UKERC
UK Energy Research Centre

The impact of shocks and disruptions in the GB energy system

UKERC Working Paper

Modassar Chaudry, UKERC, Cardiff University

Meysam Qadrdan, UKERC, Cardiff University

Lixun Chi, Cardiff University

Jianzhong Wu, UKERC Co-Director, Cardiff University

September 2022

Contents

1. Executive summary

There is growing public concern about the vulnerability of the energy system to ‘shocks’ that go beyond what can be characterised as ‘normal’ disruptions to supply. Therefore, the premise of this work is to explore the impact of hypothetical ‘energy shocks’ in the existing (2020) and two future energy systems in 2050. One configuration of future energy systems focuses on electrification of both heat and transport, the other sees a majority of heating demand met by hydrogen boilers.

To perform this work, an integrated energy supply systems model is utilised. The model includes representation of multi vector energy systems including gas, electricity, hydrogen and heat across transmission and distribution scales. The methodology allows energy ‘shocks’ to be applied and captures the operational response of the system including involuntary interruptions and with estimates for value of lost load, the cost of these interruptions can be quantified. The integrated nature of the model allows assessment of complex interactions between various energy vectors. For instance, the impact of shocks that propagate across integrated infrastructures is endogenised and the ability of the overall system to ride through such ‘shocks’ is encapsulated within the modelling framework.

The energy shocks can be described in terms of magnitude, duration of shock, location and in terms of technology or supply failures. The energy shocks applied include a decline of wind speeds and by extension reduction in wind generation, a loss of nuclear plants, electrical interconnectors, and gas supply.

Given the relatively modest wind capacity connected to the energy system in 2020 a large reduction in wind speeds did not result in energy unserved. But the impact of a gas supply shock did result in modest levels of energy unserved which could be abated by demand side response. For the future energy scenarios, the largest impact in terms of involuntary interruptions occurs with a large reduction of wind speeds this is especially the case for the scenario where heat and transport are electrified.

The ability of the system to utilise energy storage, flexible energy technologies alongside demand side participation to mitigate ‘energy shocks’ was explored. Implementation of smarter charging and Vehicle to Grid (V2G) ensured involuntary interruptions were eliminated in both future energy scenarios in 2050. However, uncertainty remains regarding consumer participation in these and other demand side response schemes. Fixed storage solutions could offer a solution to this, with hydrogen storage able to manage energy shocks that have longer durations.

The paper concludes with policy interventions that could enhance the ability of the energy system to mitigate energy shocks through greater uptake of measures such as demand side response, smarter charging/vehicle to grid and demand reduction.

2. Introduction

We rely on energy for heat, transport and to power our homes and businesses. Energy is vital to our comfort and prosperity. Great Britain has a strong historical record of energy security. Several events in 2021-22 including large increases in national and international gas demand and conflict in energy supply regions have thrust energy security to the forefront of the ‘energy trilemma’ as outlined in British Energy Security Strategy (HM Government, 2022). The report summarises a 10-point plan to increase energy security which includes acceleration of a shift to electric vehicles, greener buildings, green hydrogen production and more renewable and nuclear generation capacity. The UK statutory security of supply report 2021 details diversification of fuels such as gas (LNG, pipeline) and oil as key components of energy security (BEIS, 2021). In the report, gas storage is mainly characterised by a withdrawal metric or energy flows per day (mcm/d). Previously this and the storage capacity (energy) information was reported on, with the latter being far more useful for understanding if storage can manage prolonged tightness in energy supplies. Over recent years gas storage capacity has greatly diminished with the closure of the Rough storage facility in 2017 with owner Centrica citing the cost of maintenance. The Rough storage facility had a capacity of ~41TWh and the capability to meet ~10% of UK peak day gas demand. In 2021, UK gas storage capacity stood at ~9TWh, countries with comparable annual gas demand such as Italy and Germany have gas storage capacities that are 10 times larger (Reuters, 2021). Given the Russian-Ukrainian crises the Rough storage facility has received regulatory approval to re-open by winter 2022 (Reuters, 2022).

In GB the energy systems, gas and electricity are interlinked through reliance on gas for gas fired generation. Therefore, energy shocks in one system would, to varying degrees transfer to the other. These interactions and interdependencies were illustrated in Texas in 2021 where failures in both systems – gas and electricity created a vicious circle that resulted in loss of load and blackouts (Busby et al., 2021).

There is great uncertainty attached to the future demand for gas, for instance, if gas CCS power plants fail to emerge (due to commercial or technical reasons) as heat and transport is electrified the interdependency between gas and electricity systems would be considerably weakened. Alternatively, if hydrogen plays a large role in meeting future heating and electricity demand through hydrogen boilers and hydrogen fuelled gas turbines, then natural gas could be required for the production of large quantities of hydrogen through Steam Methane Reformation (SMR) CCS systems. This would maintain the interdependency between natural gas and electricity systems alongside interactions with energy vectors such as hydrogen.

It is often said that consumers take energy security for granted, we assume energy will always be there when we switch on the lights or turn the oven on. This narrative is now being challenged. The impact of severe cold weather, the wind not blowing (or blowing too much) and geopolitical events that trigger a potential ‘tightness’ of energy supply and demand has entered the consciousness of the public and politicians alike.

The importance of understanding the impact of energy shocks in the energy system is paramount. N-1 (loss of single piece of infrastructure or supply source) events and, or combination of shock events are required to explore the quantities of energy that cannot be delivered to meet demand and the system response in mitigating such events.

This paper explores the consequences of selected hypothetical “events” affecting gas and electricity infrastructure and supply that would stress the GB energy system. These events are applied to scenarios in 2020 and for two distinct energy futures in 2050.

Using a novel combined model of the GB gas and electricity transmission networks with representation of regional distribution systems, we explore how the GB energy sector would respond to these hypothetical energy shocks. A variety of responses are considered including involuntary interruptions and re-dispatching the gas and electricity system. The costs of the events, comprising changes to operational balancing of supply and demand and the value attached to supply interruptions are computed. The impact of mitigation measures such as demand side response and implementation of V2G services are explored.

The paper is structured as follows. The first section summarises a brief review of energy related incidents that have affected supplies in GB over the last decade. Then, the modelling methodology and the key features of the CGEN+ Energy Hubs model are described. Two background scenarios for the future development of the GB energy system are described. The paper then describes exploration of how the energy system might respond to a set of hypothetical disruptions to infrastructure and supply. Finally, we explore measures that might mitigate the impacts of supply disruptions and discuss options for policy interventions.

3. Review of GB energy system shocks and disruptions

A review of major historical electricity, gas and oil supply interruptions and energy system failures in GB over the last decade is shown in Table 1.

Table 1. Major GB energy shocks and disturbances

Date	Location	Energy vector	Duration	Cause	Loss
17 June 2022	GB, Bolton	Electricity	1 hour+	Damage to power cable	2,300+ properties impacted
16 June 2022	GB, Keswick	Electricity	6 hours+	Substation fire	7,000+ customers impacted
15-27 March 2022	GB	Electricity	6 months	A large fire at a key substation in the UK forced the shutdown of the IFA interconnector with France.	1,000MW of capacity was unavailable
18 February 2022	GB	Electricity	24 – 72 hours	Storm Eunice	At its peak the storm impacted 1.4 million customers – a record number
26 November 2021	GB	Electricity	24 hours-1 week+	Storm Arwen	Approximately 1 million customers experienced power cuts, with 3000+ without power after a week.
09 August 2019	GB	Electricity	1 hour	Failure of Barford CCGT and Hornsea offshore windfarm to ride through lightning strike to an overhead transmission line.	Disconnection of 2000MW generation capacity leading to a drop in frequency and disconnection of 1.1 million customers
30 December 2015	GB	Electricity	24 hours	Storm Frank	0.1 million customers disconnected.
23 July 2015	England	Electricity	0.5 hours	Pupils burning their books sparked a large fire.	135,000 homes and buildings without power

Date	Location	Energy vector	Duration	Cause	Loss
23-28 December 2013	GB	Electricity	24 hours	Heavy rain and strong winds	Over 2.3 million customers impacted
28 August 2013	GB, London	Electricity	2 hours	Transformer fault	0.5 million customers impacted
August 2021	GB	Gas	6 months+	Due to a combination of unfavourable conditions, which involved soaring demand for gas in Asia, and diminished supply from Russia to the European markets	Steep increases in gas prices.
1 March 2018	GB	Gas	72 hours	Increased heat demand from consumers due to very cold weather.	Several infrastructure outages occurred across asset types including Norwegian pipelines, storage, LNG terminals and UK continental shelf production. A gas deficit warning was issued and led to high gas prices.
11 December 2017	GB	Gas	24 hours	Controlled shutdown of the Forties Pipeline System	Curtailment of about 40 mcm/day of gas flowing from St Fergus Gas Terminal – no energy unserved
22 March 2013	GB	Gas	12 hours	The coldest March since 1962	Gas price rise

Sources: (BEIS, 2017; 2018; 2020a; 2022), (Guardian, 2022), (Aljazeera, 2022), (Mirror, 2022), (Ofgem, 2014), (BBC, 2010a; 2010b), (Evening Standard, 2009), (Energy live news, 2021), (Wikipedia, 2022a, 2022b)

Two general points emerge from this review. Firstly, many gas supply crises and electricity blackouts relate to equipment and infrastructure failures, extreme weather, and acts of vandalism rather than politically motivated interventions. Secondly, the durations of different type of disturbances are also different. For example, most electricity shocks last for hours to days, and gas shocks for days to weeks. Additionally, compared to gas shocks, electricity shocks have happened more frequently, albeit over shorter durations.

4. Methodology

Reliability and security analysis of energy systems can be performed by utilising several methods from direct application of shocks – loss of key infrastructure such as generation plant outages, sudden changes in weather and impact of geopolitical events on the energy system - to use of probabilistic techniques such as Monte-Carlo simulation to calculate indices such as Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU) (Chaudry et al., 2013). The difficulty with using probabilistic techniques is mainly centred around simulation time to solution which can run into several days when modelling sophisticated and large energy systems. Additionally attaching probabilities to variables such as plant outages and supply is difficult and can have a significant impact on outcomes.

Studies assessing the security and reliability of integrated energy networks are not well represented in the literature. Those that do exist do not explicitly model vital energy infrastructure such as the gas and electricity networks and other energy vectors such as hydrogen. Given the increasing interdependency between energy vectors and that any one energy vector could adversely impact the capability of the other emphasises the need for greater understanding of the reliability and security of integrated energy systems.

The security analysis of integrated energy systems will be performed by employing an updated form of the CGEN+ (Combined gas and electricity network) model (Chaudry et al., 2008; 2014). Utilising the updated model, energy unserved will be measured through the application of well-defined energy shocks and disruptions.

4.1 Application of energy shocks and disruptions

In energy (gas and electricity) systems one indicator commonly used is the 'cost of energy unserved'. This indictor captures the time spent without energy as well as the magnitude of energy unserved. It is calculated by multiplying the energy unserved (magnitude and duration of unserved energy) with the value of lost load (VOLL). The value of lost load is the monetary indicator expressing the costs associated with an interruption of energy supplies. However, it must be recognised that only imperfect estimates of VOLL exist, and that the value of unserved energy can change from consumer to consumer, hour to hour, day to day and year to year.

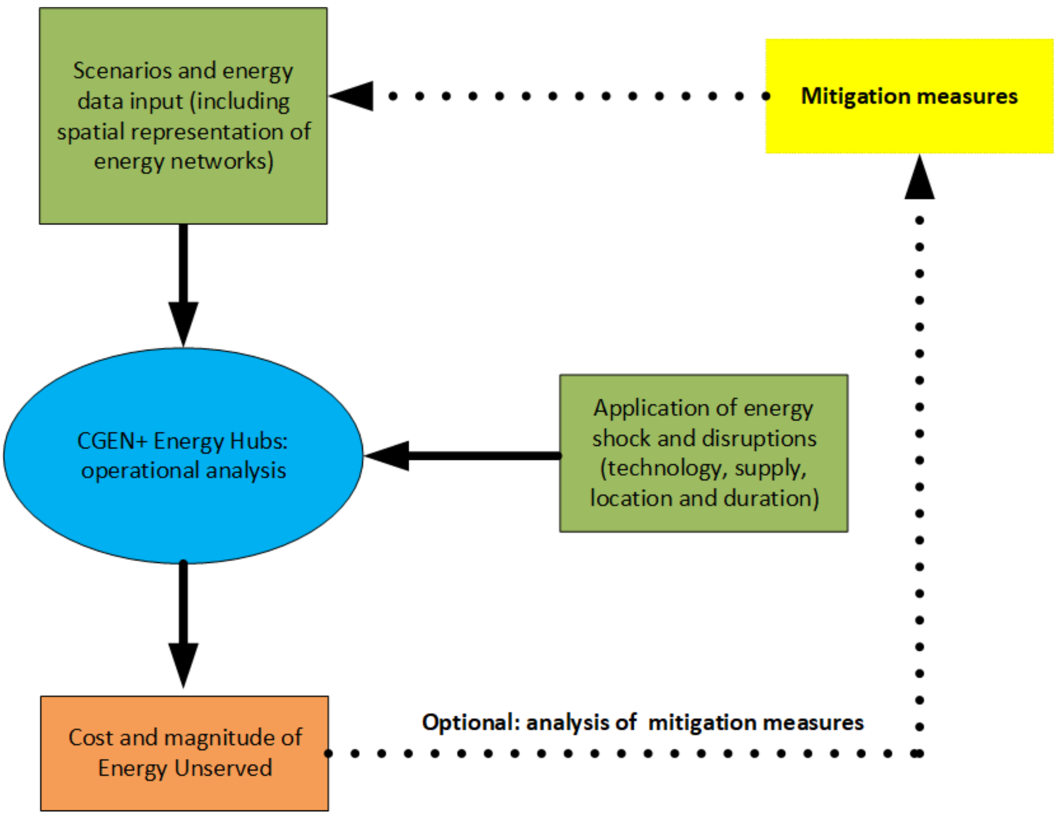


Figure 1. Application of energy shocks and disruptions

The CGEN+ Energy Hubs operational model is used to examine the impact of shocks and disruption to the energy system in 2020 and for future energy scenarios in 2050 (Figure 1). For each type of shock and disruption, the energy unserved along with the value (cost) of this shortfall is calculated alongside the change in overall operational costs.

Mitigation measures to improve the resilience to shocks/disruptions can be implemented and the costs and benefits (reduction of energy unserved) calculated. The process is repeated for each type of shock and mitigation measure.

4.2 Introduction to the CGEN+ Energy HUB model

The CGEN+ model includes characterisation of the energy supply system at both transmission and distribution scales. The integrated energy supply system model performs operational analysis over multi-time periods considering electricity, natural gas, hydrogen and heat supply systems and their interactions.

At the transmission scale, natural gas and electricity networks were modelled. A GIS spatial representation of the two transmission networks, assets such as generation plants, gas terminals, storage facilities and definition of energy hub regions (National Grid, 2021a, 2021b, 2021c) were used during the spatial modelling process. The electricity system operation is represented using a detailed DC load flow model and natural gas systems operation by a detailed gas flow model (Chaudry et al., 2008).

These two transmission networks interact through gas fired power generators. Energy resource supplies, generation technologies and networks are explicitly modelled. Detailed modelling methods are used to represent seasonal gas storage operation, variable generation of renewables and operation of interconnectors. Energy supply at the transmission level meets demands from large industrial consumers and energy flows into distribution systems.

Within the energy distribution systems, electricity, natural gas, hydrogen and heat distribution systems are modelled. To form the integrated framework of various energy carriers via energy conversion technologies an ‘energy-hub’ (Geidl, 2007) concept is adopted. The energy hubs are connected with the gas and electricity transmission networks through grid supply points. Energy hubs utilise regionally distributed energy resources, storage (batteries, hydrogen, and gas) and transmission grid supplies to meet predominantly residential and commercial energy demands. Constraints from each technology and network energy flow capacities were modelled.

A stylised representation of key electricity and gas transmission system components modelled, and a simple illustration of an energy hub are shown in Figure 2.

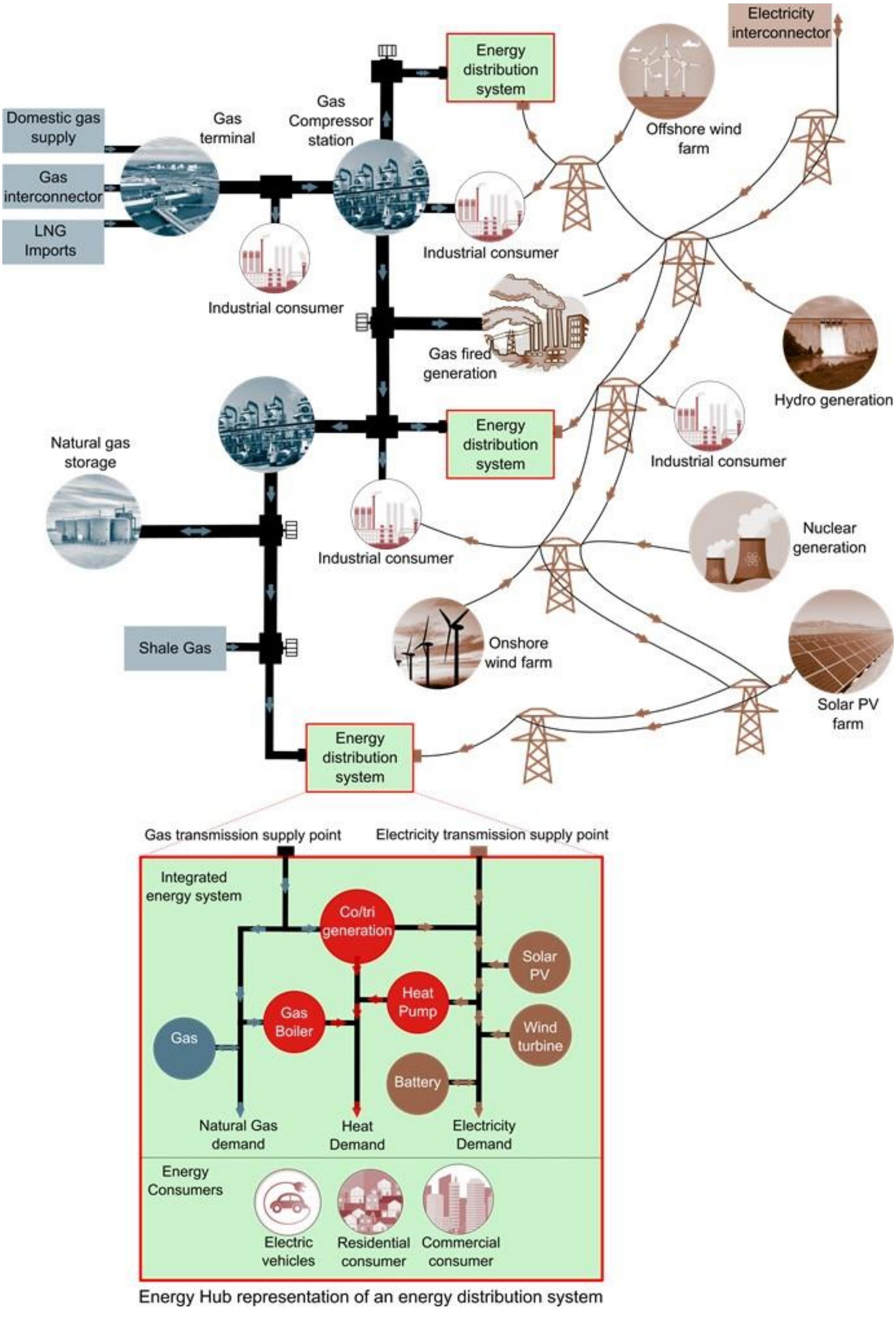


Figure 2. Stylised representation of electricity and gas transmission systems (top) and an Energy Hub representation of a local energy system (bottom)

The integrated energy supply system model minimises total operational costs (Eq. 1) to meet energy demands. The operational costs at each time step t, are derived from the natural gas $(C_t^{Gas\ Tran})$ and electricity $\left(C_t^{Elec\ Tran}\right)$ transmission networks, energy hubs $\left(C_t^{EnergyHub_i}\right)$, carbon costs $\left(C_t^{Carbon}\right)$ and energy unserved $(C_t^{energy\_unserved})$ over the time horizon. The time step t, is user defined and in this study represents an hour.

The cost minimisation is subject to constraints derived from the operational characteristics of assets in both national and energy hub systems while ensuring the balance between energy supply and demand.

$$Objective = min \sum_t \left\{ C_t^{Elec\ Tran} + C_t^{Gas\ Tran} + \sum_{i=1}^{N} C_t^{EnergyHub_i} + C_t^{Carbon} + C_t^{energy\_unserved} \right\} \quad (1)$$

Where $C_t^{Elec\ Tran}$ (Eq. 2) includes, power generation costs C_j^{gen} such as fuel costs, operational and maintenance costs of power generator j (excluding interconnectors) for generating power $P_{j,t}$; costs of importing power $P_{i,t}^{imp}$ for a unit price C_i^{imp} and the revenues from exporting power $P_{i,t}^{exp}$ for a unit price C_i^{exp} via an interconnector link i.

$$C_t^{Elec\ Tran} = \sum_j C_j^{gen} P_{j,t} + \sum_i \left(C_i^{imp} P_{i,t}^{imp} - C_i^{exp} P_{i,t}^{exp} \right) \quad (2)$$

$C_t^{Gas\ Tran}$ (Eq. 3) includes, the cost of gas supply from terminal a at time t calculated by the volume of gas supplied $Q_{a,t}^{sup}$ and gas price $C_{a,t}^{gas}$; the cost of operating a gas storage facility u calculated by the gas volume injected $Q_{u,t}^{I}$ or withdrawn $Q_{u,t}^{W}$ at time t and the cost of gas injection C_u^I or withdrawal C_u^W.

$$C_t^{Gas\ Tran} = \sum_a C_{a,t}^{gas} Q_{a,t}^{sup} + \sum_u \left\{ C_u^W Q_{u,t}^W + C_u^I Q_{u,t}^I \right\} \quad (3)$$

The energy hub costs $\left(C_t^{EnergyHub_i}\right)$ of operating integrated electricity, natural gas, heat and hydrogen distribution systems (Eq. 4), include operating costs of distributed technologies including variable costs (C_i^v) of operating technology (i) with respect to energy outputs $\left(E_{i,output,t}\right)$, and fuel costs for biomass $\left(C_{bio}^{fuel}\right)$ and solid waste $\left(C_w^{fuel}\right)$.

$$C_t^{EnergyHub_k} = \left\{ \sum_i^{\{Tech\}} E_{i,output,t} \times C_i^v \right\} + \left\{ \sum_j^{\{bio,w\}} E_{j,t} \times C_j^{fuel} \right\} \quad (4)$$

The carbon costs C_t^{Carbon} were applied across electricity generation, heat supply, hydrogen production and non-heating end-uses of fuels (natural gas, oil, solid fuel). Within both national and local energy systems, penalty costs (VOLL) were applied for unserved energy $C_t^{energy\_unserved}$ demand.

Renewables are modelled using weather parameters such as wind speed and solar irradiance through region specific historic data from the Met Office and forward projections from “Weather@Home” (Guilod et al., 2017). Using these inputs, the power output from wind and PV plants were calculated within the model. Therefore, spatial variability of wind speed and solar irradiance was accounted for across the GB transmission network and energy hubs (Chaudry et al., 2022).

Demand Side Response (DSR) capabilities were modelled within the energy hubs. DSR allows the ability to shift electricity demands (non-heating including demand for EV charging), from peak to off peak hours, such that the total operating costs are minimised (see Appendix).

The model allows unmanaged or managed charging of electric vehicles (EVs) as a simulation preference. Additionally, the model permits Vehicle to Grid (V2G) supplies (See Appendix).

The modelling approach offers a rich level of disaggregated temporal and spatial representation of energy supply systems. Key outputs from the model include the energy supply mix, emissions, cost of operation at various scales (transmission, distribution etc.) and energy unserved.

5. Description of scenarios and energy shocks

Two scenarios, Consumer Transformation (CT) and System Transformation (ST) taken from National Grid FES (Future Energy Scenarios) are used to characterise the energy systems in 2050 for application of the shocks (National Grid, 2021c). The key system indicators from the FES scenarios alongside values from 2020 are illustrated in Table 2.

Table 2. Key indicators from the FES scenarios

	2020	**FES: Consumer Transformation (CT) 2050**	**FES: System Transformation (ST) 2050**
CO_2 emissions	497mt	Net zero	Net zero
Annual electricity demand	294 TWh	702 TWh	559 TWh
Peak electricity demand (ACS)	58 GW	113 GW	99 GW
Electrical Interconnector capacity	4 GW	27GW	20GW
Total annual gas demand	891 TWh	66 TWh	512 TWh
Annual gas residential demand	334 TWh	3 TWh	1 TWh
Annual hydrogen demand	0	149 TWh	475 TWh
Annual electricity, and hydrogen demand for road transport	1.30 TWh (EV) 0 TWh (Hydrogen)	101.5 TWh (EV) 31.3TWh (Hydrogen)	94.5 TWh (EV) 58.4 TWh (Hydrogen)

Both FES scenarios have systems that have large increases in annual electricity demand in 2050 with respect to 2020. With the Consumer Transformation scenario, the increase in electricity demand is due to large scale adoption of heat pumps and proliferation of domestic electric vehicles. The System Transformation scenario sees a large installation of hydrogen boilers supplied by SMR and electrolysis systems. The Consumer Transformation scenario shows a large reduction in annual gas demand. This is less pronounced in the System Transformation scenario as gas is used for gas CCS generation and in the production of hydrogen for use in hydrogen power generation plants and for domestic and commercial hydrogen boilers.

5.1 Hypothetical shocks and disruptions

We have hypothesised four possible 'shocks' and disruptions in the GB energy system (Table 3). We have assumed the impact of each shock is experienced over a range of different durations from 1 to 5 days. These durations of energy shocks reflect the majority of historical events especially as future energy systems move to high levels of electrification of heating and transport. The hypothetical events that we explore are:

Table 3. Narratives for energy shocks

Hypothetical energy shock	Narratives
'Wind-shock' *Loss of wind generation*	Anticyclones are areas of intense high pressure. Anticyclones can occur in both winter and summer with varying effects, but both are typified by low wind speeds. In winter the longer nights combined with clear skies leads to intense cooling of the land mass. In summer an anticyclone can mean heat waves. From a geographic perspective, anticyclones can cover very large land mass. This could be at least 3,000 km wide (covers the UK and current offshore wind installations). To model anticyclonic 'shocks', wind speeds (which are based on 2010 weather patterns) across the UK are reduced by 50% (winter). Wind turbines will only generate electricity when wind speeds reach the 'cut in' wind speed (a minimum level set at 5 m/s). The reduction of wind speeds will render many wind turbines unable to generate electricity.

Hypothetical energy Shock	Narratives
'Dis-Interconnected' *Loss of electrical Interconnectors*	Loss of electrical interconnectors connected to France. This can be due to a multitude of events such as major energy outages in France leading to suspension of energy exports. This is modelled through zero flows through the interconnectors connected to France for the duration of the shock: Consumer Transformation = loss of ~10 GW interconnector capacity System Transformation = loss of ~8 GW interconnector capacity
'Gas-umped' *Reduced gas supplies*	A large disruption to gas supplies, this could be due to either infrastructure failure or be geopolitical in nature, but in both cases, this leads to shortages in supply. Two alternatives are modelled: IMPORTS: A 50% reduction available imports (LNG – pipelined). ALL: A 50% reduction of ALL gas supplies - only applied to the system in 2020.
'Nuked' *Loss of nuclear power plants*	A design type fault is discovered in certain nuclear plants. Although this would be a very serious event and most likely require long lead times to rectify if even possible, the shock will be modelled in-line with the duration of the other 'shocks'. This is modelled through outages at Hinkley Pont C, Sizewell C and Bradwell B.

Note, we do not attribute any specific underlying cause to the non-wind energy shocks although we suggest that severe accidents rather than politically motivated acts would be the more likely cause.

5.2 Energy demand profiles

We have assumed that the energy 'shocks' occur in mid-winter. A typical daily period of 'average' mid-winter (nominally January) energy demand for year 2020 is shown in Figure 3 and the FES scenarios 2050 are shown in Figures 4a, 4b.

The process in which the electricity, heat and transport energy demands were produced is described in the appendix.

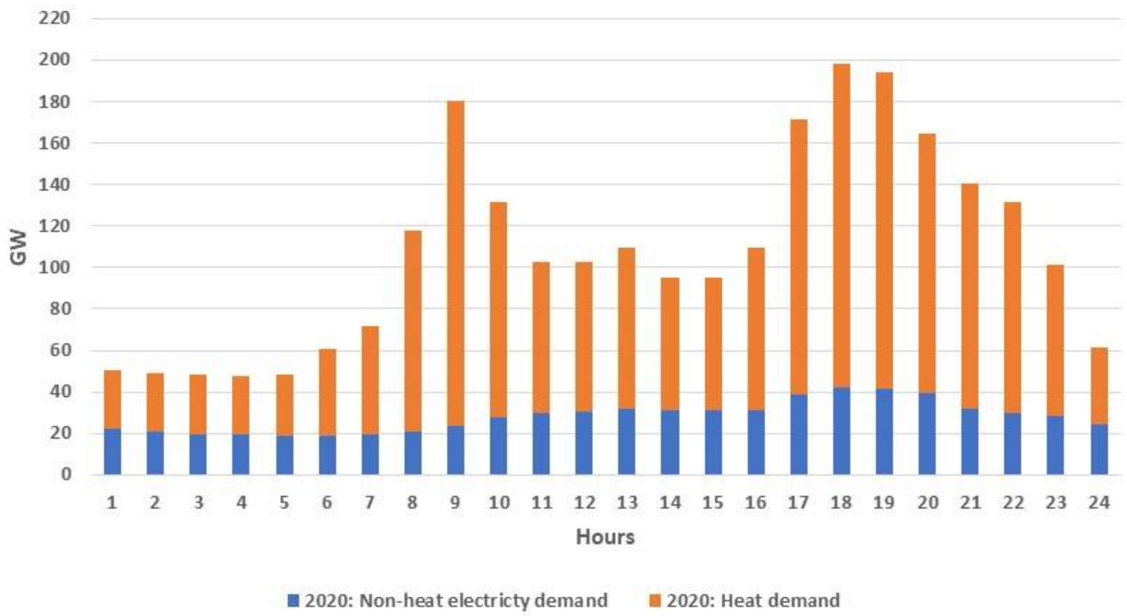
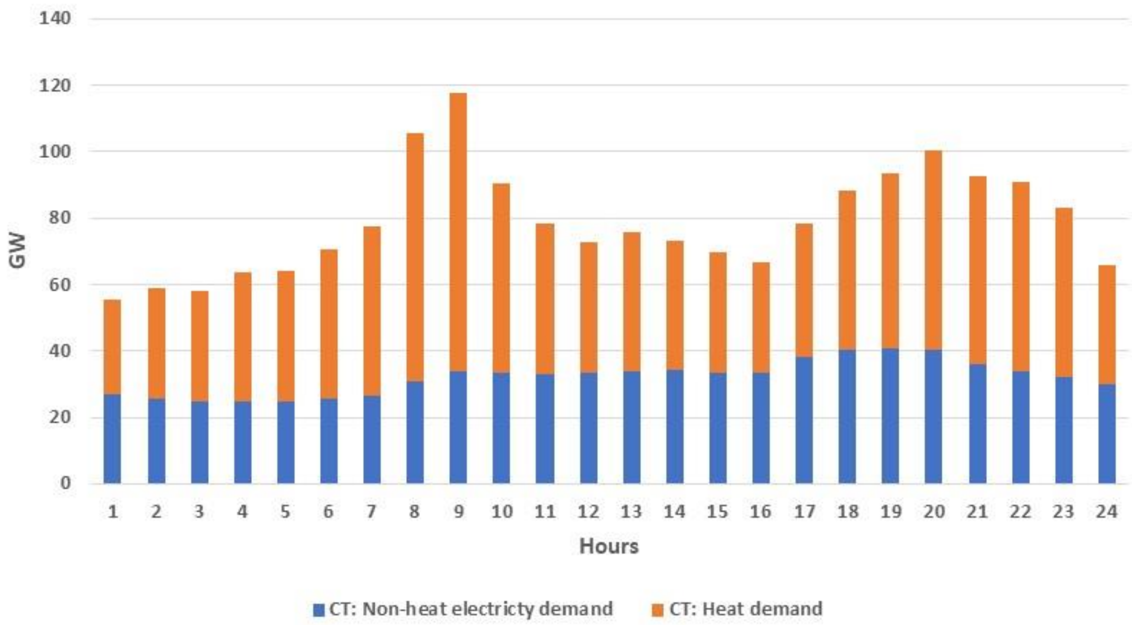


Figure 3. Daily heat (domestic + commercial) and non-heat electrical average winter demand in year 2020(day 2)

The electrical peak demand in 2020 is approximately ~58GW. Of this, around 42GW (peak) is non-heating electrical demand. Approximately 10% of heating demand is met by electrical technologies (resistive heating etc). Gas is by far the dominant fuel for heating through gas boilers and accounts for ~82% of all heat demand.



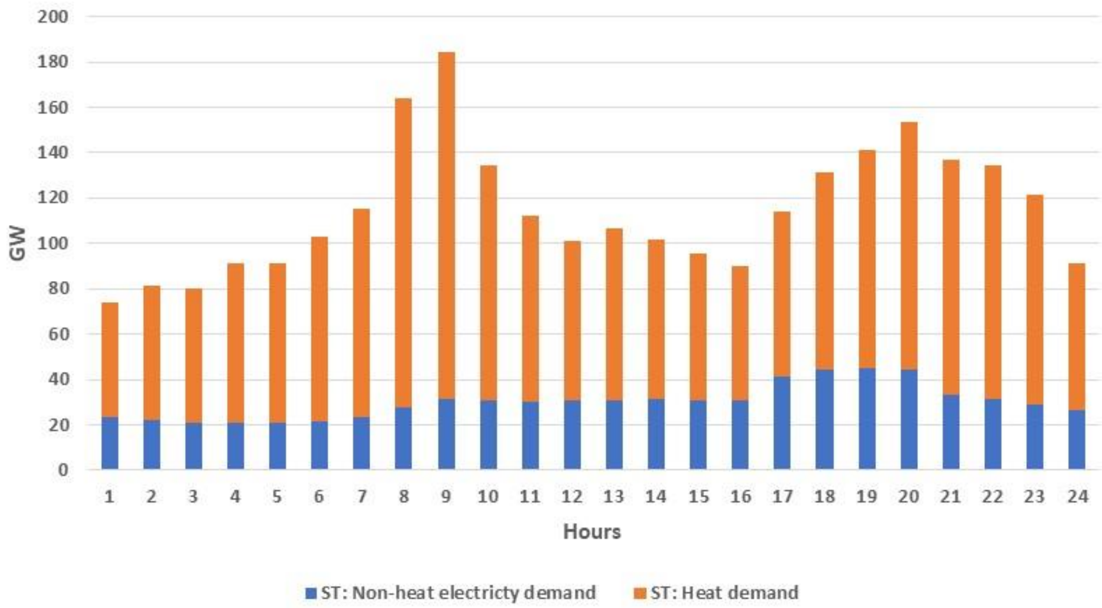


Figure 4. a) Consumer Transformation (top) b) System Transformation (bottom); Daily heat (domestic + commercial) and non-heat electrical average demand (day 2) in year 2050 – excludes demand for transport

The Consumer Transformation heat demand assumes high levels of heat pump penetration and resistive heaters (~82 %), with hydrogen and biofuel boilers comprising the remaining heating technologies. Heat demand in the System Transformation scenario consists mainly of hydrogen boilers (~70%) and heat pumps and resistive heating technologies (28%).

'Elevated' cold spell assumes increases of ~50% in heat and approximately ~20% non-heat electrical demand (residential and commercial only) over normal cold spell FES scenario demand profiles. These increases were chosen to reflect historical experiences faced by the UK during periods of high energy demand such as ‘Beast from the East’ (UKERC, 2018)

5.3 Estimates for Value of Lost load (VOLL)

The input assumptions on VOLL are shown in Table 4. The references (Electricity North West, 2019; London Economics, 2011; 2013; Van der Welle and Van der Zwaan, 2007) highlight some studies that give typical values for VOLL. In the gas sector VOLL varies from 2300 to 1600 p/therm across residential/commercial and industrial users. In the electricity system a VOLL of between 16,000 to 40,000 £/MWh was used for the residential, commercial, and industrial sectors.

Table 4: Value of Lost Load

Value of Lost Load	• 16,000 £/MWh (residential/commercial electricity) • 40,000 £/MWh (industrial electricity) • 1600 p/therm (industrial gas) • 2300 p/therm (residential/commercial gas)

6. Analysis of energy shocks and disruptions

Alongside the impact of energy shocks in the FES scenarios in 2050, selected shocks are also applied to the energy system in 2020. In all cases the energy unserved and the operational costs are recorded.

6.1 Energy shocks in the existing GB energy system

The impact of wind and gas supply shocks (1 day) for the energy system in 2020 for a simulation horizon of 3 days is shown in Table 5. We have assumed no voluntary demand side response (see Appendix) and that gas storage is 80% full at the start of the simulation[1].

Table 5. Impact of selected shocks in 2020

Shock/ Duration of shock	Winter demand profile	Energy unserved (GWh)	Change in gas[1] supplies (mcm)	Change in system[2] operating costs (£m)
Wind-shock				
- 1 day	Average	0	+30.3	+17.2
	Elevated	0	+133.8	+85.2
Gas-umped: IMPORTS				
- 1 day	Average	0	~0	+1.1
	Elevated	0	+51.6	+87.7
Gas-umped: ALL				
- 1 day	Average	0	~0	+4.3
	Elevated	38.5	+7.75	+107.1

Notes: (1, 2) Refers to changes relative to the situation where no shock occurs under average energy demand; (2) This does not allow for the likely rise in energy prices.

The impact of a large reduction of wind speed does not result in energy unserved whilst assuming average or elevated energy demand. The system in 2020 is able to call upon gas imports (LNG and pipelined) and to a lesser degree domestic supplies

[1] In January 2021 GB gas storage facilities were 75% full, this contrasts with 52% average across Europe. This was mainly due to a colder than expected winter season, a spike in energy demand and lower Russian gas supplies to Europe via Ukraine (GIE, 2022).

to meet average and elevated heat demands and flexibility is provided by gas fired CCGT generation as shown in Figure 5. Even though no energy unserved is recorded, to ensure the system is balanced operational costs rises quite notably over a simulation horizon of 3 days (1 day shock).

The impact of a gas supply shock, if only considering loss of imports, results in no energy unserved but leads to a large increase in system operation costs. If the loss of 50% of gas imports is also extended to domestic gas supplies, we get modest amounts of energy unserved during peak hours which occurs in the industrial sector. In the event that the industrial sector is unable to provide voluntarily demand response (this also is not cost free) the cost of lost load is approximately ~ £22 million for a 1-day gas supply shock. Figure 5, shows the general flexibility provided by gas fired generation which follows variations in supply and demand, and in this case a downwards response.

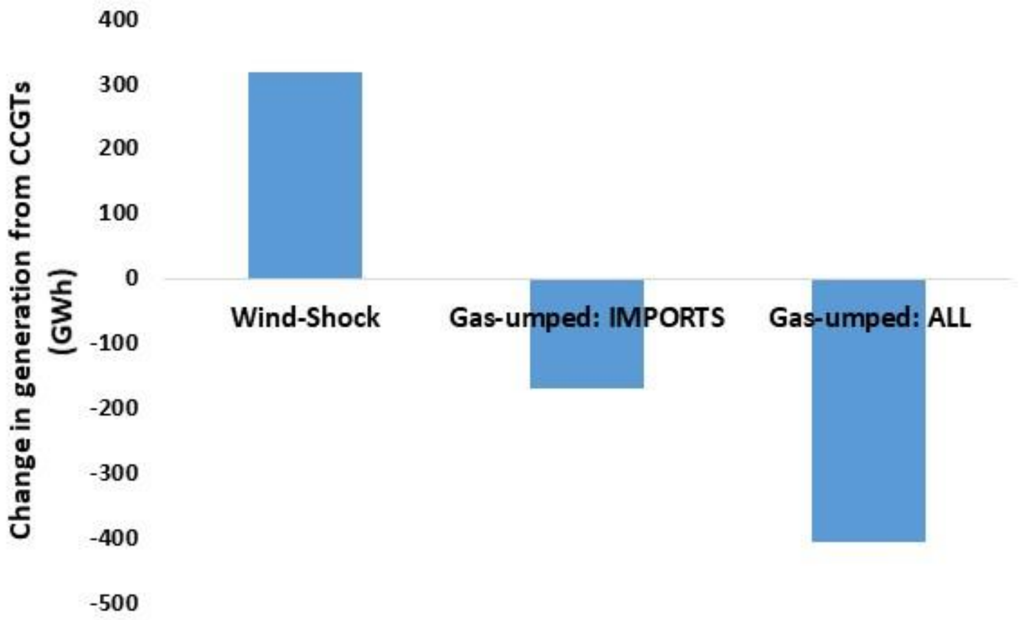


Figure 5. Change in generation from CCGTs compared with no-shock case

6.2 Impact of shocks and disruptions in future energy systems

To evaluate the FES energy scenarios, we assumed no voluntary demand side response (this is examined separately in the mitigations section) and unmanaged charging of electric vehicles with Vehicle to Grid (V2G) capability disabled (see Appendix).

The impact of a loss in wind generation across the two FES scenarios is shown in Table 6.

Table 6. Impact of 'wind-shock' in the FES scenarios: Elevated energy demand

Scenario/Duration of shock	Energy unserved (GWh)	Value of energy unserved[1] (£m)	Change in system operating costs[2] (£m)
Consumer Transformation			
- 1 day	88	1495.9	+8
- 5 days	210.5	3578.2	+190
System Transformation			
- 1 day	2.8	48.4	+15.1
- 5 days	20.7	351.9	+141.3

Notes: (1) Using the VOLL from Table 4; (2) This does not allow for the likely rise in spot prices for energy supplies

The Consumer Transformation scenario has a residential heat sector which is mainly electrified through heat pumps. Therefore, a loss of wind generation has a large impact, with a one-day wind shock, energy unserved is 88GWh across mainly peak hours and results in an equally large value of energy unserved. These losses increase as the shock is extended over 5 days. The results imply a lack of non-wind generation capacity and bottlenecks in regional electrical network capacity. The energy unserved and the associated costs are appreciably lower in the System Transformation scenario which has a mix of hydrogen boiler (70% +) and electrification (heat pumps - resistive heating) for the provision of heat.

Table 7. Impact of wind shock (Elevated demand): Response from flexible generation and hydrogen storage

Scenario/Duration of shock	Change in gas fired generation[1] (GWh)	Change in Hydrogen CCGT generation[2] (GWh)	Change in hydrogen storage flows[3] (TWh)
Consumer Transformation			
- 1 day	-	+106	+0.34
- 5 days	-	+715.1	+1.19
System Transformation			
- 1 day	+45.7	+178	+2.12
- 5 days	+123.7	+1282.3	+6.74

Notes: (1, 2, 3) Refers to changes relative to the situation where no shock occurs under average energy demand

Table 7 shows the response from gas fired and hydrogen generation and hydrogen storage supplies for the 'wind-shock' event for the FES scenarios. There is greater response across all these technologies in the System Transformation scenario, partially due to the larger capacity and gas being used to produce hydrogen through SMR and supported by flows from storage. Even gas fired CCS is able to play its part in the response which is not the case in the Consumer Transformation scenario as there is no gas fired generation capacity.

The impact of the other energy shocks across the FES scenarios is illustrated in Table 8. The impact of these shocks is not as large as the loss of wind generation but nonetheless they do result in energy unserved and by extension increases in the cost of operation to balance the system. The shocks are appreciably worse in the Consumer Transformation scenario although the cost of actions to balance the system to avoid energy unserved are higher in System Transformation (less wind generation).

Table 8. Impact of other 'shocks' in the FES scenarios over 5 days

	Energy unserved (GWh)	Value of energy unserved[1] (£m)	Change in system operating costs[2] (£m)
Consumer Transformation			
- Dis-connected	51.5	875.9	+26
- Nuked	54.4	924.3	+25.1
- Gas-umped: Imports	0	0	+25.4
System Transformation			
- Dis-connected	1.4	23.5	+46.8
- Nuked	6.1	103	+47.7
- Gas-umped: Imports	0	0	+43.2

Notes: Duration of shock is 5 days with a simulation period of 7 days. (1) Using the VOLL from Table 4; (2) Refers to changes relative to the situation where no shock occurs under average energy demand

7. Mitigation measures

Mitigation measures are applied to the FES scenarios (2050) to examine their effectiveness in dealing with various energy shocks and disruptions and are described in Table 9. These include additional energy investments, voluntary demand side response and smarter approaches to the operation of the energy systems.

Table 9. Mitigation measures

Measures	Capacity/Notes
Smart charging and V2G	Smarter charging and V2G is enabled (see appendix).
Electrical Demand Side Response (DSR)	Implementation of DSR capability. These are voluntary responses. No specific costs are attached to these responses (incentives) other than the change in costs which occurs operationally when shifting energy away from peak periods. So, for example industrial consumers could move production from peak hours to lower demand periods and potentially take advantage of lower energy costs. The 'maximum' quantities of energy that are assumed for DSR in the model are: 5% of total residential non-heat electrical demand 5% of total commercial non-heat electrical demand 10% of total industrial electrical demand
Battery storage capacity	A 50% increase (compared with 2050 base values)
Hydrogen Storage capacity	A 50% increase (compared with 2050 base values)

Notes: see Appendix for base storage capacity values

7.1 Impact of mitigation measures

The effectiveness of mitigation measures during a wind-shock event is shown in Table 10. The change in energy unserved compared without the mitigating measure is largest with smarter charging of EVs and implementation of V2G, this is especially the case for the Consumer Transformation scenario. Large reductions in the total change in costs which includes value of energy unserved and operational costs are observed.

Table 10. Impact of Mitigating Measures: Wind-shock for 5 days

	Change in Energy unserved[1] (GWh)	Change in total cost of shock (including VOLL)[2] (£M)
Consumer Transformation		
Smart Charging/V2G	-210.5	-3634
DSR	-18.3	-310.9
Battery storage capacity	-54	-914.9
Hydrogen Storage capacity	-41.1	-290.3
System Transformation		
Smart Charging/V2G	-20.7	-377.5
DSR	-14.1	-241
Battery storage capacity	-7.9	-134.3
Hydrogen Storage capacity	-20.7	-247.5

Notes: (1, 2) Refers to changes relative to the situation where a shock occurs under elevated energy demand

The implementation of DSR has limited impact in reducing the total energy unserved due to the amount of energy that can be shifted to other low demand periods. The storage solutions do well in reducing energy unserved. In the Consumer Transformation scenario hydrogen storage is limited by hydrogen production capacity through electrolysis – i.e. from a cost prospective it is not particularly helpful when the wind is not blowing. In the System Transformation scenario, all measures do well in reducing losses especially the implementation of smarter charging /V2G and greater hydrogen storage capacity.

Table 11. Impact of Mitigating Measures: other shocks for 5 days

	Change in: Energy unserved (GWh)	
	Dis-Connected	**Nuked**
Consumer Transformation		
Smart Charging/V2G	-51.5	-54
DSR	-7.9	-8
Battery storage capacity	-21.5	-21.9
Hydrogen Storage capacity	-19.1	-19.5
System Transformation		
Smart Charging/V2G	-1.3	-6
DSR	-1.38	-6.1
Battery storage capacity	-1.38	-3.9
Hydrogen Storage capacity	-1.38	-6.1

Note: Gas shock results in no energy unserved, although cost of operation is reduced through implementation of mitigation measures.

The impact of mitigation measures across the other energy shocks is documented in Table 11. In the System Transformation scenario, implementation of nearly all mitigation measures results in very low or zero energy unserved. Smart charging and V2G is the mitigation measure that performs the best in terms of reducing energy unserved to zero in the Consumer Transformation scenario.

8. Summary and policy insights

The premise of this work is to explore the impact of hypothetical ‘energy shocks’ in the existing (2020) and two future energy systems in 2050. The impacts measured include energy unserved and the operational system responses. The ability of systems to utilise energy storage, flexible energy technologies alongside demand side participation to mitigate ‘energy shocks’ was explored.

The impact of cold weather, the wind not blowing and geopolitical events on the potential ‘tightness’ of the balance between supply and demand has concerned many. The analyses of energy shock events alongside potential increases in demand are vital for operational preparedness and planning purposes.

Energy shocks in the existing system

Given the relatively modest wind capacity (~23GW) connected to the energy system in 2020, a 50 % reduction in wind speeds for one day assuming either average or elevated winter demand did not result in energy unserved. This is mainly due to the response from gas fired generator led by CCGTs. The change in operating costs corresponds to more expensive technologies and fuel (gas) being used to ensure supply and demand balance.

The impact of a single day gas shock across all supplies including domestic resulted in energy unserved. Across the peak hours this shock amounted to approximately 12 GW of energy unserved for gas industrial consumers. Currently this gap would be bridged through voluntary demand side measures.

The simulations show that GB has a strong security of supply position and that it has sufficient diversity and capacity to meet the energy demand profiles modelled.

Electrification of energy security

The reliance on gas in the in the Consumer Transformation scenario is very low, 6 BCM in 2050. The electricity system in 2050 accommodates over 350 GW capacity with wind turbines (on- and offshore) accounting for 157 GW as heat and transport is electrified. Therefore, the interactions between what remains of the gas system is much reduced.

The analysis showed a shock in gas supplies resulted in no energy unserved, but despite the low overall requirement for gas a notable increase in operational costs to balance the system to meet industrial demand and production of hydrogen (via electrolysis) was observed.

The analysis on direct electrical energy shocks such as reduction of wind speeds and loss of generation assets with mitigation measures, such as voluntary demand side response and V2G disabled results in energy unserved. A shock in wind speeds has a dramatic impact on energy unserved. A five-day shock would result in more than 200GWh of unserved energy. With a one-day shock, unserved energy, averages 20-30GW every hour during the typical 3-4 hour peak demand period. This results in a large change in operational costs and energy unserved valued in the billions. The impact of shocks on electrical interconnector and nuclear generation supplies are smaller but still result in energy unserved.

Security in a hybrid energy system

The interdependency between the gas and electricity system in the System Transformation scenario in 2050 is reduced from year 2020 levels but is still significant with annual natural gas demand of 47 BCM. This gas is used for production of hydrogen, industrial demand and for CCGT CCS plants. A gas supply shock of duration 5 days does not lead to energy unserved, as a response is observed with gas fired generation, hydrogen production switching to electrolysis and gas and hydrogen storage facilities withdrawing supplies to meet shortfalls. If the shock was prolonged over weeks, given the amount of energy storage (hydrogen and gas) at the end of the shock periods simulated suggests energy unserved would occur.

The impact of large reduction in wind speeds results in energy unserved albeit much lower than in the Consumer Transformation scenario. Less than 1GW of voluntary demand response over peak periods would eliminate energy unserved. In comparison to the levels of energy unserved the change in system costs are large. This mainly due to the use of more gas fired generation and gas used to produce hydrogen for heating purposes.

The impact of the loss of nuclear and interconnection facilities results in lower levels of energy unserved compared with the Consumer Transformation scenario but as more gas is used (expensive tranches of gas) for gas fired generation this results in higher system operating costs.

Mitigation

Greater storage capacity, battery or hydrogen, performed well in the Customer Transformation scenario although the change (reduction) in total cost of the shock (includes costs attached to VOLL) is more pronounced in the case with more battery capacity. This difference is mainly due to the lower efficiencies attached to the production of hydrogen and storage and then potential reuse for electricity generation. The roles are reversed in the System Transformation scenario where higher use of hydrogen for heating and larger reduction in energy unserved reduces overall costs by a larger amount.

Demand side reduction (DSR) does not have the capability to reduce all energy unserved, but if available it does provide the ability to shift limited amounts of energy demand to off-peak hours although the reduction in operational costs is modest across both scenarios.

The implementation of smarter EV charging and V2G services, is able to eliminate energy unserved in both scenarios. In the case of Consumer Transformation scenarios upwards of 30GW of V2G capacity is available during peak hours. This results in a large reduction in overall costs with System Transformation showing a more modest reduction due to lower pre-mitigation energy unserved. Furthermore, towards the end of the shock period the amount of energy in EV batteries is on a downwards trajectory, in this case peak demand also declined to ensure no energy unserved. A legitimate concern is regarding the ability of smarter charging/EV to mitigate shocks that last longer. This is where hydrogen storage solutions could potentially excel.

Policy Interventions

Some of the shocks modelled are extreme events and therefore the case for investment in additional infrastructure mitigation measures is challenging. Though allowing shocks to occur without mitigation measures can run into the billions as observed by the simulation of future energy system scenarios. Also, measures such as smarter charging /V2G and DSR may seem to present lower levels of perceived investment but uncertainty regarding participation and their responsiveness remains. So, we compile a list of policy interventions near and long term which could improve the ability of the energy system to ride through energy shocks.

Near-term

Both interventions would enhance energy security at modest cost and take limited time to implement.

- Approximately 16 TWh (DECC, 2012) of domestic heating demand in winter could be avoided by turning down the thermostat by 1 degree. This would require encouragement from government, local authorities and promoting the benefits to the consumer (savings on bills). A reduction in heat demand would mitigate the gas shock (ALL gas supplies) simulated in the energy system in 2020 and would also reduce system operational costs.

- Additionally, the use of radiator valves or zonal heating would prevent heating unused rooms. This could potentially save 4TWh in the residential sector over the winter season (DECC, 2012).

Long-term

- Demand reduction: The economy's energy intensity could be reduced: Adoption of high EPC (Energy Performance Certificate) bands for houses (new and existing). Energy efficient designs could be adopted in the various end-use sectors (buildings, machinery, vehicles and appliances etc). This could be encouraged through taxes on inefficient products and practices.

- The modelling suggests that there is potentially a case for investment in 'strategic' storage. This would differ compared to the operation of commercial storage which follows market rules. The storage facilities would have to ensure they are full by a specified date in winter and can only be drawn down during emergency situations. These would most likely be hydrogen or gas storage facilities.

- Encourage flexibility with smart charging/V2G and DSR: the simulations showed the benefit of flexible technologies. The charging technologies and services that enable convenient and affordable smart charging must be developed. DSR and V2G could be supported through price signals to encourage participation and therefore allow demand shifting and, or supply as envisaged in the modelling.

Future research direction

The work described in this report was motivated by growing public concern about the vulnerability of the current (2020) energy system and future system scenarios to mitigate supply shocks that go beyond what can be characterised statistically and "normal" outages of plant.

There are limitations to the work present here and a future research agenda could include the following:

- Examining a wider range of 'shocks' (single and multiple sectors,) for instance cyber- hacking and testing the limits/capability of storage facilities cross varied durations.

- Assessing market responses to energy shocks – the importance of the impact on spot prices cannot be overstated as this is often the first obvious indication of tightness of energy supplies. This could lead to examination of market designs.

- System response before, during and after an energy shock could be modelled in more detail and potential contingency improvements (physical or market based) examined.

- Examination of effects and impacts that might not be captured by a DC power flow approximation. This may underestimate for example restoration time.

- Modelling domestic, commercial, and industrial behaviour to the potential shortages in energy supply – this could be addressed by Agent Based Modelling (ABM).

- Production of new or existing energy models that could be operated using Monte-Carlo or equivalent techniques to enable statistical analysis of energy system shocks.

Refences

Aljazeera, 2022. Accessed 03/2022, https://www.aljazeera.com/news/2022/2/19/nearly-200000-uk-homes-still-without-power-after-storm-eunice

BBC, 2010a. Accessed 03/2022, https://www.bbc.co.uk/news/mobile/10423764

BBC, 2010b. Accessed 03/2022, http://news.bbc.co.uk/1/hi/northern_ireland/8597089.stm

BEIS, 2022. Energy Emergencies Executive Committee Storm Arwen Review Interim Report, Department for Business, Energy and Industrial Strategy (BEIS) 2022.

BEIS, 2021. Statutory Security of Supply Report 2021, Department for Business, Energy and Industrial Strategy (BEIS) 2021.

BEIS, 2020a. E3C GB power disruption on 9 August 2019 Final Report 2019, Department for Business, Energy and Industrial Strategy (BEIS) 2020.

BEIS, 2020b. BEIS 2019 FOSSIL FUEL PRICE ASSUMPTIONS, Department for Business, Energy and Industrial Strategy (BEIS) 2020.

BEIS, 2018. UK National Risk Assessment on Security of Gas Supply 2018, Department for Business, Energy and Industrial Strategy (BEIS) 2018.

BEIS, 2017. Gas security of Supply: A strategic assessment of Great Britain's gas security of supply 2017, Department for Business, Energy and Industrial Strategy (BEIS) 2017.

Busby, J W., Baker, K., Bazilian, M D., Gilbert, A Q., Grubert, E., Rai, V., Rhodes, J D., Shidore, S., Smith, C A., Webber M E. Cascading risks: Understanding the 2021 winter blackout in Texas, Energy Research & Social Science, Volume 77, 2021, 102106,

Chaudry, M., Jayasuriya, L., Blainey, S., Lovric, M., Hall, J W., Russell, T., Jenkins, N., Wu, J. 2022. The implications of ambitious decarbonisation of heat and road transport for Britain's net zero carbon energy systems. *Applied Energy* 305, 117905. 10.1016/j.apenergy.2021.117905

Chaudry, M., Jenkins, N., Qadrdan, M., Wu, J., 2014. Combined gas and electricity network expansion planning. Appl. Energy 113, 1171–1187.

Chaudry, M., Wu, J., and Jenkins, N. 2013. A sequential Monte Carlo model of the combined GB gas and electricity network. *Energy Policy* 62 , pp. 473-483. 10.1016/j.enpol.2013.08.011

Chaudry, M., Jenkins, N., Strbac, G., 2008. Multi-time period combined gas and electricity network optimisation. Electr. Power Syst. Res. 78, 1265–1279.

DECC, 2012. How much energy could be saved by making small changes to everyday household behaviours?, Department of Energy and Climate Change, 2012.

Eggimann, S., Hall, JW., Eyre, N., 2018. A high-resolution spatio-temporal energy demand simulation to explore the potential of heating demand side management with large-scale heat pump diffusion. Appl Energy 2019; 236:997–1010. https://doi.org/10.1016/j.apenergy.2018.12.052

Energy Barinpool, 2021. Accessed 03/2022, https://blog.energybrainpool.com/en/update-eu-energy-outlook-2050-how-will-europe-evolve-over-the-next-30-years/

Energy live news, 2021. Accessed 03/2022, https://www.energylivenews.com/2021/09/16/large-fire-at-key-uk-substation-cuts-off-power-from-france/

Evening Standard, 2009. Accessed 03/2022, https://www.standard.co.uk/hp/front/60-000-homes-are-blacked-out-as-vandal-fire-causes-huge-power-cut-6746359.html

Electricity North west, 2019. Value of Lost Load to Customers: Closedown report, A Network Innovation Allowance project, 2019.

Geidl, M., 2007. Integrated Modelling and Optimisation of Multi-Carrier Energy Systems. ETH Zurich.

GIE, 2022

Gissey, GC., Guo, B., Newbery, D., Lipman, G., Montoya, L., Dodds, P., Grubb, M., Ekins, P., 2019. The value of international electricity trading, A project commissioned by Ofgem, 2019.

Guardian, 2015. Accessed 03/2022, https://www.theguardian.com/uk-news/2015/dec/30/storm-frank-batters-large-parts-of-uk-as-weather-misery-deepens

Guilod, BP., Jones, RG., Kay, AL., Massey, NR., Sparrow, SN., Wallom, DCH., 2017, Managing the Risks, Impacts and Uncertainties of drought and water Scarcity(MaRIUS) project: Large set of potential past and future climate time series for the UK from the weather@home2 model 2017.

HM Government, 2022. British Energy Security Strategy -Secure, clean and affordable British energy for the long term, Hm Government, 2022

London Economics, 2011. Estimating Value of Lost Load (VOLL) for Electricity in Great Britain: Final report to OFGEM 2011.

London Economics, 2013. The Value of Lost Load(VOLL) for Electricity in Great Britain: Final report for OFGEM and DECC 2013.

Lovrić, M., Blainey, S., Preston, J. A., 2018. Conceptual design for a national transport model with cross-sectoral interdependencies. Transp Res Procedia 2018;27:720–7. https://doi.org/10.1016/j.trpro.2017.12.150.

Mirror, 2015. Accessed 03/2022, https://www.mirror.co.uk/news/uk-news/huge-fire-cut-power-135000-6127963

National Grid, 2021a. Electricity Ten Year Statement, UK electricity transmission.

National Grid, 2021b. Gas Ten Year Statement, UK Gas transmission.

National Grid, 2021c. Future Energy Scenarios.

National Grid, 2021d. Winter outlook report (Electricty)

National Grid, 2021e. Winter outlook report (Gas)

Ofgem, 2014, December 2013 storms review – Impact on electricity distribution customers

Reuters, 2022. Britain allows Centrica to reopen Rough gas storage facility, https://www.reuters.com/business/energy/britain-allows-centrica-reopen-rough-gas-storage-facility-2022-08-30/

Reuters, 2021. Could a 'strategic reserve' ease Europe's gas crisis? https://www.reuters.com/world/europe/could-strategic-reserve-ease-europes-gas-crisis-2021-10-06/

UKERC, 2018. Challenges for the decarbonisation of heat: local gas demand vs electricity supply Winter 2017/2018

Van der Welle, A.J., Van der Zwaan, B.C.C., 2007. An Overview of Selected Studies on the Value of Lost Load (VOLL). in National and EU level estimates of energy securities, CASES EU FP-VI project, Work Package 5 report D5.1, December 2007

Wikipedia, 2022a. https://en.wikipedia.org/wiki/2003_London_blackout

Wikipedia, 2022b. https://en.wikipedia.org/wiki/2021_United_Kingdom_natural_gas_supplier_crisis

Appendix

Energy system data

A1. Fuel and carbon prices

Fuel prices for gas, oil, coal are taken from (BEIS, 2020b). Central gas price assumption is used for domestic and pipelined imports. A high gas price assumption is used for LNG supplies.

Interconnector electricity prices are set uniformly across all imports. For 2020 this is set at ~£60 Euros/MWh (Gissey G.C et.al., 2019). For 2050 this is set at ~85 Euros/MWh (Energy Brainpool, 2021).

Carbon price in 2020 is set at £18 t/CO2. In 2050 this increases to £100 t/CO2.

A2. Electricity system data

A2.1 Generation plant data

The generation capacity mix (Table A.1.) is taken from the National Grid FES scenarios document and worksheet (National Grid, 2021a). The plant efficiencies and availabilities are taken from the Winter Outlook Report (National Grid, 2021d).

Table A.1. Generation capacity mix

	2020	Consumer Transformation (2050)	System Transformation (2050)
Interconnectors	4.75	26.95	19.55
Biomass	4.43	0.67	1.38
BECCS	0.00	12.00	11.40
Nuclear	7.07	17.14	14.94
Hydrogen	0.00	12.73	21.11
Fossil Fuel	42.00	0.00	0.04
Gas CCUS	0.00	0.00	12.50
Solar	13.05	77.84	57.18
Offshore wind	10.45	113.17	94.91
Onshore wind	12.68	44.58	30.99
Other renewables	5.57	11.52	13.31
Storage (battery/pump storage etc)	3.53	40.70	27.88
TOTAL (GW)	**103.5**	**357.3**	**305.2**

A2.2 Battery storage

A breakdown of battery storage capacities (peak) installed in transmission and distribution systems in 2050 are shown in Table A.2.:

Table A.2. Fixed battery capacity (peak power - 2050)

	Consumer Transformation	System Transformation
Transmission	10.9 GW	9.9 GW
Distribution	16.1GW	7.9 GW

A3. Gas and Hydrogen network data

All gas network data (pipes/storage) is taken from the Ten-year statement on gas (National Grid, 2021b). Gas supply availability data was taken from the FES scenarios document (National Grid, 2021c; 2021e).

Gas storage facilities are assumed to be 80% full at the start of each simulation.

A3.1 Hydrogen storage data

Hydrogen storage capacities in 2050 are shown in Table A.3.

Table A.3. Hydrogen storage capacity (2050)

	Consumer Transformation	System Transformation
Storage (TWh)	12	51

A4. Energy demand data

A4.1 Non-transport energy demand

Existing (2020) and future energy demand is simulated using a national energy demand model produced by the Infrastructure Transitions Research Consortium (ITRC) (Eggimann et.al, 2018). The simulation is based on different socio-technical scenario assumptions such as population, Gross Value Added (GVA), technological efficiencies, changes in the technological mix (this data is taken from the FES scenarios) per end-use consumption or behavioural change.

A4.2 Transport demand

The transport model is a strategic road transport model for Great Britain produced by the ITRC (Lovrić et. al., 2018). This is a road network model covering all major roads in Great Britain. The transport model requires population, GVA, fuel prices and engine type proportions (e.g. 50% battery electric, 30% hybrids and 20% internal combustion etc – Data is taken from the FES scenarios). Using these inputs, the transport model provides the number of vehicle trips (disaggregated by engine type) and energy consumed (electricity and hydrogen) for each trip within each region during each hour across weekday and weekends during a year.

An energy-transport module was used to translate the outputs from the transport model to electricity and hydrogen demand for transport, and electrical energy available in EV batteries for V2G services. The energy-transport module assumed a trip to vehicle ratio of one, a high probability that most trips are local, and an electric car battery capacity of 30kWh. The EV energy and V2G capacities for the two FES scenarios is shown in Table A.4.

Table A.4. EV energy capacity and V2G capability (2050)

	Consumer Transformation	System Transformation
V2G (peak power)	17.1 GW	8 GW
EV storage capacity	122.3 GWh	57.4GWh

EV charging is modelled within the energy hubs in two ways, unmanaged and managed charging. The hourly unmanaged EV charging, and hydrogen re-fuelling demands are modelled based on published hourly charging patterns by National Grid (National Grid, 2021b) which takes into account the differences between weekdays and weekends. Modelling of managed EV charging does not use a fixed profile as described in the unmanaged charging case. Here, a decision variable is defined for the EV charging demand, which is summed over a 24-hour period and equals the daily EV charging demand from the transport model.

A5. Demand Side Response (DSR) modelling

Demand Side Response (DSR) capabilities were modelled within the energy hubs. DSR allows the ability to shift electricity demands, from peak to off peak hours, such that the total operating costs are minimised. DSR is implemented by considering user defined inputs, these include, peak hours $\left(t_{p1}, t_{p2}, t_{p3 \ldots\ldots}\right)$, off-peak hours $\left(t_{op1}, t_{op2}, t_{op3}, t_{op4}, t_{op5 \ldots\ldots}\right)$, and maximum potential demand shift $(k\ \%)$ from the electricity demand at a given peak. For both FES scenarios the peak hours assumed are 17:00-20:00.