Distributed generation and demand study

Technology growth scenarios to 2030




East Midlands licence area

June 2017

Final

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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
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
LCOE	Levelised Cost of Energy
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
ToUT	Time of Use Tariff
WMS	Written Ministerial Statement

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Section 1

Introduction and methodology

Background to the project and methodology for a scenario based approach to the forecasting of renewable energy technologies at a local level.

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1 Introduction

This report focuses on Western Power Distribution’s East 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 five years. By late 2016, 25 per cent of power in the UK came from renewable sources, with a large number of generators connected to the distribution network. 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 nearly 700,000 renewable electricity generators in England.

Although current deployment rates for renewable energy have slowed significantly for most technologies as a result of government subsidy reductions and policy change, it is widely accepted that continued rapid change in our energy system is inevitable. Distributed generation costs are falling and transformational technologies such as storage and electric vehicles are becoming viable.

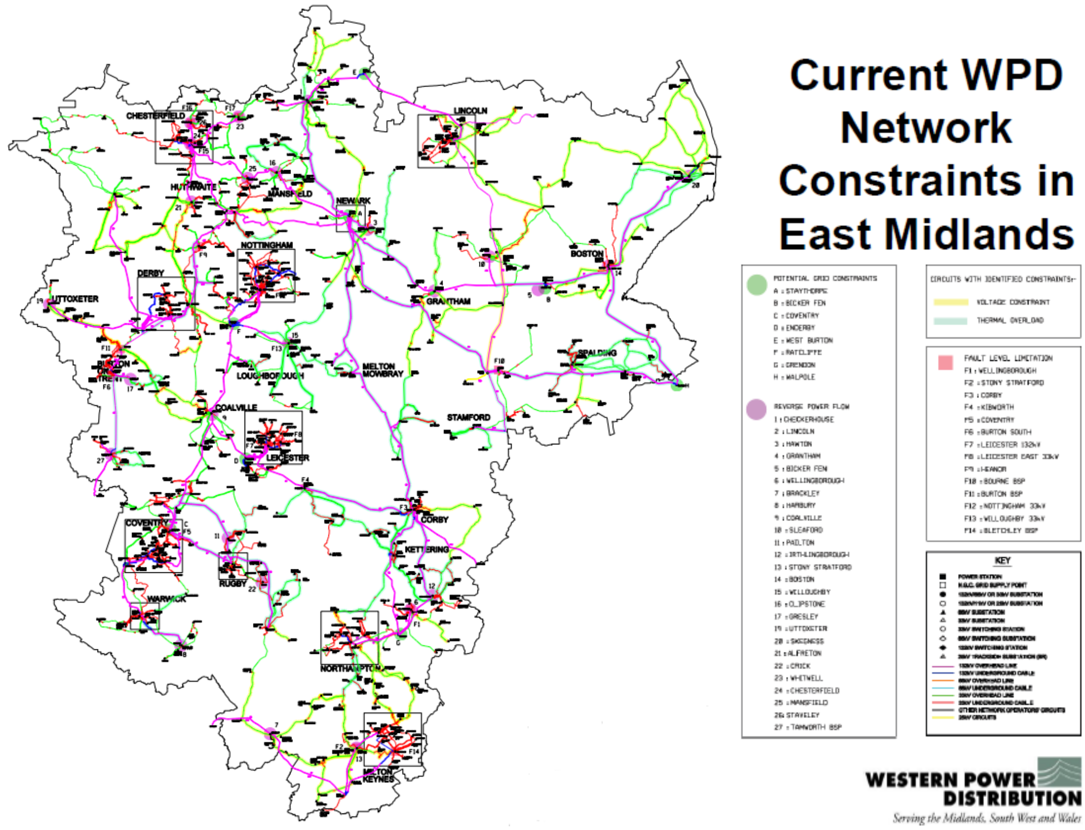
Western Power Distribution and the other Distribution Network Operators (DNOs) have had to adapt to high levels of distributed generation capacity connecting to their network. In the East Midlands there are over 3,000 MVA of projects connected to distribution network, with double that again with connections either accepted-not-yet-connected or offered-not-yet-accepted.

Table 1: WPD’s 2016 connections by technology in the East Midlands licence area

Generator type	Connected [MVA]	Accepted not yet Connected [MVA]	Offered not yet Accepted [MVA]	Total [MVA]
Photovoltaic	1,147.0	1,099.4	33.5	2,279.9
Wind	562.3	234.0	2.2	798.6
Landfill gas, sewage gas, biogas and waste Incineration	211.8	85.2	61.9	358.9
CHP	129.2	33.5	18.1	180.7
Biomass and energy crops	66.2	146.5	0.0	212.7
Hydro, tidal and wave power	1.4	0.3	0.0	1.7
Storage	0.0	292.8	311.2	604.0
All other generation	946.4	972.2	1,017.1	2,935.7
Total	**3,064.4**	**2,863.8**	**1,444.1**	**7,372.3**

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 East Midlands licence area (as at December 2016)



Current regulations require network reinforcement costs caused by generators 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 provided, 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 includes 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).

In order to address constraints on their networks, and in preparation for taking on a DSO role, Ofgem has asked DNOs to undertake scenario based planning of future investment strategies to address the potential impacts that further distributed generation, demand and storage growth will have on their networks.

WPD has recognised that, in order 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.

1.2 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:

- Currently 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 sub-transmission network that may require 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 East Midlands licence area, under four future scenarios from 2016 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 2016-2030 by technology type for each Electricity Supply Area (ESA), including:

- Current (2016) 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 heat pumps and electric vehicles from 2016 to 2030, building on the FES
- Scenario analysis of potential future growth in new development (residential, commercial and industrial)

Where appropriate, GIS based maps have also 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 East Midlands licence area. We have also analysed projects connected to or that would connect to four ESAs outside of the licence area due to the impact these areas have on the East Midlands network. The areas are: Epwell, Banbury, Bloxham, and Buxton. We have also assessed areas in UKPN's Eastern Network licence area which have an impact of the East Midlands network.

Specifically, we have examined potential growth in:

- Solar PV
- Onshore wind

- Hydropower
- Offshore energy that connects to the distribution network (wave, tidal stream and offshore wind)
- Energy from waste
- Anaerobic digestion

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 East 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
- Gas and diesel 'peaking' plant

We have not considered any projects that connect directly to the National Grid electricity transmission network, including, in particular, large scale biomass electricity generation or CHP, large scale gas powered turbines, nuclear, tidal lagoons and transmission network connected offshore or onshore wind farms.

Demand

We have considered the impact of growth in the use of electric vehicles and heat pumps. These technologies have the potential for rapid growth that could have disruptive impacts on the electricity network.

The East Midlands is expecting to see high levels of demand growth in the near future as a result of planned residential, commercial and industrial development. As a result we have undertaken a detailed study of local plans to produce an assessment of potential commercial and residential development growth in the area. Overall trends in power demand on the network are outside the scope of this report.

Electricity storage

Electricity storage is identified by BEIS and Ofgem as having a key role in the development of a smart, flexible energy system. In the East Midlands, there are nearly 300 MVA of battery storage projects with an accepted-not-yet-connected connection offer and a further 311 MVA offered-not-yet-accepted.

We have, therefore, refined our approach to scenarios for the development of electricity storage and considered five emerging business models, based on the analysis in our paper "Storage: Towards a Commercial Model":

- 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

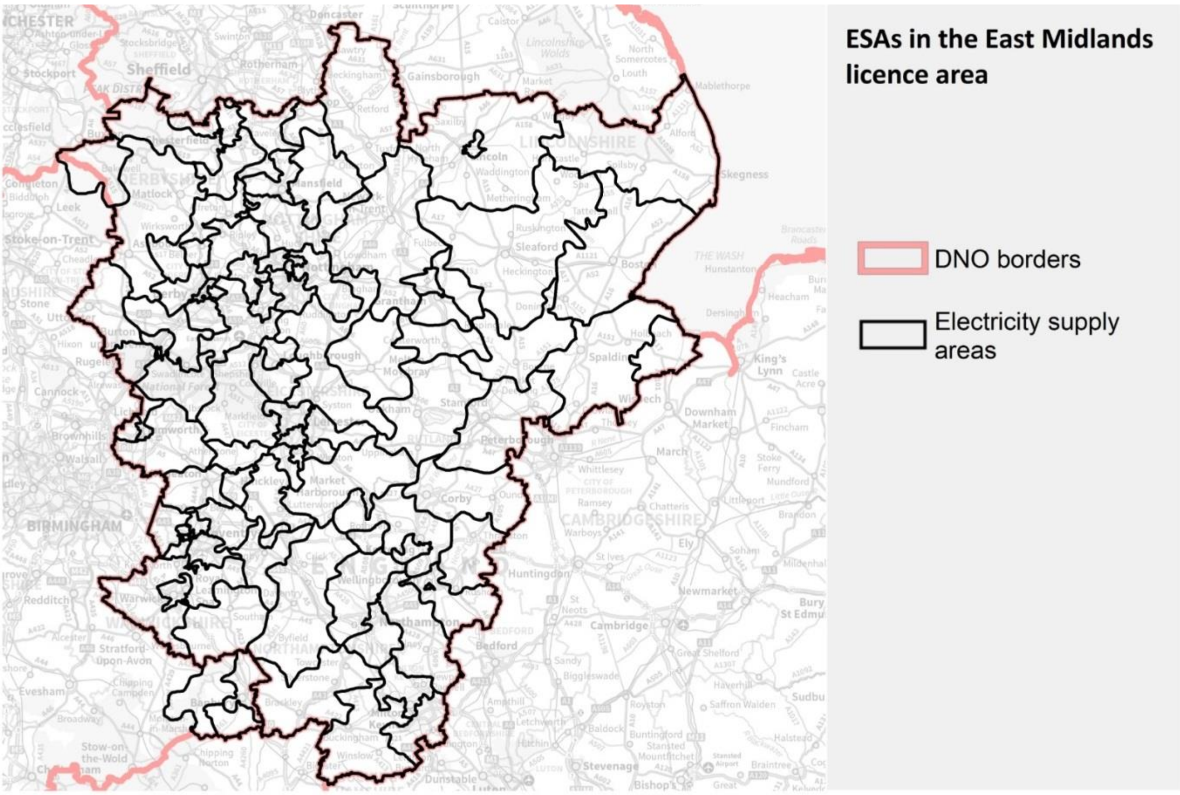
2.2.2 Geographic scope and Electricity Supply Areas (ESAs) mapping

The assessment scope is the East Midlands licence area, building on the methodology applied in the South West and South West 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; 88 ESAs have been created. We have considered growth in four ESAs in the West Midlands licence are due to the impact these areas have on the East Midlands network: Epwell, Banbury, Bloxham, and Buxton, plus areas in UKPN's Eastern

Figure 2: Electricity supply areas in the East Midlands licence area

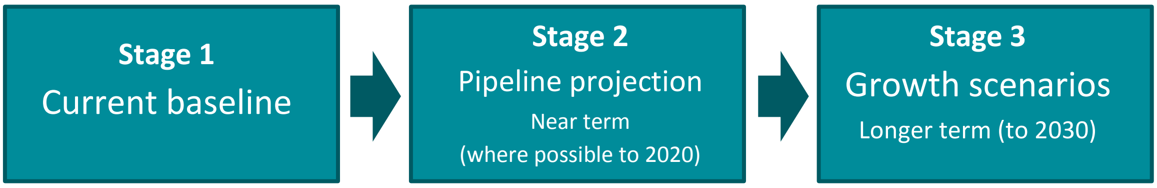


Network licence area.

2.3 Summary of methodology

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

Figure 3: This study's methodology in stages



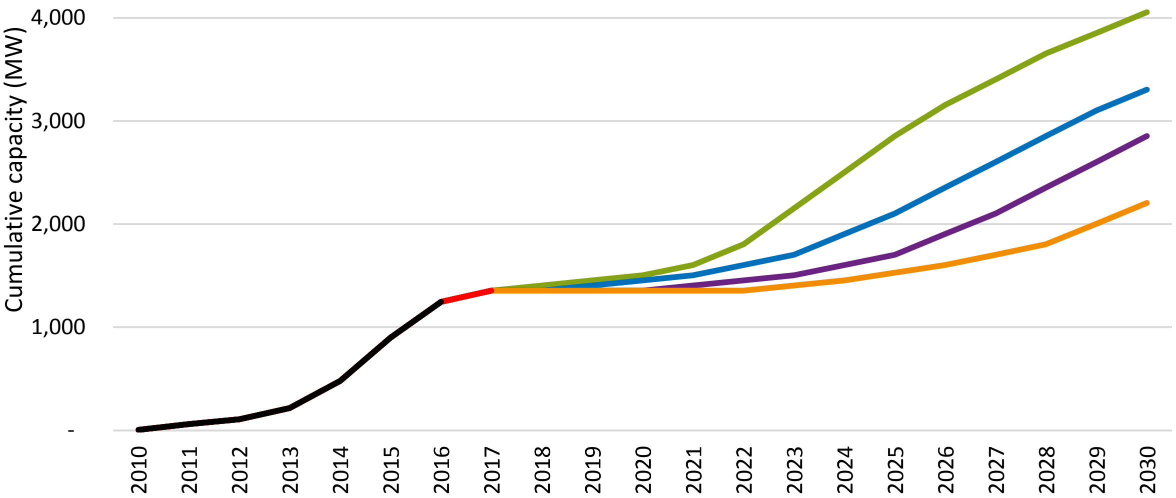
- Stage 1 - A baseline assessment – taken at the end of September 2016. The baseline has a high degree of accuracy as it is based on WPD's database of connected customers, reconciled with Regen's project database and further desktop research to address errors and inconsistencies.

- 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.

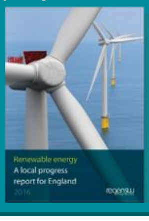
- Stage 3 - A scenario projection – out to 2030. The scenarios are based on the Future Energy Scenarios (FES), assessed and interpreted to take into consideration the specific local resources, constraints and market conditions. To inform our market insights for each technology, we have undertaken detailed 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 in the East Midlands to gather locally specific views and information.

Figure 4: Illustrative graphical representation of methodology

Current baseline up to 2016	Pipeline 2016 -2017/2020	Growth scenarios 2020 - 2030



Current baseline
WPD's connection data and Regen's extensive renewables project database



Pipeline projection (to 2017/2020)
Analysis of current projects in the planning system and with accepted connection offers for large scale technologies.

Growth scenarios (to 2030)
Growth scenarios based on National Grid's FES - applied at a local level.

Gone Green
Consumer Power
Slow Progression
No Progression

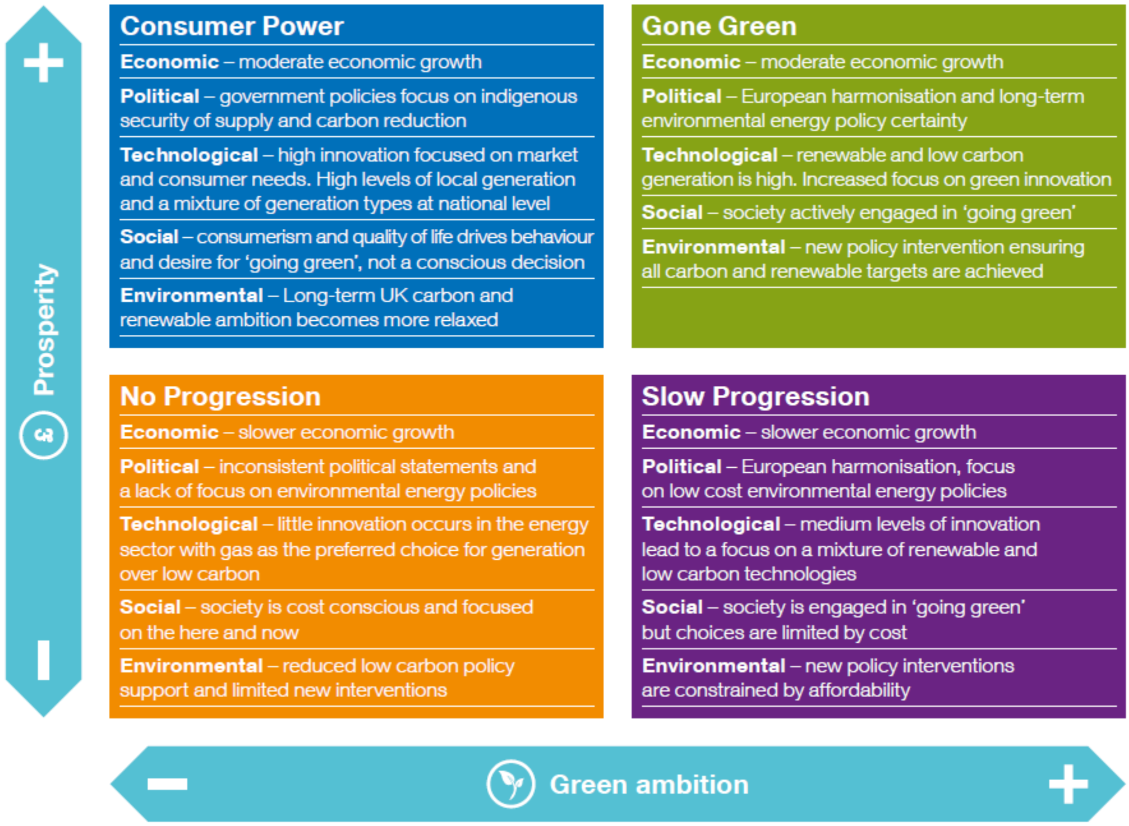
2.4 The scenarios

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 5: National Grid Future Energy Scenarios



In applying the scenarios, we have interpreted the scenarios for the East 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 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 technologies.

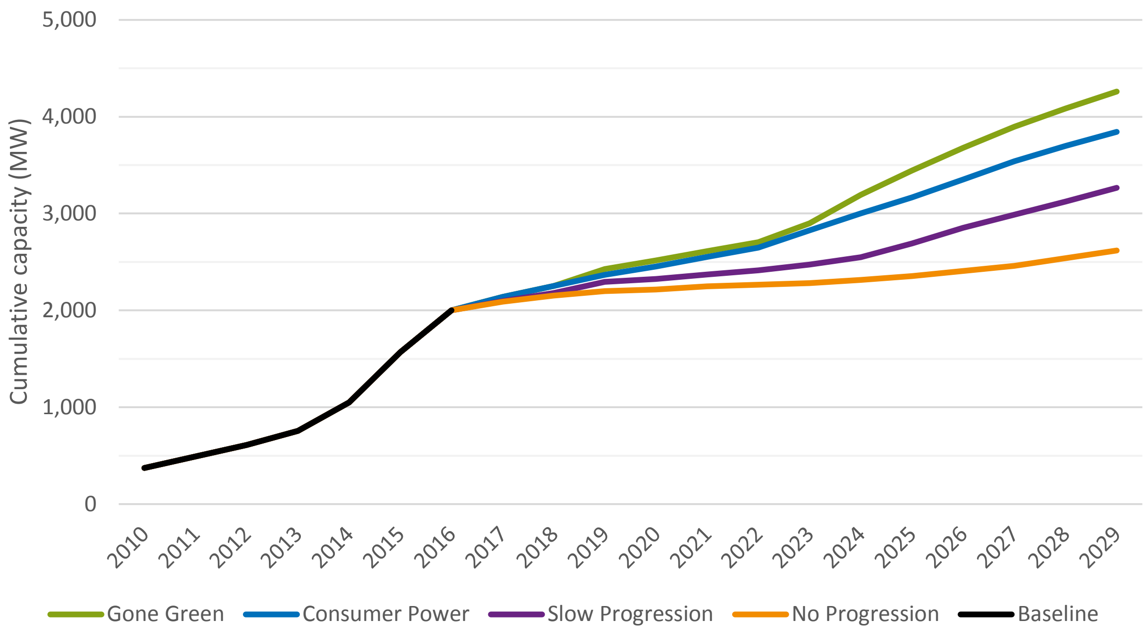
The Slow Progression scenario features a strategic approach to renewable energy by government, but in a poor economic environment which means there is a lower government budget for support, less investment capital available and fewer technological innovations. Government policy is focussed on the lowest 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 distributed generation is slow for all scales and technologies under this scenario.

2.5 Summary of results

The summary results of the distributed renewable electricity generation scenarios are shown in the tables below and show a growth from a current renewable electricity baseline capacity of circa 2.0 GW to circa 4.3 GW by 2030 under the most ambitious Gone Green scenario. Growth estimates for the other scenarios, Consumer Power, Slow Progression and No Progression are lower overall. However, even under the lowest No Progression scenario, there is an expected growth pathway to 2.6 GW of distributed renewable generation capacity by 2030.

Figure 6: Distributed renewable electricity generation capacity growth by scenario in the East Midlands licence area



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 Onshore wind

3.1 Baseline: onshore wind growth to 2016

3.1.1 Large scale wind baseline

There are 72 large scale wind projects in the licence area (500 kW and above), totalling 352.7 MW. Large scale projects are clustered in the south of the licence area in a few local authority areas. Outside of these areas, projects are relatively dispersed with large areas without any projects. Only 20 out of 56 local authorities have large scale wind projects in the licence area.

Daventry, Kettering, Harborough and South Holland have multiple large scale projects in their areas totalling over 30 MW in each area. The largest project in the area is 26 MW Bicker Fen near Boston, owned by EDF. The average size of a large scale project (over 500 kW) in the licence area is 9 MW.

Table 3: Top 10 local authorities in East Midlands licence area for large scale wind

Local authority	Number of projects	Large scale installed capacity (MW)
1. Daventry	14	69.9
2. Kettering	4	49.8
3. South Holland	6	44.1
4. Harborough	3	30.7
5. North Kesteven	2	26.2
6. Boston	1	26
7. Newark and Sherwood	12	24.5
8. East Lindsey	3	14.8
9. Milton Keynes	2	14.5
10. Derbyshire Dales	2	12.3
(Other local authorities)	(23)	(39.9)
(Total)	**(72)**	**(352.7)**

The wind resource is fairly evenly distributed across the central and eastern areas and planning applications have been dispersed relatively evenly across the areas with resource. However, there has been a high level of refusals, with only a few local authorities taking a positive stance on wind. Kettering Borough Council stands out as the area with the most positive stance, with its planning committee having approved 100 per cent of the applications taken to its planning committee (although four out of five of these applications were related to one wind farm and its extensions.)

The majority of areas have seen high levels of refusals by planning committees, with developers having to go through the appeals process to get permission, if at all: there has been a relatively low success rate at appeal outside of the key areas of Daventry, South Holland and Harborough.

Bassetlaw, West Lindsey (largely outside of the licence area), and South Kesteven are noticeable for the high numbers of large scale planning applications that have failed, with mixed success rates in

East Lindsey. Refusals tend to be on the basis of landscape concerns, with local opposition groups in place for proposed schemes.

Figure 7: Onshore wind baseline projects and projects that have failed in planning

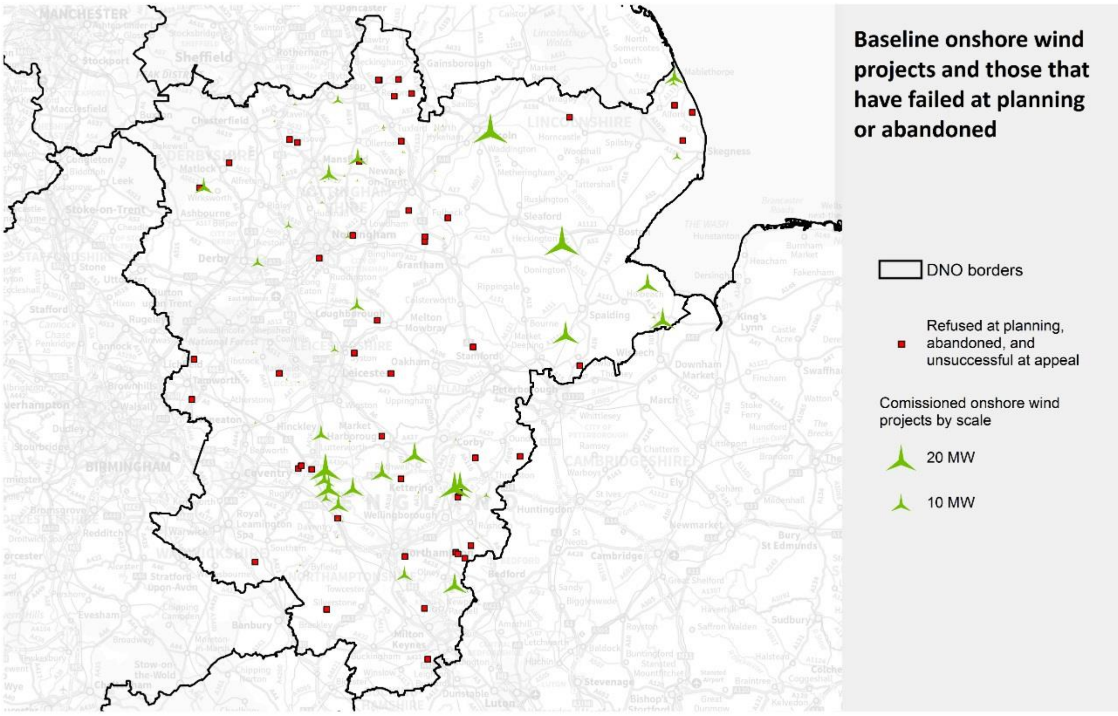
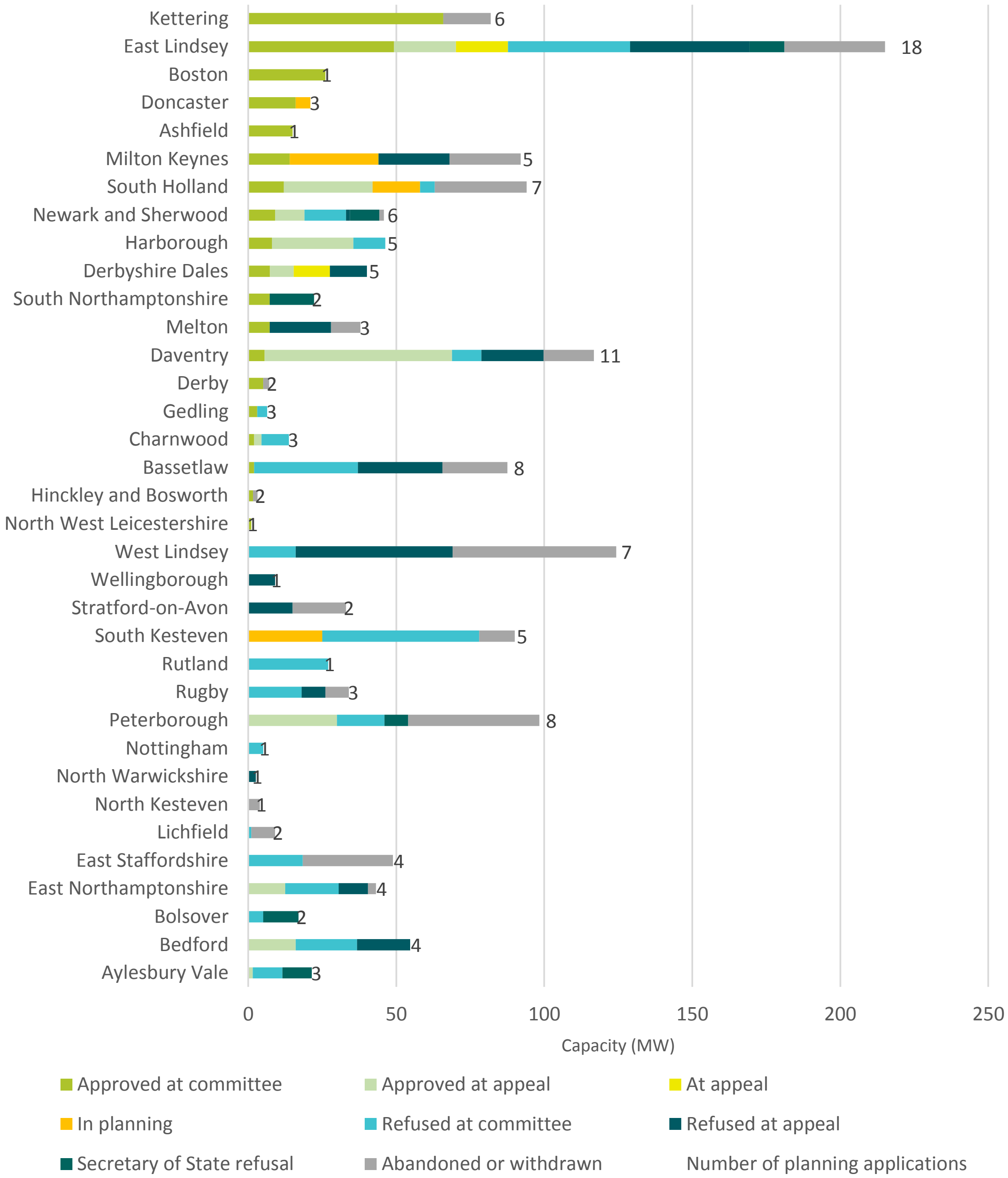


Figure 8: East Midlands onshore wind planning outcomes



3.1.2 Small and medium scale wind baseline

There are 336 small and medium scale projects, totalling 28.74 MW. This is significantly fewer than other areas of the country, such as the South West and East of England, which each have over 700 projects of this scale. Only 14 local authority areas in the licence area have over 10 small/medium turbines. More enclosed landscapes, smaller farm sizes and a higher population density are likely to be the causes of this low level of deployment of smaller turbines.

Table 4: Top 10 local authorities in East Midlands licence area for small scale wind

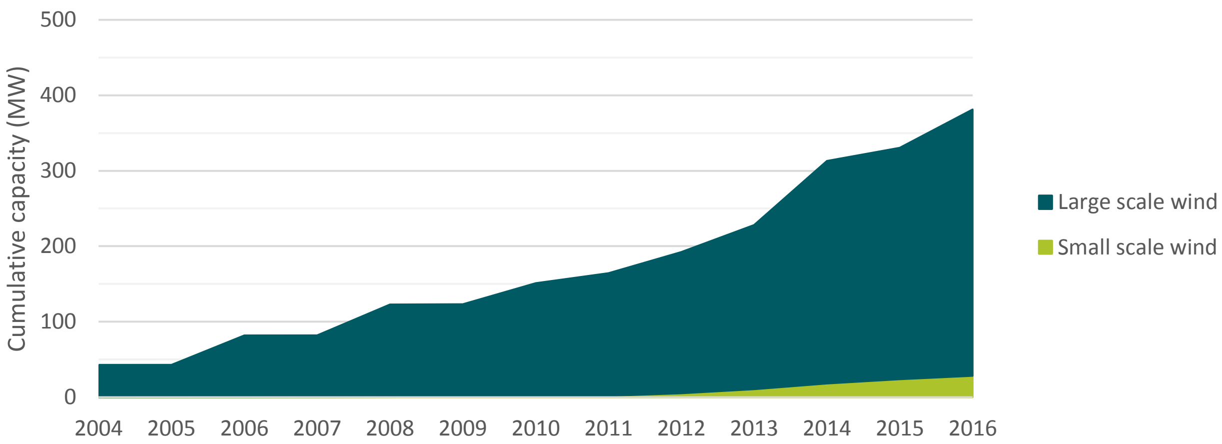
Local authority	Number of projects	Installed capacity (MW)
1. Newark and Sherwood	24	6.6
2. Daventry	12	3.5
3. Bassetlaw	19	2.2
4. Hinckley and Bosworth	9	1.4
5. North West Leicestershire	6	1.2
6. Harborough	23	1.2
7. South Kesteven	15	1.1
8. Melton	19	1.1
9. South Holland	24	1.1
10. Bedford	5	0.7
(Other local authorities)	(180)	(8.2)
(Total)	**(336)**	**(28.5)**

Newark and Sherwood has the largest installed capacity for projects 500 kW and below. Harborough has the greatest number of small scale projects with 25 turbines.

3.1.3 Historic growth rates for onshore wind

Growth of large scale onshore wind in the licence area roughly reflects the national growth curve, with a steady increase from 2005 onwards. Small scale wind capacity grew slowly from 2011 to 2016.

Figure 9: Growth of small and large scale wind capacity in the East Midlands licence area (2004- 2016)



3.2 Pipeline: onshore wind, 2016 to 2020

3.2.1 Project economics for onshore wind

Onshore wind subsidies have been significantly reduced:

- the Renewables Obligation closed a year early for onshore wind (March 2016).
- the Feed-in Tariff (for schemes up to 5 MW) has been reduced dramatically for all scales
- Contracts for Difference (the scheme which is replacing the Renewables Obligation) is unlikely to be suitable for onshore wind.

There are grace periods for wind projects for the Renewables Obligation.

Table 5: Onshore wind grace periods

Issue	Deadline
Approved development	31/03/2017
Electricity network connection or radar delay	12/05/2017
Approved development and investment freeze	31/01/2018
Approved development and electricity network connection or radar delay	31/03/2018
Approved development and investment freeze and electricity network connection or radar delay	31/01/2019

Onshore wind projects that have not qualified for an RO grace period will have to be built with no subsidy (over 5 MW), or a very low FiT (sub-5 MW). Projects currently being constructed are, in general:

- large scale projects that are eligible for one of the RO grace periods
- or single or double turbine schemes of all scales where the energy can be used on or near site through a private wire arrangement.

3.2.2 Small scale wind issues

Outside of private wire arrangements, small scale stand-alone turbines (50 kW and below) aimed at supplying the network rather than onsite demand are now rarely economically viable due to cuts to the FiT, as well as lower efficiencies and proportionately higher costs. 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.

Deployment of this scale peaked in 2012/13 with 786 projects installed across England. In 2015/16 that figure fell to just 19 projects. We have seen installers and manufacturers of this scale of turbine go out of business or concentrate on other scales or technologies.

3.2.3 Planning is currently the major constraint for onshore wind

Despite increasingly favourable project economics for private wire turbines, and medium and large scale projects, planning constraints are now a major issue. 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 practice, the impacts of the WMS will depend on the local planning authority's attitude to wind – some areas are continuing to approve schemes if community support can be demonstrated.

However, the WMS has already been used by the Secretary of State for Communities and Local Government to overturn one Inspector's decision on a medium scale (50 kW) turbine on the grounds that the community's concerns had not been adequately addressed.

3.2.4 Pipeline projects

For large scale projects, we have analysed projects that:

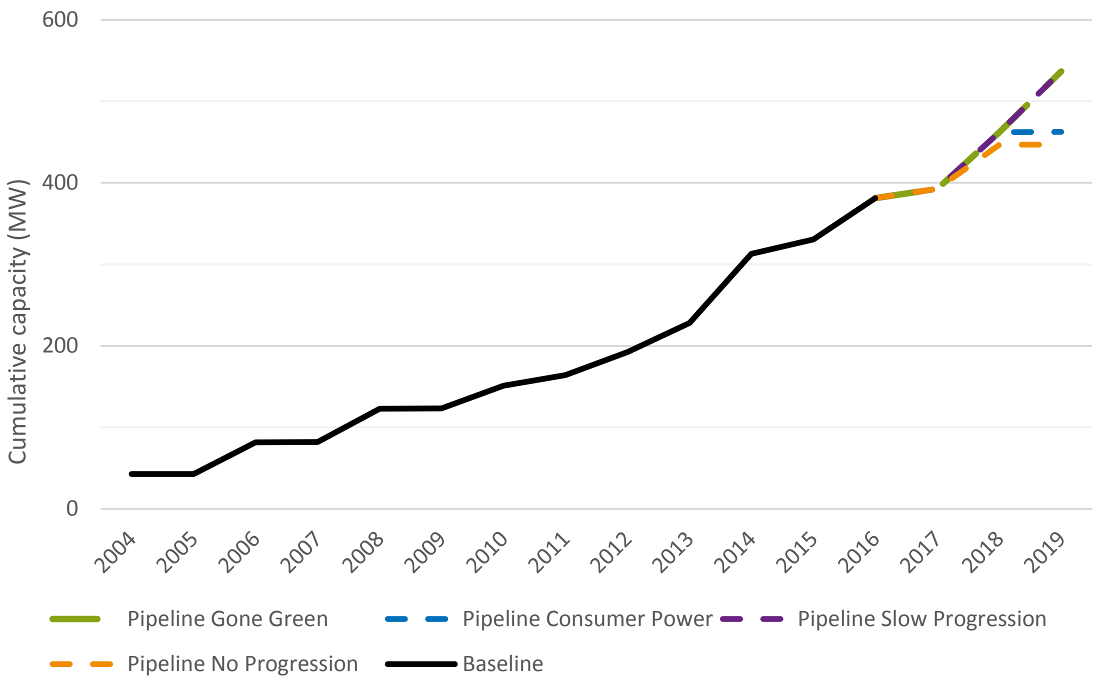
- have applied for planning permission,
- have planning permission and a network connection agreement in place

For small and medium scale projects (sub-500 kW), we have analysed WPD's database of accepted-not-yet-connected customers, taking out duplicates, commissioned projects and those that have failed in planning.

The pipeline is scenario specific. We have made the following assumptions:

- **Gone Green:** All projects with planning permission or that have applied for planning permission go ahead.
- **Consumer power:** All projects with planning permission go ahead. Large scale projects that have applied for planning permission do not go ahead – with the exception of one site which seems to have demonstrated strong community support. Small and medium scale projects that have applied for planning permission go ahead.
- **Slow progression:** As with Gone Green, all projects with planning permission or that have applied for planning permission go ahead.
- **No progression:** Only sites with planning permission go ahead.

Figure 10: Growth of onshore wind capacity in the East Midlands licence area scenarios

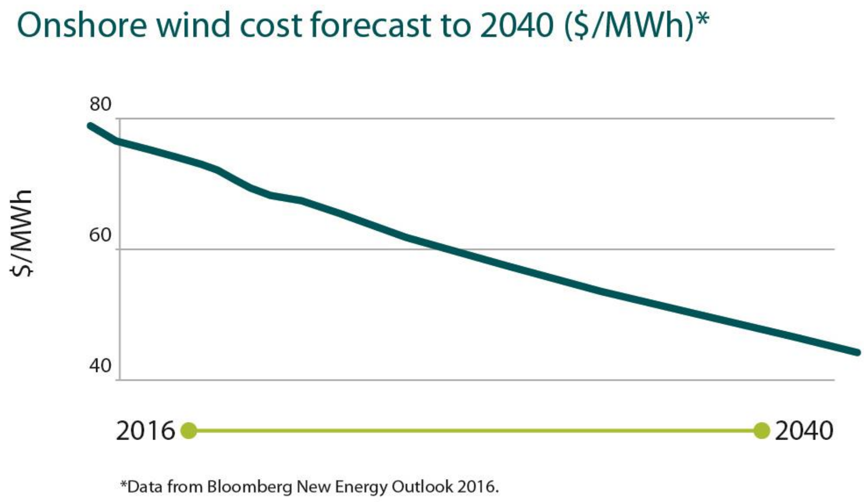


3.3 Regen's market insights: onshore wind

The best large scale onshore wind project sites are becoming viable without subsidy.

Global onshore wind costs have fallen dramatically in recent years and are expected to continue to fall. Bloomberg New Energy put the 2030 cost of onshore wind at around $60/MWh (around £48/MWh).

Figure 11: Bloomberg onshore wind cost forecast



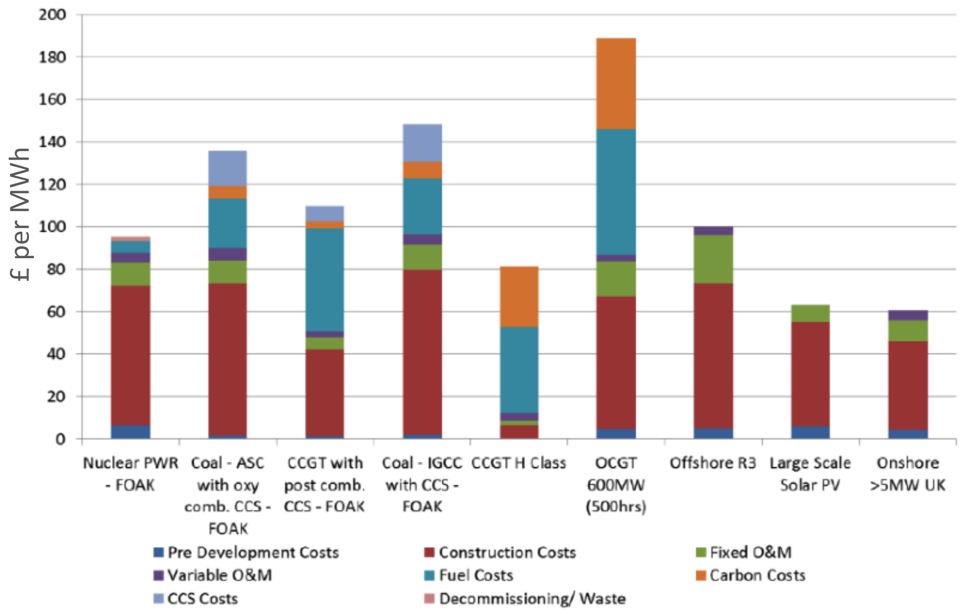
BEIS's 2016 report on the Levelised Cost of Energy (LCOE) puts new onshore wind projects commissioning in 2025 at a lower cost per MWh than the next generation of Combined Cycle Gas Turbine (CCGT) projects.

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. In Scotland, sites are beginning to come forward that are viable without subsidy, based on the wholesale price of power.

Medium scale private wire projects are also becoming economically viable. However, private wire opportunities are relatively limited. We are working with a large utility who want to develop wind on their estate; despite high energy use and green ambition, only a small number of sites have been identified where there is sufficient demand and that are appropriate for a wind turbine.

Figure 12: BEIS's 2016 LCOE: Levelised cost estimates for projects commissioning in 2025, technology-specific hurdle rates, £/MWh



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.

3.3.1 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 for power, which creates risk, increasing the cost of capital. Making the CfD 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. This approach could improve the rate of deployment of onshore wind.

3.3.2 Planning is the key issue for onshore wind

Despite falling costs, the market for all scales of onshore wind in England is stalling as a result of changes to the planning regime. The June 2015 Written Ministerial Statement has added significant risk to the planning system, with a higher proportion of projects being refused both at committee and appeal as a result, as well as the Secretary of State calling-in schemes and recovering appeals, which then result in overturned permissions.

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. 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 for the majority of developers. 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.

3.4 Scenarios: onshore wind, 2020 to 2030

3.4.1 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 6: 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	●	●	●	
Other factors				
High levels of intervention and central green ambition drives commercial investment decisions	●		●	
Local and individual green ambition drives investment decisions	●	●		
Agricultural land values fall, decreasing rents paid to landowners			●	●

3.4.2 Scenario results: onshore wind

As noted above, the planning regime is currently the main brake on onshore wind deployment, with projects otherwise beginning to be viable without subsidy (where site conditions are favourable). We have assumed this restriction is removed under Gone Green and Slow Progression, resulting in medium to high levels of large and medium scale deployment. Small 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 scale deployment is highest, but large scale deployment is limited. Under this scenario, the government favours "consumer-led" projects including projects by farmers, small businesses and community groups. 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 scales of project and turbines looking to repower have their life extended rather than upgrading the turbines.

Table 7: Scenarios summary for onshore wind in the East Midlands licence area

Consumer Power	Gone Green
• Low growth scenario for large and medium scale projects • Despite favourable economics, growth is low as the current planning regime remains in force for commercial wind projects, restricting deployment to those that can demonstrate community support. • 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 reaches its previous peak (seen in 2012/13) by around 2023. • From the middle of the decade, the installation rate of small and medium scale turbines improves further as a result of global cost reductions. • **Repowers:** Large scale sites repower after 25 years. Rather than increasing capacity, planning restrictions mean that developers apply for permission for fewer larger turbines, keeping the capacity of existing sites constant.	• 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, which begin to be deployed from 2023 onwards in areas with an existing history of wind installations, with widespread deployment in new areas from 2025 • Towards the end of the decade, the deployment rate reduces slightly as the best sites have been built out and cumulative impacts start to have an influence. • **Small scale:** Small scale remains restricted to private wire projects until technology costs fall late in the decade. Areas with large scale potential are reserved through planning for larger projects, limiting the locations for small scale turbines. • **Repowers:** After 2024, projects repower at 20 years old, rather than at the end of their 25 year life. Turbines are replaced with larger, more efficient models, increasing the capacity of existing sites by 75 per cent.

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 community support would be built in the most favourable areas. • **Repowers:** repowers are also affected by the negative planning environment, with developers applying to extend the life of their existing turbines beyond 25 years, rather than moving to install more efficient turbines. Capacities of these sites are kept constant as a result.	• Medium growth scenario • A positive planning environment is created for large and medium scale, unlocking deployment from 2021, with an uplift from 2026 as costs fall and planning successes lead to further applications • Growth is at a 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. • **Repowers:** Projects are repowered when they reach the end of their 25 year life, with turbines replaced with larger, more efficient models, increasing the capacity of existing sites by an average of 50 per cent.

Figure 13: Scenario growth of onshore wind capacity

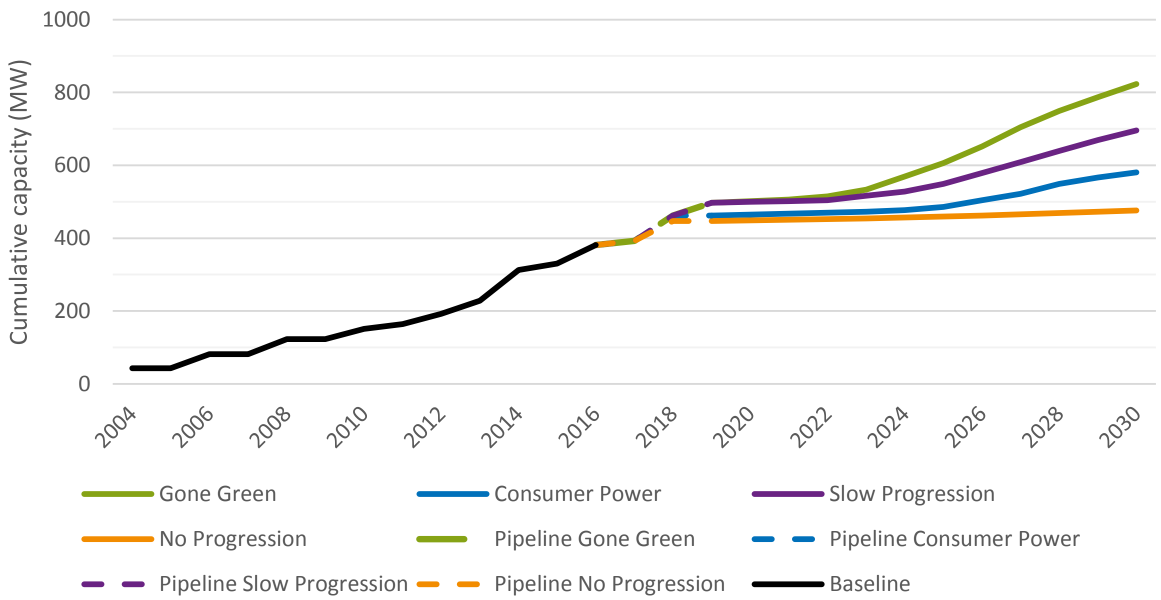


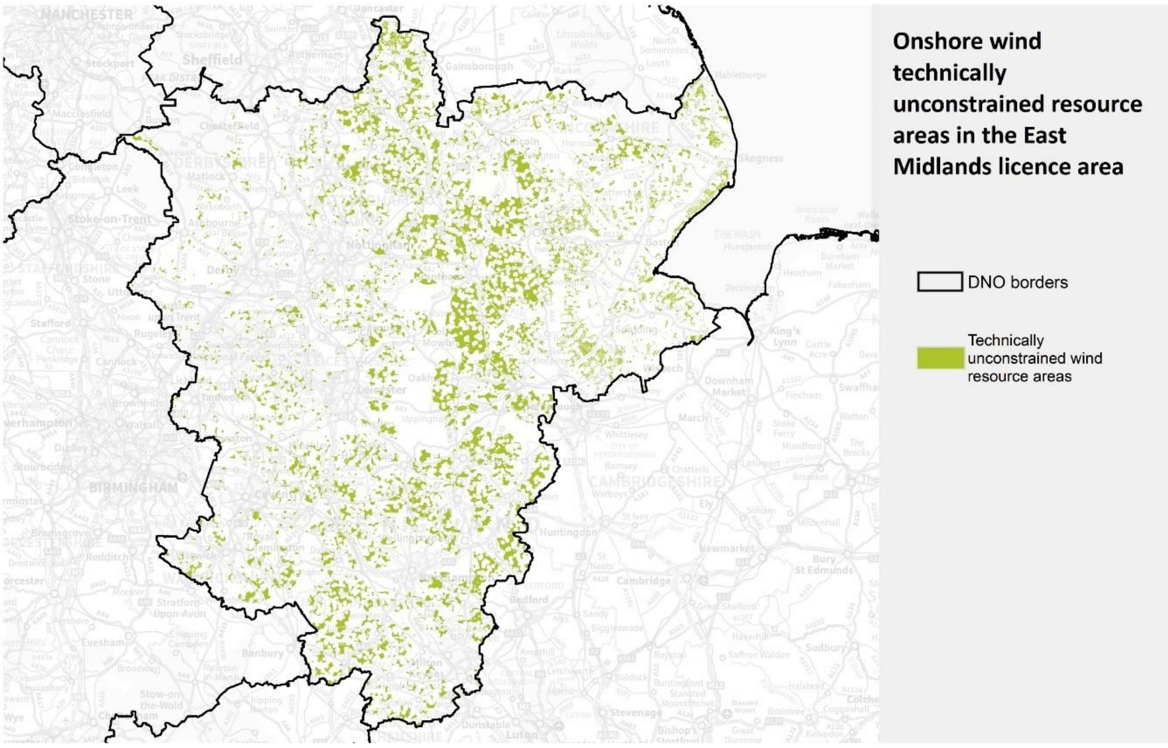
Table 8: Non-cumulative capacity breakdown of onshore wind in the East Midlands licence area (MW)

	Small and medium scale (MW)			Large scale (MW)		
Scenario	Baseline	Pipeline	Scenarios	Baseline	Pipeline	Scenarios
Gone Green	28	1	7	353	145	325
Consumer Power	28	1	14	353	80	117
Slow Progression	28	1	4	353	145	198
No Progression	28	-	1	353	66	30

3.5 Resource assessment: onshore wind potential

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 distribution network and areas with low wind speeds were excluded from the analysis. **Error! Reference source not found.**Figure 14 shows the remaining areas with potential for onshore wind.

Figure 14: Onshore wind technically unconstrained resource areas

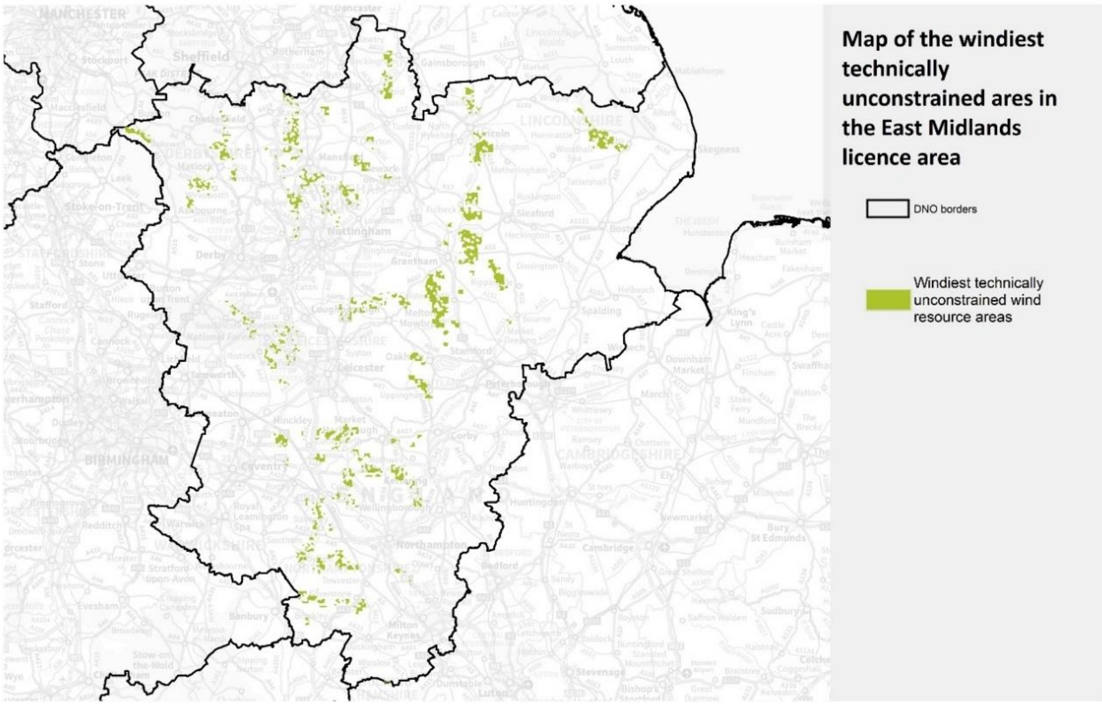


The wind resource in the East Midlands licence area is relatively widespread, with pockets of potential throughout the non-urban areas. Distances to the network are generally short across the licence area and wind speeds are relatively consistent, so these factors play less of a role in determining resource availability than in other areas. The main exclusion areas are the urban centres, including Nottingham, Coventry, Leicester, Milton Keynes, Northampton and Derby – and protected landscapes such as the Derbyshire Dales. There is a band of more concentrated resource availability down the centre and east of the licence area where there are more open spaces. The licence area is more densely populated to the west.

There are 1,500 km^2 of technically developable space, nine per cent of the total land area, which in theory could host 13 GW of wind. However, under no future scenario is the East Midlands licence area expected to reach this theoretical capacity.

Figure 15 identifies the most attractive areas to be developed. The ten ESAs with the greatest wind resource account for half of the developable land space.

Figure 15: Windiest technically unconstrained locations in the East Midlands licence area

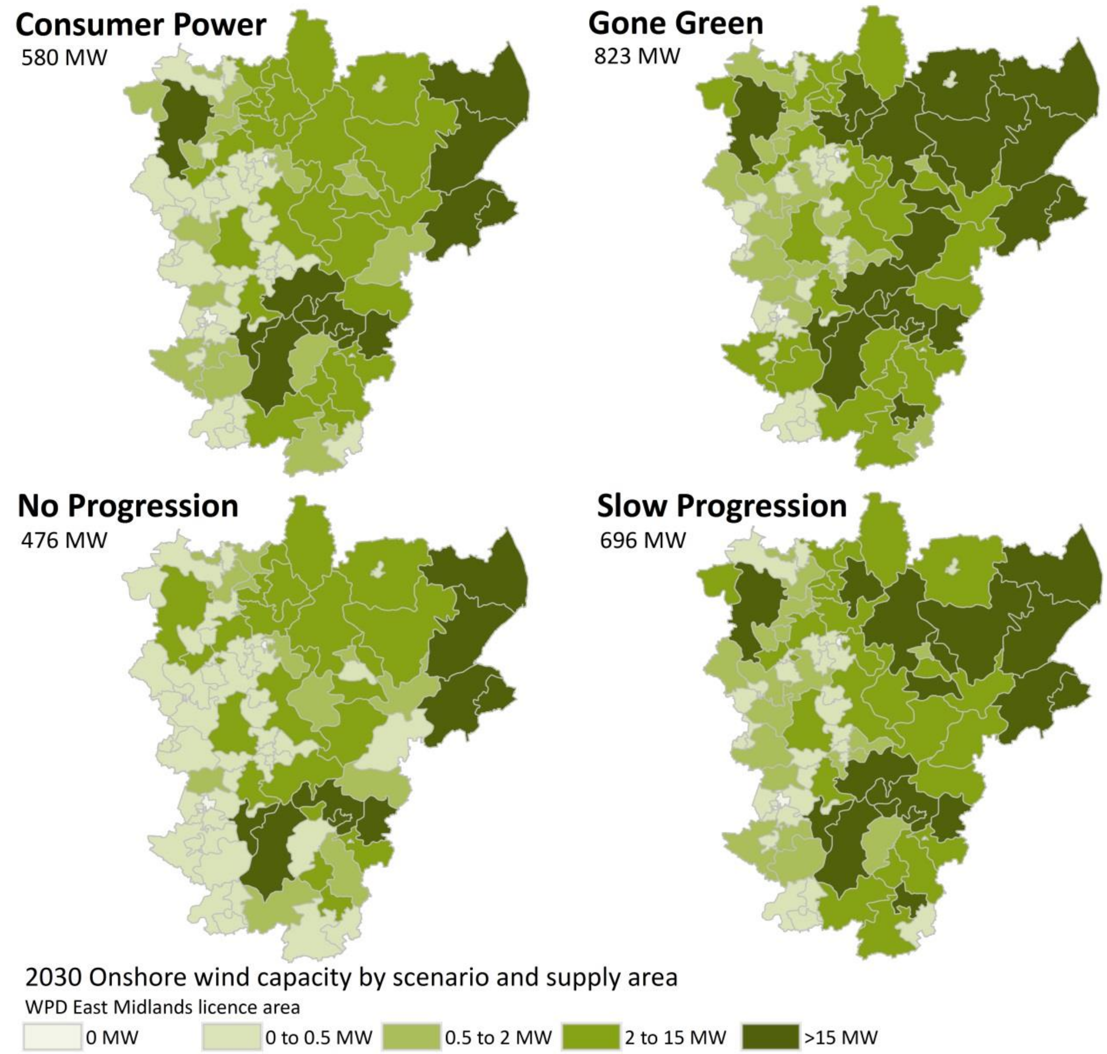


3.6 Geographic distribution of the scenarios: onshore wind

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.

Gone Green and Slow Progression see a greater weighting towards the availability of resource. For Consumer Power, the distribution is dispersed, with the weighting focused on resource availability for small scale projects, and weighted towards areas with strong planning histories for large scale projects. Under No Progression, the weighting for all scales is towards development in areas with existing wind and strong planning histories

Figure 16: Onshore wind capacity distribution in each scenario in 2030



4 Solar

4.1 Baseline: solar PV growth to 2016

To assess the baseline capacity, we used WPD's database of accepted-not-yet-connected customers and validated this against data from the Renewables Obligation, BEIS Renewable Energy Planning Database (REPD) and Regen's in house project data.

There are 1,322 MW of solar PV in the licence area made up of 88,708 projects. In comparison, this is just over half of the South West of England's total, which has over 2,500 MW of solar PV installed.

4.1.1 Ground-mounted baseline

Ground-mounted solar deployment expanded rapidly in the UK in 2010, following the introduction of the Feed-in Tariff with subsidies for ground-mounted schemes up to 5 MW and the Renewables Obligation for larger schemes. Large and medium scale solar projects were able to be deployed rapidly in response to the available subsidy as a result of:

- The large developable resource area
- The relatively straightforward and positive planning environment
- Short lead in times
- The ability of the mobile and scalable global/EU supply chain to shift attention to the UK quickly

The East Midlands is the fourth region of the UK in terms of ground-mounted solar capacity, with the South West, South West and East of England ahead of it. The installation rate was slower to take off in the East Midlands than these three other areas as developers focussed on areas with the greatest irradiance levels and open space. As network 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.

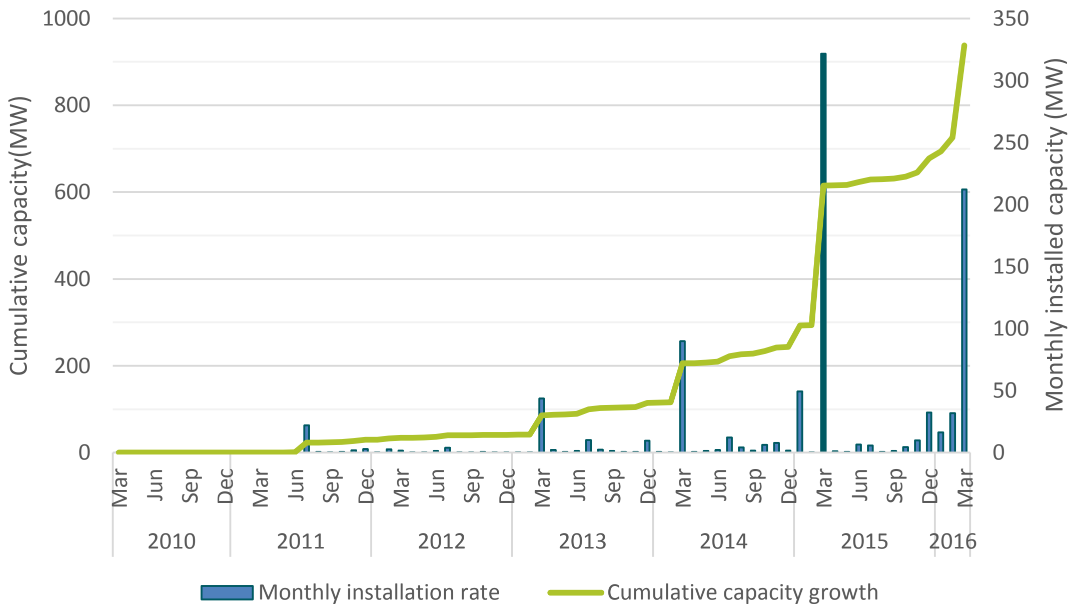
As of October 2016, there was over 940 MW of ground-mounted solar PV in the East Midlands licence area, made up of 144 projects.

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

- The first 5 ground-mounted projects were installed in the licence area in 2011 with capacities between 2.5 and 5 MW. The installation rate was then fairly low but steady until the end of 2014, with projects predominately at the sub-5 MW scale.
- In quarter 1 of 2015, nearly 350 MW of ground-mounted solar commissioned as developers raced to meet the 1 April deadline to qualify for the RO for projects over 5 MW; these projects were an average of 12 MW in size, with the largest 32.4 MW.
- From April 2015 to April 2016, around a further 220 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.

- Since April 2016, the deployment level has dropped substantially, with only a very small number of schemes eligible for the sub-5 MW grace period building out to meet the April 2017 deadline.

Figure 17: Growth of grid connected medium and large scale solar capacity in the East Midlands licence area



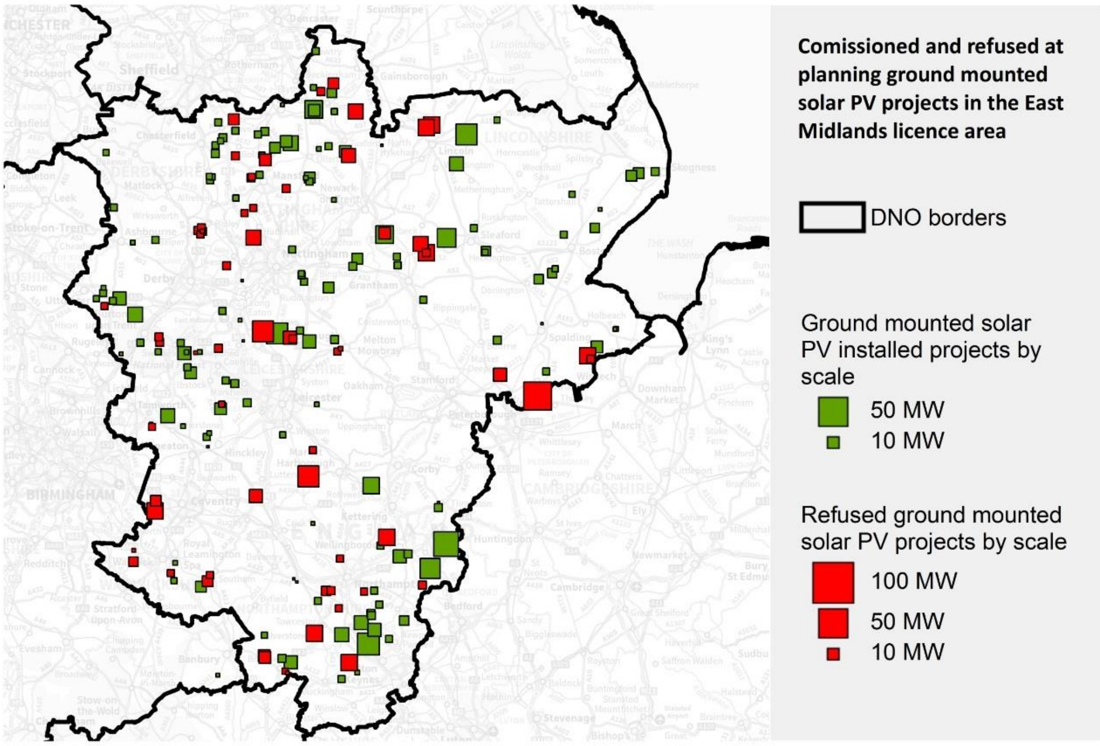
As in other licence areas, ground-mounted solar projects are concentrated in areas with good access to the network. Projects have tended to cluster in a few authorities, with the top 10 authorities hosting over 50 per cent of the ground-mounted installed capacity. Bassetlaw in the north of the licence area and South Northamptonshire in the south have the greatest installed capacity and greatest numbers of projects.

Table 9: Top ten local authorities in the East Midlands licence area for ground mounted solar PV capacity

Local authority	Number of ground-mounted solar projects	Installed capacity (MW)
1. Bassetlaw	11	80.5
2. South Northamptonshire	10	70.2
3. Milton Keynes	5	63.1
4. North Kesteven	5	53.9
5. Newark and Sherwood	8	47.4
6. East Northamptonshire	3	45.3
7. South Kesteven	5	39.0
8. Charnwood	4	37.1
9. North West Leicestershire	7	36.7
10. Rushcliffe	6	34.4
(Other local authorities)	(80)	(431.3)
(Total)	**(144)**	**(938.8)**

There are a large number of projects in the licence area which have been refused planning permission, particularly in the north west and centre of the licence area. Authorities in the north east and South West of the licence area have seen a lower rate of refusal.

Figure 18: Commissioned and refused at planning ground mounted solar PV



4.1.2 Roof-mounted baseline

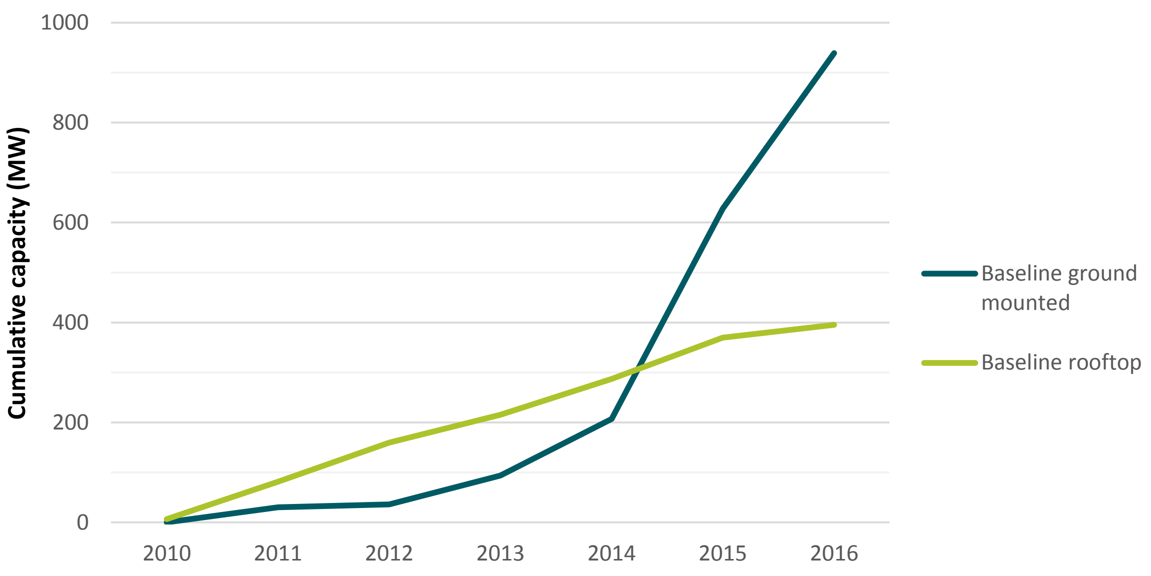
There are over 88,500 roof-mounted projects, totalling 383 MW. These are concentrated in populated areas, with the greatest numbers of suitable roofs. Bassetlaw is the local authority area with the highest proportion of homes with solar PV (7 per cent of homes) and is seventh in England against this measure, thanks largely to an investment programme by the district council and housing associations to install panels on social housing in the area. At the other end of the scale, Coventry has around 1.5 per cent of its homes with solar PV.

Table 10: Top 10 local authorities in the East Midlands for roof-top solar PV installations

Local authority	Number of installations	Capacity (MW)	Proportion of homes with PV
1. Nottingham	5,589	18	4.0%
2. Newark and Sherwood	2,929	16	5.6%
3. North Kesteven	2,824	15	5.6%
4. Leicester	3,895	14	2.9%
5. Derby	3,924	14	3.6%
6. South Kesteven	2,754	13	4.4%
7. Milton Keynes	3,083	13	2.8%
8. East Lindsey	2,317	12	5.0%
9. Bassetlaw	2,880	12	7.1%
10. South Holland	1,847	12	4.6%
(Other local authorities)	(56,522)	(245)	
(Total)	(88,564)	(383)	

With the introduction of the FiT in 2009, roof-mounted solar deployment grew steadily in the licence area from a very low base, but installation rates fell in 2015/16 as the result of cuts to the FiT. Growth was at a slower rate than in other areas of the UK.

Figure 19: Growth of rooftop and ground-mounted solar PV in the East Midlands licence area



4.2 Pipeline: solar PV

4.2.1 Ground-mounted pipeline to March 2017

Subsidies for large scale solar PV have been cut or ended, meaning that PV projects over 5 MW built post-March 2016 will have to be built without subsidy. Sub-5 MW ground-mounted projects that are not eligible for the RO grace period (available until March 2017) will have to be viable with a very low FiT.

Current intelligence from the industry is that ground-mounted sites with a private wire with a significant electricity user can be viable without subsidy. Stand-alone network-connected sites are not currently viable, but large scale sites with low electricity network connection costs could become viable in the near term, depending on the scenario.

To build the pipeline, we have examined WPD's network connection database to identify sites with a network connection agreement in place that are not yet built. We cross checked this against the BEIS planning database. We have assumed that by April 2017:

- Projects that are sub-5 MW that qualify for the RO grace period will be built out.
- Where connection agreements are for projects with a capacity between 5 MW and 10 MW, these would be built out at 5 MW to take advantage of the RO.
- Projects over 10 MW will not be built by April 2017. Developers may hold onto these sites until they become viable.

Applying these assumptions gives a total installed capacity of 190 MW from approximately 80 projects. This figure is very significantly less than WPD's solar PV network connection database, which stood at 1 GW in January 2017. However, we believe it is still an overestimate of the capacity that will be built before 31 March 2017. We have researched a sample of these projects and found a very low proportion have progressed beyond obtaining planning permission. As a result, we have applied a reduction to the capacity, assuming that only 20 per cent will be built. The pipeline for ground-mounted solar is therefore 38 MW in total.

4.2.2 Roof-mounted 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 at a significantly lower rate than pre-February 2016 and with quarterly degressions. The current FiT, current installed prices and the low cost of power mean that payback periods are usually at least 10 years for rooftop sites. As a result, in the domestic market only customers with a very low cost of capital and motivated by green ambition are currently installing rooftop PV. Large scale rooftop PV to offset onsite energy demand remains viable with the current FiT.

There is no pipeline data available for roof-mounted solar and so the scenarios begin immediately.

4.3 Regen's market insights: solar PV

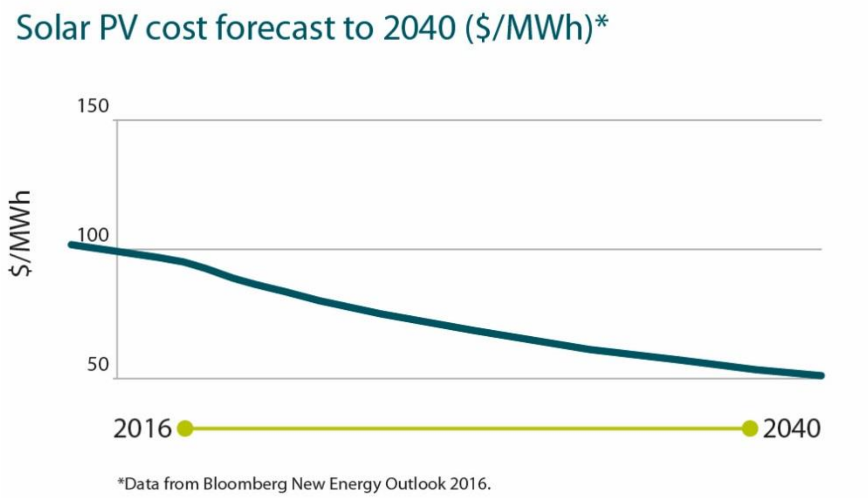
4.3.1 Rapidly reducing solar PV costs

Thanks largely to falling module prices due to increases in global supply and innovation, the installed cost of solar PV has dropped considerably in recent years. Construction costs also dropped in the UK as the industry expanded its capability.

Bloomberg New Energy Finance predicts continued price falls, with installed costs in the EU reaching $50 per MW by 2040. The exchange rate fluctuation caused by Brexit has added around 20 per cent to costs in the UK in recent months. The longer term impact of leaving the EU is uncertain. There is potential for it to unlock trade deals for the UK with China, for example, cheaper modules could become available, or for ongoing currency and trade issues to keep UK prices above the Eurozone.

4.3.2 Certainty, not subsidy for solar PV

Figure 20: Bloomberg New Energy Outlook 2016 solar PV cost forecast to 2040 ($/MWh)



Parity is often viewed simplistically as a function of falling technology costs and rising power prices. Whilst these are major factors to consider, risk has a major part to play in the availability and cost of investment capital. The loss of the RO and reduction of the FiT removes certainty of income for developers. Without these income from projects will be subject to power price risk. This risk pushes up the cost of capital.

Making the CfD accessible to solar PV (even if the price offered were at the wholesale price of power), the provision of government backed PPAs or other price guarantee mechanisms would offer certainty to the market, and therefore reduce risk and the cost of capital. This approach would have an important impact on the date at which 'parity' could be achieved for solar PV.

4.3.3 Impact of system costs on solar PV

As increasing levels of solar (and renewables with intermittent generation in general) are deployed, system costs could become an issue: that is the cost of backup and network balancing due to the variability of renewables. The government has indicated it is keeping under review if there are system costs that should be borne by variable generators.

However, new research from Aurora Energy Research for the Solar Trade Association 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.

Furthermore, the modelling shows that:

"*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.*"

4.4 Scenarios: solar PV, 2017 to 2030

4.4.1 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 East Midlands licence area.

Table 11: 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, exchange rate stabilisation and also 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	●	●	●	
Other factors				
High levels of intervention and central green ambition drives commercial investment decisions	●		●	
Local and individual green ambition drives investment decisions	●	●		
Agricultural land values fall, decreasing rents paid to landowners			●	●

Many of the factors in Table 11 also apply to roof-top installations. An additional factor considered for rooftop schemes is whether or not 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.

We have focussed the rooftop analysis on domestic properties and public sector schemes, and given some consideration to the potential for commercial/industrial rooftop schemes with onsite usage. Of course some small scale installation will be on commercial properties, but the factors that lead to deployment on these buildings do not differ greatly from domestic factors. Small scale community schemes are also included in this analysis, including multi-household and small scale community building installations. The rate of installation on new build properties is considered.

4.4.2 Scenario results: solar PV

In all scenarios, it is anticipated that there will be continued slow growth in PV in 2017 due to subsidy cuts. The key uncertainty is how quickly growth would recover under the four future energy scenarios.

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. But even under this most optimistic scenario, growth rates (for each scale) remain below the historic peak. Ground-mounted growth rates reach around half the peak seen during 2014-15, due to both a lack of subsidy and network constraints and system issues limiting overall deployment.

The Consumer Power scenario closely follows the Gone Green scenario, with slightly lower large scale deployment due to a lack of strategic network investment and no price guarantee mechanism, and fewer new build installations.

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

Table 12: Scenarios summary for solar PV in the East Midlands

Consumer Power	**Gone Green**

• High growth scenario
• For ground-mounted sites, some sites are viable from 2018, wide-spread parity achieved from 2023/24 – slightly later than under Gone Green as less government support
• Fewer private wires than under Gone Green due to lack of price guarantee mechanism
• 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.
	• Highest growth scenario
	• Price parity for ground-mounted – first large scale projects 2018/19, rapid rise from 2022
	  ○ Falling PV costs
	  ○ Price guarantee mechanism
	  ○ Technology innovation
	  ○ High carbon price
	• The business models for storage and solar work together, thanks to technology and regulatory changes, reducing intermittency issues.
	• Private wires and industrial roofs viable now, tailing off from 2023 as best sites taken
	• Rooftop installation rates rise through the decade as costs fall, with the proportion of PV installations with storage increasing.
	• Around 9.5 per cent of all homes in the licence area have solar by 2030
	• Large proportion of new homes include PV due to planning requirements

No Progression	**Slow Progression**
• Lowest growth scenario • Poor planning and economic environment • Large scale parity achieved around 2024 • Growth would be slow 2020-25 with an increase post 2025 as costs fall and power prices rise • 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 • Positive planning environment • Large scale parity achieved around 2022, with uplift in installation rate from middle of the decade – later than under Gone Green due to poor economic and finance outlook and lack of price guarantee mechanism • Widespread price parity reached and impacting around 2024/25 for medium and small scale – overall around 40 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 – but fewer new homes built than under Gone Green

4.5 Scenario results: solar PV

4.5.1 Ground-mounted results

Figure 21: Scenario growth of ground mounted solar PV in the East Midlands licence area

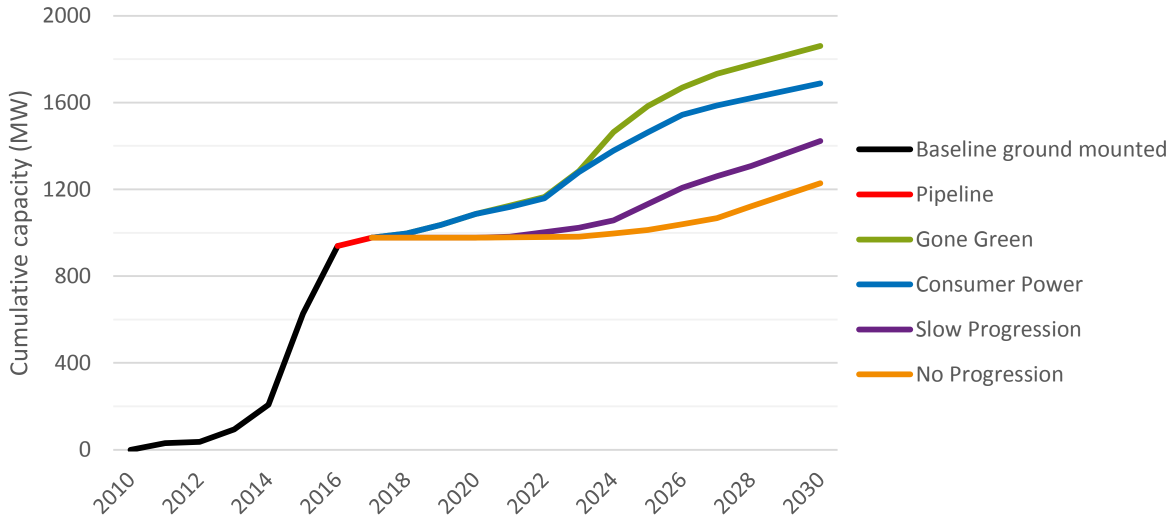


Table 13: Non-cumulative capacity breakdown of ground mounted solar in the East Midlands licence area (MW)

	Baseline (MW)	Pipeline (MW)	Scenarios (MW)
Gone Green	938.8	190.0	1,861
Consumer Power	938.8	190.0	1,689
Slow Progression	938.8	190.0	1,422
No Progression	938.8	190.0	1,228

4.5.2 Rooftop results

Figure 22: Scenario growth of rooftop solar PV in the East Midlands licence area

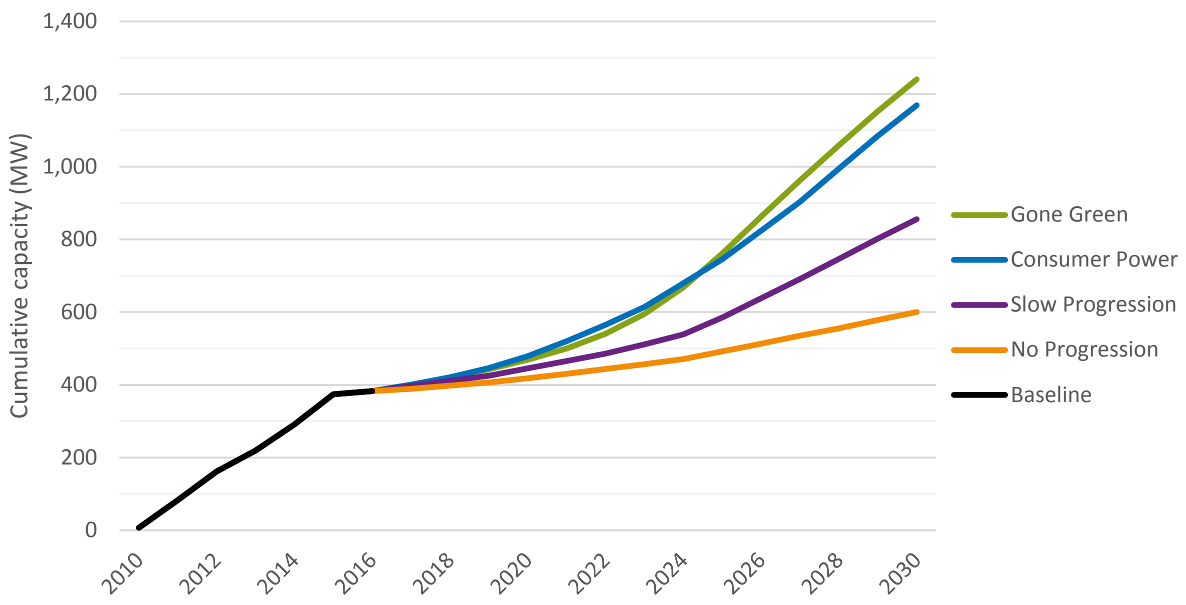


Table 14: Capacity breakdown of rooftop solar in the East Midlands licence area (MW)

		2020 (MW)		2025 (MW)		2030 (MW)	
	Baseline	Retrofit	New	Retrofit	New	Retrofit	New
Gone Green	382.8	90.7	14.5	280.6	95.2	630.6	224.0
Consumer Power	382.8	113.6	14.5	311.4	48.8	661.4	122.0
Slow Progression	382.8	71.4	5.4	147.8	51.2	292.6	177.3
No Progression	382.8	40.0	5.4	80.3	29.4	130.8	86.9

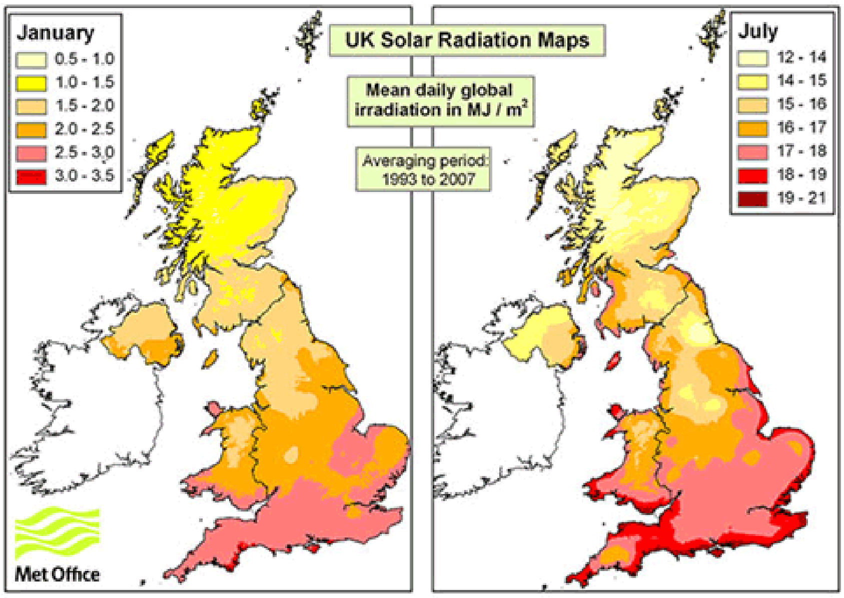
4.6 Geographic distribution

4.6.1 Resource assessment

Technical resource assessment methodology for ground-mounted

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

Figure 23: 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 distribution 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 energy 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.

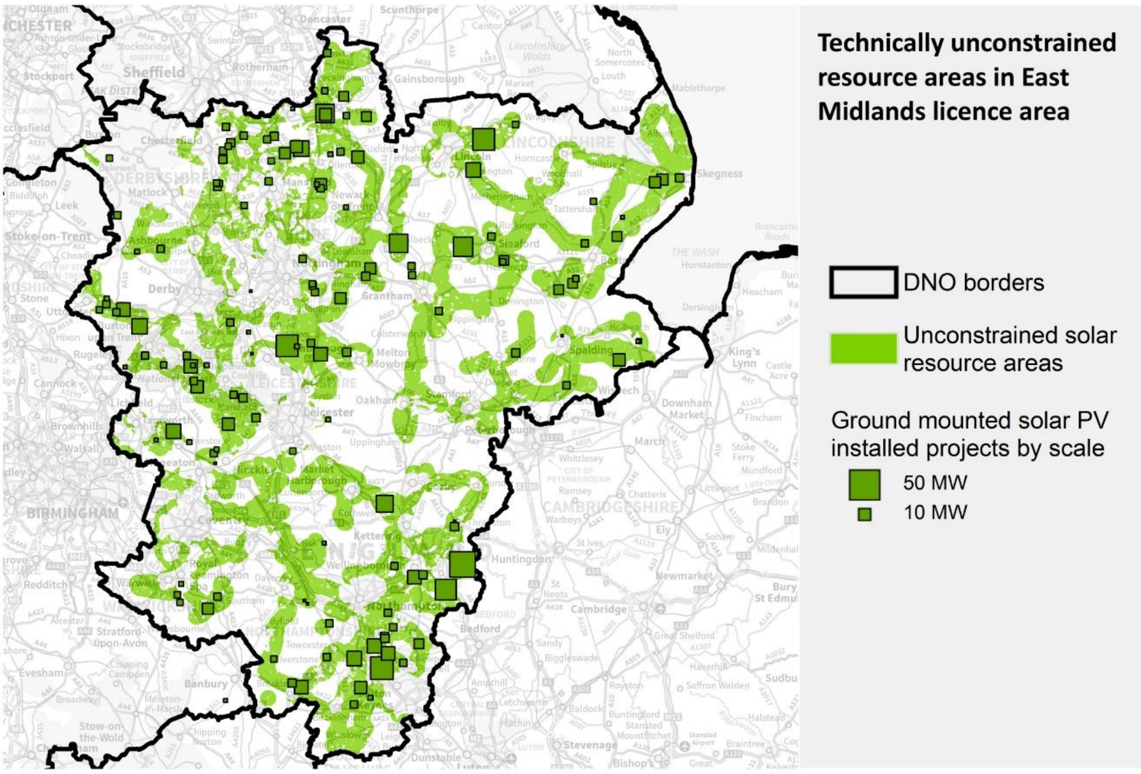
These detailed site finding points do not have a significant impact at network area level and therefore are not included in the analysis. Deployment trends should be monitored in the future to see if these factors become more important. Planning policy, guidance and local authority engagement can have 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 25 m from residential properties
- Over 2.5 km distance from 33 kV (or higher) network as a proxy for network connection costs.

4.6.2 Results of resource assessment

Figure 24: Technically unconstrained solar PV resource in the East Midlands licence area



The occurrence of existing ground mounted PV farms, shown as green squares, 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 could be over 4,000 km² of 'PV developable' land space within the WPD East Midlands licence area, which could, in theory, host 54 GW of ground mounted solar. Only 1.7 percent of the total developable resource area has so far been developed. This is equivalent to less than 0.13 percent of the total land in the East Midlands licence area.

4.6.3 The impact of planning constraints on solar PV resource potential

With planning lead times typically 6 months and a relatively high success rate, developers have been able to bring forward PV schemes with some confidence of success where there is a viable connection to the distribution network.

However, cumulative impact (where there are multiple sites in close proximity to each other causing landscape and visual issues in particular) needs to be a consideration in assessing the potential for solar farms to be developed in the area. This can be a particular issue where solar sites cluster around potential connection points. We have used two methods to assess which network supply points may need a reduction in their available resource due to cumulative impacts:

1. 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.
2. We have also limited the number of solar farms to three PV farms within a 10 km² area.

While these cumulative impact constraints do affect the siting of PV farms within a small geographic area, they do not constrain the overall growth of PV within the broader growth scenarios.

In addition, planning success rates are higher in some local authorities than others due to planning policy or local politics. Also, some areas have seen far fewer applications, despite appearing to have technically developable areas, potentially due to current network constraints. We have introduced a scaling factor to take into account the planning environment and historic deployment rates. This scaling factor reduces each ESA's available resource by 10 to 45 per cent, reducing each ESA's potential for development.

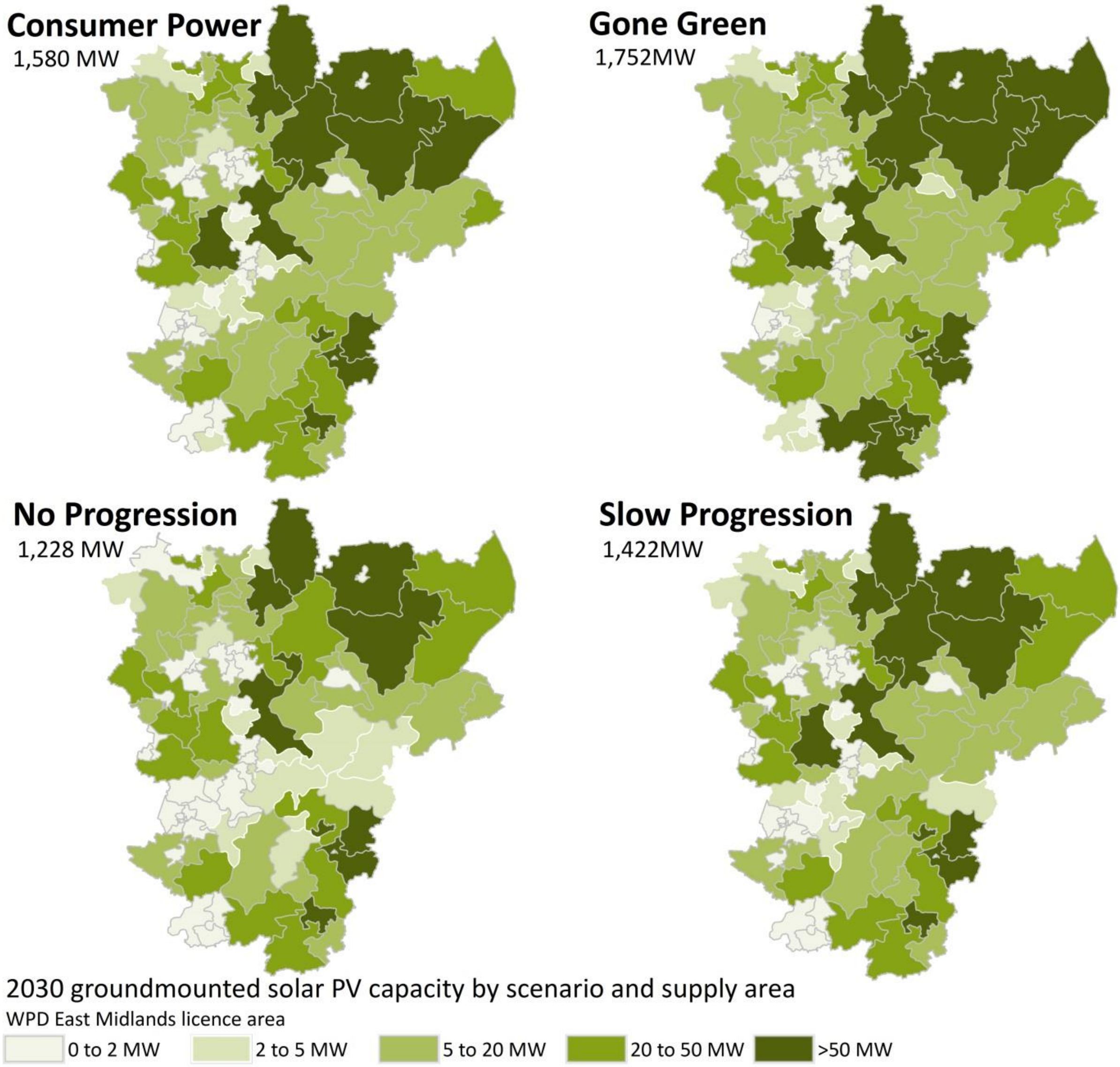
4.6.4 Private wire and industrial/commercial rooftop opportunities

To identify potential C&I companies that might present private wire/rooftop opportunities, we have identified users with a 33 kV 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 ESAs. We have assumed there is the technical potential for approximately 300 MW of private wire/rooftop opportunities.

4.7 Geographic distribution of scenarios: solar PV

4.7.1 Results of geographic distribution: ground-mounted PV

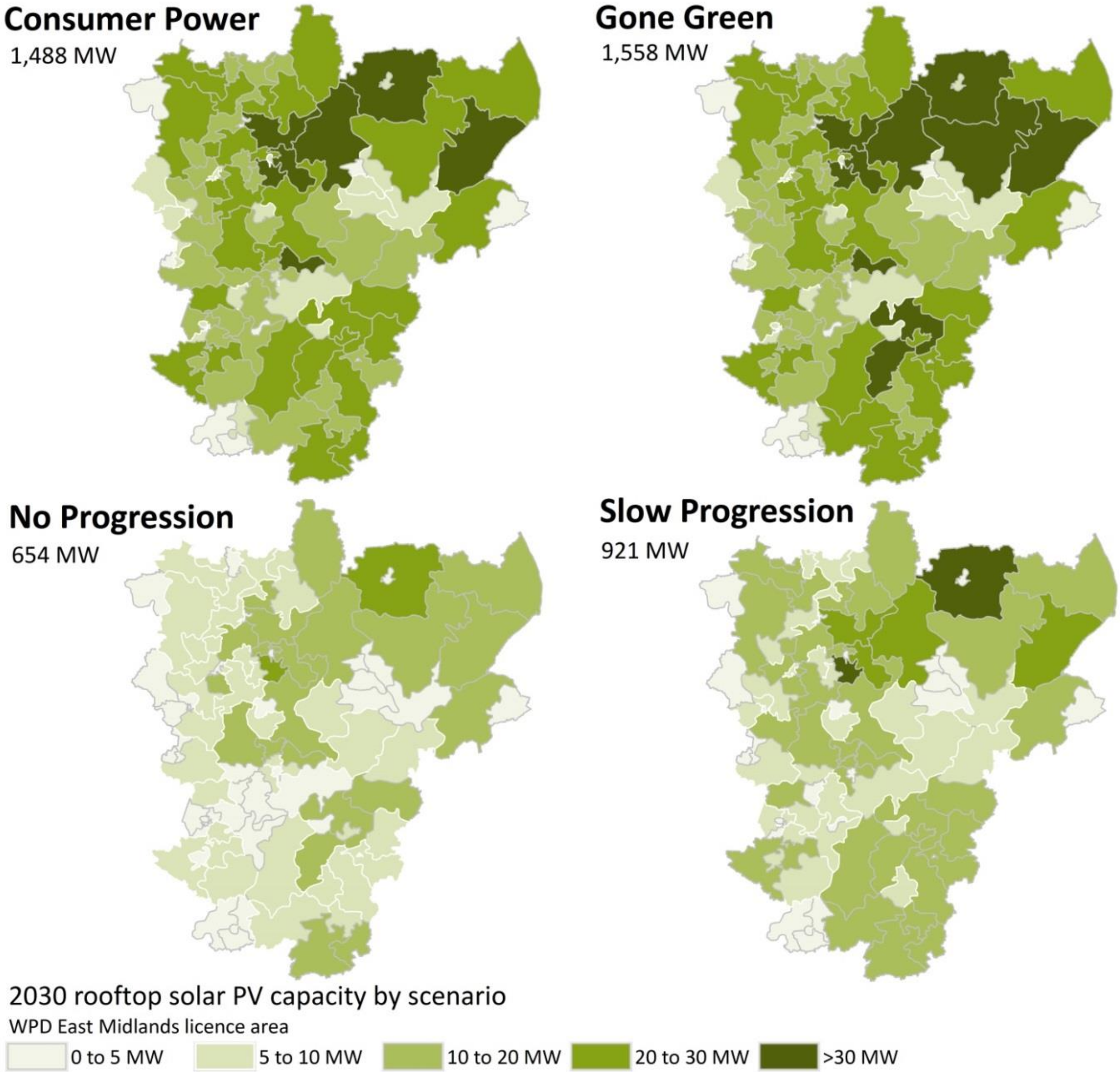
Figure 25 Geographic distribution of ground-mounted solar PV capacity by scenario



4.7.2 Results of geographic distribution: roof-mounted PV

We have considered the correlation between deployment of solar PV and affluence in the area: the finding is that there is no correlation. Having investigated the relationship, we conclude that this is due to a high proportion of social housing providers undertaking mass installation programmes. As a result, we have distributed the scenarios geographically according to the number of existing homes, the number of new homes and the existing baseline.

Figure 26: Geographic distribution of rooftop solar PV capacity by scenario



5 Offshore energy

Technologies included in this section are wave, tidal stream and offshore wind that connects to the distribution network.

5.1 Baseline

There are not currently any marine projects in the WPD East Midlands licence area.

There are a number of offshore wind farms already deployed off the coast. Two offshore wind farms, Lynn and Inner Dowsing, are connected to the distribution network, totalling 194 MW.

5.2 Pipeline

There are no projects in the pipeline.

5.3 Regen's market insights: offshore energy

The UK is currently a world leader in the innovation and development of wave and tidal technology and projects. Across the UK there are a number of world leading test centres including Wave Hub in Cornwall, for the testing of wave energy devices, and EMEC in Scotland for both wave and tidal. Other sites are being developed around other areas of the coast, including the Perpetuus Tidal Energy Centre off Portland and the Pembrokeshire Demonstration Zone. There are no sites under development in the east at present.

Tidal stream and wave energy technologies are still in a period of technology development and demonstration and so, while there are a number of projects currently in the pipeline at demonstration sites, the initial deployments are likely to be of relatively small scale pilot projects, followed by larger commercial and full scale projects in the period out to 2030.

Wave and tidal technology projects are still relatively expensive to develop, owing to the need for innovation and difficulty of deploying offshore and in marine environments. For these reasons, wave and tidal energy currently requires relatively high levels of support. In November 2016, the UK Government announced the next draft budget allocation for the Contracts for Different scheme. This budget included strike prices of £310/MWh in 2021 and £300/MWh in 2022 for wave energy, while tidal stream starts at £300/MWh and drops to £295/MWh in 2022. The government did not extend the 100 MW minima that had been previously provided for these technologies, meaning that wave and tidal projects bidding in for an allocation in that auction will be in direct competition with other technologies in the pot, which includes offshore wind, expected to be bidding at circa £100/MWh. As a result, we do not expect to see wave and tidal projects accessing the CfD in the next round.

Offshore wind is much further developed than wave and tidal energy and the UK currently has over 5 GW of offshore wind deployed and a healthy pipeline of projects that have planning permission and are likely to bid into the next auction round for delivery in 2021 and 2022. The cost of offshore wind is much less than that of wave and tidal, thanks to years of innovation in the turbines and foundations and installation methods, a more developed supply chain, reduction in operating costs, and more competition between developers.

5.4 Scenarios

There are not likely to be any wave or tidal projects built in period to 2030 in the East Midlands licence area. This is because wave or tidal stream resource are not sufficient for deploying a project that would generate electricity. Tidal stream developers are looking for a resource of greater than 2.5m/s for viable projects, and the resource in this area is approximately between 1-1.5m/s.

For offshore wind, given that the next round of development is likely to take place in the Round 3 development areas, it is extremely unlikely that there will be any new projects connected to the distribution network. This is because the scale of Round 3 projects is much greater, with turbines located much further offshore; these projects will connect to the National Grid.

As a result, marine energy does not add any additional capacity under any of the scenarios.

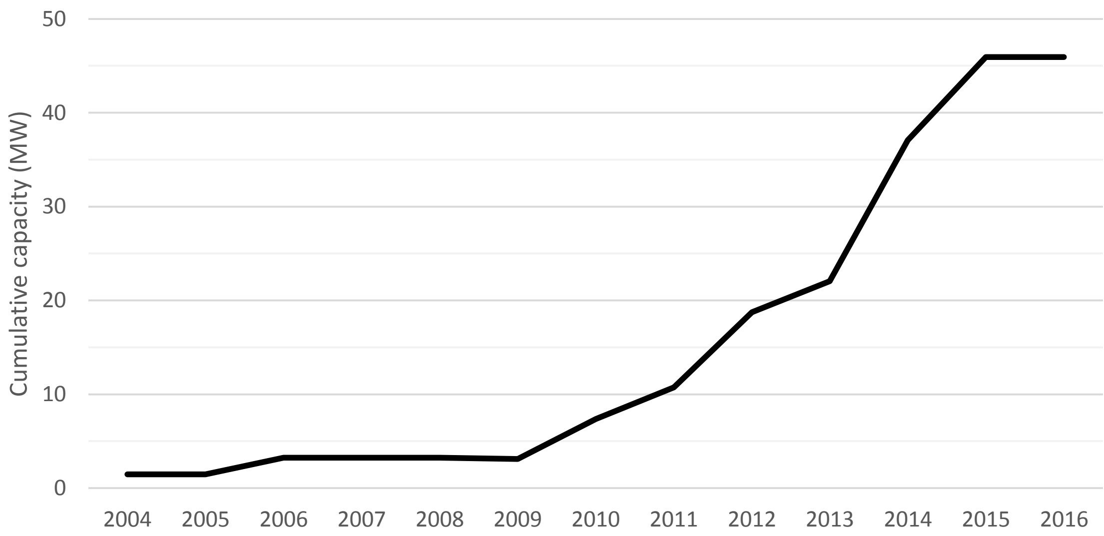
6 Anaerobic digestion

6.1 Baseline: anaerobic growth to 2016

There are 48 anaerobic digestion projects in the licence area, totalling 46 MWe in installed capacity. The average project size is just over 1 MWe, with the largest project a 3.2 MWe plant using maize, grass silage, and sugar beet.

The East Midlands region[1] has the greatest installed capacity of anaerobic digestion of any English region.

Figure 27: Growth of anaerobic digestion in the East Midlands licence area



East Lindsey is the leading local authority in England and Wales for anaerobic digestion installed capacity, with one anaerobic digestion company installing multiple projects in the area. 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 East Lindsey, projects are relatively widely dispersed across the licence area, with most local authorities having one or no projects.

[1] The region is slightly larger than WPD's licence area

Table 15: Baseline anaerobic digestion projects by local authority in East Midlands

Local authority	Number of projects	Installed capacity (MWe)
1. East Lindsey	9	9.9
2. South Northamptonshire	5	1.9
3. Gedling	4	7.8
4. South Kesteven	4	2.0
5. North Kesteven	3	4.4
6. Bassetlaw	3	4.3
7. South Holland	3	1.7
8. Kettering	2	1.6
9. North Warwickshire	1	2.1
10. East Northamptonshire	1	1.9
(Other local authorities)	(13)	(8.4)
(Total)	**(48)**	**(46.0)**

Anaerobic digestion planning applications tend to be approved at committee; out of 26 planning applications listed on the DECC 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 Feed-in Tariff in 2009 and the RHI in 2011 resulting in uplifts in capacity. The peak installation rate was in 2013/14 when 16 new projects were installed in the area. No new projects have been installed in the licence area since September 2015.

6.2 Pipeline: anaerobic digestion, 2016 to 2017

There are four projects in the area with an existing accepted-not-yet-connected connection offer. These range in capacity from 90 kW to 550 kW, totalling just under 1 MW. We expect these projects to be built in 2017.

6.3 Regen's market insights: anaerobic digestion

6.3.1 AD offers significant potential for growth in the East Midlands licence area

Given the right conditions, there is good potential for the development of AD in the area. The East Midlands has a relatively strong AD supply chain, with local companies, as well as local branches of national and international firms.

The East Midlands licence area has 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. Although most plants currently aim to generate a steady load to maximise output and therefore income, 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.

6.3.2 Issues with subsidies and other potential income streams are limiting growth in anaerobic digestion plants

Despite significant potential, at present the AD market is severely restricted at all scales, in large part due to subsidy cuts and uncertainty. Anaerobic Digestion and Bioresources Association (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 high, given the small size of the current market and the site specific nature of installations. Achievable improvements to the economics of AD are likely to be relatively small and related to increased gate fees for food waste (if food waste collections increase), improved quality of feedstock and some potential for innovative improvements to the micro-biology processes. Widespread deployment without subsidy is unlikely to be achieved until after 2030 due to continuing high technology costs.

Issues around subsidies for electricity production from AD include:

- By January 2017, the FiT for small and medium scale projects has been cut by 63 per cent compared with the rate on offer from 2011 to March 2014.
- Quarterly deployment caps for the FiT have also been introduced, adding uncertainty as projects wait in a queue before their tariffs are confirmed. The first round of applications for AD reached the 5.8 MW first quarterly cap in 20 minutes. Projects entering the queue to receive the FiT currently have to wait through three quarterly degressions before reaching the top of the queue and being assigned a FiT rate.
- If current application rates continue, the available FiT budget for AD projects may be fully allocated by 2018, effectively closing the FiT a year early for AD.
- In 2015, the government ended the issuing of Levy Exemption Certificates (LECs) to renewable generation, something which had a big impact on the economics of marginal AD projects.
- Extensions to existing AD projects are not eligible for financial incentives, despite this being the cheapest route to expanding AD capacity.
- The RO will close to new plants on 31 March 2017; some plants may commission under the RO until this date, although the current rate of 1.8 ROCs per MWH is generally considered too low.
- Large scale projects over 5 MW are eligible for the CfD, but to date little interest has been shown by developers in this route.

Other issues for AD include:

- The price that AD plant owners receive for processing food waste is low and sometimes they have to pay to access the resource rather than be paid, restricting deployment of food waste AD projects. Food waste collection rates remain low in England, with half of households not receiving a food waste collection. A rise in food waste collections would increase gate fees for AD plants in the future.
- 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.

6.3.3 AD plants producing biomethane for injection to the gas grid or for transport could see significant growth in numbers

AD plants that produce biomethane have access to additional potential income streams from the RHI for gas to grid or Renewable Transport Fuel Obligation (RTFO) for transport fuel. 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. Government announced a reset of RHI tariffs for biomethane (gas to grid) plants in November 2016 with immediate effect, which should lead to higher levels of deployment in the short term.

Ecotricity has published analysis of the potential for "green gas mills", its term for AD plants fuelled by grass that produce gas for injection to the gas grid. Their report estimates that 97 per cent of Britain's homes could be supplied by green gas mills.

Despite ambitious statements from the industry and renewed support from the RHI, there are a number of limitations at present on widespread deployment of biomethane producing plants:

- It is currently only viable for larger AD projects to buy the equipment required to export gas.
- 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 secure sufficient feedstock due to limited availability of food waste.
- There are budget caps for the RHI (the government has introduced an overall budget cap that could close the RHI to new projects in the near future), which alongside tariff uncertainty, would limit growth of this sub-sector.
- 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 is due to consult on the future of the RTFO in 2016.

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 16: 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 17: Scenarios summary for anaerobic digestion in the East 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.

Figure 28: Scenario growth for anaerobic digestion in the East Midlands licence area

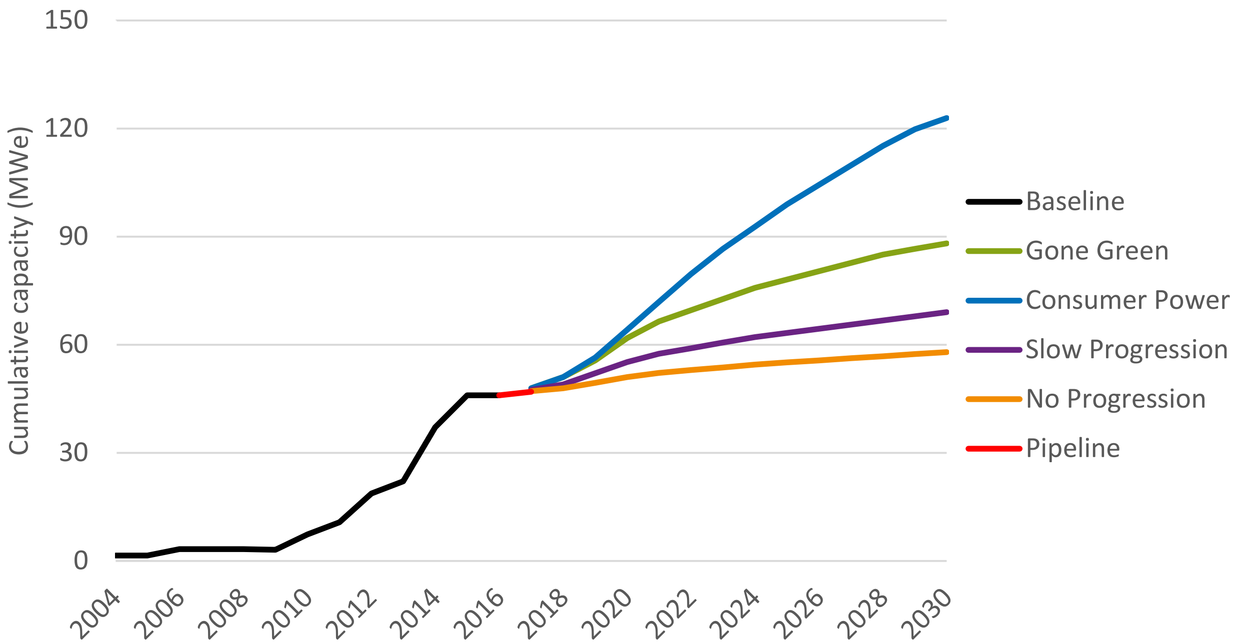


Table 18: Non-cumulative scenario capacity growth of network connected anaerobic digestion in the East Midlands licence area (MW)

Scenario	Baseline (MW)	Pipeline (MW)	2017 -2030 Scenarios (MW)
Gone Green	48	1	40
Consumer Power	48	1	75
Slow Progression	47	1	22
No Progression	47	1	11

7 Hydropower

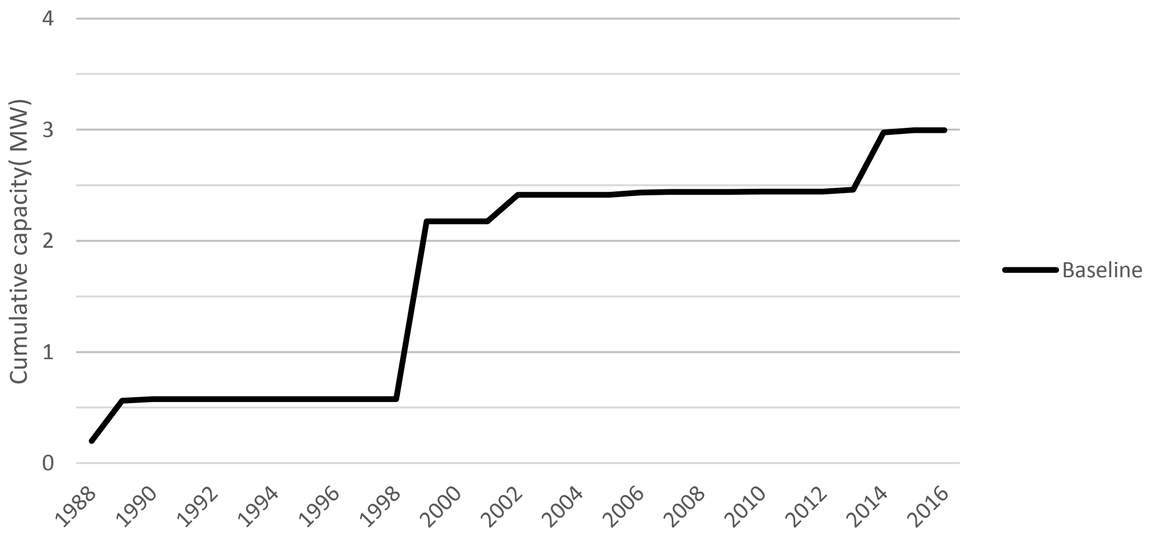
7.1 Baseline: hydropower growth to 2016

Hydropower deployment in the East Midlands licence area has been relatively limited, with just 17 projects totalling just under 3 MW in installed capacity. The local authority area with the greatest number of projects is the Derbyshire Dales, where there are six projects within the licence area[2]. Hydropower is relatively dispersed outside of this area with no identifiable patterns of deployment. Nottingham has the greatest installed capacity and the largest projects, thanks to a 1.6 MW project and a 500 kW project

Table 19: Hydropower projects by local authority

Local authority	Number of projects	Installed capacity (MW)
Nottingham	2	2.100
Amber Valley	4	0.390
Derbyshire Dales	6	0.330
Unknown	1	0.090
East Staffordshire	1	0.050
Wellingborough	1	0.015
Warwick	1	0.015
Bassetlaw	1	0.006
Grand Total	**17**	**2.996**

Figure 29: Baseline capacity growth for hydropower



[2] Some of the Derbyshire Dales is outside of the licence area boundary.

The majority of the installed capacity is from six projects installed before the turn of the millennium. Five smaller scale projects and one 500 kW project have been installed since the start of the Feed-in Tariff in 2009.

7.2 Pipeline: hydropower, 2016 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.

There are three hydropower projects in the pipeline in the East Midlands licence area: two are 100 kW projects in the North West of the licence area, the other is a 36 kW project in the east of the licence area.

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.

According to the Environment Agency resource assessment, there remains a significant resource in the area that could be developed, with a strong resource in the Derbyshire Dales in particular – but overall the resource is substantially less than other hillier areas of the UK.

Despite opportunities, hydropower is a difficult resource to harness and there are a number of obstacles to current and future development 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.
- 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 20: 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

Given the current relatively low baseline in the area and the availability of higher resource sites in other areas of the UK, deployment is low under all the scenarios. Under Gone Green, deployment reaches 5.85 MW by 2030. Although this represents an increased deployment rate, it is less than double the baseline.

Table 21: Summary of scenarios for hydropower in the East Midlands

Consumer Power	Gone Green
• High deployment rate equivalent to the licence area's previous peak. • 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 • Subsidy / increased FiT is made available for all scales of hydropower, meaning that deployment rates rise to marginally above previous peak. • Nationally, deployment remains focussed on areas with the best resource and these are largely outside of the licence area, meaning East 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 focussed 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 30: Scenario growth for hydropower in the East Midlands licence area

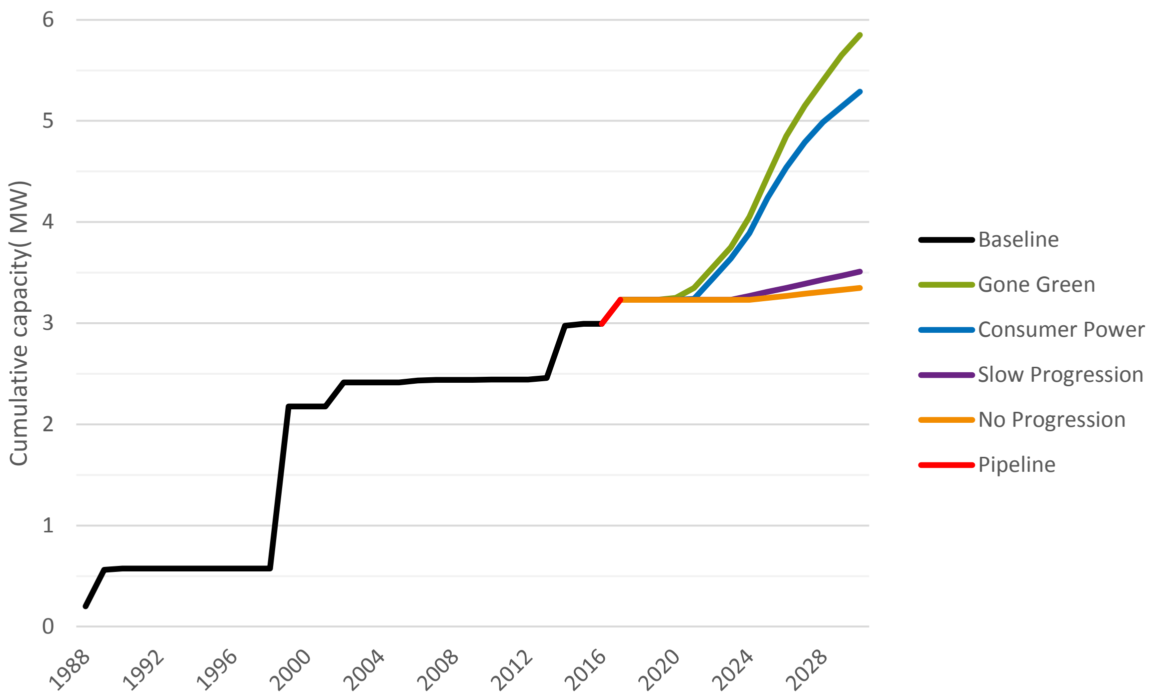


Table 22: Non-cumulative capacity breakdown of hydropower in the East Midlands licence area (MW)

Scenario	Baseline (MW)	Pipeline (MW)	Scenarios (MW)
Gone Green	2.99	0.24	2.62
Consumer Power	2.99	0.24	2.06
Slow Progression	2.99	0.24	0.28
No Progression	2.99	0.24	0.12

7.5 Geographic distribution of the scenarios: hydropower

Figure 31 shows the distribution of the hydropower resource by local authority across England and Wales. The resource is relatively low across the East Midlands licence area when compared to the west, which is hillier.

The installed capacity under each scenario is distributed according to the available resource in the ESAs. New sites are concentrated in ESAs to the west of the area, especially the Derbyshire Dales.

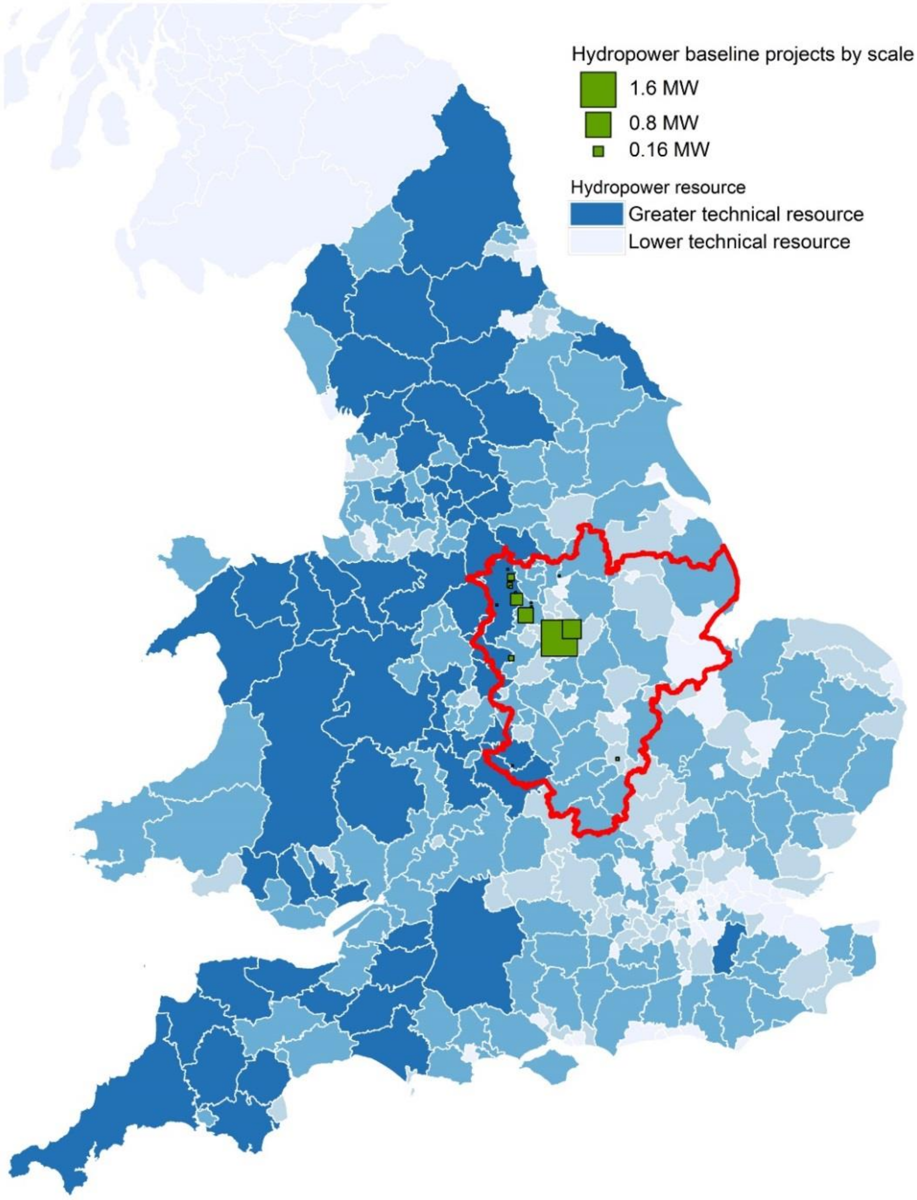


Figure 31: England and Wales hydropower resource map, illustrating lower resource in the East

Data source: Environment Agency hydropower resource assessment.

8 Energy from waste

8.1 Baseline: energy from waste growth to 2016

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

- Lincoln EFW, 13.1 MWe
- Greatmoor EfW, Buckinghamshire 32 MWe
- Coventry EfW, 6 MWe
- Eastcroft EfW, Nottingham, 20 MWe

8.2 Pipeline: energy from waste, 2016 to 2020

There is one new municipal waste incineration project under construction in the area, at Newhurst Quarry, Charnwood. In addition, planning permission has been gained for an extension to an incineration plant near Nottingham.

Current trends show that advanced thermal treatment plants have a tendency to fail, even at the construction stage. There is a risk that some or all of these sites drop out. However, for the purpose of this assessment, we have assumed that those in development in the licence area go ahead. There are, therefore, four gasification plants in the pipeline, all of which have planning permission and three of which are under construction.

8.3 Regen's market insights: energy from waste

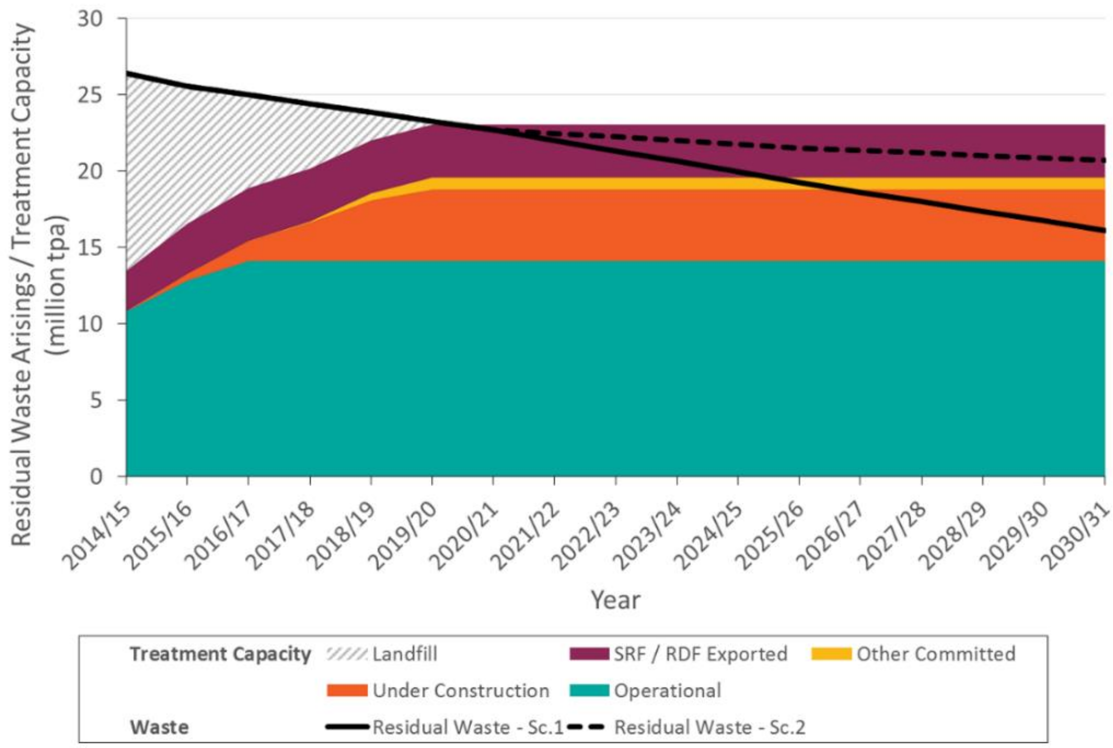
8.3.1 Limited availability of waste resource

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

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.

Figure 32: 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.

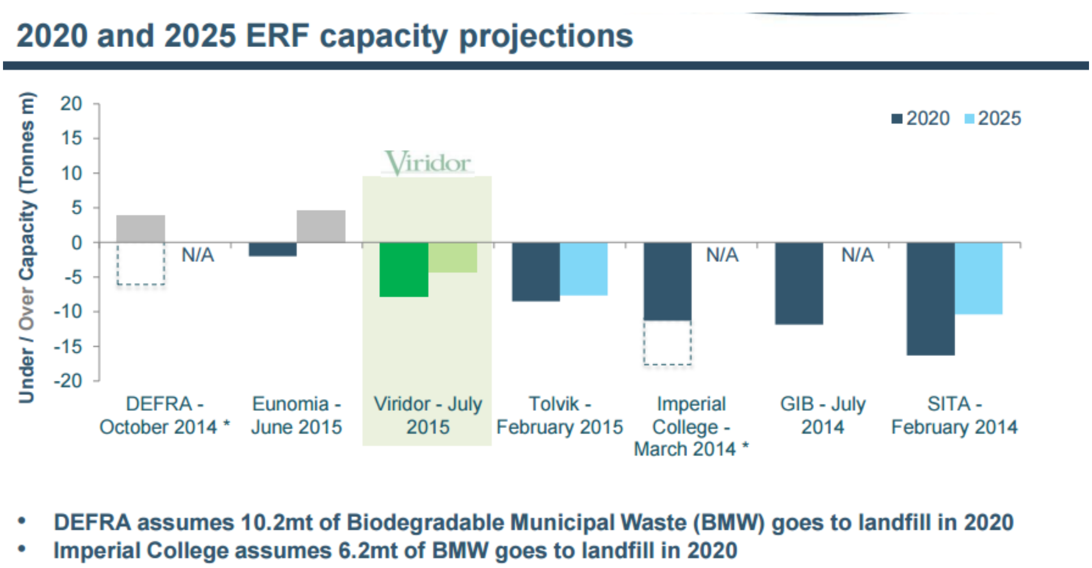


Figure 33: Energy Recovery Facility capacity projections

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, what is certain, is 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.

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 plants is approximately 70 per cent gate fees, 25 per cent power price, and 5 per cent recovered metals.

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.

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, there is only one large scale plant generating electricity. At present, there is a high failure rate for ATT projects, with technology issues resulting in investors withdrawing.

Despite these technology issues, there remain a high number of pipeline ATT projects under construction in the UK. There are five ATT plants in the pipeline in the East Midlands licence area.

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. 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 examined the location of baseline and pipeline projects (including those in neighbouring areas) against population centres. We have assumed where there is a population exceeding 200,000 without an existing or proposed municipal waste treatment plant in close proximity, that there will be the potential for a new energy from waste plant on the basis that the existing resource is currently being exported from these areas. With four plants already constructed and a further six plants (and one extension) in the pipeline in the area, as well as plants in neighbouring locations, there are no population centres not currently served. We have assumed no further incineration projects are constructed in the scenarios.

In some areas of the UK an import model has developed, where multiple projects are co-located, forming a hub. There is a proposed hub in Corby in Northamptonshire in the East Midlands licence area, where three projects have been proposed. 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. However, these 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 23: 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	●	●		

8.5.2 Scenario results: energy from waste

Conditions are most favourable to energy from waste incineration plants under the Gone Green scenario. However, we have assumed that there is insufficient municipal waste in the licence area to fuel any new incineration plants, given current installed and planned plants.

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 the seven locations where there are existing or planned projects (with the exception of Corby where multiple sites are already proposed).

Under the Gone Green scenario, we have also assumed that these new plants would focus on producing gas for heat and transport, exporting little or no electricity to the network, as this is the greenest, more efficient option. Under the Consumer Power scenario, we have assumed these new plants would export electricity to the network.

Table 24: Scenarios summary for energy from waste in the East Midlands

Consumer Power	Gone Green

• No new municipal waste incineration projects in the area due to lack of resource. • 7 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.	• No new municipal waste incineration projects in the area due to lack of resource. • 7 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 syngas production from ATT. • Impact on network is limited as focus in on producing syngas for grid and transport.
No Progression • No new municipal waste incineration projects in the area due to lack of resource. • 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.	**Slow Progression** • No new municipal waste incineration projects in the area due to lack of resource. • No new ATT projects as technology development is limited and there is a lack of subsidy. • Excess waste is exported.

Figure 34: East Midlands energy from waste scenarios

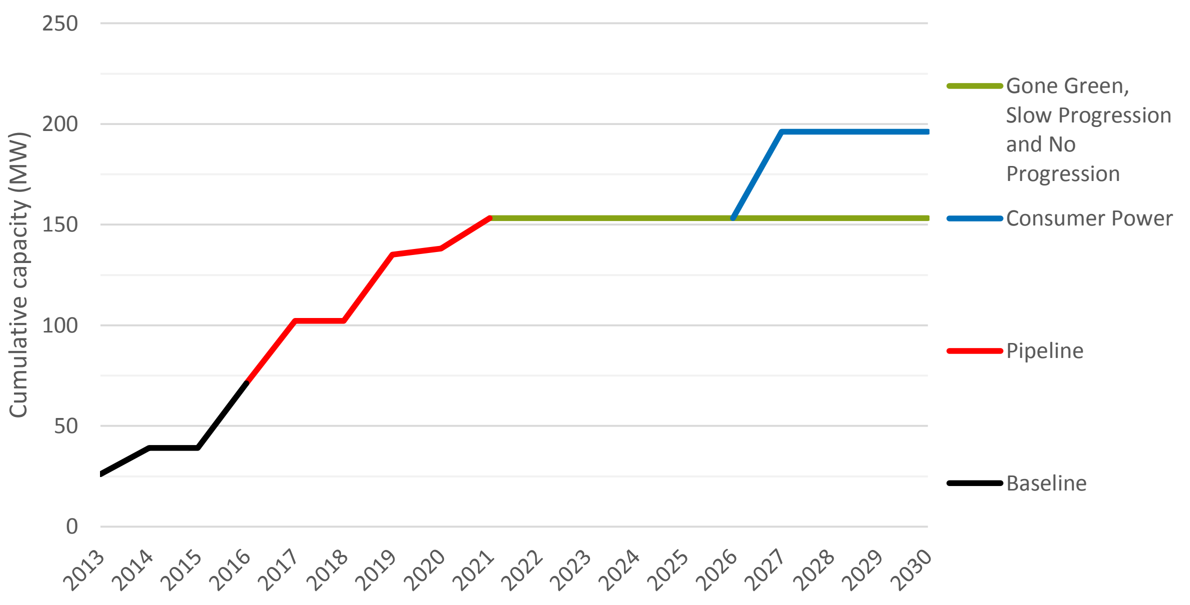


Table 25: Non-cumulative capacity breakdown of energy from waste in the East Midlands licence area (MWe)

	Baseline	Pipeline	Scenarios
Gone Green	71.2	82.0	-

Consumer Power	71.2	82.0	43.0
Slow Progression	71.2	82.0	-
No Progression	71.2	82.0	-

Section 3

Electricity storage technology growth scenarios

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

Section contents

9 Electricity Storage

9.1 Introduction to the electricity storage market

A key challenge in developing future growth scenarios for electrical storage is that, with the exception of existing hydro pumped storage, the market for new storage technologies is relatively immature. Despite this, the level of interest in electricity storage in the UK has grown rapidly in the last year. This has in part been evidenced by the number of connection applications that have received by all the UK network operators, including Western Power Distribution.

The growth in interest in energy storage has been driven by:

- The expected fall in storage costs, in particular, batteries
- The need for higher levels of flexibility and network ancillary services caused by the increased penetration of variable renewable generation and the closure of existing thermal plant
- The availability of high value revenue streams for balancing and ancillary services through the procurement of Enhanced Frequency Response (EFR) and the Capacity Market (CM)
- The parallel slowdown in development of renewable energy (onshore wind and solar PV), which means that resources and capital are available for new opportunities
- The emergence of new revenue streams and business models, which are discussed in more detail in the Regen report Energy Storage: Towards a Commercial Model.

The nature of electricity storage is that it can be used in a very wide range of applications and can therefore access a number of revenue streams. The concept of revenue stacking, putting together a number of revenue streams to create a viable business case, has led to a proliferation of potential business and operating models.

Some of the higher value business models are currently viable, in the sense that they can support investment decisions in the near term, while others are emerging business models that will rely on future cost reduction, as well as market and regulatory changes.

In the Regen market insight paper[3], we have described this market environment as a Rubik's Cube™ reflecting the fact that there are many dimensions, including technologies, revenue streams, applications, costs and regulations that will need to be aligned in order for the storage market to reach its full potential.

Despite this complexity, there is a strong consensus that, given a favourable policy environment, energy storage and electricity storage in particular, could see rapid growth in the coming decades and will become a critical part of the overall UK energy system.

[3] Regen SW, Energy Storage Towards a Commercial Model Sept 2016

It is extremely difficult to develop a firm evidence-based estimate on the level of growth of electricity storage. The FES 2016 has identified a potential market of over 18 GW by 2040[4] under the Consumer Power scenario or over 11 GW under the Gone Green scenario; but a much more modest 3.6 GW, with barely any growth, by 2040 under a No Progression scenario.

Within the FES 2016, there is also a breakdown of energy storage by transmission and distribution networks and the sub 1 MW (domestic and commercial) market. This shows a wide variation in the level of energy storage connected at the distribution network level, ranging from 3.8 GW under Gone Green to over 13 GW under Consumer Power in 2040.

The Committee on Climate Change[5] energy scenario analysis assumes that an additional 10 GW of storage could be added by 2030. This is based on an earlier Carbon Trust analysis that the UK could deploy up to 15 GW of storage by 2030, if storage costs fell significantly.

In the past six months since the FES 2016 was produced, activity in the electricity storage market has intensified and, judging by the number of companies involved, this sub-sector is probably considered to be the most vibrant and exciting area of potential opportunity since the launch of Round 3 offshore wind. Whether the level of commercial interest is realised in deployed projects is a key question.

Table 26: FES 2016 energy storage scenario summary

FES Scenario	Growth potential (inc. 2.7 GW current)	Key growth drivers
Gone Green	11.4 GW by 2040	Large scale central intervention Large scale storage associated with transmission network assets Growth of renewables and new business models.
Consumer Power	18.3 GW by 2040	Widespread deployment of energy storage associated with : • Distributed generation • C&I customers • Domestic and community • Distribution network services model.
Slow Progression	6.4 GW by 2040	Slow deployment roll-out – business models fail to materialise and technology development and cost reductions are less than expected. Lower levels of renewable energy deployment.
No Progression	3.6 GW by 2040	No growth driver – little more than current energy storage

[4] National Grid FES 2016 – including circa 2.7 GW of existing electricity storage

[5] Committee on Climate Change Power Sector Scenarios for the 5th Carbon Budget 2015

	Very low levels of renewable energy deployment.

9.2 Emerging business models for electricity storage

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 whole electricity 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 are currently considered to be the most likely future or emerging business models.

1. **Response services** – providing higher value ancillary services to transmission and distribution network service operators, including frequency response and voltage support
2. **Reserve services** – providing Short Term Operating Reserve (STOR) and Fast Reserve services to provide short and medium term reserve capacity for network balancing
3. **Commercial and industrial (C&I) high energy user behind the meter high energy 'prosumer'** - located with a higher energy user (with on-site generation) to avoid peak energy costs, and transmission and distribution costs while providing energy continuity.
4. **Domestic and community own use** – Domestic, community or small commercial scale storage designed to maximise own use of generated electricity and avoid peak electricity costs.
   Generation co-location - with variable energy generation in order to a) price/time shift b) peak shave to avoid generator curtailment or network reinforcement costs

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 the table below.

Table 27: Emerging business models for electricity storage

Emerging Business Models		Growth drivers	Geographic factors
Response service	**Response service** - providing higher value frequency response services to the grid networks, such as EFR, Firm Frequency Response (FFR), voltage support.	Current requirement for FFR/EFR circa 2 – 3 GW Future demand expected to grow as inertia is lost – potentially 3-4 GW by 2030 Cost competitiveness of battery storage	Co-location with generation assets Ease and cheap access to transmission network – especially the 132 kV network Cheap industrial land
Reserve services	**STOR and Fast Reserve -** providing short term capacity reserve to support network balancing	Development of the STOR and Fast Reserve market. Growth of variable generation and demand.	Larger scale STOR has traditionally been provided by Pumped Hydro. NB smaller and secondary

			providers of STOR services are included in other business models, including co-location and C&I high energy user
C&I high energy user and behind the meter	**High energy 'prosumer' -** located with a higher energy user (with on-site generation to also avoid peak energy costs, transmission and distribution costs while providing energy continuity and potentially STOR and capacity market services.	Viability of behind the meter storage model Price volatility – arbitrage Access embedded benefits – Distribution and transmission Triad Falling battery costs	High energy user with existing or inexpensive distribution network connection/ brown field site likely with generation and network export. Locations with higher network charges
Domestic and community own use with solar PV	**Own use** – Domestic, community or small commercial to maximise "own use " of generated electricity – mainly PV	Deployment of rooftop and small scale solar PV Storage cost reduction Time of Use Tariffs (ToUTs)	Households, commercial and/or community and commercial assets with small scale solar PV <50 kW
Generation co-location	**Co-location** with variable energy generation in order to a) price/time shift b) peak shave to avoid network curtailment or reinforcement cost	Growth of new solar PV and onshore wind generation Energy price volatility Network constraints and curtailment	Locations with new generation projects – especially solar PV and especially with network curtailment

9.2.1 Overlap and risk of double counting

Storage projects do not always fall neatly into just one business model and over the lifetime of a project the business model may change. It is expected that storage projects may target Response services initially but may then also target co-location or price arbitrage benefits in later years, for example if the response service contract is not renewed or if the future value of arbitrage increases.

For the purpose of capacity scenario planning, Regen has focused on the "primary" business model being targeted.

This is especially relevant for STOR and Reserve services business models. In practice, there will be very few storage projects that will specifically target STOR or Reserve services as their primary revenue stream. This may be confined to a small number of larger storage projects using pumped storage (such as the existing Dinorwig power station) or, in the future, compressed air energy storage (CAES). On the other hand, a larger number of Commercial and Industrial and co-location energy storage projects may dip in and out of the STOR market, depending on the time of year and the relative value of STOR contracts.

In the analysis presented below, the Reserve services capacity estimate refers specifically to those projects targeting reserve services as their primary revenue stream and is therefore smaller than the sum of all storage assets that may offer reserve services as part of a secondary service within a wider business model.

As it happens, within the East Midlands Licence Area there are currently no large scale storage (pumped hydro) projects and the opportunity for future pumped hydro would appear limited given the lack of suitable resources.

9.2.2 Other potential business models not treated as separate growth scenario projections

Other emerging business models were also considered for inclusion as part of the scenario analysis. These included:

- An energy trader business model. An energy supply company or market intermediary using electricity storage to arbitrage between low and high price periods, using aggregation and new local and virtual market platforms. While this business model is very likely to emerge in the coming years, it is likely to initially be a virtual business model using the storage assets which have been deployed under one of the other models. So, developing a separate growth projection for this model, as well as being very difficult, would risk double counting. The market is not yet seeing electricity storage deployment as standalone assets purely for the purpose of price arbitrage. For the purpose of capacity planning, we have treated the development of new trading and aggregation models as an additional revenue source and therefore as a potential uplift for the other models.

- Electric vehicles as electricity storage devices. The growth scenarios for electric vehicles is given in chapter 10 of this report. We have not, however, considered the potential use of electric vehicles as a source of energy storage and their potential ability to discharge to meet consumer demand, either directly to households or via the network.

  Upwards of 3 to 5 million electric vehicles on the road by 2030 with a potential storage capacity of 30-60 kWh per vehicle would provide a combined theoretical capacity of circa 90 GWh. If even a small percentage of these vehicles were connected to charging points at any one time, and a small percentage of those charging points were integrated to meet household demand or aggregated to discharge to the network during peak demand periods, the impact on peak supply would be significant.

  While this will be a very real possibility in the future as electric vehicles become ubiquitous, and would have significant network impacts, there are still a number of uncertainties about the uptake of vehicles, vehicle to grid/house integration, and, of course, the commercial and behavioural changes that would be needed to facilitate vehicle to grid discharge.

The growth in electricity demand caused by electric vehicles does, however, feed into the other models and, in particular, the growth of domestic electricity storage under Consumer Power.

9.2.3 Variations in business models

It is recognised that the growth scenario business models are in fact a simplification of more complex business and operating models that could appear in the market, some of which could be seasonal variations.

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 that was only concerned with maximising the consumer's own use of PV generation could evolve into a more sophisticated price sensitive model with the introduction of ToUTs or a variable Export Tariff.

Table 28: Variations in the business models for electricity storage

Business model	Variation 1	Variation 2	Variation 3
Response services	Frequency response	Combined with Triad avoidance	Combined with Capacity Market
Reserve services	STOR or Fast reserve specialist as a primary revenue stream e.g. pumped Storage or CAES	Combined with TRIAD and DUoS avoidance, high energy user and generation co-location Included in C&I high energy and generation co-location below	
C&I high energy users & behind the meter	With generation to maximise own consumption	Combined with peak demand reduction appearing as demand side response (DSR)	Sized for peak export to network to access embedded benefits (Triad and DUoS) and STOR services
Domestic and community own use	Simple rules to maximise own generation consumption	Price sensitive to time of use and/or variable export tariffs	Combined with peer-to peer, virtual or private wire micro network
Generation co-location	Generation arbitrage – time/price transfer	With network curtailment	Winter use for Capacity Market stress events, STOR and Triad avoidance

While we have not produced a separate scenario projection for each business model variation, we have considered the likely evolution of the storage market, and the increasing sophistication of the storage and operating models that that would entail. See also network impacts of electricity storage below.

9.3 UK electricity storage market outlook and scenario assumptions

9.3.1 Energy storage market growth – scenarios overview

The 2016 EFR and T4 Capacity Market auctions have jump-started the electricity storage market development in the UK.

Following on from 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.

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

Assuming that the UK government response to the consultation is positive, and that steps are 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.

In a positive market environment under a Gone Green scenario, other forms of energy storage including larger scale electricity storage such as compressed air and liquid air, heat storage and the integration between heat, power and transport (multi-vector storage) are likely to be viable.

For the Gone Green and Consumer Power growth scenario analysis, Regen has anticipated 3 waves of energy storage deployment during the next decade.

Table 29: Waves of storage deployment - core assumptions for the East Midlands licence area for Gone Green and Consumer Power

Growth factors	GG	CP
Wave 1 - led by response services	**Now 2020**	**-**
• Storage dominates the EFR, FFR, DSR and new voltage support services	●	●
• Higher value services drive market growth with focus on MW and response time	○	○
• First applications for high energy industrial and commercial users behind the meter models	●	○
• Domestic and community scale early adopters		●
• Development of a DSO distribution network model creates new market opportunities	●	○
• Government creates framework for a flexible and smart energy system	●	○

Wave 2 - co-location business models become viable	**Early 2020s**	
• Market for C&I high energy user/generators grows rapidly	○	○
• Emission controls and an attractive business case mean that storage effectively replaces diesel generators for most C&I application	○	○
• First co-location projects with solar PV lead to a rapid expansion and new ground mounted solar PV farms are developed	○	○
• Domestic and community scale storage market expands rapidly driven by falling costs		●
Wave 3 - expansion and new market models	**Later 2020s**	
• Aggregation and new trading platforms develop	○	○
• Local supply markets, private wire and virtual markets rely heavily on electricity storage		●
	○	●
• Domestic electricity storage becomes common as costs fall and electric vehicle purchases increase, alongside growth in the electrification of heat	●	○
• Most new solar and wind farms now include electricity storage to harness low marginal cost energy and price arbitrage	○	○
• Towards the end of the decade, heat storage and electricity storage are increasingly integrated	○	○
• UK meets 2030 de-carbonisation targets		

The overall storage deployment outcome for the Gone Green and Consumer Power scenarios are similar although, as discussed below, the balance of projects and drivers is slightly different.

The Slow Progression and No Progression models would imply that, after the initial enthusiasm for electricity storage as a result of the EFR and Capacity Market auctions, future growth stalls.

Given the UK's legally binding commitment[6] to decarbonisation, and the fundamental need to increase energy flexibility, it seems increasing unlikely that a No Progression scenario for electricity storage is realistic. Regen has therefore not given this scenario significant analysis and in general has assumed that No Progression is 50 per cent of a Slow Progression scenario.

[6] UK 5th Carbon Budget enacted July 2016

Table 30: Waves of storage deployment - core assumptions for the East Midlands licence area for Slow Progression and No Progression

Growth factors	SP	NP
Wave 1 - stalls	**Now 2020**	**-**
• After initial deployment of EFR and Capacity Market storage projects,	●	●
the storage market stalls	○	○
• Follow up EFR and FFR auctions are limited	●	○
• Government does not create an effective framework for a flexible and	●	
smart energy system	●	●
• Revenue uncertainty and regulatory barriers dissuade investment		○
• C&I business models are curtailed by changes to embedded benefits	●	
• Domestic and community scale early adopters		○
Wave 2 - co-location business models do not become viable	**Early 2020s**	
• Market for C&I high energy user/generators is difficult	○	○
• Lower PV and renewable energy growth and business case challenges	○	○
limit the number of co-location opportunities		
• Delays in coal decommissioning and new CCGT plants reduce need for	○	●
storage solutions	○	●
• Domestic and community scale storage market fails to take off akin to		
the current situation with heat pumps	○	●
• Anticipated cost reduction in electricity storage is less than expected		
Wave 3 - new market models curtailed as 2030 decarbonisation targets are not met	**Later 2020s**	
• Aggregation and new trading platforms struggle to become viable due	○	○
to technical, commercial and regulatory challenges		
• Local supply markets, private wire and virtual markets rely heavily on		●
electricity storage	○	●
• Domestic electricity storage becomes common as costs fall and		
electric vehicle purchases increase, alongside growth in the	●	○
electrification of heat		
• Most new solar and wind farms now include electricity storage to	○	○
harness low marginal cost energy and price arbitrage		
• UK fails to meet 2030 decarbonisation targets		

9.3.2 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[7] have projected that storage costs could fall from circa $500/kWh today to under $150 per kWh in the early 2020s.

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.

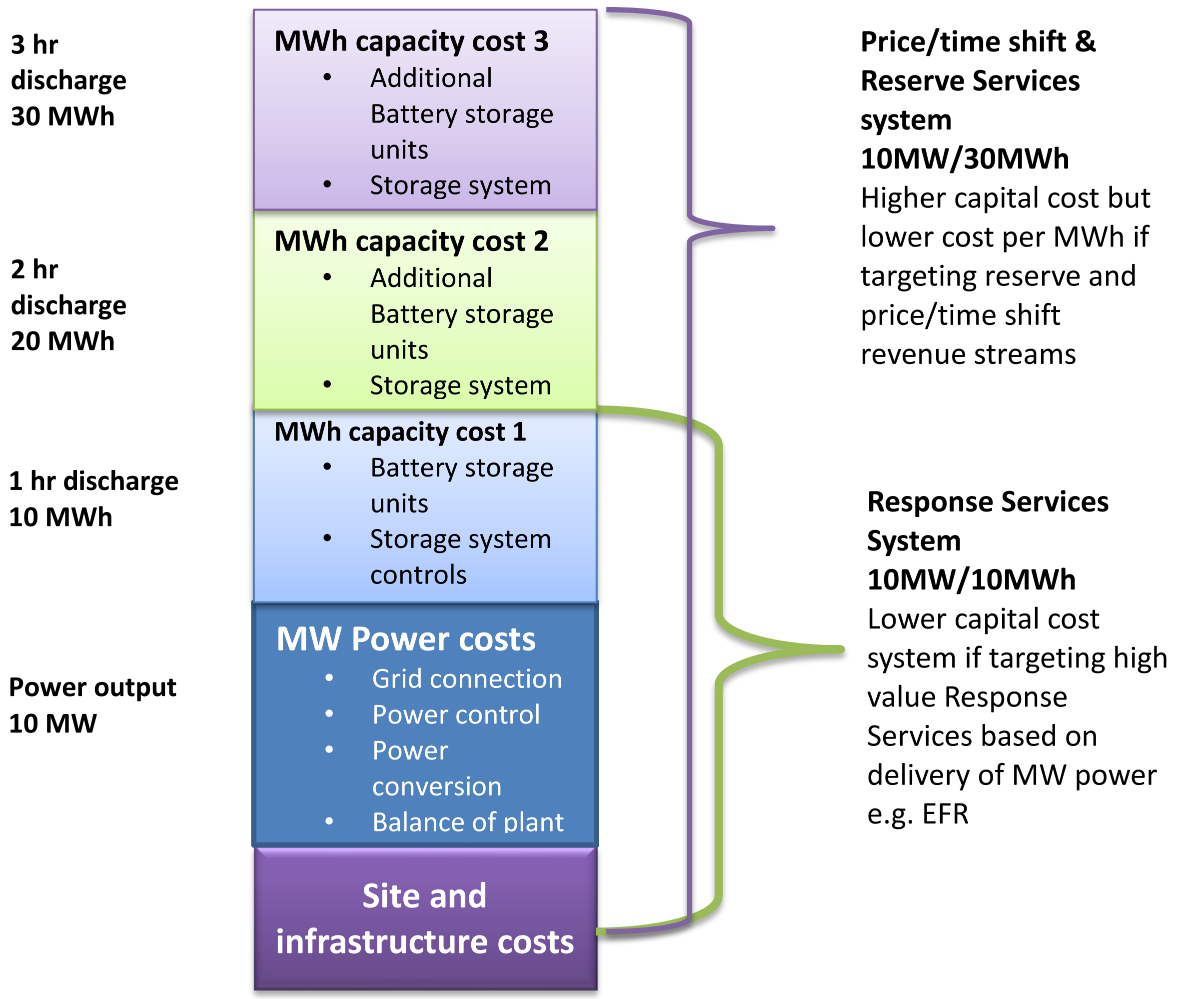
Electricity storage cost is not however a simple linear function. A key consideration to fully assess the potential cost of battery storage is to understand the relationship between the MW power requirement, MWh storage capacity and the overall system specification. This relationship is discussed in 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.

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

Figure 35: 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[8].

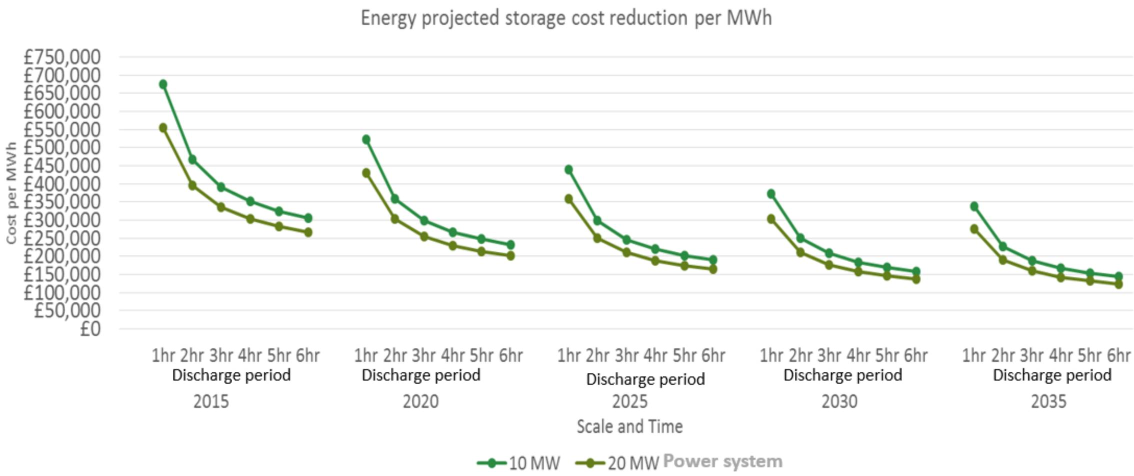
We are already seeing this trend in the domestic and small scale battery system. Installers tell us that the older 2 kW/2 kWh systems are now virtually unsellable and that most new installations are of a 2 kW/6 kWh or indeed a 4 kW/12 kWh system.

[8] 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.

A 1:4 ratio (4 hours of storage) is considered to be the current limit of cost efficiency for lithium ion batteries, but this could radically change with further innovation, including the development of alternative electro/chemical battery solutions.

The Gone Green and Consumer Power growth scenario assume that battery storage costs will fall rapidly achieving a full system cost of circa £150,000 per MWh by 2025. At this level of cost reduction, price arbitrage and peak shaving based business models become very attractive.

Figure 36: Electricity storage cost reduction



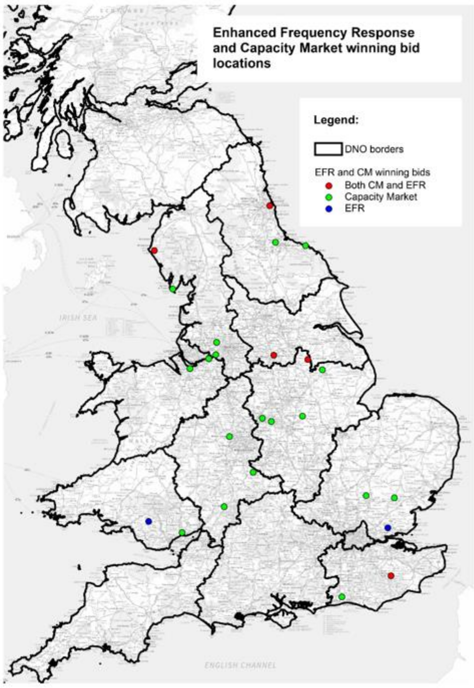
Gone Green and Consumer Power scenarios assume rapidly falling storage costs in the next ten years

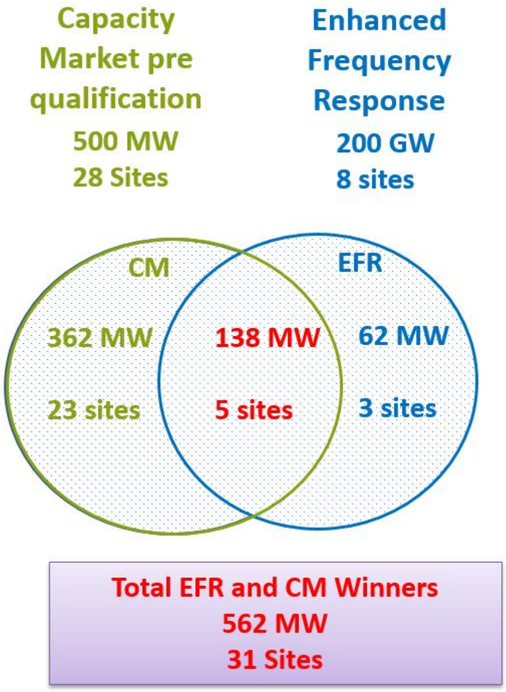
For the East Midlands licence area scenario analysis, we have assumed that the ratio of MWh to MW storage varies by business model and will also increase through the decade.

9.3.3 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.

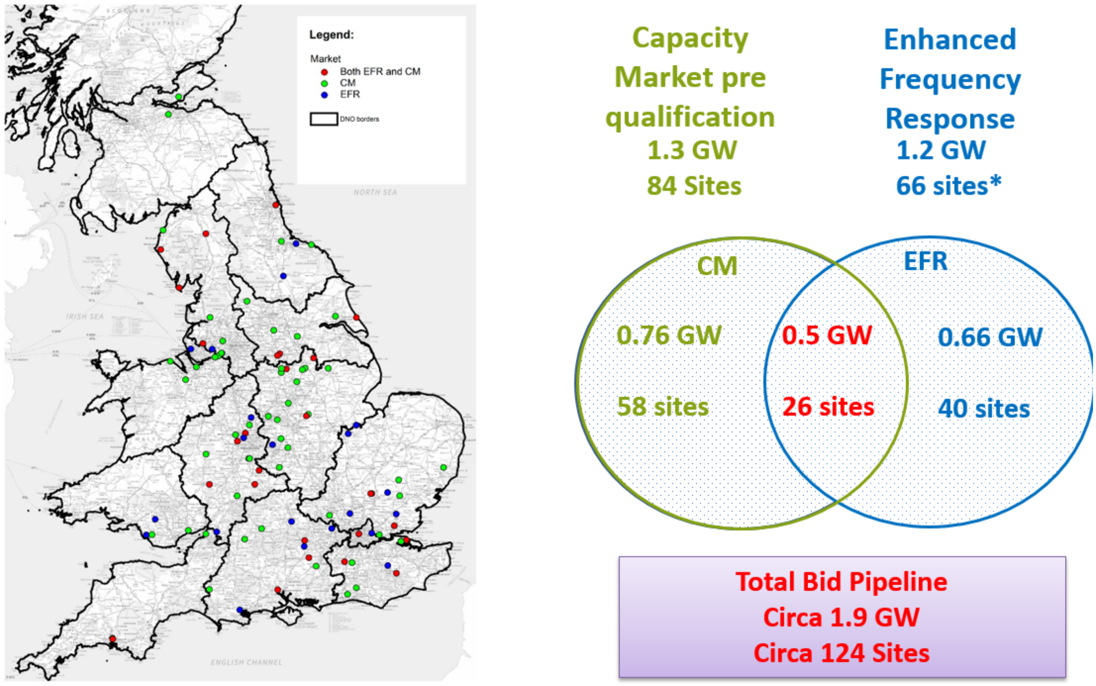
Figure 37: 2016 EFR and T4 Capacity Market auction winner - new battery storage





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[9].

[9] 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.



* National Grid reports a lower figure @ 62

Figure 38: All EFR and T4 Capacity Market auction bidders, pre-qualification

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 West, 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 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.

The implication of this locational analysis is discussed below.

9.3.4 UK growth outlook for response services

The success of the EFR auction both in terms of the number of bids received and the lower than anticipated winning prices, suggests that battery storage is well placed to dominate the future market for response services, including the key areas of frequency response and voltage support.

The key question, therefore, is the size of this market and how quickly it is expected to grow. The market growth analysis is complicated by two further factors:

- Currently a significant element of response service is provided inherently in the form of system inertia by larger generators, including coal fired power stations. As coal fired power stations are shut down, under all but in a No Progression scenario, it is expected that the requirement for response services will grow significantly. But the extent of this new market requirement is not yet clear and will depend on a number of factors.
- The move towards a DSO model for network management implies that a greater proportion of response services and network balancing will be procured and operated at the distribution network level. DSOs could therefore become a major market for storage providers. Indeed, some analysts have identified that DSOs may choose storage solutions not just as part of their active network management strategies, but also as a cost effective alternative to costly network capacity investment. The trial at Leighton Buzzard has explored this opportunity.

The recent National Grid System Operability Framework 2016 combines future industry growth scenarios with a technical assessment, to identify medium and long term requirements for operability, including the development of codes, services and asset solutions that may be required to maintain system operability.

National Grid has also announced that in the spring of 2017[10] it will publish an additional analysis of the future SOF requirements, including an indication of the market scale for operability services and an indication of timescales. When published, this "so what SOF" analysis is expected to provide a much clearer future view for investors looking at storage innovation and flexibility services. National Grid has also indicated that it intends to review the way in which flexibility is defined and procured in order to encourage greater innovation and competition in the market.

For the purpose of the WPD East Midlands licence area growth scenario analysis, we have made an assumption that in the Gone Green and Consumer Power scenarios the market for response services in Great Britain will grow in the next decade from circa 2 GW (EFR and FFR) today to circa 3-4 GW by 2030.

We have also assumed that, in the Gone Green and Consumer Power scenarios, battery storage providers connected at the distribution network level will dominate this market providing up to 2-2.5 GW of response services by 2030.

[10] National Grid Power Responsive – Energy Storage Group workshop 6th December 2016

We have also assumed that in the short term National Grid will procure additional EFR capacity before 2020 and that new entrant storage providers, especially those that have won 2016 and 2017 T4 Capacity Market contracts, will begin to compete in the Firm Frequency Response market by 2020.

These assumptions will need to be reviewed once the National Grid SOF market analysis is published.

Alternative No Progression scenarios are:

a) the market for response services fails to grow (e.g. because coal and/or new CCGTs continue to provide inertia services electricity storage)
b) the government fails to create a regulatory framework for a smart and flexible energy system
c) battery storage costs do not reduce as expected.

9.3.5 UK growth outlook for reserve service projects

The definition of Reserve service assets is confined to those projects that are primarily or wholly aimed at providing peak load capacity reserve such as STOR and Fast Reserve.

This does not therefore include the very large number of storage providers who may provide STOR and capacity market services as a secondary service alongside other business models such as co-location, Commercial and Industrial and response services.

Reserve service projects would therefore likely be larger storage projects using pumped hydro and in the future potentially flow batteries, compressed air or hydrogen conversion technologies.

It is difficult to assess the market outlook for Reserve services at present. Only one new pumped hydro scheme bid into the 2016 T4 Capacity Market, a 49 MW scheme in Snowdonia. The challenge at the moment is that the revenue returns from STOR contracts and from the wider Capacity Market make it very difficult to countenance capital investment in a long term infrastructure project.

While large scale storage is a valuable addition to the UK energy mix, the availability of other forms of flexibility through battery storage, DSR and interconnection will tend to crowd out larger more capital intensive storage schemes unless these are supported through an additional market support mechanism.

For the East Midlands Licence area, we have projected very limited Reserve service projects. This is in part due to the geography which does not lend itself to pumped storage, and the assessment that co-location and Commercial & Industrial storage business models are likely to be more prevalent in the region. A single Reserve service project has been added in the latter part of the next decade for modelling purposes.

9.3.6 UK growth outlook for C&I behind the meter electricity storage

The C&I high energy user storage business model, which includes other high energy users such as hospitals, data centres and public institutions, could become a significant area of growth.

The business model is based on using storage as a means to avoid peak energy commodity and network costs. The business model is enhanced if on-site generation, such as PV, wind or in some cases AD or other CHP is included.

The behind the meter element recognises that, in many cases, this business model will appear to the network as a demand side response or demand turndown. In many cases, however, on-site generation enhanced by electricity storage will be sized to export to the network during peak price periods. This is especially true if transmission charge Triad avoidance is a key revenue target.

Revenue or cost reduction benefit streams include:

- Electricity (commodity) peak price avoidance
- Distribution network cost avoidance (DUoS) and other distribution network charges
- Transmission network cost avoidance
- Maximising own use of self-generation
- Optimising price use of self-generation
- Capacity Market reserve services or STOR services
- Demand side response service
- Back-up continuity of supply service

The C&I high energy user model looks to be an attractive opportunity and is already being targeted by a number of storage developers. It is notable that a high proportion (over 30%) of Capacity Market bidders have located their sites within or near industrial and high energy users. Whether this correlation is because there is a long term strategy to access C&I revenue streams is not certain, and the approximate location may be as much to do with network strength and cheap brownfield land space.

Regen is aware of several developers and consultancies that are actively targeting C&I opportunities, which could herald a rapid expansion of this type of storage project.

The attractiveness of this business model has, however, been dampened by recent announcements regarding embedded benefits, including the future changes to both transmission charging[11] and a reduction in red band peak distribution network charging[12].

[11] See Ofgem Open Letter on Embedded Benefits 2016

[12] Ofgem has announced that it has approved another code modification to the Common Distribution Charging Methodology (CDP228), to be introduced in 2018, which will significantly reduce the level of peak Red Band charging in favour of higher off-peak charges.

The current and future potential size of the C&I high energy user market is uncertain. The behind the meter nature of many current applications means that there is limited visibility of the current market.

For the WPD East Midlands licence area scenario development, we have assumed that the UK market for the C&I high energy user model could grow:

- Under Gone Green and Consumer Power scenarios, the C&I market expands rapidly as storage costs fall and revenue streams become more certain. The market could increase to 2.5 GW - 4 GW by 2030 as electricity storage effectively replaces diesel generators as the preferred C&I technology
- Slow Progression is a slower uptake version of Gone Green
- No Progression would see very limited growth and a continued reliance on diesel generators – an unlikely scenario.

9.3.7 UK growth outlook for the renewable energy co-location business model

Intuitively, co-locating electricity storage next to variable renewable energy generators, such as solar PV and on or offshore wind makes perfect sense. The ability to harness very low marginal cost energy, or even effectively free energy that is network constrained, and then to price/time shift that electricity to peak demand periods, creates an obvious value stream.

The widespread deployment of storage to harness variable energy generation would be a major contribution to the UK's energy system and would truly revolutionise the extent to which renewable energy can be expanded without incurring major system costs and energy security issues.

Electricity storage would be particularly useful in areas where, although there is high energy resource, there are major network constraints; for example, in Scottish Highlands and Islands, Cornwall and the South West and Wales.

There is strong evidence that renewable energy generators are indeed looking at co-location opportunities. From the engagement work Regen is doing and through our developers' forum, we can see a strong pipeline of potential co-location projects at an early stage of development.

Further evidence comes from the 2016 EFR and Capacity Market auctions. A high proportion (circa 40 per cent) of EFR and Capacity Market bid sites were located proximate to existing and new solar PV farms, which could be evidence that bidders are looking at future co-location business models.

However, this geographic proximity evidence needs to be viewed with caution.

At present, a viable business model for renewable energy co-location is difficult to achieve in its purest form (targeting price arbitrage) and, except in places of extreme network constraint, the cost and scale of storage required to effectively price/time shift significant electricity generation is prohibitive.

The geographic correlation between EFR and Capacity Market storage projects and existing or new PV sites does not necessarily imply a firm commercial relationship and could well be due to the proximity to available network capacity or an intention to share infrastructure. There is also evidence of PV site developers effectively putting their PV projects on hold, due to subsidy reduction, and applying for a amendment to their connection offer to opportunistically switch technology to electricity storage. It would be interesting to analyse the number of technology amendments to an existing connection offer WPD has received and whether there is a pattern of switching from PV to storage.

So, there are some mixed messages at the moment regarding renewable energy co-location, and until the first commercial co-location projects are deployed – in the next 2-3 years – it is not yet clear how quickly the market will develop.

What is clear, however is that, if storage costs continue to fall, it is very likely that new renewable energy projects will combine generation and storage. In a Gone Green or Consumer Power scenario, one would expect that the bulk of new PV and wind developments would have a storage component. For a solar PV co-location, the ratio between PV generation capacity (MW), storage power capacity (MW) and electricity storage capacity (MWh) could be 1:1:4 or potentially more. Given that in a Gone Green or Consumer Power scenario, solar PV could reach 30-36 GW by 2040[13] the market for co-located storage could be significant.

Recognising the current challenge to make the business model stack up, and the present slowdown of PV and onshore wind deployments, we have assumed a more modest growth in renewable energy co-location projects of 2 GW/ 7 GWh by 2030. This is a conservative assumption and under more favourable market conditions storage growth could be significantly higher[14].

9.3.8 UK growth outlook for domestic and community scale storage

Small scale storage solutions used in domestic households, community scale projects and for smaller industrial and commercial applications could become a significant market over the next decade.

The small scale storage market could be split into a number of sub-sectors:

- Domestic consumers installing batteries – usually alongside PV – to maximise their own consumption of generated energy
- Community groups looking to install batteries with new or existing generating assets
- Small C&I companies
- There is also an emerging market for small scale storage aggregation– targeting demand side response and other revenue streams – peer-to-peer energy trading, private wire and local energy market applications.

[13] National Grid Future Energy Scenarios 2016

[14] Regen is working on a separate paper on the potential for renewable energy co-located projects due late spring 2017

How quickly these markets will develop will depend on the falling cost of battery storage.

New and cheaper battery based storage[15] solutions are already available and there has been significant public interest in the technology. Companies in the UK targeting this sector, including Regen member organisations, are reporting a small but growing market for domestic batteries. Although the business case for domestic batteries is not yet compelling, with payback periods of ten years plus, the market is beginning to pick-up through early adopters and some interest also from social housing providers.

Under a Gone Green or Consumer Power scenario, we have assumed that the market for small scale battery storage will grow rapidly in the coming decade, potentially reaching 1.5 to 2 GW by 2030. This scenario projection, which is less than the growth in solar PV we have experienced in the last five years, recognises that, in the absence of subsidy support, the business case for small scale storage will be based on variable electricity prices and ToUTs.

If 1 GW of small scale storage were domestic installations, this would represent less than 1 per cent of UK households, compared to the 2.9 per cent of UK households currently with solar PV. There will be a greater concentration of storage deployment in southern areas of the UK where there are high levels of PV installations.

Growth could be greater if a subsidy were introduced. In Germany, for example, around 30 to 40 per cent of new PV installations now include electricity storage. However, even in a Gone Green scenario, we have assumed that a storage subsidy is unlikely.

Towards the end of the decade, the roll-out of electric vehicles could, depending on how they are charged, accelerate the growth of domestic battery storage. Some households may elect to install a domestic battery in order to store self-generated energy for night-time charging of electric vehicles, while batteries may also allow more rapid electric vehicle charging.

[15] For example Tesla Powerwall www.tesla.com/en_GB/powerwall

9.3.9 Summary of Great Britain market growth outlook assumptions

Table 31: Great Britain market scenario growth assumptions to 2030 gives a summary of the Great Britain storage market growth assumptions that Regen has adopted.

Table 31: Great Britain market scenario growth assumptions to 2030

	Great Britain market scenario growth assumptions by 2030* Used to underpin East Midlands licence area scenarios		
Business model	**Gone Green and Consumer Power**	**No and Slow Progression**	**Possible upside very high growth scenario**
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.

9.4 WPD East Midlands licence area storage analysis

9.4.1 East Midlands pipeline analysis to 2020

Analysis of the EFR and Capacity Market auctions' bids plus the WPD database of accepted-not-yet-connected connection offers (September 2016) suggest that there are circa 27 storage sites in active development in the East Midlands licence area with a combined capacity of circa 395 MW[16] .

Table 32: Breakdown of visible electricity storage pipeline sites

Category	Number of sites	Capacity (MW)	With connection agreement*	Close to solar projects	Close to industrial sites
Capacity Market	14	186	11	6	5
(Of which Capacity Market winning bids)	(4)	(38)	(4)		
Both EFR and Capacity Market Bids**	2	9	1	2	1
EFR Bid Only	1	20			
Other sites with agreement accepted	11	178	11	3	5
Total	**27**	**395**	**23**	**11**	**11**

* As of Dec 2016 WPD database of accepted-not-yet-connected connection offers
**Does not include the EFR and Capacity Market EDF 47 MW project at West Burton power project which is transmission network connected.

This analysis does not include other potential storage projects that have not yet been accepted, or are awaiting a connection offer. 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]:

- Green Hedge Energy Barn Limited – Breach Farm – 9.4 MW (1)
- Green Hedge Energy Barn Limited – Breach Farm – 9.4 MW (2)
- Green Hedge Energy Barn Limited – Breach Farm – 9.4 MW (3)
- UK Energy Reserve Limited – Multiple sites – 7 MW

For the Consumer Power and Gone Green scenarios, we have assumed that the four winning Capacity Market sites are built by 2020 and that an additional 60-70 MW of capacity is added from

[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.

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

the other pipeline sites, C&I behind the meter and domestic electricity storage. This would give a total installed capacity of circa 110 MW by 2020.

For the Slow Progression scenario, Regen has also assumed that the three winning bids will be constructed. This seems likely, but could be optimistic since there is the potential in a No Progression scenario (a poor outcome to the current Smart and Flexible energy consultation for example) for winning bid project to not proceed.

9.4.2 Future East 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 around 1GW-1.2GW/ 3-3.6GWh in the East Midlands licence area by 2030. This would be consistent with the East Midlands providing around 10 per cent of the Great Britain energy storage capacity.

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.

Table 33: Electricity storage scenarios results for the East Midlands licence area

WPD East Midlands Licence Area - Electricity Storage Growth Scenarios

	Storage Power (MW)	2017	2020	2025	2030
Gone Green	Response services	-	70	130	150
	Reserve Services		-	150	150
	High energy C&I	-	22	158	264
	Domestic and community	-	10	108	362
	Co-location	-	7	164	353
			-	-	-
	Total power (MW)	-	109	711	1,279
			-	-	-
Consumer Power	Response services	-	70	130	150
	Reserve Services		-	-	100
	High energy C&I	-	20	158	264
	Domestic and community	-	12	130	417
	Co-location	-	9	101	168
			-	-	-
	Total power (MW)	-	111	519	1,099
Slow Progression	Response services	-	40	78	78
	Reserve Services		-	-	100
	High energy C&I	-	20	96	160
	Domestic and community	-	1	24	97
	Co-location	-	2	37	101
			-	-	-
	Total power (MW)	-	63	235	536
			-	-	-
No Progression	Response services	-	39	54	51
	Reserve Services		-	-	-
	High energy C&I	-	20	48	80
	Domestic and community	-	0	8	26
	Co-location	-	1	8	56
			-	-	-
	Total power (MW)	-	60	118	214

	Storage capacity (MWh)	2,017	2,020	2,025	2,030
Gone Green	Response services	-	70	130	150
	Reserve Services		-	450	450
	High energy C&I	-	66	518	930
	Domestic and community	-	16	204	920
	Co-location	-	21	557	1,217
			-	-	-
	Total capacity (MWh)	-	173	1,858	3,666
Consumer Power	Response services	-	70	130	150
	Reserve Services		-	-	300
	High energy C&I	-	60	518	930
	Domestic and community	-	18	240	1,056
	Co-location	-	26	340	575
			-	-	-
	Total capacity (MWh)	-	174	1,228	3,010
Slow Progression	Response services	-	40	78	78
	Reserve Services		-	-	300
	High energy C&I	-	60	311	560
	Domestic and community	-	2	47	253
	Co-location	-	6	124	348
			-	-	-
	Total capacity (MWh)	-	108	560	1,540
No Progression	Response services	-	39	54	51
	Reserve Services		-	-	-
	High energy C&I	-	60	152	277
	Domestic and community	-	1	15	68
	Co-location	-	2	29	196
			-	-	-
	Total capacity (MWh)	-	102	250	592

Figure 39: East Midlands Growth scenarios electricity storage power (MW)

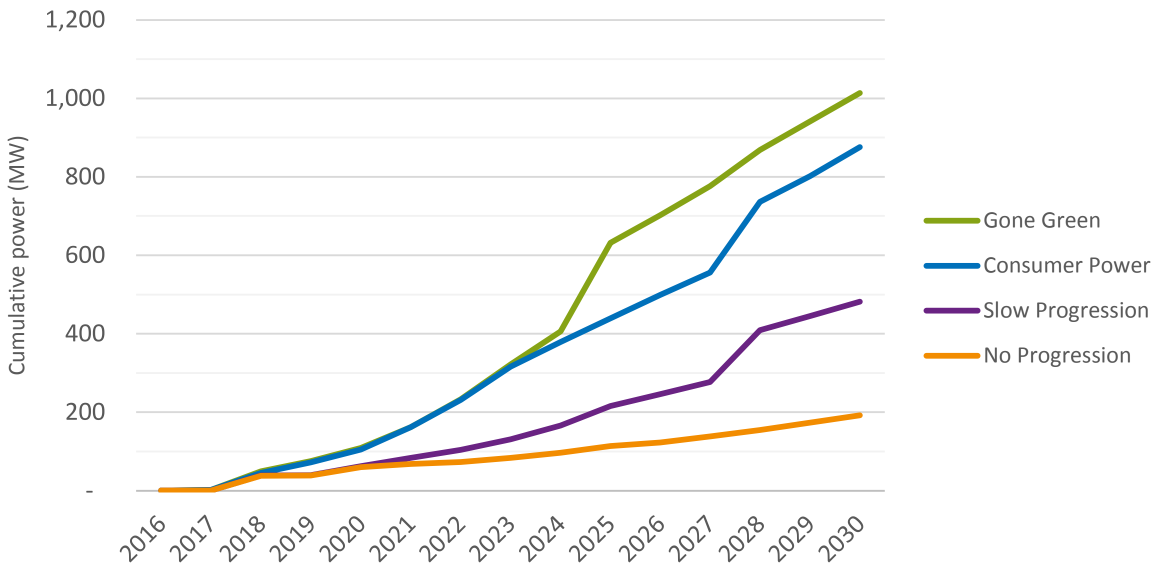
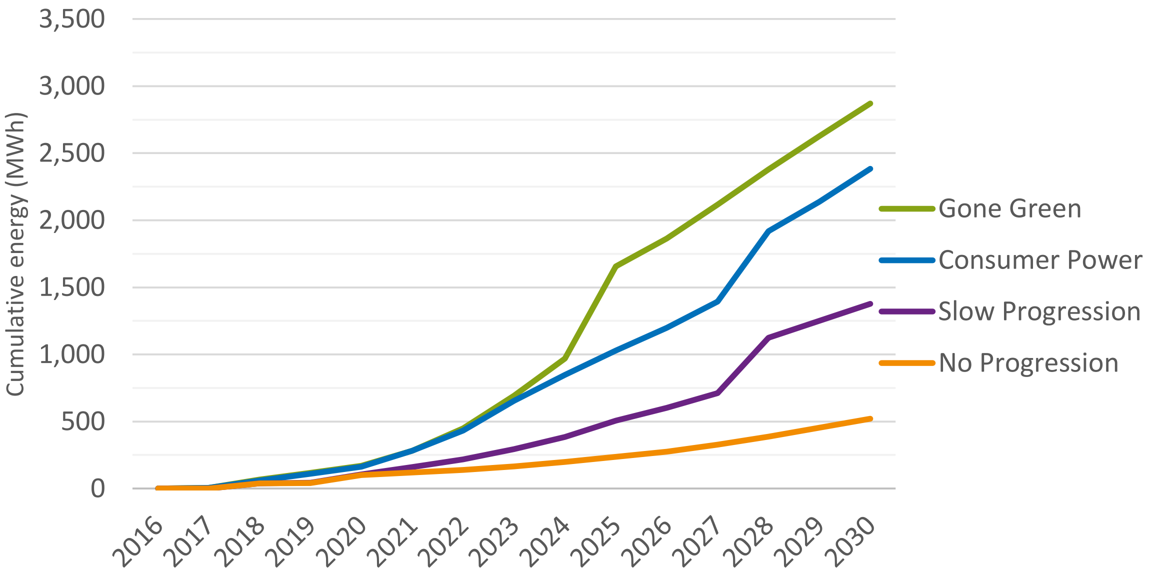


Figure 40: East Midlands growth scenarios electricity storage capacity (MWh)



9.4.3 Geographic distribution of electricity storage across ESAs

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

The evidence based on the visible pipeline of Capacity Market and EFR auction bids and current accepted network connection agreements would suggest that the bulk of early projects are likely to be in the more heavily industrialised west and north of the licence area and that proximity to available capacity on the 132 kV network is the overriding locational factor.

Analysis of the 27 pipeline sites suggests that a significant proportion (40 per cent) are located next to existing or planned solar PV projects, while an equal number are located in or near industrial sites. As discussed above, the correlation between storage sites and solar PV or industrial sites could be misleading and does not necessarily imply a commercial business model relationship, but could simply reflect network connection availability.

Geographically the majority of the East Midlands sites are to the west of the licence area, in areas of more industrial development. In fact there is a very close correlation between the site locations and the 132 kV network, which suggests that the overwhelming locational criteria is ease and cost of access to the network.

It is also notable that the majority of Capacity Market bids have already accepted a connection offer, while there are 11 accepted connection offers that do not appear to have bid into either the EFR auction or the Capacity Market. Presumably these sites have either fallen away or are intended for another business model, such as Firm Frequency Response, generation co-location and/or commercial & industrial energy user.

Looking to the future, under a Gone Green or Consumer Power scenario, the analysis would suggest more even distribution of electricity storage across the East 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 west of the region.

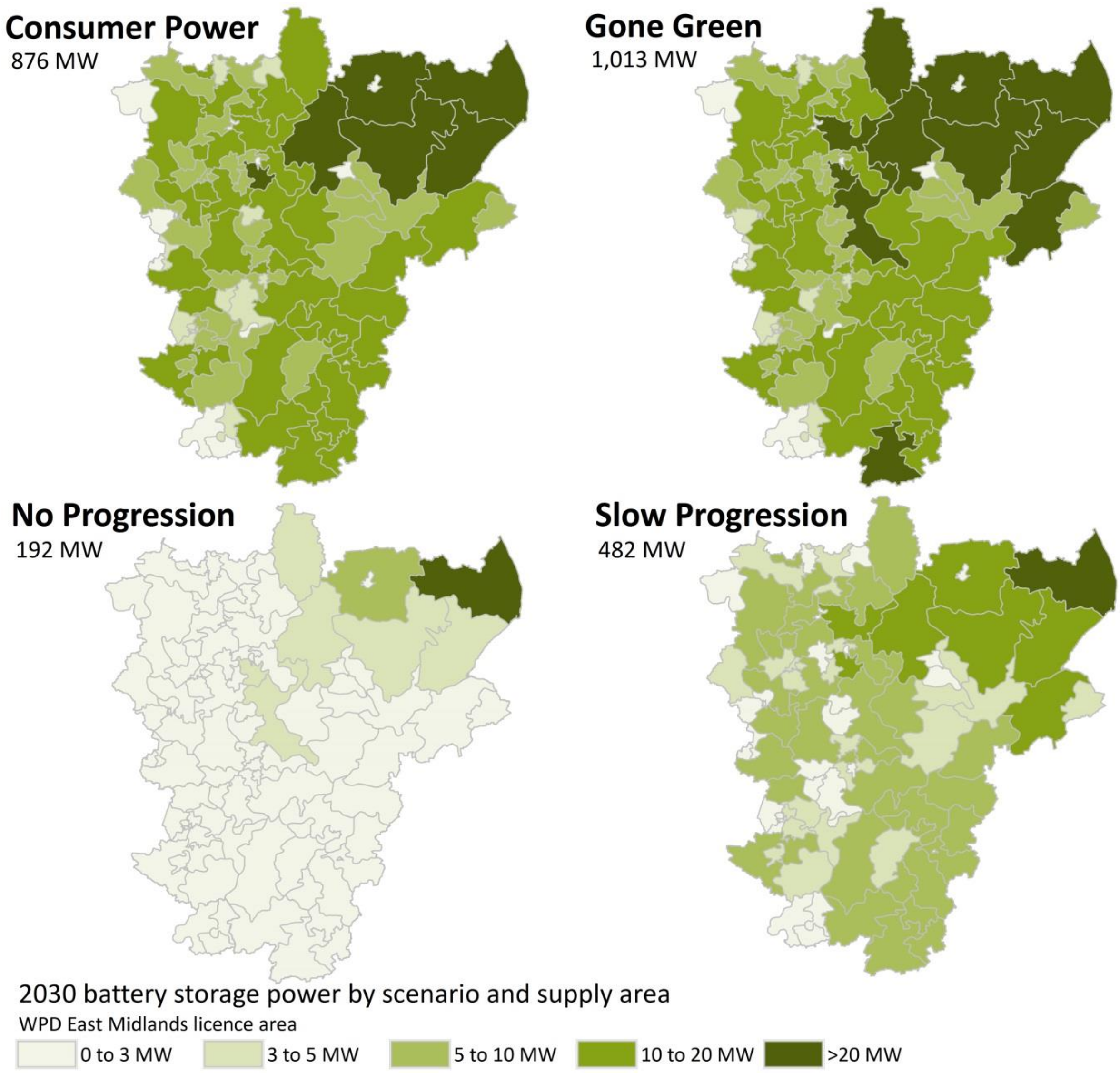
In the case of Consumer Power, the higher deployment of small scale storage would imply a greater correlation with domestic households and in particular areas with high levels of rooftop PV installation.

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

Table 34: 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-mounted solar PV
Generation co-location	Distribution of ground-mounted solar PV (will potentially underestimate correlation with wind)

Figure 41: 2030 battery storage capacity distribution



9.4.4 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 active 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, will develop a Standard Operating Mode for each of the five business model 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.

Ideally it would be preferable to have one standard operating mode for each business model and Regen will work with the WPD Network Strategy team to see if this is viable without losing model accuracy. The business models do however have a number of variations and potentially seasonal variation, which would have to be modelled separately. It is likely therefore that two or possibly three standard models will be required for each business model.

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 42: 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

10 Electric vehicles

10.1 Baseline: electric vehicles growth to 2016

The baseline for the East Midlands licence area is drawn from anonymised DVLA registered keeper data provided by WPD. Unlike other datasets available from the Office from Low Emission Vehicles which set out where vehicles were purchased, this DVLA data sets out the number of electric vehicles owned in each postcode area, for each quarter from June 2012. It gives the location of electric vehicle users with a high level of accuracy.

The data shows 6,892 electric vehicle users in the licence area. This is lower than might be expected based on the area's population. Low deployment in the east of the licence area seems to be the reason for this; vehicle use in these rural areas is less suited to current electric vehicles. However, sales growth of electric vehicles in the East Midlands has been exponential, reflecting the national picture – growing from 0.1 per cent of total vehicle purchases in quarter four of 2012, to nearly 2 per cent of purchases in quarter one of 2016.

Electric vehicle ownership is concentrated along the M1 corridor in the East Midlands. Thanks in part to "Go Ultra Low City" funding enabling a programme of council-led infrastructure investment and awareness raising, Milton Keynes and Nottingham both have high levels of electric vehicle ownership. For example, Milton Keynes now allows free parking for electric vehicles across 15,000 parking spaces, as well as investing in a charge point roll out programme; and Nottingham has the largest electric bus fleet in Europe. Derby and Leicester also have relatively high levels of electric vehicle ownership.

10.2 Pipeline: electric vehicles

There is no pipeline for electric vehicles.

10.3 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 more than 80,000 by December 2016. Electric vehicles made up 0.5 per cent of new car sales in 2014, 1 per cent in 2015 and are estimated to reach nearly 2 per cent by the end of 2016. Just under 10,000 electric vehicles were registered in the UK from April 2016 to June 2016, an increase of 49 per cent on the same period in 2015 and 253 per cent on 2014.

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.

10.3.1 High consumer awareness of electric vehicles

Buying an electric car is not radically different from buying a fossil fuel car. There were 47 different models available in January 2017[18], 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.

10.3.2 Promoting electric vehicles is politically attractive

There is strong political backing for the roll-out of electric vehicles, which are seen as 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 £150 million for cleaner buses and taxis, further charging point investment and investment in the development of advanced renewable fuels. A further £100 million is being invested in the development of driverless cars.
- Electric vehicles and hybrids do not have to pay road tax under current rules. This is due to change in 2017, with electric vehicles still free to tax, unless they cost over £40,000, and tax being introduced for hybrid models.

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[19]. Revised plans are likely to include charges for using diesel vehicles in major cities or in some locations a ban on their use altogether. There is likely to be a huge shift away from diesel vehicles in the near future.

[18] http://www.nextgreencar.com/electric-cars/statistics/

[19] http://www.clientearth.org/major-victory-health-uk-high-court-government-inaction-air-pollution/

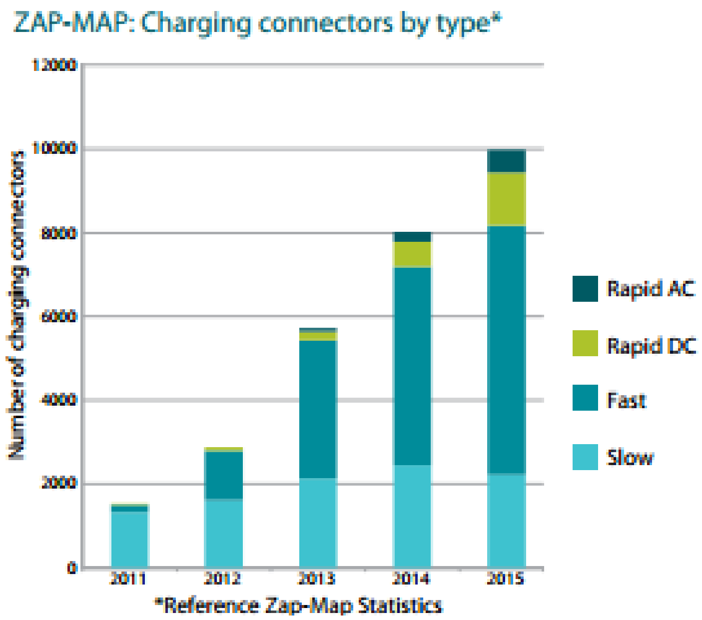
10.3.3 Falling costs, improved performance and increased availability of electric vehicle infrastructure

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 than conventional cars by 2022, based largely on falling battery prices.

There are a number of 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.

According to Zap-Map, there are over 11,850 connectors at over 4,200 public charging point locations across the UK, with their number growing consistently each month. The East Midlands has fewer public charging points than other regions, with 338 connectors in January 2017, 3.6 per cent of the UK's total charge points.[20]

Figure 43: Type of charging connectors



10.3.4 Impact of electric vehicles on the electricity network

There is the potential for electric vehicles to have a significant impact on the network. A particular concern is that they will lead to spikes in demand at both a local network level where clusters develop and at national grid level. Current 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 and WPD's project, Electric Nation.

[20] Data from Zap Map https://www.zap-map.com/statistics/#region

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.

10.3.5 New ownership models for electric vehicles

In urban centres, new car ownership models have been developed 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 vehicle sales and on electric vehicle sales in particular is uncertain and may need to be considered in future assessments.

10.3.6 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. Biomethane is also growing as a fuel.

However, these alternatives are likely to play a smaller role in the low emission vehicle market and are concentrated in freight vehicles. Electric vehicles' infrastructure is a step ahead in its development and the technology as a whole is more established in both performance terms and in the public's perception. As a result, there is a degree of first mover advantage for electric vehicles against hydrogen and biomethane vehicles, coupled with some potential technology advantages, such as the ability to "re-fuel" at home.

10.4 Scenarios: electric vehicles, 2016 to 2030

10.4.1 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 a little variation 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 needs consideration at a later date.

Table 35: Potential factors affecting electric vehicle deployment

Growth factors	GG	CP	SP	NP
Government influenced factors				
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	●	●	●	

10.4.2 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 licence area represents 8 per cent of UK car sales, which would mean that if a straightforward apportioning of the scenario FES is undertaken, 465,000 electric cars would be sold in the East Midlands licence area by 2030 under a Gone Green scenario.

However, feedback from the industry is that the FES estimates for the UK under Gone Green are lower than could occur. We estimate that a Gone Green scenario in the East Midlands licence area would result in 785,000 EV purchases by 2030, almost 1.7 times higher than the FES estimates for the UK.

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 36: Scenarios summary for electric vehicles in the East Midlands

Consumer Power	Gone Green
• High growth scenario (but lower than Gone Green) • 54 per cent of cars sold in 2030 are electric, with over 580,000 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 focussed in areas with off-road parking	• Highest overall growth scenario • 67.5 per cent of cars purchased in 2030 are electric, with over 785,000 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 • 13.5 per cent of cars sold in 2030 are electric, with just under 170,000 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 driver of reduced road tax, or the stick of restrictions on diesel vehicles.	• Medium growth scenario • 31.5 per cent of cars sold in 2030 are electric, with around 367,000 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.

10.4.3 Summary of results: electric vehicles

Figure 44: Number of pure and plug-in hybrid electric vehicle scenarios in the East Midlands licence area

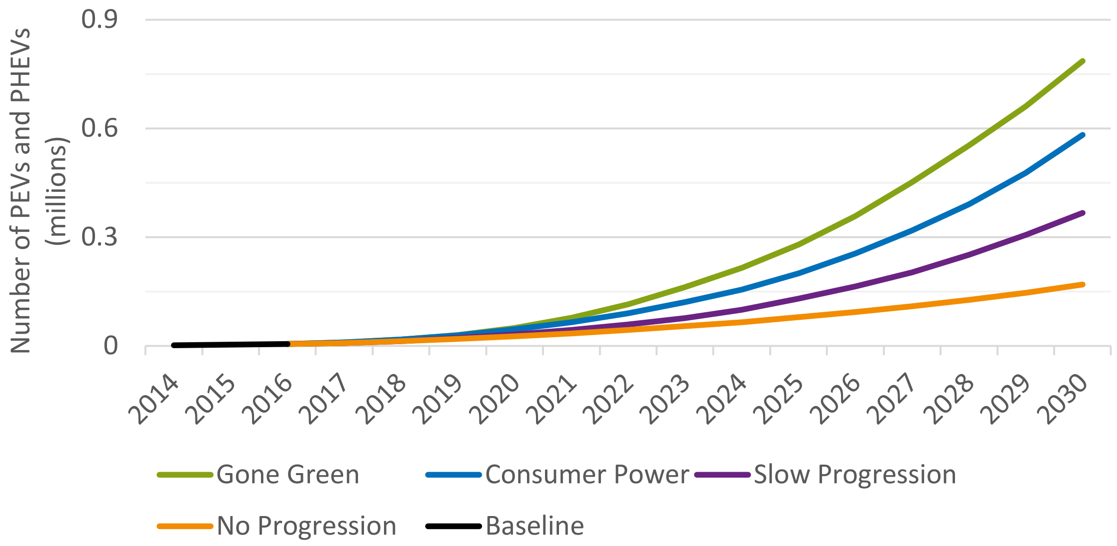


Table 37: Cumulative number of pure electric vehicles and plug-in electric vehicles in WPD licence area

	Baseline	2020	2025	2030
Gone Green	5,023	49,663	279,600	786,240
Consumer Power	5,023	45,463	199,800	582,120
Slow Progression	5,023	31,969	130,302	366,660
No Progression	5,023	26,245	79,002	169,722

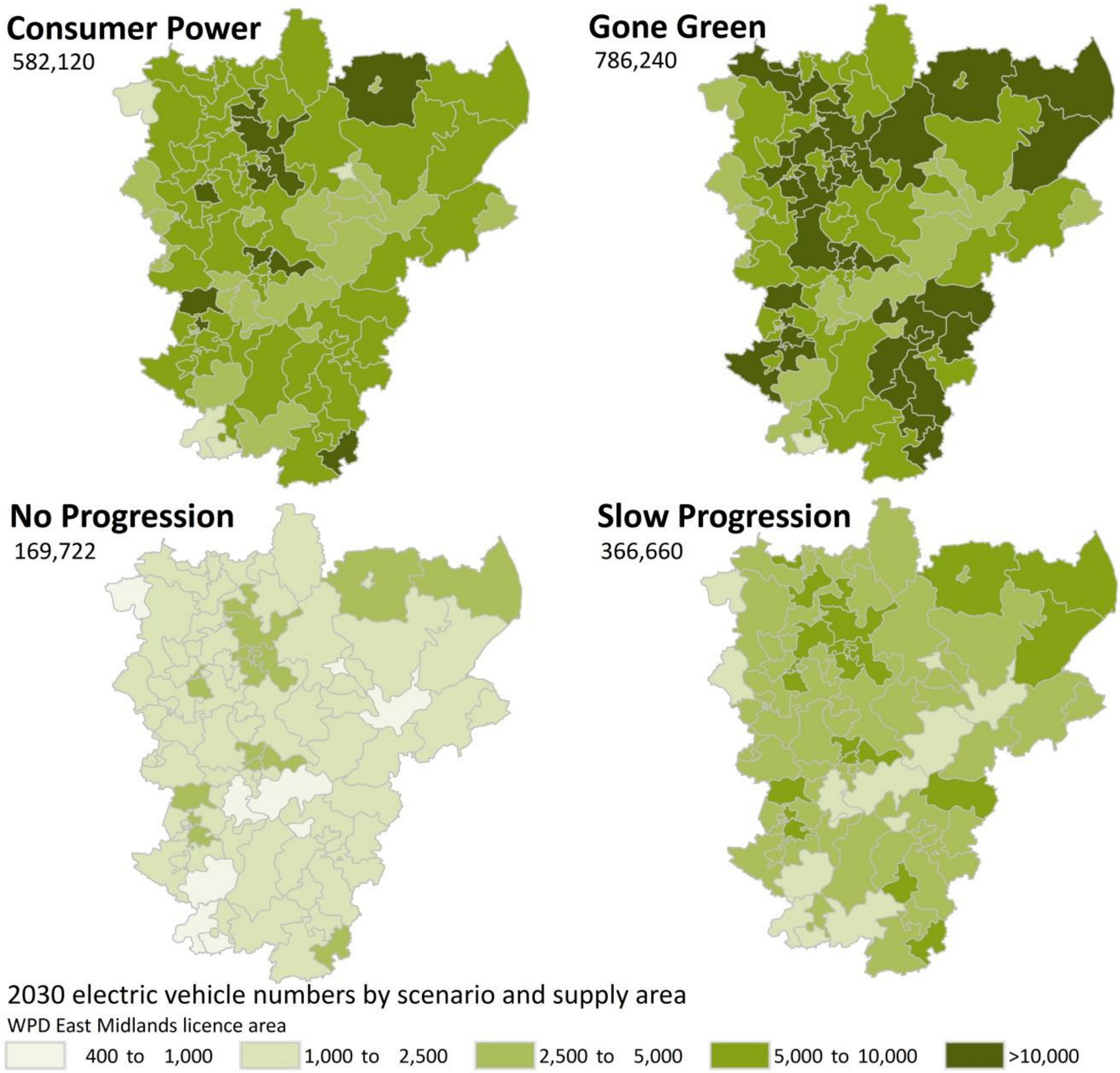
10.5 Geographic distribution by ESA for electric vehicles

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, although with a lesser weighting than in other licence areas that we have analysed.

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

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

Figure 45: Distribution of electric vehicle numbers in 2030



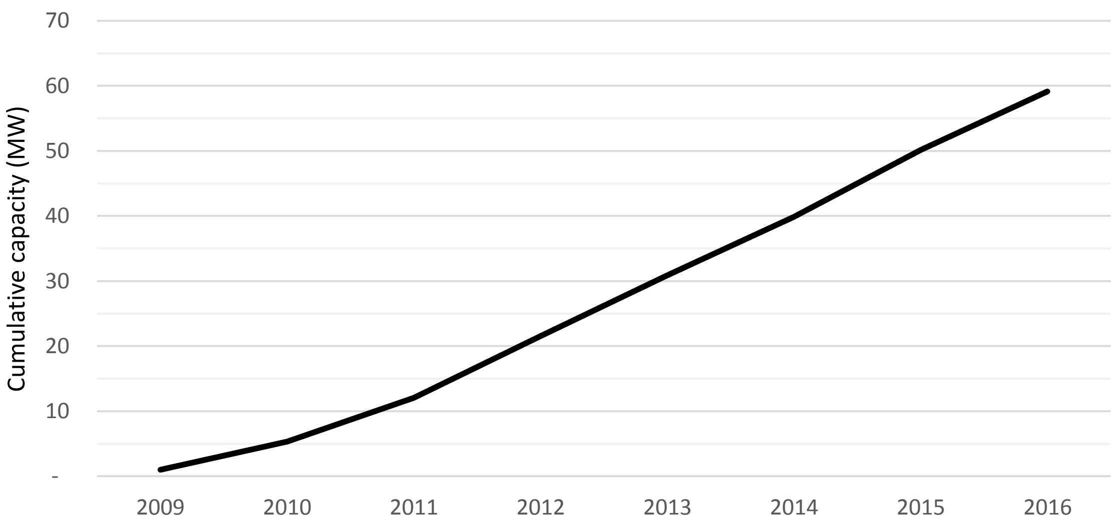
11 Heat pumps

11.1 Baseline: heat pumps growth to 2016

There were just over 6,000 heat pumps in the licence area by November 2016, totalling around 60 MW. Growth has been steady, but relatively low in the East 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 a number of barriers limiting widespread deployment.

As a region, the East Midlands is fourth in the country for heat pump installations, with around half the number installed of the leading region, the South West.

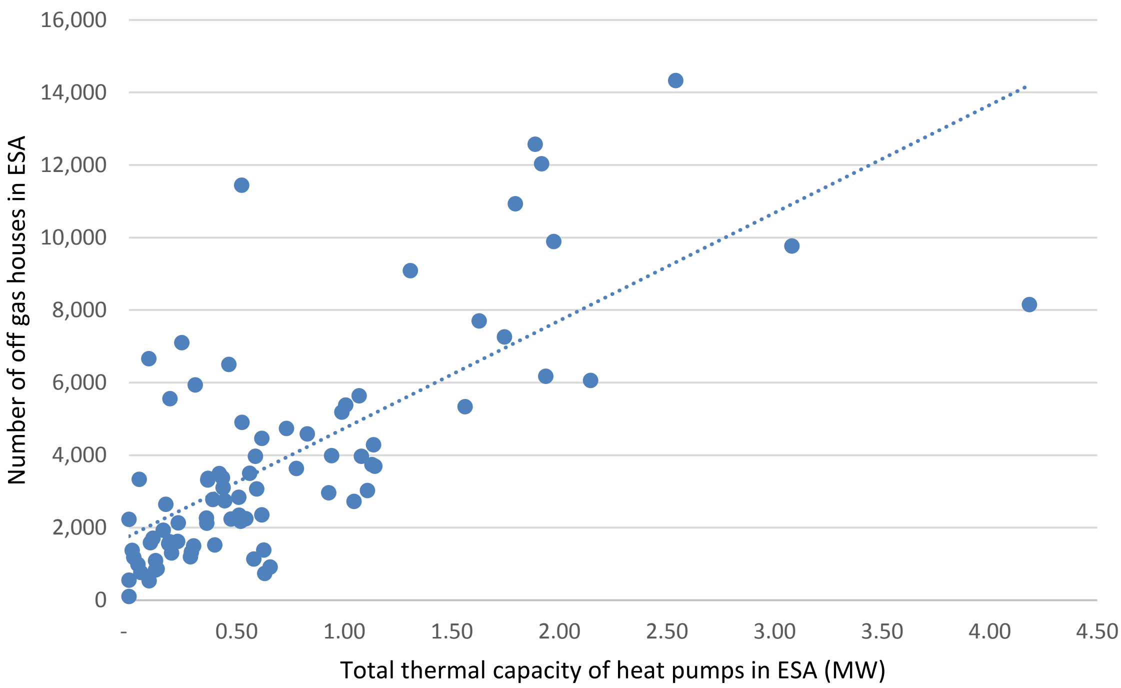
Figure 46: Heat pump thermal capacity growth in the East Midlands licence area



Across the UK, off-gas areas where social landlords have put in place investment programmes have seen the highest levels of heat pump deployment. Again this national picture is reflected in the East Midlands; there is a strong correlation between off gas areas and heat pump installations, with an estimated 80 per cent of all installations in the licence area in off gas properties.

Thanks to social housing installation programmes, Bassetlaw in Nottinghamshire is the local authority area with the greatest proportion of its homes with a heat pump; at 1.1 per cent, this is the fourth highest in England. Tamworth and Corby are the local authority areas at the other end of the spectrum with just a handful of heat pumps installed in each of these largely on gas areas.

Figure 47: Correlation between the number of off gas houses and the thermal capacity of heat pumps in each of the East Midlands licence area's ESAs (with trendline)



11.2 Pipeline: heat pumps, 2016 to 2017

Heat pumps are permitted development in most cases so there is no pipeline of projects with planning applications and/or accepted-not-yet-connected offers. We have, therefore, started the scenarios assessment from 2017.

11.3 Regen's market insight: heat pumps

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

Although the commercial sector represents an opportunity for the heat pump industry with slightly different drivers to the domestic market, to date commercial installations have made up less than 5 per cent of installations. We have, therefore, not considered commercial installations separately in this assessment.

11.3.1 Heat pumps growth forecasts to date have proved highly optimistic

The 2013 DECC strategy, the Future of Heating, estimated there will 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. The Committee on Climate Change's Fifth Carbon Budget 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, with less than 44,000 heat pumps installed in England by April 2016.

BEIS is currently considering its long term policy on decarbonising heat. Recent reports from think-tanks such as 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.

11.3.2 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 straight forward 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. DECC's Public Attitudes Tracker found in 2015 that 33 per cent of those surveyed were aware of air source heat pumps and 40 per cent were aware of ground source heat pumps, with less than 5 per cent feeling that they knew a lot about the technologies.
- 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 by the Energy Saving Trust 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.

11.3.3 RHI has an important role to play in 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.

There remains uncertainty surrounding the future of the RHI, with current budget limits having the potential to stop the scheme early at short notice. 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.

11.3.4 Emerging heat pump technologies

Recent government evidence base 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, can 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, with a pilot in construction at EON's Cranbrook network, near Exeter, Devon.

11.4 Scenarios: heat pumps, 2017 to 2030

11.4.1 Factors affecting the scenarios: heat pumps

We have considered the following factors in producing the scenarios.

Table 38: 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	●		●	

11.4.2 Scenario results: heat pumps

In total, our Gone Green scenario would see 153,250 heat pumps installed by 2030 in the licence area, totalling 1,532 MWth. Scaled up to compare this to national predictions, our scenario is the equivalent of approximately 2 million heat pumps across Great Britain. This is significantly lower than National Grid's FES Gone Green Scenario, which totals 5.7 million heat pumps by 2030.

This reflects our evidence-based view that the current barriers to heat pump deployment will result in 2030 installations remaining far lower than both the FES and government predictions.

Table 39: Scenarios summary for heat pumps in the East 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 has limited success in overcoming barriers, leaving deployment to be market-led. • 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 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. • 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.	• Medium growth scenario • The retrofit market grows slowly under this scenario as: the incentives available is lower than under Gone Green, there are fewer individuals and organisations with 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 48: Scenarios for the number of heat pumps in the East Midlands licence area

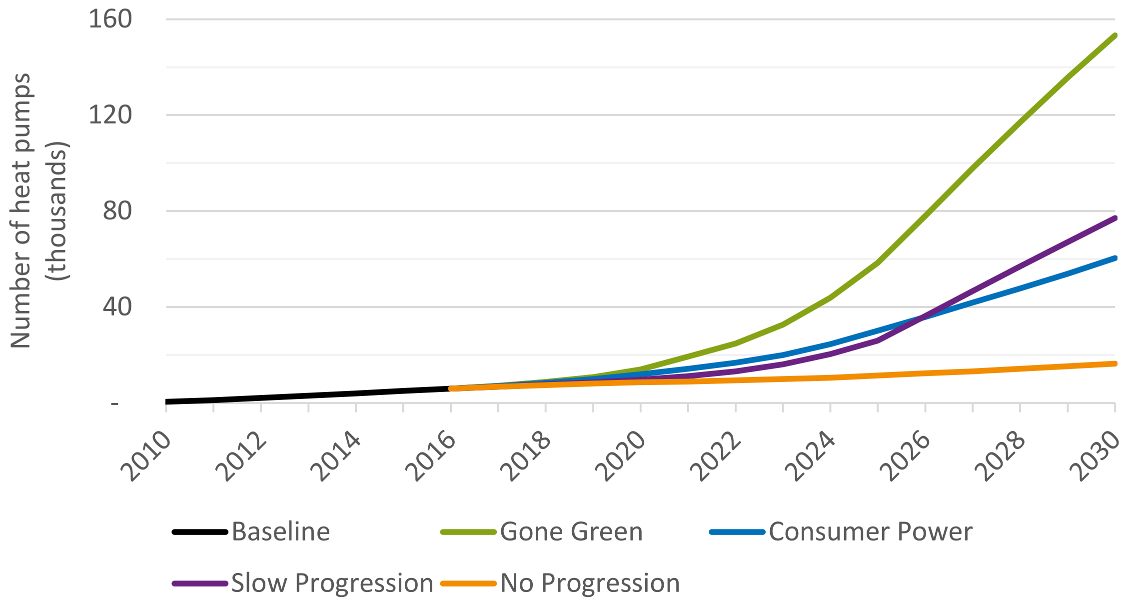


Table 40: Cumulative numbers of heat pumps in the East Midlands licence area

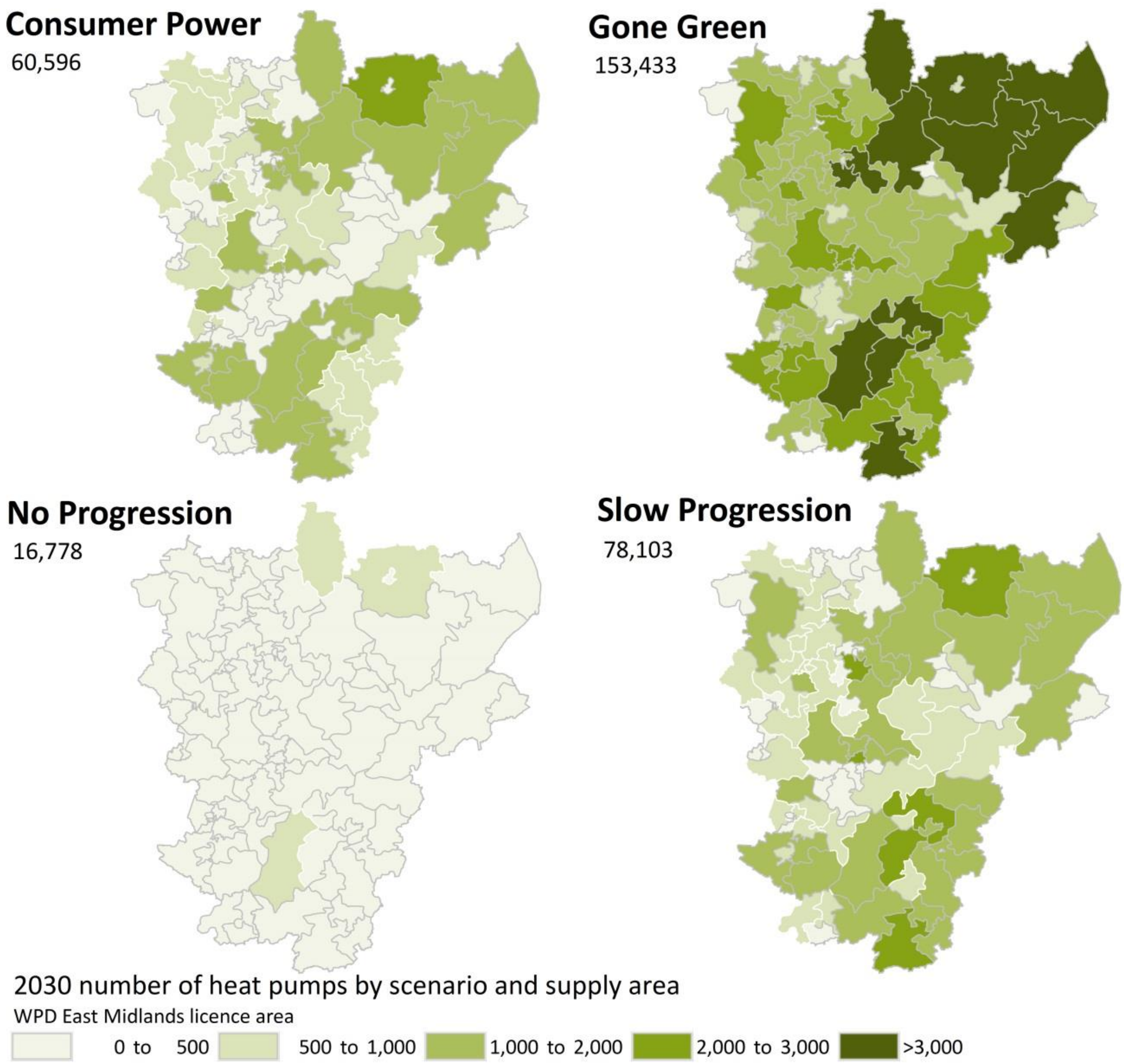
		2020		2025		2030	
Scenario	**Baseline**	**New Build**	**Retrofit**	**New Build**	**Retrofit**	**New Build**	**Retrofit**
Gone Green	5,912	2,379	11,563	6,955	51,463	28,255	124,993
Consumer Power	5,912	2,083	9,845	10,276	19,820	22,262	38,203
Slow Progression	5,912	475	9,279	2,395	23,555	26,362	50,761
No Progression	5,912	566	8,053	2,794	8,623	6,455	9,934

11.5 Geographic distribution of heat pumps by ESA

We have distributed the projected heat pump growth across the East 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 49: 2030 heat pump distribution by numbers in 2030 by scenario



The projected number of new build houses to be built by 2030 in each ESA was determined as set out in section 12.1. 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.

11.6 Heat pump capacity impact on electricity demand

11.6.1 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.

11.6.2 Size of installed heat pump

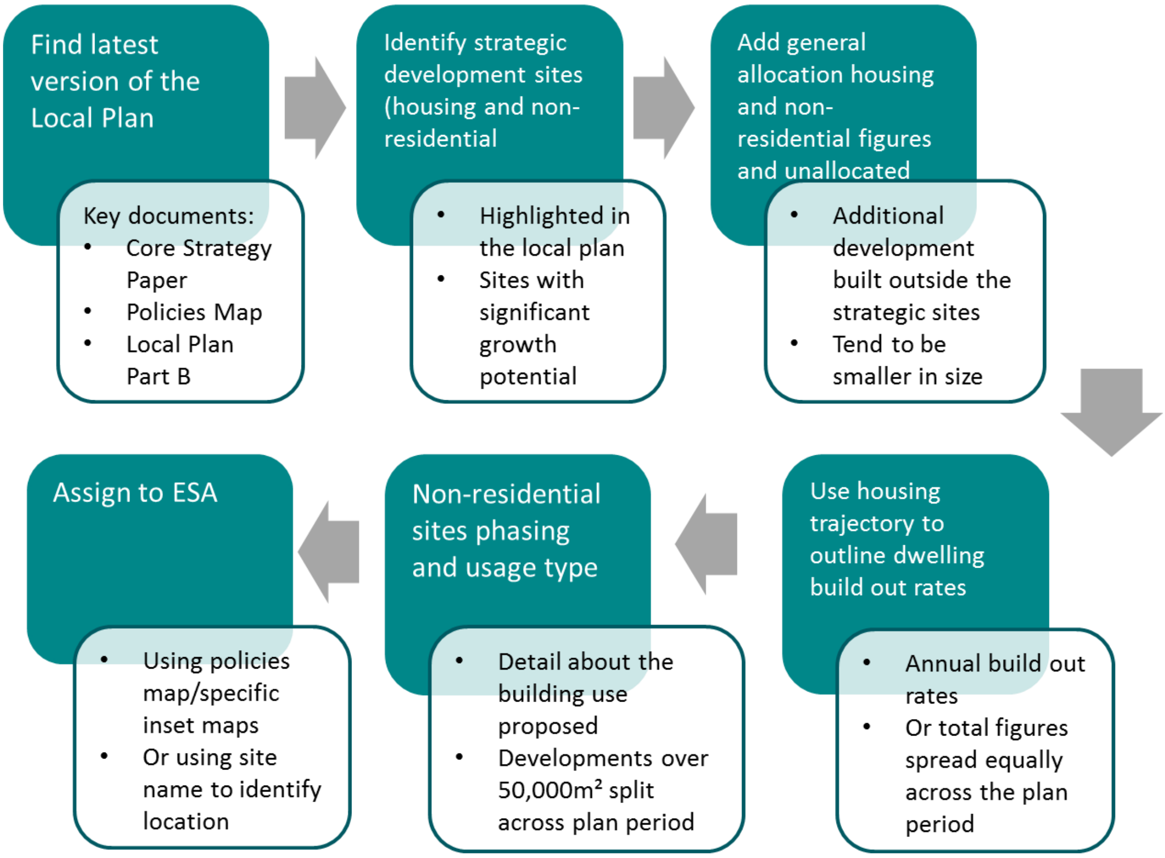
We have assumed that the average heat pump thermal capacity reduces from 10 kW in 2016 to 9 kW by 2030 as technology improvements are made and more smaller scale domestic retrofit heat pumps are installed.

12 Growth in residential and non-residential development

To develop scenarios for demand growth, we undertook an assessment of growth in residential and non-residential development. This is the first licence area that we have completed this assessment for; previous studies for the South West and South West modelled growth in housing numbers based on trends, rather than specific plans and did not examine commercial demand growth.

12.1 Methodology: growth in residential and non-residential demand

Figure 50: Summary of data collection methodology for residential and non-residential sites



12.1.1 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 and additional supporting documents, such as annual monitoring reports and policies maps identifying potential sites. Some local authorities have produced Joint Core Strategy papers with one local plan covering a wider area, such as the Central Lincolnshire local plan.

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 the strategic housing land availability assessment (SHLAA). This document is updated regularly for each planning authority and identifies all available sites within a local authority area that have the potential for housing development within the next five years.

12.1.2 Types of development

Development sites

There are 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, this varies between local authorities. Generally strategic sites are large developments; either housing led projects (minimum ~500 houses) or mixed-use regeneration projects (minimum ~100 houses).

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

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.

12.1.3 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 floor space (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 or SHLAA
- The category of planned end-use for non-residential sites/areas of sites. The non-residential categories provided by WPD are listed in Table 44 and cover 15 different profiles.

Notes on phasing

Where phasing information was not available, domestic build out figures were spread evenly across the plan period: assumed figures have been highlighted in the data collection database.

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.

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

Each non-residential site/area of a site was assigned a 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 usage based on other developments of a comparable size.

The majority of plans simply listed an area that would be used for mixed development. In these cases, we evenly split the area given into the types of usage indicated. Where plans indicated numbers of buildings (e.g. 2 schools, 1 community hall) rather than floor areas, we used information from other plans to estimate the likely floor area in square metres.

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

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.

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, we noted whether they had planning permission in place or not.

12.2 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 are, therefore, supported by the Local Authority, an extensive consultation process and a 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. However, we have a high level of confidence about new development data drawn from adopted local plans.

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
Not yet published	5
Draft plan	23
Adopted	29

However, only half of the local authorities in the licence area have an adopted local plan. The areas without an adopted local plan are more likely to change and projections will need updating once they have adopted plans. There are 23 areas with a draft plan and 5 areas with no plan published yet. For these 28 areas, the draft documents and SHLAAs that we have drawn data from offer the most detail available on potentially viable sites.

Typically, the major sites identified for developments have been discussed for many years and pass from one version of the local plan to another. However, it is possible, albeit unlikely, that in the 28 local authority areas without an adopted local plan that significant new sites not identified by our analysis could be proposed and built by 2030. This is more likely for large industrial and commercial sites, which developers may choose to bring forward in areas not identified in the local plan. Such projects do not necessarily need as much oversight from the local authority as housing developments.

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

12.3.1 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.

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.

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 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.

12.4 Findings

12.4.1 Overall development

In total, the higher economic scenario would see 346,292 houses developed by 2030 in the licence area. An additional 29 million m^2 of non-residential development is also anticipated up to 2030 using scenario 1.

The lower economic scenario (scenario 2) delivers 219,238 houses and a further 21 million m^2 of non-residential development by 2030.

Across the 57 local authorities, 124 strategic mixed use developments were identified. A further 100 strategic sites are for non-residential purposes only. Domestic strategic housing sites range in size from 100 homes at Stancliffe Quarry in the Derbyshire Dales to 8,124 homes in the Strategic Regeneration Area in Leicester.

General allocation sites total 158,795 for housing and 12 million m^2 for non-residential development.

There are 20,577 unallocated homes planned in the licence area.

12.4.2 Domestic development

Local authority	Scenario 1 total number of homes (up to 2030)	Scenario 2 Total number of homes (up to 2030)
1. Milton Keynes	19,937	9,975
2. Hinckley and Bosworth	16,528	8,226
3. Leicester	13,991	13,002
4. Rushcliffe	13,430	9,764
5. Nottingham	12,367	8,294
6. Corby	12,293	7,711
7. Warwick	12,121	7,377
8. Charnwood	12,002	8,886
9. South Northamptonshire	11,916	7,831
10. Northampton	10,600	7,338

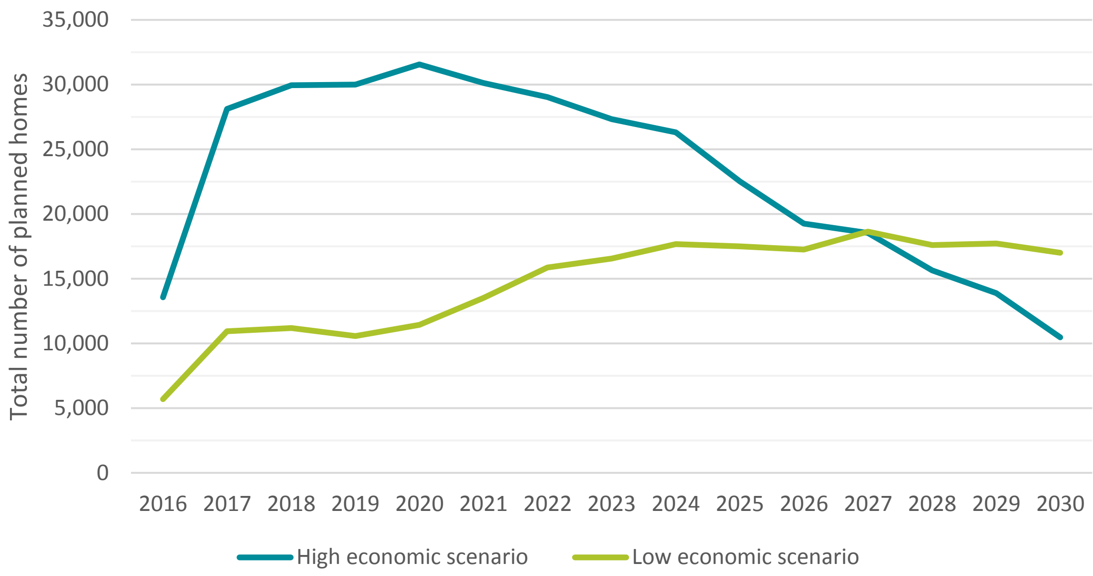
Table 42: Top 10 local authorities for planned new homes in the East Midlands licence area

The table above shows the 10 local authorities in the East Midlands licence area with the highest amount of new housing to be added by 2030. Housing development is concentrated along the M1 corridor, around areas with high population density, such as: Milton Keynes; Leicester; Nottingham; Warwick and Northampton. The other local authorities with high new homes numbers are either close to existing large conurbations or have a considerable number of strategic sites allocated within the local plan.

The graph shown in Figure 51 shows a peak early on for the high economic scenario as strategic sites with more certainty of going ahead are often focussed in the initial stages of the plan period. In addition, the data we have included from SHLAA 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, hence the decline towards 2030.

Scenario 2 shows the decreased level of growth once we have applied the percentage reduction figures taken from national growth rates 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 identified, delaying construction by 5 – 10 years.

Figure 51: Annual total for housing figures in the East Midlands licence area



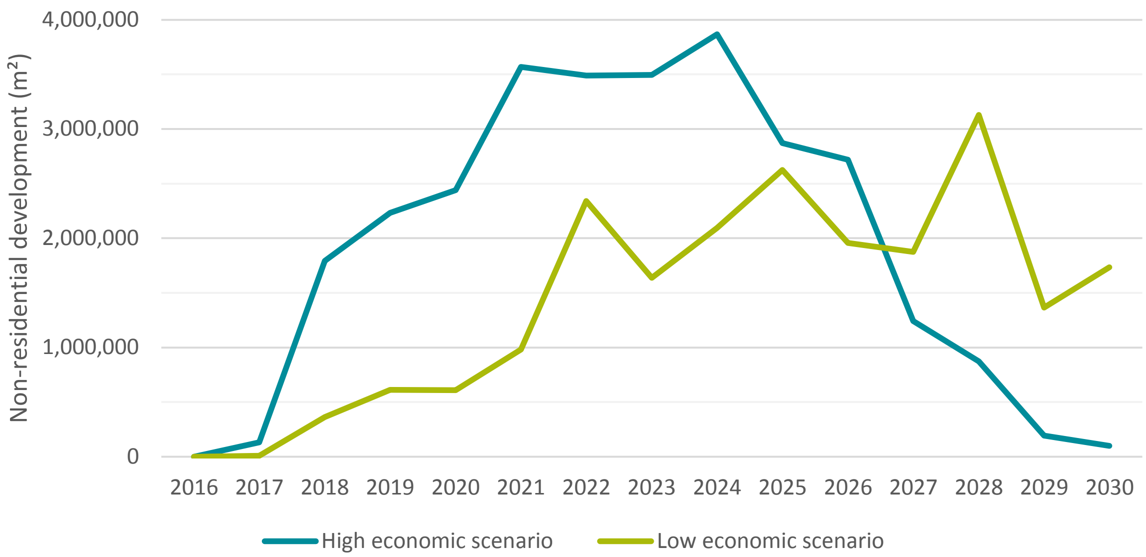
12.4.3 Non-residential development

Table 43: Top 10 local authorities for planned non-residential development

	Local Authority	Scenario 1 total non-residential (m^2) up to 2030	Scenario 2 total non-residential (m^2) up to 2030
1	Newark and Sherwood	1,845,204	1,410,011
2	Milton Keynes	1,590,500	1,058,780
3	Charnwood	1,529,524	1,447,948
4	South Northamptonshire	1,515,450	1,410,916
5	Coventry	1,485,000	824,800
6	Derby	1,445,000	1,081,667
7	South Derbyshire	1,280,000	1,280,000
8	Warwick	864,500	510,320
9	North West Leicestershire	819,800	530,072
10	Chesterfield	790,000	505,600

The table above shows the local authority of Newark and Sherwood has the highest amount of planned non-residential development. This local authority has three mix-use strategic sites, two on the outskirts of Newark and one near Fernwood. In addition, there are significant amounts of general allocation in the plan covering predominantly retail and factory or warehouse use classes.

Figure 52: Annual total for non-residential developments in the East Midlands licence area



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 22 million m^2 of employment land has been allocated for office, factory and warehouse uses. The development sites also provide over 1.8 million m^2 of retail, 86 schools and colleges, 18 local centres and district centres amongst other uses.

Table 44: Non-domestic profile categories

Non-domestic demand profile categories	Equivalent General-Use Classes Order
Factory and Warehouse	B8, B2
Government	D1
Hopsital	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

12.5 Geographic distribution by ESA

The map below 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 of Milton Keynes, Leicester and Nottingham.

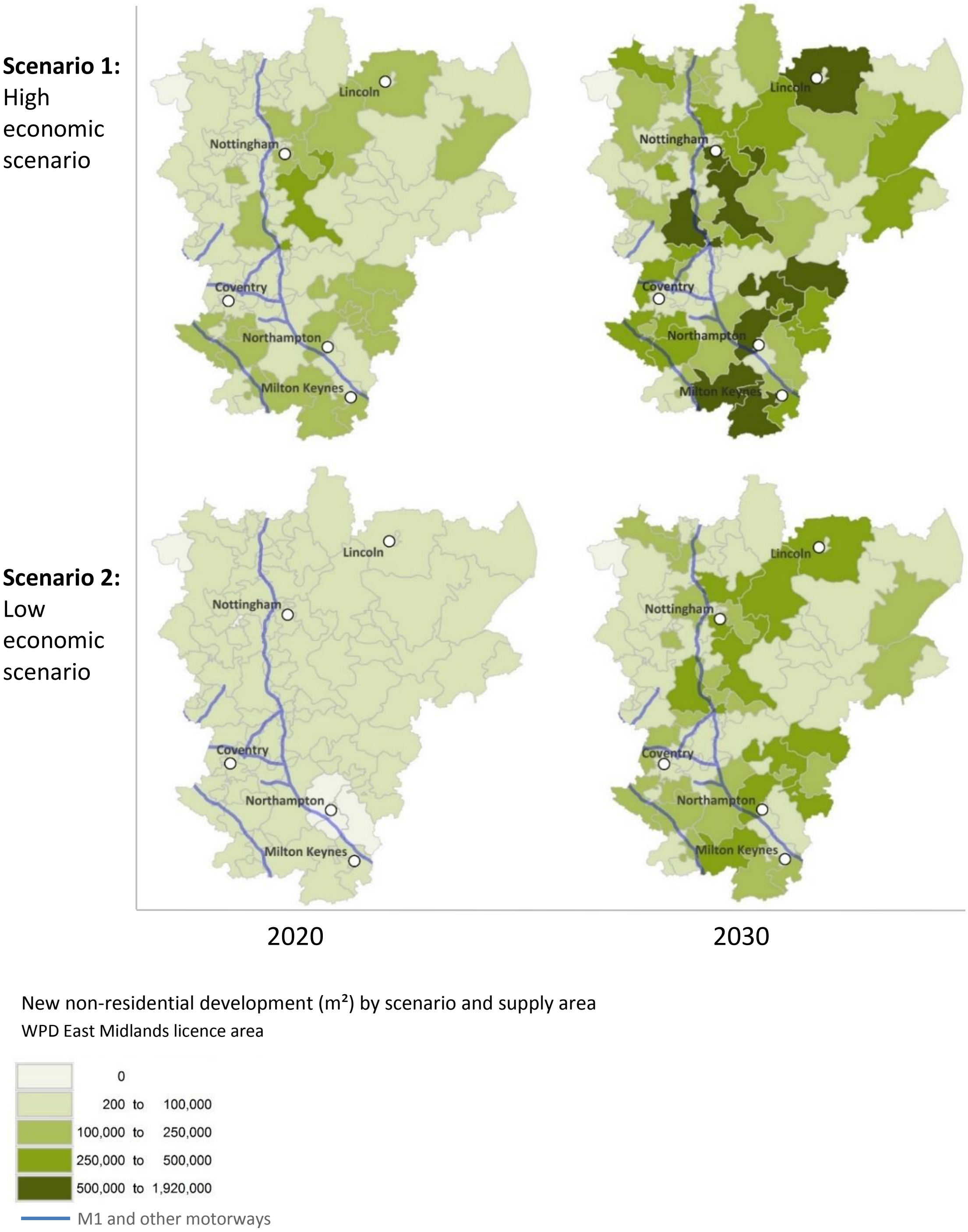


Figure 53: 2020 and 2030 housing numbers distribution in the high and low economic scenarios

The map below shows the distribution of non-residential development for each ESA in the licence area. The largest developments cluster around existing commercial sites.

Figure 54: 2020 and 2030 non-residential development distribution

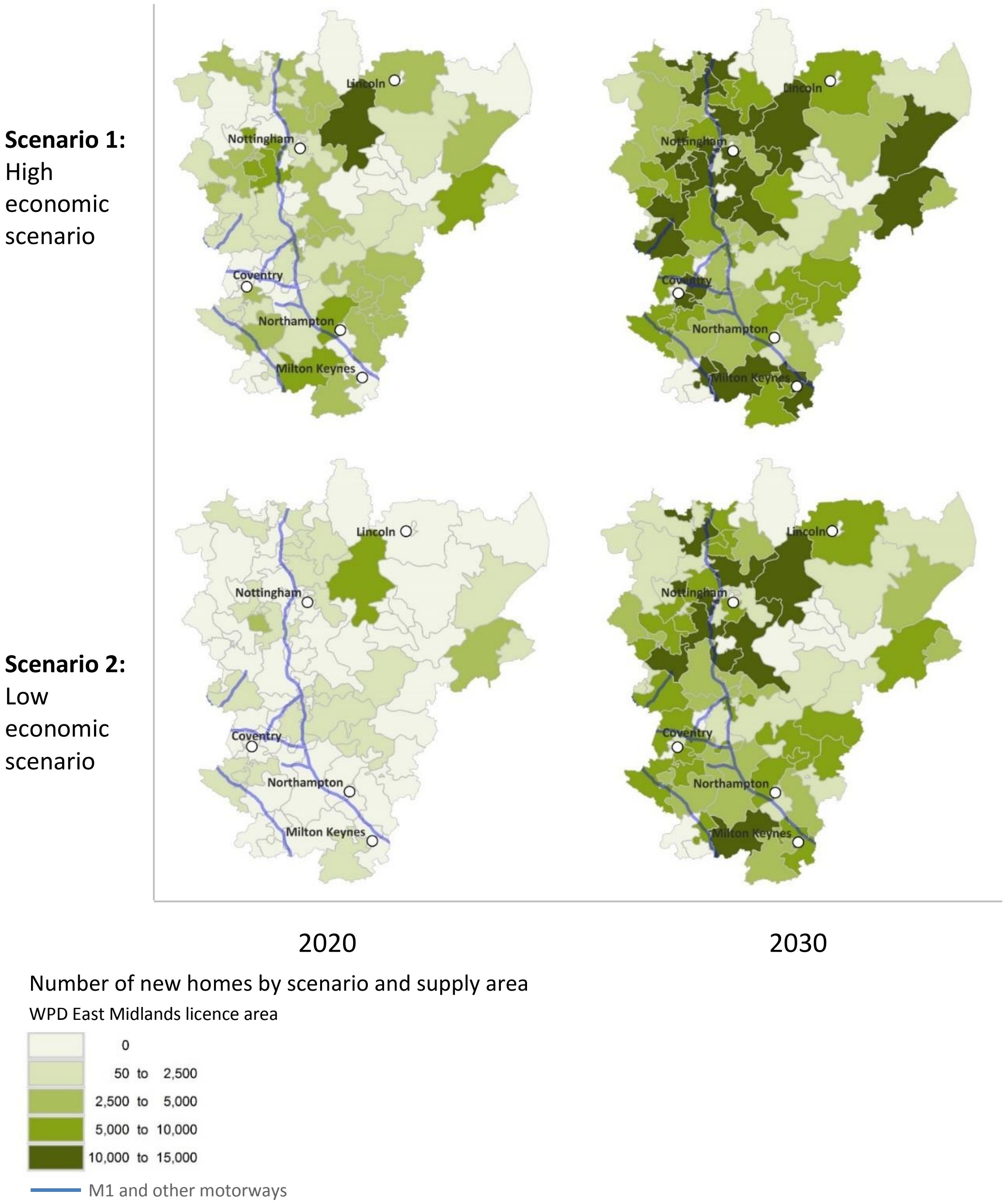
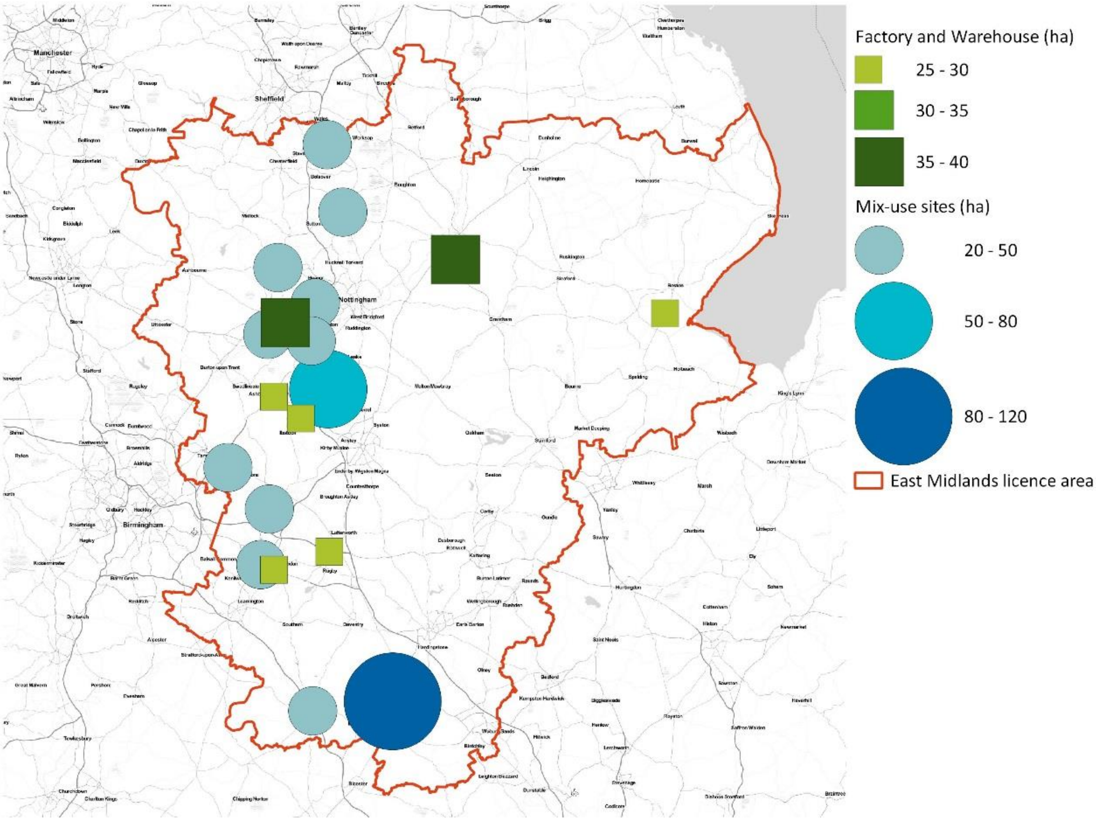


Figure 54 Figure 55: 20 largest non-residential sites in the East Midlands licence area (hectares)illustrates the significant growth in commercial and industrial developments across the East Midlands licence area. Of the largest 20 commercial and industrial sites 11 are clustered around the M1 corridor. Specific sites of note include the expansion at Silverstone in South Northamptonshire; shown in Figure 55 as the largest mix-use site to the south of the licence area, a

1,160,000m² development is planned at the circuit with a variety of uses including university, office, retail, factory and warehouse space.

Loughborough University and Science Enterprise Park is another site which anticipates major growth with a 770,000 m² development consisting of university and office land uses.

Figure 55: 20 largest non-residential sites in the East Midlands licence area (hectares)



13 Conclusion

Inevitably forecasting the development of electricity generation and demand technologies over 15 years is full of uncertainties. However, there are some clear messages from this analysis. Following a period of low growth for most technologies caused by current policy and subsidy changes, the growth of decentralised generation can be expected to recover in the next decade. Under all but the No Progression scenario, we predict significant growth of: decentralised energy generation technologies, disruptive demand technologies and electricity storage.

A key uncertainty is the speed at which that recovery in growth happens for each technology type. It will depend partly on government policy, but increasingly on the market and the ability of technologies to reach price parity. This in turn will depend on the rate of cost reduction and technology innovation as well as the adoption of new business models.

Widespread uptake of electric vehicles and storage could have particularly disruptive implications for the network, depending on how they operate.

Whatever the specific outcome, the role of the electricity networks will be critical to our future energy system. Ofgem has recognised the key role of the DNOs and, as part of the transition to becoming DSOs, is expecting them to be more actively involved in managing power flows. This will require the operators to undertake enhanced monitoring, forecasting and planning to ensure they assess and anticipate the changing requirements of their networks and are ready to respond.

The assessment documented in this report is the first step for WPD in a process of assessing the need for strategic network investment in their East Midlands licence area. The next step is to analyse the operating models for these technologies to understand the impacts of their deployment on power flows on the network.