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Techno-Economic Analysis of Low Carbon Hydrogen Production from Offshore Wind Using Battolyser Technology

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Abstract: A battolyser is a combined battery electrolyser in one unit. It is based on flow battery technology and can be adapted to produce hydrogen at a lower efficiency than an electrolyser but without the need for rare and expensive materials. This paper presents a method of determining if a battolyser connected to a wind farm makes economic sense based on stochastic modelling. A range of cost data and operational scenarios are used to establish the impact on the NPV and LCOE of adding a battolyser to a wind farm. The results are compared to adding a battery or an electrolyser to a wind farm. Indications are that it makes economic sense to add a battolyser or battery to a wind farm to use any curtailed wind with calculated LCOE at £56/MWh to £58/MWh and positive NPV over a range of cost scenarios. However, electrolysers, are still too expensive to make economic sense.

Keywords: battolyser; electrolysis; energy storage; wind generation; stochastic modelling; NPV

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1. Introduction

In addressing net-zero targets, it is recognized that green electricity alone is very unlikely to meet the requirements of the complete energy system, for example in areas such as heavy transport [1]. Therefore, alternative energy sources will be required if ambitious decarbonization targets are to be achieved. Green hydrogen has been identified as a low carbon solution that can be used to meet these requirements and a number of countries have already set low carbon hydrogen production targets for 2030 [2,3].

One approach to producing low carbon hydrogen is through the electrolysis of water using renewable electricity generation (for example wind or solar). However, the cost of electrolyser technology is currently high, and they are not typically designed for intermittent operation [4]. A novel alternative which is currently being explored to address these challenges is a battolyser. The battolyser acts like a battery until it is fully charged and then produces hydrogen gas. A single device which can produce both electricity and hydrogen has the potential to be more economically viable. There are a range of options for running a hybrid wind/battery/electrolyser/battolyser solution as shown in Figure 1.

Current figures suggest that the levelised cost of electricity (LCOE) is between $58 to $76/MWh for wind energy [5]. There exists some recent literature looking at hybrid systems including wind and battery technology [6,7] and wind and hydrogen technology [8,9]. Reference 6 uses a LCOE for a wind farm of $60/MWh and then calculates separately the cost of storage (battery and compressed air). They size the system to provide ancillary support services such as frequency regulation or load shifting. This results in a high calculated LCOE for the storage system of up to $435/MWh. Reference [7] also looks at adding battery storage to wind farms. Their numbers predict that by 2050, the cost of storage will have come down sufficiently such that the LCOE of the storage is in the range €68–€83/MWh depending on replacement costs and of comparable value to the LCOE of wind.

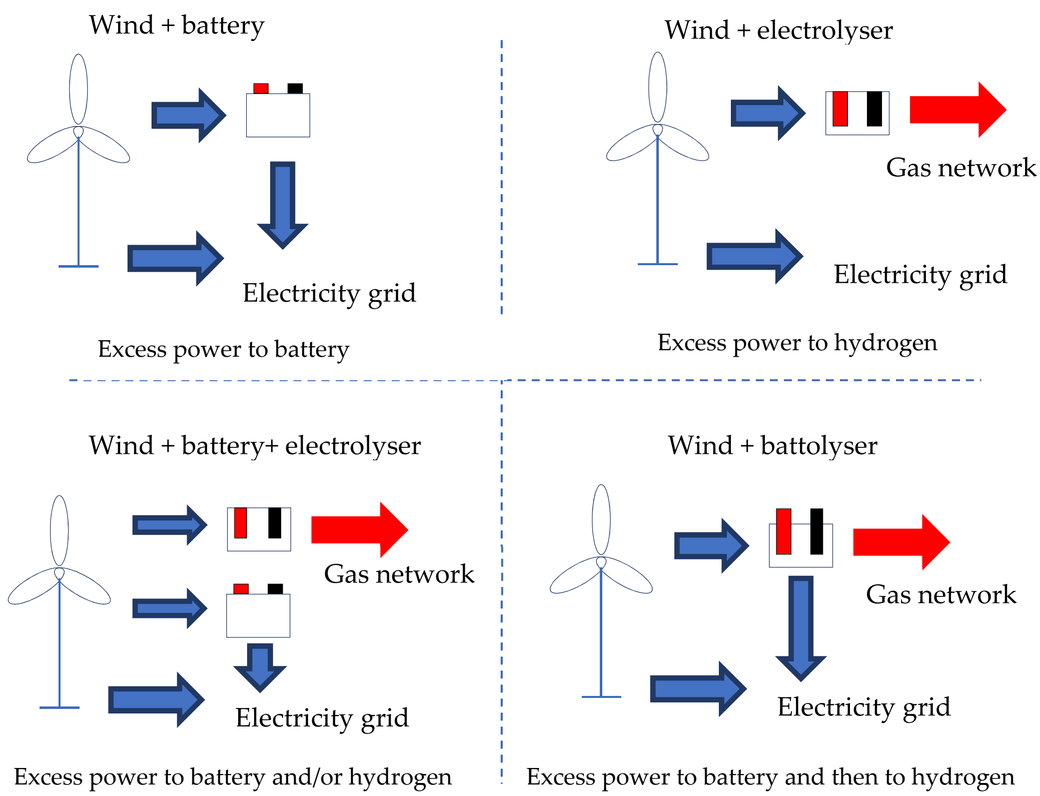

Figure 1. Options for capturing excess power from renewable generators.

Reference [8] looked at using 4% waste energy from wind farms to produce hydrogen. They showed that even if the cost of electricity from wind farms were free, the levelised cost of energy through hydrogen from fuel cells was in the order of £130/MWh. This is still very high and also suffers from the issue of fluctuating supply. Reference [9] assumed that the full potential for wind farms off the coast of China were utilised and that all excess energy is turned to hydrogen. They show that the wind and hydrogen LCOE combination is estimated to be $249–$301/MWh. These values are significantly higher than that of a wind farm on its own because of the high cost of the electrolysers.

The published research mostly focuses on conventional revenue streams for example ancillary services as a source of revenue for batteries. This means the sizing of the systems are large and the capital costs of the equipment to provide large scale services combined with the high capital cost means the LCOE is also high and the combinations of wind with these other types of services are considered not viable.

The aim of this research is to validate, through economic and energy modelling, an offshore wind generator and battolyser hybrid system as a viable economical technological solution that could be used to decarbonise the electricity and transport networks.

This work makes several novel contributions in this area. Firstly, it includes the use of a battolyser which is a new technology and for which there are few published data. The paper pulls together cost data for a battolyser based on published data for batteries and electrolysers using an acid chemistry. Secondly, it is more common to look at electricity revenue based on either wholesale market values or the frequency response markets. This paper considers revenue from wind curtailment as a defining revenue factor using a systems approach to the LCOE calculation (combining wind with the storage technology). With the integration of new technology into the market there is a risk. This paper looks at that de-risking the technology by comparing the NPV and LCOE to a wind farm and a wind farm with more conventional technology; a battery and an electrolyser to provide comparable data.

Description of Battolyser Technology

Integrating batteries and electrolysers into single units will help to reduce the burden on grid infrastructure and will allow for more flexible power management at a singular site [10]; furthermore, it allows for a single unit to be in quasi-constant operation compared with separate units where both are used with less regularity [10]. However, battolysers are in their infancy and there has been limited research into them since their conception in 2017 [10,11].

It is important that battolysers have a flowing electrolyte as bubbles in the electrolyte increase electrical losses by reducing the conductivity of the electrolyte and therefore these bubbles need to be moved on.

Figure 2 shows a high-level concept diagram of a battolyser. It contains an electrochemical cell made up of electrodes and a separator. Depending on the cell chemistry, the electrolyte could be common to both electrodes or different. The electrolyte is pumped round the cell, to help with battery action and to help remove the products of electrolysis. The separator stops the plates from touching but also prevents cross contamination of hydrogen and oxygen.

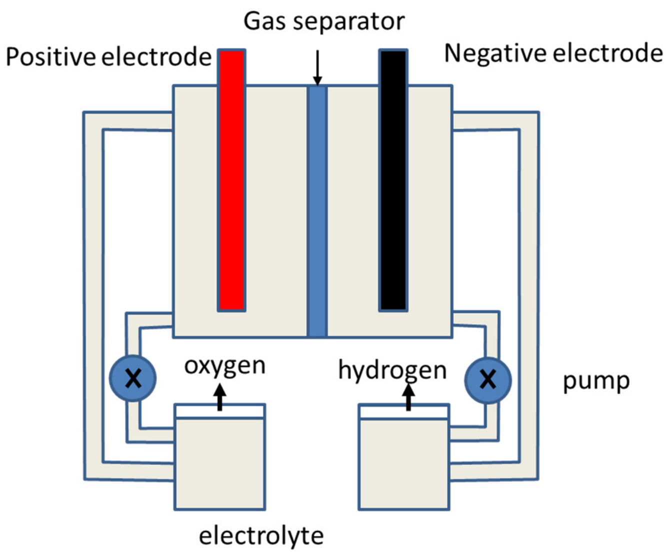

Figure 2. High level overview of a battolyser.

The inaugural battolyser used iron–nickel battery chemistry [10]; this research has been replicated [11] and an additional chemistry based on lead acid battery chemistry has been demonstrated [12].

This paper is different from previous work because it does not focus on the technical or chemical aspects of the battolyser, but instead considers the business case behind using this technology. This research looks at including a battolyser with a wind farm. The paper includes a description of the modelling along with results.

2. Methodology

To determine the economic feasibility of the battolyser system in combination with an offshore wind farm a stochastic time-series model was created. This model uses wind speed data and wind turbine power curves to estimate the electrical power produced from an offshore wind farm, along with historical curtailment data to estimate the amount of curtailed energy that is available to the battolyser system. The model then calculates the amount of energy stored and released and the hydrogen that is produced by the battolyser system. The revenue generated from the electricity and hydrogen output from the combined system are calculated. Wind farm and battolyser capital and operational costs are then used to calculate the levelised cost of energy and the net present value of the system.

This paper investigates whether a battolyser is likely to be profitable over its lifetime. The paper defines profitability as a positive NPV as shown in Equation (1) [13,14]. which represents a positive income over its lifetime.

$$\text{NPV} = \sum_{j=1}^{n_{\text{oy}}} \frac{R(j)}{(1+r)^j} \tag{1}$$

where:

n_{oy}: number of operational years;
j: index for counting years;
$R(j)$: net cashflow during the jth year;
r: discount rate.

A case is an economically feasible case if NPV > 0, and economically infeasible otherwise. The net cash flow, $R(j)$ is calculated as

$$R(j) = R_{\text{wm}}(j) + R_{\text{h}}(j) - C_{\text{op}}(j) - C_{\text{c}}(j) \tag{2}$$

where:

$R_{\text{wm}}(j)$ is the net revenue from the wholesale electricity market in the jth year;
$R_{\text{h}}(j)$ is the net revenue from hydrogen sales in the jth year;
$C_{\text{op}}(j)$ is the operational and maintenance cost of the battolyser and wind farm in the jth year;
$C_{\text{c}}(j)$ is the capital cost of the battolyser (C_{batt}) and wind farm (C_{wind}).

$$\begin{gathered} C_{\text{c}}(j=1) = C_{\text{batt}} + C_{\text{wind}} \\ C_{\text{c}}(j \neq 1) = 0 \end{gathered} \tag{3}$$

The registered site capacity (export limits) will remain the same and therefore no extra connection costs will be required and there will be no changes to capacity market revenue.

An alternative metric to NPV is the LCOE—levelised cost of energy [15,16], typically written as sum of the costs over the lifetime divided by the sum of the energy produced over the lifetime.

$$\text{LCOE} = \frac{\sum_{j=1}^{n_{\text{oy}}} \frac{C_{\text{c}}(j)+C_{\text{op}}(j)+C_{\text{f}}(j)}{(1+r)^j}}{\sum_{j=1}^{n_{\text{oy}}} \frac{E(j)}{(1+r)^j}} \tag{4}$$

$C_{\text{f}}(j)$: fuel expenditures in the year j typical equal to 0 for a wind farm;
$E(j)$: electrical energy generated in the year j.

Levelized cost of electricity metrics can have some limitations. In particular, time dependency effects of matching generation to load. For example, the generator may have a dispatch or ramp up time associated with coming online or the generation availability does not match market profile.

An alternative analysis around energy storage has been developed to take into account the impact of the battery; LCOS—levelised cost of storage [17]. LCOS is defined as the discounted cost per unit of discharged electrical energy. This calculation is complicated when the battery can operate as both a generator and a load. The LCOS calculation is comparable in form to the LCOE as a generator where charging cost replaces fuel cost. It is dependent on storage type and application and quantifies the present discounted value of the storage [18].

$$\text{LCOS}\left[\frac{\pounds}{\text{MWh}}\right] = \frac{\sum_{j=1}^{n_{\text{oy}}} \frac{C_{\text{c}}(j)+C_{\text{op}}(j)}{(1+r)^j} + \sum_{j=1}^{n_{\text{oy}}} \frac{\textit{Charging cost}}{(1+r)^j} + \frac{\textit{End of life cost}}{(1+r)^{j+1}}}{\sum_{j=1}^{n_{\text{oy}}} \frac{\textit{Elec DisCharged}}{(1+r)^j}} \tag{5}$$

An equivalent formula relating to electrolysers has also been developed. The levelised cost of hydrogen (LCOH) is calculated by dividing the lifetime cost by the lifetime thermal energy generation [19,20]. In this instance $C_c(j)$ includes the cost of the electrolyser.

$$\text{LCOH}\left[\frac{£}{\text{MWhe}}\right] = \frac{\sum_{j=1}^{n_{oy}} \frac{C_c(j)+C_{op}(j)}{(1+r)^j}}{\sum_{j=1}^{n_{oy}} \frac{Thermal\ H_2\ Energy\ Generated}{(1+r)^j}} \tag{6}$$

A LCOWB (levelised cost of wind/battolyser) is a modification to the LCOE, LCOS and LCOH to reflect that the battolyser includes both storage and hydrogen. However, the charging cost are not required, as this is "free" energy from the wind farm. In this instance $C_c(j)$ is the cost of the battolyser and wind farm.

$$\text{LCOWB}\left[\frac{£}{\text{MWhe}}\right] = \frac{\sum_{j=1}^{n_{oy}} \frac{C_c(j)+C_{op}(j)}{(1+r)^j} + \sum_{j=1}^{n_{oy}} \frac{End\ of\ life\ cost}{(1+r)^{j+1}}}{\sum_{j=1}^{n_{oy}} \frac{Elec\ exported}{(1+r)^j} + \frac{Thermal\ H_2\ Energy\ Generated}{(1+r)^j}} \tag{7}$$

At this time, the end-of-life costs have been set to zero. This is because a lead acid battolyser chemistry is assumed and this can directly feed into the lead acid battery recycling chain. This paper uses a case study approach using real data related to existing windfarms. To narrow down the scope, this paper looks a large wind farm scenario (1 GW), and considers comparisons between the battolyser and an electrolyser and battery solution.

2.1. Techno-Economic Model

A high-level overview of the model is shown in Figure 3. This consists of three sub modules (wind-farm revenue, curtailed-wind revenue and the business case) which are described in more detail throughout this section.

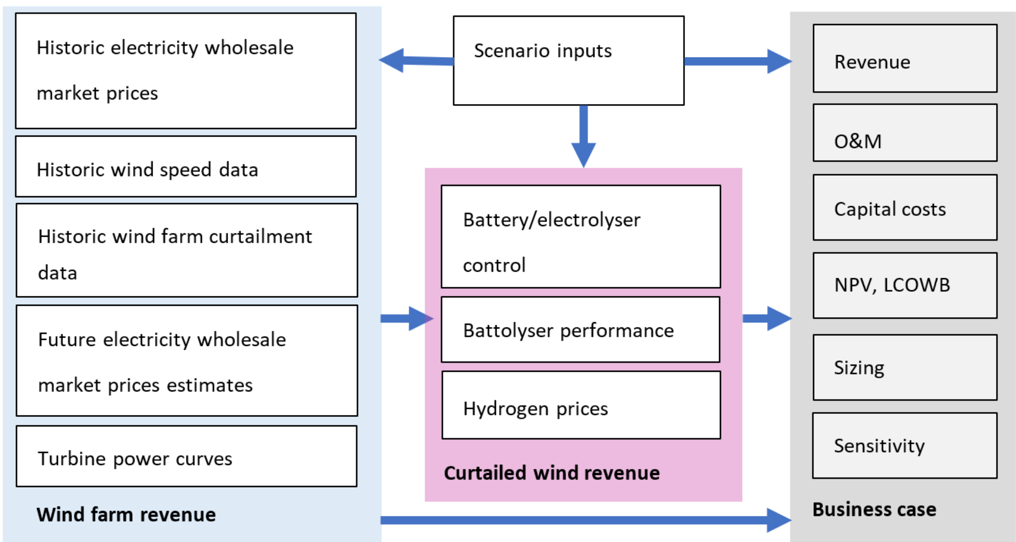

Figure 3. High level overview of methodology.

2.2. Wind Farm Revenue Model

The aim of the wind farm revenue model is to calculate the amount of energy produced by a case-study offshore wind farm, how much of this may be curtailed and how much revenue is generated from energy exported to the grid. The inputs and outputs for this model along with the key steps are summarised in Figure 4. The model randomly selects a year from a range of historical offshore wind speed data at 10 min intervals. This is used with a chosen wind turbine power curve to generate a year-long time series worth of turbine and wind farm power production. It is assumed that there are no wake losses between turbines and that the same wind speed was seen at each turbine, hence each turbine produced identical power.

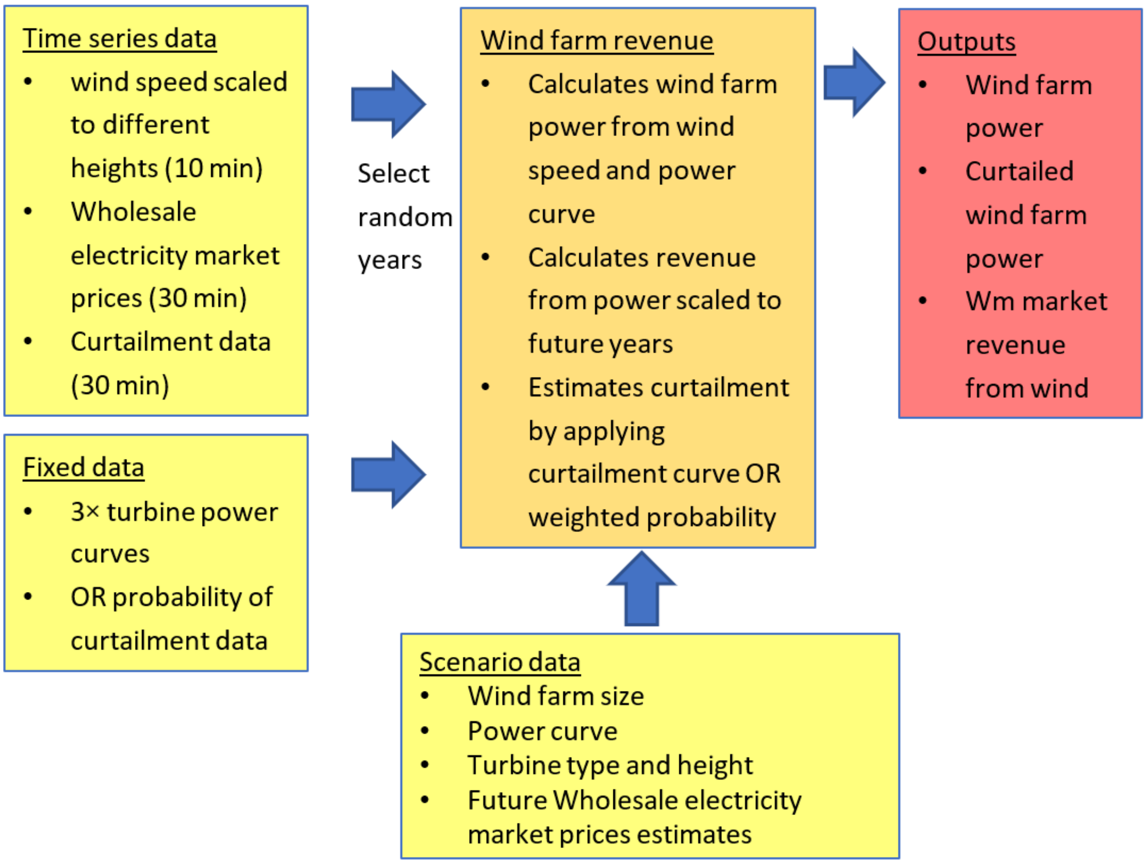

Figure 4. Wind farm revenue methodology.

Similarly, historical wholesale market electricity prices were gathered, and a random year chosen amongst the data collected. This was scaled by a factor to represent the shift in energy prices from a historical average to a future predicted average. The energy produced from the windfarm over each 10 min interval is multiplied by the scaled price for that 10 min interval period to generate the revenue for that period. This was then summed over the period of a year. This process was repeated over the user-defined operational lifetime.

The wind farm generates revenue through exporting electricity at market price. However, the wind farm may need to be curtailed occasionally and the payment for this is market dependent. It is assumed that the windfarm continues to be paid at the wholesale market value even though its export is curtailed. If the wind farm continues to generate power but not export it—this then becomes "free" electricity that can be used for other purposes and provide an additional source of income through this stored energy.

Wind farm curtailment is estimated using two years of historical curtailment data for a UK offshore wind farm. As there were very few data available, two different methods were used to estimate wind farm curtailment in the model as explained in Table 1.

Note—the majority of curtailments start when it is windy and at night when generation is not required. Table 2 was produced from the curtailment data set and represents the probability of curtailment happening over a half hour period in a year (e.g., 344 events out of 17,520) based on a combination of the wind farm output and the time of the day. The reason there are some zero numbers is that at this time of day no recorded curtailment data were present in the original data set.

Table 1. Curtailment choices as applied to the wind farm.

Method	Comments
Apply time series curtailment with no changes	There are only two years' worth of data, so a year is chosen at random. The time periods over which curtailment has occurred and percentage of energy reduction over that period are applied directly to the time series of wind farm energy production and the curtailed energy passes to the battolyser revenue sub system. However, available data show curtailment is more likely at high wind speed (high power output) and at night (when demand is low) and this method includes no mechanism for accounting for the former.
Use weighted stochastic modelling to determine when the wind farm is curtailed	A curtailment start look-up table was produced based on analysis of the curtailment data as shown in Table 2. For every data entry in the time series wind farm output, a random number was generated between 0 and the total number of half hourly periods in a year (17,520). This was compared to the probability of curtailment from Table 2 depending on time and wind farm output. If the random value was less that in Table 2, the wind farm was curtailed. The depth of curtailment (Table 3) and duration of curtailment (Table 4) were then established using another random number generator based on probability of duration and length of curtailment. These were then applied to the following relevant time period. The curtailment process was validated by producing 200 runs of data, and checking that the average curtailment data matched that for the two years' worth of data.

Table 2. Curtailment start look-up table.

Start Up ½ Hour Period	Wind Farm Output %					
	95–100	90–95	85–90	80–85	75–80	0–75
0–1	344	100	102	69	6	27
2–5	372	109	111	75	6	29
6–9	286	84	85	58	5	22
10–13	29	8	9	6	0	2
14–17	57	17	17	12	1	4
18–21	86	25	26	17	1	7
22–25	57	17	17	12	1	4
26–29	86	25	26	17	1	7
30–33	143	42	43	29	2	11
34–37	0	0	0	0	0	0
38–41	200	59	60	41	3	16
41–45	945	276	281	191	15	73
45–48	0	0	0	0	0	0

Table 3. Curtailment power reduction table.

% Curtailment	No of Times Curtailed to This Depth	Cumulative % of Depth
0	0	0
2.5	165	13
7.5	194	28
12.5	179	42
17.5	212	59
22.5	191	74
27.5	171	87
32.5	83	94
37.5	64	99
42.5	15	100

Table 3 shows that the wind farm is never fully curtailed but only partially curtailed.

There are instances where a wind farm maybe completely curtailed, (e.g., maintenance on a Network or under dynamic generation); however, these data were not available. The result of this is that curtailment is potentially under-estimated, and the business case would be better if these numbers could be established. In addition, there are onshore wind projects that exist (e.g., in the Orkneys) where automatic network management is used and curtailment may be imposed as part of this. However, data from this were not available.

Table 4. Curtailment duration table.

No of Half Hour Periods Curtailment Lasts	No of Times Curtailed for This Length of Time	Cumulative % of Length of Time
0	0	0
3	25	27
8	21	51
13	20	73
18	12	86
23	2	88
28	3	91
33	1	92
38	1	93
42	6	100

At the time of writing this paper, the future of curtailment is not clear. Re-enforcement of the network could reduce curtailment while more active network management schemes would increase curtailment. From discussions with network and system operators, it is most probable that curtailment is more likely to increase with increases in renewable generation leading to a better business case. The results of this study are therefore on the conservative side. Sensitivity analysis in this area will form future work.

Table 4 shows the majority of the curtailment periods are between 1 h and 7 h long; however, the majority of this is at less than 17.5% curtailment depth.

2.3. Battolyser Revenue Model

The aim of the battolyser revenue model is to calculate the electricity revenue generated when the battolyser is run as a battery exporting power and the volume of hydrogen and associated revenue produced by the battolyser system using curtailed energy output from the wind farm revenue model. In order to calculate the revenue from the battolyser it is first necessary to develop a control system around the operational state of the battolyser. The battolyser can operate under three different regimes: (1) charging as a battery, (2) discharging as a battery or (3) producing hydrogen as an electrolyser. The control system implemented in the model is based on the flow diagram in Figure 5. Any curtailed energy is first used to charge the "battery" part of the battolyser. When the battery is full, any additional curtailed energy is used to produce hydrogen. When the curtailment period is over, the battery is discharged until it is either empty or another curtailment period is reached. The model considers the efficiency of the battery and discharges less energy than is used in charging. The power the battery discharges plus the un-curtailed power being exported by the wind farm cannot exceed the site export limit (assumed to be the rated power of the wind farm). All charge/discharge is limited to the power limit of the battolyser. The energy the battery discharges over each ½ period is used to calculate the additional wholesale market electricity revenue. The overall methodology of the revenue model is summarised in Figure 6. At this time there is no attempt to optimise when this stored electrical energy could be exported. However, designing a control system to optimise this will improve the business case. Any hydrogen that is produced is turned into revenue through a £/MWeH_2 lookup table which also takes into account conversion efficiency. This is based on a single figure at today's prices. It should be possible to generate a future average hydrogen cost and use time series market figures similar to the wholesale market costs. However, this would have introduced more complexity and a complex optimisation problem around storage sizing. This is considered too complex for the research at this stage which is looking at early feasibility studies when figures for battolyser costs are themselves not exactly known, but could be considered as an area of investigation in the future.

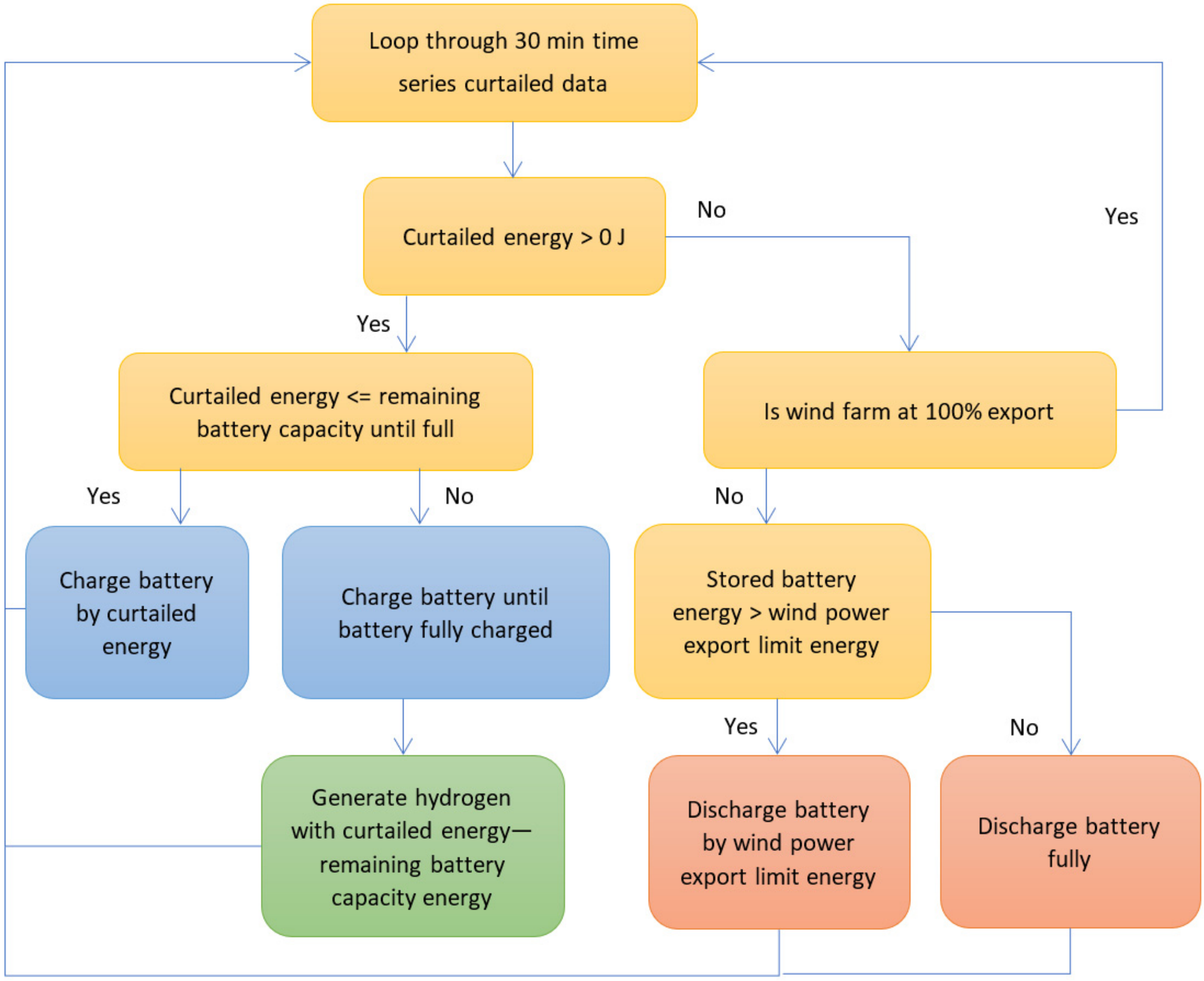

Figure 5. Battolyser control.

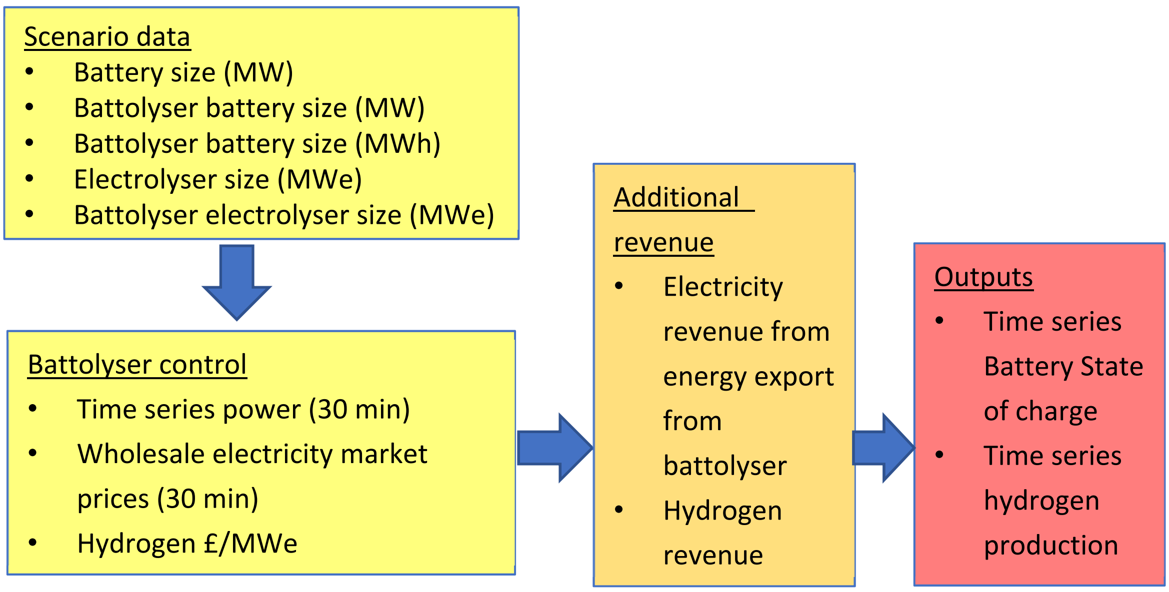

Figure 6. Battolyser revenue methodology.

The model also includes the ability to include a battery or electrolyser as additional separate items. In this case the battery is charged/discharged before the battolyser and the electrolyser produces hydrogen before the battolyser.

2.4. Business Case Model

The aim of the business case model is to calculate the LCOE and NPV of the case study scenario, as outlined in Section 2. This is the most straightforward aspect of the modelling and is summarised in Figure 7. The wind farm and battolyser (or battery/electrolyser) size is used to calculate the capex and yearly opex costs of the system. These are then used with the revenue values calculated in the wind farm revenue and battolyser revenue model in conjunction with Equation (1) to calculate the NPV over the number of operating years and Equation (6) for the LCOE. For the purposes of this paper, this value is set to 15 years.

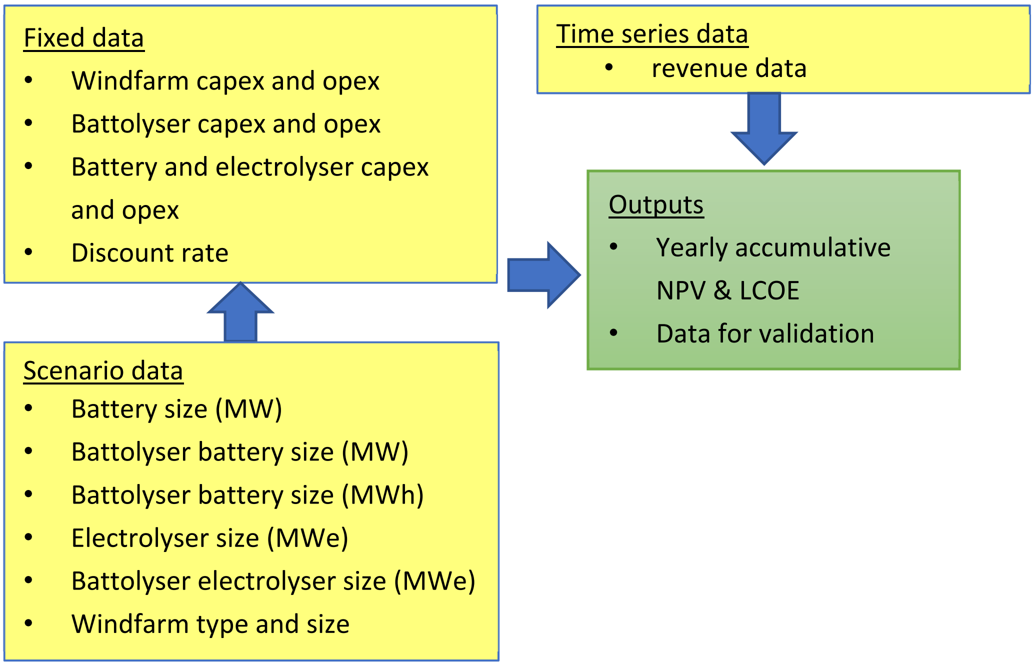

Figure 7. Business case process.

It is difficult to validate a model of this nature because there are no existing data on which to validate the output results based on operational parameters. This work therefore uses conceptual validation (i.e., by determining whether the theory, calculations, input data and assumptions underlying the model are justifiable). Independent checking of each stage of the model was undertaken by someone independent to the person who coded the model to check the outputs at each stage were as expected. Once this had been full checked over all different scenario types, the model was assumed to be validated.

2.5. Scenario Studies

The model was run for a number of different scenarios as shown in Table 5 each over 100 times to understand the variability due to the stochastic nature of the model. All the models assumed a 9.5 MW turbine and the time series wholesale market values. The other options (using the strike price and other turbine types were assumed to have negligible impact). A retrofit wind farm (one where the capex for the wind farm has already been accounted for) has not been included but would improve the economic case significantly. As the depth of curtailment from Table 3 is lower than 15% the size of the different energy storage options is investigated up to 150 MW/150 MWh. Additional studies were undertaken over and above what is presented here. As the average depth of curtailment is low and the duration of curtailment is mostly less than 8 h, one hours' worth of energy storage was adequate to deal with the majority of curtailment events. Energy storage sizing over 1 h therefore had a negative impact on the business case and the results below are limited to 1 h storage.

Table 5. Scenario studies for a new 1 GW windfarm.

Battolyser Details	Battery Details	Electrolyser Details
-	-	Low and high costs
-	-	50 MW, 100 MW, 150 MW
-	Low and high costs	-
-	50 MW/100 MW/150 MW with 50 MWh, 100 MWh, 150 MWh storage	-
Low and high costs	-	-
50 MW/100 MW/150 MW hydrogen with 50 MW/100 MW/150 MW (battery component) with 50 MWh, 100 MWh, 150 MWh storage	-	-

3. Input Data

The following subsections describe the input data that have been used in the model.

3.1. Wind Input Data

3.1.1. Wind Speed Data

Thirteen years' worth of wind speed data from the FINO1 offshore measurement platform (coordinates: N 54°00′53.5″ E 6°35′15.5″) [21] were used as the basis for this analysis. These provide 10-min average wind speed values at a height of 102 m and are considered to be representative of typical wind conditions seen at a North Sea offshore location. During analysis of the wind speed data, there were a number of error values recorded (around 2.8% of the data points). These error values were replaced with hourly values from the ERA5 reanalysis data [22] at the closest available location (N 54°00′53.5″ E 6°30′00″) downloaded from the online ESOX tool developed by Lautec [23]. Both datasets had similar mean and standard deviation values, as well as a high correlation (R^2 = 0.9), and the statistical properties of the dataset were not significantly changed by the substitution, as shown in Table 6.

Table 6. Mean and standard deviation values of the original and modified wind speed data with error values replaced with ERA5 hourly values.

Dataset	Mean (m/s)	Standard Deviation (m/s)
FINO1 original	9.66	4.66
FINO1 modified	9.67	4.64

To accommodate the modelling of different turbine sizes, the wind speed values at different hub heights were then estimated using the log law, as shown in Equation (8) [24]. Where $u(z)$ is the wind speed at height z, $u(z_r)$ is the wind speed at the reference height, z_r and z_0 is the surface roughness length, taken here to be the mid-point between the values for a calm open sea and a blown sea, given in [24]. This was carried out for hub height values of 80 m, 105 m and 110 m to represent different turbine sizes within the model.

$$u(z) = u(z_r)\frac{\ln\left(\frac{z}{z_0}\right)}{\ln\left(\frac{z_r}{z_0}\right)} \tag{8}$$

3.1.2. Wind Turbine Power Curves

To determine the impacts of different wind turbine and wind farm sizes on the viability of the battolyser, three different wind turbine sizes are included within the model—3 MW, 8 MW and 9.5 MW. The power curves for these turbines were taken from various online sources [25–27].

3.1.3. Wind Farm Curtailment Data

The estimation of wind farm curtailment was based on time-series data available from the UK electricity grid Balancing Mechanism (BM), reported through the Elexon Balancing Mechanism and Reporting Service [28]. As part of the balancing mechanism, wind farms can submit bids to reduce their energy production (i.e., curtail their production) [29] and the details of the accepted bids, along with data on the metered volume of energy produced by wind farms, are reported. The annual percentage of energy curtailed from UK offshore wind farms over 400 MW which finished construction in 2018 or earlier as detailed in the Renewable UK database [30], were compared for 2019 and 2020. This was based on the volume of accepted bids and the metered volume, where each wind farm is considered to be the total of all of its individual Balancing Mechanism Units (BMUs) in the BM. The annual curtailment percentages for these wind farms are shown in Table 7. It can be seen that the curtailment percentage from UK offshore wind farms is currently low.

Table 7. Windfarm curtailment.

Wind Farm	Energy Curtailed in 2019 (%)	Energy Curtailed in 2020 (%)
Walney Extension	0.01	0.72
London Array	0.06	0.02
Race Bank	0.60	0.61
Gwynt y Mor	0.43	3.08
Greater Gabbard	0.02	0.01
Dudgeon	0.03	0.004
Rampion	0.01	0.01

The representation of curtailment in the model is based on the 2020 Gwynt y Mor curtailment data. This is considered to be more representative of a future scenario with greater levels of renewable energy penetration into the grid and higher offshore wind farm curtailment.

3.1.4. Wind Farm Cost Data

To determine the economic viability of the battolyser system in combination with an offshore wind farm using the model, cost data for offshore wind farms were required. The capital (capex) and operational costs (opex) for a large offshore wind farm were based on values published by BVG Associates on behalf of The Crown Estate and the Offshore Renewable Energy Catapult to represent a large offshore wind farm project [31]. The basis of this report was a 1 GW offshore wind farm with 10 MW wind turbines. For a small offshore wind farm, the opex costs were based on a techno-economic analysis of a 504 MW offshore wind farm with 3.6 MW turbines carried out by Ioannou et al. [32]. The capex and opex values estimated from these publications are shown in Table 8.

Table 8. Windfarm costs.

Cost Parameter	Cost
Capex (large wind farm)	£2.7 M/MW
Opex (large wind farm)	£0.075 M/MW·year
Opex (small wind farm)	£0.112 M/MW·year

3.2. Battolyser/Battery/Electrolyser Data

3.2.1. Performance Data

The different energy storage types are not 100% efficient and therefore some compensation has to be made for the loss of energy with their use. Table 9 shows the efficiency data used within the modelling.

Table 9. Energy storage operating efficiencies.

Energy Storage Device	Battery Efficiency	Hydrogen Conversion Efficiency
battery	80%	-
electrolyser	-	80%
battolyser	80%	62%

From an alkaline or PEM published estimates of hydrogen efficiency can be summarised as follows:

Hydrogen conversion for an alkaline electrolyser is typically quoted as 50 to 78 kWh/kg and AEM 57 to 69 kWh/kg [4]. Ref. [33] quotes a single value of 54 kWh/kg. A handy online calculator from [34] suggests an optimistic case of 45.3 kWh/kg. AEM manufacturers are aiming for better than 57 kWh/kg [35]. A figure of 54 kWh/kg has been chosen as a typical value for alkaline electrolysers. This gives a figure of 1 kWh input makes 18.5 g of hydrogen.

The battolyser is going to be less efficient than an electrolyser because it is low cost and designed to be a battery as well as an electrolyser. A good estimate for cell voltage when electrolysing is 2.5 V if the cell is acidic and 2.1 V if alkaline. The thermo-neutral voltage is 1.48 V and the HHV of hydrogen is 39.37 kWh/kg. So:

Acidic battolyser cell: energy = $2.5/1.48 \times 39.37 = 66.5$ kWh/kg;
Alkaline battolyser cell: energy = $2.1/1.48 \times 39.37 = 55.9$ kWh/kg.

Divide these numbers by 95% for balance-of-plant efficiency, so:

Acidic battolyser: 70.0 kWh/kg;
Alkaline battolyser: 58.8 kWh/kg.

So, each kWh makes 14.3 g of hydrogen in an acidic battolyser and 17.0 g in an alkaline battolyser. If the efficiency of an electrolyser is 80%, then the efficiency of an acidic battolyser by proportion is 62%. This paper uses a lead acid based battolyser in its analysis because of hardware cost, future manufacturability and the existence of a recycling chain. Hence the value of 62% is used above.

The efficiency of both a battery and battolyser are dependent on the operating regime and balance of plant. A typical 80% value has been used for both as this is a common value quoted in the literature.

3.2.2. Cost Data

The capex and opex costs for each of the energy storage elements are shown below. Lithium ions are used in the calculation of the battery energy storage models. However, hardware being developed at Loughborough University suggests that a lead acid battolyser is a feasible technology. Therefore the cost is based on lead acid batteries shown in Table 10. The cost values from Table 10 are used along with estimates for common balance of plant (BOP) between the electrolyser and battolyser such as scrubbing, reverse osmosis units and hydrogen compression/storage, shown in Table 11, in the battolyser cost tables of Table 12.

Note the BOP for an electrolyser includes the power electronics which is also included in the battery costs. It is important therefore not to double account this. The battolyser cost would change for different flow batteries in line with the different chemistry costs. Examples of these are shown in Table 13. The electrolyser BOP would need to be included to convert these to a battolyser.

Table 10. Battery cost ranges.

Battery Type	Min-Max Cost Range (£k/MW for 1 h Storage)	Reference
Capex cost Lithium Ion (encompassing NMC, LFP and LTO)	£147 k–£697 k	[36–44]
Lead Acid	£98.4 k–£238 k	[41,45,46]
Opex cost (pa)	£8 k–£10.3 k	[36]

Table 11. Electrolyser cost ranges.

Electrolyser Type	Min-Max Cost Range (£k/MW for 1 h Storage)	Reference
Capex cost Electrolyser (encompassing Alkaline and PEM)	£410 k–£1476 k	[4,47,48]
BOP	£80 k–£362 k	[4]
Opex cost (pa including stack replacement x2)	£93 k–£104 k	[4]

Table 12. Battolyser cost ranges.

Electrolyser Type	Min-Max Cost Range (£k/MW for 1 h Storage)	Reference
Capex cost Lead acid battolyser (battery part)	£98.4 k–£238 k	[45,46]
Capex cost Lead acid battolyser (hydrogen part)	£80 k–£362 k	
Opex cost (pa)	£8.4 k–£18 k	Adjusted up from [36,48]

Table 13. Flow battery cost ranges.

Company	Chemistry	Price (£/kW)	Reference
EOS	Zinc variant	728 (retail)	[49]
ESS Inc.	All-Iron	1968 (target)	[50]
RedFlow	Zinc-Bromine	2187 (retail)	[51]
VIZn	Zinc-Iron	1640 (target)	[52]
RFC Power	Hydrogen-Manganese	164 (target)	[53]
Form Energy	Iron-Air	1181 (target)	[54]
Aquion, Bluesky Energy	Saltwater	1059 (retail)	[55]
CellCube	Vanadium	1312 (retail)	[56]
Invinity	Vanadium	344 (not clear)	[57]

3.3. Wholesale Electricity and Hydrogen Price Data

The wholesale market electricity values to calculate wind farm revenue are taken from Elexon [28]. UK based energy consultancy firm Aurora's GB distributed and flexible energy services sell a forecast report every 6 months where the annual averages of wholesale market electricity prices are published. These values were used to give the average wholesale market price in future years. The half hourly figures of historical data were scaled to meet this average. Reference [35] gives a conversion from MWh to cost of hydrogen as £2.36 per kg. The 18.5 g of hydrogen from 1 kWh of electricity can therefore sell for 4.366p. Battolysers can sell their hydrogen at the same (wholesale green hydrogen) price as electrolysers, about £2.36 per kg. So:

An amount of 14.3 g of hydrogen from an acidic battolyser is worth 3.375p;

An amount of 17.0 g of hydrogen from an alkaline battolyser is worth 4.012p.

4. Results

As this is a stochastic method, 100 hundred runs were conducted on each scenario. The discount rate was set to 0% at this time. Figure 8 shows some example data for three of the scenarios to show the spread of the data. All of the data follow a normal distribution shape as expected. The results following report only the average value of the normal distribution curves to enable easier comparison.

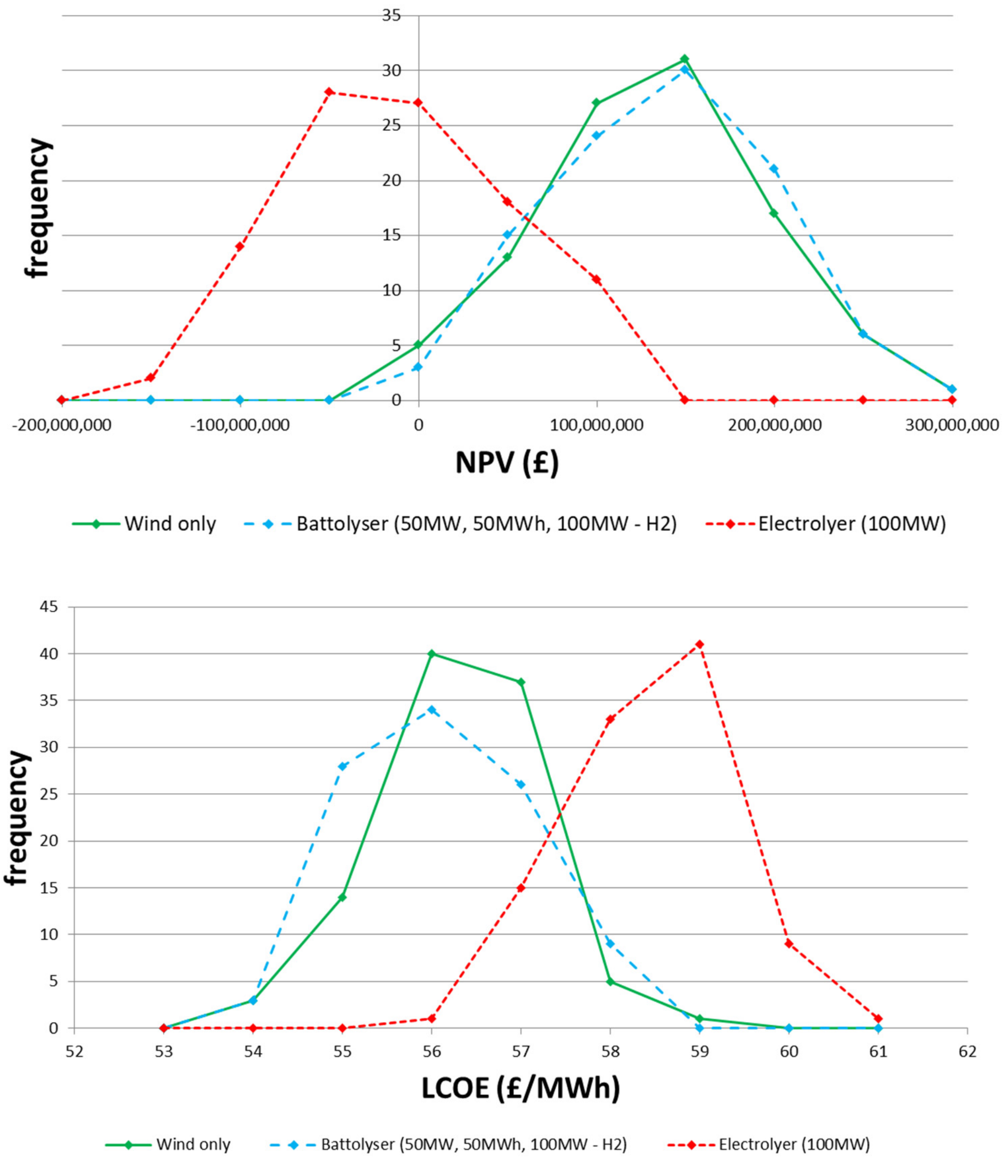

Figure 8. Frequency data over 100 runs (NPV and LCOE).

In all of the following results the average for the wind farm only is plotted as the "0" size value. Two different costs are used—referred to as low cost and high cost to represent the spread of costs estimated from the literature and show the likely spread of the results.

5. Discussion

Figures 9–11 show the NPV and LCOE for different sizes of hybrid units along with a 1 GW new windfarm. The results from the modelling studies show the following main points:

1. It makes no financial sense to include an electrolyser on its own with a wind farm as the capex and opex costs for an electrolyser results in a higher LCOE than just

the wind farm on its own. As the size of the electrolyser increases, the financial case reduces further. At the upper end of the electrolyser capex limits—even a small electrolyser is unprofitable over a 15-year period.

2. Adding a small battery or battolyser at the lower end of the cost range could prove to be more profitable than just having a wind farm on its own. The LCOE figure remains stable over a range of battery and battolyser sizes and is of comparable value to that of the wind farm on its own.
3. A battery at the upper end of its cost range may not be profitable and the LCOE increases in line with this. As the battery was sized based on MW rather than MWh, there is little difference in the cost between the different MWh figures. This is because the cost does not increase between these scenarios and the increase in revenue is not significant after the first 50 MWh because this is the most significant part of the storage. As the MWh increases beyond that which is produced in curtailment, the storage is then underutilised.
4. A battolyser at the upper end of its cost range looks to be more profitable than a battery of similar size. This is because the upper cost of a battolyser is lower than that of an expensive battery. In addition, the LCOE is not significantly higher than that of a wind farm on its own. Increasing the size of the hydrogen beyond 50 MW acts to decrease the profitability as there is cost dependency on the hydrogen storage size.

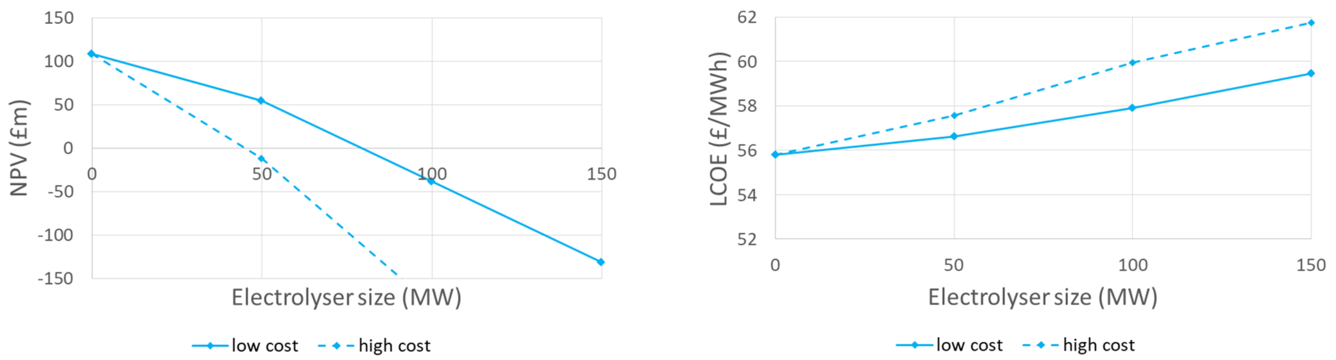

Figure 9. Calculated NPV and LCOE for different size electrolysers.

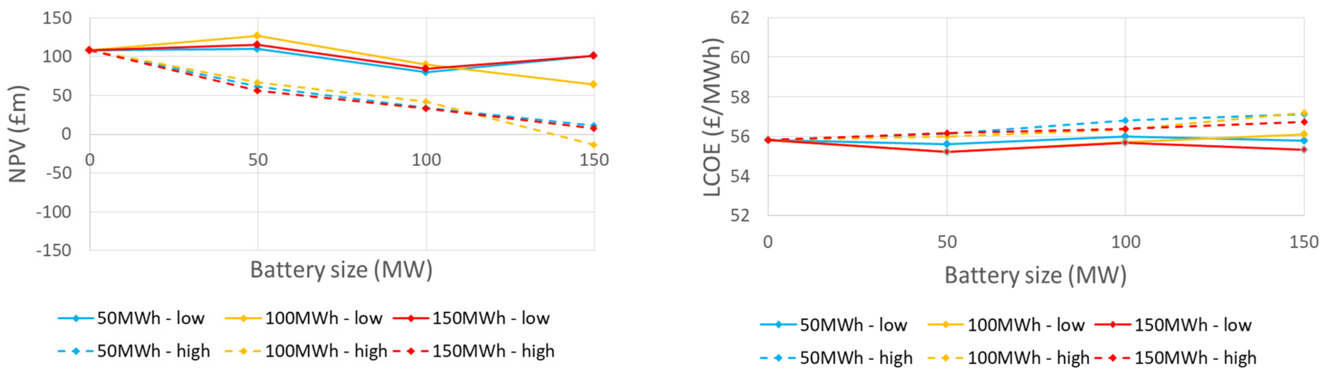

Figure 10. Calculated NPV and LCOE for different size batteries.

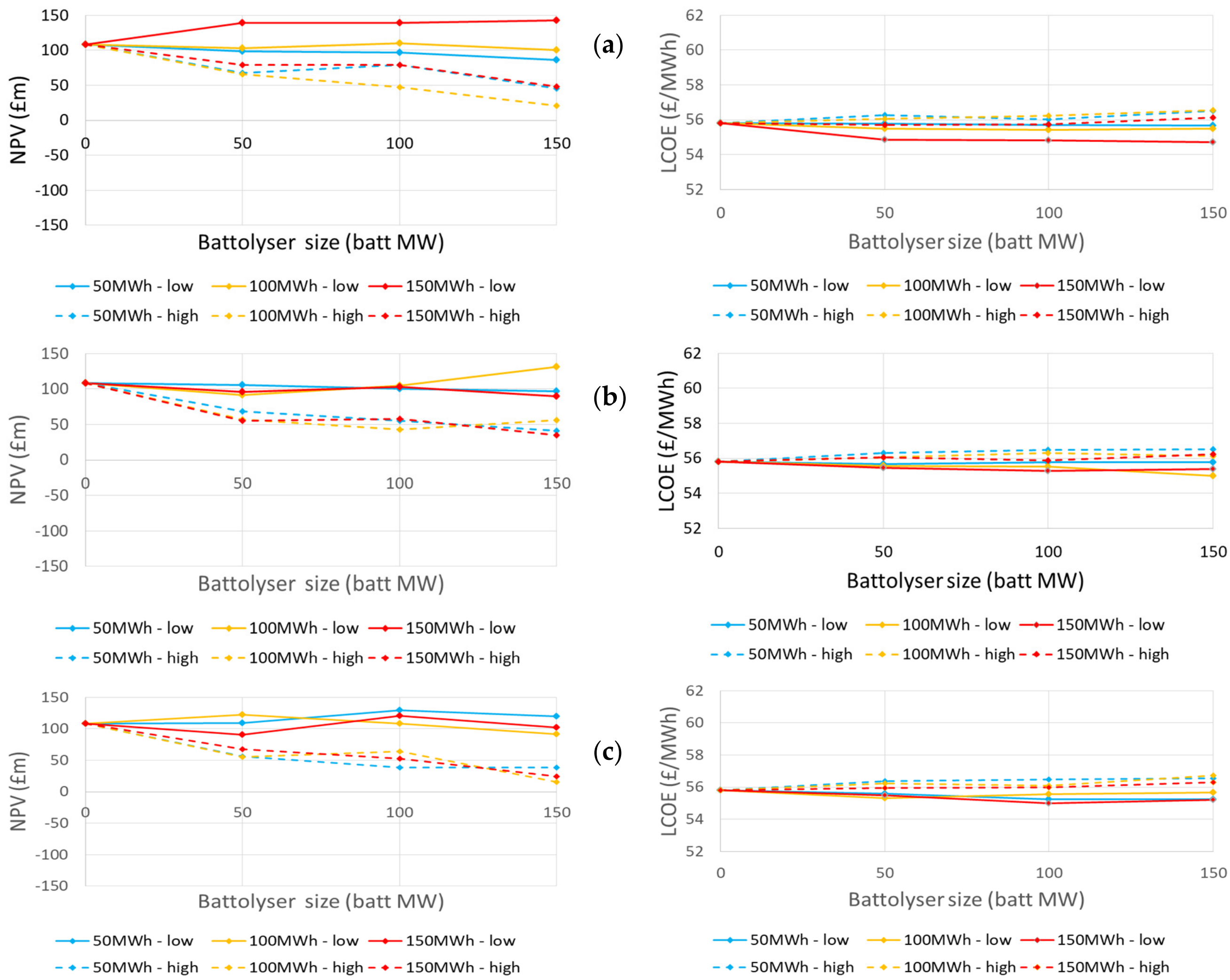

Figure 11. Calculated NPV and LCOE for different size battolysers with hydrogen production sizes of (**a**) 50 MW, (**b**) 100 MW and (**c**) 150 MW.

The results are significant because they show that adding a small battolyser or battery of around 5–10% of the size of the windfarm with 1 h of storage capability to a new wind farm can help with profitability. It can be more profitable to have a windfarm/battery or windfarm/battolyser hybrid than just a wind farm when the wind farm is subject to curtailment.

Where the windfarm already exists, the economic case is better still as some/all of the wind farm costs have already been covered.

The costs of the batteries and battolysers have minimum and maximum values based on the published literature. Where the minimum cost for both are used, there is little difference financially between adding a battery or a battolyser. However, an expensive battery is less profitable than an expensive battolyser. There is no techno-economic case for adding an electrolyser to a new wind farm as results indicate that in all scenario's the profitability of a wind farm with an electrolyser is less than the wind farm on its own.

6. Conclusions

The aim of this research was to validate, through economic and energy modelling, an offshore wind generator and battolyser hybrid system as a viable economical technological solution that could be used to decarbonise the electricity and transport networks. A techno-economic model was developed that looked at wind farm revenue, battolyser revenue and combined them to evaluate the business case. The results indicated that the main aim of the paper to confirm the hybrid system as a viable economic technological solution was achievable under certain circumstances, such as a battolyser set to 5–10% of the size of a new wind farm.

To conclude, there is less risk to the business case of adding a battolyser to a wind farm to help with curtailed wind than adding an electrolyser. The size of the energy storage needs to be carefully sized to avoid under-utilised assets. This work looked at curtailed power that has been brought about through Network constraints and is competed and paid for in the open market. It is likely that curtailment brought about through active network management (e.g., in the Orkneys) will have a different business case that may be made more helpful with the addition of a battolyser. It is also likely that curtailment will increase in volume as more wind is added to the system as additional constraints around inertial response may need to be included. It should be noted that adding additional energy storage could reduce the market value of the curtailed wind in the future.

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