International Journal of Greenhouse Gas Control 120 (2022) 103740

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

The role and value of inter-seasonal grid-scale energy storage in net zero electricity systems

Caroline Ganzer [a,b,*], Yoga W. Pratama [a,b], Niall Mac Dowell [a,b]

[a] Sargent Centre for Process Systems Engineering, Imperial College London, UK
[b] Centre for Environmental Policy, Imperial College London, UK

ARTICLE INFO

Keywords:
Energy systems
Energy storage
Power-to-gas storage
CCS
Deep decarbonisation

ABSTRACT

Grid-scale inter-seasonal energy storage and its ability to balance power demand and the supply of renewable energy may prove vital to decarbonise the broader energy system. Whilst there is a focus on techno-economic analysis and battery storage, there is a relative paucity of work on grid-scale energy storage on the system level with the required temporal resolution. Here, we evaluate the potential of power-to-gas-to-power as inter-seasonal energy storage technology. Our results suggest that inter-seasonal energy storage can reduce curtailment of renewable energy, and overcapacity of intermittent renewable power. Importantly, grid scale energy storage assumes a critical role especially when the technology options for dispatchable power are limited. It appears that neither high CAPEX nor low round-trip efficiency preclude the value of the technology *per se*, however the rate of charge and discharge of the technology emerges as key technical characteristic. This study emphasises the rising importance of balancing seasonality in energy systems characterised by a high penetration of renewable energy, and prompts questions regarding sector integration and resilient decision-making toward a zero-carbon economy.

1. Motivation and background

The decarbonisation of the world's energy system is crucial to mitigate anthropogenic climate change and poses challenges specific to each sector of the energy system. Owing to its relatively large contribution to CO_2 emissions, and traditional domination by large, fixed-point emitters, the power sector has historically been the primary focus of broader decarbonisation efforts. Furthermore, *via* electrification, a low/zero-carbon power sector enables the subsequent partial decarbonisation of the heating, mobility, and industrial sectors. While there is focus on technological solutions for the electrification of heat and transport, *i.e.*, electric vehicles (EV) and heat pumps (HP), concerns remain regarding the system impacts of large-scale electrification (Teng et al., 2016).

The challenges in the design of a power system which provides carbon-neutral electricity for power applications but also for carbon-neutral heat and transport services go beyond a mere expansion of grid capacity. Not only is the quantity of power demand expected to change, but so too is the qualitative shape of this demand profile. Importantly, peak demand may significantly increase as a result of the cumulative demand of the three sectors during peak hours of the day (Watson et al., 2019). Moreover, the inter-seasonal variation in power demand may become more pronounced owing to the impact of the electrification of heat. This is especially true for countries, such as the UK and most other European countries, with a seasonal climate and resulting seasonal variation in heating needs. Although not evaluated in this paper, inter-seasonal energy storage may also be important for warm countries with seasonal cooling requirements. For example, some Australian states (VIC, NSW and SA) experience black/brown outs during the hottest days of the year. Similar instances have been observed in the USA, *e.g.*, California, South East Asia and Middle East.

Globally, the number of countries committing to a net zero target appears to be rapidly increasing. At the time of writing, the UK, EU, South Korea, and Japan have committed to achieving net zero carbon emissions by 2050, with China making the same commitment for 2060. It is important to note that a net zero system, as opposed to a low-carbon system, either precludes the operation of any fossil emitters with residual emissions, or necessitates the deployment of negative emission technologies (NETs). Thus, the stipulation of a net zero target acts as a key constraint on the evolution of the electricity system. In this context, increased levels of political ambition notwithstanding, the design of a power system which not only meets this target but also does so in a cost-optimal and socially equitable way (Patrizio et al., 2018, 2020), with

* Corresponding author at: Sargent Centre for Process Systems Engineering, Imperial College London, UK.
E-mail addresses: caroline.ganzer17@imperial.ac.uk (C. Ganzer), niall@imperial.ac.uk (N. Mac Dowell).

https://doi.org/10.1016/j.ijggc.2022.103740
Received 30 March 2021; Received in revised form 11 July 2022; Accepted 27 July 2022
Available online 8 August 2022

sufficient resilience to future uncertainty, within the boundaries of capacity expansion speed and ecological constraints, remains a topic of active research.

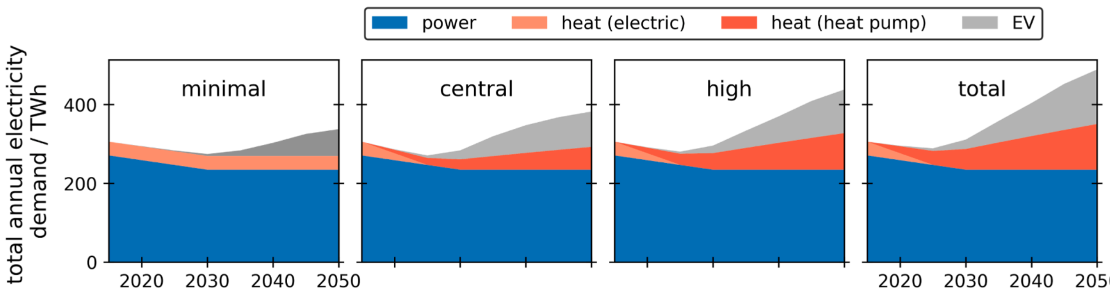
One major point of discussion is the optimal capacity mix, *i.e.*, the combination of power generation and storage technologies which can best satisfy these requirements. It is worth noting that when designing the power system in particular, ancillary services - reserve capacity and inertia provision - and the ability to maintain them throughout the day and the year, must also be considered (Heuberger and Mac Dowell, 2018; Heuberger et al., 2016, 2018). Here, we take the system perspective, and view individual technologies as archetypes characterised by the grid services they provide and their advantages and challenges in that context. A brief overview of these archetypes is as follows:

- Intermittent renewable energy sources (iRES), *e.g.*, onshore & offshore wind, solar, provide zero-carbon power, but are limited in their ability to provide ancillary services, such as firm reserve and inertia. The level to which their intermittency poses an issue for their integration into the system is highly dependent on their share of the capacity mix, the level of interconnection, and available transmission capacity. Limited flexibility can be provided in the form of curtailment. Their expansion may be limited by consideration of ecological constraints (Gove et al., 2016). Beyond a certain level of deployment, synchronous compensator technology may be needed to provide synthetic inertia and maintain grid stability (Nedd et al., 2017). The provision of ancillary services by renewable energy sources is currently an active area of research.
- Baseload dispatchable generators, *e.g.*, most nuclear plants, geothermal, tidal, supply a steady level of power and ancillary services with reduced flexibility and emissions.
- Dispatchable emitters, *e.g.*, combined cycle and open cycle gas turbines (CCGT & OCGT), oil, coal, provide power from fossil fuels with (relatively) high emissions at (relatively) low CAPEX and OPEX. They can provide flexibility and ancillary services but emit CO_2. The presence of a carbon price can substantially increase their operating cost.
- Low-carbon dispatchable power generation technologies, *e.g.*, gas-fired CCGT with carbon capture and sequestration (CCS), coal with CCS, blue/green H_2-CCGT, blue/green H_2-OCGT, provide power from fossil fuels with reduced CO_2 emissions. They can provide flexibility and ancillary services at higher CAPEX compared to unabated plants.
- Negative emissions technologies (NETs), *e.g.*, bioenergy with CCS (BECCS), direct air capture with CO_2 storage (DACCS), operate a net negative CO_2 balance, while either producing or consuming heat and power.
- Short-term energy storage, *e.g.*, battery storage, can smooth the variation of power demand and power production at sub-hourly or hourly, or inter-daily time scales. It can further provide ancillary services.
- Inter-seasonal energy storage, *e.g.*, power-to-gas-to-power, power-to-liquid-to-power, balances inter-seasonal variation in power demand. The exact classification amongst storage technologies as short-term, long-term, or inter-seasonal storage may depend on the context. These storage technologies may provide ancillary services.

The way in which technology archetypes interact with each other influences both the design and the operation of the electricity system. For example, the level of deployment of intermittent renewable energy impacts the necessity and, depending on the structure of the market, profitability of storage technologies. Similarly, the presence or absence of low-OPEX peaking plants can shift the role of dispatchable technologies between load-following and baseload. Further, the choice of BECCS or DACCS will impact the broader structure and operation of the electricity system (Daggash et al., 2019; Daggash and Mac Dowell, 2019a, 2019b). It has been shown elsewhere that low-carbon dispatchable generation can provide value across a wide range of scenarios (Heuberger et al., 2017a, 2017b, 2018; Mac Dowell and Staffell, 2016; Sepulveda et al., 2018), and the operation of negative emissions technologies is key to reaching net zero in a technologically feasible way (Daggash et al., 2019; Fajardy and Mac Dowell, 2018; Mac Dowell and Fajardy, 2017). Furthermore, systems with 100% intermittent renewables and storage may encounter challenges with demand satisfaction and ancillary services (Heard et al., 2017; Heuberger and Mac Dowell, 2018).

As the power system evolves to incorporate a greater proportion of renewable power, electricity storage technologies are expected to be key in balancing any potential mismatch between availability and demand. While a representation of hourly/daily storage and an inclusion of short-term storage technologies such as battery storage and pumped hydro storage is standard in energy systems models, there is a paucity of work which incorporates grid-scale inter-seasonal energy storage in power systems modelling. Seasonal energy storage may be of interest in countries where the operation of low-carbon dispatchable power may be limited, or the potential of iRES is particularly high. Importantly, the deployment of energy storage capacity in electricity systems impacts investment and market decisions for generation capacity (Borozan et al., 2019; De Sisternes et al., 2016; Guerra et al., 2020; Oderinwale et al., 2019), emphasising the need for detailed study in this area.

The majority of work on energy storage has focused on short-term electrochemical (batteries) and mechanical (compressed air, flywheel) storage technologies (Akinyele and Rayudu, 2014; Beaudin et al., 2010; Chen et al., 2009; Díaz-González et al., 2012; Mahlia et al., 2014). In the context of grid-scale energy storage, the most mature option is pumped hydro; the currently installed capacity in the EU is on the order of 0.6 TWh. However, the potential for expansion is inherently limited; there is an insufficient amount to balance inter-seasonal variations (Geth et al., 2015), leading to a search for alternatives, such as chemical storage in the guise of so-called "power-to-x". However, when chemical storage is discussed, this tends to be limited to hydrogen (Akinyele and Rayudu, 2014; Beaudin et al., 2010; Chen et al., 2009; Díaz-González et al., 2012; Mahlia et al., 2014), despite there being limited evidence that it is the most cost-effective option (Yao et al., 2019). Research efforts in this space have, thus far, focused on the techno-economics of standalone power-to-gas systems in Germany, possibly due to the focus of the *Energiewende* on the expansion of renewable energy generation (Glenk and Reichelstein, 2019; Götz et al., 2016; Schiebahn et al., 2015; Varone and Ferrari, 2015). System-level studies in Germany have shown promise for power-to-gas, however they do not include nuclear or CCS which may compete with power-to-gas (Schill, 2020; Schill and Zerrahn, 2018). US-based analysis suggests power-to-gas has merit in systems lacking dispatchable power options and highly renewable systems (Dowling et al., 2020; Safaei and Keith, 2015). Studies for the EU energy system and the global energy system indicate potential for power-to-gas for balancing intermittent renewables (Bogdanov et al., 2019; Brown et al., 2018; Victoria et al., 2019). However the studies exclude CCS and nuclear and arrive at low-carbon (not net zero) systems. Recent analyses for multiple electricity systems in the US discern which technology characteristics would be required for long-term storage to be competitive (Guerra et al., 2020; Sepulveda et al., 2021). In the UK context, power-to-hydrogen has been explored as a link between the electricity system and the natural gas grid and shown to potentially reduce the curtailment of wind power (Clegg and Mancarella, 2015; Qadrdan et al., 2015). However, all of this work notwithstanding, there is a marked absence of the evaluation of grid-scale energy storage technology in the context of the whole system (Schnellmann et al., 2018). To our knowledge, no study has assessed the potential role of power-to-gas-to-power in the UK energy system. There also seem to exist gaps in the analysis of power-to-gas competing in a diverse system with nuclear and CCS. Furthermore, analysis of net zero, as opposed to low-carbon, systems becomes increasingly important.



power	demand reduction through efficiency improvements until 2030, then offset by growth; profiles from one year of full-hourly power demand			
EV	steady progression	by 2050 ∼50% of road transport	by 2050 ∼80% of road transport	by 2050 ∼100% of road transport
heat	maintain level of electric heating, no heat pump deployment	70% air-sourced, 30% ground-sourced heat pumps, no heat storage; profiles from one year of full-hourly heat pump COP & heat demand		
		by 2050 ∼50% of residential & commercial heat demand	by 2050 ∼80% of residential & commercial heat demand	by 2050 ∼100% of residential & commercial heat demand

Fig. 1. Total annual electricity demand, comprised of baseline power demand, power demand for electric vehicles (EV) and power demand for heat (electric heating and heat pumps), for electrification scenarios; as well as corresponding assumptions. This study neglects the potential impact associated with the electrification of the industrial sector, which could increase future demand.

Thus, we have identified a research gap for technology agnostic system analysis of grid-scale energy storage and a resulting lack of road maps for developing impactful energy storage technology. In this work, we explore the potential for inter-seasonal energy storage in the context of a net zero energy system. We present a thought experiment wherein the potential role and value of an archetypal grid scale energy storage technology is analysed at the system level. We explicitly account for the electrification of heating and mobility services and the consequent quantitative and qualitative impact on the power demand curve. We further examine the importance of key technology characteristics and perform a sensitivity analysis of the charging and discharging rate, round-trip efficiency, and CAPEX of the technologies to examine the robustness of the findings. We assess how characteristic technology parameters impact the design at the system level. The purpose of this contribution is not to design the optimal deployment of grid-scale energy storage, as this is a function of a wide range of factors dependent on both public policy and the natural year-on-year uncertainty associated with the availability of renewable energy. Rather, it is to provide insight as to the services that inter-seasonal storage provides to the energy system, and to discern which technical parameters are most important.

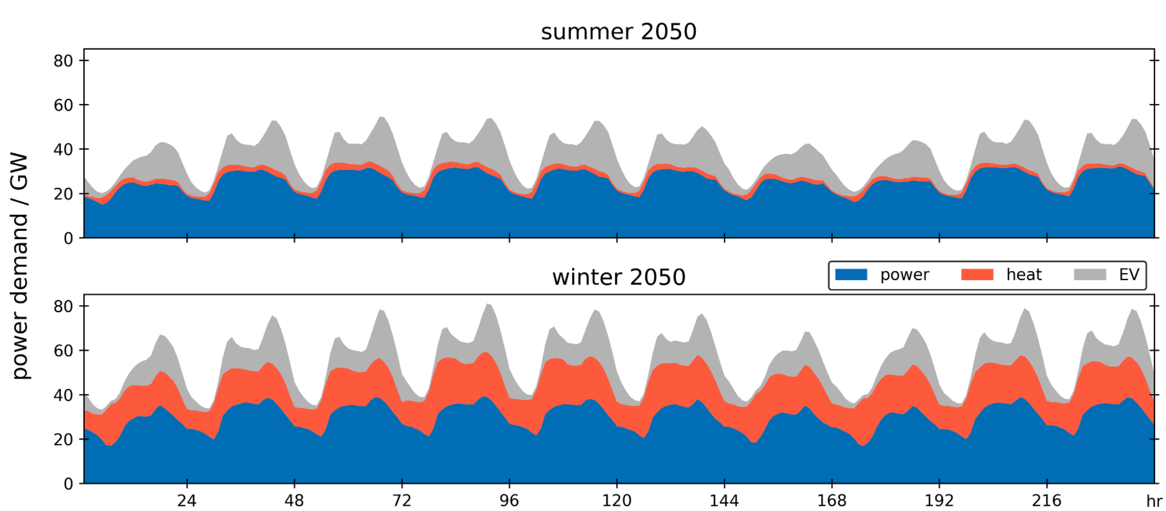


Fig. 2. Excerpt of power demand profile for central electrification in 2050, for 10 consecutive days in summer and winter.

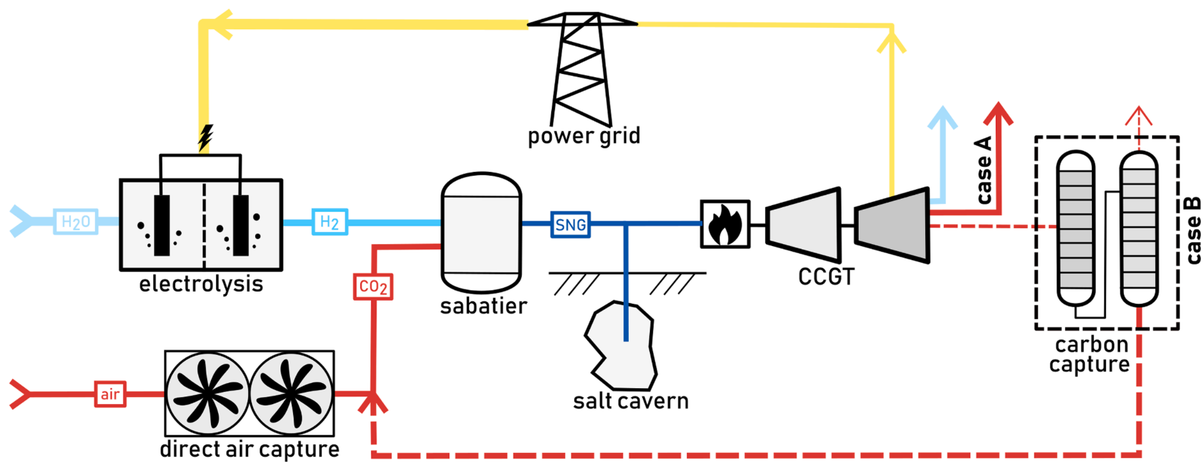


Fig. 3. Power-to-gas storage types used in this work following Yao et al. (2019). In Case A, the CO_2 is vented to atmosphere and is subsequently recaptured via DAC, whereas in Case B, the CO_2 is recovered via a carbon capture plant and is recycled to the Sabatier process.

2. Model and assumptions

This work builds upon the Energy Systems Optimisation framework with capacity expansion (ESO-X) (Heuberger et al., 2017a, 2017b). We extend the ESO-X framework to enable inter-seasonal energy storage, and use full-hourly time representation – optimising 8760 h in the year – to allow seasonal effects to emerge. Perfect foresight over the time horizon (2020–2050) is assumed. The model is solved in its linear relaxation. The resulting LP exhibits solution times ranging from 1 h to more than 1 day, with most cases requiring 2–3 h.

2.1. Electrification and power demand curve

We obtain historical full-hourly power demand data describing the UK grid (spatially aggregated) from *OPSD* (Open Power System Data, 2019), full-hourly heat pump coefficient of performance (COP) data from *when2heat* (Ruhnau et al., 2019), and EV profiles from the *Element Energy EV charging behaviour study* (Element Energy, 2019). Estimates for total power, heat, and EV demands are derived based on BEIS/DECC data (UK DECC, 2013, 2014) and scenarios (UK BEIS, 2018a) as well as on the *National Grid Future Energy Scenarios* (National Grid, 2019). Fig. 1 summarises the main assumptions around the electrification scenarios which were constructed for this work. Total power demand is assumed to be the aggregate of electricity demand, added demand from heat pumps, and added demand from EVs. The share of deployment varies for each of the scenarios, and with it the power demand profile. The impact of electrification becomes visible in the demand profile when comparing summer *vs.* winter – shown in Fig. 2 – as increased seasonality and "peakiness". The resulting peak demand of the central electrification scenario increases from 52 GW in 2020 to 81 GW in 2050. The total electricity demand in 2050 for the central electrification scenario comprises 235 TWh of baseline power demand, 90 TWh of added demand from EVs, and 58 TWh of added demand from the heating sector. Electrification of the industrial sector is excluded in this analysis.

2.2. Capacity expansion and retirement

The remaining lifetime of existing capacity is estimated using the plant commissioning year from BEIS data (UK BEIS, 2019a). Capacity is retired at the end of its normal lifetime, but early retirement is not permitted, in order to reduce the degrees of freedom and thus solution time. The capacity expansion is limited by maximum build rate constraints for individual technologies. These constraints are a substitute for a description of the hurdles in the system which restrict large-scale deployment of technologies. Reference case build rates are based on historical capacity deployment in order to provide a reasonable starting point for analysis (see Table A.1 in the appendix) (Heuberger et al., 2017a; UK BEIS, 2019a). In addition to existing technologies (coal, bioenergy, CCGT, OCGT, solar, onshore & offshore wind, interconnection, pumped hydro storage), CCGT-CCS, BECCS, battery storage, and power-to-methane storage are included in the technology portfolio. For novel technologies, build rate limits are estimated based on similar technologies. Scenarios are run with relaxed build rate constraints to study the impact of allowing higher build rates on the results.

2.3. Costs

Technology CAPEX are based on a combination of BEIS assumptions and literature review (Bhave et al., 2017; European Association for Storage of Energy (EASE)/European Energy Research Alliance (EERA), 2017; IEA, 2017; UK BEIS, 2016) and can be found in Table A.1 in the appendix. Since technology learning has been evaluated in previous work (Heuberger et al. (2017a)), it is neglected in this study. The OPEX includes start-up OPEX, no-load OPEX, fixed variable OPEX, and the carbon price for emitters. Fuel prices are contained in Table A.3.

2.4. System reliability

ESO-X includes constraints for system inertia and reserve requirements. We assume these constraints remain the same regardless of system design, *i.e.*, the demands for system stability are identical for systems with high shares of intermittent capacity or firm capacity. The lower bound on the system inertia is 100,000 MWs (Heuberger et al., 2018; National Grid plc, 2016), and the reserve margin is set to 4%. Onshore and offshore wind technologies are assumed to be deployed with synthetic inertia providing technologies (Heuberger, 2018). Unmet demand is penalised by the value of lost load (40,000 £/MWh) (Flamm and Scott, 2014; Heuberger et al., 2018). Plant flexibility is constrained via up-time and down-time constraints. Interconnection, a contributor to balancing intermittency, is included in the model. Both model features are detailed in Heuberger et al. (2017a).

2.5. Availability of renewable energy

Full-hourly country average profiles for the capacity factors of onshore wind, offshore wind, and solar power for 2016 are obtained from *renewables.ninja* (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). These profiles are assumed to remain constant throughout the planning horizon. We recognise that capacity factor profiles, and with them optimal renewables capacity in the system, may

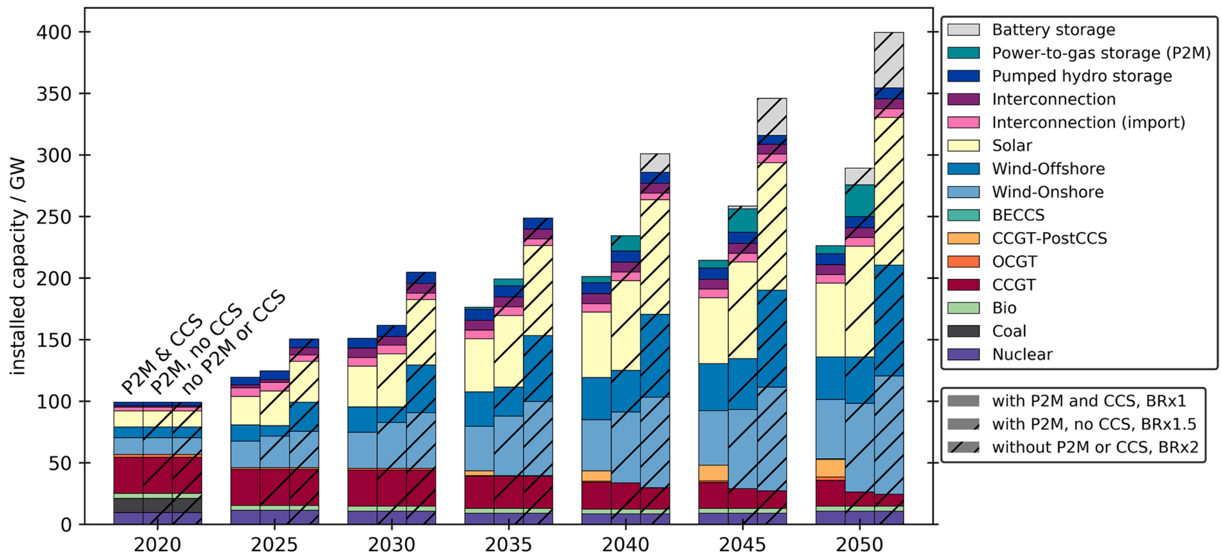


Fig. 4. System design for scenarios with P2M and CCS, with P2M without CCS, and with neither. CCGT and Bio capacity in 2050 in scenarios without CCS is unused. The presence of P2M reduces the capacity stack compared to the scenario with only renewables and short-term storage. When adding CCS, even less generation capacity is needed, and P2M capacity is replaced with CCGT-CCS and CCGT for balancing seasonality.

change for different years and with increased renewables penetration. However, sampling from multiple years of data and analysing the magnitude of this impact is beyond the scope of this study.

2.6. Storage technologies and power-to-gas storage

Pumped hydro storage, battery storage, and power-to-gas storage are included in this analysis. Table A.2 in the appendix summarises relevant technology data. The parametrisation of the power-to-gas technology is based on the work of (Yao et al., 2019). They suggest that power-to-methane (synthetic natural gas (SNG)) may be more cost-effective compared to power-to-hydrogen, when considering the complete balance of chemical conversion, storage, and re-electrification. Consequently, power-to-methane (P2M) is used as power-to-gas technology for inter-seasonal storage in this work. A schematic representation of the process is shown in Fig. 3. The charging process of the storage comprises electrolysis to form H_2 and the Sabatier reaction converting it to SNG. The SNG is then stored in a salt cavern, and combusted in a combined cycle gas turbine (CCGT), which represents the discharging process. In *case A* of Fig. 3, all carbon in form of CO_2 is recycled via the atmosphere and re-captured using direct air capture (DAC), whereas *Case B* incorporates a carbon capture (CC) unit to recover the majority of the CO_2. All electricity requirements are satisfied with grid electricity, heat requirements are met by conversion of CH_4, energy requirements of the capture unit are covered by the CCGT. Almost the entire technology cost is contributed by the power conversion systems, with the storage system representing only $\approx$ 10% of the total cost. For technological details concerning the storage technology, the reader is referred to Yao et al. (2019). Both cases are relatively close with regard to efficiency and cost. Case A may be preferred due to the presence of fewer process units and reduced complexity, whereas case B may be optimal due to the smaller size of the potentially expensive DAC unit. For the main runs, we assume 1700 MW charging power and 500 MW discharging power per unit, 8400 h of storage duration, and a round-trip efficiency of 29%. This can represent both case A and B, or a similar power-to-gas-to-power technology. Results therefore apply to both configurations. It is assumed the storage site is taken into operation once at the beginning of its lifetime and remains available thereafter. Therefore, all storage levels refer to the working capacity.

Storage is assumed to be flexible, *i.e.*, able to switch between charging and discharging as well as ramping up and down, below the time step of one hour. Given that the round-trip efficiency of short-term storage options is significantly higher than that of seasonal storage, one point which will be important to consider is the potential for a “merit order” for energy storage on this basis. However, it is not yet obvious which technical characteristics will emerge as dominant in this context. Ultimately, the purpose of energy storage technology is to absorb excess power when it is available, and discharge that power to meet demand in a timely fashion. In this context, charge and discharge rates have the potential to be of significant importance in establishing the role of these technologies in the energy system, and may well exhibit complex trade-offs against capital cost and round trip efficiency. Simply put, no matter how cost-effective or efficient an energy storage technology is, if it cannot provide the services required of it in a timely fashion, its potential to add value to the system may well be greatly diminished. Consequently, this aspect is explored in detail.

2.7. Bioenergy

Previous work on bioenergy has demonstrated the impact of embodied emissions of biomass on its carbon balance and resulting abatement potential (Fajardy et al., 2018; Fajardy and Mac Dowell, 2017; 2018; Tanzer and Ramirez, 2019). In this work, biomass is therefore assumed to have a non-zero amount of embodied emissions (0.25 t-CO_2/t) associated with the cultivation, harvesting, processing, and transportation of biomass (Zhang et al., 2020). The amount is kept constant over all planning periods by default. This is due to the fact that while the bioenergy infrastructure may decarbonise leading up to 2050, one also moves up the biomass supply curve with increased utilisation of bioenergy, potentially using biomass sources with lower accessibility and larger carbon footprint. A full analysis of the impact of the trajectory which the embodied emissions of biomass may take over time is beyond the scope of this work and is left for future work.

In terms of biomass cost and availability, a UK-specific biomass supply curve is taken from Zhang et al. (2020) and comprises waste wood, forest residue, virgin biomass, municipal solid waste (MSW), crop residue, and imported biomass, detailed in Table A.4. This provides a representation of biomass utilisation in terms of feedstock type and availability.

Table 1
Total system cost (tsc), curtailment, power-to-gas storage (P2M) capacity in terms of output power and maximum energy stored, and unmet demand for different combinations of technology options and maximum build rate (BR) multipliers. The presence of P2M reduces curtailment and lost load substantially, adding CCS achieves further reduction of tsc.

			tsc	curtailment in 2050			P2M in 2050		unmet demand
			b£	TWh			GW	TWh	GWh
CCS	P2M	BR		solar	on-wind	off-wind			
✓	✓	1	237			0.83 (<1%)	6.4	3.6	
✓		1	240		0.54 (<1%)	15.4 (16%)			
✓	✓	1.5	228		0.02 (<1%)	1.3 (1.7%)	9.3	6.0	
✓		1.5	232	0.007 (<1%)	8.8 (6%)	12.9 (26%)			
	✓	1.5	233				25.9	12.9	4.3
		2	458	0.58 (<1%)	44 (20%)	193 (69%)			1630

2.8. *Carbon price and carbon target*

We consider a carbon price which ramps up from 18 £/t-CO_2 to 236 £/t-CO_2 in 2050 (UK BEIS, 2018b). A net zero carbon target in 2050 is imposed since previous work suggests a carbon price does not suffice to reach net zero (Daggash and Mac Dowell, 2019a). No intermediate carbon budgets are enforced as to not bias the results with regard to the optimal trajectory.

3. Results

3.1. *Deployment and role in the system*

This analysis proceeds *via* a scenario-based approach where we discuss

- a system with neither power-to-gas storage (P2M) or CCS,
- a system with P2M, without CCS,
- and a system with both.

Fig. 4 shows the capacity stack arising for each scenario. Total capacity decreases when P2M and CCS are added to the system. Build rate constraints are relaxed for systems without CCS in order to maintain grid reliability. The performance indicators in Table 1 suggest that the presence of P2M leads to a reduction in curtailment almost to zero. Without CCS in the system, more P2M is needed to balance seasonality. A significant amount of storage volume is achieved through P2M, ranging up to 12.9 TWh, or 3.4% of total power demand in 2050. The lowest system cost is achieved when CCS and P2M are combined, and build rate constraints are relaxed.

A key emerging characteristic of systems without the option of either CCS or P2M is that renewable capacity must be deployed at rates which significantly exceed that which has been historically achieved. In the scenario shown here, build rates are double the historical precedent, reflecting a very significant and sustained policy commitment to this effect. This scenario precipitates the significant deployment of both renewable capacity and large amounts of short-term storage. Nevertheless, as shown in Table 1, 1.63 TWh, or 0.43% of demand is unmet, and up to 69%, or 193 TWh of off-shore wind power are curtailed.

A system with P2M but without CCGT-CCS and BECCS will also require higher than historical build rates in order to decarbonise while maintaining demand satisfaction. In the scenario shown in Fig. 4, 1.5× baseline build rates are allowed. The absence of a NET precludes the operation of low-carbon dispatchable power (CCGT-CCS & bioenergy) and unabated peaking plants (CCGT & OCGT). This means all differences in renewables supply and power demand are satisfied by interconnection and storage. In the case of the UK, 26 GW of P2M are used in the system in 2050, with a maximum storage level of 13 TWh. This indicates that in a high-renewables system, seasonal storage will be key to maintain system reliability. In this scenario, the amount of storage volume required cannot be provided by short-term storage alone.

It is important to recognise that the optimum system design with CCS and P2M still comprises a high share of intermittent renewable generation. Here, renewable energy is complemented by CCGT-CCS, interconnection, pumped hydro, and inter-seasonal storage (P2M), with residual carbon emissions being mitigated via BECCS. Importantly, the availability of BECCS allows the retention of existing CCGT assets which, owing to their age, are not retrofitted with CCS, but are now used as peaking plants, thus avoiding both early retirement of CCGT and the deployment of additional, new, capital assets. In this scenario, the system can reach net zero by 2050 under historical build rate constraints. These observations serve to underscore and emphasise the value of a

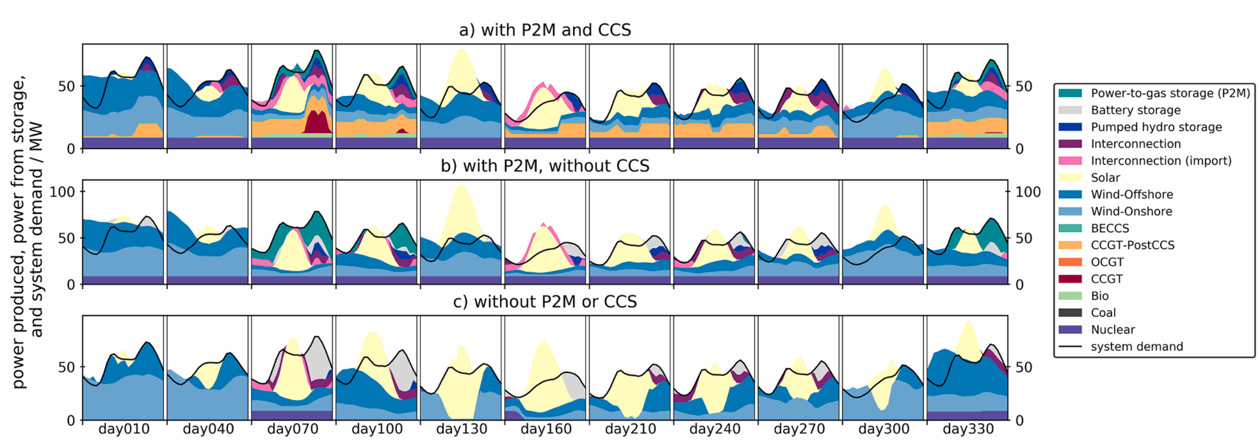


Fig. 5. Excerpts of full-hourly dispatch schedules in 2050 (one day every 30 days) for scenarios a) with P2M and CCS, b) with P2M, and c) without either. When power exceeds system demand, the excess power is fed to storage. Peak demand is met with a) CCGT, CCGT-CCS and P2M, b) P2M, and c) battery storage. High levels of renewable power are integrated in each scenario. c) requires high levels of curtailment, whereas in a) and b) renewable power can be used to charge P2M storage.

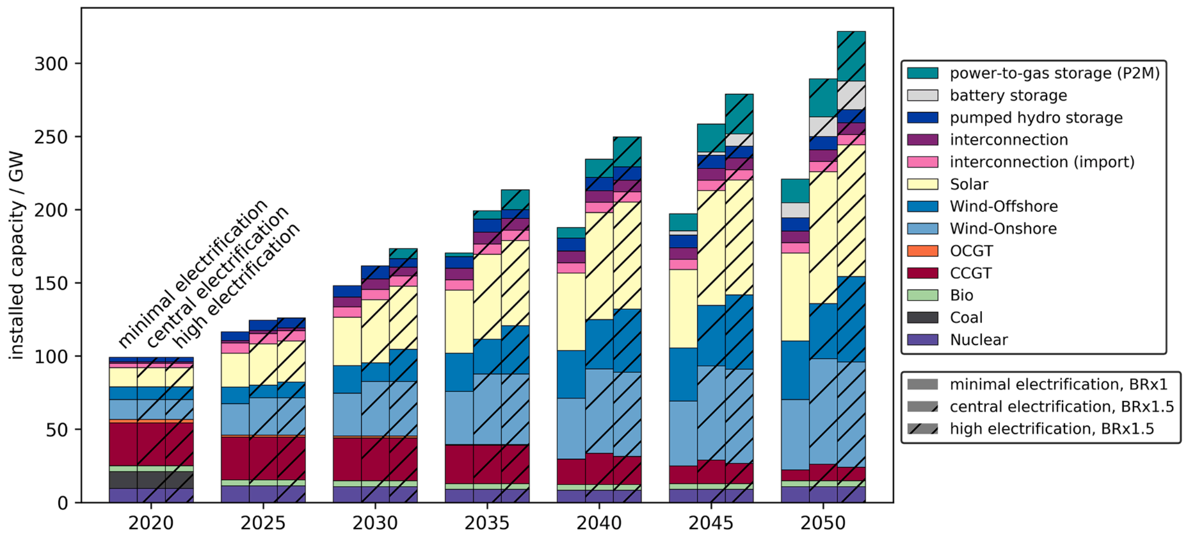


Fig. 6. Capacity deployed in a no-CCS scenario for minimal, central, and high electrification. Qualitative structure of the system remains the same. More generation and storage capacity is needed, and build rates are higher for central and high electrification.

technology agnostic portfolio strategy when pursuing an ambitious decarbonisation agenda.

Inspection of the dispatch schedules for the three scenarios illustrated in Fig. 5 gives further insight into the role of individual technologies within the system. A sample of one day every 30 days out of the full year is shown, illustrating how the system responds across a range of weather patterns and demand levels. In the scenario without either P2M or CCS (Fig. 5c), most of the demand has to be met by wind, solar, and short term storage. However, the storage duration of the storage options limits the shifting of renewable power produced, and large amounts of power remain unused. Arguably, this power could be utilised by renewable fuel production concepts, however it is questionable how much these potential concepts could cope with a very intermittent and uncertain power supply (Daggash et al., 2018; Ganzer and Mac Dowell, 2020). Despite the large amount of storage, some demand remains unserved, potentially leading to damaging impacts on the economy (Patrizio et al., 2020). Notably, the utilisation of the existing nuclear capacity in 2050 is also reduced dramatically in the system. This indicates that not only the utilisation of renewables themselves but also the utilisation of zero-carbon stable generation is decreased. While this may not cause issues for maintaining system reliability, it shows that a sub-optimal system design could prohibit the optimal use of existing assets. This observation is consistent with previous work on the value of low-carbon dispatchable technologies (Pratama and Mac Dowell, 2019).

A system with seasonal storage (P2M), shown in Fig. 5b), seems to allow more renewable power to be transferred to storage. Curtailment is reduced to almost zero, which means that the capacity built can be utilised optimally. The dispatch shows that short term storage is used whenever possible, *i.e.*, when enough power is produced on the same day, such as day 160 in Fig. 5, owing to the higher round-trip efficiency. When shifting the power within a 24 h period does not suffice, long-term storage is utilised, such as in day 70. Long-term storage not only provides power but also reserve and inertia. Inspection of the storage level throughout the year indicates that the increasing seasonality in the system, introduced by the combination of intermittent renewable energy capacity and electrification, could further increase the value of long-term storage. The quantity of stored energy increases over the summer, with the maximum storage level reached in October (day 300). It then decreases as heat demand increases and the availability of solar power reduces. The availability of wind power typically remains strong during the autumn and winter months, and, during this period, a substantial fraction of wind energy is directed to long term storage. Ultimately, reserves of stored energy reach a minimum in April (day 100).

The exact storage level is, of course, a function of the individual shares of the renewables energy sources, the capacity factor profile of the year, and the level of electrification of other sectors of the economy. The effective storage duration utilised by the model is 500 h, or 21 days (measured by output power). In other words, the system in this scenario optimally includes P2M with enough storage volume to discharge continuously over multiple weeks. This service cannot be provided by other storage options such as pumped hydro storage, battery storage, or compressed air storage, *etc.* (Schaaf et al., 2014)

In a system with all the options including negative emissions (BECCS), low-carbon dispatchable power (CCGT-CCS) and inter-seasonal storage (Fig. 5a), the cost optimal combination of technologies to achieve zero carbon depends on the day and season. Renewable energy contributes most of the power on days with high availability, with surplus fed into storage. By 2050, BECCS has evolved to operate as a baseload asset, providing value through both power generation and also negative emissions. CCGT-CCS provides load-following throughout the year, whereas CCGT is exclusively utilised as a peaking plant. The flexibility provided by BECCS and low-CAPEX CCGT significantly reduces the quantity of required capacity – this can be observed on day 70 in the dispatch schedule. Delivering an equivalent amount of power from CCGT-CCS or renewables would add considerable cost to the system (Heuberger et al., 2016). Power-to-gas storage reduces the level of renewables curtailment to zero, and contributes to the power mix on high demand days. The evolution of the storage level over the year is as previously described. Notably, where P2M is available, it is deployed in greater amounts than battery storage despite the higher CAPEX and lower round-trip efficiency, indicating the increased need for inter-seasonal as opposed to short-term storage. Thus, the value of balancing inter-seasonal variations appears greater than the service of balancing daily fluctuations.

3.2. *Impact of electrification*

When comparing the scenarios with P2M without CCS, and with both, for minimal, central, and high levels of electrification, the qualitative structure of the system design does not change. The amount of capacity needed naturally increases with the amount of electrification, with P2M deployed in every scenario. Using our estimates, it seems high electrification scenarios with CCS, and minimal electrification without CCS with P2M, could be achieved under baseline build rate constraints, but in more ambitious scenarios, build rates had to be increased, as shown in Fig. 6. The challenge associated with greatly increasing build

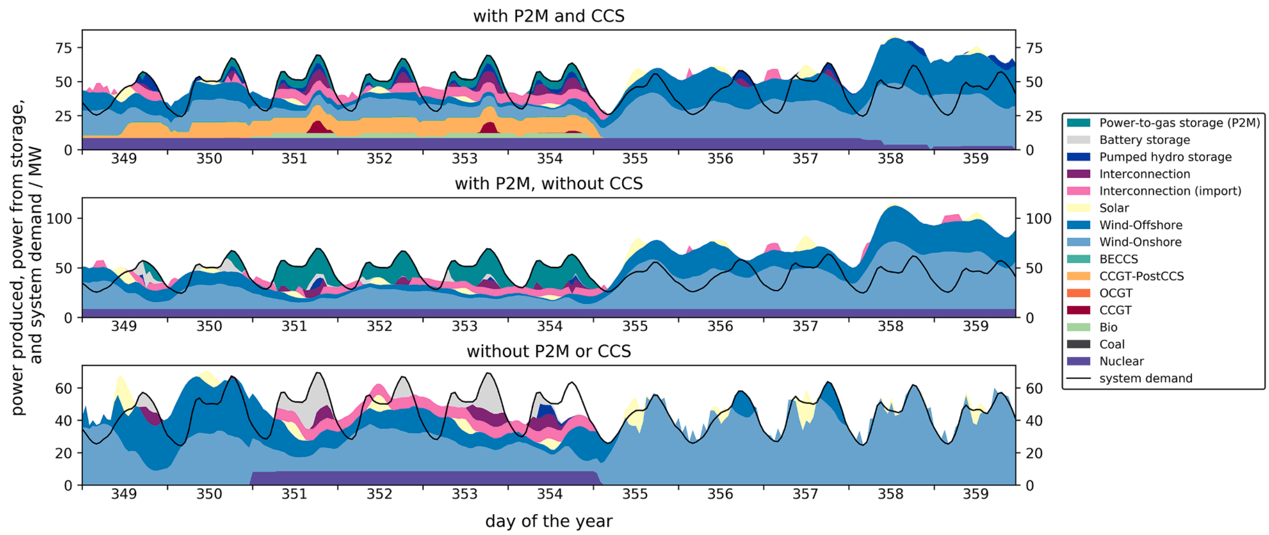


Fig. 7. Dispatch schedules for systems during a period of low wind and solar availability. It shows CCGT-CCS running baseload and CCGT being utilised (top), P2M discharging every day over four days (middle), as well as a day where demand cannot be met due to lack of seasonal storage or dispatchable power (bottom). This sequence may function as a bottleneck for the system design.

rates should not be underestimated; this parameter consistently emerges as being decisive for the viability or otherwise of a great range of decarbonisation strategies, but delivering this result in practice requires the substantial and sustained upward flexing of existing supply chains – not a trivial exercise. The EVs in the system might act as energy storage, smoothing out the demand slightly, decreasing peak demand and thereby reducing the required power generation capacity. However, they can only act as daily storage – which does not address the need for dispatchable power in a seasonal system.

We further examine the difference in model results for the demand

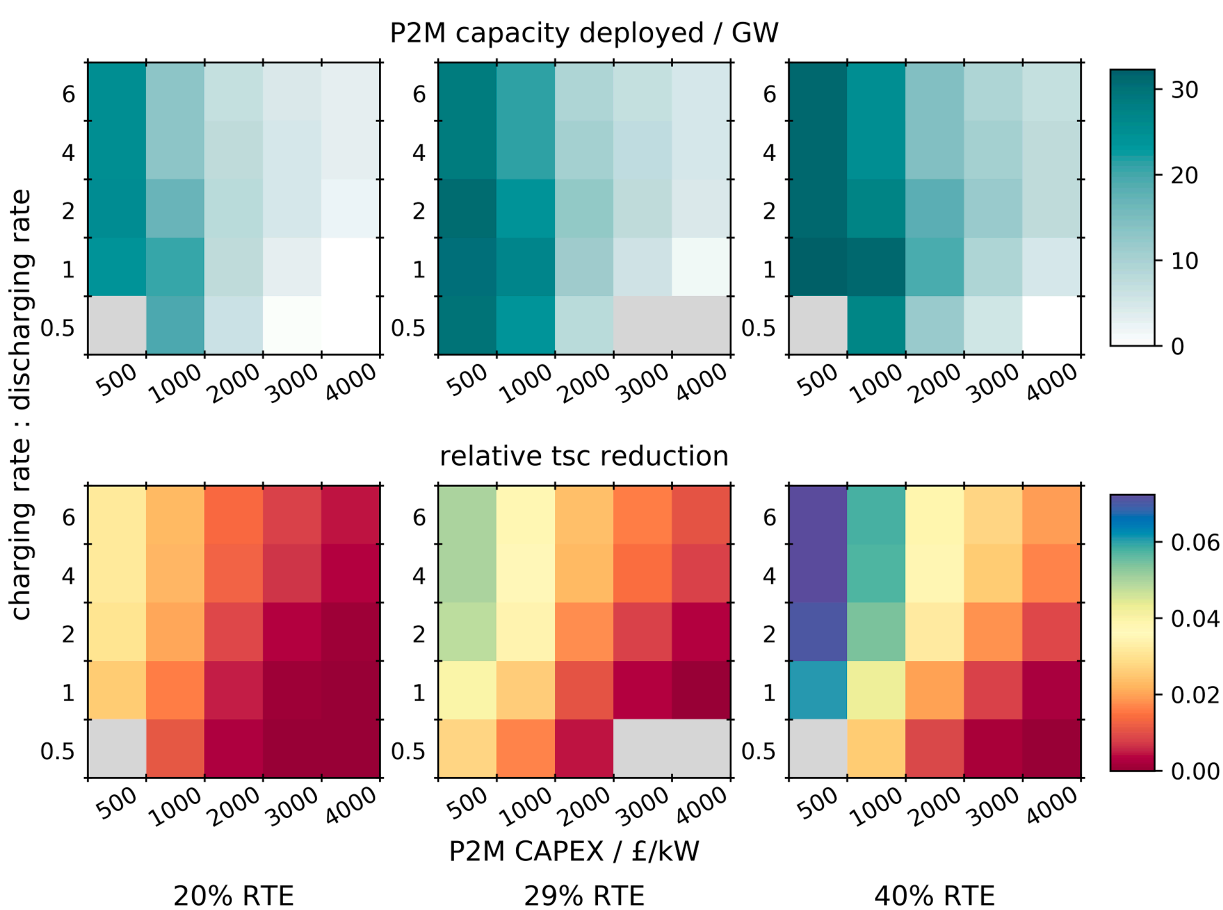


Fig. 8. Power-to-gas (P2M) capacity deployed (measured by output power) and total system cost (tsc) reduction relative to a system without P2M for varying round trip efficiency (RTE), and charging to discharging power ratio. Grey indicates model did not converge in allocated time. P2M is deployed even at low RTE and low charging rate. Higher charging rate and RTE reduce tsc, however benefits may be offset by higher CAPEX.

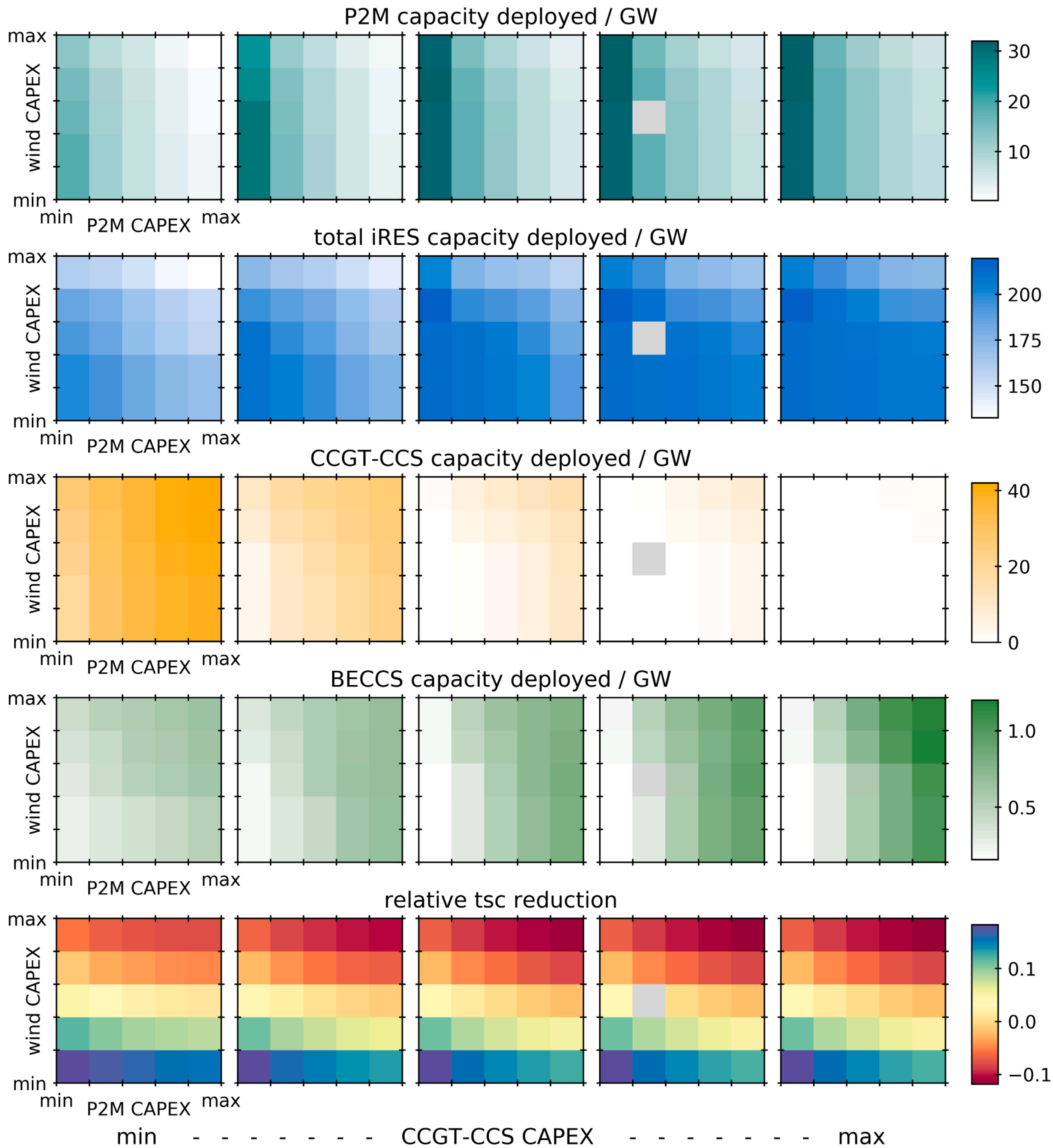


Fig. 9. Results of the sensitivity analysis. Colours indicate installed capacity in 2050 for key technologies and total system cost (tsc) for varying onshore-wind, CCGT-CCS, and power-to-gas storage (P2M) CAPEX. Build rate limits set to 2× historical values for all cases. Grey indicates model did not converge in allocated time. Higher CCGT-CCS CAPEX leads to more deployment of renewable generation capacity and storage. P2M CAPEX influences both P2M capacity as well as optimal capacity of CCGT-CCS and iRES. Wind CAPEX has the largest influence on tsc but less impact on the optimal design.

profile with and without electrification. Specifically, we compare the profile used in this work with the 2015 power demand profile, inflated 1% per year, which approximates the change in total power demand but neglects the evolution of the shape of the demand curve. We find that while the inflated profile equals a slightly higher total annual power demand, the model determines a slightly smaller capacity stack. In a scenario predicated on the availability of CCS, it is specifically the amount of dispatchable generation which is significantly higher, when the profiles with electrification are used. This could be a result of the impact of the seasonality and the peak demand in particular. It could indicate that the amount of flexible capacity required in the system increases with the level of electrification.

3.3. Bottlenecks

For the central electrification scenario, we evaluate the potential for periods of low availability of renewable energy to become bottlenecks for system design. First, the capacity factor profiles of solar and onshore wind are searched for periods of consecutive days with low capacity factor in one or both of the energy sources. Subsequently, the dispatch schedule for these periods is analysed.

The results indicate that weeks with low solar availability alone do not seem to introduce particular challenges in meeting demand, as there is enough wind availability to compensate. Lows during the day are addressed with interconnection and short-term storage, short-term storage and P2M, or CCGT-CCS and storage, depending on the scenario. However, weeks with low wind availability seem to present greater difficulties for the system, even when solar energy is available. Either load-following CCGT-CCS or larger amounts of storage are required to complement the available renewable power. Unsurprisingly, it is a period where the availability of both solar and wind are low and demand is high that becomes constraining to the system. Fig.7 shows the dispatch schedules for the three scenarios during a bottleneck period. Using the iRES availability data discussed previously, we identify a period of four days in winter when all capacity factors are low, yet demand is relatively high. In the scenario without P2M or CCS, this is when a significant amount of demand goes unmet. For three days, interconnection and short-term storage are sufficient to satisfy demand. On the fourth day, storage levels are depleted, and demand cannot be met in full. When P2M is added, it can discharge varying amounts throughout the period due to its long storage duration, supplying around a third of the total power. In the CCS scenario, unabated CCGT are used during this period in addition to CCGT-CCS, P2M, and interconnection. Increasing electrification of the economy may exacerbate the gap between power demand and availability and present similar challenges to the system more frequently.

This result ties into larger questions in energy systems modelling, design of energy systems, and policy for capacity expansion. A strong fluctuation of power capacity required depending on the day and season may result in a great variation in the utilisation of different dispatchable generators or inter-seasonal storage. However, since unmet demand and associated economic loss are to be avoided, the presence of this flexible capacity in the system could be crucial. The distinction between base-load, load-following, and peaking plants for dispatchable capacity may impact not only the design and operation of these plants but also inform the policies needed for the transition.

3.4. Importance of charging rate and round trip efficiency

In addition to capital cost and round trip efficiency, grid-scale energy storage technologies are further characterised by the charging and discharging rates. Greater charging rates implies a larger power-to-fuel component, *i.e.*, greater electrolyser, DAC and sabatier capacity, and thus there is a likely implication to capital cost. Given the low TRL of this technology, and its potential importance to future energy systems, it is therefore instructive to evaluate the impact of these technology parameters on the P2M capacity deployed, and overall system value, articulated here *via* the total system cost (tsc). These results are presented in Fig. 8. As can be observed, higher charging rates and round trip efficiencies lead to a reduction in total system cost. There are, however, diminishing returns for increases in charging ratio. This means that a ratio of higher than 2 does not yield much more reduction in system cost. The additional power-to-fuel components of the technology cannot be used and the storage would operate sub-optimally.

In the context of total system cost, depending on the charging ratio and round-trip efficiency, one can compare cases where technological advances (improved charging rates and increased round trip efficiency) come at the cost of a greater capital intensity. This kind of analysis is important for both setting goals for technology innovation and also defining the value proposition for public investment into improved technologies. As can be observed from Fig. 8, improved round trip efficiency or charging rates do not obviously provide value at the system level, if they come at the cost of significantly increased capital cost, thus the viable budget for improving this technology may be limited. Hence, a less costly technology with lower charging rate and round-trip efficiency may provide more value to the system than expensive technology with ostensibly improved performance when viewed in isolation.

It is worth noting that the relatively low round-trip efficiency of the power-to-gas technology does not prevent it from adding value to the system. This may be primarily due to the fact that the power being subjected to the round-trip efficiency comes at near-zero marginal cost in conventional terms, though, the capital intensity of this capacity has a cost. Thus, in the context of a high renewable energy plus storage paradigm, minimising the capital cost of power generation is key. By considering the value proposition of future energy systems through this lens, the limits of evaluating technologies in isolation comes into focus, as does the value of adopting a whole-systems perspective. While it might seem intuitive that a round trip efficiency of 20% would be too low for a storage technology to have value, our results suggest that in a system characterised by a high penetration of intermittent renewable energy sources, it could provide substantial value, as long as this service is available at a low capital cost.

3.5. Synergies of P2M with other technologies

Building on the argument in the foregoing section, it is thus key to understand how advances in one technology systemically impact the deployment of others. Thus, in Fig. 9 the capacity in 2050 of P2M, wind power, CCGT-CCS, BECCS, as well as total system cost reduction, are evaluated as a function of capital cost. Large cost ranges are deliberately used for this analysis, with minimum costs estimated on the basis of a hypothetical limiting scenario, *i.e.*, CCGT CAPEX for CCGT-CCS, CCGT and natural gas storage for P2M, and the lowest historical value for onshore-wind. It is important to emphasise that we are not suggesting that these limits are likely, or even possible – they simply provide context for this thought experiment. The maximum values represent 2× the central value for P2M, and 1.5× central value for CCGT-CCS and onshore wind. Exact values are presented in Table A.5 of the appendix . Finally, it is important to recognise that this evaluation is intended to be an exploration of how technologies interact with each other rather than an assertion of the likelihood or plausibility of specific scenarios.

The results illustrate a strong correlation link between the deployment of renewables and P2M. Lower P2M CAPEX appears to enable higher amounts of renewables, the same is true to a certain extent in reverse. Furthermore, wind CAPEX has greater influence on the total system cost than P2M or CCGT-CCS CAPEX due to its large share in the capacity stack. The value of renewables and storage depends on their CAPEX and combined deployment, whereas the CAPEX of CCGT-CCS hardly impacts the system cost. This is plausible considering intermittent renewables and storage are CAPEX-dominated technologies, whereas CCGT-CCS requires continuous operating expenditure. Thus, in the context of this energy system archetype, cost reduction of wind power ought to be emphasised.

It is also evident that the combination of renewables plus seasonal storage and low-carbon dispatchable power provide similar functions and thus may compete in the system. Depending on the CAPEX of the three technologies, there are cases dominated by P2M, and cases dominated by CCGT-CCS. This suggests that when the deployment of low-carbon dispatchable power is limited, seasonal storage becomes crucial, and *vice versa*. The optimal combination of inter-seasonal storage and CCS may depend on the country, the seasonality of its power demand, its endowment of renewable energy resources and infrastructure.

Importantly, the flexibility provided by BECCS appears valuable in almost all scenarios. When all technologies are assumed to be expensive, more BECCS is deployed to offsets emissions from the required CCGTs. Only when P2M is assumed to be at its lower bound of cost, and CCGT-CCS it at its upper bound does BECCS deployment minimise.

The effects of technology learning can be estimated to some degree *via* this sensitivity analysis. Cost reductions in onshore wind, for instance, can increase the optimal capacity of onshore wind and inter-seasonal storage in the system and reduce total system cost.

In conclusion, the optimal system design depends on a range of factors. High shares of intermittent renewable energy can be complemented by inter-seasonal storage and low-carbon dispatchable power. A diverse system with many options for power generation and storage - renewable energy, low-carbon dispatchable generators such as

CCGT-CCS/H_2/bioenergy, flexible high-carbon, negative emissions, daily and seasonal energy storage – would appear to minimise cost under a net zero constraint. Such a system could also be the most resilient to future uncertainty in technology cost, demand profiles, availability of renewable power, *etc.*

4. Conclusions and future work

We have explored the potential of power-to-gas-to-power as an archetypal inter-seasonal energy storage technology in a UK-type power system. Systems with and without CCS and inter-seasonal storage were evaluated under a range electrification scenarios. We found that inter-seasonal storage can provide value despite its high CAPEX and low round-trip efficiency. Instead, its value proposition is a function of the availability of renewable energy that would be otherwise curtailed. This is only material at very high deployment levels – and balance of the portfolio of technologies allowed in the system (Daggash et al., 2018). In the absence of low-carbon dispatchable power and negative emissions, inter-seasonal storage may emerge as a critical technology to ensure grid resilience. In combination with both, it may maximise the utilisation of renewable energy and reduce the total power generating capacity required to deliver a net zero electricity system. Through this analysis, we identified the ratio of the charging-to-discharging rates as a key technology parameter. This insight can be used by technology developers to better design power-to-gas technologies so as to maximise the provision of value to the system.

Our results further suggest that a diverse system will prove the most resilient to uncertainties and increase the likelihood of reaching carbon targets. Further work is needed in evaluating the potential emergence of a "merit order" within energy storage technologies, and the position of inter-seasonal storage in this context, and further quantifying the value of grid flexibility and resilience they provide. Additional critical questions for future work include how to incentivise the deployment of technologies which aid decarbonisation in different ways, and how to define criteria for the set of services they need to provide.

This work provides further evidence that sector-coupling, *i.e.*, the linking of individual sustainable and renewable energy vectors (electricity, heat, fuel), could represent a critical element in the decarbonisation of energy systems with significant seasonality in demand. The ability to store renewable energy in dense energy carriers enables the integration of renewable power in other aspects of the economy. Gaseous and liquid energy storage media allow the cost of intermittency of wind and solar power to be borne by central pieces of infrastructure, such as the gas grid, and achievements in the decarbonisation of power to be passed on to heat and transport, which have proven harder to decarbonise.

Results were obtained using an archetype of power-to-gas storage as inter-seasonal storage which recycles CO_2 *via* a carbon capture and a direct air capture unit. This is not necessarily the best performing configuration of power-to-gas storage, other storage media such as hydrogen and other configurations may emerge as superior. The sensitivity analysis suggests however that this category of storage can provide value across a range of technology parameters. Further, the results remain valid regardless of the specific long-term storage technology, it is the role in the system of balancing seasonal intermittency which needs to be filled. This study shows that there can be a place in the system for inter-seasonal storage with relatively low RTE and high storage duration.

A limitation of this work arises from the use of one year of demand and capacity factor data, capturing seasonal effects, but neglecting inter-annual variation. Optimal results likely vary for different years, therefore including multiple years in the analysis could produce a more robust system design (Zeyringer et al., 2018). The demand profile used in this work incorporates a fixed demand from the electrification of heat and transport. EVs, household level energy storage, and the industrial sector could, however, have the potential of providing demand side management, and smoothing the demand profile, reducing peak demand and the capacity required in the power sector. Exploring this is another possible direction for future work. Moreover, the UK was used as case study, hence there is limited applicability in other countries. It is expected that P2M could have potential in countries with similarly seasonal power demand and renewables availability. In countries with limited access to CO_2 storage sites, inter-seasonal storage may be required to balance renewable energy – this would have to be evaluated for the country in question. Furthermore, disaggregating the inter-seasonal storage technology by power-to-storage, storage, and storage-to-power, instead of using one archetype of storage, may provide further insight into optimal configurations (Sepulveda et al., 2021). Another aspect not currently captured in the model is technology learning. It is estimated to have effects similar to those observed in the sensitivity analysis, but future analysis is needed to confirm this. Lastly, the assumption of perfect foresight over the year ensures optimal operation of the storage technologies. Modelling inter-seasonal storage with limited foresight could reveal more realistic charging/discharging profiles.

Finally, we would emphasise the value of evaluating technologies in the context of their services to the whole energy system as opposed to in isolation as has traditionally been the convention. Considering the technologies' portfolios of services provided to the system, the relative scarcity of those services in a given scenario, and a set of potential costs and drawbacks (economical, environmental, social) enables a movement beyond zero-sum technology advocacy. Bridging between techno-economic assessment of novel generation and storage technologies and system-level modelling and thinking identifies new perspectives and informs priorities for future work. A future energy system comprised of a broad portfolio of technologies and energy vectors, each with its individual competence, may evolve as the most capable to achieve the transition with the highest amount of economic, ecological, and social benefits.

CRediT authorship contribution statement

Caroline Ganzer: Conceptualization, Methodology, Visualization, Investigation, Writing – original draft, Writing – review & editing. **Yoga W. Pratama:** Methodology. **Niall Mac Dowell:** Conceptualization, Supervision, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

Caroline Ganzer gratefully acknowledges her studentship sponsored by TotalEnergies.

Yoga W. Pratama (LPDP ID: 201711220111875) thanks the Indonesia Endowment Fund for Education (LPDP) for funding his PhD study.

The authors would like to thank the *Open Power System Data (OPSD)* platform (Open Power System Data, 2019) for providing openly available and accessible data.

Appendix

Table A.1
Central technology CAPEX and maximum build rate assumptions. CAPEX data from (Bhave et al., 2017; European Association for Storage of Energy (EASE)/-European Energy Research Alliance (EERA), 2017; IEA, 2017; UK BEIS, 2016; Yao et al., 2019); build rates based on (Heuberger et al., 2017a; UK BEIS, 2019a).

technology	central CAPEX £/kW	baseline maximum build rate MW/yr
Nuclear	5270	360
Coal	1550	600
Bio	1860	300
CCGT	565	900
OCGT	846	500
Coal-PostCCS	4030	600
CCGT-PostCCS	2060	900
BECCS	4250	900
Wind-Onshore	1430	1600
Wind-Offshore	2770	1500
Solar	606	2000
Interconnection	1000	1000
Pumped hydro storage	1220	600
Battery storage	1800	1500
Power-to-methane storage	2400	900

Table A.2
Central storage technology data (European Association for Storage of Energy (EASE)/European Energy Research Alliance (EERA), 2017; UK BEIS, 2016; Yao et al., 2019).

	PHSto	battery	P2M
round trip efficiency	75%	85%	29%
storage duration	5 h	5 h	8,400 h
input power : output power ratio	1	1	3.4
self-discharge rate	0	0.005%/h	0

Table A.3
Central fuel prices [£/MWh] (UK BEIS, 2019b).

	natural gas	coal	nuclear
2020	16.6	7.8	5.2
2025	19.3	7.8	5.2
2030	21.7	7.9	5.2
2035	21.7	7.9	5.2
2040	21.7	7.9	5.2
2045	21.7	7.9	5.2
2050	21.7	7.9	5.2

Table A.4
Biomass supply curve (Zhang et al., 2020).

biomass type	max. availability [TWh/yr]	cost [£/MWh]
waste wood	17	16
forest residue	7	20
indigenous virgin miscanthus	98	23
crop residue	41	25
municipal solid waste	35	27
import (US)	800	28
import (EU)	800	36

Table A.5
CAPEX ranges for sensitivity analysis (International Renewable Energy Agency (IRENA), 2017; UK BEIS, 2016; Yao et al., 2019).

£/kW	P2M	CCGT-CCS	onshore wind
min	530	565	606
low	1460	1310	1020
central	2400	2055	1430
high	3590	2570	1790
max	4780	3080	2150

References

Akinyele, D.O., Rayudu, R.K., 2014. Review of energy storage technologies for sustainable power networks. Sustain. Energy Technol. Assess. 8, 74–91.

Beaudin, M., Zareipour, H., Schellenberglabe, A., Rosehart, W., 2010. Energy storage for mitigating the variability of renewable electricity sources: an updated review. Energy Sustain. Dev. 14 (4), 302–314.

Bhave, A., Taylor, R.H., Fennell, P., Livingston, W.R., Shah, N., Mac Dowell, N., Dennis, J., Kraft, M., Pourkashanian, M., Insa, M., et al., 2017. Screening and techno-economic assessment of biomass-based power generation with CCS technologies to meet 2050 CO_2 targets. Appl. Energy 190, 481–489.

Bogdanov, D., Farfan, J., Sadovskaia, K., Aghahosseini, A., Child, M., Gulagi, A., Oyewo, A.S., Barbosa, L.d.S.N.S., Breyer, C., 2019. Radical transformation pathway towards sustainable electricity via evolutionary steps. Nat. Commun. 10 (1), 1–16.

Borozan, S., Evans, M.P., Strbac, G., Rodrigues, T., 2019. Contribution of energy storage to system adequacy and its value in the capacity market. 2019 IEEE Milan PowerTech. IEEE, pp. 1–6.

Brown, T., Schlachtberger, D., Kies, A., Schramm, S., Greiner, M., 2018. Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system. Energy 160, 720–739.

Chen, H., Cong, T.N., Yang, W., Tan, C., Li, Y., Ding, Y., 2009. Progress in electrical energy storage system: a critical review. Prog. Nat. Sci. 19 (3), 291–312.

Clegg, S., Mancarella, P., 2015. Integrated modeling and assessment of the operational impact of power-to-gas (P2G) on electrical and gas transmission networks. IEEE Trans. Sustain. Energy 6 (4), 1234–1244.

Daggash, H.A., Heuberger, C.F., Mac Dowell, N., 2019. The role and value of negative emissions technologies in decarbonising the UK energy system. Int. J. Greenh. Gas Control 81, 181–198.

Daggash, H.A., Mac Dowell, N., 2019. Higher carbon prices on emissions alone will not deliver the Paris Agreement. Joule 3 (9), 2120–2133.

Daggash, H.A., Mac Dowell, N., 2019. Structural evolution of the UK electricity system in a below 2 °C world. Joule 3 (5), 1239–1251.

Daggash, H.A., Patzschke, C.F., Heuberger, C.F., Zhu, L., Hellgardt, K., Fennell, P.S., Bhave, A., Bardow, A., Mac Dowell, N., 2018. Closing the carbon cycle to maximise climate change mitigation: power-to-methanol *vs.* power-to-direct air capture. Sustain. Energy Fuels 2 (6), 1153–1169.

De Sisternes, F.J., Jenkins, J.D., Botterud, A., 2016. The value of energy storage in decarbonizing the electricity sector. Appl. Energy 175, 368–379.

Díaz-González, F., Sumper, A., Gomis-Bellmunt, O., Villafáfila-Robles, R., 2012. A review of energy storage technologies for wind power applications. Renew. Sustain. Energy Rev. 16 (4), 2154–2171.

Dowling, J.A., Rinaldi, K.Z., Ruggles, T.H., Davis, S.J., Yuan, M., Tong, F., Lewis, N.S., Caldeira, K., 2020. Role of long-duration energy storage in variable renewable electricity systems. Joule 4 (9), 1907–1928.

Element Energy, 2019. Electric vehicle charging behaviour study. http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/04/20190329-NG-EV-CHARGING-BEHAVIOUR-STUDY-FINAL-REPORT-V1-EXTERNAL.pdf.

European Association for Storage of Energy (EASE)/European Energy Research Alliance (EERA), 2017. Joint EASE/EERA Recommendations for a European Energy Storage Technology Development Roadmap: 2017 Update.

Fajardy, M., Chiquier, S., Mac Dowell, N., 2018. Investigating the BECCS resource nexus: delivering sustainable negative emissions. Energy Environ. Sci. 11 (12), 3408–3430.

Fajardy, M., Mac Dowell, N., 2017. Can BECCS deliver sustainable and resource efficient negative emissions? Energy Environ. Sci. 10 (6), 1389–1426.

Fajardy, M., Mac Dowell, N., 2018. The energy return on investment of BECCS: is BECCS a threat to energy security? Energy Environ. Sci. 11 (6), 1581–1594.

Flamm, A., Scott, D., 2014. Electricity Balancing Significant Code Review - Final Policy Decision. UK Office of Gas and Electricity Markets (Ofgem).

Ganzer, C., Mac Dowell, N., 2020. A comparative assessment framework for sustainable production of fuels and chemicals explicitly accounting for intermittency. Sustain. Energy Fuels 4 (8), 3888–3903.

Geth, F., Brijs, T., Kathan, J., Driesen, J., Belmans, R., 2015. An overview of large-scale stationary electricity storage plants in Europe: current status and new developments. Renew. Sustain. Energy Rev. 52, 1212–1227.

Glenk, G., Reichelstein, S., 2019. Economics of converting renewable power to hydrogen. Nat. Energy 4 (3), 216–222.

Götz, M., Lefebvre, J., Mörs, F., Koch, A.M., Graf, F., Bajohr, S., Reimert, R., Kolb, T., 2016. Renewable power-to-gas: a technological and economic review. Renew. Energy 85, 1371–1390.

Gove, B., Williams, L.J., Beresford, A.E., Roddis, P., Campbell, C., Teuten, E., Langston, R.H., Bradbury, R.B., 2016. Reconciling biodiversity conservation and widespread deployment of renewable energy technologies in the UK. PLoS One 11 (5).

Guerra, O.J., Zhang, J., Eichman, J., Denholm, P., Kurtz, J., Hodge, B.-M., 2020. The value of seasonal energy storage technologies for the integration of wind and solar power. Energy Environ. Sci. 13 (7), 1909–1922.

Heard, B.P., Brook, B.W., Wigley, T.M., Bradshaw, C.J., 2017. Burden of proof: a comprehensive review of the feasibility of 100% renewable-electricity systems. Renew. Sustain. Energy Rev. 76, 1122–1133.

Heuberger, C.F., 2018. Electricity system modelling for optimal planning and technology valuation. PhD Thesis.

Heuberger, C.F., Mac Dowell, N., 2018. Real-world challenges with a rapid transition to 100% renewable power systems. Joule 2 (3), 367–370.

Heuberger, C.F., Rubin, E.S., Staffell, I., Shah, N., Mac Dowell, N., 2017. Power capacity expansion planning considering endogenous technology cost learning. Appl. Energy 204, 831–845.

Heuberger, C.F., Staffell, I., Shah, N., Mac Dowell, N., 2017. A systems approach to quantifying the value of power generation and energy storage technologies in future electricity networks. Comput. Chem. Eng. 107, 247–256.

Heuberger, C.F., Staffell, I., Shah, N., Mac Dowell, N., 2016. Quantifying the value of CCS for the future electricity system. Energy Environ. Sci. 9 (8), 2497–2510.

Heuberger, C.F., Staffell, I., Shah, N., Mac Dowell, N., 2018. Impact of myopic decision-making and disruptive events in power systems planning. Nat. Energy 3 (8), 634–640.

International Energy Agency (IEA), 2017. World Energy Outlook 2016: Power Generation Assumptions. https://www.iea.org/media/weowebsite/energymodel/WEO_2016_PG_Assumptions_NPSand450_Scenario.xlsb.

International Renewable Energy Agency (IRENA), 2017. Renewable Power Generation Costs. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf.

Mac Dowell, N., Fajardy, M., 2017. Inefficient power generation as an optimal route to negative emissions via BECCS? Environ. Res. Lett. 12 (4), 045004.

Mac Dowell, N., Staffell, I., 2016. The role of flexible CCS in the UK's future energy system. Int. J. Greenh. Gas Control 48, 327–344.

Mahlia, T.M., Saktisahdan, T.J., Jannifar, A., Hasan, M., Matseelar, H., 2014. A review of available methods and development on energy storage; technology update. Renew. Sustain. Energy Rev. 33, 532–545.

National Grid, 2019. Future Energy Scenarios. http://fes.nationalgrid.com.

National Grid plc, 2016. System operability framework 2016.

Nedd, M., Hong, Q., Bell, K., Booth, C., Mohapatra, P., 2017. Application of synchronous compensators in the GB transmission network to address protection challenges from increasing renewable generation. 2017 CIGRE B5 Colloquium.

Oderinwale, T., Ye, Y., Papadaskalopoulos, D., Strbac, G., 2019. Impact of energy storage on market-based generation investment planning. 2019 IEEE Milan PowerTech. IEEE, pp. 1–6.

Open Power System Data, 2019. Data package time series. Version 2019-06-05. 10.25832/time_series/2019-06-05.

Patrizio, P., Leduc, S., Kraxner, F., Fuss, S., Kindermann, G., Mesfun, S., Spokas, K., Mendoza, A., Mac Dowell, N., Wetterlund, E., et al., 2018. Reducing US coal emissions can boost employment. Joule 2 (12), 2633–2648.

Patrizio, P., Pratama, Y.W., Mac Dowell, N., 2020. Socially equitable energy system transitions. Joule 4 (8), 1700–1713.

Pfenninger, S., Staffell, I., 2016. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, 1251–1265.www.renewables.ninja

Pratama, Y.W., Mac Dowell, N., 2019. The role and value of CCS in different national contexts. Report for the Coal Industry Advisory Board (CIAB).https://www.iea.org/areas-of-work/industry-engagement/coal-industry-advisory-board

Qadrdan, M., Abeysekera, M., Chaudry, M., Wu, J., Jenkins, N., 2015. Role of power-to-gas in an integrated gas and electricity system in Great Britain. Int. J. Hydrog. Energy 40 (17), 5763–5775.

Ruhnau, O., Hirth, L., Praktiknjo, A., 2019. Time series of heat demand and heat pump efficiency for energy system modeling. Sci. Data 6 (1), 1–10.https://data.open-power-system-data.org/when2heat

Safaei, H., Keith, D.W., 2015. How much bulk energy storage is needed to decarbonize electricity? Energy Environ. Sci. 8 (12), 3409–3417.

Schaaf, T., Grünig, J., Schuster, M.R., Rothenfluh, T., Orth, A., 2014. Methanation of CO_2-storage of renewable energy in a gas distribution system. Energy Sustain. Soc. 4 (1), 1–14.

Schiebahn, S., Grube, T., Robinius, M., Tietze, V., Kumar, B., Stolten, D., 2015. Power to gas: technological overview, systems analysis and economic assessment for a case study in Germany. Int. J. Hydrog. Energy 40 (12), 4285–4294.

Schill, W.-P., 2020. Electricity storage and the renewable energy transition. Joule 4 (10), 2059–2064.

Schill, W.-P., Zerrahn, A., 2018. Long-run power storage requirements for high shares of renewables: results and sensitivities. Renew. Sustain. Energy Rev. 83, 156–171.

Schnellmann, M.A., Heuberger, C.F., Scott, S.A., Dennis, J.S., Mac Dowell, N., 2018. Quantifying the role and value of chemical looping combustion in future electricity systems via a retrosynthetic approach. Int. J. Greenh. Gas Control 73, 1–15.

Sepulveda, N.A., Jenkins, J.D., Edington, A., Mallapragada, D.S., Lester, R.K., 2021. The design space for long-duration energy storage in decarbonized power systems. Nat. Energy 6 (5), 506–516.

Sepulveda, N.A., Jenkins, J.D., de Sisternes, F.J., Lester, R.K., 2018. The role of firm low-carbon electricity resources in deep decarbonization of power generation. Joule 2 (11), 2403–2420.

Staffell, I., Pfenninger, S., 2016. Using bias-corrected reanalysis to simulate current and future wind power output. Energy 114, 1224–1239.www.renewables.ninja

Tanzer, S.E., Ramirez, A., 2019. When are negative emissions negative emissions? Energy Environ. Sci. 12 (4), 1210–1218.

Teng, F., Aunedi, M., Strbac, G., 2016. Benefits of flexibility from smart electrified transportation and heating in the future UK electricity system. Appl. Energy 167, 420–431.

UK BEIS, 2016. Electricity generation costs. UK Department of Business, Energy, and Industrial Strategy.

UK BEIS, 2018. Clean Growth - Transforming Heating. UK Department of Business, Energy, and Industrial Strategy.https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/766109/decarbonising-heating.pdf

UK BEIS, 2018. Updated Short-Term Traded Carbon Values used for UK Policy Appraisal. UK Department of Business, Energy, and Industrial Strategy.https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-uk-policy-appraisal-2018

UK BEIS, 2019. Digest of UK Energy Statistics (DUKES): Electricity. UK Department of Business, Energy, and Industrial Strategy.https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

UK BEIS, 2019. Fuel Price Assumptions. UK Department of Business, Energy, and Industrial Strategy.https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2019

UK DECC, 2013. The Future of Heating: Meeting the Challenge. UK Department of Energy and Climate Change.

UK DECC, 2014. Estimates of Heat use in the United Kingdom in 2013. UK Department of Energy and Climate Change.https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/386858/Estimates_of_heat_use.pdf

Varone, A., Ferrari, M., 2015. Power to liquid and power to gas: an option for the German energiewende. Renew. Sustain. Energy Rev. 45, 207–218.

Victoria, M., Zhu, K., Brown, T., Andresen, G.B., Greiner, M., 2019. The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system. Energy Convers. Manag. 201, 111977.

Watson, S.D., Lomas, K.J., Buswell, R.A., 2019. Decarbonising domestic heating: what is the peak GB demand? Energy Policy 126, 533–544.

Yao, J.G., Bui, M., Mac Dowell, N., 2019. Grid-scale energy storage with net-zero emissions: comparing the options. Sustain. Energy Fuels 3 (11), 3147–3162.

Zeyringer, M., Price, J., Fais, B., Li, P.-H., Sharp, E., 2018. Designing low-carbon power systems for Great Britain in 2050 that are robust to the spatiotemporal and inter-annual variability of weather. Nat. Energy 3 (5), 395–403.

Zhang, D., Bui, M., Fajardy, M., Patrizio, P., Kraxner, F., Mac Dowell, N., 2020. Unlocking the potential of BECCS with indigenous sources of biomass at a national scale. Sustain. Energy Fuels 4 (1), 226–253.