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A Multi-model Method to Assess the Value of Power-to-Gas using Excess Renewable

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Abstract

Power-to-Gas (P2G) is a process that produces a gas from electricity, which is most commonly hydrogen via electrolysis. While some studies have considered hydrogen as a power-to-power storage vector, it could also be used as a fuel across the energy system, for example for transport or heat generation. Here, two energy models are used to explore the potential contribution of P2G as a cost-effective source of hydrogen, particularly for future energy systems with high variable renewable energy (VRE) in which there are occasional periods when electricity supply exceeds demand. A detailed electricity system model is iterated with a multi-vector energy system model using a soft-linking approach. This iterative approach addresses shortcomings in each model to better understand the optimal capacity of P2G and the potential economic capture rate of excess VRE. The modelling method is applied to Great Britain in 2050 as a case study. A substantial proportion of excess VRE in 2050 can be captured by P2G, and it is economically competitive compared with alternative sources. Moreover, the effectiveness and economic viability of P2G for reducing excess renewable is robust at even very high levels of renewable penetration.

Keywords

integrated energy systems, energy system modelling, power system modelling, hydrogen economy, renewable integration, power-to-gas (P2G)

1 Introduction

To avoid dangerous climate change by meeting the target in the Paris Agreement, the global energy system needs to transition from a fossil fuel-based system to a low-carbon system [1]. Variable renewable energy (VRE) using wind and solar is widely seen as the core part of such transformation for electricity generation [2]. It is very likely that as the proportion of renewable generation continues to increases, in the long term, the electricity sector in Great Britain (GB) by 2050 will be dominated by VRE [3], [4]. However, renewable energy systems are non-dispatchable and outputs vary both temporally and spatially [5]. As the proportion of VRE in electricity generation increases in the future, periods of excess generation, resulting from imbalances between electricity supply and demand, will become more frequent and larger. This will lead to a lower utilisation factor and higher system cost if these excesses are not addressed [6]. One option would be to deploy energy storage technologies to capture as much of the excess generation as possible, but most energy storage technologies have high capital costs. Another option that might be also competitive in the long run would be to produce alternative fuels using excess electricity for use across the whole energy system.

One promising option for producing an alternative fuel is power-to-gas (P2G), which is a process of converting electricity into hydrogen gas by electrolysis, and, if necessary, converting the hydrogen into methane, ammonia, or other gaseous energy carriers. Hydrogen produced from P2G has a wide range of potential end uses, including power generation [7], [8], transportation service [9], [10], heat generation[11], [12], and as an industrial feedstock [13], [14] [15]. The application of P2G can be found at both local level and large-scale national level, such as adding valuable flexibility for micro grid [16] [17] and smart urban system [18], providing onsite hydrogen supply for refuelling stations [19] [20], [21] , and playing as the key enabler for national overall plan to decarbonise the whole energy systems [22]–[25]. The highest value markets for hydrogen would likely change over time. In short to medium term, given the lack of hydrogen demand and infrastructure, P2G hydrogen could be methanated or directly injected into an existing natural gas system in small quantities. In the longer term, the high-purity hydrogen produced by P2G would likely have greater value in the transport sector for fuel cell vehicles, and onsite production at hydrogen refuelling stations would minimise the infrastructure barrier [26]. Hydrogen could also be used for heat generation using boilers or fuel cell micro-CHP in buildings if the gas networks were converted to deliver hydrogen [27].

Many previous works on P2G for renewable integration at national level has been set in the short to medium-term future and aimed at injecting the produced hydrogen into existing gas networks, which has demonstrated the technical feasibility of coupling electricity and gas networks in a 'hydrogen-light' energy system. These previous studies typically fall into two categories: (i) investment planning studies of the whole energy system [11], [28]–[31], with aggregated temporal resolution that cannot account for variations in renewable generation; and, (ii) operational studies of power and gas systems over short periods with pre-determined generation plant and P2G systems [32]–[36]. While the sizing, location and operational performance of P2G depend on the spatial and temporal variability of the renewable supply, limiting factors also arise from aspects characterised by the wider energy system such as the capacity split between VRE and non-VRE, and the trade-off and competition with any alternative hydrogen supply, etc. It is challenging to consider these factors simultaneously. To build on existing studies, the focus here is on the value of P2G in a 'hydrogen-rich' energy system that may develop in the long term (e.g. 2050). Given that unabated natural gas combustion would not likely be compatible with meeting climate targets by 2050, natural gas networks are not considered in this work. An alternative option would be to fully convert the existing gas networks to deliver hydrogen instead of natural gas [29] with a recent city-scale study suggesting this is feasible in principle [37]. The aim of this paper is to assess the potential of P2G to reduce curtailment from excess renewable production under plausible high-VRE energy system scenarios in 2050 and to examine the cost relative to hydrogen produced by fossil-fuelled steam reformation using carbon capture and storage (CCS).

The approach adopted in this paper is to combine long-term energy planning, to understand electricity supply and demand in a low-carbon energy system, with high-resolution power system operations that capture spatial and temporal variability of VRE for P2G use. Long term energy planning is commonly studied using Energy System Models (ESM). Power system operation is often examined using Power System Models (PSM). In the literature, models are combined through hard-linking and soft-linking. The hard-linking approach integrates the two models into a hybrid model so that they can be simultaneously solved in a single optimisation. For example, MARKAL-Macro [38] and MESSAGE-Macro [39] integrate partial equilibrium energy system models with general equilibrium macroeconomic models. In contrast, soft-linking approaches run the models sequentially, with a selected set of outputs from one model used as exogenous inputs into the other, and this process is iterated until (and if) the model solutions converge. For example, ESMs have been soft-linked to PSMs [4], [40], Computable General Equilibrium (CGE) models [41], [42], and to Housing Stock Models [43], [44]. While the hard-linking approach often requires a simplified representation of either or both models in order to obtain a tractable hybrid model, soft linking recognises the strength and focus of each model class and investigates the research question in a way that preserves these strengths in full.

In this study, a suite of sequentially soft-linked models has been developed and used to examine the value of a P2G system in avoiding 'excess' renewable generation losses in future energy systems with high VRE penetrations. This multi-model method can optimise the capacity of P2G systems based on their operational performance on an hour-by-hour basis over a yearly horizon, in order to determine the economic capture rate of excess VRE and minimise the cost of hydrogen generation. While soft-linking of models is not new per se, to the best of the authors' knowledge, there is no existing study that explicitly combines ESM and PSM with focus on the value of P2G for integrating VRE in the plausible hydrogen-rich energy system. As a result, the main contribution of the present work could be summarised as follows:

- Developing a 'hydrogen-rich' energy system pathway to assess the value of hydrogen from excess-renewable powered P2G, with energy system model configured to favour a future energy system where hydrogen is a common low-carbon fuel for end-use demands.

- Designing a tailored power system model to simulate the operation of the GB electricity network. Detailed hourly profiles for VRE generation over a typical year are provided based on the localised weather data.

- Proposing a soft-linking approach to combining both models to examine the value of P2G, and modelling the economic capture rate of excess renewables for P2G production with good spatial and temporal representation of VRE variability.
- Investigating, in a GB case study, whether power-to-gas could be a cost-effective technology for integrating high VRE into a 'hydrogen-rich' energy system in 2050, and whether this value is sensitive to the level of renewable penetration in the electricity system.

The paper is structured as follows: Section II presents the methodology, and its application to Great Britain is analysed in Section III. The discussion and conclusions are presented in Sections IV and V, respectively.

2 Methodology

The methodology of soft-linking the energy system model with a more detailed power system dispatch model is presented in this section. Please note the scope of P2G here: while concept of P2G in general can use power from any source, not just excess renewable generation. However, given the focus of this paper, it is explicitly referred to use *excess renewable generation* to produce hydrogen.

The motivation for this soft-linking is to simulate the operation of the power system within future energy system evolution, and specifically to understand the value of P2G using 'excess' renewable electricity. We use the UK TIMES model as the ESM, and a unit commitment and economic dispatch model (UCED) for the PSM. The differences between these two models' key characteristics and input data are summarised in Table I, with details discussed in following sections, Additional information of input data can be found in Supplementary Note 1,

Table I. Comparison of UK TIMES and UCED model.

Property	**UK TIMES**	**UCED**
Type	Linear optimisation	Mixed integer linear optimisation
Scope	Whole energy system	Electricity system
Boundary	UK border	GB National electricity transmission network
Spatial	single region	29 regions
Temporal	4 seasons; 4 intraday timeslices; 5-year time steps	Full hourly timeslices over a year
Exogenous inputs	Energy service demands; resource availabilities and costs; technology costs and performance [45], [46]	Electricity demand, generation capacity, renewable time series

Outputs for model linking	UK TIMES provides boundary conditions for UCED	UCED provides detailed information on the operational performance of the electricity system for UK TIMES

2.1 Energy system model: UK TIMES

UK TIMES is an economic optimisation model that minimises the whole system cost over the full time horizon (normally the period from 2010 to 2050) [46]–[49]. It models the entire UK energy system, from fuel extraction and trading, to fuel processing and transport, generation and all final energy demands. It is built using the widely-used TIMES model generator developed by IEA-ETSAP [50] and can be characterised as a partial equilibrium, bottom-up, dynamic, linear programming optimisation model. The model generates future evolution of the energy system based on assumptions about demand, commodity costs and future technology costs. UK TIMES identifies the energy system that meets energy service demands with the lowest discounted capital, operating and resource cost over the time horizon from 2010 to 2050, subject to constraints such as greenhouse gas emission targets and government policies. In addition to academic use, users of the model include the UK Government and the Electricity System Operator (National Grid) [51].

The key strength of UK TIMES is that it represents the full UK energy system on a technology-rich basis driven by a given decarbonise target, which allows insights into the relative importance of different energy vectors, technologies and policies, and the trade-offs between decarbonising different sectors of the economy. Power sector modelled in UK TIMES is fully endogenous, with both supply and demand optimised by the model.

UK TIMES, like most energy system models, compensates for the high level of detail across the energy system by representing only low temporal and spatial resolution. Spatially, the UK is represented as a single region. Temporally, four seasons are defined to enable some inter-seasonal properties to be represented. Four sequential intraday time-periods are also defined for each season: night, day, evening peak and late evening.

The low temporal resolution causes UK TIMES to not resolve the excess generation that would occur with a high penetration of VRE. To address this issue, UCED is used to calculate the excess rates for the renewable generation capacity in the future as identified in the initial UK TIMES run, and then fed back into the additional UK TIMEs run as an extra inputs. A fraction of VRE generation in each timeslice is then defined as excess generation that can only be consumed by electrolysers for P2G, or by storage technologies. Other hydrogen production routes are also included in UK TIMES, such as steam reforming using fossil fuel and biomass with CCS. By accounting for the cost and efficiency of electrolysers, the amount of the electricity flowing through the P2G route is optimised by UK TIMES to minimise the overall cost of the energy system.

2.2 Electricity system model: unit commitment and economic dispatch model

A dedicated power system model with high temporal and spatial resolution, especially for VRE, is required to accurately assess the excess generation. A combined unit commitment and economic dispatch model (referred to as 'UCED') has been developed to simulate the hourly operation of the UK power system and find the optimal dispatch for each generation unit.

The bespoke UCED model minimises total system operational costs to meet hourly demand, subject to system and unit-specific operating constraints. The system costs consist of the variable operating, start-up, shut-down costs of generation portfolio:

$$\min \sum_{t=1}^{T} \sum_{g \in G} \Big[p_g(t) C_g + v_g(t) C_g^{start} + w_g(t) C_g^{shut} + \kappa^{-}(t) C^{\kappa-} \Big] \tag{1}$$

where $p_g(t)$ is the generation level of generator g at time t; $v_i(t), w_i(t)$ are the binary variable indicating start-up and shut-down events; and, $\kappa^{-}(t)$ are any unserved demand requirements. C_g are the operating costs of conventional generators that represent the sum of variable costs of fuel,. $C_g^{start/shut}$ are the associated generator start-up and shut-down costs. $C^{\kappa-}$ are the penalty costs associated with demand shedding.

The mixed integer linear optimisation is subject to a range of constraints. For power plants, it accounts for unit level characteristics (e.g. ramping up and down of thermal generation plant; minimum up and down times; and minimum and maximum power output). For the system, accounts for demand balance, system reserve requirements, and transmission capacity.

A rolling-horizon technique is used to improve the computational efficiency of the UCED model. The UCED model has been established to operate efficiently in a discrete horizon time but also continually over a long study period. The model runs over a two-day horizon at each step, minimising the total operational cost during this period. At the end of each control horizon, the calendar moves forward by one day, as illustrated by Fig. 1. The results of the unit commitment at the previous steps are recorded as the initial input status for the next step. This allows the model to simulate real-time operation of power system with a good representation of VRE generations among other operational constraints, and is sufficiently fast to allow a number of UK TIMES scenarios to be investigated. The modelling framework has been developed to operate either with or without transmission network constraints. The model is constructed using the AIMMS modelling language and employs the CPLEX solver.

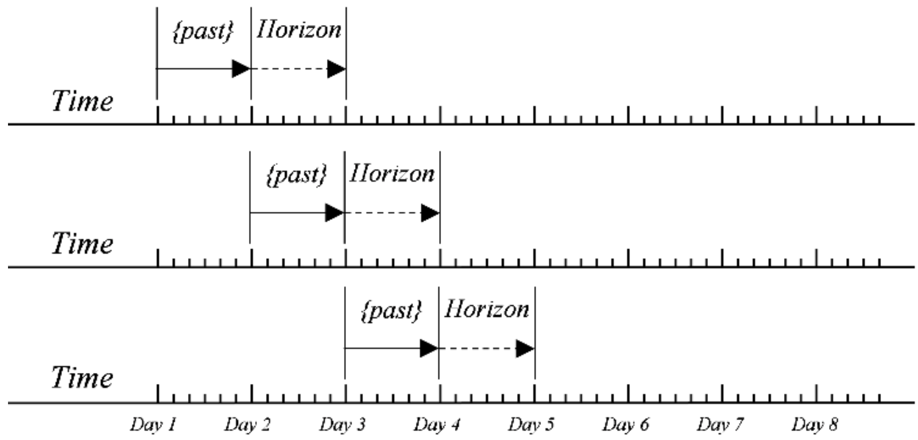


Fig. 1. Illustration of the rolling-horizon solution process.

P2G is not directly modelled within UCED. The main reason is that we need to feed the full value of the potentially 'free' excess renewable (the excess before any flexible option) back to the UK TIMES for additional run. UCED, as an operation model, is not able to make planning decision on the P2G size. . The analysis of P2G optimal capacity for cost-competitive hydrogen production is carried out in a procedure embedded in the second UK TIMES run with the additional input - the excess rate of electricity generation as calculated by UCED (see section 2.4). A more detailed mathematical description of the model can be found in the Supplementary Note 6..

2.3 Bi-directional soft-link approach

A key challenge of employing multiple models is to keep them consistent. A bi-directional soft-linking approach is designed which combines the two models in the preceding sections to examine hydrogen-orientated future energy systems in general and perform assessments of power-to-gas in particular. The process to iterate the two models involves the following steps, as illustrated in Fig. 2:

1. Produce an energy system pathway scenario over the studied decades using UK TIMES.

2. Extract results for the electricity sector from UK TIMES for the target year (2050 in this study). Generation capacity mix, demand profile, and fuel and carbon prices are provided to the UCED model. These relevant values used in the work are also listed in the Supplementary Notes.

3. Convert the overall generation capacity mix to individual units with specific technical detail (ramp rates, etc.) in regional nodes. Allocate location-specific resource availability time series to renewable generation.

4. Downscale the UK TIMES aggregated demand profile to produce an hourly chronological time series. Note that the demand data and generation capacity in Northern Ireland are removed given that UK TIMES models the entire UK but UCED only represents GB. Northern Ireland only accounts for 3% of the UK's population, it is low demand as relative to the rest of the UK.

5. Run the UCED model at a full hourly resolution for the target year to produce system operational cost and hourly excess electricity, etc.

6. Determine the optimal capacity of P2G so that the cost per unit production is below a given threshold. The hydrogen production from this P2G is considered being economic competitive against alternative supply and return back to UK TIMES as exogenous inputs.

7. Feed electricity system results from UCED back to UK TIMES. Excess renewable generation and P2G production are translated from UCED to UK TIMES by aggregating hourly values to the 16 UK TIMES timeslices. (additional details can be found in Supplementary Note 3)

8. Re-un UK TIMES, but with this certain amount of renewable is treated as excess and constrained to be used in P2G. This may affect the optimum renewable generation portfolio within UK TIMES, may need extra iteration between steps 3–7 to reach similar generation portfolios between power system and energy system model.

9. From the additional run of UK TIMES, the optimal capacity of P2G using excess renewable for cost-competitive hydrogen production is identified. The economic capture rate of P2G from excess renewable-powered P2G can also be estimated and its role as one of the hydrogen supply sources can be established

Additional details on how the national total generation capacity, demand as identified by UK TIMES are then processed and used as inputs for UCED (as in point 2, 3, 4 and 7) can be found in the Supplementary Note 2-3.

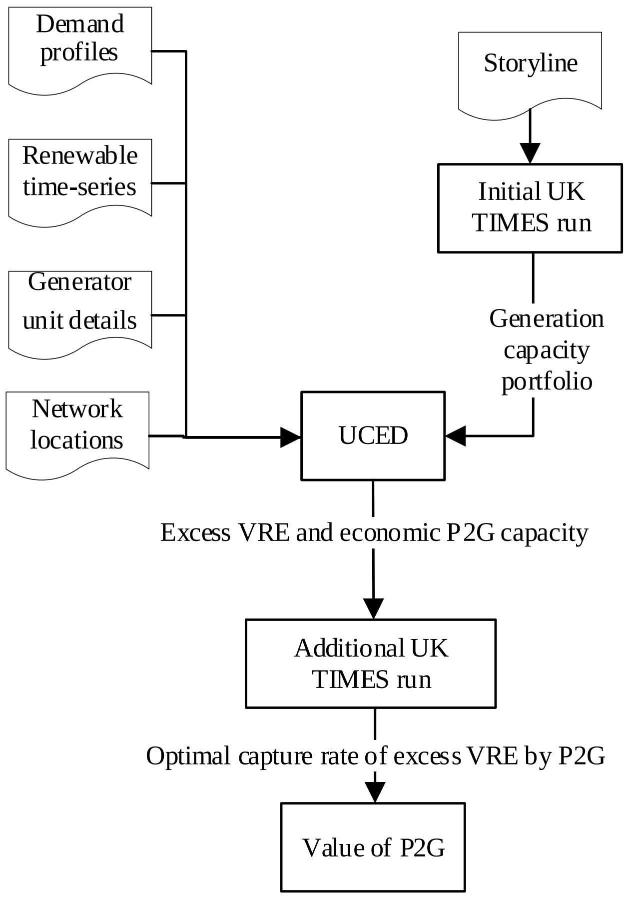


Fig. 2. Schematic representation of the soft-linking methodology.

2.4 Economic evaluation of P2G

The magnitude of excess electricity supply varies over time. Investing in additional electrolysers enables a greater proportion of the total excess to be utilised, but the higher capital cost for electrolysers and their lower capacity factor increases the overall cost of hydrogen production from excess generation (the price of excess electricity is assumed zero). Once this cost reaches the cost of hydrogen from other production routes, it is no longer economic to deploy further electrolysers.

This economic capture rate is also fed into UK TIMES. It is calculated from UCED outputs using:

$$\max\ P_{P2G} \tag{2}$$

where P_{P2G} is the installed capacity of P2G in terms of electricity input. The equivalent annualised cost of this P2G system is given as:

$$C_{P2G} = P_{P2G} \cdot C_{cap} + P_{P2G} \cdot C_{M\&O} \tag{3}$$

where C_{cap} is the annualised capital cost per MW of P2G, and $C_{M\&O}$ are the yearly operations and maintenance (O&M) costs. The total hydrogen energy production (E_{P2G}) in the given year from this capacity is calculated as:

$$E_{P2G} = \sum_{t} \min(P_{P2G,} \, E_{exc,t}) \cdot \eta_{H2} \quad \forall t \tag{4}$$

where $E_{exc,t}$ is the excess electricity identified from UCED at each hourly time step t. The hourly output of P2G is the minimum between its installed capacity and the available excess supply, and also accounts for the efficiency of electrolysers (η_{H_2}). The unit production cost for hydrogen from P2G (in Currency/ MWh) is therefore calculated as:

$$C_{H2,P2G} = E_{P2G} \, / \, C_{P2G} \tag{5}$$

The maximisation of P2G capacity is subject to additional economic constraints identified by the energy system model, UK TIMES. To be cost-effective, the unit production cost of P2G hydrogen cannot exceed the cost of alternative hydrogen generation source identified in UK TIMES:

$$C_{H2,P2G} \le C_{H2,UKTM} \tag{6}$$

This maximisation problem is embedded into UKTM in the soft-linking process. In the additional run of UKTMS after the UCED, the P2G capacity is identified. The economic hydrogen production and capture rate of excess derived from the final P2G capacity are the main performance metrics to understand the value of P2G.

3 Application of the method and results

The multi-model methodology to assess the value of P2G was applied to Great Britain as a case study. First, a specific storyline of how a hydrogen-rich economy could potentially develop in the UK was created. The storyline was modelled quantitatively in UK TIMES to project potential future sizes and locations of generation plant in general, and renewables in particular, and the operation of the electricity system in 2050 was then examined using UCED. After two iterations, the renewable deployment produced by UK TIMES became stable, as the converged scenario.

3.1 Initial Set-up

3.1.1 Configuring a 'hydrogen-rich' energy system pathway

To explore the value of hydrogen, UK TIMES was configured to favour a future energy system where hydrogen was a common low-carbon fuel for end-use demands. The starting point for this study was the 'Full Contribution' hydrogen scenario from a report for the UK Committee on Climate Change [45]. Please note that as UK TIMES is a whole society energy system model (ESM)), therefore there are a large and extensive dataset of assumptions that depict the whole energy supplies and usage cross various sectors. The parts, other than electricity and hydrogen, are not directly relevant in this work but can be found in the comprehensive report for description of full hydrogen contribution future [45].

This scenario is characterised by an early, consistent and long-term commitment to the extensive use of hydrogen across the economy. It is driven by an early decision to decarbonise heat provision across the UK by delivering hydrogen using repurposed existing infrastructures and dedicated new hydrogen transmission pipelines, and this subsequently provides some of the infrastructures for fuel cell vehicle adoption in the transport sector. By 2050, it is assumed that hydrogen will become the dominant clean fuel for road transport, and for residential and commercial heat demand. The detailed definition and narrative of this hydrogen-rich scenario can be found in [45].

Five variations of the 'Full Contribution' scenarios were generated using UK TIMES. The principal difference between these cases was the share of renewables in the total electricity generation. UK TIMES was constrained so that the minimum fraction of total electricity generation from renewables varied from 40% to 80% in 2050. These cases are to examine the implications for optimal P2G deployment if different levels of renewables are deployed.

3.1.2 Configuring the electricity system in 2050

The electricity generation capacity portfolio from UK TIMES was used as an exogenous input to UCED. The total national capacity per generation type was spatially assigned to network nodes with localised output profiles. The GB electricity transmission network was represented using a simplified network [52]. Spatial distribution of renewable generation was based on current generation patterns and planned deployments listed in [53]. The locations of these renewable sites are used. We input them into geographic information system (GIS) software, as well as the node locations of GB electricity network (as shown in Figure 3 in the main text). We then use the GIS software to identify the nearest network node for each renewable site, and calculated the aggregated capacity (in MW) by adding together these sites to the node with shortest distance. Other types of generation were assigned to be consistent with existing plant (i.e. nuclear plants on existing sites, natural gas generation near urban demand centres [54]). The spatial design of the network, and the renewable sites before aggregation into the network nodes, is shown in Fig. 3. Renewable deployment in the model follows the current pattern of resource locations in Great Britain, with most solar PV and offshore wind in England while onshore wind is in Scotland. Tables of the network parameters can also be found in the Supplementary Note 1.

A high-resolution wind speed hindcast of the British Isles and surrounding waters has been created in [55]. The work uses a Weather Research and Forecasting (WRF) mesoscale atmospheric mode to produce wind speeds at hourly intervals covering the whole region, at typical turbine hub heights and a spatial resolution of 3 km, for the period 2000–2010. Hourly capacity factors for onshore and offshore wind farms were derived using a generic wind turbine power curve. For rooftop- and ground-mounted PV, a dataset from [56] was used. This provided hourly solar PV output for all 2880 GB postcode districts in 2000–2015, based on data from The Satellite Application Facility on Climate Monitoring (CM SAF). The year 2010 from each dataset was used as it was the most recent available. Similar to the aggregation of capacity from renewable sites, the hourly capacity factor by sites are then aggregated into the nearest nodes of GB network (weighted by its capacity) for UCED model execution.

The spatial demand distribution in the electricity network was assumed as following the current pattern in [14]. We employed a historical hourly demand profile from the National Grid in 2010 but scaled this to match total electricity demand that was optimised in UK TIMES for 2050. Additional details about spatially distributing national total electricity generation and demand as calculated by UK TIMES to the nodes of electricity network for UCED runs can be found in in the Supplementary Note 2.

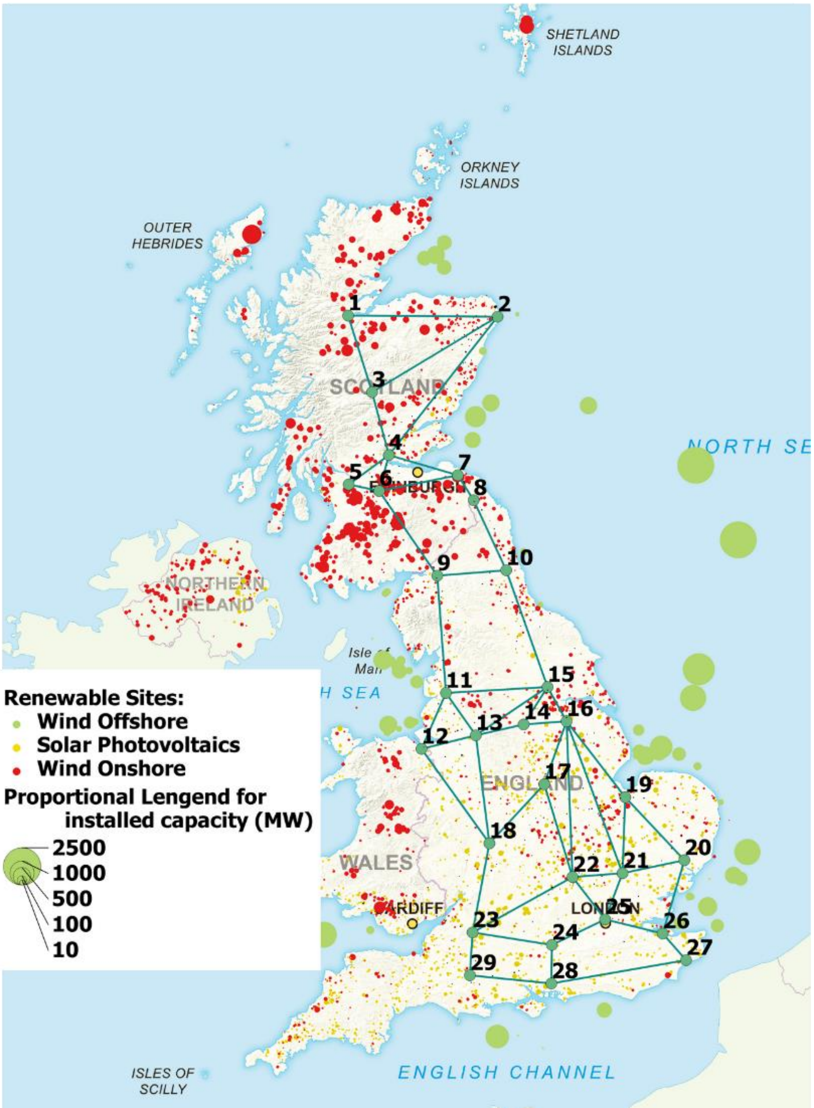


Fig. 3. GB transmission network representation with renewable sites.

The configured power system in 2050 was analysed without network transforming constraints. This effectively assumed that network transmission capacity would increase due to future reinforcements, and essentially forced UCED to operate as a point model that balanced supply and demand across the system.

3.2 Results and discussion

3.2.1 Renewable deployment and hydrogen demand

The final renewable deployment for each renewable penetration case, as optimised by UK TIMES, is given in Fig. 4. When renewables are the cheapest low-carbon generation technology, this leads to high deployment beyond the minimum required level. For example, the renewable generation capacity optimised by UK TIMES has already accounted for over half of the total capacity at a minimum 40% renewable level. While both meet the minimum required level, UK TIMES dynamically changes the generation portfolio in an optimal way to minimise the whole system cost. To increase renewable penetration, onshore and offshore wind and solar PV are not increased at the same rate. The largest renewable generation capacity at high renewable level case is solar PV, as shown in Fig. 4, followed by offshore wind.

The final hydrogen supply and consumption are both determined by UK TIMES. Hydrogen consumption by sectors in these VRE cases is shown in Fig. 5. Given the way that UK TIMES is configured in this work to achieve a hydrogen-rich energy system, hydrogen has a substantial and consistent role in decarbonising all sectors in these cases of different renewable levels:, the decarbonisation of transportation and heating in 2050 are mainly achieved by fuel cell vehicle and hydrogen boilers/CHP, instead by EV or Heat pump; hydrogen also has a prominent role for cost-effectively decarbonising industry; . Varying the renewable generation levels in total electricity production will have minor impact on the final hydrogen demand (as in figure 5), but it will have significant impact on how much of these hydrogen demand is provided by excess renewable powered P2G. The higher level renewable penetration level, the more excess renewable is potentially available, and so it can be used for hydrogen production, as shown later in figure 7(b). Additional discussion on the hydrogen demand across different sectors can be found in Supplementary Note 5.

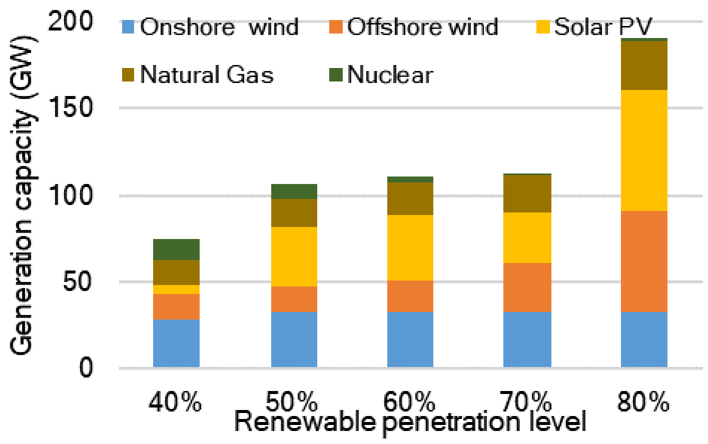


Fig. 4. Electricity generation portfolio identified by UK TIMES in 2050 under different assumption of renewable penetration levels.

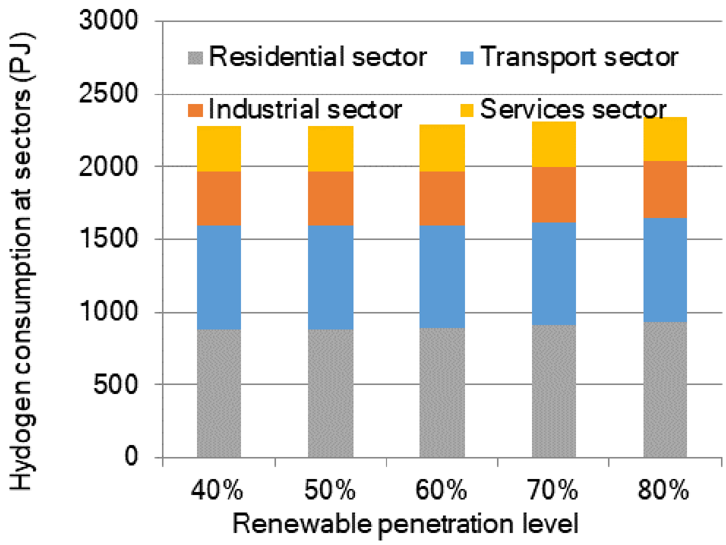


Fig. 5. Hydrogen consumption by sectors as identified by UK TIMES in 2050 under different assumption of renewable penetration levels.

3.2.2 Excess generation for P2G

The excess renewable generation found by UCED for each of the renewable level cases in 2050 is shown in Fig. 6. The excess renewable volume increases with higher level of renewable penetrations. A 50% share of renewable generation means around 16 TWh excess generation due to supply/demand mismatch, and this increases to 95 TWh at an 80% share.

The demand from various hydrogen markets in Fig. 5 is much higher than the excess renewable generation found in all penetration cases, suggesting the P2G might be a suitable use of excess generation but that hydrogen from other sources would also be required.

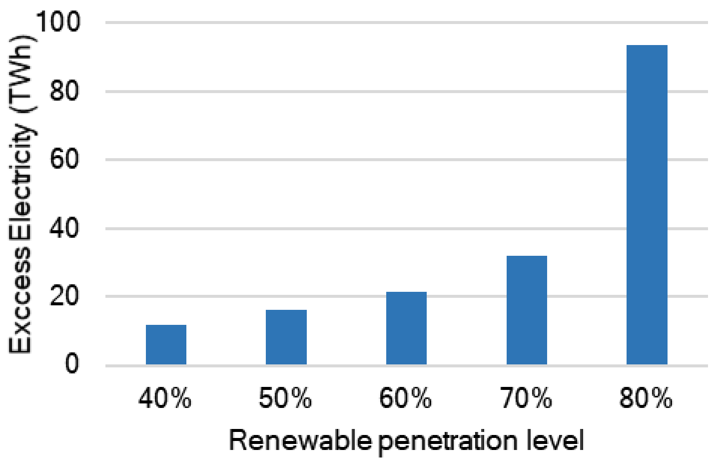


Fig. 6. Excess renewable electricity generation in 2050 as obtained by UCED in cases with different renewable penetration levels.

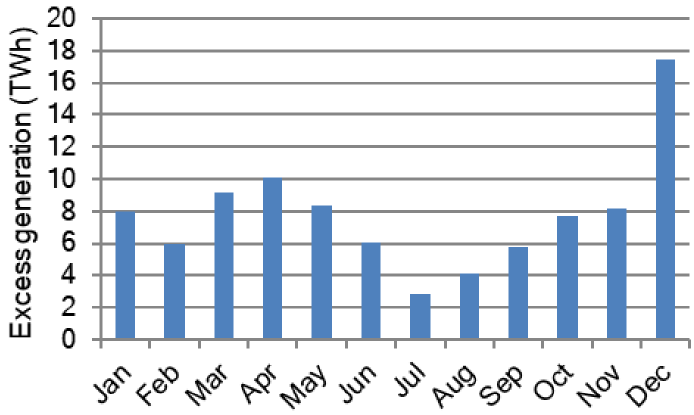


Fig. 7. Monthly variation in excess renewable generation in 2050 as obtained by UCED in the 80% VRE case.

Excess renewable generation has strong intraday, interday and monthly fluctuations (Fig. 7 shows monthly fluctuations). It is important to quantify the amount within the total excess electricity shown in Fig. 6 that can be economically used by P2G, so that the unit production cost is competitive against alternative production methods. The variation of excess VRE for each UK TIMES case is summarised using its duration curve in Fig. 8. When converting excess renewables using a fleet of electrolysers, power-to-gas necessarily has low capacity factors, as even in the 80% VRE case there is zero excess for almost half of the year. The capacity factor varies among UK TIMES cases. For example, assuming with 10GW size, P2G can run at full capacity for only 5% of the whole year in 40VRE case but it jumps to 35% in 80VRE case. For each renewable penetration case, every extra P2G unit will reduce the capacity factor and increase the marginal hydrogen production cost of all the deployed electrolysers, so it is necessary to calculate the optimum capacity from a cost point of view.

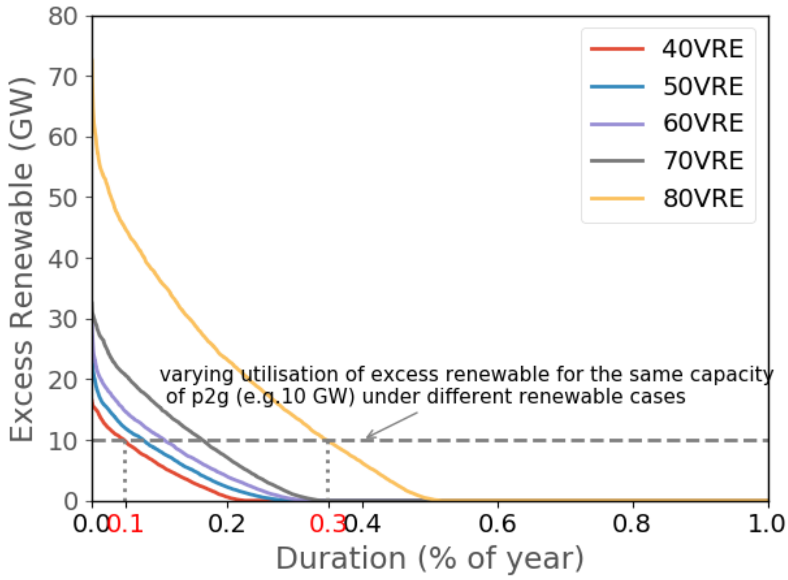


Fig. 8. Duration curve of hydrogen production from P2G under different renewable penetration levels..

3.2.3 P2G and its value in the energy system

The capital cost, operations and maintenance cost, and energy conversion efficiency assumptions for the electrolysers for 2050 are listed in Table II. The cost reduction and efficiency improvement of electrolysis for P2G is considered. The comparison between current value and the value in the future can be found in the Supplementary Note 4.

The cost per unit hydrogen production from P2G as a function of total P2G output is shown in Fig. 9. In all renewable penetration cases, the unit cost of hydrogen increases when more hydrogen is produced, but producing the same amount of hydrogen is cheaper when renewable deployment increases. The marginal hydrogen production cost tends to increase and this differs between cases. In the 80% VRE case, the unit cost of hydrogen increases at a much slower rate over a large production range, and a maximum of 306 PJ per annum is available below an economic threshold defined as the cost of the alternative hydrogen supply source (the red line).

Total economic production of P2G for cases with varying renewable penetration levels are shown in Fig. 10. These are the production levels at which the unit cost of hydrogen does not exceed the production cost using steam-methane reforming with CCS, which is forecast to be £11.60/PJ in UK TIMES. Economic production increases with renewable deployment. It is interesting to see the economic capture rate, which is proportion of excess generation that can be economically captured by P2G, is high at all renewable penetration cases and reaches 100% for the 80% VRE case.

TABLE II: COST AND EFFICIENCY ASSUMPTIONS FOR ELECTROLYSERS.

Electrolyser capital cost	468 £/kW
Fixed O&M cost	5% of the capital cost
Energy efficiency	84%
Lifetime	20 years
Discount rate	10%

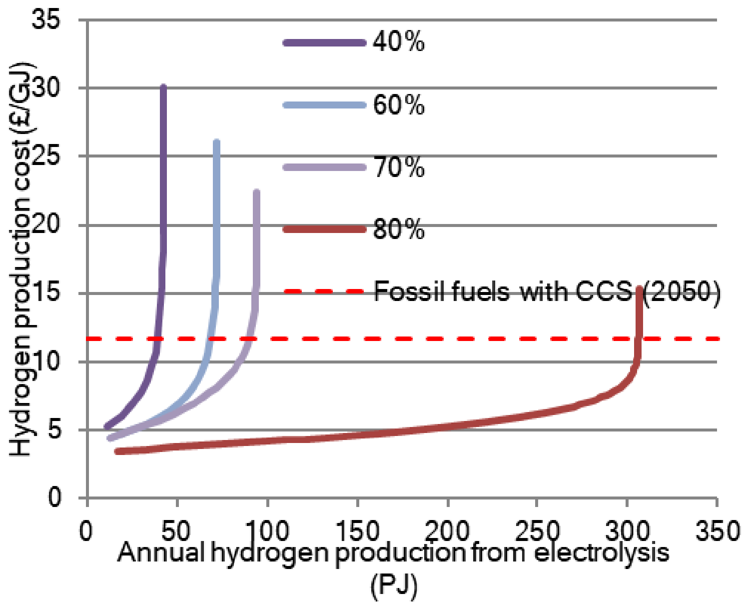


Fig. 9. Cost of hydrogen production from P2G for different cases of renewable penetration levels.

A high economic capture rate demonstrates that P2G can effectively capture excess generation and provide economically-competitive hydrogen to a hydrogen-rich economy. In the final converged scenario in UK TIMES, generating hydrogen through P2G is generally more cost-effective than using energy or heat storage. It accounts for 100% of total excess generation in the 80% VRE case, and varies between 87% and 97% in the other cases, with compressed air storage and heat storage accounting for the remainder.

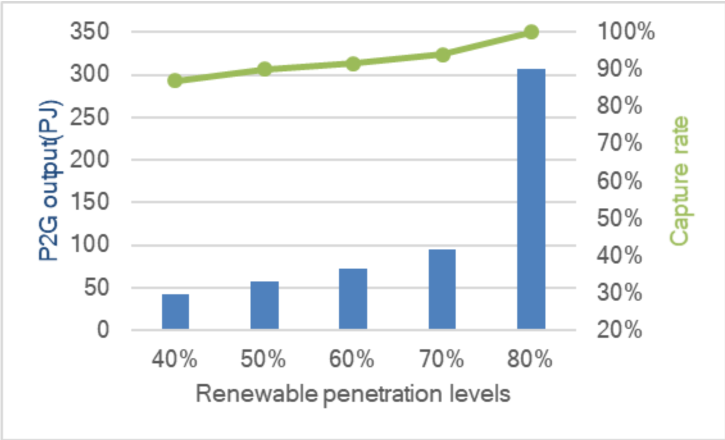
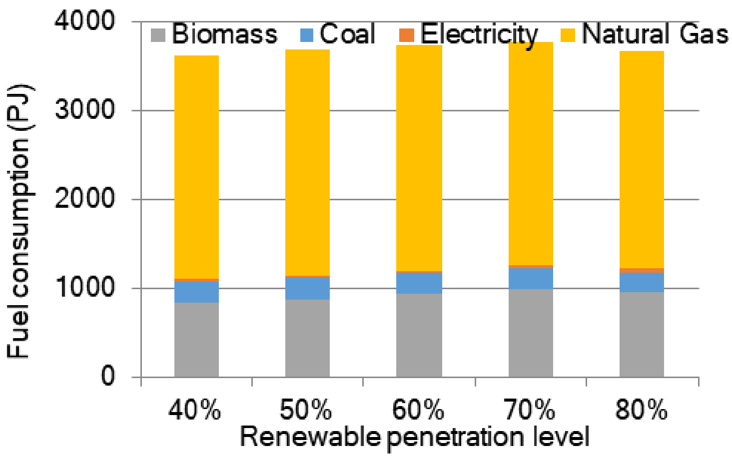
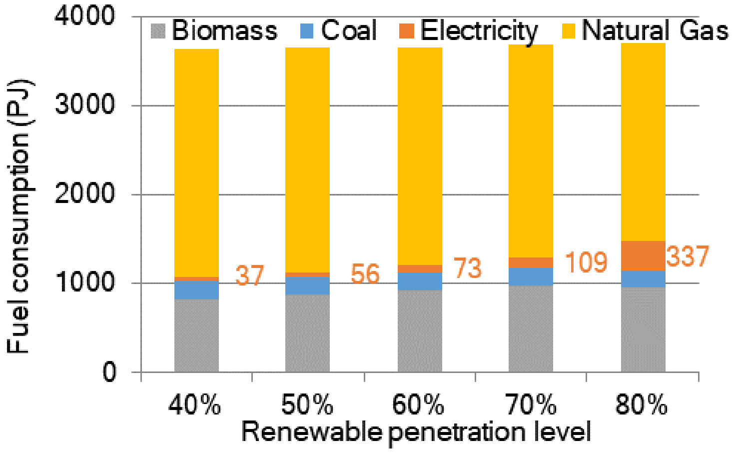


Fig. 10. Economic capture rate of excess renewable by P2G and P2G outputs in cases with different penetration levels

The impact of accounting for excess renewable generation on hydrogen production is shown in Fig. 11. For each graph, the hydrogen production technology portfolio was optimised by UK TIMES. CCS technologies are assumed available at large scale at 2050, and thus a broad portfolio of fossil-fuel based technologies for producing hydrogen are deployed in all cases with different penetration levels. Natural gas reforming persistently accounts for near two-thirds of hydrogen supply. Virtually no electrolysis is used in the initial scenario for 2050, but introducing excess generation from UCED causes a move from fossil-fuelled to electrolysis technologies. Total hydrogen production does not change.



(a)



(b)

Fig. 11. Fuel source for hydrogen production. (a) is initial result from initial UK TIMES run before being updated by UCED. (b) is the result of the balanced 2050scenario produced by iterating the two models.

4 Discussion and conclusions

A multi-model suite has been developed and an iterative soft-linking approach employed to examine the potential role of power-to-gas for integrating intermittent renewable generation in the future hydrogen-rich energy system, using Great Britain as a case study. Power-to-gas using excess renewable generation could be the most cost-effective technology for producing hydrogen in 2050, and could achieve a very high economic capture rate. Moreover, this appears to be robust at even very high levels of renewable penetration. This study can underpin transition strategies for renewable deployment and the development of a hydrogen economy in transportation and heating over coming decades.

The modelling challenge addressed in this paper is also important. Integrating power system and energy system models has drawn increasing research interest recently and adopted worldwide to investigate low-carbon issues. Both types of model have their own focus but important limitations for the research aim of this paper. Potential future evolutions of the energy system with high deployments of renewables can be better understood by combining these models. The multi-model iterative process developed here could be applied to understanding renewable integration in other countries.

This paper has focused on understanding the potential role of power-to-gas in renewable integration. While this study suggests that power-to-gas is a cost-competitive option in the future scenarios discussed here, it would not be the only option. The optimum solution for integrating high levels of VRE would likely utilise a variety of integration options. Future studies might develop and combine similar models that represent a wide range of energy storage and demand management options, and also interconnections to other electricity systems. These would enable us to better understand the strengths and weaknesses of different approaches to integrating VRE into electricity systems over the long term.

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