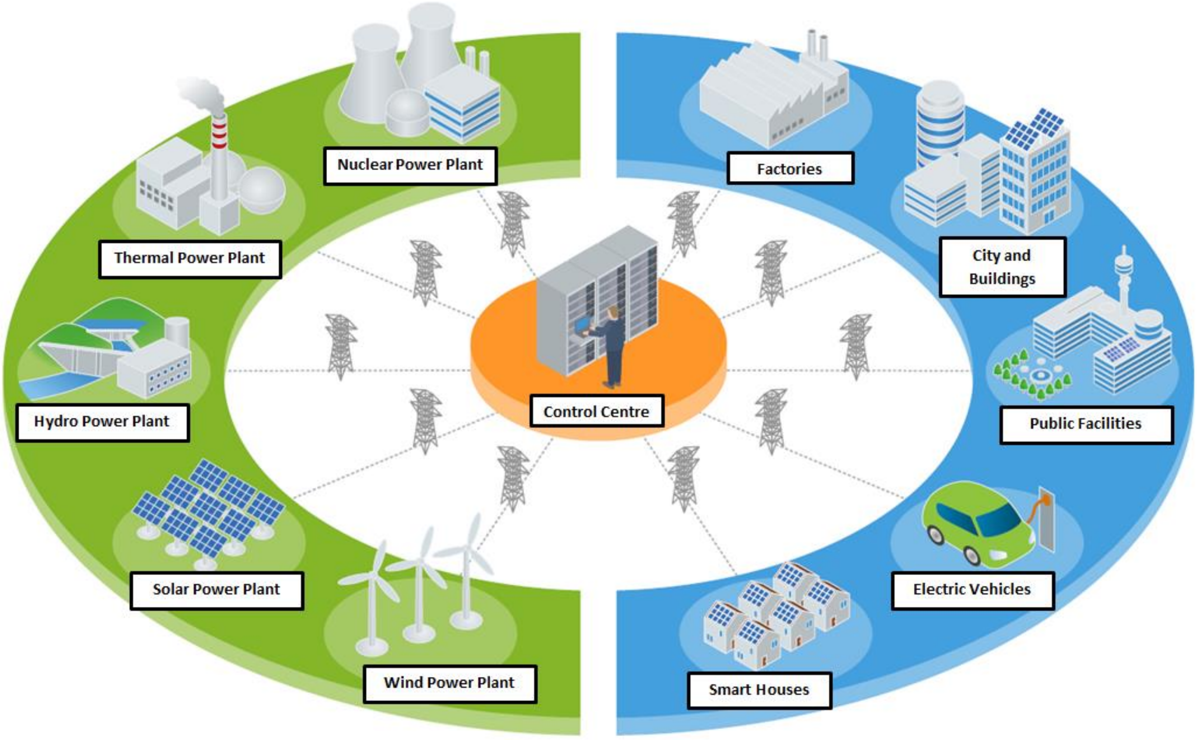
Changing Load Profiles



Summary

Prior to the substantial connection of Distributed Generation (DG), distribution network loading was predominantly demand dominated. In recent years, areas of network with a high uptake of DG have seen a notable change in network loading; this includes reverse power-flow at times of high generation output. This report investigates how the load profile of a typical substation may continue to change out to 2030. It considers how the move towards a smarter, more flexible network with solutions like Active Network Management (ANM) to control generation output will inevitably impact network loading. The impact of emerging technologies such as Electric Vehicles (EVs), heat pumps (HPs) and battery storage are also assessed along with the use of managed EV charging. The case study shows how future network loading is heavily dependent on the technology type of demand and generation growth and the level of flexibility solutions adopted. The article then identifies short-term and long-term solutions that WPD will need to investigate and implement to ensure they can manage the issues associated with the change in network loading.

DSOF November 2018

Note: a glossary and diagram key can be found in the DSOF introduction document on our website

Background

The demand on the network has remained relatively constant for many years, with the growth of industrial, domestic and commercial demand largely offset by the improvement of appliance efficiency and the increase in property thermal insulation.

The network is beginning to see a change in not only the peak demand, but also the composition of network loading. The main factors that are forecast to impact network loading are:

- **Heating** – A growth in electrified heating is forecast as gas becomes less economic, this will lead to an increased uptake of electrical resistance heating and heat pump installations.
- **Cooling -** The forecast increase of air-conditioning units will also impact the demand profile and network loading. This will predominately be at times of high ambient temperature, where demand has traditionally been relatively low.
- **Transport** – The increase in Electric Vehicles (EVs) and other forms of electrified transport such as rail are starting to have a more pronounced impact on network loading. EV incentives, low emission zones in cities and the government targets to stop the sales of petrol and diesel cars by 2040 are all contributing to the increased uptake of EVs.
- **Domestic and non-domestic** – The increase in new domestic and non-domestic (i.e. factory and office) developments will increase the demand on the network.
- **Generation** – The continued connection of intermittent and non-intermittent Distributed Generation (DG) onto the distribution network will further change the loading on the network.
- **Flexible demand and generation** – The use of storage to time-shift energy and domestic smart devices that have the ability to change their consumption through market signals have the potential to significantly impact network loading.

Terminology

Demand is the consumption of electricity (kW) from the network.

Generation is the export of electricity (kW) onto the network.

Load is combination of net demand and generation that results in a specific loading on an asset.

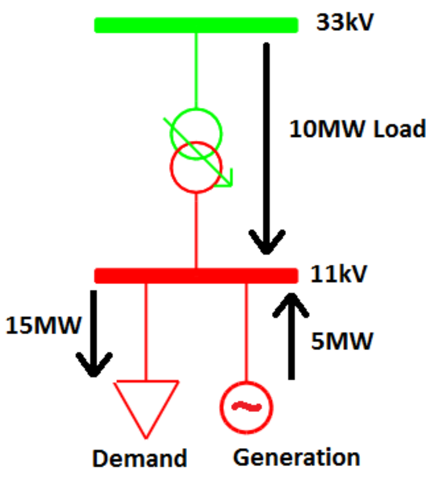


Figure 1: Example showing the difference between demand and load

Figure 1 shows a simplified single transformer Primary substation, with 15 MW demand and 5 MW of generation connected onto the 11 kV busbar. The load on the transformer is only 10 MW, as 5 MW of the demand is supplied locally via the 5 MW generator(s).

Traditional Demand

Distribution networks were traditionally designed to supply a demand dominated network, with the majority of the demand being domestic, commercial and industrial. There are many factors that affect the loading on the network, these include:

- Time of day
- Ambient temperature
- Wind speed
- Sunlight hours
- Weekday, weekend and public holidays
- Major events such as sporting events
- The number and type of domestic, commercial and industrial customers that contribute to a given network asset
- The level of diversity between different demand types

The historic maximum demand of WPD's South West and South Wales licence areas are shown in Figure 2. This shows there has been a general downward trend in maximum demand over the last 10 years.

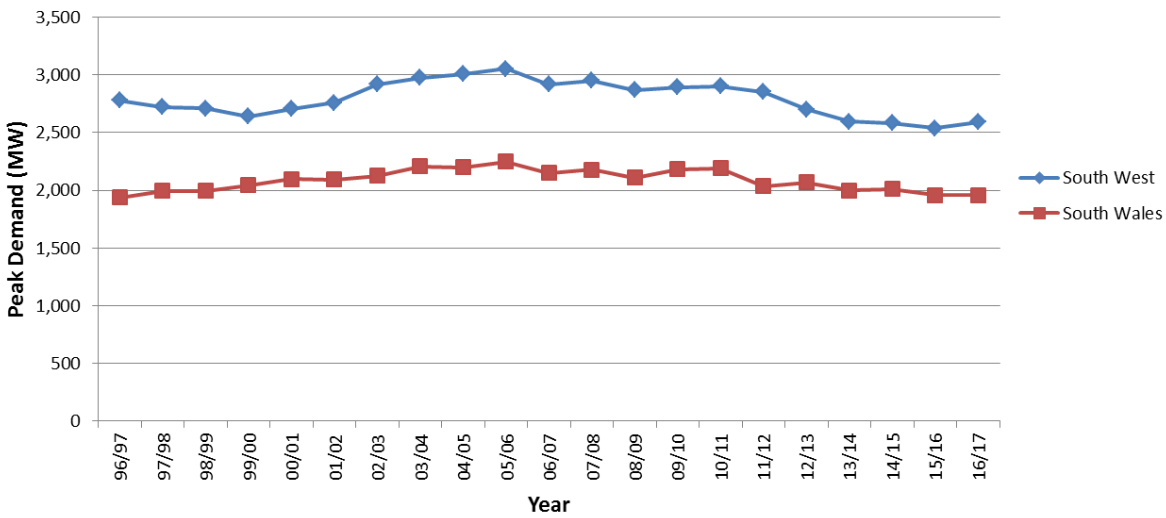


Figure 2: Historic maximum demand in WPD's South West and South Wales licence areas

Maximum demand typically occurs in winter during early evening due to the pickup of domestic demand as people return from work. This normally coincides with a low ambient temperature and darkness, as the requirement for heating and lighting are higher.

The underlying demand of a substation is predominately influenced by the breakdown of commercial, industrial and domestic properties that are fed out of them. Figure 3 shows examples of demand profiles that are commonly seen:

1. **Domestic dominated** – The majority of substations within the WPD licence area feed domestic homes with evening peak demands.
2. **Domestic dominated (night-time peaking)** – There are a number of substations within WPD's licence areas that actually have a night time peaking load, predominately due to storage heat and the use of economy 7 metering.

3. **Commercial dominated** – The majority of demand is commercial, these will quite often have a daytime peaking load as they are typically shops and offices.
4. **Industrial dominated** – Industrial customers quite often have a flatter profile, where power output is relatively constant throughout the day. Some industrial customers will have a highly variable load such as arc furnaces, so it is more difficult to generalise an industrial load, hence no profile is given in the graph below.

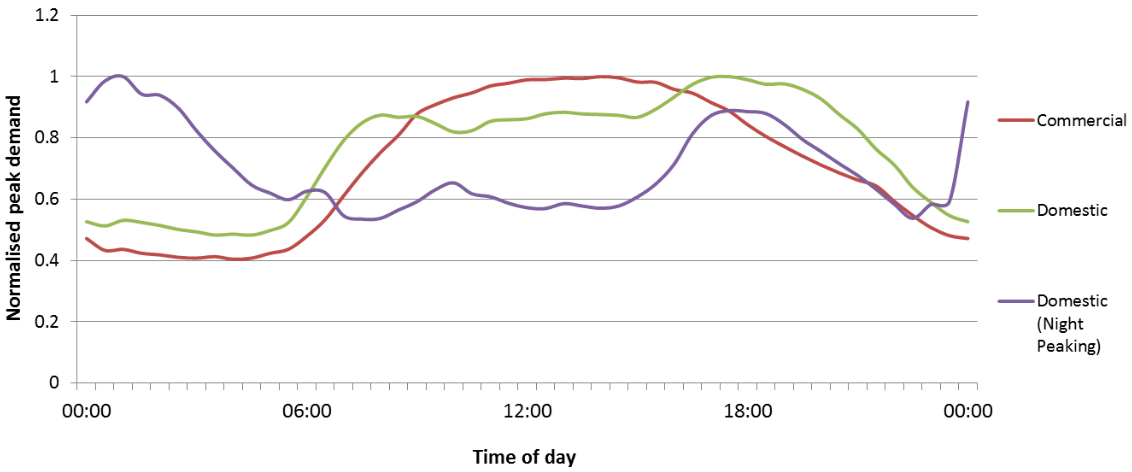


Figure 3: Typical demand profiles for different BSP types

Diversity of Demand

An important factor when assessing network loading is the level of diversity between the same type of demand and the coincidences of different demand types. Figure 4 and Figure 5 show the impact that diversity can have on the same demand type. These figures are based on the Elexon profile classes, which define the different classes of demand by grouping similar customers to represent a large portion of the population [1]. There are currently 8 Elexon profile classes, with 1 and 2 being domestic (unrestricted and economy 7 respectively) and 3 through 8 are non-domestic premises. The Elexon profiles are produced for daily and seasonal variations for each of the profile classes.

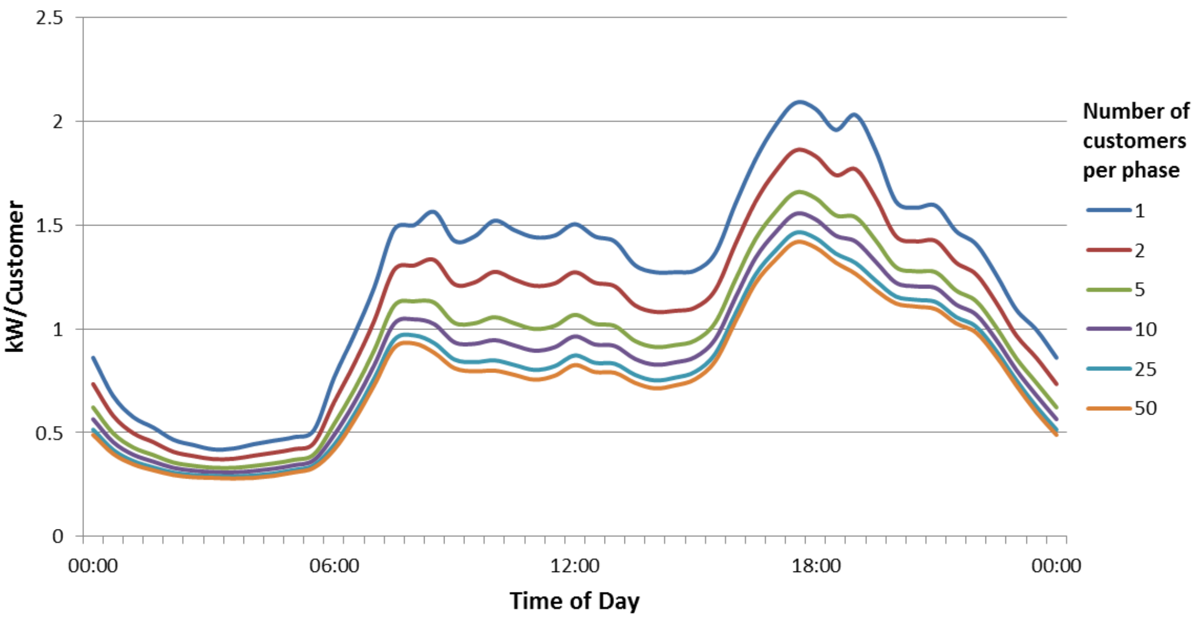


Figure 4: Impact of diversity on a typical domestic demand (based on Elexon 1 profile – Domestic unrestricted customer)

Figure 4 uses the Elexon class 1 profile (domestic unrestricted customer) to show the impact diversity can have when assessing the peak demand of multiple class 1 customers. This is based on an annual energy usage of 3,600kWh per house. This highlights how assessing network loading for a single house, compared with 50 gives a peak demand difference per home of 2.2kW per customer down to 1.35kW.

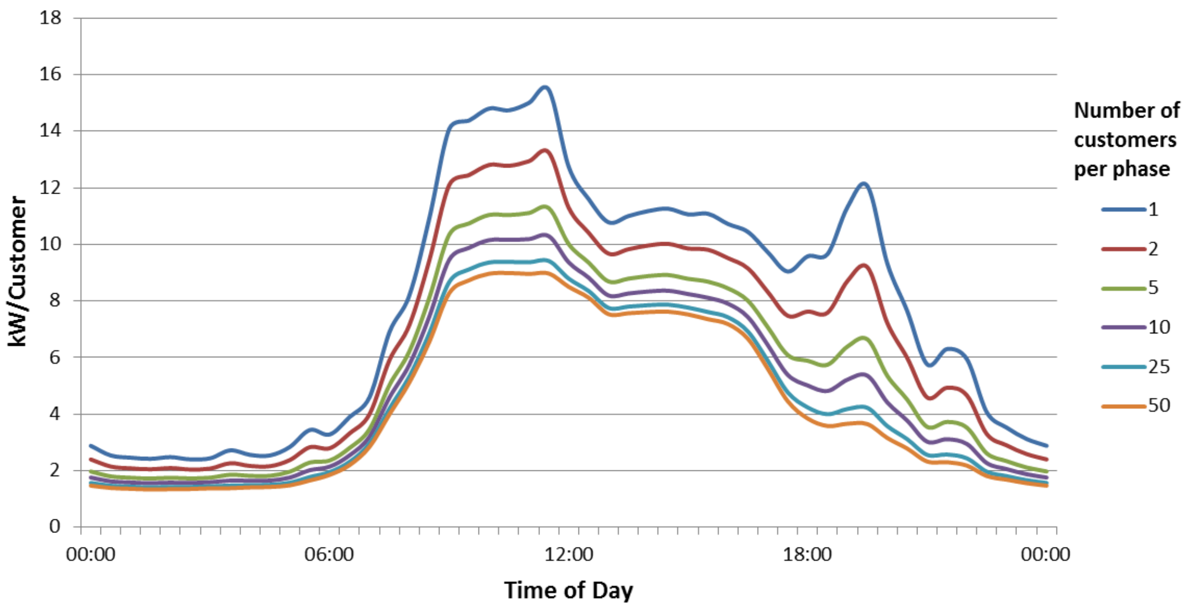


Figure 5: Impact of diversity on a typical domestic demand (based on Elexon 3 profile – Non-domestic unrestricted customer)

Figure 5 shows the diversity seen on the unrestricted non-domestic (Elexon profile class 3); the peak is predominately daytime peaking.

The purpose of Figure 4 and Figure 5 is to highlight that it is not just the aggregation of peak demands (domestic, non-domestic and industrial), but the coincident peaks and persistence of these peaks that need to be assessed when determining network loadings and reinforcement requirements. This principle of diversity is particularly important when looking at some of the new demand types with less predictable behaviour that are starting to connect to the network; in particular the connection of Electric Vehicles (EVs), heat pumps (HPs) and energy storage. The impact of connecting HPs and EVs will be more pronounced on the LV network, due to the traditional demand assumptions used in network design and the ease of access for customers to connect to the LV network.

Network Impact

Emerging Demand

To help ensure that demand and generation growth are forecast in sufficient time to implement a reinforcement scheme or an innovative solution, WPD have commissioned Regen to produce WPD's Distribution Future Energy Scenarios (DFES); these reports forecast the demand and generation growth of each licence area in turn on a rolling 6 monthly cycle (every 2 years per licence area).

These forecasts use the National Grid's (NG) Future Energy Scenarios (FES) as a basis for the scenario based forecasting [2]. The latest round of Regen forecasts assess the demand and generation technologies detailed in Table 1.

Table 1: Key DG, storage and demand technologies which are assessed by the WPD and Regen forecasts

Electricity Generation Technologies	New Demand Technologies
• Solar PV – ground mounted • Solar PV – roof mounted • Onshore wind – large scale • Onshore wind – small scale • Anaerobic digestion (AD) – electricity production • Hydropower • Energy from waste (EfW) • Diesel • Gas • Other generation • Deep geothermal • Floating wind • Tidal steam and wave energy	• Electric vehicles • Heat pumps (domestic) • Domestic air conditioning **Conventional Demand Technologies** • Domestic • Industrial and Commercial (I&C) **Energy (electricity) storage** • High Energy Commercial and Industrial • Domestic and community own use • Energy trader • Generation co-location • Reserve service • Response service

All of the demand technologies identified in Table 1 have the potential to impact the peak demand on the network. Actual changes in network loadings will be dependent on the combination of demand and generation growth. Forecasting future load profiles is challenging as it requires not only forecasting the future demand and generation growth, but also how they are likely to operate. This could include:

- Time-of-use Tariffs (TOUT)
- Active Network Management (ANM)
- Demand Side Response (DSR)
- Storage operating in different modes and for different market signals
- EV charging management

Electric Vehicles

The uptake of Electric Vehicles is increasing; with government policy making diesels and petrol's less desirable through increased fuel prices and low carbon emissions zones in city centres. The government have committed to ban the sales of petrol and diesel cars by 2040. However, the market may lead to this happening earlier.

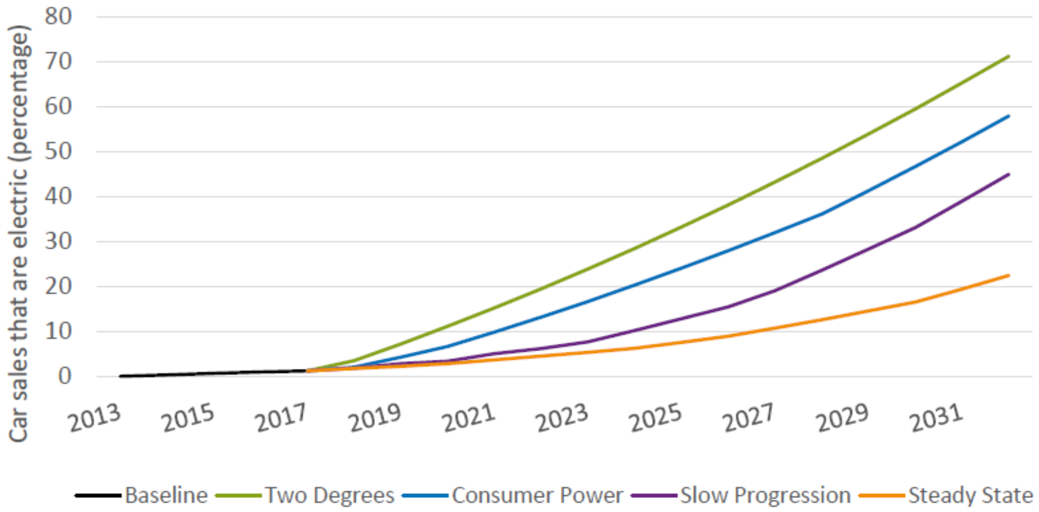


Figure 6 Electric Vehicle uptake in the latest South West DFES report

Figure 6 shows the number of EVs that will be sold as a proportion of all cars in WPD's South West licence area, as this is the latest scenario report to have been published; Figure 7 shows how this relates to the total number of EVs on the road across all WPD licence areas.

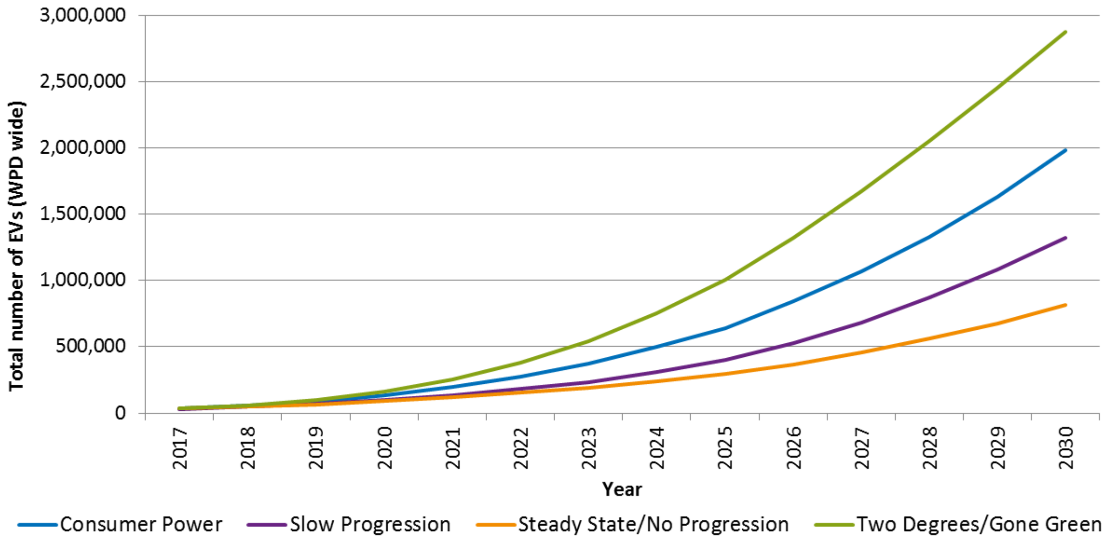


Figure 7: Total number of electric vehicles forecast across all WPD licence areas, taken from the DFES publications

Figure 7 highlights how the growth of EVs in WPD licence areas varies significantly by scenario out to 2030, with Two Degrees/ Gone Green having over 2.8million EVs and Steady State having just over 800,000 EVs. The large difference between forecasts takes various factors into account, such as changing government policy and availability of charging infrastructure.

The charging profiles from the Electric Vehicles Insight Report of the Customer-Led Network Revolution project are shown in Figure 8 [3]. This figure shows the diversified EV profile, for vehicles that have a Time of use Tariff (TOUT) and ones that are on unrestricted charging.

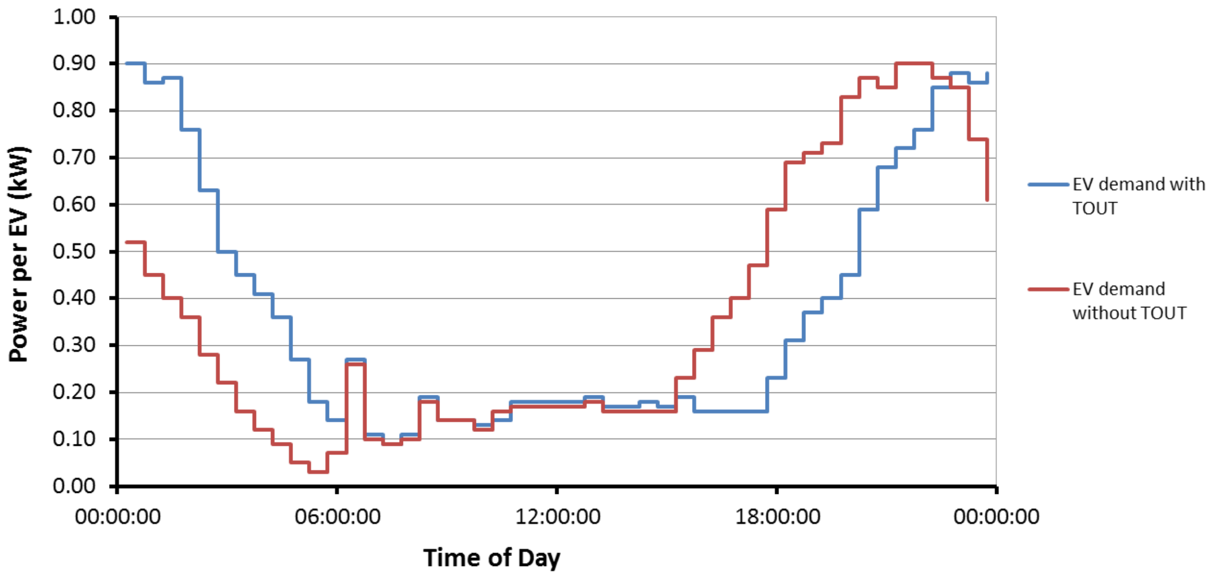


Figure 8: EV profiles with and without TOUTs

The profiles shown in Figure 8 give two examples of potential charging profiles for EVs based on the 16A domestic charge point used in the Customer-Led Network Revolution project. There are many factors that could impact EV charging profiles:

- There is a general trend towards 32A over 16A domestic chargers.
- WPD are looking to assess 3-phase into new build homes, which could increase the size of typical domestic chargers.
- An uptake of work placed chargers would mean an increase in day-time peaking EV demand.
- There are also non-domestic chargers, located at service stations that vary anywhere between 22kW to the Tesla 145kW super-charger.
- There is currently a trial in Europe to install 350kW chargers at service stations. In the ChAdeMO suite of charger specifications, the latest version 2.0 is capable of 400kW by 1000V and 400A direct current.
- The increase in the size of the EV batteries will also impact the profile, as the amount of energy used is likely to increase as people will be able to do longer journeys
- Longer term, the uptake of autonomous vehicles that charge at a centralised location would dramatically change the impact on the network

There is still a level of uncertainty on the speed of EV uptake and how they will charge, this has the potential to significantly impact network loading.

WPD is currently hosting the Electric Nation project in partnership with EA Technology, this project is funded by OFGEM. The aim of this project is to determine the impact EVs will have on the network and the effectiveness of DSR. Whilst there is not currently enough data from the Electric Nation trial to create new profiles, there was sufficient data to back up the Customer-Led Network Revolution profiles used. The project is currently in the operational phase with over 600 customers participating. The data gathered from this trial will be invaluable in giving the industry a better understanding as to how EVs are likely to charge, likely diversity factors and the effectiveness of managed charging.

Heat Pumps

Another emerging technology that has the potential to considerably change the demand profile is heat pumps. A heat pump absorbs heat from a cold place (typically the outside air of ground) and releases it into a warmer one, using similar principles to a refrigerator.

The profiles for heat pumps were derived from the Electricity North West Limited (ENWL) Network Innovation Allowance (NIA) funded study: Managing the Impact of Electrification of Heat, dated March 2017 [4].

The study considered various types of heat pump as follows:

- Lower temperature Air Source Heat Pump (ASHP)
  - Seasonal performance factor of 2.5-3.0
  - Generates flow temperatures of up to 55 degrees C
  - Suitable for well insulated buildings and new builds

- Higher temperature ASHP
  - Seasonal performance factor of 2.3-3.0
  - Generates flow temperatures of up to 80 degrees C
  - Suitable for older dwellings with a moderate thermal demand

- Hybrid ASHP
  - Lower temperature ASHP plus a boiler
  - Switches between fuel sources, based on efficiency/running costs
  - Suitable for older dwellings with larger thermal demand

Ground source heat pumps were not considered in the ENWL study as they are expected to be less prevalent due to space requirements for the ground source loop. The profiles for gas and electric back-up heat pump are shown in Figure 9 and Figure 10.

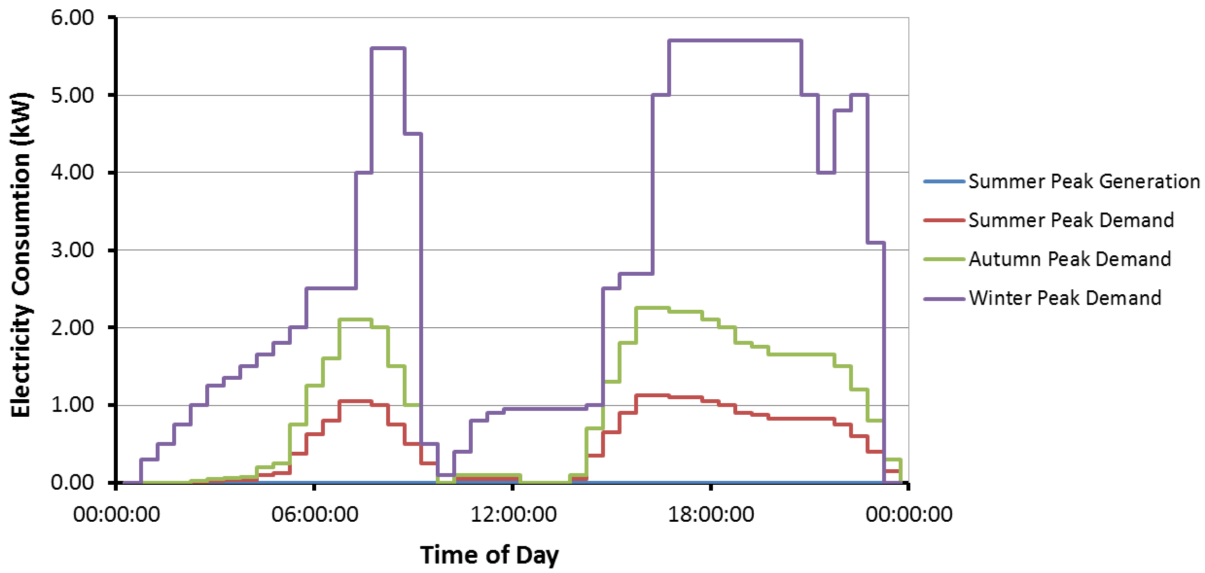


Figure 9: Electric back-up heat pump profile

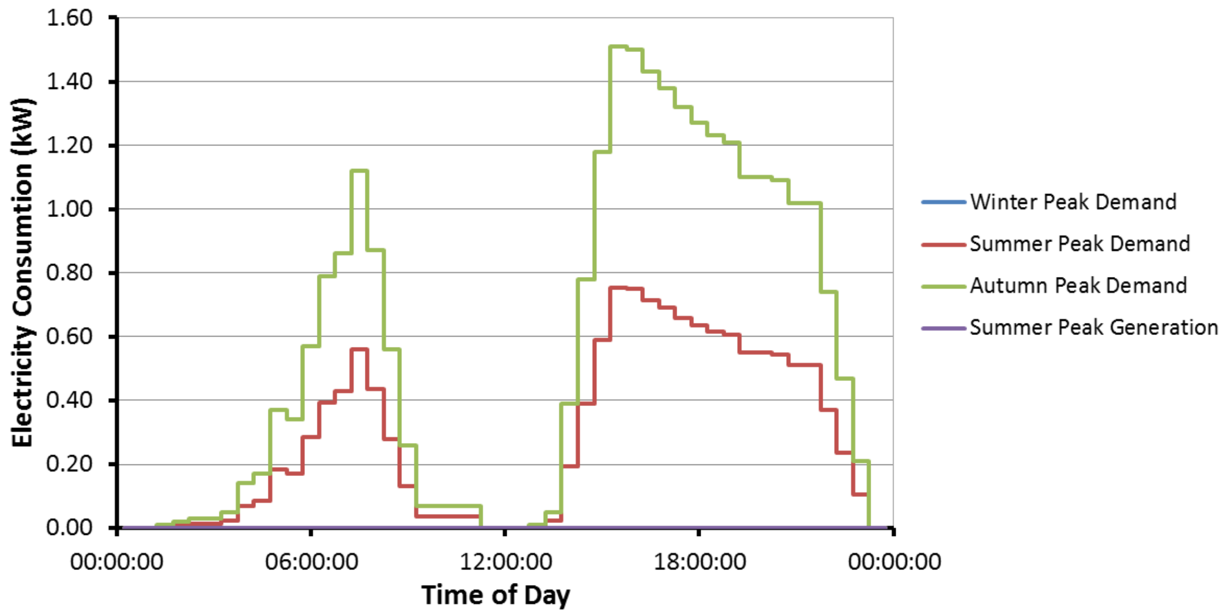


Figure 10: Gas back-up heat pump profile

Figure 9 and Figure 10 highlight the differences in electrical energy usage of an electric back-up heat pump has compared with a gas back-up. The winter peak demand from an electric back-up heat pump is 5.7kW, due to the 3kW electric back-up. The gas back-up heat pump at winter peak demand can switch to entirely gas, meaning there is the potential for no demand on the electricity network at times of high loading. This requires the correct market signals to ensure the hybrid heat pumps are running on entirely gas at times of peak electrical demand. The profiles assumed there was no demand in summer from heat pumps during the peak generation studies.

There is more certainty in when and how heat pumps will operate, due to more data availability obtained from current installations and less factors that could influence operation. On the other hand, the main uncertainty around heat pumps is the level of uptake; this will be heavily dependent on government incentives. The other factor that will impact network loading is the type of heat pump installed (gas or electric back-up).

There are low levels of diversity between heat pump demands at times of low ambient temperature, due to customers all wanting to heat their houses at the same time. Heat pumps work best by constantly running at times of cold ambient temperature.

Distributed Generation Growth

It is not only the increase in demand on the network that has the potential to cause technical challenges, but also the growth of generation. Whilst changes in demand as described above will impact the network, it is the actual load on the network that will determine what reinforcement or flexibility will be required. The loading on network assets will be determined by the combination of demand and generation on a given asset (i.e. circuit or transformer).

There are already significant levels of distributed generation connected to the distribution network, particularly in the South West licence area, of which a large portion is PV. A summary of the forecast generation output for the South West can be seen in Figure 11.

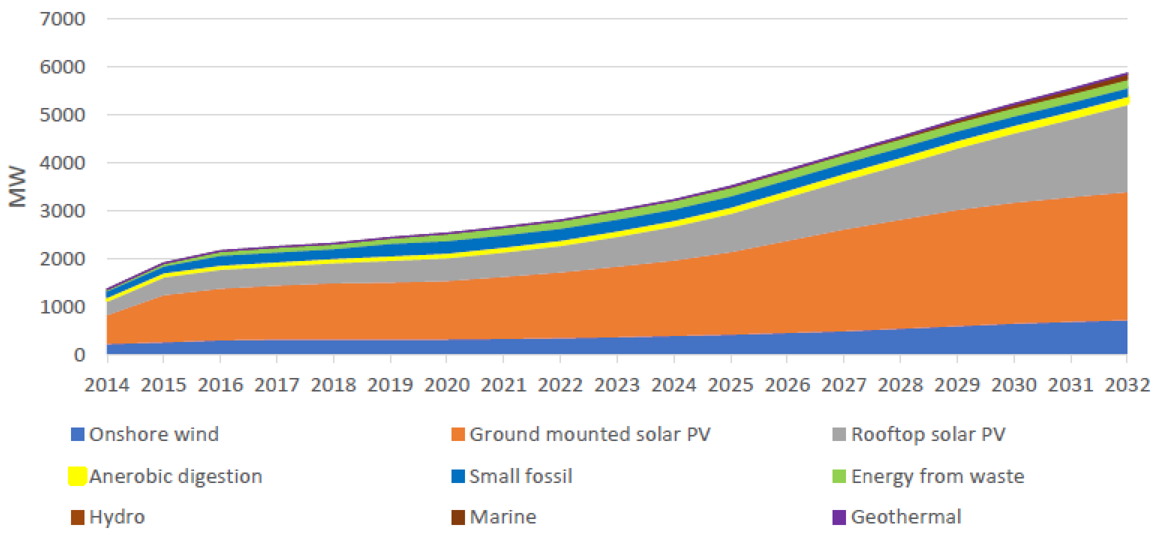


Figure 11: Generation growth in WPD's South West licence area under a Two Degrees scenario

This increase from a 1.5GW in 2014 to almost 6GW in 2032 indicates the continued impact generation could have on network loadings.

Traditional design assumptions assume that the network is designed for the worst edge cases. These are typically:

- **Winter Peak Demand**, with no generation output – an assessment of the network's capability to meet peak demand conditions;
- **Summer Peak Demand** and **Autumn Peak Demand**, with no coincident generation – an assessment of the network's capability to meet maintenance period demand conditions;
- **Summer Peak Generation**, with minimum coincident demand – an assessment of the network's capability to handle generation output.

Whilst these assumptions ensure a worst case network condition is assessed and compliance with existing policy such as ‘ENA Engineering Recommendation P2/6-Security of Supply’, the more DG that connects will make this assumption less representative [5].

As part of WPD’s Network Strategy Shaping Subtransmission work, the coincident peaks of generation with maximum demand are also assessed. WPD also have an ongoing Network Innovation Allowance(NIA) project called Curtailment and Dispatch Estimation Toolkit (CADET), which is going to explore coincident peaks of generation and demand, with the long-term aim of enabling better assessment of time-series data to determine more realistic network loadings and curtailment.

Storage

Currently, two of the main storage technologies are batteries and hydropower; the technology that has the highest forecasted growth is battery storage. Other emerging technologies include flywheels, hydrogen and super capacitors. The growth of battery storage for all four WPD licence areas is shown in Figure 12.

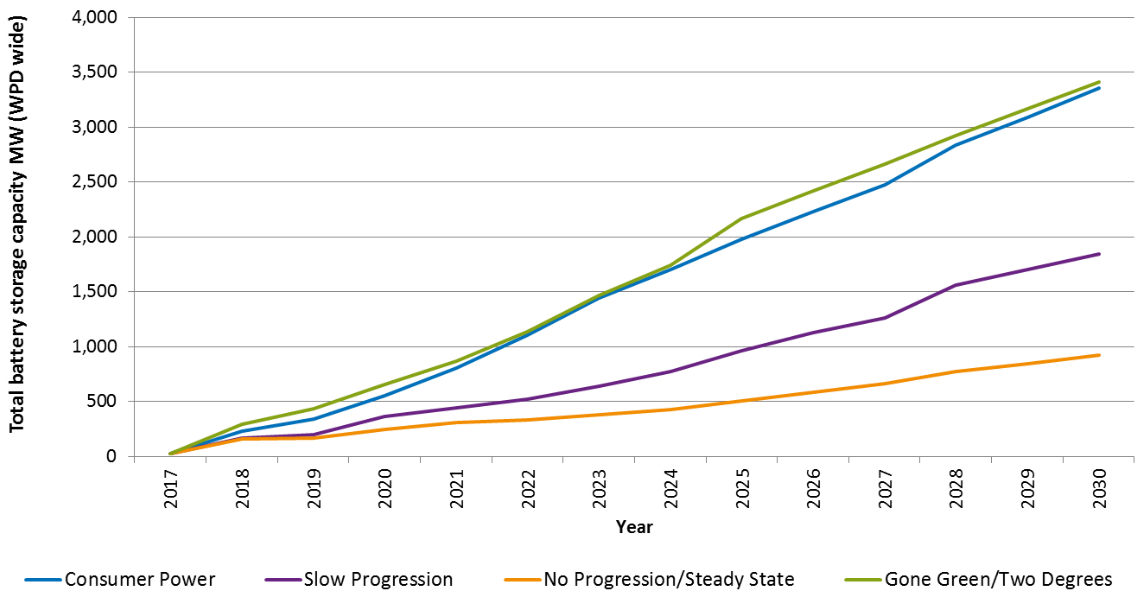


Figure 12: Battery storage growth out to 2030 for all four WPD licence areas

Storage is particularly challenging from a design perspective as it can import and export energy. The current design methodology is that a storage site will be modelled as importing at times of high demand and exporting at times of high generation. Whilst this is the worst case assumption, there are no contractual obligations which can prevent storage sites operating in this way.

WPD commissioned a consultation with Regen to develop an approach to model the growth and operation of storage. The results of this consultation paper were published in July 2017 and are available here:

www.westernpower.co.uk/energystorage

The report groups/classifies energy storage into 5 main storage asset types, based on their core business models, these are:

1. **Response Service** - Providing higher value ancillary services to transmission and distribution network operators, including frequency response.

2. **Reserve Service** - Specifically aiming to provide short/medium term reserve capacity for network balancing services.
3. **Commercial and Industrial** - Located with a higher energy user (with or without on-site generation) to avoid peak energy costs, and peak transmission and distribution network charges while providing energy continuity.
4. **Domestic and Community** - Domestic, community or small commercial scale storage designed to maximise own use of generated electricity and avoid peak electricity costs.
5. **Generation Co-location** - Storage co-located with variable energy generation in order to a) price/time shift or b) peak shave to avoid grid curtailment or reinforcement costs models.

The consultation results stated that response, reserve and time shifting are going to see the biggest growth. Also, 88% of responses falling into the 'Completely Agree' or 'Mostly Agree' categories showed broad agreement with the core business models we have proposed.

These different revenue streams can be stacked by combining multiple benefits/income streams to create a viable business case; this has led to a proliferation of potential business models. Understanding what markets and revenue streams a storage site is likely to be key to network design in the future.

A summary of the amount of generation connected, accepted, offered and enquired is given in Table 2.

Table 2: WPD Generation Capacity Register data for storage, dated 1st October 2018

	Connected		Accepted		Offered		Enquired	
	Sum of Capacity (MVA)	Count	Sum of Capacity (MVA)	Count	Sum of Capacity (MVA)	Count	Sum of Capacity (MVA)	Count
West Midlands	24	7	814	40	77	6	4	3
East Midlands	35	10	453	22	314	16	25	3
South Wales	0	3	21	2	0	1	0	0
South West	20	6	147	17	22	10	5	1
Total	79	26	1,436	81	413	33	34	7

The storage power output (MW) to storage capacity (MWh) will also affect how battery operation impacts network loading. The consultation results showed there was a general agreement that the MWh element of the ration will increase as time goes on. The current services are generally response services such as Fast Frequency Response (FFR) and Enhanced Frequency Response (EFR), where the ratio is currently around 1:1 (MW:MWh).

The report also gives 9 operating modes:

i) Network Auxiliary Services - Operating under direct contracted response services such as frequency response. This mode is for battery systems that are dedicated to being available for these response programmes 24hrs a day.

ii) Network Auxiliary Services and Network Peak – Similar to mode i), but reserving a small window of operation (2-4hrs) to discharge in peak network charge and high commodity price periods.

iii) Balancing Service Standby - Operating mode reflecting operation under balancing service contracts, effectively operating to be available for Short Term Operating Reserve (STOR), Fast Reserve, Capacity Market etc.

iv) Balancing Service and Network Peak - Operating under balancing services contracts as above, but also carving out a window of operation to discharge during peak network charge and high commodity price periods.

v) Network Peak Charge Avoider - A mode of operation designed predominantly for behind the meter classes of project, whereby a storage system has been implemented to supply a demand load during network peak charges. Storage system charging is during lowest price periods.

vi) Cost Sensitive Self-Use - A mode where a demand user with generation is using storage to increase self-consumption of on-site generation, but weighted towards high commodity/delivery charge periods. This could currently be a commercial and industrial (C&I) user with generation, subject to cost sensitivity or smaller users with Time of use Tariffs.

vii) Maximise Self-Use - A mode where a demand user with generation is using storage to maximise self-usage of on-site generation, but is not sensitive to high/low price thresholds (i.e. domestic solar with a flat electricity import tariff). Charging when solar is generating, discharge when energy is needed.

viii) Generation Time and Price Shift – Using energy storage co-located with generation to time shift energy from a low to a higher price period.

ix) Generation Peak Shaving – Using energy storage co-located with generation, but diverting a proportion of the generation into storage, so as to bypass grid export constraints. Likely to also discharge during high price periods.

Detailed graphs of the behaviour of each operating mode can be found in the consultation report. It should be noted that these modes have been chosen as typical/generic modes and do not account for every possible variation. The consultation results showed that 91% of respondents either completely or mostly in agreement with the 9 operating modes.

The general consensus of the consultation was that storage operators currently want the flexibility to play into any market. This justifies the existing worst-case design approach of assuming the batteries may be operating for a wider system need and not in a way that will benefit the local network.

These are just some of the challenges of storage that will impact network behaviour in the future. As the markets develop there may be more certainty in the operation of batteries, so they less onerous design constraints have to be applied. This could include contractual arrangements with storage sites to operate in a way that is beneficial to the distribution network. The detailed assessment below looks at how the assumptions made around battery operation can have a significant impact on peak network loading.

Case Study

This section looks at a BSP within the WPD licence area and how the peak demand and load profile is forecast to change out to 2030 under the FES Two Degrees scenario. The forecast data and technology profile information used in this case study is from WPD's Shaping Subtransmission work. The purpose of this case study is to highlight some of the challenges of changing load profiles from the disruptive technologies described above and the increase in conventional demand.

The actual net impact these demand and generation technologies will have on the network will be dependent on:

- Rate of domestic, non-domestic and industrial growth
- Level of distributed generation connected to the network and the technology type
- How well implemented TOUTs, flexibility and other smart solutions are used to mitigate the changing load profile

Peak Demand Growth

Using the Regen forecast data, and the detailed time-series analysis undertaken as part of the Shaping Subtransmission work, it is possible to assess the load curve at a BSP for a peak demand day from 2017 out to 2030 under the different scenarios.

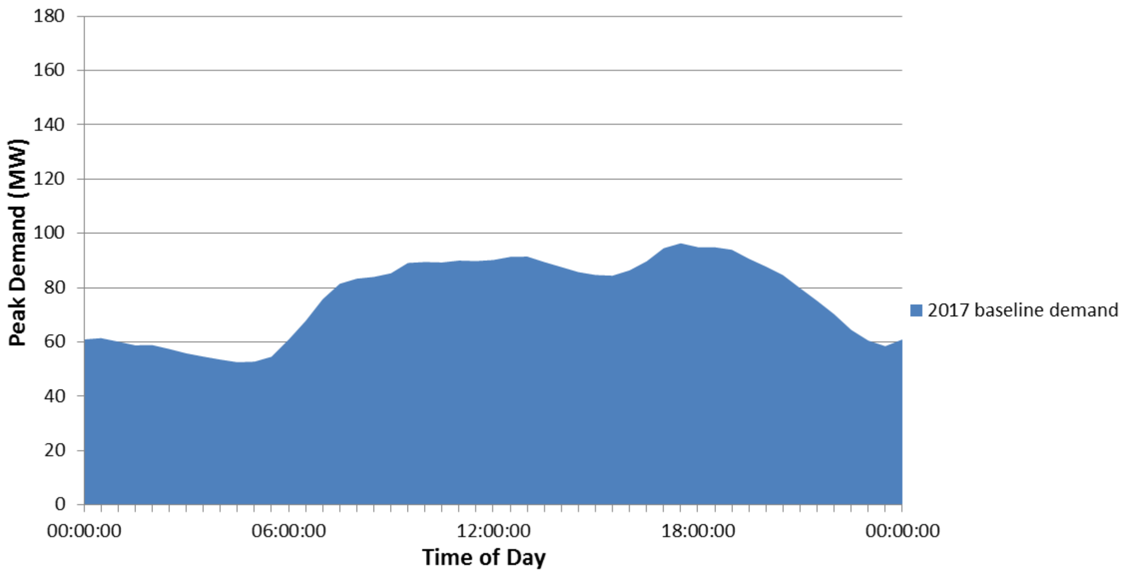


Figure 13: WPD BSP day load profile for 2017 winter peak demand

Figure 13 shows the BSP in 2017 had a peak demand of 99 MW, with the peak occurring at half hour 36 (17:30 and 16:00) in winter. Figure 14 shows the forecast peak loading for the same BSP under the 2030 Two Degrees scenario without any flexibility services applied.

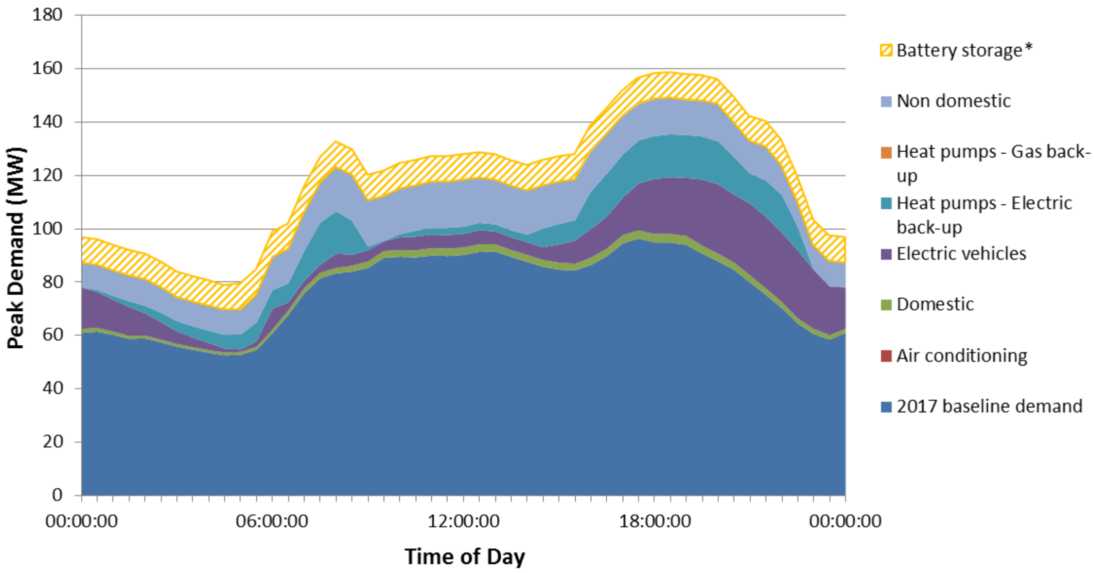


Figure 14: WPD BSP day load profile for 2030 peak demand under the Two Degrees scenario

**Batteries are modelled as importing for the entire period, whilst this is not representative of how a battery could operate, without certainty of when and how they will operate, it must be assumed they could import at any point. Storage is ignored for any energy comparisons.*

The key points from this 2030 load profile are:

- The peak demand on the BSP has increased to 159 MW (including batteries importing) or 149.5 MW (batteries not operating), this is up from 99 MW in 2017, a 60% increase in peak demand.
- The peak half hour changes from 17:30-18:00 in 2017 to 18:30-19:00 in 2020 Two Degrees.
- There is an increase in total energy of 42% excluding batteries importing/exporting.
- There is a minor morning peak predominately caused by the electric backup heat pumps, as shown in Figure 9.
- For this particular BSP, HP, EV and non-domestic account for the majority of the demand growth.

Whist this BSP example shows a significant growth of EVs and HPs under the Two Degrees scenario, other substations within WPD's licence areas see a demand growth dominated by non-domestic, in particular factory, warehouse and office developments.

Mitigation through Flexibility

If the level of demand growth shown in Figure 14 was to occur by 2030 it would inevitably cause challenges on the distribution network, which will need to be managed to ensure the network remains compliant and operable. This demand growth would be staged, meaning it would need periodically assessing, so appropriate reinforcement or flexibility can be put in place.

One option to resolve this level of demand growth is through traditional reinforcement; this would include replacing existing assets and commissioning new assets. Moving towards a smarter, more flexible network the use of flexibility services will be able to defer or remove the need for traditional reinforcements. Some options to resolve the overload this demand growth is likely to include:

- Demand turn up or turn down
- Generation turn up or turn down

- EV charging management
- Energy storage

The following sections look at some of the management options used to deal with the combination of increasing demand and generation and hence the changing load profiles.

Energy Reduction vs Time-shifting

There is a difference between time-shifting energy, through mechanisms like managed EV charging and an actual reduction in total energy. Demand can be categorised into three categories:

- **Inflexible demand** – this type of demand will occur at a set time and cannot be easily reduced through the use of TOUTs and incentives. For example, lighting, cooking, major events and resistance heating.
- **Time-shifting demand-** This is demand where the energy is required but there is flexibility in time-shifting when it is actually drawn from the distribution network. For example, EV charging, washing machines (set on a delay), storage heating and commercial/domestic refrigeration.
- **Energy reduction –** This is demand that has the ability to actually reduce its energy consumption, normally through sufficient financial incentives. For example, industrial production lines, reducing EV usage or increased efficiency.

Whilst inflexible demand requires supplying at a specific time, the use of energy storage can be used to reduce the impact it has on the network at times of high demand.

Time of use Tariffs

The demand growth out to 2030 is shown in Figure 14 with a peak demand of 159 MW, Figure 15 shows the same forecast growth, but with a TOUT tariff applied to the EVs. The TOUT is based on the Customer-Led Network Revolution project as described in the Electric Vehicles section of this report.

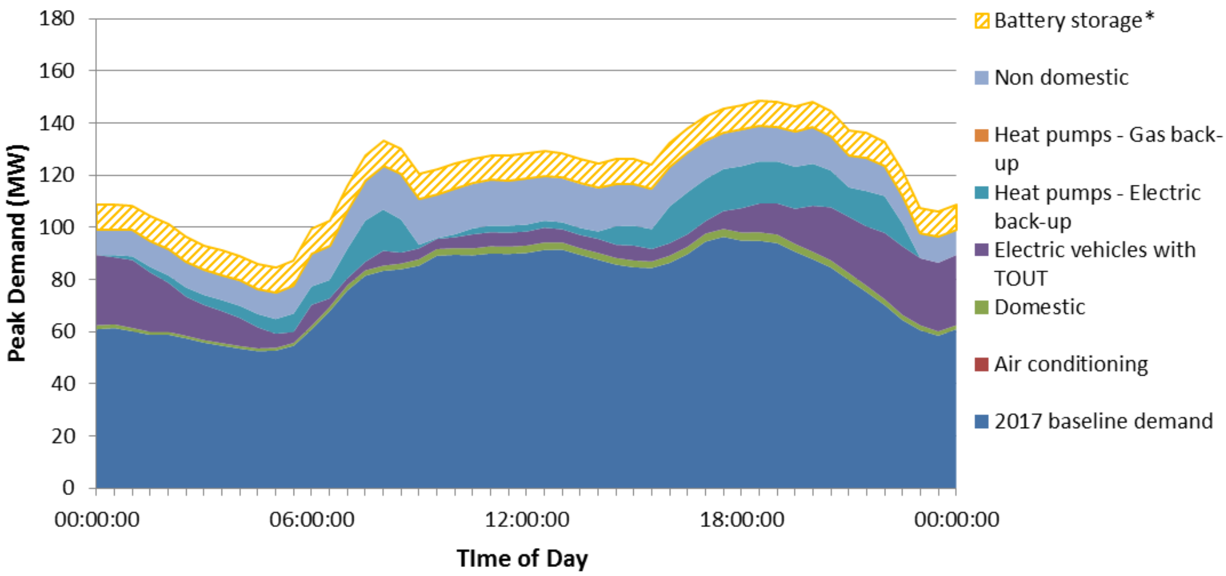


Figure 15: WPD BSP day load profile for 2030 peak demand under the Two Degrees scenario with TOUT applied to EVs

**Batteries are modelled as importing for the entire period, whilst this is not representative of how a battery could operate, without certainty of when and how they will operate, it must be assumed they could import at any point. Storage is ignored for any energy comparisons.*

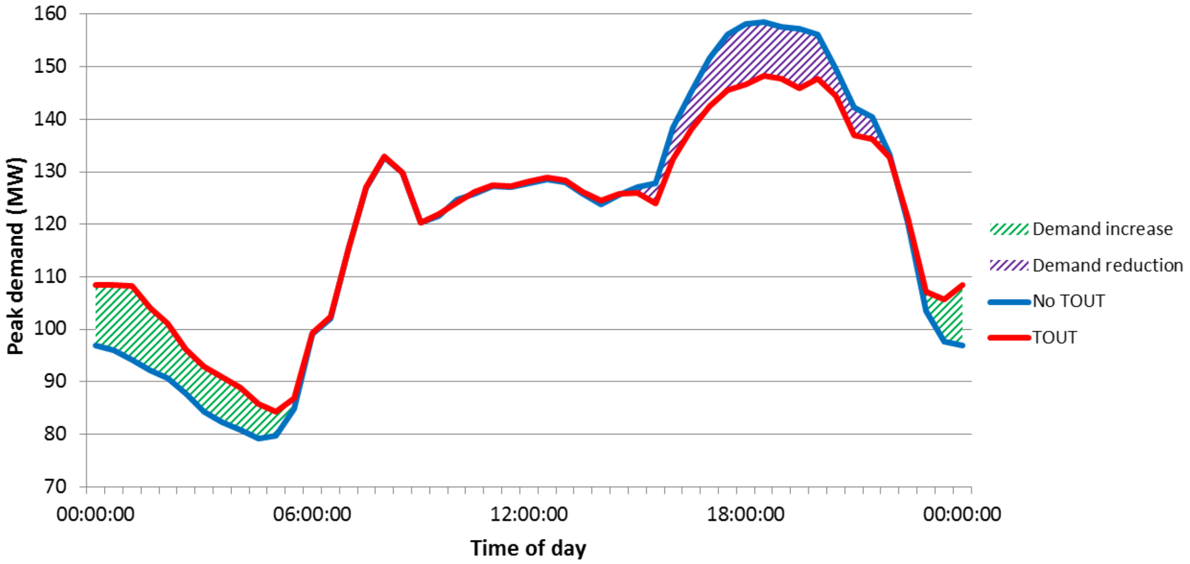


Figure 16: Impact of a TOUT on the EV demand for 2030 Two Degrees

The time of use tariff means that at the time of high demand on the network (16:00-20:00) the EV users are incentivised to charge their vehicle later. The impact of this is that the peak demand is reduced to 148 MW, this could mean over a 10 MW reduction compared if a TOUT was not applied.

Whilst there is a reduction in the peak demand, the total energy requirement across the day is the same. This has the effect of flattening the demand curve, for at 23:30 to 00:00 the peak without a TOUT is 97.5 MW, but with the TOUT it is at 106 MW. The use of a TOUT is just one example of the way EV charging will impact network loading.

Impact of DG

This case study has focused on a winter peak demand day, where the assumption is that almost no generation will export for any period throughout the day and batteries will be importing at the time of peak demand.

This approach mirrors how the network is currently designed, as there is no guarantee that any generators will be running at the times of network peak demand. Furthermore, network designers can count the output of certain non-intermittent generator types if a detailed assessment is undertaken.

This assumption is necessary for current network design, where no specific market and contractual agreements are typically in place. By 2030 it is likely there will be full flexibility markets in place to ensure generation (intermittent and non-intermittent) is operating in a way that means a worst case design assumption is no longer required.

This section looks at the impact the forecast generation on the BSP assessed in the case study. The total amount of generation connected to the case study BSP by 2030 under the Two Degrees scenario is given in Table 3.

Table 3: Case study BSP installed capacity by generation type by 2030 under Two Degrees

Technology	Installed Capacity (MW)	Technology Type
Anaerobic digestion	2.5	Non-intermittent
Battery storage	9.5	Storage
Hydropower	0.037	Non-intermittent

Onshore wind	0.37	Intermittent
Other generation	21.1	N/a
Ground mounted PV	3.2	Intermittent
Rooftop PV	37.0	Intermittent

Battery Storage

There is currently 78 MW of battery storage connected onto the WPD network, but there is 1,500 MW of accepted-not-yet-connected offers across all four licence areas.

Figure 14 and Figure 15 show the peak demand with and without TOUT, the batteries are assumed to be importing (an effective demand) for the whole day. A battery is unable to operate like this, but if there is uncertainty about when a battery would operate a worst case assumption must be taken that it will be importing at times of high demand.

By 2030 battery storage is forecast to grow to as much as 3,400 MW. It is likely there will be markets and contractual arrangements in place to ensure most battery storage sites will not be importing at times of peak demand. If this was the case then the peak demand would reduce by 9.5 MW. In reality, some of the batteries would be operating for wider systems services like FFR or Balancing Mechanism (BM).

A battery has a limited energy (MWh) it can store and a maximum power export/import (MW). WPD and Regen have completed the battery storage consultation that suggests most batteries will have a MW/MWh ratio of 1:4 by 2030. This means that for the 9.5 MW connected at the case study BSP, that it could output 9.5MW for 4 hours.

If all 9.5 MW of batteries were operating in a price arbitrage (time-shifting) for a high demand day this would mean the battery site(s) exporting at times of high demand and then importing at times of lower demand. If this operating mode was to become financially viable, it would have the following benefits on the network loading.

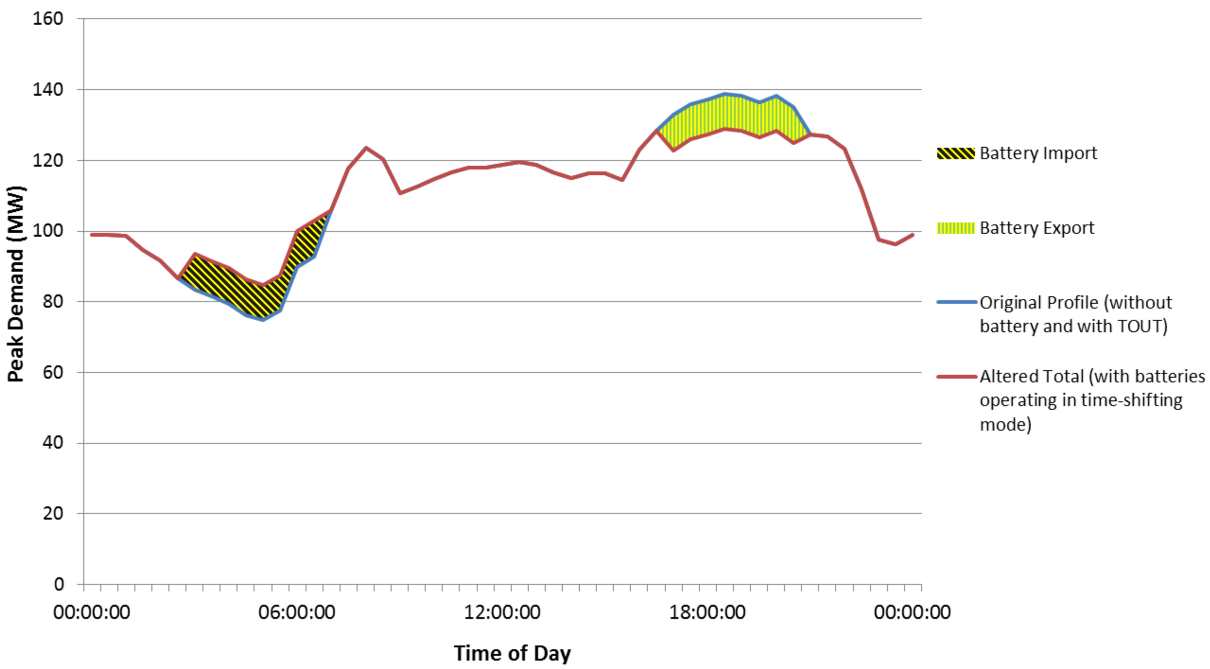


Figure 17: Battery Storage operating in price arbitrage mode (exporting at peak demand)

Figure 17 shows that the battery storage operating for 4 hours in full export between 17:00 and 21:00 (assuming a 1:4 MW to MWh ratio) in price arbitrage mode (time-shifting energy), further reduces the demand peak to 129 MW, from 159 MW (without EV TOUT) and 148MW (with EV TOUT). The battery storage operating in this way further flattens the load curve on the BSP transformer and associated circuits.

Non-intermittent Generation

Non-intermittent generation is defined as generation plant where the energy source of the prime mover can be made available on demand; for example diesel, gas and Combined Heat and Power CHP. As with batteries it may become easier to contract with this type of generation to further reduce the loadings on assets.

For the case study BSP, there is a total of 14MW of non-intermittent generation; this consists of 2.5MW of anaerobic digestion and 11.5MW of the other generation is also classed as non-intermittent generation.

If all of this generation was to generate at its export capacity for the entire day, the peak demand at the BSP would further reduce by 14MW. This can be seen in Figure 18. As with the batteries it is likely that this generation could be operating in other markets, so not all non-intermittent generation would be available through the entire day.

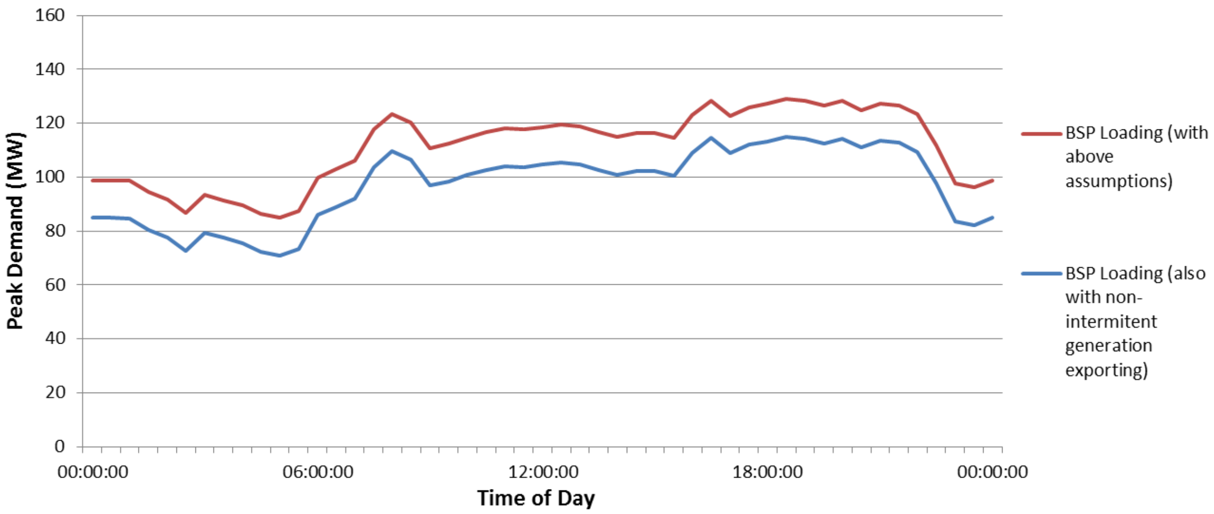


Figure 18: Reduction in BSP loading through non-intermittent generation exporting at peak demand

The export of the non-intermittent generation reduces the peak demand from 129 MW to 115 MW. For this case study, it is assumed the generation exports for the entire day, in reality it might be contracted just for the peaks. This operation would cause further flattening on the load curve.

Intermittent Generation

Intermittent generation is defined as the generation plant where the energy source of the prime mover cannot be made available on demand. The most commonly installed intermittent generation on the distribution network are PV and wind. There is a total of 39.2MW of PV in the case study BSP and negligible wind generation.

The existing ENA P2/6 - Security of Supply recommendation states the level of security required on the network. Currently it states that PV cannot be considered as outputting at times of peak demand, due to the intermittent nature. Whilst this is a reasonable assumption, WPD's Network Strategy Shaping Subtransmission has done some detailed assessment to determine the minimum output of PV at time of winter demand peak. A detailed description can be found in the South West Shaping Subtransmission report:

www.westernpower.co.uk/netstratswest

ENA P2/7 has recently been out for public consultation and changes to this standard allow similar assessment methods to be undertaken by the DNO to allow for all types of generation to provide security of supply. An ENA group has also been set up to revisit the work within “ETR 130 – Application guide for assessing the capacity of networks containing distributed generation”. This working group will review the existing F-Factor table; these factors define the level of contribution to system security from intermittent and non-intermittent DG plant as defined in ER P2/6.

Existing PV and wind sites cannot currently be relied on to be outputting at times of peak demand, particularly because this normally occurs in the evening in winter. One way that new intermittent generation sites could better support times of peak demand is co-location with batteries; where the batteries charge from the PV/wind at times of low demand and then output at times of high demand, even if the PV/wind is not outputting at this time. If there was financial justification for this type of operation, there is also potential to retrofit existing PV/wind sites with batteries.

Impact on Asset Ratings

Existing assets (transformers, circuits etc.) typically have a number of ratings that will be used for different design assessments. Determining how heavily an asset can be loaded is predominately driven by the thermal loading and the level of heat dissipation. This means ambient temperature is a significant factor when determining asset ratings; other factors include wind speed and construction. For this reason, assets typical have different ratings dependent on seasons, where the calculation of a seasonal rating uses assumed ambient temperatures.

Within a season assets may also have a number of ratings that can be used dependent on the design or operational requirements. The most common breakdown of these is continuous and cyclic ratings.

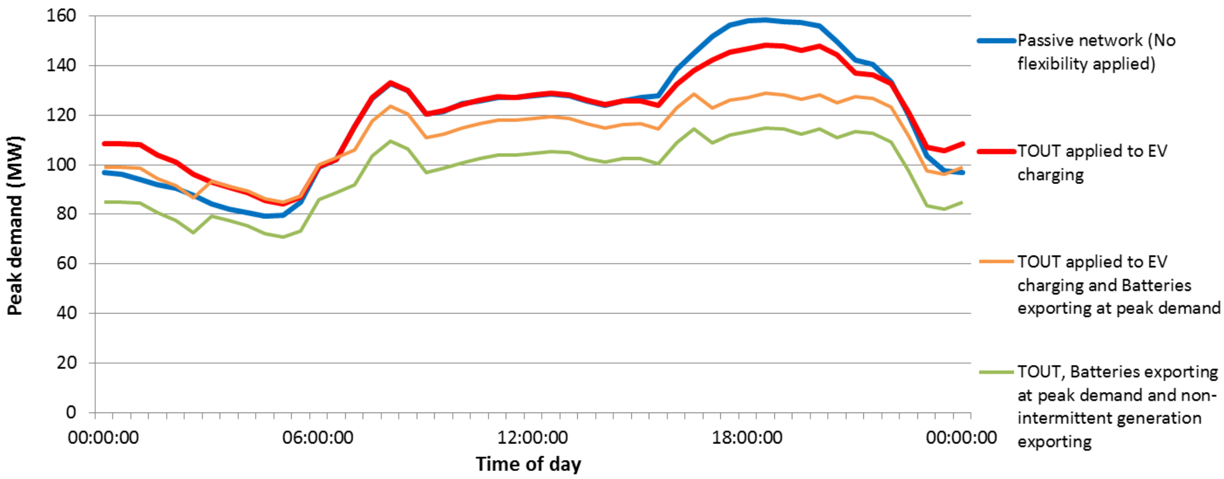


Figure 19: Impact of flexibility and smart solutions on case study BSP for 2030 Two Degrees

Figure 19 shows how the loading on the case study BSP for a given installed capacity of demand and generation could change for winter peak demand dependent on the level of flexibility that is implemented. This shows a general flattening on the load curve as energy is time-shifted from times of high demand towards periods of lower demands.

The flattening on the demand curve means the traditional assumptions used to determine the cyclic loadings of assets may become outdated. If the traditional cyclic load curve was to flatten, it would mean cyclic ratings would have to reduce to account for less periods of low loading. As network loadings continue to change there may become a point where asset ratings will need reviewing.

Case Study Summary

The aim of this case study was to show how the forecast growth out to 2030 under the Two Degrees scenario will cause significant load growth if no flexibility and smart solutions were implemented. There are many ways in which the combination of demand and generation could operate; this case study shows how this change could be managed through flexibility for a high demand day.

Figure 19 shows how the combination of TOUT, batteries operating in time-shifting mode, and the non-intermittent generation can reduce the peak from 159MW down to 115MW. This is a 28% reduction in peak demand but only a 20% reduction in energy. This is because the batteries and EVs are time-shifting energy rather than actually reducing total energy.

The main points to be taken from this case study are:

- The demand growth forecast at this BSP is seen across many BSPs in all licence area, the breakdown of the type of demand and generation varies by BSP.
- If no smart solutions of flexibility were to be used, loadings could increase by as much as 60%
- If it was possible to implement the smart solutions described above, only a 19% rise in peak demand would occur, but a 28% increase in the energy requirement.
- This would change the load curve; by flattening the load curve it could cause existing assumptions on cyclic ratings of transformers and cables to become obsolete.

One of the biggest challenges facing DNOs is forecasting the amount of demand and generation that will connect and where it is likely connect. The next challenge is determining how it will operate, i.e. how and when will EVs use TOUT or managed charging and will batteries operate in a way that is beneficial to the distribution network at all times.

It is important to note that this example focuses on a peak demand day and the associated challenges. Many BSP with large generation growth will also see generation driven issues that could be dealt with via generation turn down (using ANM) or demand turn up.

From this assessment it is likely that this BSP would require traditional reinforcement as the limits of flexibility would have been reached. In addition, the use of flexibility has significantly reduced the level of reinforcement that would be required by reducing the peak demand on the network (i.e. flattening the load curve).

Short Term Mitigation and Solutions

The first challenge is forecasting connections to the distribution network sufficiently far enough in advance to ensure appropriate mitigation or reinforcement can be undertaken. This also requires forecast data at a level which is granular enough to the network area of interest. This forecast data can be broken down into:

- **Traditional demand** – Forecasting domestic, commercial and industrial growth. There are well defined profiles for this type of connection and appropriate connection processes are in place.
- **Established generation technologies** – technologies like PV and wind where DNOs have a high confidence in customer behaviour.
- **Emerging demand technologies** – The two emerging demand technologies that are forecast to impact the networks the most are EVs and heat pumps. EVs are particularly challenging as it is not just the forecasting of the number of EVs, but also the charger locations and charging patterns. The factors influencing heat pump energy requirements and operation (i.e. ambient

temperature) are better understood than EVs, but the type of heat pump and actual uptake is more uncertain.
- **Emerging generation technologies** – This could include technologies like tidal and floating wind, that have the potential to impact the generation mix of the network in the future.
- **Energy storage** – Energy storage will play a role in flexible network, but there is a real challenge regarding the prediction of the amount of energy storage connections and how they will work.

WPD currently carry out the following forecasting in an effort to capture any demand or generation growth (or reductions):

- **Long-term Development Statement (LTDS)** – This is compiled by WPD on a yearly basis to assess current and future opportunities available on the distribution network.
- **Shaping Subtransmission –** Part of WPD's Strategic Investment Options series of reports that uses the National Grid FES scenarios to forecast demand, generation and storage growth at an Electricity Supply Area (ESA) level.

For most demands and mature generation technologies there is a relatively high confidence in their operating behaviour. Emerging technologies are much more challenging, as forecasting the likely growth can be challenging as it will depend on whether there is a high adoption rate. DNOs cannot justify reinforcing ahead of need, without a high confidence in the network load actually materialising. The Shaping Subtransmission work forecasts these emerging technologies by either installed capacity or numbers; it does not provide a likely operating behaviour. A priority in the short-term is determining how these emerging technologies are likely to operate and how existing demand behaviour may change. To help determine different technology behaviours WPD are running the following initiatives:

- **Electric Nation** – This active project aims to help DNOs better understand charging behaviours of EV users. There are over 600 participants in the trial using a combination of pure EVs and Plug-in-hybrids. It will also assess control systems for managed charging and if Vehicle-2-Grid (V2G) can help defer reinforcement.
- **Freedom** – This active project is due to complete in January 2019 and the objectives of this project is to better understand if hybrid heating systems are technically capable, affordable and their actual operating regime.
- **Demand Side Response (ENTIRE)** - This active NIA funded project will address many of the key issues a DNO is presented with as they develop DSR. This project aims to test comprehensive DSR capability to control generator and customer loads.
- **Signposting** - Facilitating new neutral markets around flexibility is a key objective in WPD's DSO Strategy. This will require us to provide a greater level of information on the performance characteristics of our network than ever before and in a format which is understandable and transparent. This new style of information presentation has been developed through close engagement with our stakeholders and we anticipate this signposting information to inform the market ahead of us requesting tenders for flexibility. A signpost provides general directions to a number of destinations, though does not describe the exact path in the way a map would. In the same sense, WPD's signposting information directs flexibility providers to the different distribution system needs required under a range of scenarios and timings.

One of the other challenges facing DNOs is the lack of detailed monitoring on the network, in particular on the lower voltages. Increased monitoring will enable WPD to have a higher confidence in network conditions and will be better equipped to manage the network. WPD currently have an ongoing project to improve the amount and quality of monitoring on the network to include more 4-quadrant directional metering.

As highlighted in this report, network design traditionally assesses static edge cases. As the network load profile changes and the increase in flexibility services increase, there will be a need to move away from edge case power assessments at the design stage towards energy assessments. This will require significantly more data as an entire year will need assessing. WPD are currently running the NIA funded CADET (Curtailment and Dispatch Estimation Toolkit) project that is using stochastic analysis techniques to determine the minimum amount of studies required to accurately determine energy curtailment or utilisation for an entire year. The output of this project will aid in the development of energy assessments. The case study in this report highlighted that the use of flexibility has the potential to reduce the cyclic nature of network loading. This could have the potential of reducing the available ratings of assets.

Long Term Solutions

The short-term solutions are focused on forecasting potential growth and determining how different technologies and flexibility services are likely to operate. In the longer term, there will need to be a detailed Cost Benefit Analysis (CBA) to determine where flexibility is the best solution to reduce network loading and where traditional reinforcement is the best option. This may lead to a distribution-led Network Options Assessment (NOA) process. Also, this will require integrating a large number of the inputs described in the short-term solutions.

The ability to contract with storage sites and certain batteries to provide support to the distribution network when required is something has the potential to reduce. Conversely, if there is no contractual arrangement or market that ensures certain technologies will not import at times of high demand then pessimistic assumptions will be required.

As other demand and generation technologies emerge the impact they could have on the network will need assessing through innovation projects. The increase in smart network management and flexibility services will also need detailed assessment to ensure the impact they have on network loading are fully understood.

WPD are currently running an NIA project called Curtailment and Dispatch Estimation Toolkit (CADET) which is looking at how the coincidence of demand and generation, with the aim of reducing the analysis requirements to assess yearly energy requirements. The output from this project should feed into future analysis to help better determine flexibility energy requirements.

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