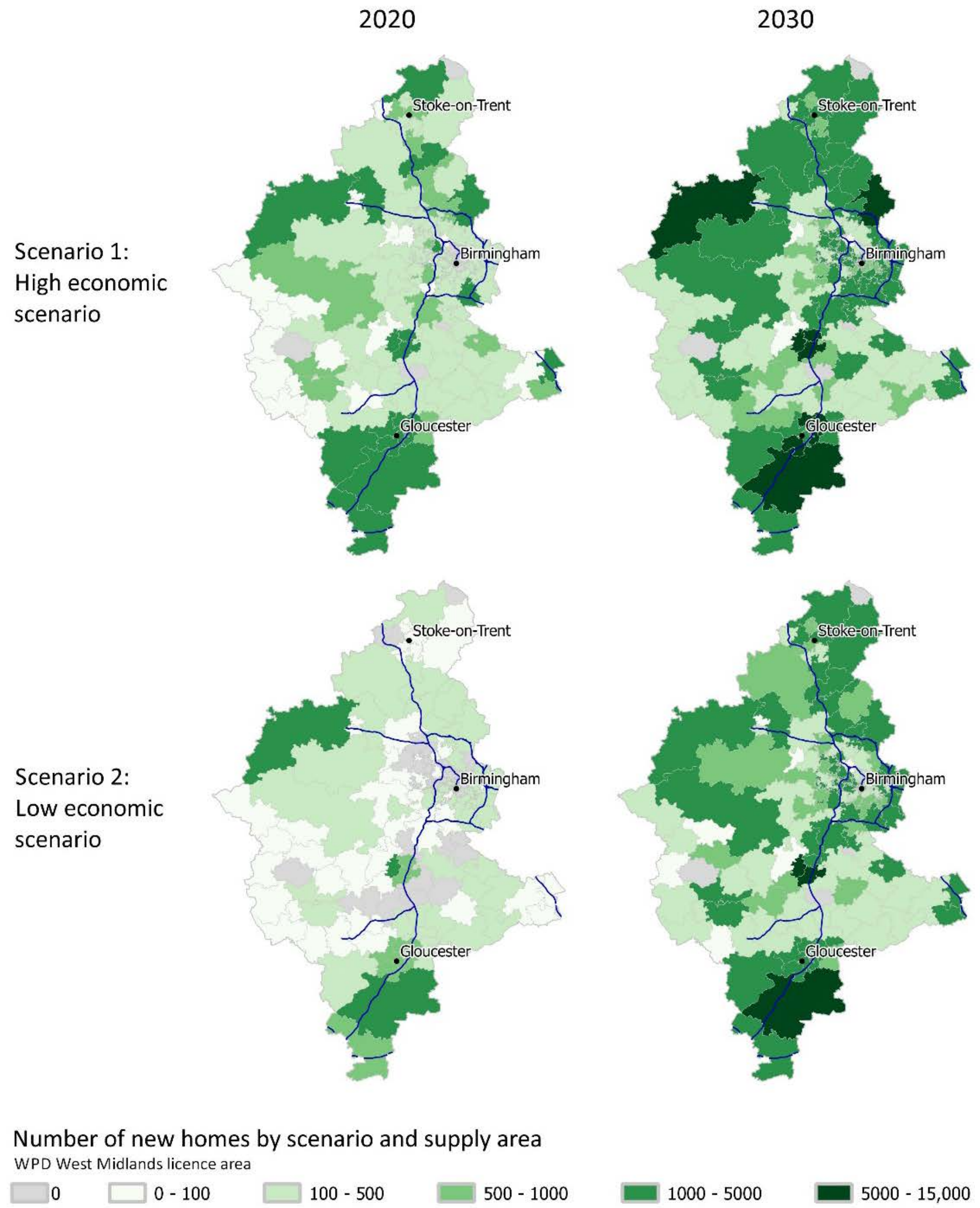
The remaining local authorities have a combination of multiple strategic sites and general allocation to provide the non-residential development anticipated. Across the licence area an additional 1,861 ha of employment land has been allocated for B1, B2 and B8 (office, factory and warehouse) uses. The development sites also provide over 145 ha of retail development.

14.6 Geographic distribution by ESA

Figure 81 shows the distribution of total housing figures for each ESA in the licence area. Naturally the largest growth is focused around areas with high population density or in the local authorities surrounding the major cities. The exception to this is the Birmingham, Solihull, Worcester area, due to the high number of ESAs across the West Midlands conurbation total figures to the ESAs have been distributed across those ESAs.

Figure 83: 2020 and 2030 new housing distribution by supply area in the high and low economic scenarios

The local authorities with high existing domestic demand in the West Midlands overlap with the local authorities where the highest amounts of residential growth are planned. Birmingham, Worcester,



Shropshire and Solihull are the top areas for future residential development, this follows existing trends, as these local authorities are in the highest band for electricity sales per meter (350+ GWh).

Figure 84 shows the distribution of non-residential development for each ESA in the licence area. The largest developments cluster around existing commercial sites and are often strategic economic growth area, such as the Peddimore and UKC Hub sites in Birmingham and Solihull.

Due to the number of strategic sites identified for employment land, the phased delay to development of such sites in scenario 2 results in particularly low figures up to 2020. These sites often have very long lead in times and are heavily dependent on the economic climate to gather substantial investment. Therefore, the majority of sites identified in the local plans are anticipated for development beyond 2020.

Figure 84: 2020 and 2030 non-residential development distribution by supply area in the high and low economic scenarios

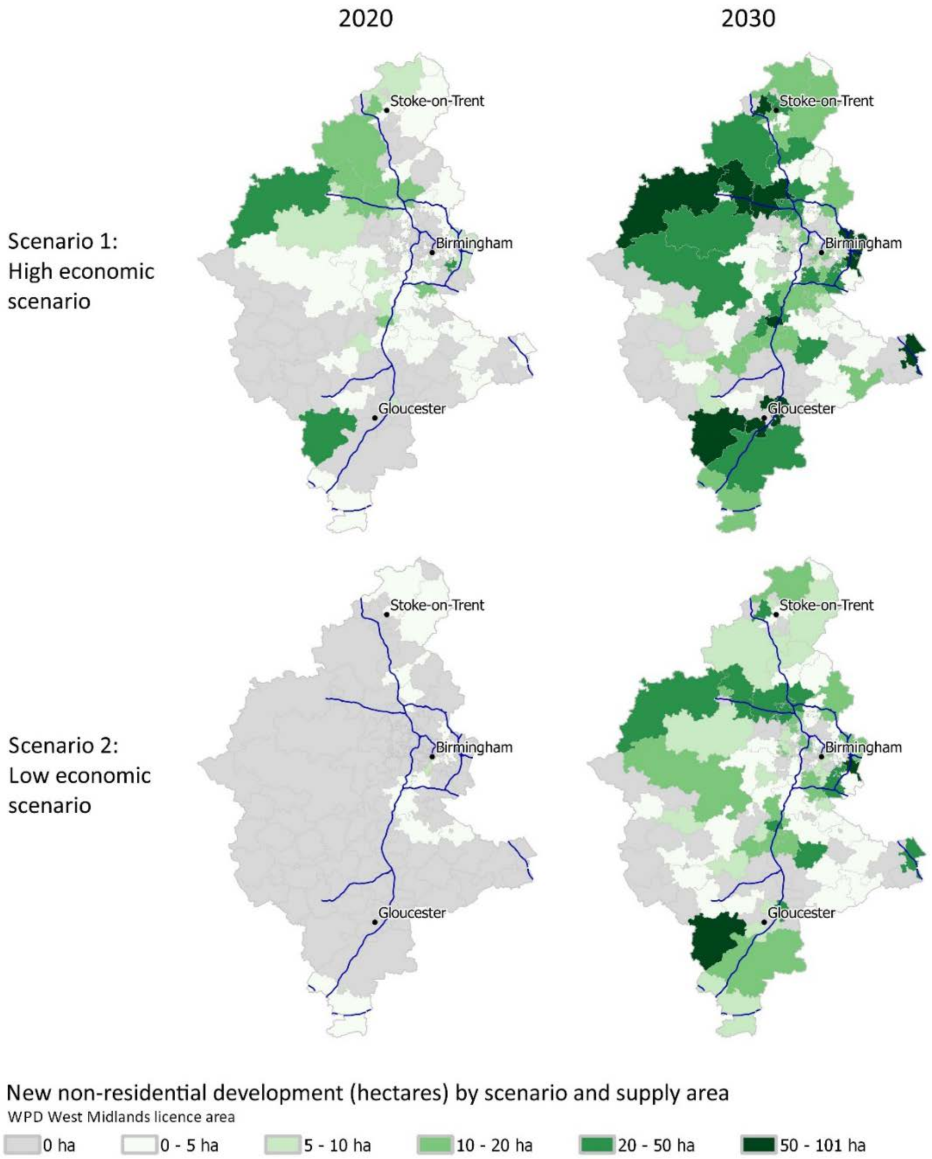


Figure 81 illustrates the growth in commercial and industrial developments across the West Midlands licence area. Of the largest 20 commercial and industrial sites 18 are focused around the main motorway arteries of the M5, M54 and M6, where key existing infrastructure and accessibility allow for larger C&I sites.

Overall, total figures for commercial and industrial development in the West Midlands are lower than totals in the East Midlands licence area. There are several major sites across the West Midlands conurbation (includes Birmingham and Wolverhampton), which make up a significant portion of the planned developments and are capitalising on the opportunity provided by the HS2 development. Additional large developments are anticipated near established commercial sites and existing transport infrastructure.

Figure 85: 20 largest non-residential sites in the West Midlands licence area (hectares)