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Role of power-to-gas in an integrated gas and electricity system in Great Britain

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ABSTRACT

Power-to-gas (PtG) converts electricity into hydrogen using the electrolysis process and uses the gas grid for the storage and transport of hydrogen. Hydrogen is injected into a gas network in a quantity and quality compatible with the gas safety regulations and thereby transported as a mixture of hydrogen and natural gas to demand centres. Once integrated into the electricity network, PtG systems can provide flexibility to the power system and absorb excess electricity from renewables to produce hydrogen. Injection of hydrogen into the gas network reduces gas volumes supplied from terminals.

In order to investigate this concept, hydrogen electrolysers were included as a technology option within an operational optimisation model of the Great Britain (GB) combined gas and electricity network (CGEN). The model was used to determine the minimum cost of meeting the electricity and gas demand in a typical low and high electricity demand day in GB, in the presence of a significant capacity of wind generation. The value of employing power-to-gas systems in the gas and electricity supply system was investigated given different allowable levels of hydrogen injections. The results showed that producing hydrogen from electricity is capable of reducing wind curtailment in a high wind case and decreasing the overall cost of operating the GB gas and electricity network. The northern part of GB was identified as a suitable region to develop hydrogen electrolysis and injection facilities due to its vicinity to a significant capacity of wind generation, as well as the existence of gas network headroom capacity, which is expected to increase as a result of depletion of UK domestic gas resources.

Introduction

The UK government has ambitious plans to deploy renewable sources of energy and reduce greenhouse gas (GHG) emissions from the energy sector. As part of the EU 2020 target [1], the share of electrical energy generated from renewables needs to increase to approximately 30% by 2020. Furthermore, the UK is committed to reduce its GHG emissions by at least 80% (from 1990 levels) by 2050 [2].

Wind generation is projected to play an important role in achieving the UK's renewable and emissions targets. The onshore installed wind capacity is expected to increase to

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21 GW by 2035 from 5.5 GW in 2012 [3]. Offshore wind capacity is expected to increase to 12 GW by 2020, 28.6 GW by 2025 and up to 37.5 GW by 2035 [3]. As the penetration of renewable power increases, periods of excess generation will become more frequent and of larger magnitude. Previous studies [4,5] suggest electricity curtailment could reach 2.8 TWh per annum by 2020 and as much as 50–100 TWh per annum by 2050 depending on the amount of installed renewables. If storage is used the monetary value of storing this excess energy could be as high as £10 bn/year by 2050 [4].

The integration of large capacity of wind generation into the grid poses a number of challenges. Given that large wind farms (especially offshore wind farms) are located far away from demand centres, significant investment is required to build or reinforce the electricity transmission network to transport the power generated. The variability of wind power, which results in an annual capacity factor of 27%–35% [6], makes it difficult to justify the expansion of transmission capacity to accommodate the maximum wind power produced. Previous studies [6] showed that the curtailment of wind power is sensitive to insufficient transmission capacity, low consumer demand and installed must-run generation units such as nuclear. Currently, UK wind curtailment is 0.1 TWh/annum [5] and occurs primarily due to transmission line constraints. In a future scenario where the UK increases its nuclear power generation capacity alongside wind, curtailment will increase further.

Owing to a number of financial incentives supporting efficiency improvements (Green Deal, Energy Company Obligation) and a shift to electrified heating [7], the demand for gas to domestic dwellings is projected to decrease over the next few decades [3]. The decrease in gas demand combined with the depletion of the UK domestic gas resources is changing the pattern of gas flows in the National Transmission System (NTS), as shown by Fig. 1. In particular, the north-south gas flow is projected to decrease further despite the large capacity of the gas transmission network in Scotland.

Power-to-gas (PtG) converts electricity into hydrogen using the electrolysis process and uses the gas grid for the storage and transport of hydrogen. This method is different from conventional electrical energy storage systems, which absorb and output electrical energy (pumped storage, batteries). PtG systems produce hydrogen that can be blended with natural gas in a quantity and quality compatible with the gas grid. Fig. 2 shows a schematic of a PtG system. In a

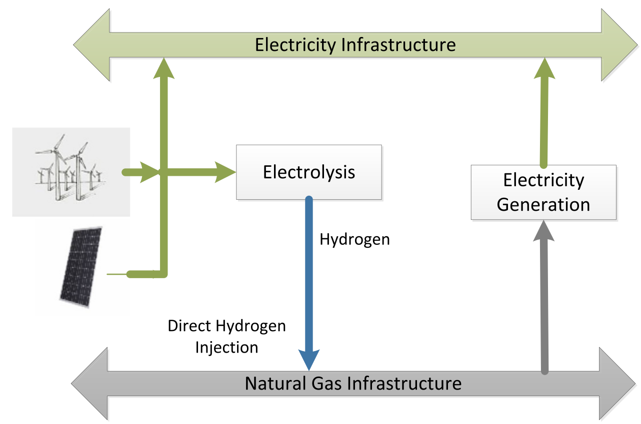


Fig. 2 – Power-to-gas system schematic.

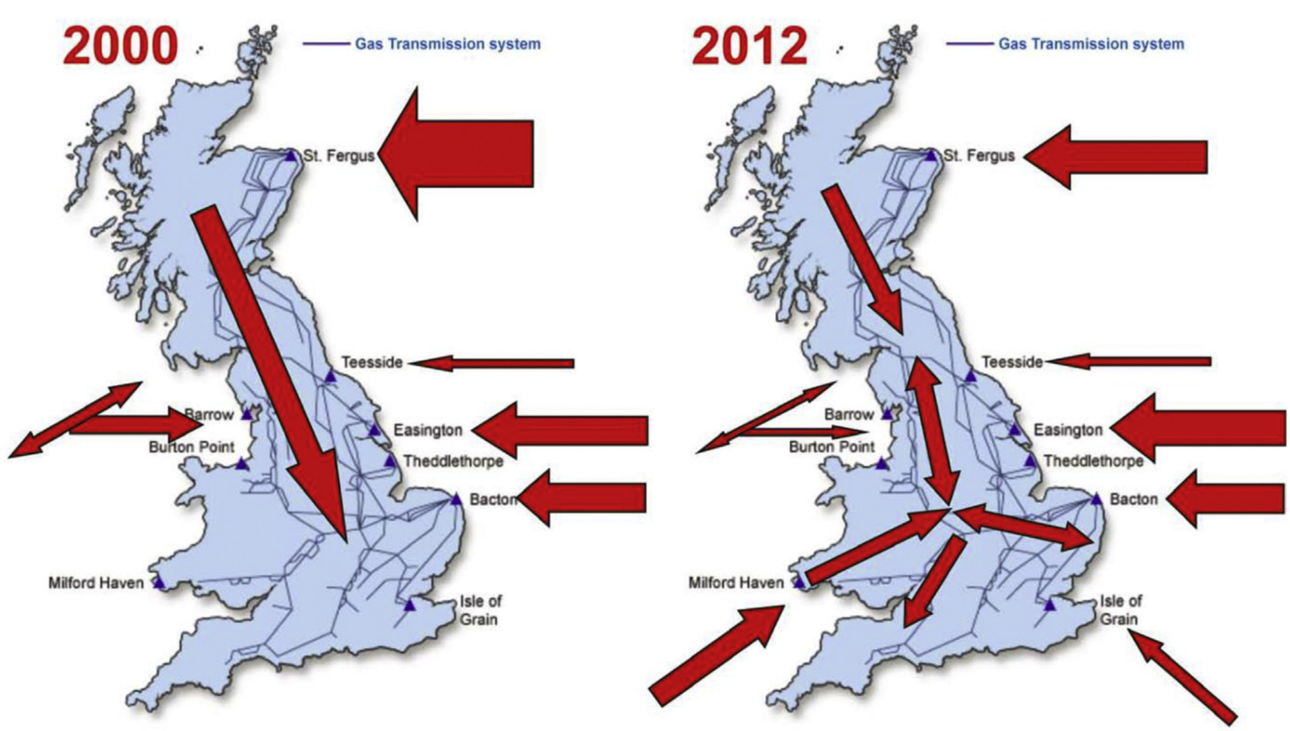


Fig. 1 – Gas flow pattern in the NTS [8].

PtG system hydrogen also can be stored or converted to methane, however hydrogen storage or methanisation process are not shown in Fig. 2, as it is not considered in this study.

PtG systems can be operated to [5]:

- absorb otherwise curtailed wind/solar electricity
- use a combination of grid electricity and local renewable electricity to produce low carbon rather than zero carbon hydrogen and
- operate on a time base that meets load levelling and/or balancing services objectives

Electrolysers in PtG systems can be operated as controllable loads. The potential of large scale integration of hydrogen technologies in balancing the Spanish power system was studied in Ref. [9]. PtG has the potential to reduce investments required for electricity network capacity reinforcement. Currently, wind farms in areas with network constraints are able to bid 'not to generate' at times of overload with potential payments that can be very high [10]. In these situations, curtailed energy could be used to generate hydrogen which is subsequently injected into the gas grid. By transporting low-carbon/carbon neutral gases within the GB gas network, the infrastructure is better utilized and the life of the network extended. Storing energy in this way could reduce reliance on gas imports in the long term, while potentially reducing price volatility and thereby delivering value for consumers.

In this study, the impacts and benefits of employing PtG systems in the integrated operation of the GB's electricity and gas networks were investigated. The study allows minimum cost of operation in the combined system to determine the electricity generation mix and gas supply dispatched to meet the diurnal electricity and gas demand.

An operational optimisation model of GB combined gas and electricity network [11] was used to determine the minimum cost in meeting the electricity and gas demand in a typical low and high electricity demand day. A case with no PtG systems in the model was compared with two modes of the PtG system operation (quantity of hydrogen injection constrained and unconstrained). The combined gas and electricity network operation with the predicted significant installed wind generation capacity was simulated. The research examines the temporal and spatial interactions of multiple energy infrastructures in the supply of electricity and gas demand in GB. The material and safety aspects and the economic feasibility of installing PtG systems were not within the scope of this research.

Effects of hydrogen injection in the gas network

Whereas the injection of upgraded biogas or synthetic methane to the natural gas pipeline is unproblematic [2], the injection of hydrogen has several implications. It is not clear to what extent hydrogen can be fed into the gas distribution system and information about the impacts and risks of doing so is contradictory. There have been several research project reports [5,12] and publications [13–15] highlighting the effects and implications of hydrogen injection in a natural gas pipeline. At present, natural gas network cannot be used to transport hydrogen due to regulations on gas quality and standards [16]. The maximum level of hydrogen content that is allowed in the UK is 0.1% (by volume). Nevertheless, several studies have shown injections of up to 17% (by volume at Standard Temperature and Pressure) of hydrogen into the natural gas network should not cause difficulties [12].

The volumetric energy density of hydrogen (13 MJ/m^3) is one third of that of pipeline natural gas (39 MJ/m^3). Therefore, injecting hydrogen reduces the thermal energy delivered to the customer if supplied at the same flow rate. Due to the lower energy density of the gas mixture and a higher flow rate required to meet the demand, the energy stored in the pipeline (linepack) will be reduced and may undermine short term security of supply [17]. The most important impact of using hydrogen in burners, boilers or gas engines is the increase of the flame speed, which brings the risk of flashback.[1] There are also concerns over the effect on the pipeline material of an increased fraction of hydrogen in the gas. The phenomenon of hydrogen embrittlement is one such problem but is complicated to predict as it not only depends on the material of the pipeline but also on the pipeline's history [12]. Volumetric losses of hydrogen by leakage will be larger than natural gas but the energy content of the losses are smaller due to comparatively lower energy density of hydrogen [5,12]. The higher pressure ratios required at the compressor stations to make up for the decrease in calorific value can cause problems due to material strength limitations.

A feasibility study of power-to-gas in the UK [5] suggests a revision of the Gas safety and management regulations [16] to consider increasing the hydrogen limit to 3% (to commence in 2015) which will not require burners or gas fired equipment to be adjusted or replaced.

Combined gas and electricity networks (CGEN) model

A combined gas and electricity network optimisation model (CGEN) was used to analyse the role of hydrogen injection to the GB gas network. CGEN model minimises the total operational cost of the combined gas and electricity system (Eq. (1)) including the costs of gas supplies, gas storage operation, power generation and costs of unserved energy over the entire time horizon while meeting gas and electricity demand. Technical limitations and characteristics of components of both networks are considered as constraints of the optimisation. Complete formulation of the CGEN model can be found in Ref. [11].

[1] Flash back occurs when the combustion flame travels upstream from the combustion zone into the premixing sections of the combustor. This upstream propagation of flame takes place whenever the flame speed exceeds the approach flow velocity.

$$Z=\min\sum_{t}\left\{\underbrace{\sum_{i}\left(C_i^f+C_i^{var}\right)P_{i,t}^{gen}}_{\text{Costs of electricity generation}}+\underbrace{\sum_{a}C_a^{gas}\ Q_{a,t}^{supp}+\sum_{s}C_s^{\omega}\ Q_{s,t}}_{\text{Costs of gas supply}}+\underbrace{\sum_{b}C^{ue}\ P_{b,t}^{ue}+\sum_{n}C^{ug}\ Q_{n,t}^{ug}}_{\text{Costs of unserved energy}}\right\} \tag{1}$$

In Eq. (1), index t is operational time step (every 1 h), C_i^f is fuel cost of power plant i, C_i^{var} is variable operating cost of power plant i, $P_{i,t}^{gen}$ is electricity generated by power plant i at time t, C_a^{gas} is price of gas at terminal a, $Q_{a,t}^{supp}$ is gas supply from terminal a at time t, C_s^{ω} is cost of gas withdrawal from storage facility s, $Q_{s,t}$ is gas withdrawal from storage facility s at time t, C^{ue} is cost of unserved electricity, $P_{b,t}^{ue}$ is electricity demand unserved at busbar b at time t due to power generation and/or transmission constraints, C^{ug} is cost of unserved gas, and $Q_{n,t}^{ug}$ is gas demand unserved at node n at time t.

Gas network operational optimisation with hydrogen injection

The main components of a gas transmission network, including pipelines, compressors, storage facilities and gas terminals, were modelled in CGEN. At each node in the gas network, gas flow balance (Eq. (2)) and pressure constraints were applied. At each node, gas supply from terminals, storage facilities, pipes (delivered from other nodes) in addition to hydrogen produced by electrolysers is equal to gas consumption:

$$\underbrace{\sum_{a\to n}Q_{a,t}^{supp}+\sum_{s\to n}Q_{s,t}+\sum_{p\to n}Q_{p,t}}_{\text{gas supplies}}+\underbrace{\sum_{e\to n}Q_{e,t}^{electrolyser}}_{H_2\ \text{from electricity}} =\underbrace{\sum_{c\to n}\tau_{c,t}+Q_{n,t}^{demand}-Q_{n,t}^{ug}}_{\text{gas consumption}} \tag{2}$$

where, $Q_{p,t}$ is gas delivered by pipe p at time t, $Q_{e,t}^{electrolyser}$ is hydrogen production by electrolyser e at time t, $\tau_{c,t}$ is gas consumed by gas-driven compressor c at time t, and $Q_{n,t}^{demand}$ is gas demand at node n at time t.

For the purpose of network analysis, the amount of hydrogen injected into the gas network ($Q^{electrolyser}$ in Eq. (2)) was converted to a volume of equivalent natural gas at standard temperature and pressure which carries the same amount of energy.

Having met the constraints of the gas network, the optimal volume of gas supplied from various sources (terminals and storage facilities) as well as gas flow along the pipes are determined as a result of minimising the total costs of operating the combined gas and electricity system.

Electricity network

A least cost generation dispatch determines the power output from each power plant. Power transmission capacity limits maximum real power flow between different busbars. Transmission line resistance and therefore real power losses were neglected. These losses are typically of the order of 1–2% of total electrical energy transferred across the GB transmission network [18]. The power balance equations are satisfied such that total generation is equal to total demand minus load shedding at each time step. The generation schedule produced is kept within the physical limits of each generation plant. All thermal generators are modelled with ramp rate constraints.

A balance constraint is applied to ensure electricity generation satisfies electricity demand at each busbar (Eq. (3)), so that power generation at each busbar in addition to power delivered to the busbar via transmission lines is equal to the power consumption including power consumed by electrically driven gas compressor and power used by electrolysers to produce hydrogen.

$$\underbrace{\sum_{i\to b}P_{i,t}^{gen}+\sum_{l\to b}P_{l,t}}_{\text{electricity supplies}}=\underbrace{\sum_{e\to b}P_{e,t}^{electrolyser}+P_{b,t}^{demand}+\sum_{c\to b}P_{c,t}^{compressor}-P_{b,t}^{shedding}}_{\text{electricity consumption}} \tag{3}$$

where, index b represents electrical busbars, $P_{l,t}$ is electricity delivered by transmission line l at time t, $P_{e,t}^{electrolyser}$ is electricity consumed by electrolyser e at time t, $P_{c,t}^{compressor}$ is electricity consumed by compressor c at time t.

In this study, the linkages between the gas and electricity networks are gas-fired generators, electrically driven compressors and PtG systems. Gas turbine generators provide the main linkage between the gas and electricity networks. The relationship between the gas consumption and the real electrical power generation is expressed as Eq. (4):

$$P^{Gen}=\varphi QH \tag{4}$$

where, P^{Gen} is power output from a gas-fired plant, φ is efficiency of the plant, Q is volume of gas input into the plant, and H is gas heating value (~39 MJ/m^3).

With regards to reducing the emissions from the GB National Transmission System (NTS), three gas powered compressors are being replaced by electrically driven compressors at St Fergus, Kirriemuir and Hatton. The power consumptions by compressors are calculated by Eq. (5).

$$P^{compressor}=\frac{Q^{compressor}\ \alpha}{\eta(\alpha-1)}\left[\left(\frac{p^{out}}{p^{in}}\right)^{(\alpha-1)/\alpha}-1\right] \tag{5}$$

where, $P^{compressor}$ is power consumption by compressor, p^{out} and p^{in} are pressure of the gas coming out of the compressor and going into the compressors, and $Q^{compressor}$ is volume of gas passing through the compressor, η is compressor efficiency and α is a polytropic exponent.

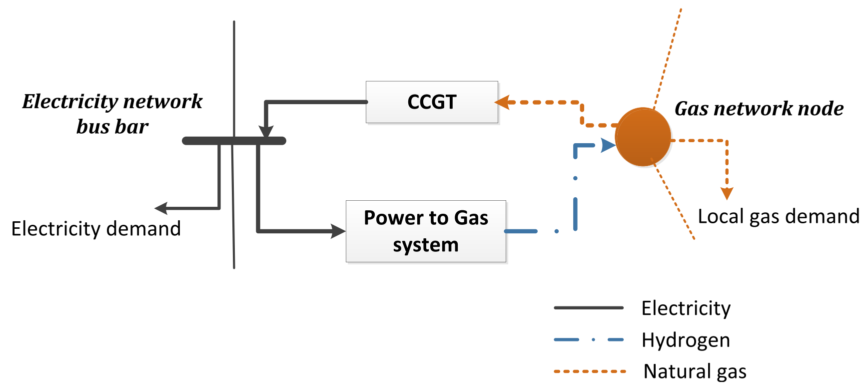


Fig. 3 – Schematic of the integration of electricity and gas network by Combine Cycle Gas Turbine (CCGT) and PtG systems.

Modelling power-to-gas systems

PtG systems inject hydrogen produced from grid electricity, into the gas network. These systems are deployed at bus bars with an existing linkage to the gas network (Fig. 3).

The amount of hydrogen production and the electrolyser efficiency (Assumed 70% [5]) determine the additional electricity demand at the busbar. The PtG system was modelled using Eq. (6):

$$Q_t^{electrolyser} = C \times P_t^{electrolyser} \tag{6}$$

where, C is a coefficient used for converting electricity to hydrogen taking into account efficiency of electrolysers.

Simplified GB gas and electricity networks

The National Transmission System (NTS) [8] was simplified and used to represent the GB gas network. The simplification of the NTS reduces network complexity and simulation runtime. The major difference between the NTS and the simplified network is the number of pipes and nodes. Gas terminals and storage facilities are kept the same for both networks. The simplified GB gas and electricity networks are presented by Figs. 4 and 5, respectively.

Case studies

Case studies were defined to investigate the optimal operation of a GB gas and electricity networks in 2020 during high wind periods in the presence of PtG systems. The generation capacity mix as well as maximum power transmission capacity are provided in Tables A.1 and A.2 in the Appendix. Costs and technical characteristics of various generation technologies are provided in Table A.3 in the Appendix. Electricity demand for a typical low and high demand day were considered. Operation of the combined gas and electricity network was optimised for the two electricity demand cases with different levels of hydrogen injection permitted. The following section describes the case studies simulated.

Limitations on the quantity of hydrogen injection

No-H2: This case models the combined GB electricity and gas network without PtG systems. It was used as a reference to which all other case studies were compared.

H2-5%: This represents case studies in which hydrogen is injected at levels up to 5% of the gas demand at a specified node.

H2-Unlimit: In these case studies PtG systems were not constrained in the amount of hydrogen which can be injected at any gas node.

In the cases with PtG considered, the injected hydrogen can be either used locally or transported using the National Transmission System (NTS) to other parts of the network.

Demand and wind generation data

The gas demand (except for electricity generation) was assumed to be same for all case studies (250 mcm in a day). Gas demand for electricity generation is an output of the model and was determined based on the economic dispatch model.

High and low electricity demand data was taken from real time data reported by National Grid [19] on 16 January 2013 and 15 April 2013. Wind power data was taken from real power output of 7136 MW wind farms on 15 April 2013 [20]. The wind power data was then scaled up to represent the power output from 29.5 GW wind generation capacity projected to be installed by 2020 [3]. The geographical distribution of wind generation capacity is provided in Table A.4 in the Appendix. Fig. 6 shows the two aggregated electricity demand profiles and the up-scaled aggregated wind power data used in this study.

Results

Power generation mix and wind curtailment in the No-H2

Optimal dispatch of power generation units to meet the hourly power demand of the reference cases (No-H2) are shown in Fig. 7.

Power generation from nuclear and coal supplied a significant part of the base load in No-H2 case (for both low and high electricity demand). CCGT units are used to meet the remaining electricity demand (electricity demand not met by wind, nuclear and coal). However, in both the low and high power demand cases wind curtailment occurred as shown in Fig. 8. The total curtailed wind energy was almost 29 GWh for the low demand case and under 9 GWh for the high demand case. The large variation highlights the sensitivity of wind curtailment to electricity demand. Curtailments were shown

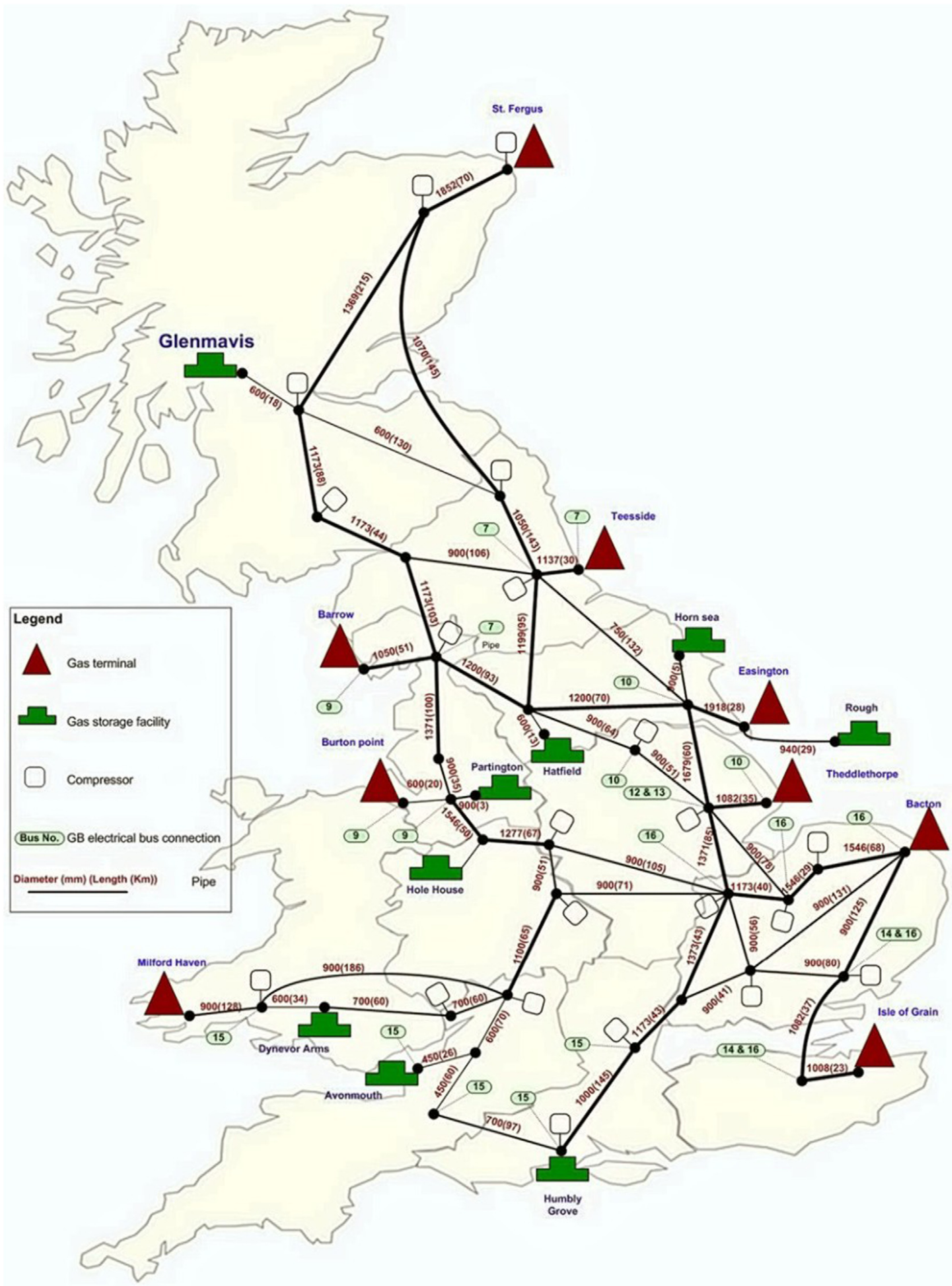


Fig. 4 – A simplified GB gas transmission network.

to be largest in the early periods (0 h–8 h) in both demand cases and prevalent in the bus bars located in the north of GB (Scotland and North England regions). The curtailment is due to the low power demand during early hours, the highly congested north-south power transmission line and the inflexibility of nuclear power plants.

The total gas supplies required over the day from terminals and storage facilities were 259.5 mcm for high electricity demand case, and 251.7 mcm for low electricity demand case and the total cost of operation of the combined infrastructure was £76.3 million for low electricity demand case and £86.1 million for the high electricity demand case.

The impact of power-to-gas systems on wind curtailment

Introducing PtG systems in the model reduces the amount of wind curtailment compared with the No-H2 case. This is due to the ability of power-to-gas systems to use electricity in

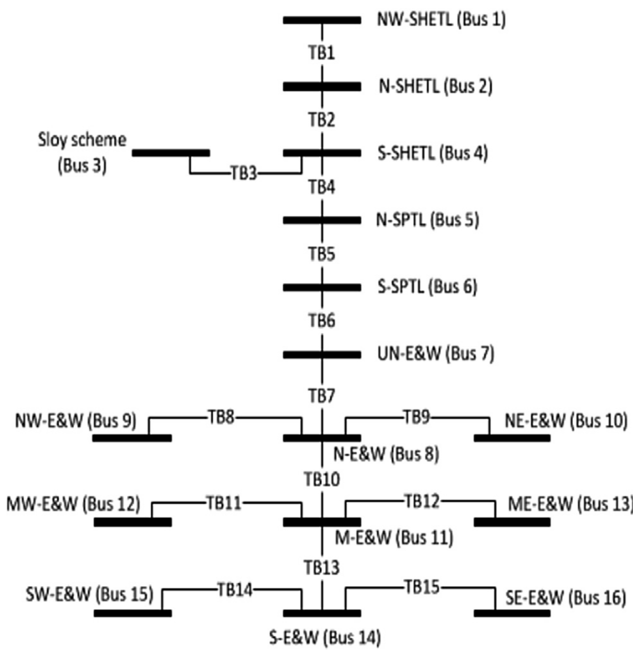


Fig. 5 – A simplified electricity transmission network.

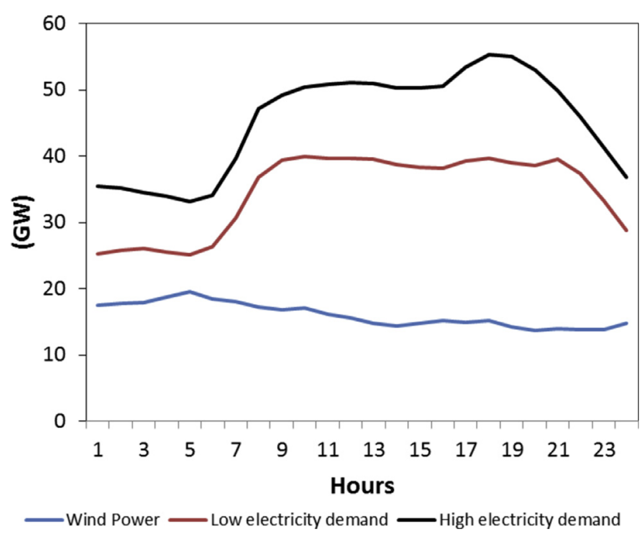


Fig. 6 – Electricity demand (high and low) and wind power used in various case studies.

producing hydrogen at locations where wind generation was previously curtailed. However, the cases with a 5% hydrogen injection limit still showed a small amount of wind curtailment. This is due to reaching the upper limit of the allowable hydrogen injection at locations with large quantities of excess electricity and at periods of low gas demand. Wind curtailment was eliminated completely when the limit to hydrogen injection was removed. Fig. 9 shows the hourly variation of aggregated wind curtailment across GB in the No-H2 and H2-5% cases where hydrogen injection is constrained. The percentage reduction in wind curtailment is much lower in the high demand case. The total residual wind energy curtailment in the H2-5% case is approximately 11 GWh for the low electricity demand case just over half this number for the high electricity demand case. This is a reduction of 62.3% and 27% from the No-H2 case.

Operation and locations of electrolysers

The electrolysers in PtG systems are operated at times and locations where they have the most impact in minimising the total cost of operating the combined system. Fig. 10 shows the aggregated hourly electrolyser electricity demand across GB for each case study. In both low demand and high demand days the hourly electrolyser demand in the H2-Unlimit case is higher than in H2-5% case. Electrolysers are mostly operated during the early morning periods when the electricity demand is low and the wind generation is high. The highest aggregated electrolyser power demand in a single hour of over 12 GW occurs during the morning period in the low demand case of H2-Unlimit. In the H2-5% case, the aggregated electrolyser power demand during the same period is 4.4 GW. The highest hourly aggregated electrolyser power demand in the high demand case is just under 5 GW during the morning period of H2-Unlimit. The same for the H2-5% case is 1.9 GW.

Consequently the daily electrical energy consumed by electrolysers is much higher in the low demand case than in the high demand case. It was also observed that the electrolysers are primarily dispatched in the northern parts of GB where wind curtailment was prevalent due to power transmission constraints. Fig. 11 shows the electrical energy consumed by electrolysers in each region.

Of the total electrical energy consumed by electrolysers in the low demand case (48 GWh in the H2-5% case and 117 GWh

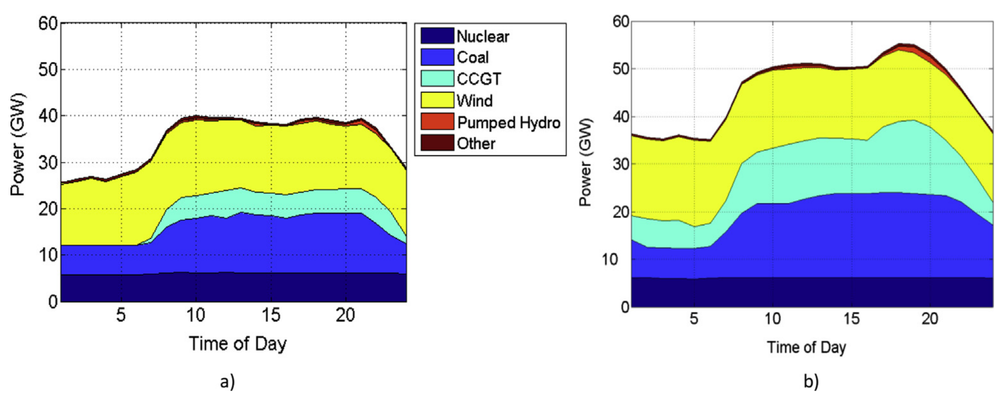
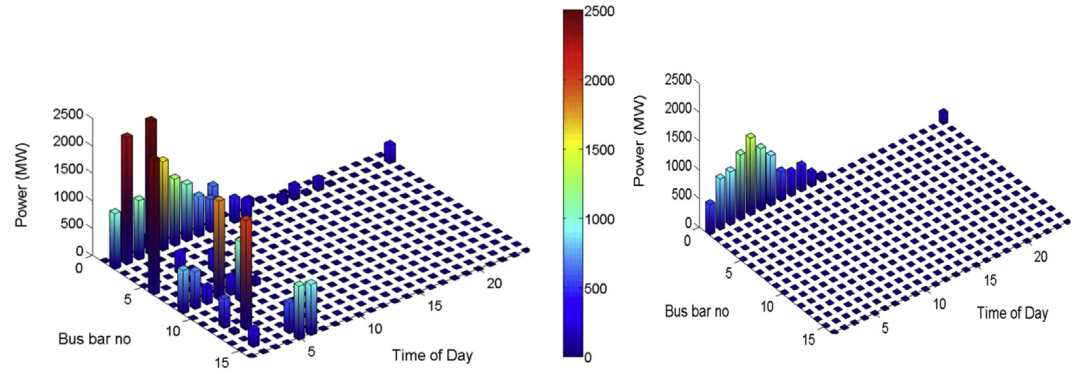
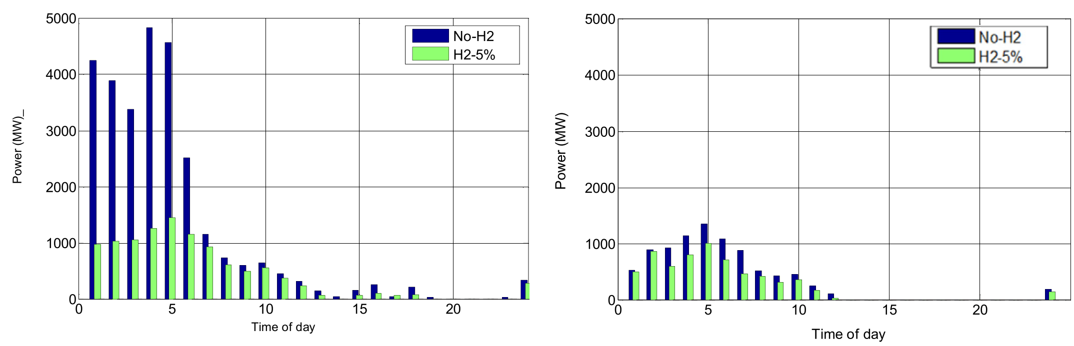


Fig. 7 – Optimal dispatch of power generation units for the No-H2. a) Low power demand. b) High power demand.



a) b)

Fig. 8 – Wind curtailment for the No-H2 case. a) Low power demand. b) High power demand.



a) b)

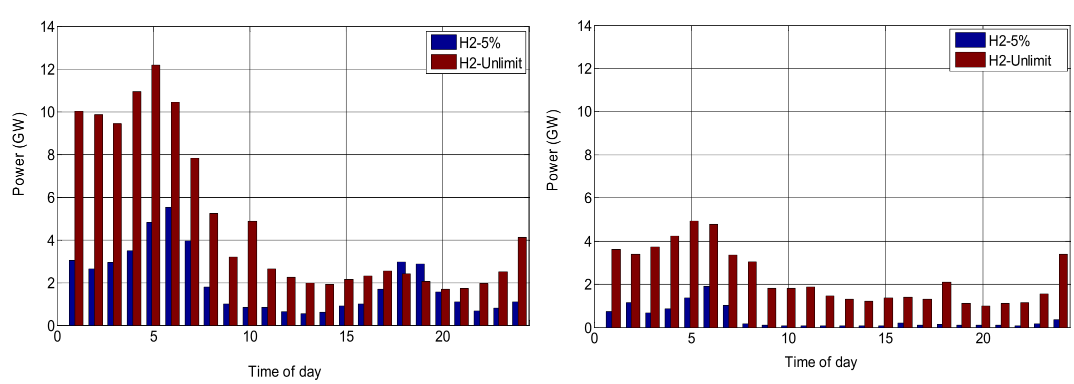
Fig. 9 – Wind curtailment with power-to-gas systems in the model. a) Low power demand. b) High power demand.

in the H2-Unlimit), 70% of the demand in the H2-5% and 96% in the H2-Unlimit case is located in the Scotland and North England and Wales (E&W) regions. The corresponding values for the high electricity demand day are above 95% in both cases. Operation of electrolysers in the northern parts of GB shows the suitability of the gas and electrical infrastructure in these regions for accommodating PtG systems.

Impact of power-to-gas systems on electricity demand

The operation of PtG systems increases both the peak (only in Scotland and North E&W) and the total electrical energy demand during a day. This is due to the operation of electrolyser units at optimal periods and locations. Table 1 shows the peak electrical power demand, the daily electrical energy demand, wind energy absorbed by the electricity network and the CCGT energy dispatched in each case study.

In the low electricity demand case, the peak electricity demand increases by 6.25% for the H2-5% case and double this for the H2-Unlimit case. The corresponding increases in the high electricity demand case are far smaller. In the low electricity demand case the daily electrical energy demand increases from 838 GWh in the No-H2 case to 883 GWh (5%



a) b)

Fig. 10 – Aggregated hourly electrolyser demand. a) Low power demand. b) High power demand.

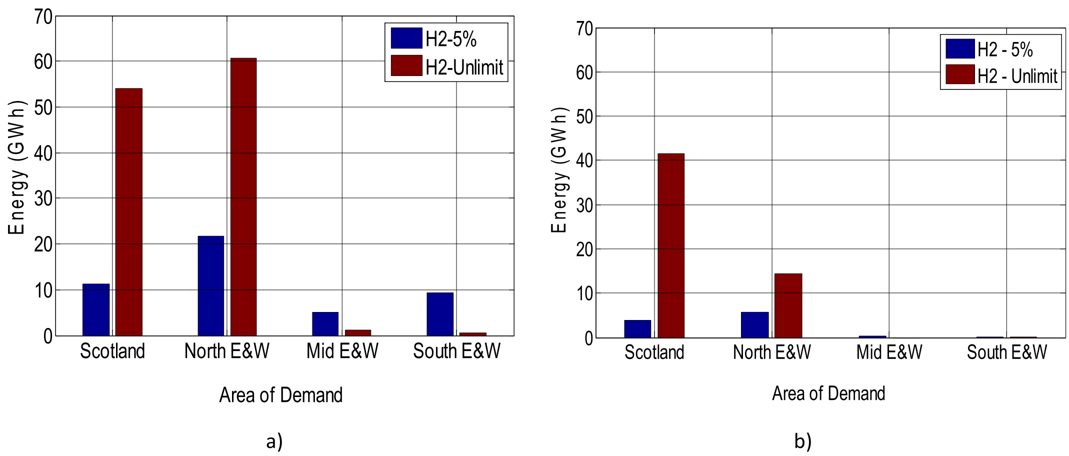


Fig. 11 – Regional electricity demand for electrolysers. a) Low power demand. b) High power demand.

Table 1 – Impact of power-to-gas systems on the electricity demand.

Case study		Peak electricity demand (GW)	Daily electrical energy demand (GWh)	Wind energy absorbed (GWh)	CCGT energy (GWh)
Low electricity demand case	No-H2	40	837.99	352.45	83.68
	H2-5%	42.5	882.88	370.28	103.36
	H2-Unlimit	45	947.25	381.01	157.42
High electricity demand case	No-H2	55	1095.75	372.30	234.50
	H2-5%	55	1103.73	374.67	233.27
	H2-Unlimit	57	1145.24	381.01	269.86

increase) in the H2-5% case and up to 947 GWh (13% increase) in the H2-Unlimit case. In the high electricity demand case the daily electrical energy demand increases from 1096 GWh in the No-H2 case to 1104 GWh (0.7% increase) in the H2-5% case and up to 1145 GWh (4% increase) in the H2-Unlimit case.

The impact of PtG systems on gas supplies

The utilisation of hydrogen electrolysers leads to a fraction of the gas demand to be met through the hydrogen produced from electricity, and therefore reduces gas flow from terminals and consequently compressors gas consumption (Table 2).

On the other hand power output from CCGTs in the vicinity of gas terminals increases as more wind power is utilised for hydrogen production.

The introduction of electrolysers leads to new sources of gas (hydrogen) supply and therefore alters the optimal gas flow pattern in the network to minimise the total operating cost of the gas and electricity system.

Table 3 shows the natural gas supplied from gas terminals and storage facilities and hydrogen injected from PtG systems to the gas grid in each case study. As a fraction of the total gas supplied, hydrogen injected from PtG systems is low. The highest fraction of hydrogen in the gas supply (3%) was observed in the low demand case of H2-Unlimit.

Table 4 shows the spatiality of accumulated hydrogen injection across GB over the day. Corresponding to electrolyser demand, hydrogen injection is prevalent in the northern parts of GB. Due to decreasing UK domestic gas production and the reduction of gas flow from Scotland to the southern parts of GB, there is an opportunity to use the gas transmission network to deliver otherwise wasted energy from the north to demand centres.

Table 2 – Daily compressors gas consumption (MWh).

		Daily compressors gas consumption (MWh)
High demand	No-H2	946
	H2-5%	800
	H2-Unlimit	708
Low demand	No-H2	882
	H2-5%	793
	H2-Unlimit	578

Table 3 – Total gas supply for different case studies.

		Gas supplies from terminals and storage facilities (mcm)	Hydrogen injection (mcm of equivalent natural gas)
High demand	No-H2	259.5	–
	H2-5%	258	0.6 (0.2%)
	H2-Unlimit	253.6	3.6 (1.4%)
Low demand	No-H2	251.7	–
	H2-5%	248.6	3 (1.2%)
	H2-Unlimit	244.4	7.4 (3%)

Table 4 – Hydrogen production in various regions (mcm of equivalent natural gas).

		Scotland	North E&W	East E&W	West E&W	South E&W
High demand	H2-5%	0.25	0.37	0	0.01	0
	H2-Unlimit	2.65	0.92	0	0	0
Low demand	H2-5%	0.71	1.41	0.3	0.23	0.35
	H2-Unlimit	3.44	3.87	0.04	0.05	0

The impact of PtG systems on system operating cost and carbon emissions

The operating costs of the combined operation of the energy system for all case studies are shown in Fig. 12. Both the low and high electricity demand cases displayed a reduction in operating costs after PtG systems were introduced. In the low electricity demand case a small to moderate (~7%) reduction in operating cost were achieved for the H2-5% and H2-Unlimit cases respectively. In the high electricity demand case the corresponding reductions were above 8% for both cases.

Absorbing wind energy that would otherwise be curtailed results in a lower operating cost of the combined gas and electricity networks. Producing hydrogen in PtG systems using cheap electricity and substituting it for gas supplies from terminals reduces the operational cost of the system further.

Analysis of carbon emission in various cases shows that hydrogen injection can contribute in lowering the total emission, especially in cases where electricity demand is low. The carbon emissions in the high electricity demand case show no decrease in H2-5% compared to the corresponding reference case. This is because the model is a cost optimisation tool and attempts to minimise the operating cost of the energy system by meeting the constraints. The carbon cost was not included on the optimisation objective function. The increase in carbon emissions is attributed to the dispatch of cheap yet carbon intensive power generation technologies (e.g. coal).

Policy discussion

The UK has an extensive gas distribution network supplying 80% of domestic and 67% of service sector heat demands [21]. Moreover, natural gas accounts for 38% of the primary energy demand in the UK.

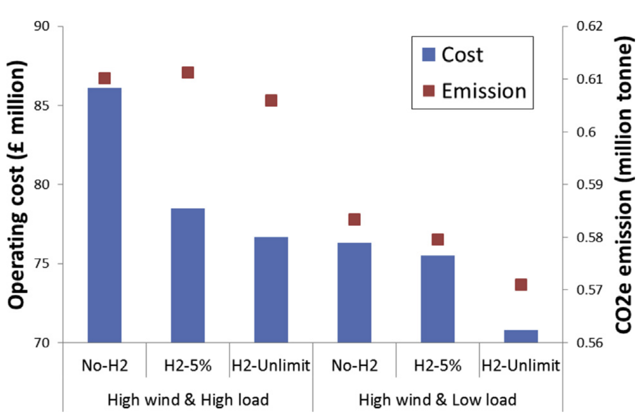


Fig. 12 – Operating cost and carbon emissions in case studies.

The UK government plans to reduce its greenhouse gas emissions by at least 80% (from 1990 levels) by 2050. When compared with fuels such as coal, burning gas for either electricity generation or for heat produces far lower CO_2 emissions. Despite this many have suggested that the gas system may need to be decommissioned to meet ambitious CO_2 targets by 2050. One way to meet these targets and therefore preserve the gas network is to partially decarbonise the network through renewable hydrogen injection.

Gas safety (Management) regulations [16] specify the gas quality requirements to be maintained in the UK gas mains. A maximum percentage of 0.1% hydrogen (by volume) is allowed in the contents of natural gas in the UK. To realise the potential of hydrogen injection into the gas grid as illustrated by the study hydrogen limits will need to be relaxed subject to a full health and safety appraisal.

An important aspect of realising the potential of hydrogen injection and the continued use of the gas grid is the decarbonisation of the electricity grid. The CO_2 emission reduction virtues of the hydrogen injection process are wholly dependent on the carbon intensity of the electricity grid. The case for hydrogen production and injection during periods of high wind and low demand is strong especially given the headlines surrounding large ‘constraint payments’ made to generators and in particular to wind farms to reduce output at certain times due to congestion on the electricity transmission network.

The GB gas network is an extensive network of pipes over 280,000 km in length. To maintain the gas network, refurbishment and expansion costs run in to billions of pounds for pipes that have a lifetime of around 60 years (20 years longer for distribution pipe lines). As an example the GB gas mains replacement programme will cost approximately £7 billion. Given that these costs have already or are about to be sunk into the gas system, abandoning such a system comes at a cost and therefore alternatives such as hydrogen injection must be explored.

Conclusion

The potential impact of integrating GB gas and electricity networks operation using power-to-gas systems was investigated. Given the large capacity of wind generation expected to be installed in Scotland and the northern parts of England and Wales, significant investment is required to reinforce the power transmission capacity between these areas and the demand centres located in the southern parts of England. Variability of the wind power output makes it difficult to justify expanding capacity of the power transmission lines to accommodate wind farms. On the other hand, lack of sufficient transmission capacity to deliver wind farms’ output to the demand centres and low consumer demand during high wind periods may result in wind power curtailment.

Modelling of the GB gas and electricity networks shows that employing electrolysers to produce hydrogen and injecting it into the GB gas network (power-to-gas) can significantly reduce wind curtailment during high wind periods. The level of hydrogen injection that is permitted is an important factor that affects the extent to which wind curtailment can be avoided. For instance, allowing injection of hydrogen up to 5% of the local natural gas demand (H2-5%) was shown to reduce wind curtailment by 62% on a typical low electricity demand day and by 27% on a high demand day with high wind energy availability, whereas allowing injection of hydrogen without any constraint (H2-Unlimit) eliminates wind curtailment completely.

The introduction of PtG not only reduced the wind curtailment via converting the excess wind into hydrogen, but also improved the optimal dispatch for electricity and gas through using cheap electricity (not only from wind) in congested zones to produce hydrogen and meet a fraction of gas demand locally. This reduced utilisation of compressors to transport gas from terminals, and consequently reduced the operating cost of the combined gas and electricity networks.

A maximum electricity demand of 12 GW of electrolyser power was observed in H2-Unlimit in a low electricity demand case. This reduces to below 5 GW for the high electricity demand case of H2-5%. Over 70% of the hydrogen produced in the low electricity demand case and over 95% in the high demand case occurred in the northern parts of GB. This is due to the vicinity to large wind generation capacity, lack of sufficient power transmission capacity and existence of gas infrastructure capacity.

The study allowed the model to determine the cost optimal use of power generation technologies and gas supplies in meeting the energy demand. The increase in electricity demand due to the electrolyser operation was met predominantly by a combination of increased use of available wind energy and an increase in the use of CCGT's. As a result, hydrogen produced in PtG systems was not carbon neutral. By limiting power-to-gas systems to only absorb otherwise curtailed renewable electricity or to utilise some proportion of the output energy of a wind/solar farm within a constrained region, the carbon intensity of hydrogen can be reduced to near zero. This would however reduce plant utilisation and affect the economics of such an investment. The implications of imposing an operational regime on PtG systems should be analysed further. Nevertheless, as GB's electricity supply is decarbonised, the carbon intensity of hydrogen produced via PtG system will reduce.

It was shown that connecting power-to-gas systems and the subsequent injection of low carbon hydrogen to the GB gas network can lead to considerable reduction of operational costs of the GB gas and electricity networks. A cost reduction of daily operation of up to 11% was shown in H2-Unlimit case. Assuming that the cost savings calculated in this study will be achieved during at least half the year, a simple payback period of investment in power-to-gas technologies (electrolysers, compressors etc.) was calculated to be 10 and 14 years respectively for the H2-5% and H2-Unlimit cases. The increase in the payback period for the H2-Unlimit case is due to the higher capital cost of the PtG system.

It was shown that, as a fraction of the total gas supplied, hydrogen delivered from PtG systems is quite low. The highest fraction of hydrogen in the overall gas supply (3%) was observed in H2-Unlimit. However, hydrogen fractions are higher in the northern parts of GB, due to the higher curtailed wind availability and prevalence of electrolyser units. The current regulation of 0.1% of hydrogen in the natural gas blend in the GB will require a revision if the PtG systems are to be economically viable.

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Appendix

Table A.1 – Installed power generation capacity in 2020 (GW) (total 100 GW).

Busbar	Nuclear	Coal	Gas-fired	Interconnector	Biomass	Wind	Hydro and pumped storage
1	–	–	–	–	–	3	0.9
2	–	–	1.64	–	–	3.9	–
3	–	–	–	–	–	–	0.25
4	–	–	–	–	–	–	0.23
5	–	1.3	–	–	0.05	0.5	0.44
6	1.2	–	0.34	–	0.05	4	0.03
7	1.2	2.93	3.21	–	0.3	2.4	–
8	–	–	–	–	–	–	–
9	2.22	1.48	4.26	0.87	–	4.2	2
10	–	4.7	4.7	–	–	2	–
11	–	–	–	–	–	–	–
12	–	2.97	2.85	–	–	1	–
13	–	1.8	3.88	–	–	4.5	–
14	–	–	2.43	–	–	1	–
15	–	3.16	5.88	–	0.4	1.5	–
16	2.28	1.46	5.71	3.33	–	1.5	–
Total	**6.9**	**19.8**	**34.9**	**4.2**	**0.8**	**29.5**	**3.85**

Table A.2 – Capacity of interconnecting GB transmission circuits.

GB transmission boundaries	Capacity (MW)
TB1	1600
TB2	2800
TB3	500
TB4	3300
TB5	5150
TB6	5800
TB7	7500
TB8	649
TB9	3842
TB10	10,800
TB11	3908
TB12	5215
TB13	11,724
TB14	3381
TB15	2590

Table A.3 – Power generation costs [22], efficiencies and ramp rates.

Generation technology	Fuel cost (£/MWh)	O&M costs (£/MWh)	Efficiency (%)	Ramp up and down (MW/h)
Coal	19.9	2.2	40%	200
Nuclear	5.2	1.8	32%	–
CCGT	50.9	2.3	55%	250
Pumped storage		3	80%	–
OCGT	66.3	1.5	35%	300
Biomass	70	2.2	40%	200

Table A.4 – Wind power installations in 2020 (13.1 GW onshore, 16.4 GW offshore) [23].

Location	Capacity (GW)	Busbar
North Scotland (onshore)	3	1
Northwest Scotland (onshore)	3.9	2
Firth of Forth (offshore)	0.5	5
South Scotland (onshore)	4	6
Dogger Bank (offshore)	2.4	7
Rhyl (onshore)	0.7	9
North West (offshore)	3.5	9
Hornsea (offshore)	2	10
West Wales (onshore)	1	12
Norfolk and Triton (offshore)	4.5	13
Isle of Wight (offshore)	1	14
South West England (onshore)	0.5	15
Bristol Channel (offshore)	1	15
Thames (offshore)	1.5	16

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