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Research Article

Net Zero UK – Generation and Energy Storage Requirements for the UK to Become Carbon Neutral

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Abstract

This paper sets out a quantified scenario for the UK to reach net zero carbon emissions. Wind and solar are the main energy sources and their intermittency is accommodated through hydrogen electrolysis, biogas from anaerobic digesters, and their combination into biomethane. Hydrogen and biomethane stocks are tracked. A daily energy balance model is presented, using the most recent recorded weather data-2017 to 2021. Long periods of low wind in 2021 indicated the necessary energy storage capacities, which were adjusted relative to energy generation capacities so as to achieve an economic minimum cost. The projected levelized cost of electricity is £92/MWh (which is well below the current energy wholesale price of £130) though this does assume greatly improved thermal insulation of most UK buildings. A 10% reduction of this cost is shown to be possible through the application of demand side management (retiming of energy consumption) thus illustrating the value of such flexibility. Carbon capture and storage (CCS) applied to power stations running on the biomethane could provide up to 21 Mt of negative emissions to offset other sectors, imports and even remove some of the excess emissions that have already occurred. The work goes beyond previously published scenarios: energy pricing is calculated, demand response measures have been modelled, and embedded carbon in imported goods is considered. The

Python model is available, open-source, for inspection and further development.

Keywords
Net-zero; biomethane; renewables; hydrogen; grid-balancing; demand-response

1. Introduction

The IPCC report of 2018 showed that the world must become carbon neutral by 2050 and thereafter carbon negative. On 27th June 2019 the UK government passed legislation committing the country to a legally binding target of net zero emissions by 2050. Many would argue that 2050 is far too late, and that wealthy countries, which have long-since had their industrial revolutions, need to lead the way [1].

The Digest of UK Energy Statistics [2] for 2021 indicates that 78.3% of the UK's primary energy consumption is still derived from fossil fuels, while only 6.2% (122 TWh out of 1,978 TWh) is from renewables. There are many reasons for this lack of progress not least of which is the lack of an agreed vision of how decarbonisation can be achieved. Existing scenarios (decarbonisation pathways) often fall short of reducing UK energy-sector emissions to zero and have no headroom to deal with other sectors, residual and imported emissions, still less to provide the negative emissions required by the IPCC.

This paper presents a scenario for a Net Zero UK (NZUK) showing that enough renewable energy could reasonably be generated in the UK and its waters, and showing how the grid could be balanced. In a zero-carbon future it will be necessary to store large amounts of energy during times of surplus so as to provide a reliable supply throughout the year. Batteries and thermal storage are good for the short term (a few hours) but the greater challenge is for the longer term (months) for which hydrogen is often proposed. NZUK relies on hydrogen but mostly in combination with anaerobic digestion (AD) to form biomethane which can be stored in existing facilities, and burned in conventional power stations when needed. The Python model, described herein and available open-source [3], uses recent weather data, and projected future energy demand, to determine the scale of zero-carbon generation and storage required, and to estimate costs. It also shows how residual emissions can be removed, and thus how to achieve net zero for the UK.

The most comprehensive prior study of a *Zero Carbon Britain* was produced by the Centre for Alternative Technology (CAT) in 2017 [4] and served as a useful background document. A companion document to the CAT study, [5], gives a breakdown of expected future demand, and was used as a starting point for NZUK. CAT also set out the hydrogen plus AD route to biomethane which is developed in NZUK. However, NZUK diverged on the supply side figures. A feature of the CAT study is that it based its analysis on a continuous weather period from 2002 to 2011. Very large capacity gas storage allowed the grid to be (mostly) balanced across years of low and high generation. NZUK, by contrast, considered only recent weather (2017 to 2021) and required that the grid balanced for each discrete year. The reasoning was that recent weather is the best guide to future weather, and indeed 2021 was found to be a very challenging year for renewables, with low generation in the summer, and prolonged periods in the spring and early winter with very little wind. With the climate changing, it is no longer reasonable to assume that a good year for renewables will follow a bad one.

NZUK went beyond the CAT study in several areas, notably: calculating future energy costs; modelling possible demand reduction measures; and accounting for imported emissions; as well as using the most recent weather data.

The National Grid's *Future Energy Scenarios* (FES) [6] considers four possible pathways with different assumptions for each, and is updated every year. *System Transformation* relies heavily on carbon capture and storage (CCS), which is far from perfect as, alongside the problem of continued reliance on imported natural gas, the CCS process still emits substantial CO_2 and other greenhouse gases [7]. *Steady Progression* does not even lead to net zero by 2050. The other two pathways, *Consumer Transformation* and *Leading The Way* are more ambitious and have been used for benchmarking of NZUK. However, all pathways rely on importing large amounts of electricity to balance the grid. Although energy imports and exports will be important in smoothing the grid, they have not been used in NZUK. Oswald et al [8] points out that weather systems are often very large, so a deficit of renewables in one country will probably coincide with a deficit in nearby countries.

The Climate Change Committee report [9] sets out a further alternative proposed infrastructure for achieving close to net-zero power delivery by 2050. Its strategy relies heavily on "blue" hydrogen, which is produced by reformation of fossil gas coupled with CCS, which, as noted above, still causes substantial emissions. Renewables contribute just 59% of the energy in the CCC scenario.

The analysis in the BEIS paper [10] does not actually lead to zero emissions. As well as wind and solar power there is a reliance on nuclear, gas generation with CCS, unabated gas generation, and blue hydrogen. The study seems to be driven by economics: it notes that "minimum electricity system cost is found at carbon intensities between approximately 5-15 gCO_2/kWh".

The NZUK scenario, presented below, and its associated Python model, have the following objectives:

- Identify a set of generation and storage technologies to enable net zero UK emissions.
- Quantify the annual generation of those technologies required to meet expected demands.
- Include expected reductions in transport, heating, and other demands.
- Ensure adequacy for each of the five most recent years of weather.
- Determine and minimise levelised energy costs of the required generation and storage.
- Model and graph generation and demand. The daily difference between generation and demand is also traced on the resulting graphs. When supply exceeds demand, some of the surplus is used to make hydrogen (which is used in biomethane production). When there is a deficit in primary supply, biomethane is burned in power stations to balance the grid. The state of hydrogen and biomethane stores must be tracked. The grid must be shown to balance on each day of the five years tested.
- Explore the use of demand side management (retiming of demand) to reduce energy costs. Two mechanisms are explored: partial industry shutdowns during times of low primary generation; and demand elasticity driven by energy prices.
- Estimate residual and imported emissions, and quantify proposed measures for removal, including carbon capture and storage (CCS) from already carbon neutral biomethane.
- Show how this might be expanded to achieve net negative emissions.
- The Python model must be documented and published, so the basis of the results can be reviewed, or freely updated.

2. Methods

The Python programming language was selected to build a model of expected daily electricity demand and supply when the UK is carbon neutral, and to use the graphs and data generated to determine energy generation and storage requirements. The graphs were to span one year, and the weather in each year, 2017 to 2021, was used to determine the level of generation and storage required.

In brief, the model was to perform the following tasks, with a granularity of one day:

- Plot and add the expected electricity demands. Cooling and heating demands are based on daily average temperature. See section 2.1.
- Plot and add the contribution of each type of generator. These are based on published data for the five years under test, but with multipliers to model the increased requirement for renewables. See section 2.2.
- The difference between supply and demand defines the power required from dispatchable biomethane generators. Track the hydrogen as it is generated by surplus renewable energy and used to make biomethane, and the biomethane as it is produced and used to run power stations to balance the grid. See section 2.3.
- Calculate and plot the daily levelised cost of energy (LCOE). See section 2.6.
- Model the effects of possible demand-side responses: partial industry shutdowns when energy is scarce, and elastic demand based on energy price. See section 2.7.
- Calculate the possible carbon capture and storage (CCS) – leading to negative emissions – from biomethane power stations. See section 2.8.

Most of the results in this report are taken directly from the model. The graphs presented are just for one representative year, but the numerical results are averages over the five years tested.

2.1 Electricity Demand

The demand figures were based on those defined in the CAT study [4] which in turn were influenced by DECC 2050 Pathways [11]. Heating and cooling demand depend on temperature, so daily temperature data from CEDA [12] for Central England was used. In line with DECC figures, the heat loss rate from buildings was assumed to be roughly half the present value, due to much better insulation. For NZUK, heating was assumed to be by 50% ground source heat pumps[1], 25% air source heat pumps, and 25% resistive heating, giving an average CoP of 2.9. The CAT study is slightly more optimistic, with an implied overall CoP of 3.1. Demand figures for NZUK are given in Table 1.

Table 1 List of electrical demands.

Demand type	Average power demand	Notes
Heating	5.6 * (13.1° – temperature) GW	Derated by CoP of 2.9, and 10% for geothermal contribution
Hot water	10.7 GW in winter, 7.3 GW in summer	Derated by CoP of 2, and 10% for geothermal contribution

[1] Ground source heat pumps are more efficient than air source in the winter, and they can be used for air-conditioning, which also warms the ground, leading to better winter CoP. Heat-exchangers are expensive to lay or drill, but could be combined with groundworks, such as house-building, road-mending, carpark-making, etc.

Cooking & appliances	15.1 GW	20% higher than in CAT report
Cooling	5.6 * (temperature-14°)/3	A little higher than overall CAT figure
Industry	29.1 GW	
Industrial hydrogen	3.6 GW	With 80% electrolysis efficiency
Transport	17.8 GW in winter, 11.9 GW in summer	8% lower than in CAT due to slightly different assumptions

The geothermal contributions to space heating and hot water mentioned in Table 1 make use of geological features existing in some parts of the UK. The heat would be from deep underground (as distinct from the shallow heat harvested by ground source heat pumps) and would be used in district heating schemes.

2.2 *Electricity Supply*

The supply figures were not based on those in comparable studies, and only proven generation technologies were used. Limited nuclear power was included in NZUK. It was assumed that Hinkley Point C (3.26 GW) and Sizewell C (3.34 GW) will be running, with a load factor of 75%, but with all other nuclear stations decommissioned. Nuclear power is not a good fit with renewables: it is not readily dispatchable and it creates a dangerous waste product. However, these stations will have been built and will be producing 5% of total electricity demand with low CO_2 emissions.

Biomass combustion will continue, but only with domestically produced feedstock – currently more than half the biomass used at the Drax plants is imported. Biomass combustion will only account for about 1% of total generation and has been modelled to run dispatchably, on the 60 days of the year with the greatest energy deficit.

In line with comparable studies, a very large proportion of energy will be from wind turbines (predominantly offshore) and from solar photovoltaics (PV). These two sources are complimentary, as the summer months, when PV generation is at its highest, generally experience relatively low winds. Unlike in the CAT study, no solar thermal systems have been used: rooftops will be needed for PV.

Hydro power was expected to remain the same as today at just 3 TWh/y. Tidal energy was projected at 16 TWh/y – the government's estimate of practical resource – rather than the more optimistic estimates to be found elsewhere in the literature, for example 34 TWh/y [13]. Because this represents just 2% of generation, no attempt has been made to model the tidal periodicity.

Data from Gridwatch [14] was used to find the daily figures for renewable energy. Suitable records are available from 2017 to the present. Biomass power was multiplied by 0.47, the proportion of domestically sourced biomass.

Some further adjustments were made, to corroborate Gridwatch data and to reference all five years to 2021 levels of installed capacity.

1. Gridwatch data has a granularity of five minutes, but ONS figures [15] exist for complete years of generation. So for each year, 2017 to 2021, Gridwatch wind generation figures were integrated to find annual totals, and compared to the corresponding ONS figures. There was strong agreement between ONS and Gridwatch, but small multipliers were introduced for each year so that Gridwatch data would exactly match the ONS totals. This was then repeated

for PV generation.

2. The ONS publishes figures for installed capacities of each type of generator for each year [15]. Gridwatch wind energy figures for years 2017 to 2020 were multiplied by C_{2021}/C_{year}, where C_{2021} was the installed capacity in 2021 and C_{year} was the installed capacity for the selected year, 2017 to 2020, so that wind generation was uplifted to 2021 capacity figures for each year. This was repeated for PV generation. The ONS wind capacity figures are separated into onshore and offshore, so the different capacity factors for each had to be part of the equation.

After these adjustments had been made, each year of generation – 2017 to 2020 – could be tested as if it had the same installed wind and solar capacities as existed in 2021: differences were then due to weather alone. (It would have been possible to use raw wind and sun data for each year – as some other studies had done – and compute the resulting energy production, but using actual energy data was thought to be more robust). Derating factors were also applied to nuclear power for each year.

With the above adjustments in place, the model was then used to determine capacities required to achieve net-zero:

- Wind and PV capacities: initially quantified as multiples of their respective capacities in 2021, later converted to GW as presented below
- Electrolyser capacity: maximum electricity used to make hydrogen (GW)
- Hydrogen bleed rate: daily amount of hydrogen used to make biomethane (GW)
- Hydrogen capacity: size of the hydrogen buffer store (GWh)
- Biomethane capacity: size of the biomethane store (GWh)

These five parameters were adjusted manually to achieve supply meeting demand at minimum overall cost. Use of a mathematical optimisation algorithm was rejected in order to gain insight of the interactions of varying capacities. Graphs produced by the model, including those presented below, provided clear indication of adjustments needed. Three main scenarios were tested, one relying heavily on primary renewables, one biased towards production and use of biomethane, and one intermediate scheme. It was found that high biomethane use produced the cheapest energy, so further refinements were made to that scenario.

2.3 Storage and Backup Supply

When demand exceeds supply of renewable energy, conventional power stations will fill the deficit, but using biomethane rather than fossil gas. Biomethane will be fabricated from biogas from anaerobic digesters (ADs), plus hydrogen, produced by a set of electrolysers when electricity supply exceeds demand. Neither biogas nor hydrogen is as convenient to store or to burn as methane. Biogas consists mainly of methane and carbon dioxide; Rusmanis et al [16] describes an extremely valuable technology to react hydrogen with the carbon dioxide in biogas to form more methane. The Sabatier process is well known, but Rusmanis describes how the process could take place biologically in an AD. It appears to be an immature technology but has great potential. Open Energy Monitor [17] describes the process quantitatively, including conversion ratios and expected efficiencies. If it proves to be non-viable at scale, then external, chemical, Sabatier synthesis could be considered.

The resulting biomethane could be stored in the existing gas networks and burned dispatchably in existing CCGTs. However, as AD needs to be processed at a steady pace, but hydrogen production will be intermittent, buffer hydrogen storage facilities will need to be created.

Methanol and ammonia are possible alternatives to biomethane; they could serve as effective and highly practical hydrogen carriers, but would not make use of the AD resource. Whilst they are not considered further in this paper, they do warrant further investigation.

2.4 The System

The complete system that is modelled is illustrated in Figure 1, showing electricity flows (grey lines) and gas flows (orange and red lines). The flow lines are labelled with approximate average annual flows in units of TWh/y: these figures will be derived and discussed in Section 3.

Much of the electrical energy from the primary generators (top left of Figure 1) supplies the demand (on the right hand side), but, due to temporal mismatches between supply and demand, some energy is wasted ("Spillage"). When surplus energy is available, some is used to make hydrogen, and this is stored in a buffer tank. Some hydrogen is used to meet industrial demand, but most is reacted with biogas in the anaerobic digesters to make biomethane. The biomethane is stored for use in power stations for when there is a deficit of primary renewable power.

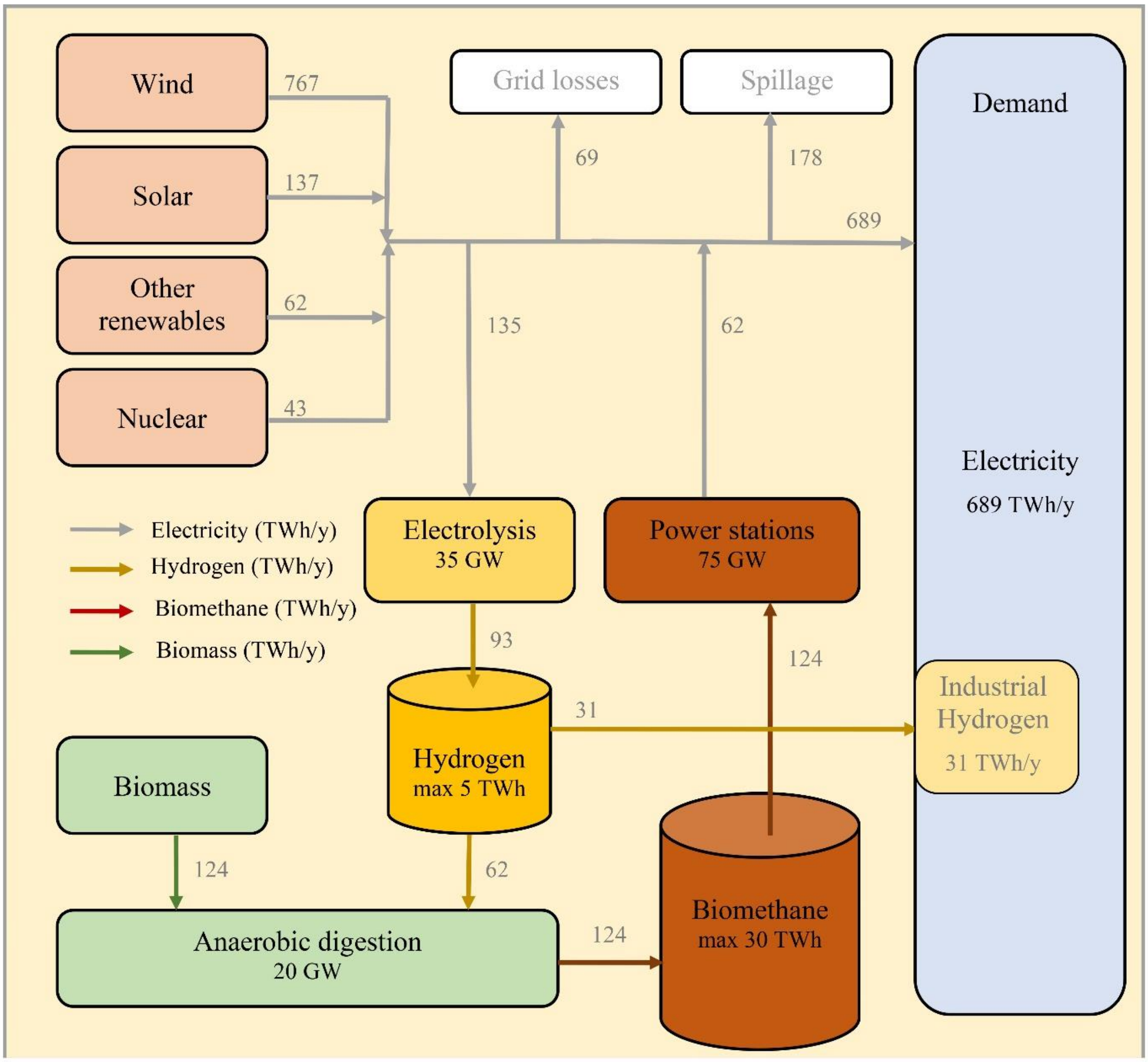

Figure 1 System diagram showing indicative annual energy flows.

2.5 The Model

The model plots supply and demand for one calendar year with a time step of one day. Intra-day balancing is assumed to be achieved by batteries (including vehicle batteries), pumped storage, compressed air storage, and smart appliance switching, and is not included in the model. For each year (from 2017 to 2021) the model uses daily Central England temperature records [12] and levelized (see above) Gridwatch records, resampled to an interval of one day. The average daily power from each generator was found and summed, and average daily power was the main unit used throughout the model. Demand is treated likewise.

Figure 2 illustrates how the basic model works for an example period of 30 days.

- The black trace is the sum of all the daily electrical demands.
- The blue trace is the sum of all the electrical generation, and being weather dependent, it is highly variable.
- The shaded area is the difference of supply and demand – i.e. the black trace minus the blue trace.

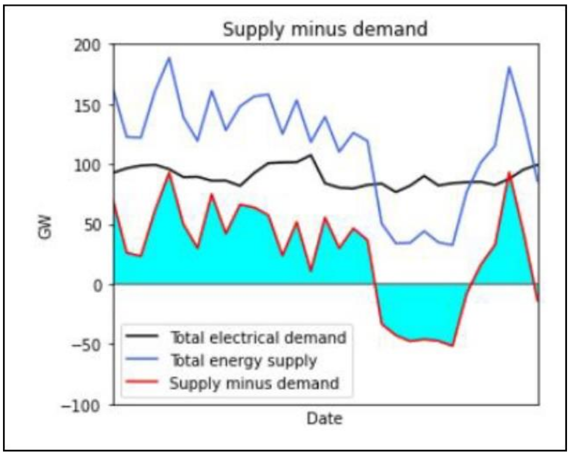

Figure 2 Electrical supply and demand curves for 30 days in late 2021, showing deficits and surpluses of primary energy production during the timeframe.

For much of the term shown it can be seen that there is a surplus of energy, but there is also a serious deficit for a period of more than a week. The period of deficit needs to be balanced by generation from dispatchable power stations, as described below, and illustrated in Figure 3.

As described above, biomethane, from hydrogen plus biogas, was considered to be the most practical long-term store of energy. Daily hydrogen production and storage was traced by the model. Electrolysis efficiency of 80% was assumed, and energy equivalent to 15% of the hydrogen produced was used to compress the gas for storage [18].

The model uses a fixed daily amount of hydrogen to react with the biogas to form biomethane [17]. The model tracks the daily status of the methane store as it is produced and is burned to generate electricity, at an efficiency of 50%. The hydrogen and methane stores both start the year at 75% capacity, and are expected to end the year at roughly 75% (75% is reasonable because the autumn is generally windy, and hence the peak time for renewable generation).

Figure 3 shows hydrogen and biomethane storage for an example 90-day period. The cyan shaded area is electricity supply minus demand as illustrated (for a different period) in Figure 2, but *after* some surplus energy has been used for electrolysis. The black trace tracks the state of the biomethane store on the right-hand axis. Running the power stations can be seen to rapidly deplete the biomethane stocks (black trace). The orange trace is the state of the hydrogen buffer. This buffer empties completely for a short period, but rapidly recovers as excess energy is generated. When there is gas in the hydrogen store, a portion is used to generate biomethane, and indeed the biomethane stocks (black trace) can be seen to recuperate rapidly. During the final quarter, the hydrogen buffer is full, but the level fluctuates slightly as hydrogen is generated and used to replenish the biomethane store.

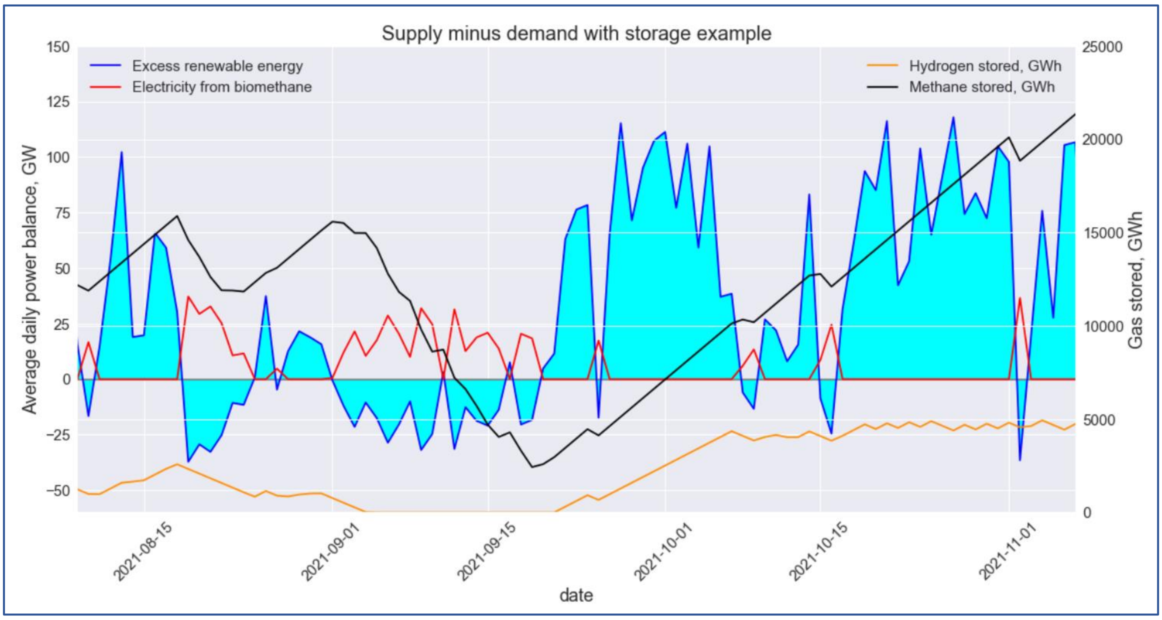

Figure 3 Illustration of gas storage and generation for a period of 90 days in 2021.

When the model is run, several graphs are plotted for each year plus many calculated parameters. The Python code, together with the supporting data files, is available on GitHub [3].

2.6 Comparative Costs

There are many different combinations of renewables, storage, and biomethane generation that could lead to a balanced grid. To help find the most cost-effective combination, it was necessary to find the approximate levelised cost of energy (LCOE) – in terms of £/MWh – for each type of generator. The LCOE takes amortised capital costs and load factors into account, so provides a level playing field. The approximate figures in Table 2 were used in the LCOE calculations.

Table 2 Electricity generation costs.

Item	Ref	Units	Cost
Large scale solar LCOE, 2030	[19], p28	per MWh	£39
Onshore and offshore wind LCOE, 2030	[19], p28	per MWh	£46
Nuclear LCOE, late 2020s	[20]	per MWh	£70
CCGT capex	[21]	per MW	£500,000
CCGT infrastructure	[21]	for 1 GW station	£15 m

CCGT operating costs	[21]	per MW/y	£16,000
CCGT fuel (biomethane) costs	see notes	per MWh	£105
Other renewables (tidal, hydro, biomass)	estimate	per MWh	£100

The cost of the biomethane to run the gas turbines (CCGTs) for grid balancing includes AD-derived biogas at £70/MWh [22], plus hydrogen infrastructure costs of £35/MWh, derived from [18]. The cost of the electricity to generate the hydrogen has not been included, because this is “surplus” electricity which is already included in electricity costs.

For gas-fired power, the model calculates for how many other days the marginal power station for each day will run, and from this the load factor can be determined and hence the LCOE of energy from gas for the day. Please see the Python model itself for the full calculation [19].

The model calculates the total cost of energy in several different ways, but the most practical is to charge customers for all electricity produced, since surpluses are a necessary part of obtaining a balance.

Note that only generation LCOEs are calculated. The very large upgrades to the transmission and distribution infrastructure were not taken into account, nor much of the gas storage infrastructure. These will be fairly similar for all the scenarios that were considered for NZUK: the main point was to find comparative costs between scenarios.

2.7 Demand-Side Response

Initial results showed that there were difficult periods – many consecutive days with little renewable generation – and the marginal extra generation and storage required for these periods is the most expensive. A number of demand-shifting measures have been considered. Two of the most promising are:

- The market would dictate low electricity prices when renewables are abundant, with much higher prices when biomethane is being used in power stations. Siddiqui [23] estimates that a demand elasticity of-0.2 is possible. This has been modelled as an optional extension.
- Increase the holiday allowance to six weeks in certain industries but allow employers to dictate four of the weeks, instigating company shutdowns at short notice during weeks with highest predicted energy costs. This was assumed to cut industrial demand by 50% during those four weeks (and raise it to compensate on the other 48 weeks) and has been tested in the model. (The cost to industry, however, has not been modelled).

Fuel poverty and equity issues could be addressed by allowing domestic consumers a certain quota of electricity at a reasonable price per kWh. Any consumption above the quota would be charged at a rate related to wholesale prices. This approach has not been modelled. Industrial users would pay at a rate related to wholesale prices to encourage demand response to energy supply.

2.8 Emissions

Even when energy has been fully decarbonised there will remain substantial emissions, and also the emissions embodied in imports. According to CAT, agricultural emissions are expected to be 19.7 Mt/y, with a further 20 Mt/y from industrial, urban, waste, and domestic sources. Imported emissions can be inferred from government figures [24] as 235 Mt CO_2e/y.

Clearly imported emissions will need to be greatly reduced if net negative emissions are to be achieved. As exporting countries gradually decarbonise, imported emissions will naturally fall. A carbon duty on imports would favour items with lower carbon footprints while encouraging further decarbonisation measures in exporting countries. The tax raised could be used to help fund the carbon reduction measures – perhaps in exporting countries also. CO_2 emitted overseas is as much against UK interests as home-produced emissions.

According to CAT [4], doubling the UK's forested area to 24% of land, and restoring peatlands, captures 47 Mt/y. This balances residual domestic emissions. Further CO_2 removal can be achieved by adding carbon capture and storage (CCS) to biomethane power stations. The model calculates how much can be removed in this way.

3. Results

To simplify manual optimisation, many supply-side parameters were made easily adjustable in the top level of the model. Several net-zero scenarios – high renewables, high biomethane etc – were investigated, with the cost of electricity being the main determinant of virtue. Only the solution which was found to be the cheapest will be discussed in detail in this report.

3.1 Electricity Demand

Contributors to demand are as discussed in Section 2.1. Figure 4 shows stacked demand for 2021 weather; (the graph, like all graphs in this report, is a direct output of the model). Other years were broadly similar. With industry (red) decarbonised, it represents the largest single electricity demand category, with "cooking, lighting and appliances" in second place.

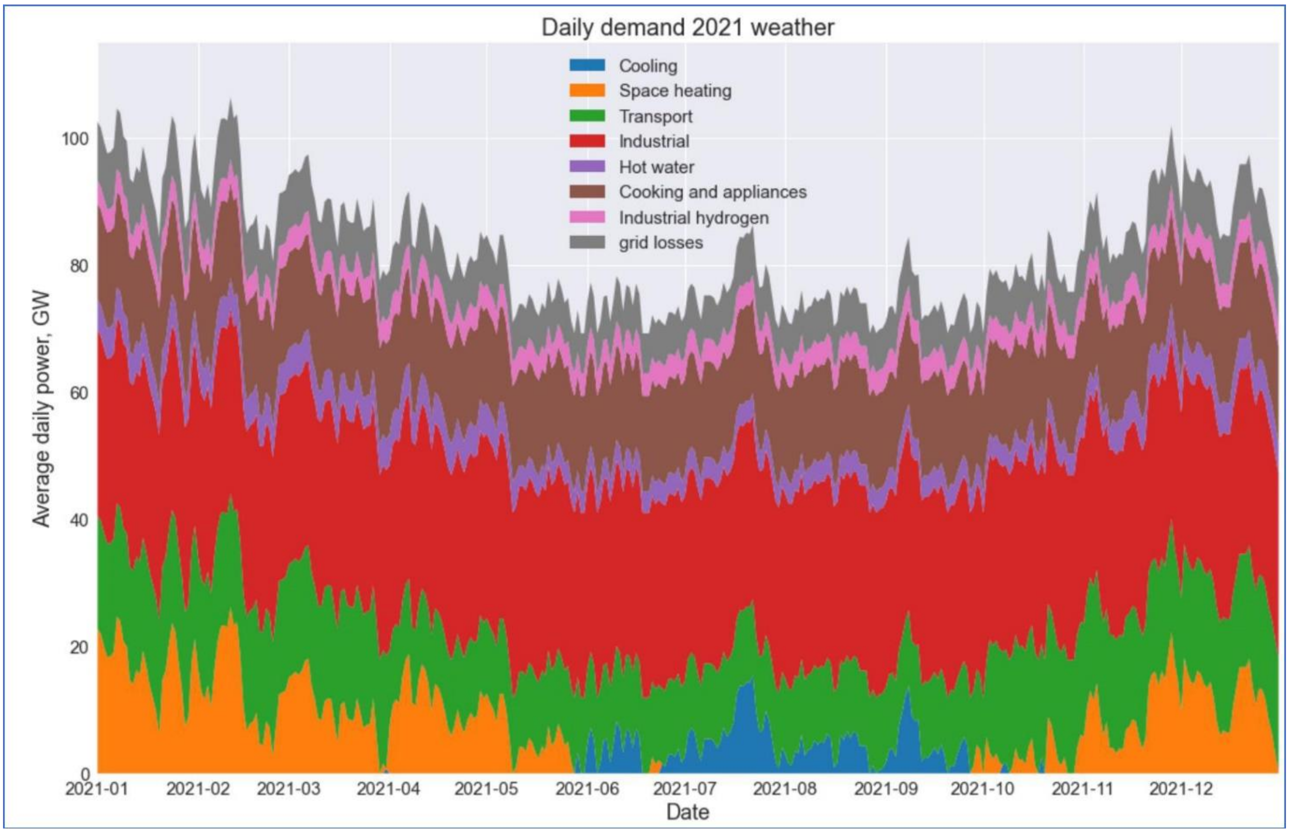

Figure 4 Daily demand for 2021 weather.

The annual demand breakdown for 2021 weather is shown in Table 3. With buildings properly insulated and decarbonised, it can be seen that electricity for heating represents quite a small proportion of overall demand, while industry accounts for 35%.

Table 3 Breakdown of energy demand for 2021 weather.

Demand Category	**Total Energy for Year (TWh)**	**Equivalent average power (GW)**
Space heating	60	6.8
Hot water	35	4.0
Cooking and appliances	132	15.1
Cooling	14	1.6
Industrial	255	29.1
Industrial hydrogen production	31	3.6
Transport	130	14.8
10% Grid losses	66	7.5
Total demand	**723**	**82.5**

Total electricity demand for 2021 weather was 723 TWh, and this was broadly similar for other years' weather. This contrasts with total UK energy demand in 2021 of 1,978 TWh, and electricity demand of 334 TWh in 2021 [2]. So total energy demand has reduced to 36% of 2021 demand, while electricity demand has more than doubled.

3.2 Electricity Supply

Wind and solar power produce 80%-90% of the primary electricity in this study. The installed capacities of each were manually adjusted, together with the electrolyser capacity and several other parameters, to give the lowest-cost solution to keeping the grid balanced for all five years of weather that were tested: 2017 to 2021.

Initially, three scenarios were tested: one biased towards primary renewables, one with high use of biomethane power stations, and one intermediate scenario. Table 4 summarises the two extreme cases.

Table 4 Comparison of two scenarios - high use of primary renewables against high use of power from biomethane power stations.

Parameter (Average figures for the five years of weather)	**High primary renewables**	**High biomethane power stations**	**Difference with high biomethane power stations**
Wind generation (TWh/y)	868	767	-11.6%
Solar generation (TWh/y)	156	137	-12.4%
Energy from biomethane power stations (TWh/y)	46	61	34.6%

Total generation (TWh/y)	1095	975	-10.9%
Spillage (TWh/y)	336	189	-43.8%
Biomass required for biomethane (TWh/y)	90	124	34.8%
Possible CO_2 removal by CCS (Mt/y)	17	21	28.9%
LCOE (£/MWh)	94	92	-3.0%
Total LCOE (£m)	69,012	66,980	-2.9%

High use of primary renewables would mean 35% less biomass requirement to generate the biomethane for power stations, but on the other hand the extra generation needed would lead to much higher spillage. Although energy from power stations is more expensive than from primary renewables, the spillage meant that the high primary renewables scenario was the more expensive. The intermediate scenario (not shown) was also slightly more expensive than the high biomethane power case, for the same reason.

The cheapest option was selected for this study – the scenario with most power from biomethane power stations.

It was found that the year 2021 presented the most difficulties with grid balancing. In the spring and the winter there were prolonged periods with very little wind but high demand. Throughout the summer and early autumn, wind power was much lower than average. Figure 5 shows supply based on 2021 weather, with a lowest-cost mix of supplies.

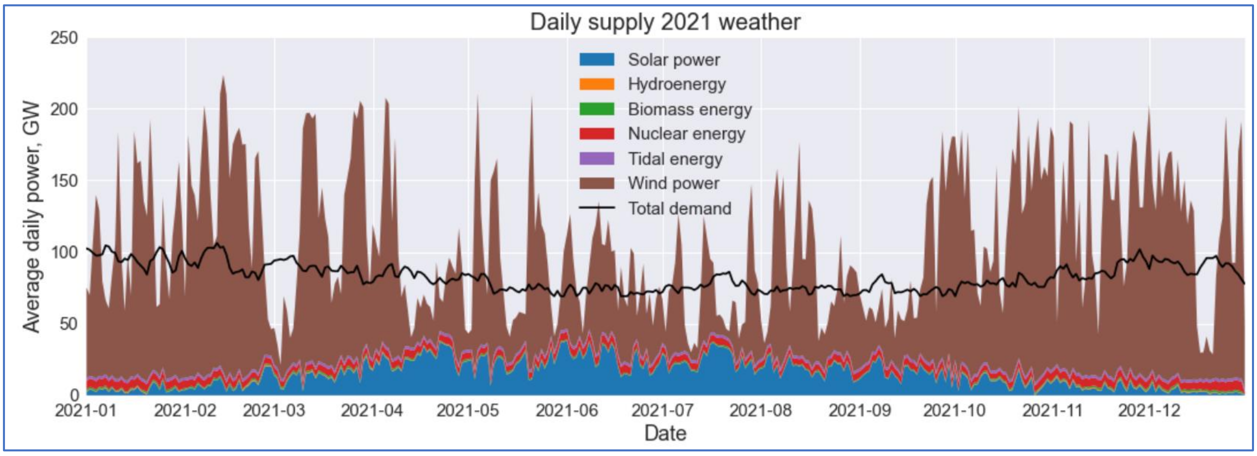

Figure 5 Daily supply for 2021.

It can be seen that wind (brown) dominates, but solar (blue) contributes substantially in the summer, partially compensating for the low wind. The other supplies are much smaller.

For reasons described in Section 1, electricity imports and exports are not included in NZUK.

The total demand is superimposed in black on Figure 5 for reference. There are many days when demand exceeds supply, and on these days, biomethane is used to run the power stations. 2021 weather data is used in these illustrations because, as mentioned above, it was a challenging year to balance.

3.3 Generation of Renewables

The renewables used in this scenario are given in Table 5. As the generation depends on the weather, the figures in the table are the average of all five years tested. Figures from comparable studies are shown alongside for reference, where LtW is the FES [6] "*Leading the Way*" scenario, and CT is "*Customer Transformation*".

Table 5 Generation statistics compared to comparable studies.

	TWh/y			
Item	**NZUK**	**CAT** [4]	**FES–LtW** [6]	**FES-CT** [6]
Wind generation	**767**	607	526	645
PV generation	**137**	74	81	68
Solar thermal	**0**	25	0	0
Hydro	**3**	8	0	0
Biomass combustion	**9**	0	0	0
Biomass for AD etc	**124**	230	200	200
Nuclear generation	**43**	0	33	88
Tidal generation	**16**	42	17	0
Wave generation (or other renewables)	**0**	25	103	35
Geothermal	**34**	39	0	0
Total low carbon supply including biomass	**1121**	1050	960	1032
Electrolysis capacity required (GW)	**35**	25	58	42
Hydrogen storage (TWh)	**5**	20	14	15
Biomethane storage capacity (TWh)	**30**	80	n/a	n/a
Total demand	**719**	679	811	749

The two FES scenarios cannot really be compared as they rely on imports to help balance the grid. Compared to CAT [4], NZUK generated 7% more energy to meet 6% more demand, so reasonably closely matched.

Wind generation was substantially higher than in comparable studies, at some 11.5 times 2021 production. However, the practical potential for UK offshore wind is about 2,000 TWh/y [25, 26].

Solar power also plays a significant role in NZUK, in order to counter the very low summer wind resource in 2018 and 2021. 137 TW/y equates to an installed capacity of about 157 GW with 2021 weather, ten times the 2021 installed capacity. According to CAT [4] roofs could produce 140 TWh/y of PV energy, equating to an installed capacity of about 160 GW. Other studies, however, have estimated much lower figures. If domestic and commercial rooftops could only accommodate 80 GW, that would leave a further 80 GW solar farm requirement. At a packing density of 50 Wp/m^2 (now increasing as PV efficiency rises), that would require a ground area of 1,600 km^2, or about 0.7% of UK land area. To put that figure into context, 9.4% of UK area is composed of peat bogs. Sea-borne solar panels are now being investigated: they are predicted to be more efficient than land-based PV due to cooler temperatures and less cloud cover. An initiative has recently been launched to tether floating solar farms between North Sea wind turbines [27].

The biomass requirement is substantially lower than in the CAT or FES studies. According to a paper commissioned by Ecotricity [22], 288 TWh of biomass could be harvested from suitable grassland, more than double the NZUK requirement. At present, only 7 TWh/y of biogas is injected into the National Grid [2].

The biomethane storage requirement is much lower than for CAT. A capacity of 30 TWh is higher than present capacity of about 19 TWh, but the Rough storage facility which closed a few years ago could store 35 TWh of gas, and, at the time of writing, it is being refurbished. 5 TWh of hydrogen storage would need to be provided. This would require about 20,000,000 m^3 of storage at a pressure of 100 bar (10 Mpa). However, as shown in Table 5, this is much less storage than required in the comparable studies.

About 75 GW of CCGT capacity would be needed, well over double the present capacity of 32 GW. This is slightly higher than the CAT estimate (up to 70 GW), but NZUK generates about 60 TWh/y from gas – six times more than CAT.

Figure 1 is a useful visual summary of the system, marked up with approximate energy flows, averaged over the five years that were modelled.

3.4 Grid Balancing

In the top graph of Figure 6 the red trace is the difference between supply and demand. In this scenario 34 GW of electrolysis capacity is installed, so unless the hydrogen store (orange trace in lower graph) is full (5,000 GWh), the first 34 GW of any surplus energy is used to make hydrogen.

Figure 6 Supply minus demand, biomethane-generated power, and gas stores.

The purple shaded areas in Figure 6 are the energy surpluses after electrolysis. The turquoise trace in the lower graph is the daily biomethane produced by using hydrogen – multiplied by 20 to make it clearly visible. Only when the hydrogen store is empty or the biomethane store (black trace) is full (30,000 GWh) is there a pause in biomethane production. 250 GWh of hydrogen is drawn off each day: when combined with 500 GWh of biogas, 500 GWh of biomethane is produced-see [17].

The green shaded areas in the top graph of Figure 6 represent balancing power supplied by biomethane power stations. There are ample gas supplies to keep the grid balanced through most times of low generation, but the biomethane store (lower graph) runs very low after the long summer with low winds.

The biomethane is produced from biogas and hydrogen in a biological process, so this should be a continuous process. The discontinuities shown by the turquoise trace in Figure 6 are not ideal, and in practice could be mitigated by a larger hydrogen store.

3.5 Testing

For a solution to be successful, supply had to meet demand for every day of the five years of weather data tested. At the start of each year, the hydrogen and biomethane stores were initialised to 75% full, and they were expected to end the year at least 75% full, so that each year was self-contained.

This scenario passed all these tests with the small exceptions of 2020 and 2021 when the biomethane store ended the year 73% full and 64% full respectively. This could have been fixed by making the hydrogen-to-methane conversion run a little faster, but that would have been at the expense of making the AD stations run less evenly.

3.6 Economics and Demand Side Response

The daily electricity price was calculated by summing the LCOEs of the generators for each day. This was much higher on days when power from biomethane power stations was needed, and the more power stations that had to be online to meet demand, the higher the price, since CCGTs with lower load factor are brought online. Counter-intuitively, perhaps, electricity costs were also raised on days when there was high renewable generation, since the spillage also had to be paid for. For the lowest-cost solution the average annual LCOE (over five years) worked out to be £92/MWh with a total annual LCOE of £66,980 m.

Figure 7 shows the total daily projected cost of energy for 2021 weather. The y-axis has been deliberately truncated so that lower level detail can be seen. The two highest peaks (£2,000 m in March, and £1,200 m in December) reflect the fact that the last one or two most marginal power stations will only run on those one or two days of the year.

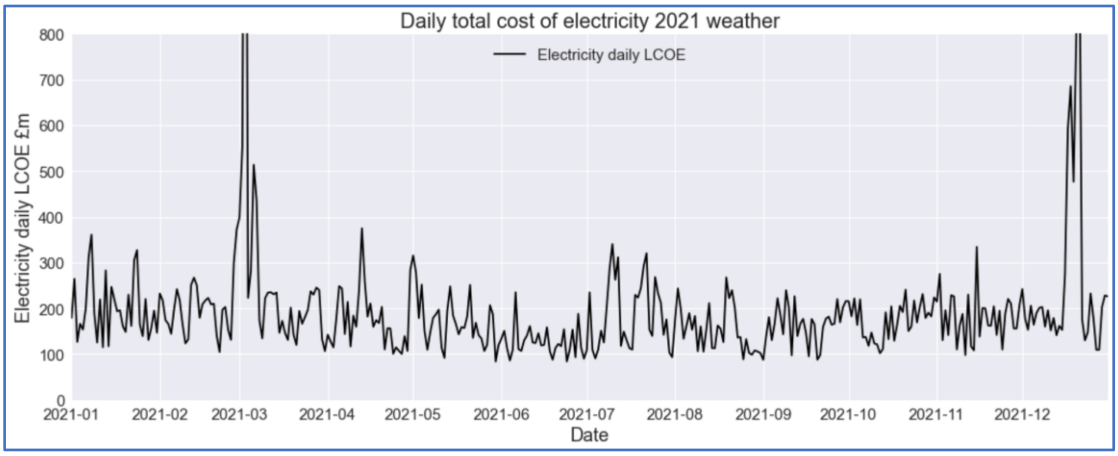

Figure 7 Daily total LCOE-y axis truncated to show detail.

Two demand side responses were modelled. The first was to reduce industrial demand by 50% during the four weeks with the largest deficit of primary renewables (and to increase demand during the other 48 weeks to compensate). This is shown in Figure 8. The light brown line represents industrial demand, and the black trace is the total demand with the shutdowns included (compared to the red trace which is the original demand). The shutdowns do not necessarily coincide with the worst deficit days since whole calendar weeks were used.

Figure 8 also shows the biomass power stations' outputs (green trace), which were made dispatchable, and were operated on the 60 individual days of greatest energy deficit in the year. It should be borne in mind, however, that the effects of industrial shutdowns and biomass dispatch may be optimistic since in practice their deployment would have to be planned, at least a few days ahead, based on weather forecast.

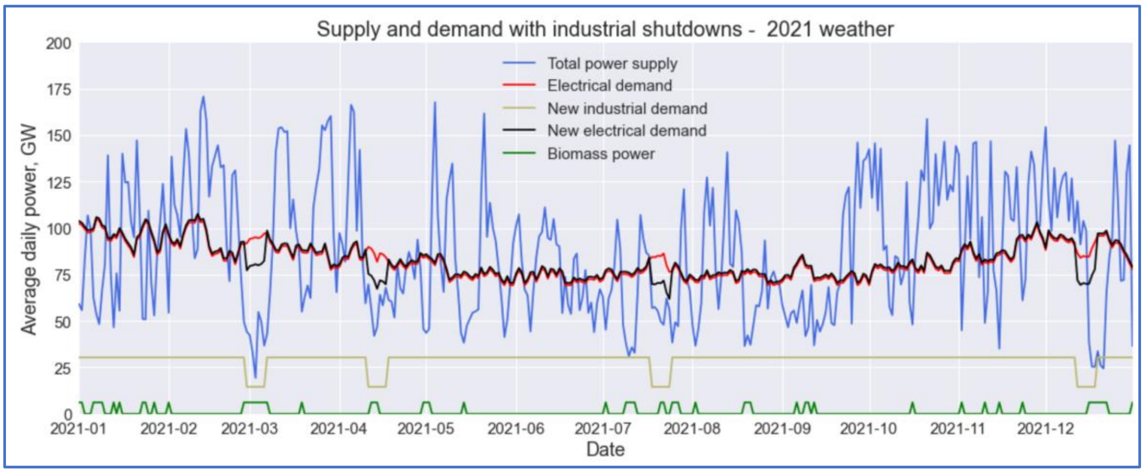

Figure 8 Illustration of the effect on demand of four week-long industrial shutdowns.

The second demand side response to be modelled was elasticity with price. Figure 9 illustrates how the price of electricity could affect demand if elasticity of -0.2 is factored in. The green trace is the electricity generated from biomethane without elasticity. This has a large influence on electricity price (blue trace). The black and red traces show the total electricity demand without and with elasticity respectively. The total electricity used is actually 1% to 2% more with elasticity, but the effect is to reduce demand at peak times.

The elasticity calculations have been modified in two ways:

- Demand (red trace) has been limited to a maximum reduction of 25%, as greater reductions would probably be infeasible in practice.
- Spillage was not taken into account with the cost of primary renewables when calculating demand changes. This would have had the unfortunate effect of limiting demand when there was an excess of renewables. This means that demand is reduced when biomethane power stations are used, else increased.

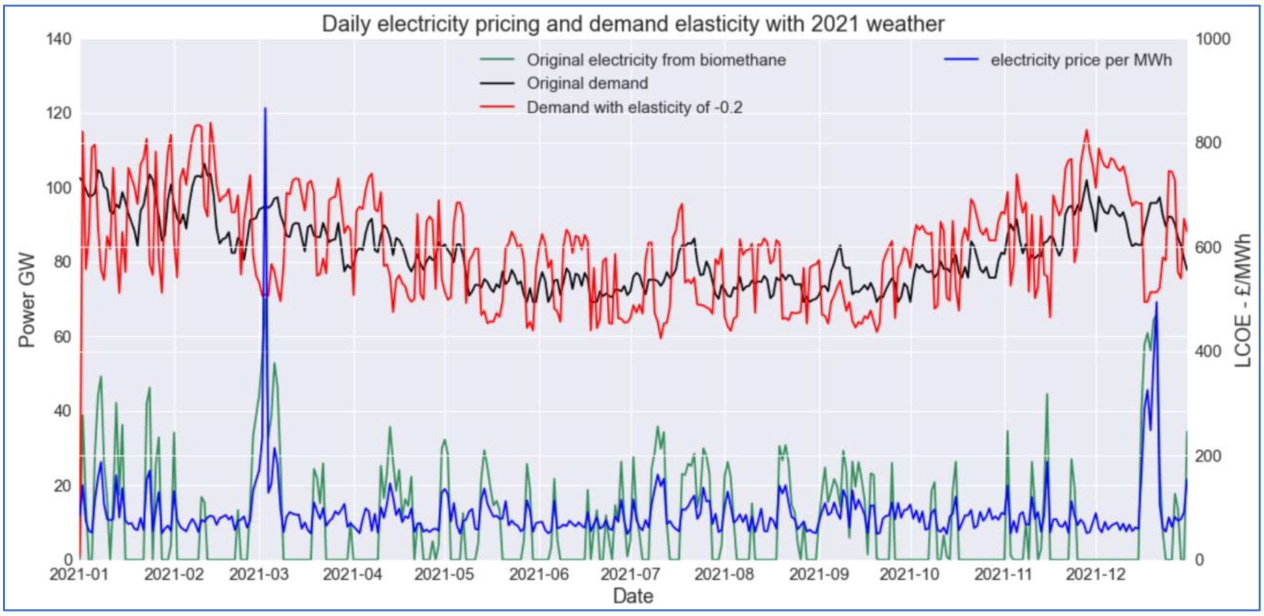

Figure 9 Illustration of how price could influence demand via elasticity.

Table 6 shows how the two demand response measures affect the figures. Elastic response had a bigger effect than industrial shutdowns, but when combined, the unit electricity costs were reduced by nearly 10% to £83/MWh. The responses would also lead to 33% fewer power stations being required and much less spillage. Elastic response would involve consumers reducing demand by up to 25% on certain days, and it is not known if this is feasible.

Table 6 Effects of demand response measures.

	Normal case	With industrial shutdowns	With elasticity reductions	With industrial shutdowns and elasticity
Total primary generation (TWh/y)	975	912	848	831
Spillage (TWh/y)	189	133	76	58
Power stations needed (GW)	75	72	59	60
Unit LCOE (per MWh)	£92	£89	£86	£83
Total LCOE	£66,980 m	£64,710 m	£62,806 m	£61,031 m

Electricity pricing was calculated in order to find the least cost balance of technologies, and does not include the massive grid strengthening or gas storage costs, nor the intra-day balancing systems needed, but it does give a useful indication that energy prices with a clean grid may not be any higher than at present, and may be substantially lower.

3.7 Emissions

This paper has mainly focused on achieving a balanced electricity grid. But to achieve UK net zero emissions, the remaining, non-energy sector, emissions need to be addressed. As noted in Section

2.8, it may be possible to absorb all UK residual emissions by biological means. But it will still be necessary to offset imported emissions. The level of imported emissions will depend on how much is imported and the embodied emissions of the goods, neither of which can be predicted.

One promising technology for carbon dioxide extraction would be to fit CCS to the biomethane power stations. Since the power stations will be running on renewably produced gas, all CO_2 captured would represent negative emissions. Several different technology types for sequestering CO_2 from power station emissions exist. The most well known is *post combustion capture* in which the carbon dioxide is separated out from the flue gases and stored securely underground. However this could possibly be enhanced by a technology known as *oxy-fuel combustion* [28]: when methane is burnt in pure oxygen, rather than air, the combustion is not only more efficient, but the flue gases are almost pure carbon dioxide, ready for immediate sequestration. In the context of NZUK, the electrolysers produce oxygen as a waste product of hydrogen generation. Further analysis is beyond the scope of this paper, but it may prove efficient to store the oxygen for use in oxy-fuelled biomethane power plants.

The model calculates the annual CCS extraction based on 0.365 Mt of CO_2 per TWh of electricity generated by biomethane and biomass power stations, with an extraction efficiency of 85%. This would lead to an average of 21.5 Mt being removed per year. (Note that the additional cost of CCS equipment has not been included in the indicative LCOE for gas-fired generation).

To remove more CO_2, direct air capture (DAC) would be possible. At a removal rate of 1 Mt per 2 TWh [29], the predicted energy surplus could remove 95 Mt CO_2/y. The fuel would be “free”, and the cost of the machines is likely to reduce considerably. However, the load factor of the DAC machines (<50%) would not be favourable. The UK has the “geological storage potential for over 70 billion tonnes [of CO_2] deep under the UK seabed” [30], so capacity should not be an issue.

4. Discussion and Conclusions

In the NZUK scenario, with most energy requirements electrified, total energy demand has reduced to 36% of 2021 demand, while electricity demand has more than doubled. At the same time the electricity grid, and hence the energy sector, has been completely decarbonised.

This paper has shown that, with a greatly expanded mix of renewables, enough electricity could be produced to power the UK without using fossil fuels or imported energy. Backup power stations, to balance the grid at times of low renewable generation, would run on biomethane made from “green” hydrogen plus biogas from anaerobic digesters.

NZUK is only directly applicable to the UK: other countries will have very different renewable resources and different energy usage patterns. For example the UK, and its waters, has a world-leading wind resource. Regions with different geographies may be able to derive much of their energy from hydroelectric stations, and in this case pumped storage could play a large part in grid balancing, greatly reducing the need for biomethane. Other regions might be able to rely on year-round solar generation, storing night-time energy in molten salt for example. However, the Python model could be modified and adapted for a wide range of scenarios.

NZUK assumes that the UK will be completely energy-independent. If there is a deficit of renewable energy in the UK, it is likely that the UK’s close neighbours will also be in deficit, so there will be no energy to import [8]. However, if the grid was greatly extended to include Iceland and North African countries, for example, with their different resources, this could change. For example, Xlinks has published plans to import 3.6 GW of solar-produced power from Morocco [31].

The NZUK scenario requires a great deal of new renewable generating capacity and other infrastructure to be built. Table 7 shows the approximate levels of increase compared to 2021. Note that the generation figures are in terms of energy generated rather than installed capacity. For wind, the multiple for installed capacity will be significantly less than for generation, since most new turbines are expected to be offshore, achieving higher load factors than the current mix of turbines.

Table 7 Approximate resource multiples compared to 2021.

Resource	**Units**	**Requirement**	**Multiple compared to 2021**
Total energy demand	TWh/y	719	0.4
Wind generation	TWh/y	761	11.5
Solar generation	TWh/y	137	10.5
Biomass combustion generation	TWh/y	9	0.5
Geothermal heat	TWh/y	34	4.5
Nuclear generation	TWh/y	43	1.0
Total primary electricity generation	TWh/y	975	3.0
Anaerobic digestion	TWh/y	124	18.0
Electrolysis capacity	GW	34	>100.0
Hydrogen storage	TWh	5	>100.0
Biomethane storage	TWh	30	1.6
Grid strengthening	-		~3.0

The Python model – written for this project, and freely available to download [3] – shows that the proposed solution would keep the future electricity grid balanced for every day of the last five years of weather (with electricity demand comparable to other studies). There are many possible combinations of technologies, so the costs of each were calculated, and informed the choices made.

Net-zero electricity prices appear to be lower than at present, with an average overall LCOE of £92/MWh. According to Ofgem figures [32], the wholesale energy price for a typical dual fuel customer for October 2022 is £130/MWh. However, network costs will be higher for NZUK. But crucially, prices would be decoupled from volatile world commodity prices.

Market-based demand-side responses led to a reduction of 10% in electricity costs, but this must be balanced against the practical difficulties of achieving the modelled responses. The National Grid has reported some success in achieving short term demand response, based on pricing. However, it is easy to imagine that heat pumps could be turned off for a few hours – especially for well-insulated buildings with high thermal mass – or electric car charging could be deferred, for example. It is less easy to imagine how significant demand reduction could be sustained over continuous periods of days. Perhaps domestic or community-scale heat stores could be charged during periods of cheap electricity, and used when electricity is expensive. Perhaps domestic and commercial life could be organised with due respect for prevailing weather conditions, as was the case not many generations ago.

The costs of installing the renewable energy generators, the hydrogen production, and the power stations are expected to be borne by the private sector – the LCOE figures given above include the capital costs. However, some of the expenses of insulation and decarbonisation, and most of the infrastructure costs, such as grid strengthening and gas storage, may have to be paid for by government, as national investments. These costs are beyond the scope of this paper.

In contrast to comparable studies, imported and greenhouse gas emissions have been addressed. Biological extraction, plus carbon capture from the (already carbon neutral) power stations may prove sufficient, but more aggressive removal technologies have been considered, and might be needed for a truly net zero UK. The carbon removal that can be achieved could force a hard limit on the embodied carbon in imports.

Technologies to remove methane from the air are starting to emerge. As much of the emissions from agriculture are in the form of methane, and as methane is 80 times more potent, in terms of global warming potential than carbon dioxide, methane removal is likely to receive much more interest in the near future.

This work could be extended by reducing the model's granularity and introducing short term storage technologies for intra-day balancing. It would also be interesting to model ways for using the waste heat from power stations, and the surplus electricity. The costs of grid strengthening and other infrastructure requirements could be quantified to provide a broader view of anticipated costs. And much further work is required on demand reduction measures.

Some major assumptions have been made, one of the most serious being that the weather will be no worse for renewables than it was in the five most recent years, 2017 to 2021. With the weather changing this is a risky assumption. But most importantly, it is assumed that there will be the public and political will to build out the massive infrastructure needed, to insulate dwellings properly, and to contribute to the large demand reductions that will be needed to balance the grid and achieve net zero emissions.

The figures in Table 7 indicate that the changes needed are large, but are within the range of the possible. Net zero needs to be achieved, and the projected LCOE figures, when viewed in the light of current rapidly rising energy prices, means that there would likely be a significant dividend for energy customers, as well as for the UK balance of payments.

Author Contributions

A Williams: preparation of Python model, data collection and analysis, report writing. Dr M Thomson: project guidance and direction, report writing and editing.

Competing Interests

The authors have declared that no competing interests exist.

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