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Flexibility Solutions for High-Renewable Energy Systems

United Kingdom

BloombergNEF

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Foreword

Decarbonising the power system is imperative if we want to bring carbon emissions to a sustainable level. The last decade we have made important steps forward, increasing the share of renewables in the European power system significantly while bringing down the cost of renewable energy. This is only the beginning – dramatic growth in the share of renewable power generation capacity will be necessary in the future.

A key challenge is to integrate a large and growing share of intermittent power generation from wind and solar plants into the power system. This study shows that it is possible – stronger connections to the Nordic hydropower system, demand side flexibility, battery solutions and smart charging of EVs can play together, reducing the need for keeping fossil fuel capacity as a backup, thereby bringing down both costs and emissions.

For Statkraft, as the largest generator of renewables in Europe, it is interesting to see that Nordic hydropower reservoirs can play an important role for decarbonisation of the European power systems, together with other flexibility solutions. This is consistent with our own analyses – confirming that a global renewables share of 70 percent is possible by 2040 if we let modern solutions for flexibility and market design allow cheap renewables to replace more expensive fossil solutions.

Henrik Sætness, SVP Strategy & Analyses, Statkraft AS

The relentless advance of solar and wind energy technologies are driving us inexorably towards an electricity system dominated by variable renewable power generation. Combined with the expected growth in electric mobility, we are now in the midst of an energy transition which will massively lower carbon emissions and improve air quality. However, this opportunity will be appreciably limited unless energy markets are designed and regulated in a way that unlocks the full value of flexibility in the electric system.

Eaton is delighted to be co-sponsoring a new, wide-ranging study by BloombergNEF, which makes a compelling economic case for a wide variety of solutions to address the flexibility challenge faced by two countries – Germany and the UK – who are both at the forefront of the energy transition. This report is a follow up on BloombergNEF's Beyond the Tipping Point study from last year, which explained that much of the energy transition will occur in less than a decade, thus engendering a need for increased flexibility. The time is already upon us to prepare and start investing in the technologies, services, and modifications that can enable our energy system to cope with the dramatic shift in how we generate and use electricity. We expect that the findings of this report will help spur both industry and government across Europe to take the steps needed to prepare their grids for a high renewable future, and at the same time, fully realise the enormous commercial and environmental opportunities such actions will create.

Cyrille Brisson, Vice President of Sales and Marketing for the EMEA region, Eaton

The authors would like to express their gratitude to the Renewable Energy Association for their support and help in preparing this study.

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Section 1. Executive summary

25%

Lower U.K. power sector emissions in 2030 with Nordic interconnectors

12%

Less backup fossil capacity required in 2030 with faster battery deployment

13%

Higher power generation system costs in 2040 without new flexibility technologies

New forms of flexibility are key to an affordable, renewables-led power system. Without energy storage, smart-charging electric vehicles, demand response and interconnectors, the U.K. energy transition risks proceeding on a suboptimal path, with a power system reliant on fossil backup and oversized renewables capacity. This will come at a higher cost, and with higher emissions.

This report, authored by BloombergNEF in partnership with Statkraft and Eaton, explores the newer possibilities for solving the power system flexibility challenge in the U.K.: energy storage, demand response, flexible electric vehicle charging and interconnections to Nordic hydro. (We are simultaneously publishing a similar report for Germany. Although both countries are on a path to higher renewable penetration, our analysis has led to different conclusions about the role of flexibility in each nation's transition.)

Building on BloombergNEF's flagship forecast for the global electricity system, the New Energy Outlook (NEO), this report develops scenarios to explore alternative futures for the power system, depending on how each flexibility technology might develop in the coming years. It uses BNEF's proprietary New Energy Outlook modelling tools, meaning that every scenario is, for the given assumptions, a least-cost optimal solution. Each scenario starts with different underlying assumptions about what each technology can provide, and/or at what cost.

The report analyses seven scenarios (Figure 1). They are all variants of the NEO base case, which was published in June 2018 and contains some degree of demand response, flexible EV charging and a relatively large volume of batteries.

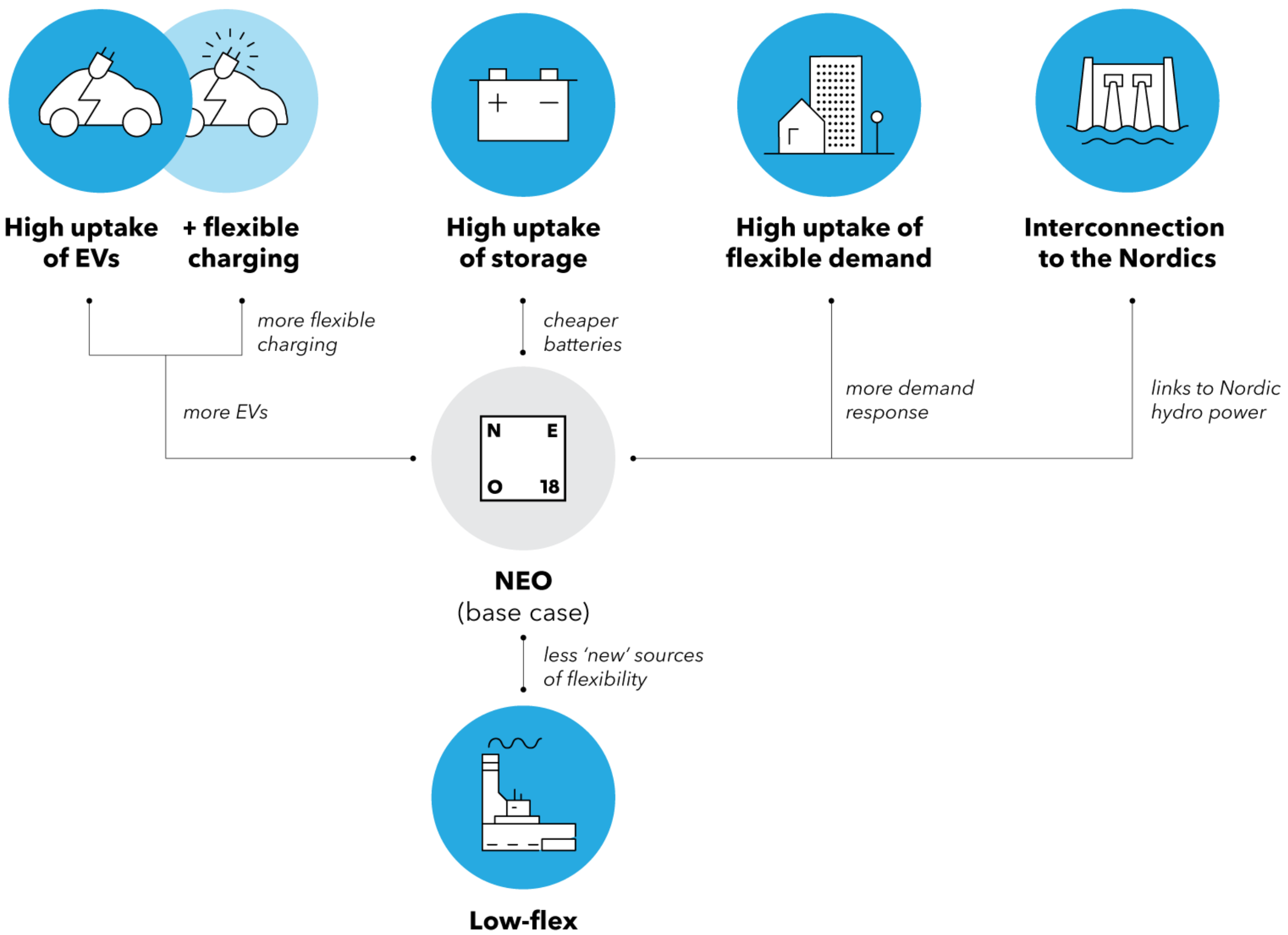
The low-flex scenario considers the consequences if these technologies are substantially held back, whereas each of the other scenarios introduces or accelerates a single 'new' source of flexibility. The accelerating factors that we consider include a 2040 internal combustion engine ban, the increased popularity of flexible EV charging, faster battery cost declines, increased demand response uptake and the introduction of several interconnection lines to the Nordics and their substantial hydro resources.

The main conclusions are that:

- **There are two types of benefits provided by these flexible technologies**:
  - **Integrating large volumes of renewable generation**. This is done either by shifting excess demand to periods of high renewable generation, or by storing the excess renewable generation for periods of high demand.
  - **Displacing (fossil) backup capacity** that would otherwise be needed for extended periods with little wind or solar generation.
  - Both of these benefits produce good results in terms of reducing cost and emissions.
- **None of the scenarios halt the transition to a low-carbon power system**, not even the low-flex scenario. The continued, steep decline in wind and solar costs means that over 90% of generation is zero-carbon in 2040 in all scenarios. However, a lack of 'new' flexibility would have a real cost: a more expensive, over-built system with high curtailment, reliant on fossil fuel plants for backup that produce over a third more emissions than in the NEO base case.

- **New sources of flexibility are needed in the near term.** Across all scenarios, there is a need for battery storage from the early 2020s onwards. In the U.K., by 2025, the storage capacity required by the system in our base case NEO scenario is 4.0GW, and ranges across scenarios from 1.5GW to 4.8GW. Allowing the aggregation of storage to provide grid services as well as rewarding utilities and distribution companies for contracting distributed energy resources are key to supporting these new sources of flexibility that will enable the transition to a high renewable energy system.
- **Greater electrification of transport yields major emissions savings with little risk to the power generation system.** A larger fleet of electric vehicles, of which we assume 50% can charge flexibly by 2040, is very helpful for integrating renewable energy generation – by shifting demand to 'high-renewable' periods, resulting in lower demand at times of low renewables output. This results in a slightly higher share of renewable electricity and slightly reduced power sector emissions. Still, most of the emission savings from transport electrification come from reduced transport fuel demand. Adding electric vehicles does increase the per-terawatt-hour system cost, but only by around 4% in 2040, and because we assume half of cars are charging non-flexibly, this results in 3% more fossil peakers being required for backup than in the NEO case.

Figure 1: The scenarios



Source: BloombergNEF

- **EV benefits to the power generation system are even greater if most charge flexibly.** When we model both a greater number of electric vehicles (consistent with a 2040 internal combustion engine, or ICE, phase-out) and assume that 80% are able to charge flexibly – a very strong assumption – then emissions decline even further as the power sector gets even cleaner, so carbon emissions are down 96% by 2040 after netting off transport fuel consumption. What is more, no additional fossil plants are required by 2040 compared to the NEO base case, despite the higher overall electricity demand.
- **More energy storage can accelerate the transition to a renewable power system.** Our NEO base case sees battery storage costs come down enough for a tipping point to be reached. This eventually makes the technology very prevalent in the U.K. and by 2040 it reaches a plateau where adding more batteries provides little added benefit to the system. By that point, batteries are already helping integrate a lot of renewable energy. However, the rate of battery deployment before 2040 – whether as a result of faster cost declines or of policy support and market opportunities – has a very large influence on the speed of the renewable energy transition in the U.K. The high-storage scenario finds that by 2030, lower storage costs reduce power sector emissions by 13% and fossil backup capacity by 12%.
- **Flexible demand has long-term benefits.** Shifting, and especially curtailing, demand is particularly good at reducing backup capacity requirements and the need for battery investment. We assume an increase that is weighted towards limited-frequency, short-duration dispatchable demand curtailment. By 2040, when fossil plants are only around for pure backup reasons and only generate when there are no other options, such limited-use dispatchable demand response is able to displace them. This allows the energy system to operate with 10% less fossil capacity, 42% less battery storage and 5% lower system costs by 2040 than in NEO. But such capacity is not able to benefit the system earlier in the forecast when fossil plants remain online for economic reasons, not just reliability requirements.
- **Interconnection with the Nordics could provide a formidable source of flexibility for decades.** Interconnectors, linked to flexible Nordic hydro resources, can help the U.K. system integrate large volumes of variable renewables by providing a market for, and storing, excess generation and filling gaps in output. They are also able to displace fossil fuel backup capacity by providing a reliable source of capacity during times of prolonged low wind and solar output. As a result, they reduce emissions by about 25% and fossil capacity by about 10% in both 2030 and 2040. Furthermore, as system needs evolve, the way interconnection is used – when, how long for, in which direction – adapts to suit system needs, with more low-cost power imports early in the forecast and more gap-filling and backup provision later.

The scenarios nominally explore technology outcomes, but they can also be seen through a policy lens: policymakers and regulators can help to bring them about by creating favourable market environments for flexibility sources. Favourable market conditions for flexibility might include:

- Introduction of dynamic power pricing (potentially mandatory) for energy customers – and for electric vehicle charging
- Establishment of frameworks for distribution network operators to share the value of flexibility
- Greater incentives or compensation for rapid-responding resources within capacity and ancillary markets
- Shortening of the trading and settlement interval in the wholesale power market

- Expansion of market access for energy storage and demand-side resources – including aggregated resources – and lower barriers for participation, across capacity, energy and balancing markets
- Equal treatment of interconnectors/overseas resources within these markets.

Table 1: Summary of scenario outcomes in 2030

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	32.8 GBPm/TWh	16.8 MtCO2	49%	74%	88%
Relative change vs NEO					
Low-flex	3%	9%	10%	-1%	-1%
High uptake of EVs	2%	-19%*	0%	1%	0%
High uptake of EVs and flexible charging	0%	-30%*	-7%	2%	1%
High uptake of storage	-2%	-13%	-12%	1%	1%
High uptake of flexible demand	1%	1%	1%	0%	0%
Interconnection to the Nordics	-2%	-25%	-11%	3%	3%

*Source: BloombergNEF. Note: Colour scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Table 2: Summary of scenario outcomes in 2040

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	39.8 GBPm/TWh	11.6 MtCO2	34%	80%	94%
Relative change vs NEO					
Low-flex	13%	36%	45%	-1%	-2%
High uptake of EVs	4%	-88%*	3%	1%	0%
High uptake of EVs and flexible charging	4%	-96%*	0%	1%	0%
High uptake of storage	0%	1%	-1%	0%	0%
High uptake of flexible demand	-5%	2%	-10%	0%	0%
Interconnection to the Nordics	-2%	-24%	-10%	2%	2%

*Source: BloombergNEF. Note: Colour scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Section 2. Introduction

The U.K. has made great strides in reducing carbon emissions from the power sector, with renewables achieving 29% penetration in 2017 – but much more still needs to be done to meet long-term climate goals.

Thanks to the rapidly falling costs of wind and solar energy, it is now possible to envision a future U.K. power system dominated by renewables. BloombergNEF's *New Energy Outlook* forecasts that a least-cost scenario would lead to 80% renewable energy in the power system by 2040, with most of the gains made before 2030.

Operating such a system will require significant new sources of flexibility. Last year, BNEF, Eaton and REA published *Beyond the Tipping Point: Flexibility Gaps in Future High-Renewable Energy Systems in the U.K., Germany and Nordics.* That report identified the following key issues:

- In 2030 and 2040, variable renewables meet more demand, more of the time – impacting other generators and creating opportunities for flexibility, including storage, flexible demand and interconnectors. In 2040, these resources contribute to more than 55% of hourly demand in the U.K. for over half of the year.
- With increasing frequency, there will be entire days and even weeks when total renewable energy supply exceeds demand, but also days, weeks and even months when the majority of demand must be met by other sources.
- System volatility increases markedly in the U.K. and Germany – by 2040, the highest U.K. hourly ramps are 21GW up and 25GW down, equivalent to around 20-25% of the U.K.'s entire generation fleet turning on or off in one hour. This creates a very challenging environment for 'baseload' technologies such as nuclear, coal and lignite and increases the need for flexible, fast-acting technologies.

Figure 2: Highest wind and solar output week in the U.K., 2040

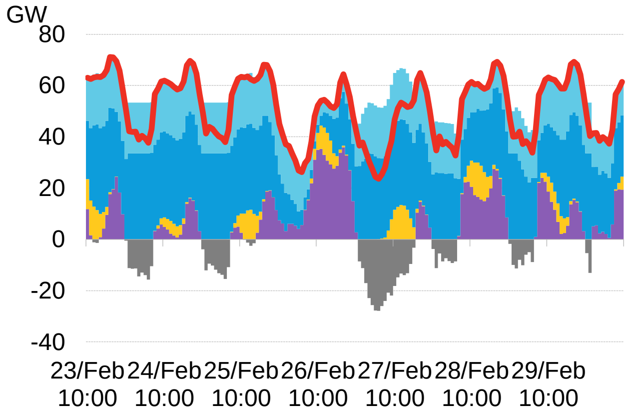
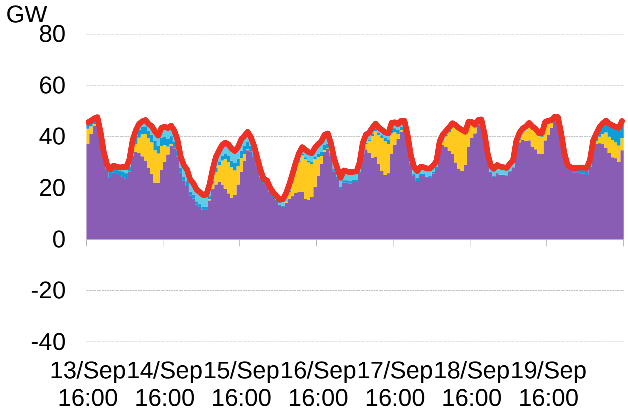


Figure 3: Lowest wind and solar output week in the U.K., 2040



Curtailment Offshore wind Onshore wind Solar Other generation Demand

Source: BloombergNEF, Beyond the Tipping Point, 2017

In short, that report gave a shape and size to the flexibility challenge facing the power sector as it decarbonises. Thanks to technology innovation in areas such as energy storage and demand response, there is a growing set of options available to address these challenges – but there is also a degree of uncertainty around costs and availability of these technologies, and their implications for the system.

This report, authored by BNEF in partnership with Statkraft and Eaton, explores the newer possibilities for solving the flexibility challenge: energy storage, demand response, flexible electric vehicle charging and interconnections to Nordic hydro.

In reality, all of these technologies (as well as traditional peaking plant) will play a role, so we have adopted a scenario-based approach to explore different assumptions about each technology, and how they might impact the overall trajectory of energy transition. Each of our scenarios solves the flexibility challenge, but in different ways. Some rely more on thermal plants, while others build more renewable energy or rely on the new technologies.

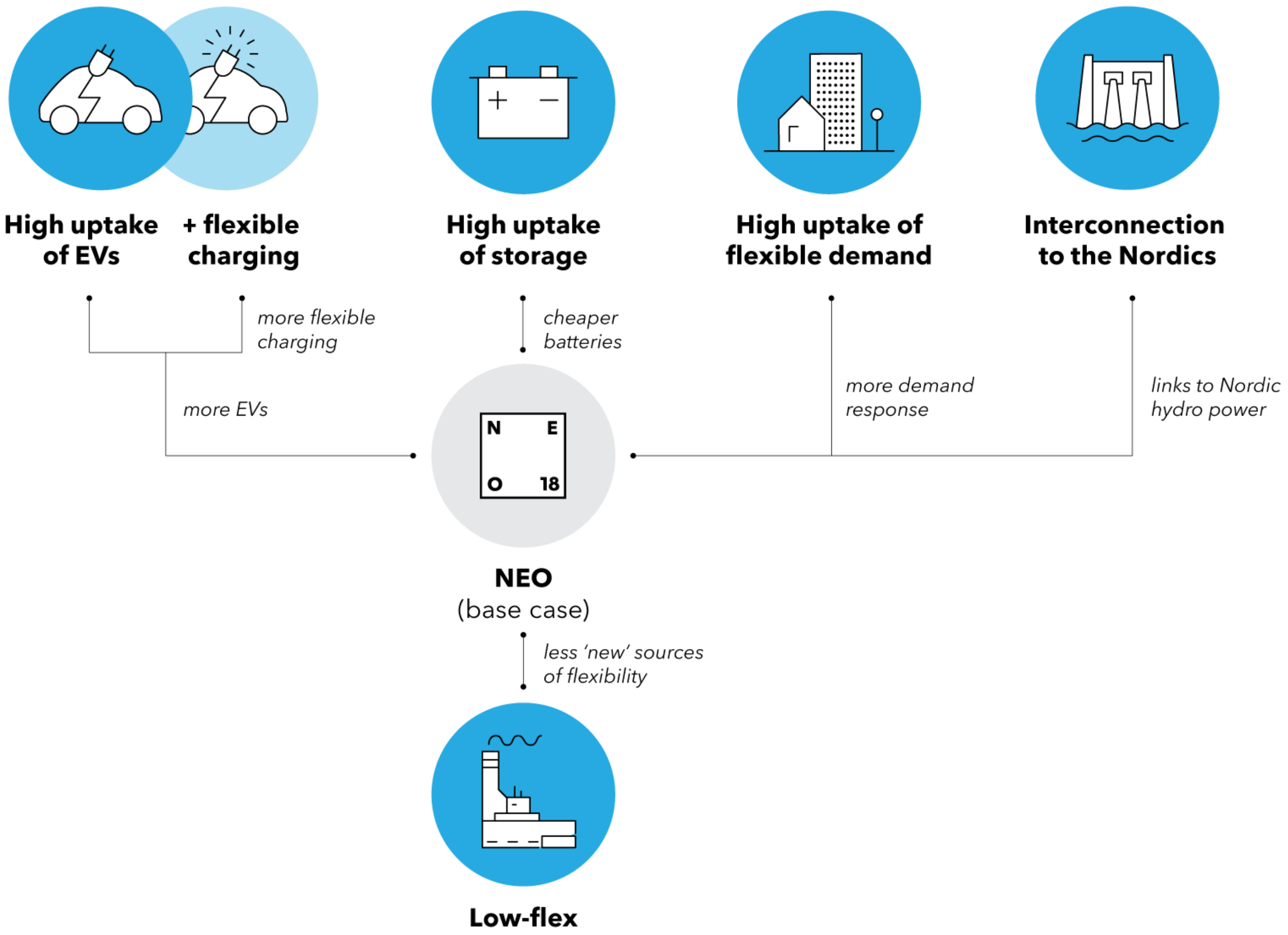
The modelling was undertaken using BNEF's proprietary New Energy Outlook modelling tools, meaning that every scenario is, in its own way, a least-cost optimal solution. What differs across scenarios is the underlying assumptions about what each technology can provide, and/or at what cost. In this way, we are able to explore alternative futures for the power system, depending on how each flexibility technology might develop in the coming years.

Of course, technology is not the only issue. Policy and regulatory approaches to enabling the addition of flexibility are critical, and the scenarios can also be seen in this light. Where demand response, storage, interconnectors and flexible EV charging are successful in our scenarios, it can be inferred that market designs had to be favourable to their introduction and adoption.

The scenarios in summary:

- **New Energy Outlook (NEO base case):** this scenario is the U.K. forecast from our 2018 *New Energy Outlook*, published earlier this year. The cost and availability assumptions on demand response, energy storage and electric vehicles are consistent with BNEF's house view (but interconnectors are not modelled). Demand response grows, battery storage becomes cheaper, and electric vehicle charging is partially flexible (ie, some of it can be moved to different hours to take advantage of cheap renewable power).
- **Low-flex:** this scenario looks at the consequences of a future with almost no new sources of flexibility. Here we assume that storage costs remain higher, demand inelastic and demand response unattractive. Electric vehicles are charged with no regard for grid conditions or power prices.
- **High uptake of electric vehicles:** this scenario is consistent with a ban on the sale of internal combustion vehicles by 2040. The result is an accelerated rate of adoption of electric vehicles, leading to higher power demand.
- **High uptake of electric vehicles and flexible charging:** considers the same uptake of electric vehicles as in the previous scenario, but with greater adoption of flexible charging.
- **High uptake of storage:** this scenario explores a future where battery costs fall faster than expected.
- **High uptake of flexible demand:** assumes a more widespread uptake of flexible demand as a result of successful market design and aligned incentives for demand shifting.
- **Interconnection to the Nordics:** analyses the benefits of interconnecting the British power market with Nord Pool, and in particular the hydro resources in Norway.

Figure 4: The scenarios



Source: BloombergNEF

All of the scenarios are variants of the NEO base case – in other words, the storage scenario *only* differs from the NEO base case in its assumptions about storage. The interconnector scenario *only* differs from the NEO case in that it includes interconnectors – and so on. So when comparing scenarios, it is best to compare each one to the NEO case.

The remainder of this report first explains the NEO base case, and then explains each of the other scenarios in turn, how they differ from NEO, and what implications to draw from them. Each scenario is evaluated in terms of emissions, cost and security of supply. We then end with a set of summary conclusions across all scenarios

Section 3. NEO (base case) scenario

Our base scenario is based on the U.K. forecast within BNEF's *New Energy Outlook 2018*. The *New Energy Outlook*, or NEO for short, is our annual long-term analysis of the future of energy.

3.1. A word on NEO

NEO forecasts the global electricity system with a focus on technologies that are driving change in markets and business models across the sector, including solar PV, onshore and offshore wind, and batteries. In addition, we put special focus on changing electricity demand, electric vehicles, air-conditioning, and the growing role of consumers.

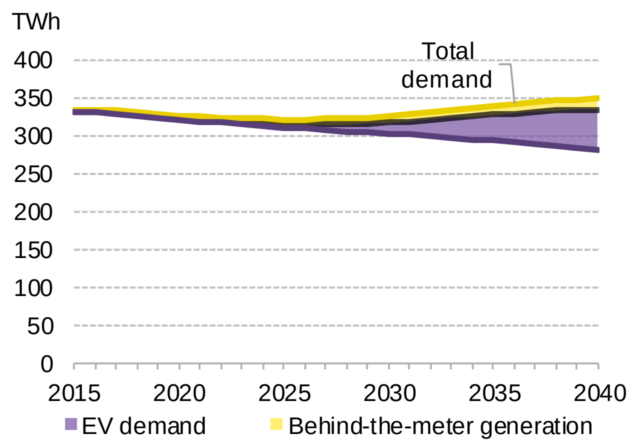
For the near term, we make market projections based on an assessment of policy drivers and on BloombergNEF's proprietary project database, which provides a detailed insight into planned new build, retrofits and retirements, by country and sector. For the medium to long term, our results emerge from a least-cost optimization exercise, driven by the cost of building different power generation technologies to meet projected peak and average demand, taking into account weather extremes, country by country.

3.2. U.K. forecast

Demand and distributed capacity

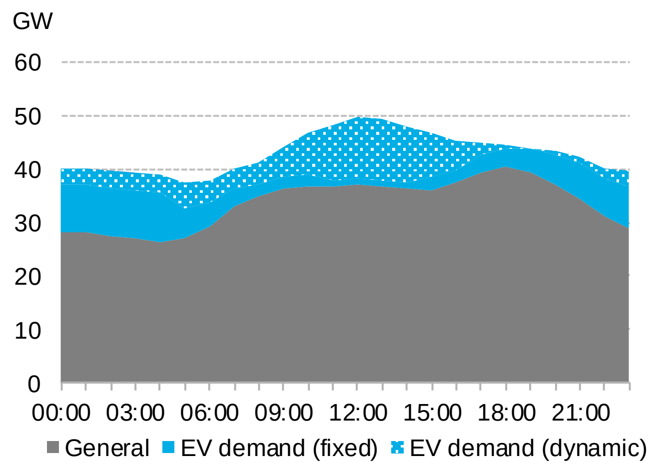
NEO assumes that U.K. demand grows 4% between 2017 and 2040, primarily on the back of electric vehicle (EV) demand growth, which rises to 22% of total electricity by 2040 (Figure 5). By 2035, we assume around half of the EVs on the road can charge whenever they are plugged in and can shift their load to hours of low power prices. As a result, the U.K.'s intraday demand profile (Figure 6) changes significantly, shifting to the middle of the day, when cheap solar is available. The U.K. adds 14GW of distributed capacity, made up of rooftop solar, behind-the-meter batteries, and demand response.

Figure 5: Electricity demand breakdown



Source: BloombergNEF

Figure 6: Daily hourly demand profile, 2040

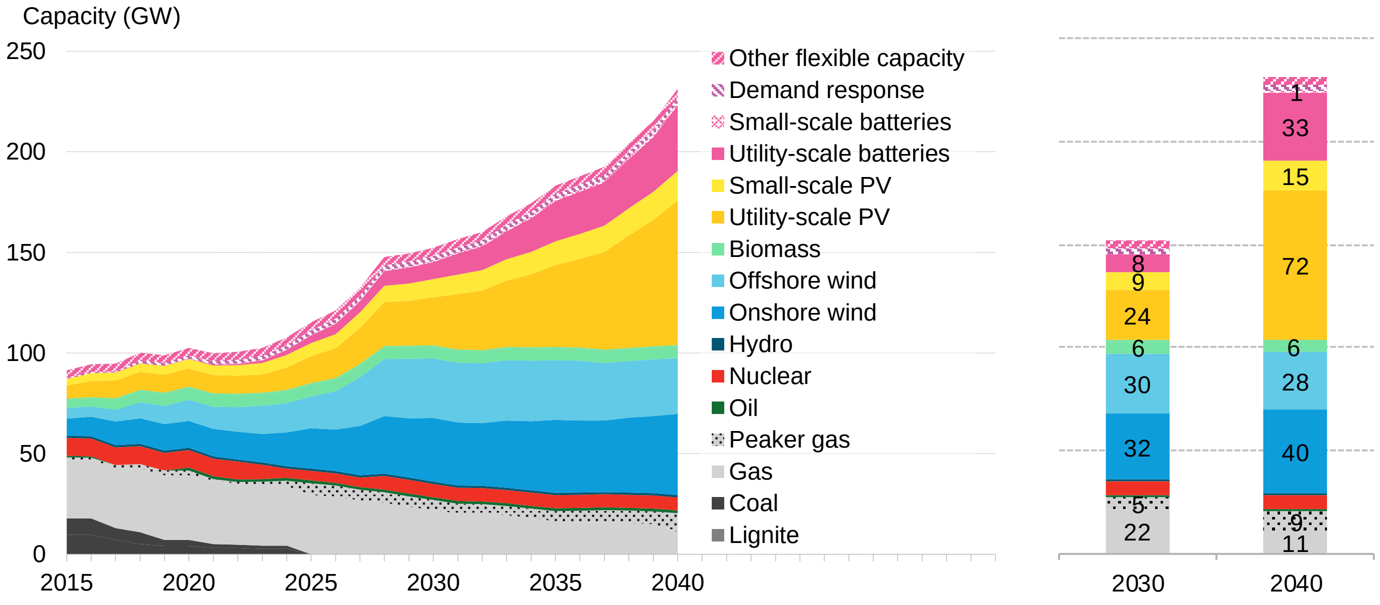


Source: BloombergNEF

Generation capacity and generation mix

The U.K.'s generating fleet more than doubles over 2017-40, to 231GW. The growth comes primarily from an increase in utility-scale PV capacity, which goes from 9GW in 2017 to 72GW, and wind, which nearly quadruples to 68GW over 2017-40. Most of the growth in wind capacity comes between 2025 and 2030, when it nearly doubles from 36GW to 61GW as subsidised offshore wind projects come online. Wind accounts for half of capacity added during this period. After 2030, utility-scale PV and batteries become cheap enough to push into the mix and together account for 70% of the 137GW added out to 2040.

Figure 7: Evolution of U.K. generation capacity in NEO



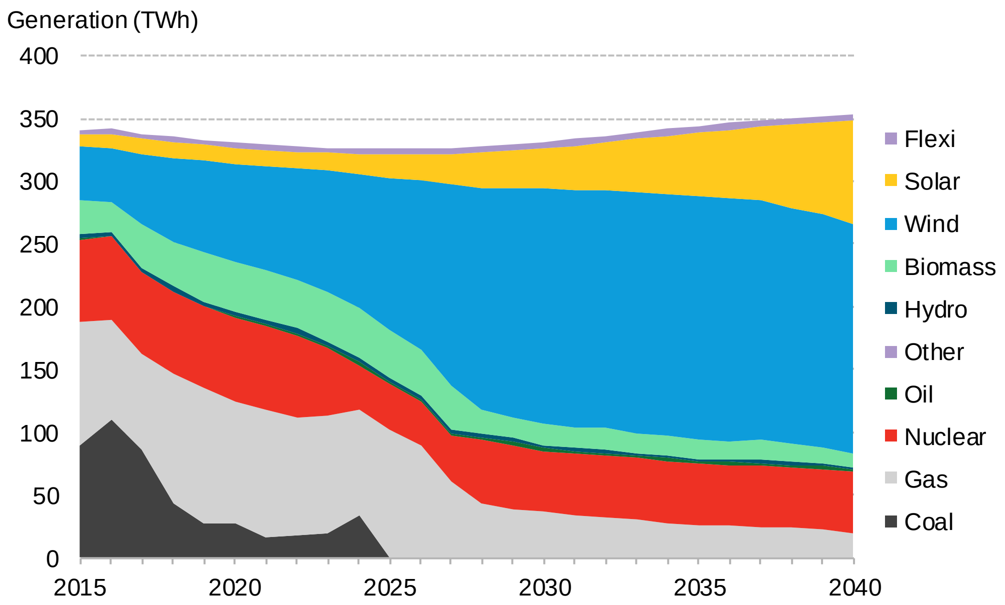
Source: BloombergNEF

The shift in the U.K.'s capacity mix is reflected in its generation. Wind and solar quickly increase their share, from 20% in 2017 to 67% in 2030 and 75% in 2040. PV generation grows tenfold over 2017-40, to 83TWh, meeting 24% of demand. From 2030 onwards renewable energy build-out slows, with wind reaching a saturation point where adding more capacity leads to more curtailment.

The U.K.'s capacity mix goes from being 47% fossil fuel and 32% wind and solar in 2017, to 75% wind and solar and 6% fossil fuel in 2040

Fossil fuel capacity in the U.K. halves over 2017-40, going from 44GW to 22GW, with coal eliminated by 2025. Conventional gas capacity shrinks 63% to 11GW, as close to 800MW retire per year. In its place, we see around 350MW of peaking gas per year, and by 2040 it has grown sevenfold to 9GW. As a result of these dynamics, the U.K.'s capacity mix goes from being 47% fossil fuel and 32% wind and solar in 2017, to 75% wind and solar and 6% fossil fuel in 2040.

Figure 8: Evolution of U.K. generation mix in NEO

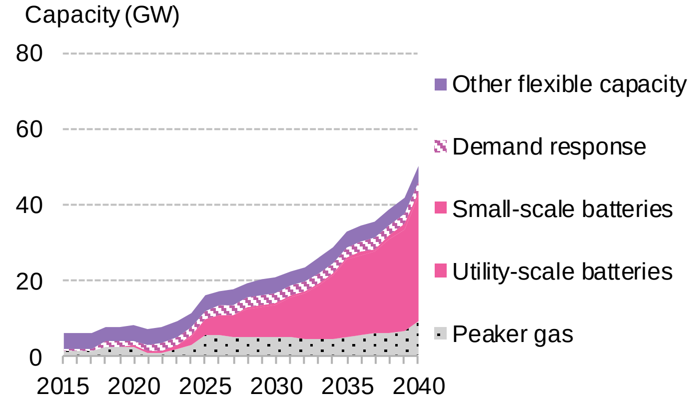


Source: BloombergNEF

Flexibility

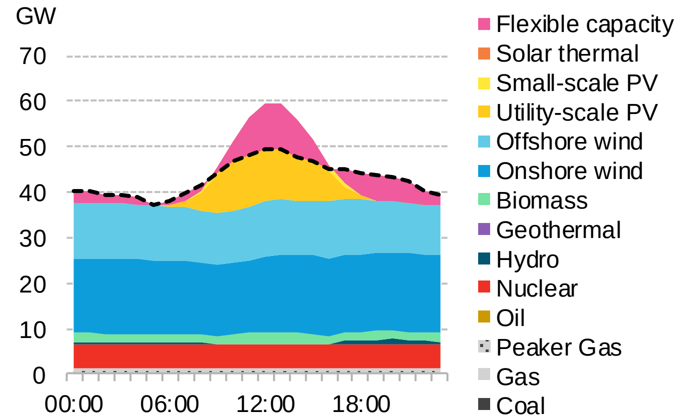
As its large round-the-clock coal and gas power plants come offline, the U.K. shifts to smaller, more nimble installations. By 2040, new flexible capacity accounts for over 50GW, or around 22% of the U.K. system (Figure 9). Batteries make up 68% and peaking gas a further 19%. Batteries help the U.K. absorb solar generation in the middle of the day, and redistribute it to the early morning and later afternoon hours (Figure 10). They also provide quick response to sudden changes in wind and solar output. Gas peakers, for their part, can shoulder the brunt of prolonged lulls in variable renewable output.

Figure 9: Cumulative new flexible capacity



Source: BloombergNEF. Note: Flexible EV demand not shown

Figure 10: Daily dispatch, 2040



Source: BloombergNEF

The combination of unattractive tariffs, and poor insolation, mean the U.K. shies away from consumer PV and batteries. By 2040, only 8% of capacity is behind the meter, significantly lower than the European average of 16%. Of the 19GW of distributed capacity in 2040, some 79% is small-scale PV, with the rest made up of batteries and demand response.

Figure 11 through Figure 13 show how flexible technologies contribute to meet demand and integrate renewables during weeks with different levels of renewable generation in 2040:

- During a 'low-renewable' output week (Figure 11), there are over four consecutive days when large gas generators are needed to meet demand. Batteries also charge and discharge on a daily basis, to shift renewable generation from high to low output hours. Peaking gas comes online during such low-renewable output hours to meet demand, and it even contributes to charge batteries when renewables and large gas cannot do it on their own. Charging batteries is critical, as meeting evening peaks relies on it.
- On a more typical week (Figure 12), we observe higher levels of wind and solar generation, which leaves little room for constant gas generation. CCGTs come on and off sporadically, while batteries are used at some point on a daily basis, charging during the day and discharging when the sun sets.
- In weeks where renewable output is at its highest (Figure 13), all demand is met without the need for fossil generation. Batteries play a minor but important role, to help meet demand during the few hours when there is not enough low-carbon generation, but they do little to reduce curtailment, since once charged there is no opportunity for them to discharge.

Figure 11: Week with low renewable output in 2040

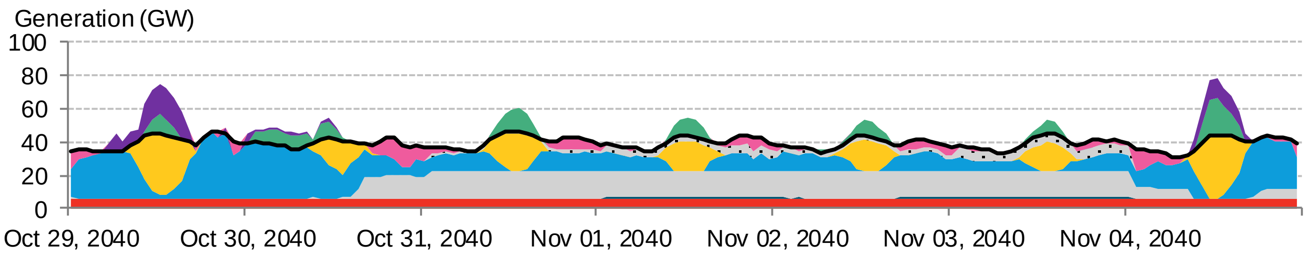


Figure 12: Week with median renewable output in 2040

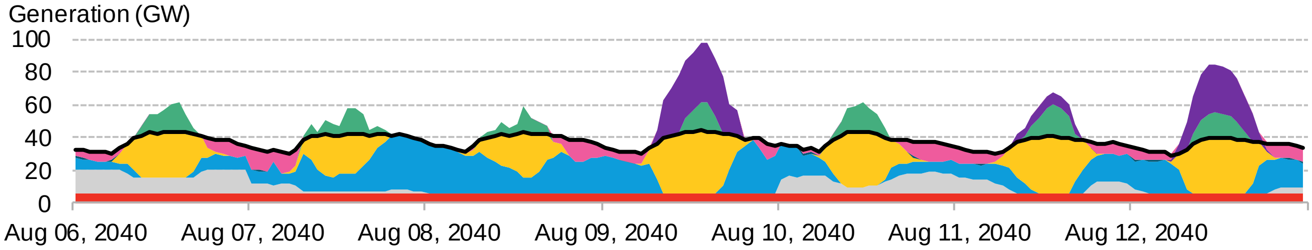
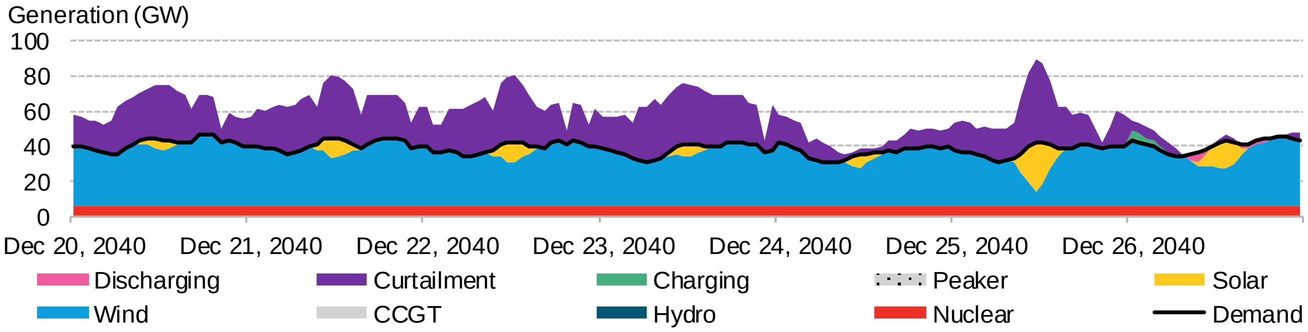


Figure 13: Week with high renewable output in 2040



Source: BloombergNEF

3.3. Implications

The U.K. already reduced its power sector emissions by 19% over 2014-17, as 8GW, or 38%, of the coal fleet retired. By 2023, we see the U.K. halving its remaining emissions, and by 2030, they are down 84% from current levels. This impressive fall to 17MtCO_2 per year in 2030 is primarily driven by the U.K. carbon price floor – a U.K. specific tax on CO_2 emissions – and by the mandated closure of all coal by 2025. After 2030, emissions decline more slowly, reaching 12MtCO_2 in 2040. This difficulty in cutting emissions beyond a certain point demonstrates the challenge in reaching fully decarbonised systems with just wind, solar and batteries.

With that said, flexible resources such as energy storage, demand response and flexible EV charging play a critical role in the NEO scenario. By 2040, there is a total of 34GW of battery storage, 2.7GW of demand response, and 27TWh of flexible EV demand that can be shifted to meet renewables production. The next section discusses the low-flex scenario, which highlights how different the outcomes would be if these sources of flexibility were unavailable.

The system that NEO forecasts to 2040 is based on a least-cost optimization. The model builds the cheapest system that can meet demand at all times, but it does not ensure that each individual asset makes a return on market revenues. As such, for the NEO outlook to materialise would require careful market design and the right market-based price signals. This would include frameworks for efficient investment in solar PV and both onshore and offshore wind, as well as market-based signals for energy storage and demand shifting.

Table 3: Key metrics for NEO scenario

Metric	units	2018	2030	2040
System cost	GBPm/TWh	38.8	32.8	39.8
Emissions	MtCO2	79	16.8	11.6
Fossil capacity as share of peak demand	%	78%	49%	34%
Renewable share of generation	%	37%	74%	80%

Source: BloombergNEF

3.4. Other scenarios

The next sections explore other scenarios for flexibility, and compare each of them to this NEO base case. It is worth keeping in mind when comparing scenarios that NEO represents a future in which there are significant flexible resources, in particular with a high volume of batteries and a large share of electric vehicles (50%) engaged in smart charging. This is why we present a low-flexibility scenario next for comparison, before showing the high-storage and other scenarios.

Section 4. Low-flex scenario: limited flexibility

In this scenario, we look at the consequences of a future with almost no new sources of flexibility, where storage costs remain higher, demand inelastic and demand response unattractive – either due to technical or regulatory reasons.

In recent years, variable renewables, namely wind and solar, have experienced cost reductions that have exceeded expectations. In this scenario, wind and solar continue to decline in cost as expected, but new barriers mean that demand response, flexible EV charging and energy storage are expensive or unavailable.

Like wind and solar, lithium-ion batteries have also experienced large cost reductions, but there is some uncertainty surrounding their future costs. If manufacturing does not scale up as quickly as expected, or if there are bottlenecks on critical materials such as lithium or cobalt, this could lead to higher battery pack prices than expected. Trade barriers, or an immature supply chain in Europe and the U.K., could also lead to higher costs.

This scenario is also intended to explore the effects of suboptimal policy and regulatory frameworks. Poor market design decisions that introduce misaligned incentives could slow or stop the adoption of storage, demand response and flexible EV charging. For example, dynamic pricing or aggregation can encourage residential and business customers to invest in demand-side flexibility, such as small-scale storage or dynamic EV charging. Without these incentives, the U.K. power system might not realise the potential of these technologies. Similarly, if power market, balancing mechanism and capacity market rules do not appropriately value new sources of flexibility, these technologies may not achieve scale.

EV charging patterns: what does bad look like?

Current EV charging is not very flexible: EVs charge mainly at home when owners return from work, and for the most part chargers do not respond to power price signals. As a consequence, EVs act as a fixed load that peaks around 6:00 or 7:00 PM – the same time when power demand is at its highest – increasing the stress on the system.

This can be avoided by distributing charging events throughout the day in response to price signals. However, to do so EVs need access to charging infrastructure for most of the day (not only in the evening). This implies additional investment in workplace and other destination chargers.

This scenario considers the impact on the system in a world where EV drivers are not able to access charging infrastructure outside their homes and thus charge mostly during the evenings, in an uncontrolled manner. What could make matters worse (which we do not explore here) is if rapid charging were to capture a large share of EV charging load. If left uncontrolled (and not supported by onsite storage, for example), this could lead to demand spikes that would drive up costs in the power system.

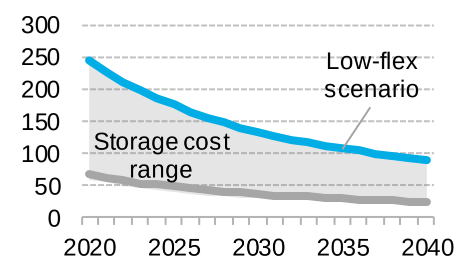
4.1. How this scenario differs from the NEO base case

Input assumptions

To model the low-flexibility scenario, we altered our input assumptions to make battery storage, demand response and EV charging less flexible, available or affordable:

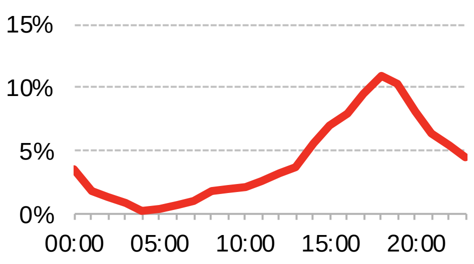
- For battery storage, we assumed a cost trajectory at the higher end of our range, giving a levelised cost of finance (LCOF)[1] about four times more expensive than the costs used in NEO (Figure 14). It is worth mentioning, however, that NEO is quite aggressive in terms of battery storage and assumes costs on the lower end of our cost range.
- We assume that there is no flexible charging for electric vehicles. Instead, they follow a fixed charging pattern that peaks during the evenings – specifically between 6:00 and 7:00 PM based on existing charging data (Figure 15). The vast majority – about 80% – of the fleet charges at home, while the remaining vehicles utilise some sort of public charging infrastructure. This assumption contrasts with our NEO scenario, which assumes 50% of the fleet charges flexibly by the early 2030s.

Figure 14: Storage levelised cost of finance



Source: BloombergNEF

Figure 15: EV charging profile



Source: BloombergNEF

In addition to the battery storage costs and EV charging parameters, we assume that demand response remains at existing levels and does not play a significant role in this scenario.

Together, these assumptions are intended to reflect a future where new flexibility technologies are rendered unattractive, either due to technological reasons or due to sub-optimal power market design and regulatory approaches.

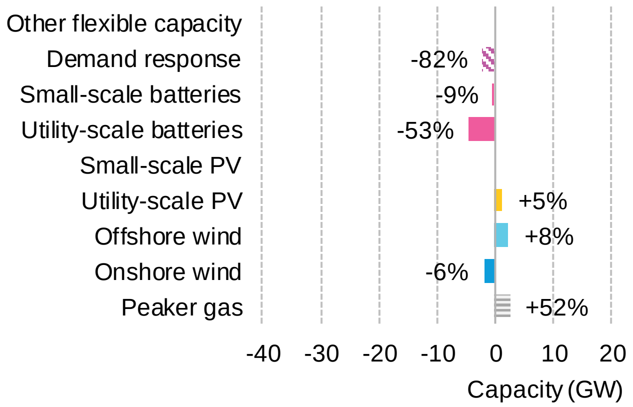
Outcomes

In a future where new flexibility technologies do not fulfil their potential, the U.K.'s power system looks markedly different. The limited contribution of new sources of flexibility (batteries and demand response) means the system instead relies heavily on conventional, fossil-based ones – ie, peaking gas. By 2030, the system in this scenario requires about 2.6GW (52%) more peaker gas capacity than the NEO base case, but builds 53% (4.5GW) less storage (Figure 16). By 2040, the system needs twice as much peaker gas capacity than the NEO base case, to make up for the lack of battery storage capacity, which is reduced by 85% (27.7GW) (Figure 17).

The lack of battery storage and demand response means that the most economical option is to build some 10GW of additional renewables capacity to meet demand during certain hours, even if this means curtailing renewable generation more frequently at other times.

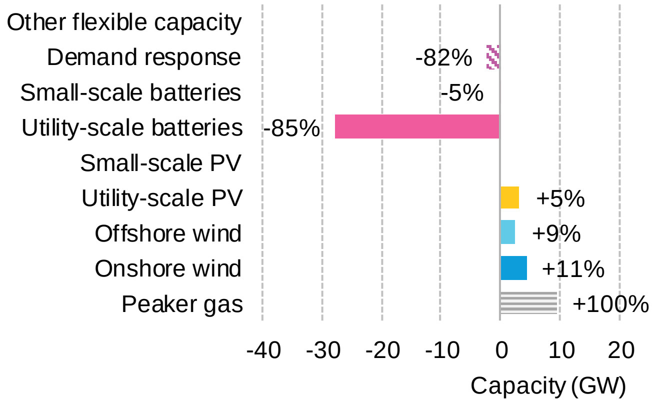
[1] The levelised cost of finance is the long-term off-take price on a MWh-basis needed for a project to pay back its capital costs and hit the equity requirements of investors; it excludes variable costs such as fuel, carbon or charging costs in the case of batteries.

Figure 16: 2030 generation capacity change for low-flex scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 17: 2040 generation capacity change for low-flex scenario, versus NEO base case



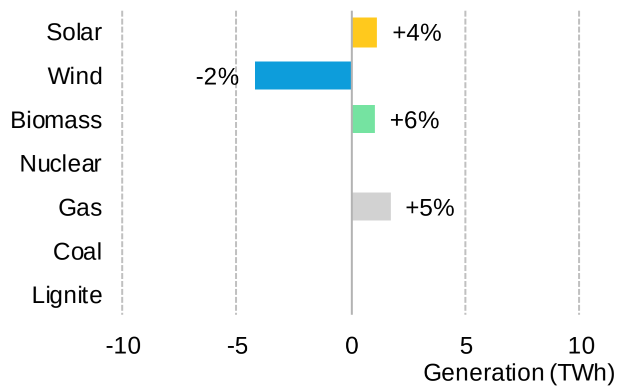
Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

The lack of new sources of flexibility also impacts the generation mix. Gas and biomass generation are both substantially higher, as these are the main sources of flexibility in the near-absence of batteries and demand response. In 2040, gas generation grows by almost a third compared to the base case, and biomass by nearly a fifth.

On the other hand, wind power's contribution to the power mix is lowered, as the lack of flexibility leads to higher curtailment. This is despite the presence of *more* wind generation capacity in the stack in 2040 – illustrating how important flexibility is to integrating renewables.

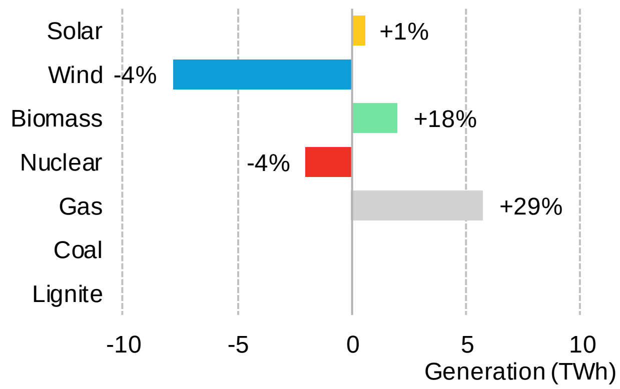
Strikingly, nuclear also contributes less in 2040, in a low-flexibility scenario. Nuclear's lack of flexibility means that it continues generating even at times when there is high renewable output and low demand. It therefore experiences greater curtailment. This illustrates the importance of flexibility in supporting nuclear, as well as renewables.

Figure 18: 2030 power generation change for low-flex scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 19: 2040 power generation change for low-flex scenario, versus NEO base case



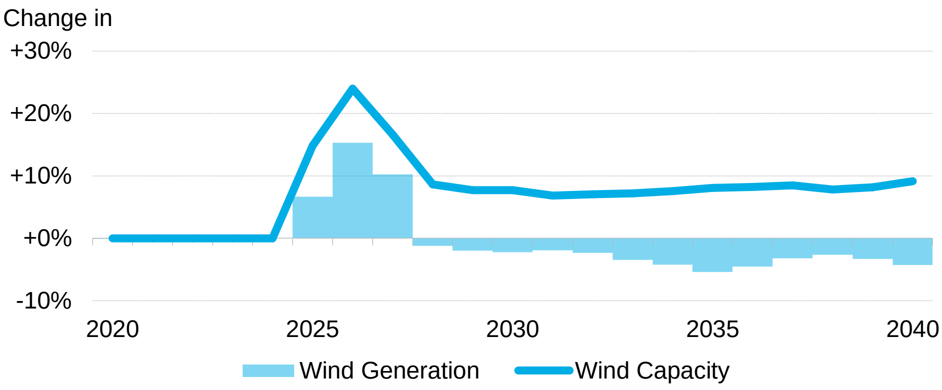
Source: BloombergNEF. Note: generation figures do not include curtailment

4.2. Implications, benefits and drawbacks of this scenario

In all of our scenarios, the system has enough flexibility to maintain reliable operation – and this one is no different. However, without new sources of flexibility, this is achieved primarily by relying on conventional flexible generators, such as peaker gas capacity, complementing a high penetration of renewable generation. This comes at a significant cost, as it substantially over-sizes renewables and additional investment is needed to build extra peaking capacity. In 2030, the low-flex system is 3% more expensive than the NEO base case, and by 2040, the difference in system costs is 14% (Table 4).

Inflexible assets, such as renewables and nuclear, are underutilised as a result, and there is much more curtailment. Importantly, however, a lack of new flexibility does not halt the transition to a renewables-led system, as renewables are still cheap to build (even if they go underutilised). Even in a world where DR, storage and flexible EV charging fall short of their potential, renewables still achieve almost 80% penetration by 2040 (Table 4).

Figure 20: Growth in wind capacity vs generation



Source: BloombergNEF

Figure 20 illustrates how wind additions are changed in this scenario. Additional wind capacity is required from 2024 onwards, but by the 2030s, actual wind production is lower than the NEO base case, due to curtailment.

Table 4: Key metrics for low-flex scenario

Metric	Units	2030	2030	2040	2040
		Value	∆ vs NEO	Value	∆ vs NEO
System cost	GBPm/TWh	33.9	+3%	45.2	+13%
Emissions	MtCO2	18.4	+9%	15.8	+36%
Fossil capacity as share of peak demand	%	54%	+10%	50%	+45%
Renewable share of generation	%	73%	-0.7%	79%	-1.2%

Source: BloombergNEF

U.K. carbon emissions are higher in this scenario. The reduction of battery storage and demand response results in a significant increase in emissions of 9% in 2030 and 36% in 2040, compared with NEO. While the penetration of renewable generation is not significantly affected, dropping by roughly 1 percent in 2040, it is clear that relying more heavily on gas for flexibility will lead to a higher trajectory for carbon emissions. Without low-carbon flexibility sources, it will prove very difficult to achieve deep decarbonisation of the U.K. power system.

Section 5. Scenario: high uptake of electric vehicles

In an effort to combat air pollution and climate change, various countries around the world are supporting the uptake of electric vehicles, with some going as far as announcing bans on the sale of new vehicles powered by internal combustion engines.

The U.K. government has announced its intention of ending the sales of conventional vehicles by 2040. This scenario looks at what this might mean for the power system. To do this, we use an accelerated rate of adoption of EVs that sees petrol and diesel-fuelled vehicles go from making up 78% of the fleet in 2030 to just 17% by 2040 (Figure 21), consistent with the termination of conventional vehicle sales by 2040.

Managing local grid constraints

Growing penetration of electric vehicles has the potential to cause problems for the physical network. Distribution system operators, already having to adapt to distributed generation, will have to manage higher peak load on increasingly constrained lines – this is especially true of EVs using fast chargers.

Solving this issue will be paramount to the widespread adoption of EVs. There are various solutions, ranging from the deployment of additional network capacity to making more efficient use of existing infrastructure – for example, via the deployment of demand response, smart charging and active network management.

Although there are various issues around it, bi-directional vehicle charging, also known as vehicle-to-grid (V2G), has the potential to provide the electricity system with a wide range of load shifting and balancing services.[2]

5.1. How this scenario differs from the NEO base case

Input assumptions

Using the same tools and methodology as in our Electric Vehicle Outlook,[3] we modelled the impact a ban on sales of new internal combustion engine (ICE) vehicles from 2040 would have on the makeup of the U.K. fleet (Figure 21). This allowed us to estimate the additional electricity demand needed to power the increase in electric vehicles (Figure 22).

We assume the same proportion of flexible charging for electric vehicles as in NEO. That is, at the start of our modelling timeframe, vehicles charge following a fixed pattern that favours charging overnight, while vehicles are parked at home (Figure 23). As the years go by, we assume time-of-use pricing is implemented and vehicles increasingly charge flexibly, responding to conditions in the system. Between 2025 and 2035, we assume that flexible charging grows to account for about half of the EV fleet (Figure 24).

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[2] Bloomberg subscribers can read more in our *Vehicle-to-Grid: the Slow Roll from Demonstration to Commercial Projects* (web | terminal).

[3] Bloomberg subscribers can read more in our Electric Vehicle Outlook (web | terminal).

Figure 21: Vehicle fleet

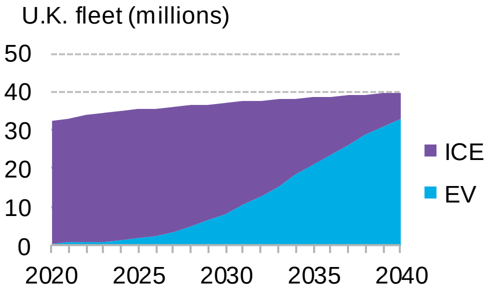


Figure 22: EV demand

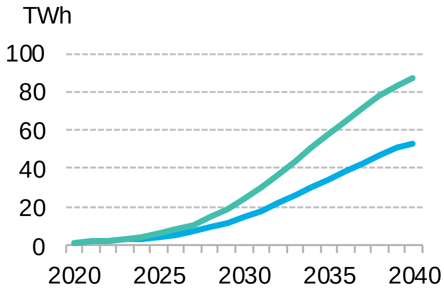


Figure 23: Fixed charging pattern

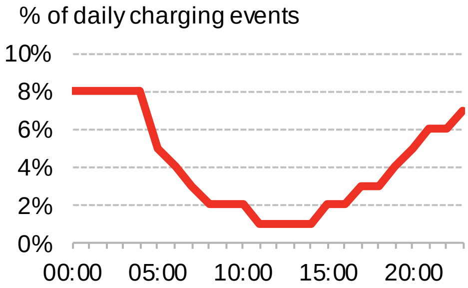
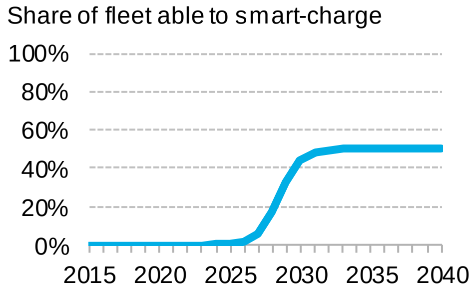


Figure 24: Penetration of flexible charging



Source: BloombergNEF

Outcomes

More generation capacity is needed to meet the additional demand from electric vehicles. To do this, the system chooses a varied mix of technologies that include wind and solar as well as gas peakers and utility-scale battery storage. By 2030, these additions add up to about 5.5GW of extra capacity – an increase of 4% over the NEO base scenario (Figure 25). By 2040, additional demand is significantly higher, and consequently the system adds around 15.6GW of capacity, or 7% more than in the NEO scenario (Figure 26).

Figure 25: 2030 generation capacity change for high EV uptake scenario, versus NEO base case

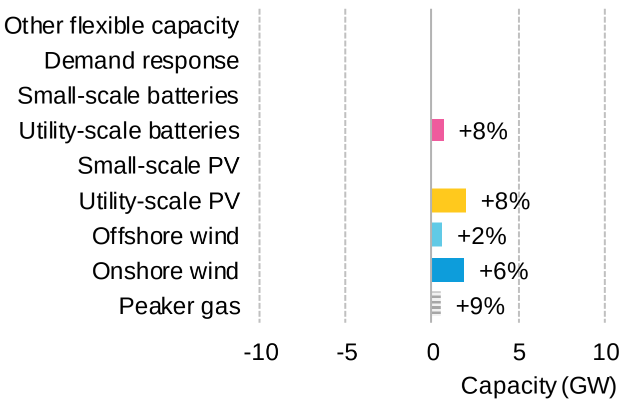
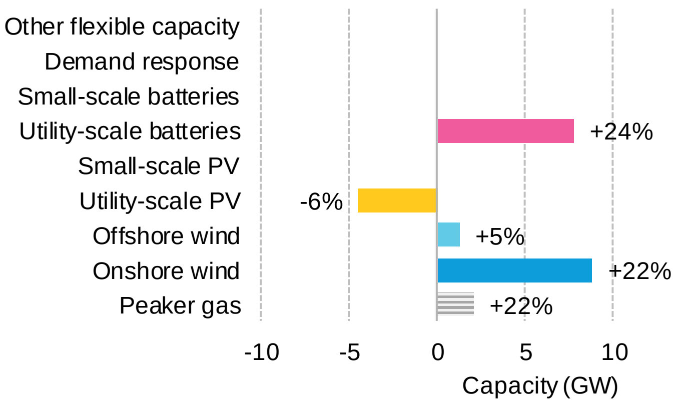


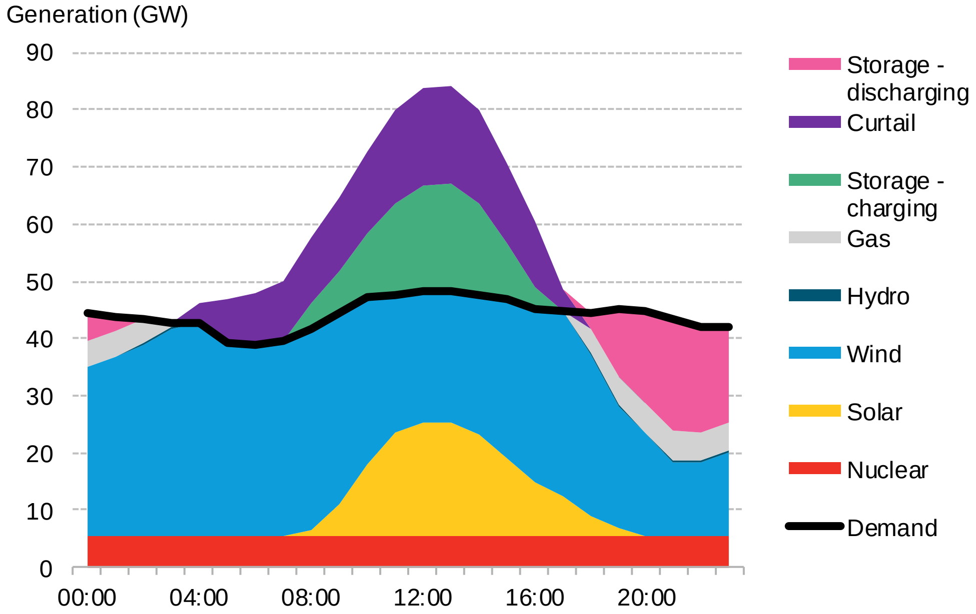
Figure 26: 2040 generation capacity change for high EV uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

A key difference in 2040 (Figure 26), when the EV fleet is reaching sizeable proportions, is that since most of the fixed EV charging happens overnight, solar can contribute little to meet charging demand – so the system builds less solar, and much more wind. Flexibility is provided by additional batteries that shift excess wind and solar generation to meet the evening peak, but also via gas peakers that step in during low renewable generation periods (Figure 27).

Figure 27: Hourly generation during a typical autumn day in 2040 for the high EV uptake scenario

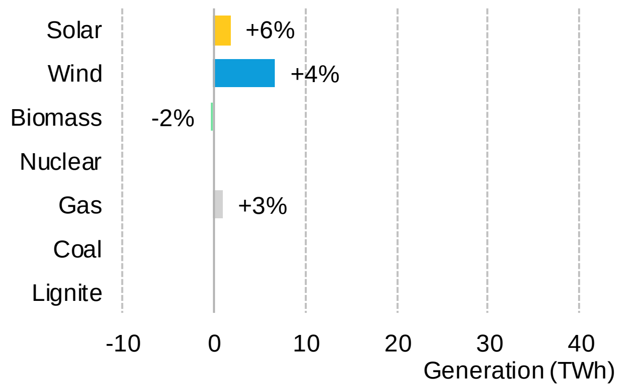


Source: BloombergNEF

The additional EV load raises power demand but also helps to flatten the daily load profile, which impacts the generation mix.

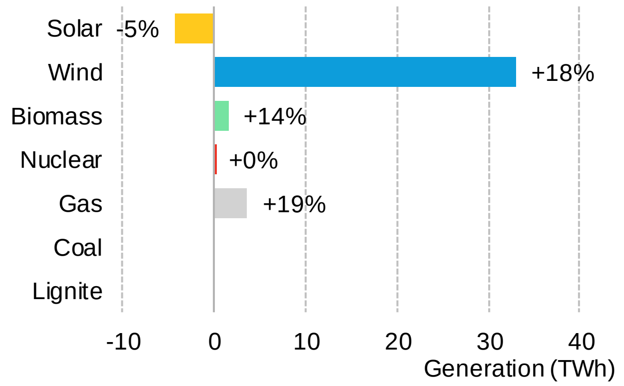
Wind and gas generation increase both in 2030 (Figure 28) and 2040 (Figure 29). Biomass and solar generation move in opposite directions, with solar generating less than NEO in 2040 and biomass generating more. Since wind generation occurs throughout the day and night, it is better suited to meet the base level of inflexible EV charging demand. Gas generation increases roughly in proportion to the additional demand, leaving gas' share of generation roughly at the same level as in NEO.

Figure 28: 2030 power generation change for high EV uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 29: 2040 power generation change for high EV uptake scenario, versus NEO base case

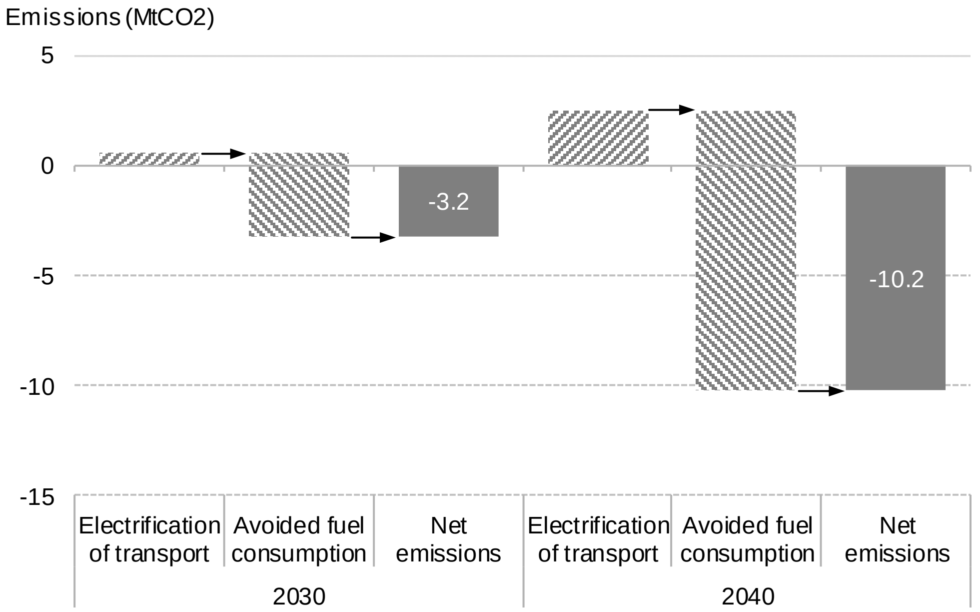


Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

5.2. Implications, benefits and drawbacks of this scenario

EVs are the clearest pathway to decarbonizing road transport, with avoided tailpipe emissions more than compensating for relatively small additional power sector emissions. Our analysis shows that the higher EV penetration resulting from a ban on ICE sales in 2040 produces a net reduction in emissions of 3.2 MtCO2 in 2030 and 10.2 MtCO2 in 2040 (Figure 30).

Figure 30: Net emissions after considering avoided fuel consumption, relative to NEO



Source: BloombergNEF

On top of the emissions reduction, the metrics for this scenario show how increasing the amount of electric vehicles has a minimal (slightly positive) effect on the penetration of renewables in the generation mix. Equally, although the power system becomes more expensive in absolute terms due to the extra capacity needed to meet more EV demand, it has a very small impact on per-MWh power system costs,[4] which increase by just 2% in 2030, and by 4% in 2040 (Table 5: Key metrics for the high uptake of EVs scenario).

In other words, phasing out the sales of ICE vehicles in favour of EVs could be done without 'breaking' the power system. Table 5 summarises the key metrics for the scenario and compares them to the NEO base case scenario.

Table 5: Key metrics for the high uptake of EVs scenario

Metric	Units	2030	2030	2040	2040
		Value	∆ vs NEO	Value	∆ vs NEO
System cost	GBPm/TWh	33.4	+2%	41.3	+4%
Emissions	MtCO2	13.6	-19%	1.4	-88%
Fossil capacity as share of peak demand	%	49%	-0%	35%	+3%
Renewable share of generation	%	74%	+0.5%	81%	+0.9%

Source: BloombergNEF

Discussion on emissions and oil displacement

To estimate net emissions, we calculate the impact of passenger EVs on oil consumption. In our ICE ban scenarios, we estimate that EVs displace 453 thousand barrels per day (kb/d) of fuel in 2030 and 233 kb/d by 2040 in the U.K.

Fuel displacement from EV sales is estimated using the following assumptions[5]:

- Each new EV displaces the sale of a new internal combustion engine (ICE) vehicle of equivalent type – small, medium, large or sports utility.
- The resulting level of fuel demand displaced by each EV is a function of the average fuel economy (measured in miles per gallon, or MPG) and utilization (measured in annual miles travelled) of the displaced ICE. Average vehicle utilization in Europe is around 8,000 miles per year, lower than for the U.S. and China.
- We break down fuel displacement across gasoline and diesel by taking into account the split of gasoline versus diesel ICE sales for each vehicle type in each region.
- We assume that a battery electric vehicle (BEV) displaces 80% of the average miles travelled per vehicle in each region. For plug-in hybrid vehicles (PHEVs), we do not discount vehicle utilization, but assume that a PHEV consumes 50% of the fuel of an equivalent ICE.

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[4] This estimate does not consider additional infrastructure costs nor cost savings from avoided fuel consumption.

[5] Bloomberg subscribers can read more on how we estimate oil displacement in *How Much Oil Are Electric Vehicles Displacing?* (web | terminal)

Section 6. Scenario: high uptake of electric vehicles and flexible charging

In an effort to combat air pollution and climate change, countries around the world are incentivizing the uptake of electric vehicles, with some going as far as setting dates from which sales of new internal combustion engine vehicles will be banned. The degree to which the charging of these electric vehicles is flexible to market conditions significantly alters the impact they have on the power system.

In this scenario, we consider the same high uptake of electric vehicles as in the previous scenario (ie, an ICE ban by 2040), but with much greater adoption of flexible charging.

How high levels of smart charging might be achieved

This scenario considers the implications of most cars (essentially four out of five) being able to charge at any point in time. There are two ways in which such a high share of flexible load could be achieved, both of which require major investments and behavioural change, and rest on some major assumptions:

- **Ubiquitous smart charging points:** for up to 80% of EVs to be able to charge at any point in time essentially means that they have to be connected to a charge point whenever they are stationary. That means charge points at work, at home, in cities, at restaurants, at shopping malls, at sports centres, at schools, by the lake, by the beach, etc. It also requires drivers to be comfortable with an algorithm controlling and optimizing the car's charging in response to power market conditions. The latter requires strong financial incentives and policy measures.
- **Many more batteries at charge points:** it is possible to have the same flexible load outcome by having more batteries at charge points. This means using stationary batteries to charge vehicle batteries, whether at home, at public slow charge points or at fast charge points. This disconnects the process of charging from the process of optimizing when to draw power from the grid. This is one example of how batteries could be plentiful for uses other than those analysed in the high battery uptake scenario outlined here.

In both cases, the local network challenges could be substantial. This is especially the case on sunny, wind-still days, when most EVs are charging simultaneously to capture the abundant cheap solar power, overloading local networks. Managing this, alongside the optimization to benefit from cheap energy, will require the kinds of measures outlined in the box at the start of Section 5.

6.1. How this scenario differs from the NEO base case

Input assumptions

This scenario assumes the same uptake of electric vehicles (and its associated increase in electricity demand) as the previous scenario. The key difference is that the share of EVs charging flexibly grows to 80% in the early 2030s, as opposed to the 50% share achieved in the previous scenario and NEO (Figure 34).

Figure 31: Vehicle fleet

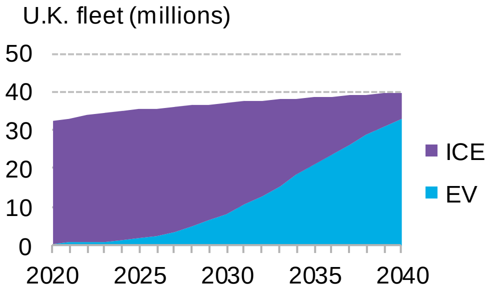


Figure 32: EV demand

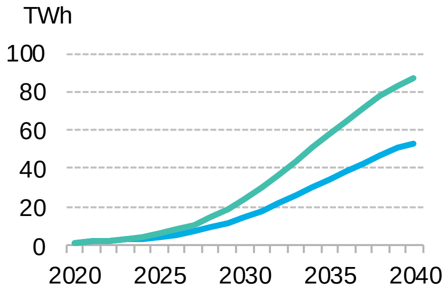


Figure 33: Fixed charging pattern

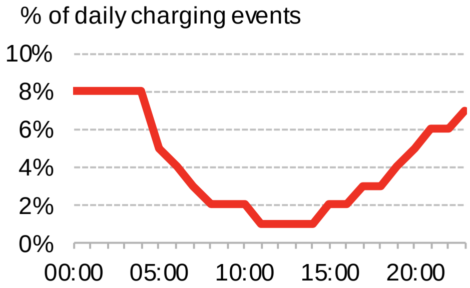
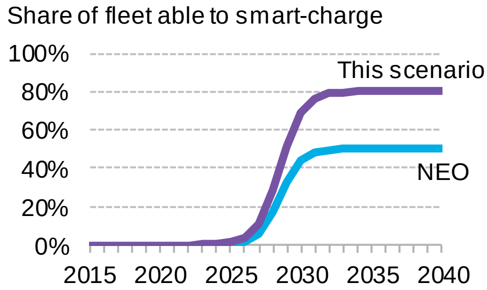


Figure 34: Penetration of flexible charging



Source: BloombergNEF

Outcomes

Although most of the inputs are similar to the previous scenario, the ability to charge flexibly has a strong influence on the energy system. For starters, charging flexibly is equivalent to load shifting, which reduces the need for system flexibility. Consequently, in 2030, the need for peaking gas capacity is reduced by 41% relative to NEO, and 46% relative to the previous (high-EV) scenario. We also see more wind capacity and twice as much solar as in the previous scenario. Highly flexible EV charging is effectively supporting renewable energy (Figure 35).

By 2040, we see more peaking gas capacity than in NEO, as there is now a noticeable increase in power demand. However, this 21% gain in gas is still less than the capacity needed in the previous scenario, when EV charging is less flexible. The biggest difference in 2040 is the nearly 9.4GW of solar capacity addition, which contrasts with the reduction of 4.4GW in the previous scenario (Figure 36).

In spite of the demand-side flexibility provided by EV charging, the system adds 9.6GW of batteries, which are still needed to shift around excess wind and solar during periods of high output when flexible EV demand is not enough.

Figure 35: 2030 generation capacity change for high flexible EV uptake scenario, versus NEO base case

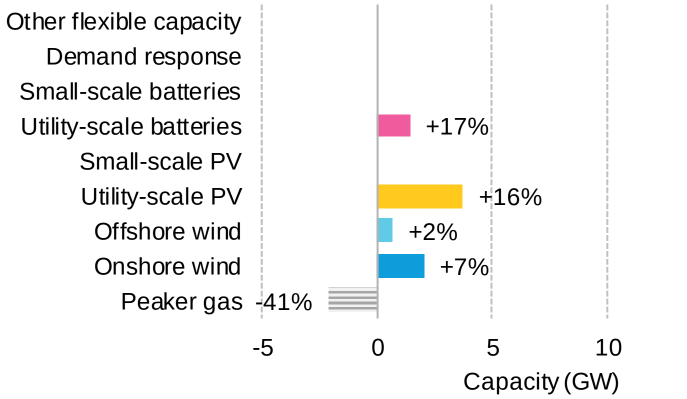
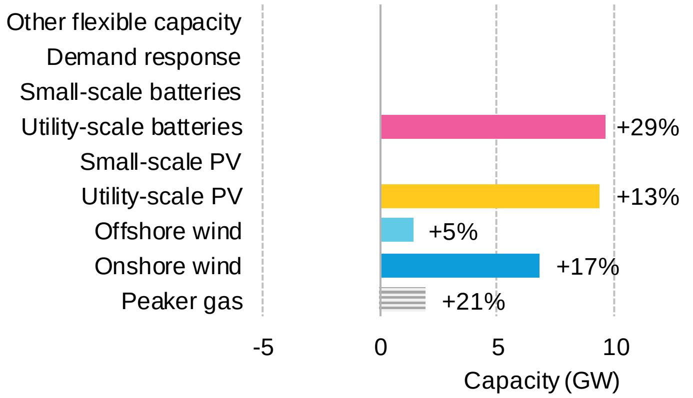


Figure 36: 2040 generation capacity change for high flexible EV uptake scenario, versus NEO base case

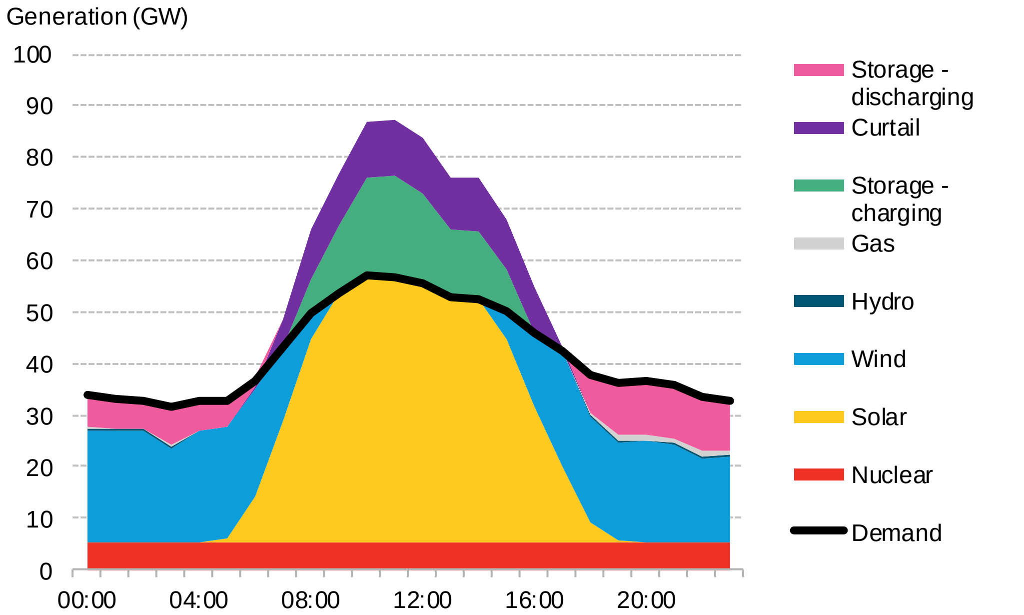


Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Flexible charging has a strong impact on hourly load profiles, concentrating demand during periods of abundant generation. This tends to favour solar over wind in this scenario. For example, Figure 37 shows a typical day in the third quarter of 2040, where the clustering of demand during the middle of a sunny day is clearly visible. During the night, demand falls and batteries shift excess mid-day generation to fill the gap, requiring very little fossil generation.

Note that even with batteries and flexible demand there is some curtailed energy. This reflects a new economic reality: due to the low costs of solar capacity, it will be more economical to waste solar generation on some days than to rely on other more flexible sources of generation.

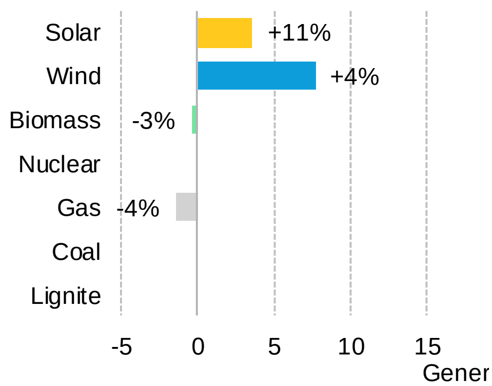
Figure 37: Hourly generation during a typical autumn day in 2040 for the high flexible EV uptake scenario



Source: BloombergNEF

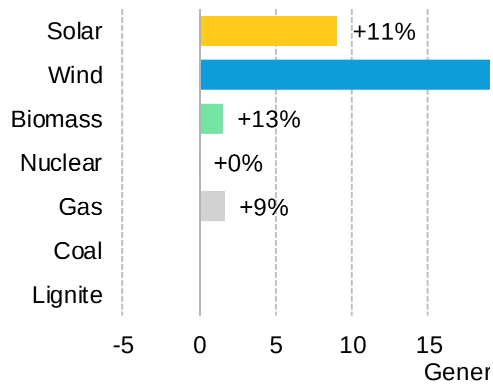
In terms of generation, we see that the additional charging flexibility helps to integrate variable renewables and reduce the need for gas generation. This is most obvious in 2030, when gas generation is lower than in NEO (Figure 38); in 2040, although there is more gas generation than in NEO, this is considerably less than in the previous scenario (9% more versus 19% more). Since EVs have led to higher power demand, this actually represents a reduction in the share of gas generation per MWh even when compared to NEO. In other words, the system is burning less fossil fuel for each unit of energy, while at the same time supplying more electricity overall.

Figure 38: 2030 power generation change for high flexible EV uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 39: 2040 power generation change for high flexible EV uptake scenario, versus NEO base case

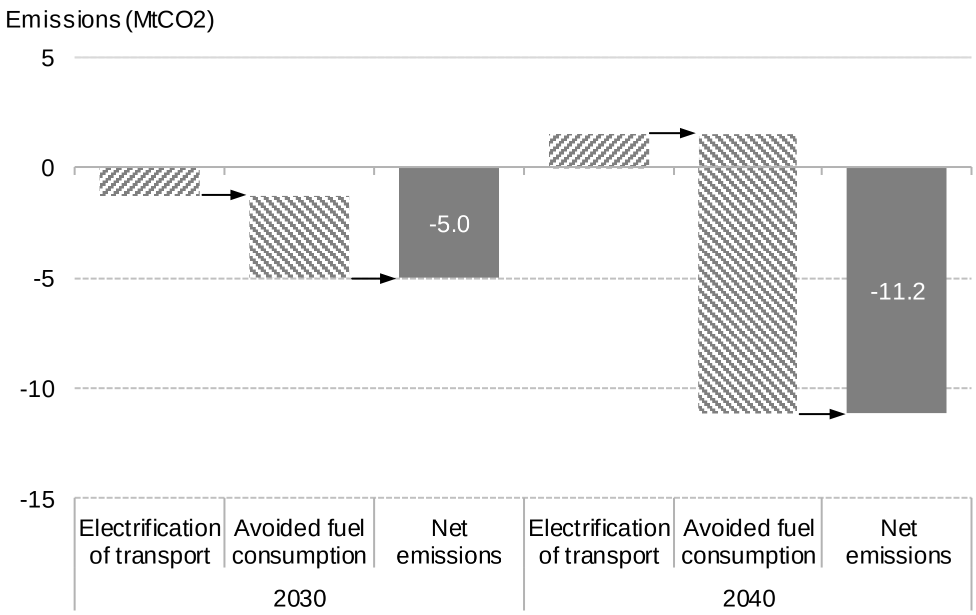


Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

6.2. Implications, benefits and drawbacks of this scenario

EVs are the clearest path to decarbonise road transport and flexible EVs even more so, reducing overall emissions by 2030 even before considering avoided fuel consumption. This is a striking finding: that a faster transition to EVs in the U.K., if accompanied by flexible charging, could actually help to reduce the absolute level of emissions in the power sector in 2030 – even before considering emission reductions from avoided fuel consumption –, by making possible greater penetration of renewable energy. In the longer term, there are some additional power sector emissions but these are far outweighed by reductions in tailpipe emissions.

Figure 40: Net emissions after considering avoided fuel consumption, relative to NEO



Source: BloombergNEF

By comparing these results with those in the previous scenario, we can conclude that, in 2040, flexible charging alone results in about one MtCO2 of emission reductions. In summary, the system becomes cleaner the more flexibly EVs charge, without incurring serious additional power generation system costs (Table 6).

However, this imposes costs and challenges at other levels, such as behavioural change and digital infrastructure to enable flexible charging, or charging infrastructure and network costs to cope with high coincident grid load whenever renewable supply is abundant. Table 6 summarises the key metrics for the scenario and compares them to the NEO base-case scenario.

Table 6: Key metrics for the high uptake of flexible EVs scenario

Metric	Units	2030	2030	2040	2040
		Value	Δ vs NEO	Value	Δ vs NEO
System cost	GBPm/TWh	32.7	-0%	41.3	+4%
Emissions	MtCO2	11.8	-30%	0.5	-96%
Fossil capacity as share of peak demand	%	46%	-7%	34%	-0%
Renewable share of generation	%	75%	+1.5%	81%	+1.5%

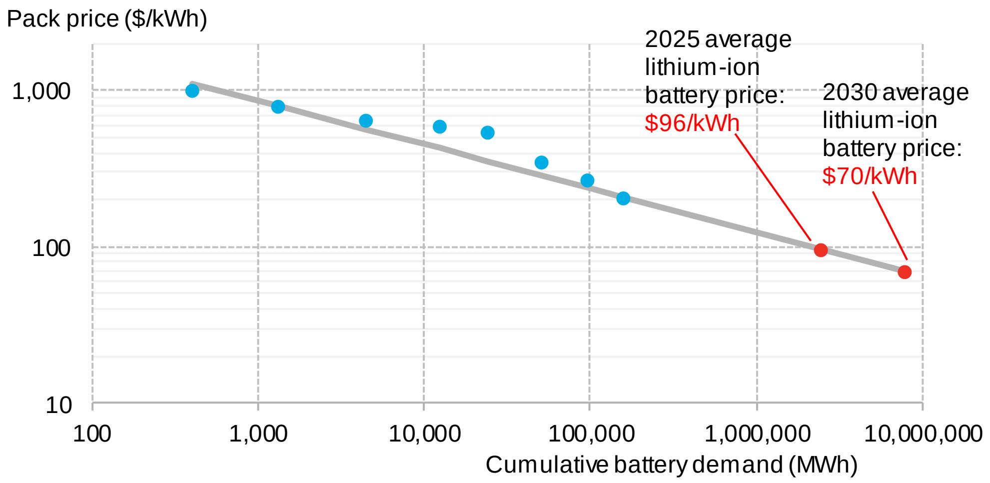
Source: BloombergNEF

Section 7. Scenario: high uptake of storage

Battery storage costs – like those of wind and solar power – have come down fast. Thanks to technological innovation and scale expansion, lithium-ion pack prices have fallen by 79% since 2010 on the back of increasing annual battery demand from the automotive and portable electronics sector.

Our data show that lithium-ion battery packs are experiencing an 18% cost reduction for every doubling in capacity. By 2025, we expect that with current lithium-ion battery technology, the industry will be able to produce an average battery pack at $96/kWh, and at $70/kWh by 2030 (Figure 41).[6]

Figure 41: Prices and learning rates for lithium-ion battery packs



Source: BloombergNEF

However, battery costs could come down faster than we project, just like wind and solar costs did, and this scenario investigates the impacts of this possibility on the U.K. power system. We are already seeing significant investment in manufacturing globally, with production capacity expected to more than triple by 2021. The fight to secure market share in such a growing market could see prices drop faster than our expectations, which are based on recent trends.

The removal of major regulatory barriers, such as the double application of network charges while charging and again when discharging, could also accelerate the growth of battery storage. Equally, direct support or market adjustments to reflect the benefits of battery storage would result in a more favourable environment for batteries. For example, the ongoing overhaul of the U.K.'s frequency response requirements values the fast response times of battery storage.[7]

A breakthrough in technology could also result in a step-change in cost reductions. Our forecasts are based on existing lithium-ion technologies, but breakthroughs in different chemistries, high voltage-cells or solid-state batteries could result in lower costs.

[6] Bloomberg subscribers can read more in our *2017 Lithium-Ion Battery Price Survey* (web | terminal).

[7] Bloomberg subscribers can read more in *New U.K. Frequency Response Products Require Batteries* (web | terminal).

Behind-the-meter versus utility-scale batteries: where will they be?

While the technology is the same, there are important differences in how utility-scale battery storage and smaller scale storage deployed behind the meter are used, as well as the type of services they can provide to the grid.

Where batteries are deployed will depend on a range of conditions – retail and wholesale power prices, deployment of rooftop PV, market design (eg, capacity payments, balancing requirements, etc.).

For example, in Germany, retail power prices are relatively high and many households have rooftop PV systems. As a result, storage is mainly deployed behind the meter and utilities have created interesting business models.

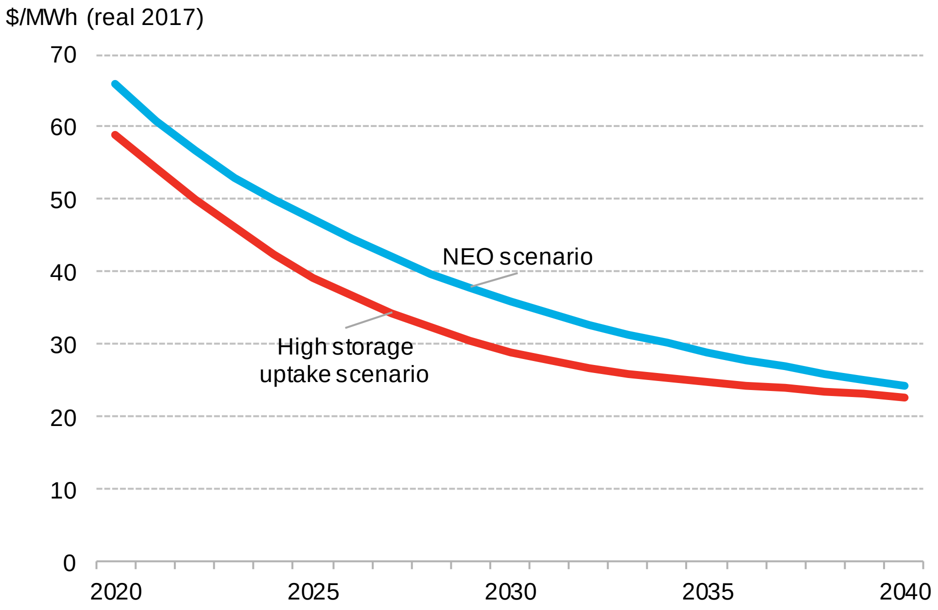
On the other hand, the U.K.'s capacity market and enhanced frequency response scheme have incentivised the deployment of hundreds of megawatts of large-scale battery storage.

7.1. How this scenario differs from the NEO base case

Input assumptions

To reflect a low-cost battery scenario, we used the parameters on the lowest end of our cost range. This gives us a reduction in the levelised costs of finance for battery storage of roughly 10% over the forecast period – the difference is greater in the short-term, at around 17% lower costs, and smaller in the long-term, with a cost reduction over NEO of 6% in 2040[8]

Figure 42: Battery storage levelised cost of finance[9]



Source: BloombergNEF

[8] It is worth noting that our NEO scenario already takes an aggressive view on storage costs.

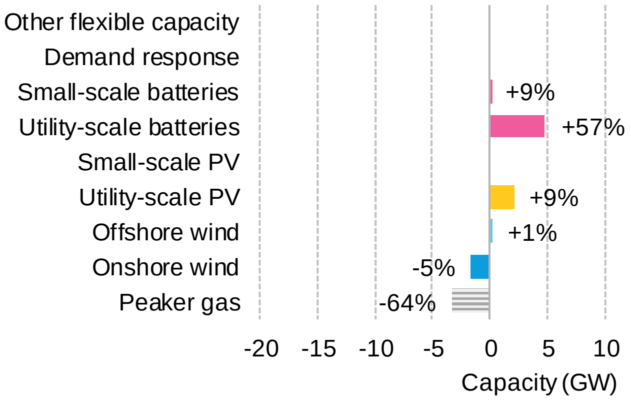
[9] The levelised cost of finance is the long-term off-take price on a MWh-basis needed for a project to pay back its capital costs and hit the equity requirements of investors; it excludes variable costs such as fuel, carbon or charging costs in the case of batteries.

Outcomes

Cheaper storage results in more battery build, and much less peaking gas. Relative to our NEO base case, 4.8GW or 57% more utility-scale battery capacity is built by 2030. Small-scale storage, driven by consumer uptake, grows more modestly, increasing by 9% by the same year. The main effect of this extra battery capacity is to displace more than half of the peaking gas capacity by 2030. The system also swaps about 1.5GW of wind for 2.1GW of solar capacity (Figure 43), thanks to the added storage capacity.

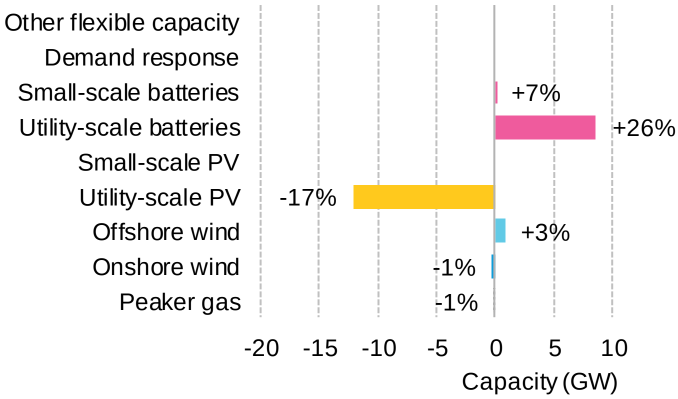
By 2040, there are 8.7 more gigawatts of battery storage than in NEO, an increase of 26% (Figure 44). The NEO base-case system is already flexible enough to integrate high levels of solar penetration, but shows relatively high curtailment of wind energy. The additional battery capacity in this scenario is able to make better use of this excess wind energy, meaning 12.1GW less solar capacity is needed, resulting in a better utilised system overall.

Figure 43: 2030 generation capacity change for high storage uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 44: 2040 generation capacity change for high storage uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

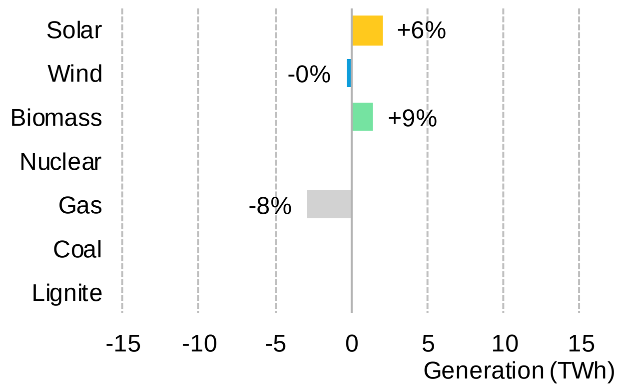
Interestingly, by 2040 the additional storage capacity does little to displace fossil backup capacity, as this is still needed to meet peak demand in periods when there is little renewables output over several consecutive days. Over time, gas plants retire or are pushed out of the system by poor economics – including 10GW of CCGTs,[10] which are decommissioned between 2030 and 2040. By 2040, only system-critical backup fossil plants remain, and even very cheap battery storage, which mostly shifts energy over short periods, is not able to displace these.

Although the growth in storage capacity reduces peaker gas capacity by 64% in 2030, it only cuts gas generation by 8% (Figure 45). Far fewer peaker plants are required to fill the short gaps in renewables output that batteries can close, but those gas plants that remain see higher utilization. With fewer gas plants to fill longer gaps, biomass is called on a bit more often too.

Renewable generation grows slightly in 2030, with more solar output reflecting the increase in PV capacity. Wind generation remains constant despite the reduction in its capacity compared to that shown in NEO. This is clearly the effect of more batteries, which reduce curtailment.

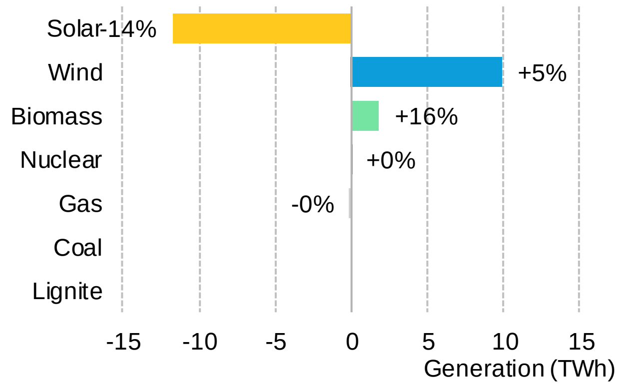
[10] Combined-cycle gas turbines

Figure 45: 2030 power generation change for high storage uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 46: 2040 power generation change for high storage uptake scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Growth in energy storage increases the utilisation of wind and reduces curtailment in general

In 2040, solar generation is 14% below that in NEO (Figure 46), as there is less capacity installed. However, the growth in energy storage allows the system to increase the utilization of wind and reduce curtailment in general (Figure 47 and Figure 48), resulting in more wind generation than in the NEO scenario despite capacity remaining the same. This is complemented by an increase in relatively expensive biomass generation at extreme times.

Figure 47: Hourly generation during a typical autumn day in 2040 for the NEO scenario

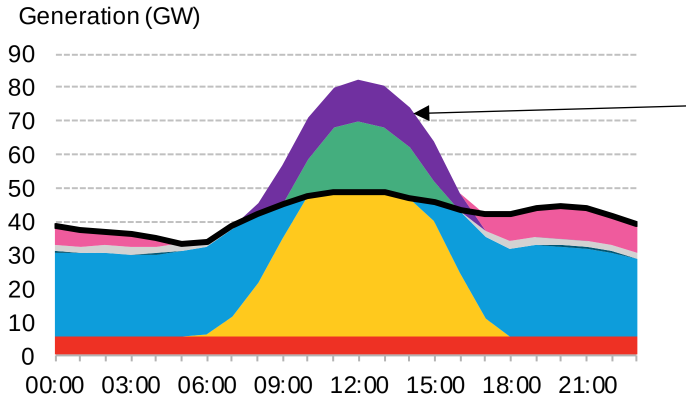
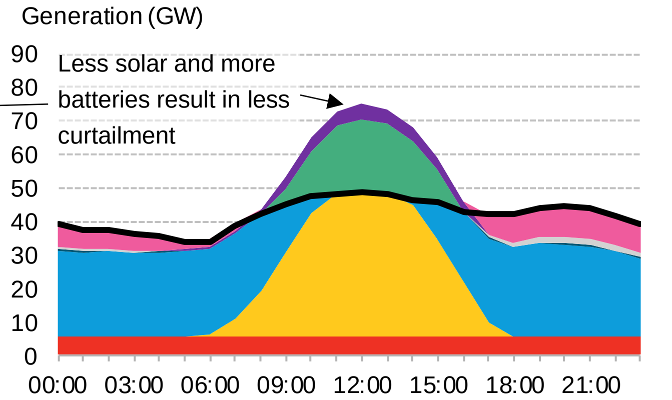


Figure 48: Hourly generation during a typical autumn day in 2040 for the high storage uptake scenario



Source: BloombergNEF

Source: BloombergNEF

7.2. Implications, benefits and drawbacks of this scenario

Cheap batteries can accelerate the energy transition by adding value to renewables. They also increase the utilization of existing capacity and defer investment in further generating capacity. Such deferral means that, because of continuing renewable energy cost declines, capacity built later on will be cheaper. This results in a lower system cost in 2030 (Table 7). By 2040, cost differences between this scenario and NEO are not as significant, resulting in virtually no change in system costs.

Cheap storage also accelerates decarbonisation, particularly around 2030, when total emissions are 13% lower than in the NEO scenario, equivalent to a reduction of 2.2MtCO_2 in that year.

However, by 2040 there is little difference in emissions compared to NEO. This is because any emissions by that point are as a result of fossil capacity acting as backup, filling longer gaps.

Batteries are a good way to shift energy across hours or days, where they can contribute significantly to meeting peak demand. However, there is little batteries can do to help meet demand during extended periods of low renewable output. Thus, a system running on batteries is not capable of completely displacing fossil peaking capacity. This would require zero-carbon seasonal storage or dispatchable generation.

Table 7 summarises the key metrics for the scenario and compares them to the NEO base case scenario.

Table 7: Key metrics for the high uptake of storage scenario

Metric	Units	2030	2030	2040	2040
		Value	Δ vs NEO	Value	Δ vs NEO
System cost	GBPm/TWh	32.1	-2%	39.9	+0%
Emissions	MtCO_2	14.6	-13%	11.7	+1%
Fossil capacity as share of peak demand	%	44%	-12%	34%	-1%
Renewable share of generation	%	75%	+1.2%	80%	-0.0%

Source: BloombergNEF

Section 8. Scenario: high uptake of flexible demand

In order to reduce costs, encourage and integrate the uptake of clean energy and increase customer participation, regulators are making changes to incentivise services like demand response. These efforts include introducing financial mechanisms that reward utilities and distribution companies for contracting distributed energy resources in place of capital investments – a departure from traditional regulation in which the addition of new capital assets is the main source of profits.[11]

Under the new approach, network operators are allowed to earn a return on operational expenditure for distributed energy resources. Treating any mix of capex and opex equivalently removes the preference to own and operate assets over seeking third-party alternatives.

Demand-side resources are also being offered broader access to participate in wholesale energy, capacity and ancillary service markets. And as smart meters are more widely adopted, dynamic tariffs will help to encourage demand shifting among business and household consumers.

If successful, these new approaches could have widespread ramifications and result in a more widespread uptake of demand response and other services. This scenario considers the impact of greater demand response uptake on the U.K. power generation system.

How commercial and industrial loads could be managed more actively

- Data centres are a good example of a large commercial load that has the potential to support the power grid and be compensated for the flexibility services provided. Data centre operators require resilient power infrastructure no matter what happens in the grid. To achieve this, they typically deploy UPS systems and on site generation with back-up generators. Eaton's UPS-as-a-Reserve (UPSaaR) enables data centre operators to make money from their existing UPS systems by helping energy providers balance sustainable energy demands. Large data centre operators, such as co-location and cloud service providers, can be compensated for immediate adjustments to power demand that help the grid avoid power outages, without compromising critical loads.
- Eaton has performed two pilots with TSOs. One, with Svenska Kräftnet, and another with Statnett, in Norway. Both pilots proved that UPS technology fits perfectly for rapid frequency regulation type services. Frequency regulation in this context is more focused on very short time frequency variations – timescales of seconds – caused by minute variations in production, disturbances and also by reduced amounts of inertia in the grid.
- While UPS systems today are not used to reduce peak demand or time of use, this is certainly possible with investment in larger batteries. UPS technology could easily be linked to various energy management schemes behind the meter, or more demanding grid support schemes. With new business models, such as revenue sharing and aggregators investing in additional hardware required for more lucrative services, this is possible today.

[11] Bloomberg subscribers can read more in *Grid investment gives way to distributed energy* (web | terminal)

8.1. How this scenario differs from the NEO base case

Input assumptions

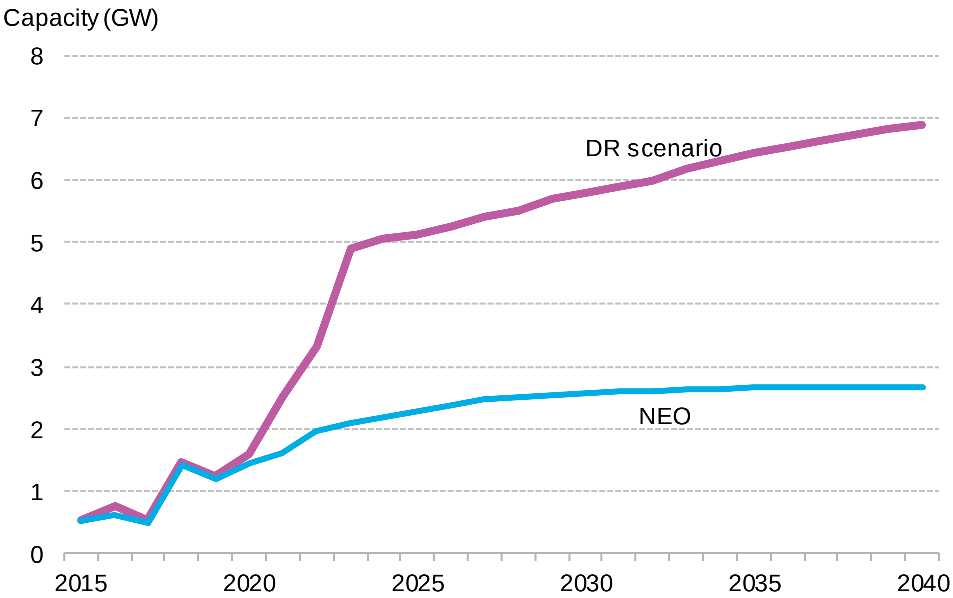
The main difference between this scenario and NEO are the higher levels of both dispatchable and non-dispatchable demand response:

- Dispatchable demand response is load that can be reduced voluntarily for a short period and for a limited number of times a year (we assume four hours and 20 times per year). This is actually a form of minor demand destruction and its main benefit is to reduce peak time generating capacity requirements.
- Non-dispatchable demand response, on the other hand, is dynamic load that shifts in response to market signals such as time-of-use pricing. Much like EV charging, it is able to accommodate larger amounts of renewable energy generation.

In the U.K., we assume that dispatchable demand response could reduce peak load by up to 8.5% in 2030 and 10.3% by 2040, compared to 5.5% for both years in our base case NEO scenario. A figure of 10% represents a very substantial fraction of the economy able to curtail demand to avoid peak loads (and related charges) – even if only a few times a year and for a short period. However, similar levels of demand response have previously been procured in the U.S.'s PJM market.

Non-dispatchable demand response capacity is 1.7GW in both 2030 and 2040 (Figure 49), versus 0.3GW and 0.6GW in NEO for the same years. This is equivalent to assuming that roughly 3% of system peak load could be moved to different times of day.

Figure 49: Demand response capacity

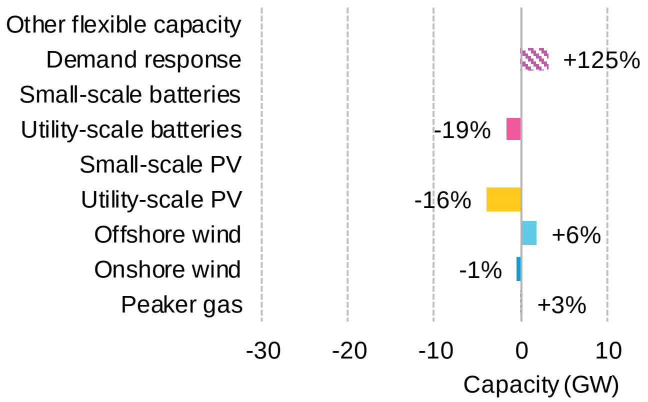


Source: BloombergNEF

Outcomes

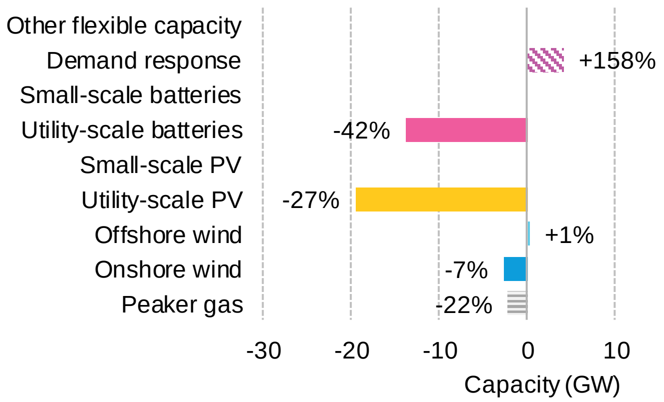
In a future with higher deployment of demand response, less battery storage and solar capacity is required. This is most likely because the added demand-side flexibility reduces the need for storage, which is an enabler of higher solar capacity. Offshore wind capacity fares better than onshore wind, in spite of the former's higher costs. With fewer batteries, this illustrates the value of offshore wind's more regular generation profile.

Figure 50: 2030 generation capacity change for high demand response scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 51: 2040 generation capacity change for high demand response scenario, versus NEO base case

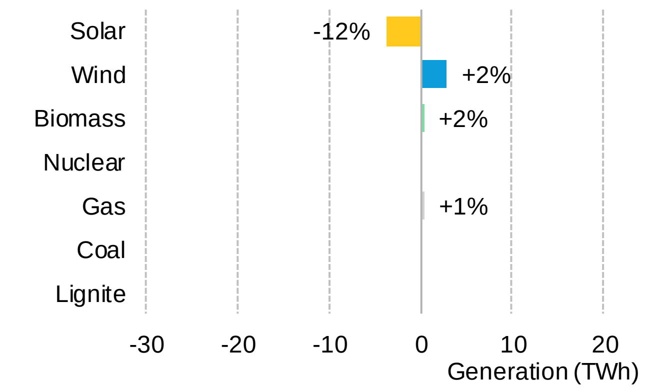


Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

While in 2030 there is little change in fossil peaking capacity (Figure 50), the increase in demand response results in a significant reduction in peaker gas capacity in 2040 of 2.1GW, or 22%, compared to that shown in NEO. This is primarily because dispatchable demand response is able to shave the extreme net load peaks, resulting in a reduced need for backup capacity for those few very high peak loads that cannot be met with renewables and batteries.

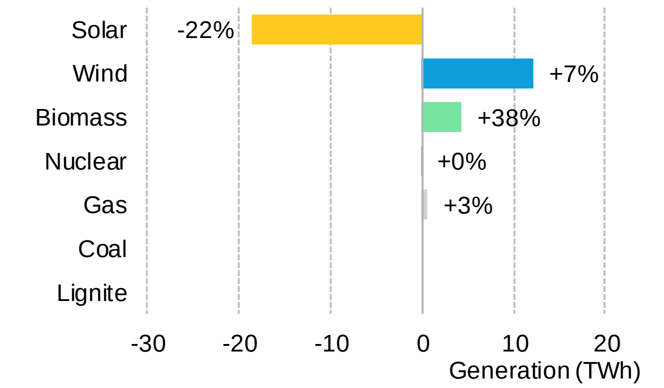
Solar generation also falls, with a decline of 12% compared to NEO in 2030 (Figure 52) and 22% in 2040 (Figure 53). But this is a smaller reduction for generation than for capacity build, which means that solar utilization is actually higher. This illustrates how flexible demand boosts the usefulness of solar generation by shifting load to hours with high solar output.

Figure 52: 2030 power generation change for high demand response scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 53: 2040 power generation change for high demand response scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Wind generation similarly benefits from the higher level of demand response in the long term. Its increase in 2030 is not as high as the growth in wind capacity, but by 2040 wind generation is 7% higher vs NEO, in spite of a net reduction in capacity.

Dispatchable generation is a different story. There is little change in gas and biomass generation in 2030, but interestingly, by 2040, they go up by 3% and 38%, respectively, compared to generation levels in NEO. Gas's 3% increase is notable when considering that more than a fifth of the NEO scenario's peaking capacity is displaced in this scenario. With a reduction in all forms of generating capacity except for a bit of offshore wind, added demand response results in a more heavily utilised power system, where less capacity generates more of the time.

8.2. Implications, benefits and drawbacks of this scenario

Demand response can displace fossil capacity and reduce the need for other flexible technologies like battery storage. It also increases capacity utilization, which means the same level of electricity demand can be met with less plant capacity. This results in a cheaper system, as evidenced by the 5% reduction in system costs by 2040 (Table 8).

However, the extent to which it can displace fossil capacity is primarily a function of the frequency and duration of dispatchable demand response activation. These two parameters have a major impact on how much capacity demand response can displace. In other words, such capacity is less effective at displacing fossil plants if it is needed for many events during the year, or if those events last a long time.

Boosting the utilization of existing assets does not just result in less renewables curtailment, but can also result in higher fossil generation and emissions. Because fuller use is made of fewer assets, less new (renewables) build is required. As a result, the remaining fossil plants find their economics strengthened and generate more.

Interestingly, the increase in emissions against NEO levels (1% in 2030 and 2% in 2040, Table 8) is not proportional to the increase in gas generation, which goes from 1% in 2030 (Figure 52) to 3% in 2040 (Figure 53). This is because the increase in gas generation is due to an uptick in CCGT capacity factors. The use of more-efficient CCGTs more than makes up for a fall in less efficient peaking gas generation, which suffers because much of the peak load flexibility is instead provided by demand response. Although the net outcome is more gas generation, it is produced more efficiently, tempering the growth in emissions.

The following table summarises the key metrics for the scenario and compares them to the NEO base-case scenario.

Table 8: Key metrics for the high uptake of flexible demand scenario

Metric	Units	2030	2030	2040	2040
		Value	∆ vs NEO	Value	∆ vs NEO
System cost	GBPm/TWh	33.2	+1%	37.9	-5%
Emissions	MtCO2	17.0	+1%	11.9	+2%
Fossil capacity as share of peak demand	%	50%	+1%	31%	-10%
Renewable share of generation	%	74%	-0.2%	80%	-0.3%

Source: BloombergNEF

Section 9. Scenario: interconnection to the Nordics

The interconnection of neighbouring systems enables resources to be shared over larger geographical regions. This increases the diversity of generation resources and smooth the aggregated output of variable renewable resources, thanks to their dispersal over a wider area. In principle, more interconnection results in a less volatile and more flexible system overall.

This is especially true when interconnecting to a region like the Nordics that has unrivalled clean, cheap and flexible resources thanks to the abundance of hydropower. This combination is not only low-carbon and cheap, but also well suited to deal with demand volatility and its corresponding ramping requirements.

Electricity interconnection is a well-rounded source of flexibility that provides access to overseas generation when needed and also allows exports of generation that might otherwise be curtailed. This can be viewed as equivalent to seasonal storage from various points of view. It also provides balancing tools to system operators and additional resources in the event of an emergency.

For countries that are in the middle of a transition to a system driven mainly by variable renewables, interconnecting to the Nordics presents an opportunity to increase flexibility. So much so, in fact, that there is a healthy pipeline of interconnector projects currently being developed. This scenario considers the impact of such interconnection on the U.K. power system.

9.1. How this scenario differs from the NEO base case

Input assumptions

We modelled interconnector capacity between the Nordics and the U.K. based on three projects with a combined capacity of 4.2GW: two links to Norway, North Connect and North Sea Link; and one to Denmark, Viking Link (Figure 54). These are projects that are either being built or have a good chance of going ahead, and as such give a good idea of future trading capacity between the British and Nord Pool markets.

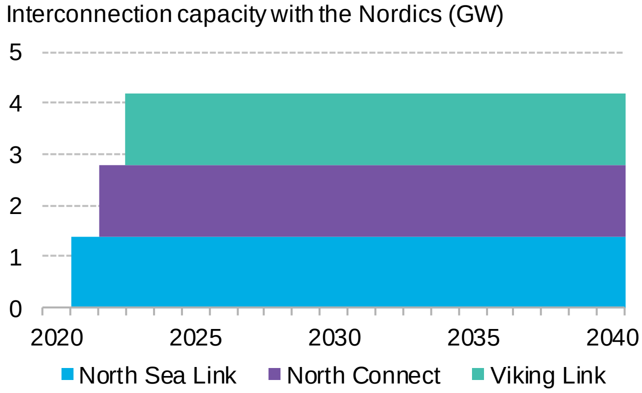
We assume that all three projects begin operations in the early 2020s, based on their expected completion dates. This means that the interconnector capacity remains constant from then on and any changes in flows between the regions are solely due to market conditions.

Our approach to modelling interconnection

- Our New Energy Outlook methodology, which forms the basis of this report, is a global exercise that does not normally consider interconnection between modelled regions. To incorporate the impact of Nordic interconnection in our model, we added an interconnector class with similar operational characteristics to pumped hydro storage. We assigned it a short-run marginal cost slightly below that of U.K.'s fossil generators and energy reserves that reflect the Nordics' export potential. We also assumed that 50% of line capacity can be relied upon at all times – i.e. the interconnectors contribute at least 50% of their nameplate capacity to the U.K. system to help meet peak load.

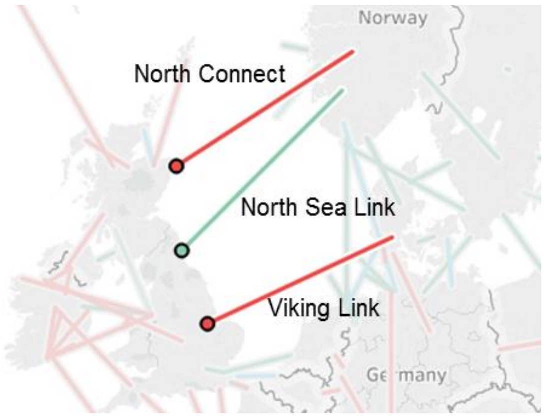
- This ensures that the interconnector acts as an alternative to fossil generation without exceeding available energy or capacity in the Nordic system. We assumed that the U.K. only exports excess energy that would have otherwise been curtailed.

Figure 54: Timeline of Nordic interconnection capacity



Source: BEIS, ENTSOe, BloombergNEF

Figure 55: Interconnector projects map



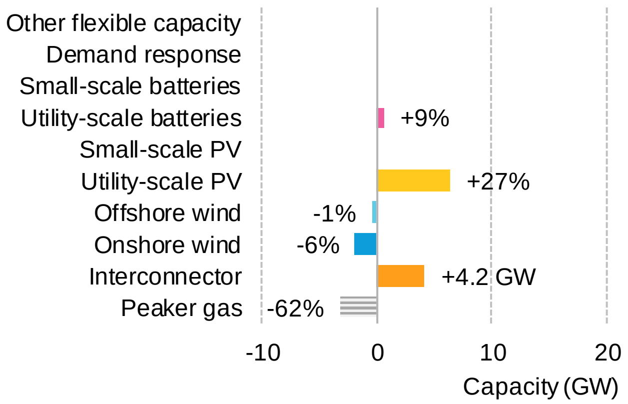
Source: BEIS, ENTSOe, BloombergNEF

Outcomes

Interconnecting Great Britain's power market to Nord Pool has a clear impact on the need for peaking gas capacity. It reduces gas peaker requirements by 3.2GW compared to the figure in NEO, a reduction of 62% (Figure 56). By 2040, the system needs 2.1GW less peaking gas capacity than in NEO, or a reduction of 22% (Figure 57). These figures show that interconnection is an effective substitute for flexible fossil capacity.

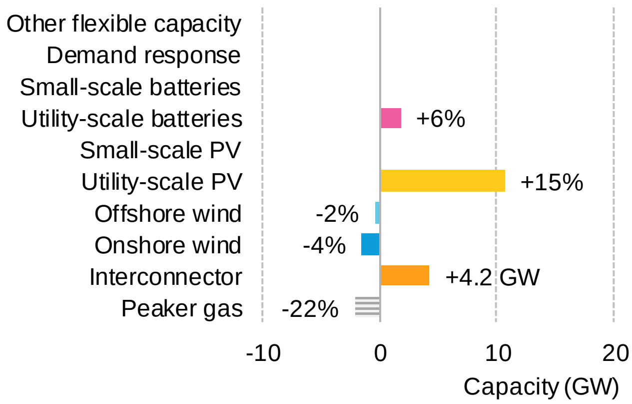
In addition, because the interconnector acts as a flexible generator, it is able to complement the daily fluctuations in very cheap solar output. This negates some of the advantages of wind power, which provides a more stable output through day and night-time hours. As a result, the interconnectors enable more than 6.4GW of cheap solar capacity on top of NEO levels to come online in 2030, in lieu of 2.3GW of wind. This is also observed in 2040, when the system has 10.6GW of solar in addition to that in NEO, making up for a 2GW relative decrease in wind capacity. An extra 0.7GW in 2030 and 1.8GW in 2040 of battery storage is built to further integrate the extra solar capacity.

Figure 56: 2030 generation capacity change for interconnection scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

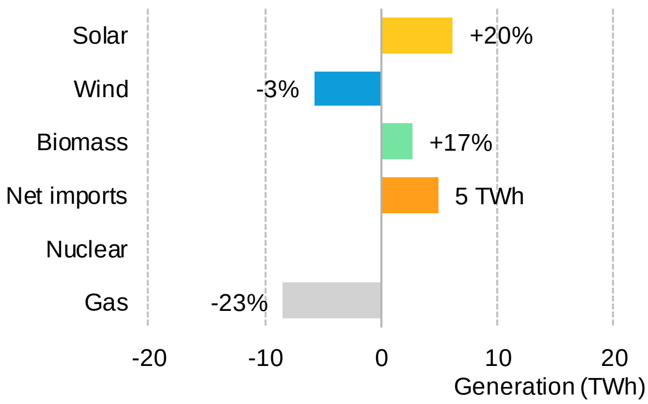
Figure 57: 2040 generation capacity change for interconnection scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

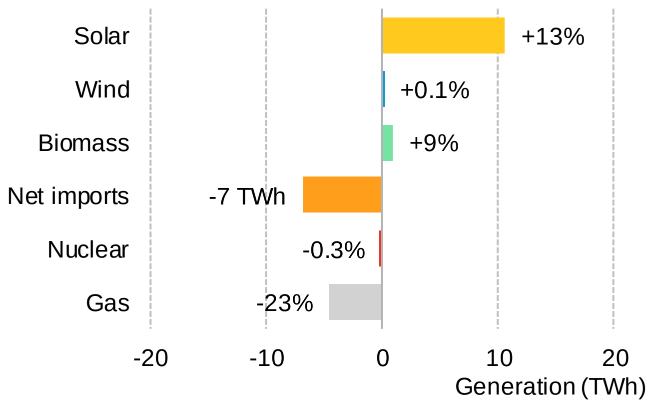
From a generation point of view, having the ability to tap into a different market means nearly a quarter less gas generation is needed – a figure that is valid for both 2030 and 2040. And, while having the ability to export excess generation into the Nordics allowed for greater solar build, with such high a capacity, there are sunny times when there is much more excess solar power than the lines are able to transport. As a result, the increases in solar generation are less than the increases in solar capacity (Figure 58 and Figure 59). The opposite is true for wind generation, which sees an increase in capacity factors.

Figure 58: 2030 power generation change for interconnection scenario, versus NEO base case



Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Figure 59: 2040 power generation change for interconnection scenario, versus NEO base case

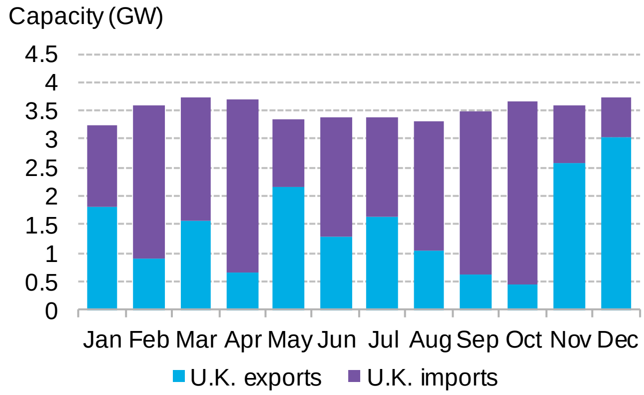


Source: BloombergNEF. Note: percentages show relative change against the NEO scenario

Another important aspect is how the interconnection capacity is utilised: which way does the power flow and how often is it used? As we progress through the forecast period, and more wind and solar are installed in the U.K., the role of the interconnector changes.

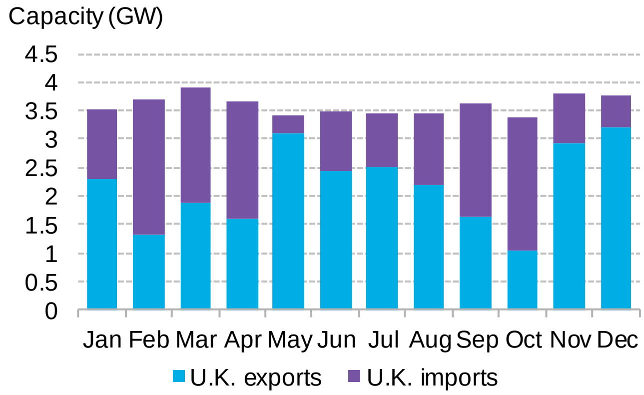
- Around 2025, when coal comes offline, the interconnector is used almost exclusively to import cheap power from the Nordics to help meet British demand. However, as the U.K. installs more and more variable renewable capacity, this trend starts to reverse.
- In 2030, U.K. power imports from the Nordics still make up 58% of interconnector flows. The average line utilization throughout the year is 84%. It is used most during March and April, mostly for imports, and December, mostly for the export of excess wind generation (Figure 58).
- By 2040, we see this balance overturned, with fewer imports from the Nordics (39% of flows), while average line utilization for the year remains similar (86%). March and November see the highest utilization, but the increase in solar generation shows in the higher share of exports during summer months (Figure 61).

Figure 60: Interconnector utilisation in 2030



Source: BloombergNEF

Figure 61: Interconnector utilisation in 2040



Source: BloombergNEF

This shift reflects the changing nature of a system driven by vast wind and solar capacity that often generates more than it needs. More importantly, it reflects how the value of the interconnection to the Nordics will shift from providing bulk electricity to becoming more like a long-duration battery. It would absorb excess power from the U.K. to return it later at high-value times of potentially prolonged low-renewable output, when flexibility is most needed and valued.

9.2. Implications, benefits and drawbacks of this scenario

Interconnection to the Nordics, and their flexible hydro resources, benefits the system across the metrics we consider (Table 9). From a reliability perspective, the extra interconnection capacity is an excellent flexible resource that can operate over short and long timescales alike, shifting energy over hours and across seasons. It also provides an additional source of electricity that can contribute to security of supply.

The interconnector's ability to replace gas capacity and generation with hydropower and more renewables translates into a reduction in emissions throughout the entire forecast period. By 2030, the system sees a reduction in emissions of 35% against the NEO base case, or 4.1MtCO2. In 2040, already-low NEO emissions are further reduced by 24%, avoiding an additional 2.8MtCO2 of emissions that year (Table 9).

Not including the cost of the cable (estimated at 5 billion pounds), the interconnection results in a roughly 2% system cost reduction. This is due to three main factors: the avoided costs of building flexible gas, access to lower-cost electricity and a reduction in total carbon costs.

Unlike individual technologies such as storage and flexible EV charging, interconnection with the Nordics improves both short-run and seasonal flexibility. This reduces the need for other flexible capacity, which in turn reduces system costs. It also reduces the need for fossil fuel burn, resulting in fewer emissions. As more renewables are deployed, the value of interconnectors shifts from providing bulk, cheap, clean power to providing valuable flexible power during high-value hours.

Table 9 summarises the key metrics for the scenario and compares them to the NEO base-case scenario.

Table 9: Key metrics for the interconnection scenario

Metric	Units	2030	2030	2040	2040
		Value	∆ vs NEO	Value	∆ vs NEO
System cost	GBPm/TWh	32.2	-2%	38.9	-2%
Emissions	MtCO2	12.7	-25%	8.8	-24%
Fossil capacity as share of peak demand	%	44%	-11%	31%	-10%
Renewable share of generation	%	76%	+3%	81%	+2%

Source: BloombergNEF

Section 10. Final thoughts

This section presents some overall observations and findings from across the scenarios, and the lessons they provide as the UK prepares for a future power system dominated by renewables. We also provide a comparison of the seven scenarios - though we do this with some caution. This report is not intended to 'pick a winner' from the technologies analysed – all of these technologies will play a role – but comparing scenarios does provide insight into their relative contributions and roles.

10.1. Roles and contributions of each technology

The tables below compare the main outcomes for each technology scenario in 2030 and 2040.

Table 10: Summary of scenario outcomes in 2030

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	32.8 GBPm/TWh	16.8 MtCO2	49%	74%	88%
Relative change vs NEO					
Low-flex	3%	9%	10%	-1%	-1%
High uptake of EVs	2%	-19%*	0%	1%	0%
High uptake of EVs and flexible charging	0%	-30%*	-7%	2%	1%
High uptake of storage	-2%	-13%	-12%	1%	1%
High uptake of flexible demand	1%	1%	1%	0%	0%
Interconnection to the Nordics	-2%	-25%	-11%	3%	3%

Table 11: Summary of scenario outcomes in 2040

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	39.8 GBPm/TWh	11.6 MtCO2	34%	80%	94%
Relative change vs NEO					
Low-flex	13%	36%	45%	-1%	-2%
High uptake of EVs	4%	-88%*	3%	1%	0%
High uptake of EVs and flexible charging	4%	-96%*	0%	1%	0%
High uptake of storage	0%	1%	-1%	0%	0%
High uptake of flexible demand	-5%	2%	-10%	0%	0%
Interconnection to the Nordics	-2%	-24%	-10%	2%	2%

*Source: BloombergNEF. Note: Colour scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

None of the scenarios halt the transition to low-carbon

The scenario outcomes differ in system cost and emissions, but in all cases renewable energy achieves roughly three-quarters of the energy mix by 2030, and four-fifths by 2040. This reinforces our findings from NEO 2018 that wind and solar are the cheapest forms of power generation and will come to dominate the future energy mix. In modelling terms, their cost-effectiveness makes them the number one choice for power supply, regardless of how the flexibility challenge is solved. Including nuclear and clean imports, the zero-carbon share of power generation is above 90% by 2040 in all scenarios.

However, a lack of 'new' flexibility would have a real cost

For both 2030 and 2040, the low-flex scenario is the least desirable across all metrics. The lessons are clear: in a world where new forms of flexibility do not realise their potential, the power system has to adapt in other ways to maintain reliability and provide the flexibility to complement renewables. This means a greater reliance on gas peakers, leading to higher system costs, higher emissions and a greater level of back-up capacity. Power sector emissions are a full 36% higher in 2040 under this scenario.

New sources of flexibility are needed in the near term.

Across all scenarios, there is a need for battery storage from the early 2020s onwards. In the U.K., by 2025, the storage capacity required by the system in our base case NEO scenario is 4.0GW, and ranges across scenarios from 1.5GW to 4.8GW. Allowing the aggregation of storage to provide grid services as well as rewarding utilities and distribution companies for contracting distributed energy resources are key to supporting these new sources of flexibility that will enable the transition to a high renewable energy system.

Adding even more electric vehicles can be achieved without major negative ramifications

Even in our high-uptake scenario, where internal combustion engine vehicles are phased out by 2040, EVs do not 'break' the power generation system. System costs are raised just 2% and 4% in 2030 and 2040 respectively on a per-TWh basis, and the fossil fuel capacity share is raised by just 3% in 2040 (and not at all in 2030). However, impacts on the transmission and distribution network may be more significant – see discussion below.

In fact, the net emission savings are significant…

Adding more EVs by 2040 of course leads to higher power demand and therefore higher emissions in the power sector, but once we net off the emission reductions from gasoline and diesel savings (which we have done in the tables above), the overall emission savings are substantial. Our high-EV scenario has 19% better emissions performance in 2030 than the base case on this basis, and 88% better by 2040.

…especially if they are flexibly charged

In our high-uptake, high-flexibility EV scenario, the results are even better, with net emissions down 30% and 96% in 2030 and 2040 respectively. The fact that EV charging load can be shifted throughout the day allows the power system to absorb slightly more renewable energy (2% by 2030 compared to the NEO result) and reduce the need for fossil back-up (by 7% in 2030). This underscores the benefits of developing a strong base of charging infrastructure at workplaces, commercial destinations and residential buildings that can charge responsively depending on pricing and grid conditions.

Energy storage is a critical piece of the puzzle, and can act as an accelerant

The NEO base case already includes a significant share of energy storage, but in a scenario where storage gets even cheaper, the outcomes are striking. By 2030, fossil back-up can be reduced by a relative 12% and emissions by 13% through displacement of gas peakers by battery plants. This effectively accelerates the energy transition by moving the U.K. more quickly down the emissions reduction curve. However, by the time 2040 is reached, the advantages of this scenario have largely disappeared. This is because even in the NEO case, batteries have already maximised their potential in managing hourly and daily fluctuations on the grid – and what is left are the weeks and months of low renewables production. Even if batteries are very cheap, these gaps can only be met by other forms of generation, interconnection or seasonal storage.

Flexible demand is needed in the long run

The ability to shift or curtail greater portions of demand allows the energy system to operate with 10% less fossil capacity, 42% less battery capacity and 5% lower system costs in 2040, reflecting the importance of flexible demand in a high-renewable energy system. However, a surprising finding is that these impacts are not felt until after 2030. Our modelling indicates that, during the transitional phase, demand response has a marginal impact, shifting the relative mix of wind, solar and gas (and displacing some energy storage build), without meaningfully changing emissions or fossil back-up.

Increasing links with highly flexible markets can improve outcomes across decades

The interconnector scenario delivers the best performance on emissions (next to the high-EV scenario when emissions are counted on a net basis), with 24% and 25% reductions in 2030 and 2040 respectively. The interconnectors are also able to displace 11% and 10% of fossil capacity in these years. Unlike energy storage, demand response and flexible EV charging, the interconnectors are able to provide both short-run flexibility (to manage hourly and daily variability) and seasonal back-up. In this way, they are able to displace fossil fuel burn both in the near-term to 2030, and in the long term once renewables achieve 80% penetration. This highlights the versatility of interconnectors when used to connect to a market with a high degree of clean flexibility.

10.2. Getting the market environment right

The scenarios nominally explore technology outcomes, but they can also be seen through a policy lens: policymakers and regulators can help to bring about these outcomes by creating favourable market environments for flexibility sources. Favourable market conditions for flexibility might include:

- Introduction of dynamic power pricing (potentially mandatory) for energy customers – and for electric vehicle charging
- Establishment of frameworks for distribution network operators to share the value of flexibility
- Greater incentives or compensation for rapid-responding resources within capacity and ancillary markets
- Shortening of the trading and settlement interval in the wholesale power market
- Expansion of market access for energy storage and demand-side resources – including aggregated resources – and lower barriers for participation, across capacity, energy and balancing markets
- Equal treatment of interconnectors/overseas resources within these markets

10.3. The glass ceiling of 80% renewable (and 94% carbon-free)

None of the scenarios achieve much more than 80% renewable energy by 2040. There are a number of reasons for this: new sources of flexibility such as batteries are unable to fill ‘seasonal gaps’ of weeks and months when renewables production is low; the U.K. does not have significant hydropower generation, and our model is a least-cost optimization and therefore does not over-build batteries and renewables to boost their share beyond an economic optimum.

There is academic debate in the U.K. and internationally on whether or not 100% renewable power is achievable. While this report does not seek to answer that question directly, we do find that going far beyond 80% renewables is likely to require new technologies such as power-to-gas or greater use of bioenergy.

However, we do find that near-100% *carbon-free* power can be achieved with known flexibility technologies. In our modelling, the presence of nuclear generation means that the zero-carbon share achieved is as high as 94% in 2040. Including clean imports under the interconnector scenario, the figure is as high as 96%. There is therefore little space left to add more renewables, and little need for it.

10.4. Grids, customers and distributed resources

This study has not investigated the network reinforcement or expansion that would be needed to integrate new renewable energy sources and new forms of flexibility. It also does not analyse in detail the specific characteristics of distributed or customer-sited resources such as small-scale storage. There are several important dynamics, challenges and opportunities that will need to be taken into account:

- It is likely that significant network investments will be required to integrate both bulk and distributed renewable energy sources. Digital grid technologies and innovative commercial arrangements will be part of the solution as penetrations rise, and these will play a big role in limiting curtailment and maximising the utilisation of both generation and network assets.
- By the same token, distributed sources of flexibility, such as demand response, smart EV charge points, onsite generation and small-scale storage, can help to manage both the system-level flexibility needs analysed in this report and the network congestion challenges above (not examined in this report). These represent an opportunity, particularly for distribution system operators, to take a more proactive role in managing their networks, eg by procuring distributed flexibility through competitive tendering mechanisms.
- Energy storage is perhaps unique as a source of flexibility, in that it can be installed as a customer-sited device, eg at a business or household, or as a utility-scale resource. In this study, both types of storage are included and play a role in providing flexibility at the system level. In the real world, only distributed storage will be able to help manage local network congestion, and only utility-scale storage will have access to wholesale markets – unless aggregation becomes widespread. The relative balance of large- versus small-scale storage in the U.K. is likely to depend on how regulations and tariff designs evolve in this area.

10.5. EV unknowns

This study has investigated the possible ramifications of an internal combustion engine phase-out, leading to faster EV adoption, and the impact of making EV charging highly flexible. However, there are several important unknowns about the future development of EVs that might lead to quite different outcomes, for example:

- If, as now seems the case, the internal combustion phase-out continues to allow conventional hybrid vehicles to be sold (without a plug), then the impact on the grid will be significantly lower.
- Assuming highly flexible EV charging relies on virtually ubiquitous charging infrastructure, so that EVs can essentially charge whenever called upon by power price signals. The U.K. is currently far from this situation – and even if charging infrastructure becomes widely available, dynamic EV charging will require the consent of customers.
- If instead a large portion of EV charging takes place at rapid charging sites, this might have a negative impact on the power system – it could cause large ramping events, and reduce the opportunity to time charging to coincide with renewable generation. These issues could potentially be managed by having onsite storage, as is planned by some charging operators. Overall, the impact of rapid charging requires further work.
- Other future changes, such as vehicle-to-grid storage or autonomous fleets, could further alter the outlook for how EVs interact with the power system. These were not examined in this study.

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