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COST OPTIMIZATION OF OFFSHORE WIND FARM COMBINATION WITH REVERSIBLE SOLID OXIDE CELL SYSTEM PRODUCING HYDROGEN USING THE PYPSA POWER SYSTEM MODELLING TOOL

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Abstract

In the context of reaching the net zero carbon target, the UK has set an ambitious target of having a green hydrogen production capacity of 5 GW by 2030. As part of the EPSRC-funded project on high efficiency reversible solid oxide cells (rSOC) for the integration of offshore renewable energy (ORE) using hydrogen, eight scenarios where hydrogen is combined with offshore renewable energy were identified. A model using the PyPSA power system modelling tool combined with a sensitivity study, investigated optimized rSOC system capacities, hydrogen storage capacities, and subsea cable connection capacities under various combinations of infrastructure cost, rSOC system efficiencies, and electricity prices for one of the scenarios. Preliminary results for a 600 MW wind farm situated 60 km from shore combined with offshore hydrogen production illustrate the impact of electricity price on decision-making in energy dispatch and on optimization of infrastructure of an ORE-rSOC system. Results indicate that high electricity price fluctuations call for large amounts of hydrogen production and storage capacity. Further refinement of input data would make this approach a promising decision-making tool for the use in the design of an ORE-rSOC system.

1 Introduction

The Climate Change Act makes achieving net zero carbon by 2050 in the UK not only a target, but also a legal obligation [1]. One of the methods to reach this target is to increase the amount of low or zero carbon power stations, such as those based on nuclear power and renewable energy. Wind energy is one of the renewable energy sources expected to contribute significantly in meeting this target [2]. High penetration levels of intermittent renewable energy sources will require increased energy storage capacity. Furthermore, certain hard to electrify sectors that currently utilise fossil fuels, such as steel production and long-distance and heavy-duty transport will need to find low or zero carbon alternatives. Hydrogen has the potential to provide both energy storage and replace fossil fuels [3]. Green hydrogen produced via electrolysis from renewable energy can be stored over extended periods of time and either be reconverted into electricity using a fuel cell or a gas turbine, be burned to produce heat, or used for propulsion.

A range of electrolysis and fuel cell technologies have been or are in development. Alkaline electrolysers and fuel cells are the most established and currently cheapest technologies [4]. Proton Exchange Membrane (PEM) technologies are gaining in importance. PEM electrolysers have fast response time to changing renewable power output, better suited to renewables, compared to alkaline electrolysers which typically operate at a steady load. PEM electrolysers are also more compact. However, certain platinum group metals required for their production are rare and costly. A third emerging technology are reversible solid oxide cells which have the potential to deliver high efficiencies in electrolyser mode, which can exceed 100 % (efficiency being defined as the ratio between energy contained in the hydrogen produced and the electrical energy required to produce it) if combined with waste heat ([5]). Furthermore, the cell stack is able to operate both in electrolyser and in fuel cell mode, if the balance of plant required for both modes is present.

The Crown Estate has planned a leasing round for 4 GW of floating offshore wind in the Celtic Sea by 2035, with plans to extend to 20 GW by 2045 [6]. The present paper investigates the use of a reversible system based on rSOC with an offshore wind farm situated in the Celtic Sea. The location of the wind farm was chosen to be in between the lease areas of Petroc and Llywelyn, and the capacity of the wind farm was chosen to be the added capacities of what is planned for Petroc and Llywelyn, that is 300 MW each [7, 8], making it a total of 600 MW.

Modelling scenarios have been identified where an ORE farm is combined with hydrogen production. The following four actions can all be done either onshore or offshore, which makes a total of eight scenarios:

- Dedicated hydrogen production (no fuel cell)
- Hydrogen production and electricity production in parallel (no fuel cell mode)

- Pure electricity production – hydrogen is temporary storage for electricity
- Hydrogen production with partial reconversion of hydrogen into electricity

Figure 1 illustrates one of the more complex scenarios where both hydrogen and electricity would be sent to shore, and in addition, at peak demand times, hydrogen is converted into electricity. This is the scenario investigated here.

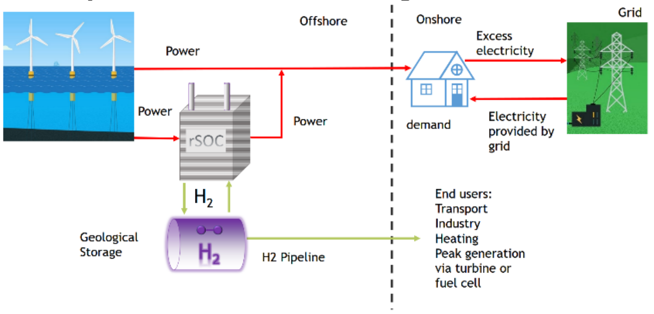

Figure 1 Schematic of hybrid offshore hydrogen and electricity production (Images of wind farm and electricity pylon are from [9]. Reproduced with permission from Supergen ORE)

2 Methodology

2.1 Presentation of the PyPSA Modelling tool and overview of the model

The PyPSA modelling tool is a code written in Python for energy system modelling and optimization. A detailed description can be found on the PyPSA documentation website [10]. The PyPSA modelling tool allows users to build a network from a collection of predefined elements.

- "buses": nodes of the network where energy flowing in and out needs to be balanced
- "generators": energy sources which can be connected to a bus
- "loads": represent demand, connected to a "bus"
- "stores": represent energy storage, connected to a "bus"
- "links": connections between "buses" which allow energy flow. These typically represent electric cable connections or energy conversion processes.

The following subsections describe each of those elements, and in particular the properties used for the model.

2.1.1 "Generators": "Generators" are sources of energy, such as power stations. Power provided can be constant or time-varying. Maximum installed capacity can be fixed or optimized. Power availability may be higher than power actually used. That is, if the optimization determines that it is more cost-efficient to curtail part of the energy coming from a given generator at a given time-step, it will do so, and thanks to the output data the amount of curtailed energy can be determined.

2.1.2 "Loads": "Loads" represent demand. Loads can be constant or time-varying. Cost-optimization in PyPSA always requires demand to be met 100 %. If the network is defined in a way that this is not possible, the optimization will fail.

2.1.3 "Stores": "Stores" represent storage options that can take multiple forms. Amongst the properties which can be defined for a "store" are maximum storage capacity, which can be fixed or optimized by the model, and initial energy stored.

2.1.4 "Links": "Links" represent electric cables or energy conversion processes. "Links" are by default directional and a starting "bus" and a receiving "bus" must be defined. In practice, this can be a cable connecting a wind farm to demand, or the energy conversion process, which includes electrolysis, compression, and other processes, which allows going from electricity produced by a wind farm to hydrogen storage. Properties which can be defined for a "link" include efficiency and maximum capacity (maximum power which can be sent from one bus to another). The maximum power can be fixed by the user or optimized by the simulation. Ramp-up and ramp-down limits can also be defined if needed.

2.1.5 Costs: For each of the above elements, one can attribute "capital_costs" and "marginal_costs". "capital_cost" is the sum total of all the costs needed in order to install 1 MW of a "generator" or a "link" (device allowing the transfer of 1 MW between 2 "buses"). OPEX costs that are independent from the frequency of use of a device need to be included in this cost. For the element called "store", it is the cost for each MWh of storage capacity.

"marginal_costs" are the costs incurred whenever that device is used. That is, for a generator, this would be a cost incurred for every MWh produced. For example, for a gas turbine this would be the cost of the fuel to produce 1 MWh of electricity. For a "link", it is the cost incurred whenever 1 MWh is transferred or converted. For a "store", it is the cost of every MWh taken out of storage.

Figure 2 gives a schematic overview of the PyPSA model used. 4 "buses" were used, one for the wind farm, one for everything related to hydrogen, one for demand, and one for the grid, from which electricity could be obtained or sent to. The "bus" for the wind farm had an element of type "generator" connected to it to represent wind farm production. The "bus" for hydrogen had an element of type "store" connected to it, to represent hydrogen storage. Between the wind farm and the hydrogen, there were two links. The first one represents the whole energy conversion process to go from electricity provided by the wind farm to hydrogen, thus representing electrolyser mode, but also including peripheral processes needed such as desalination, compression, and heating. The second represented fuel cell mode and in a similar manner included gas expansion and cooling.

Between the wind farm and the demand there is a link which represents the subsea electrical connection and allows transfer of electricity from the offshore electricity production site (which includes the rSOC system) to demand. Demand was furthermore connected to the grid. Details of input data for the elements are given in the next section.

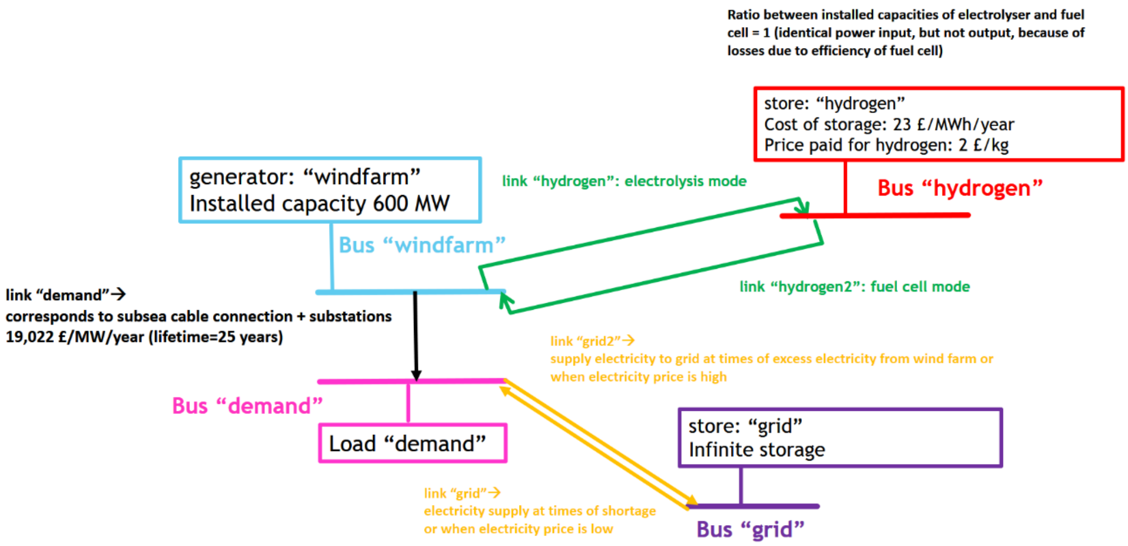

Figure 2 Schematic view of model in PyPSA

2.2 *Sources for the inputs of the PyPSA model*

2.2.1 Wind farm: The production of the wind farm was determined using wind data retrieved on [11]. Wind data was taken for the following coordinates: 51° latitude, -5.6° longitude. This is situated in Search Area 2 [12] of the areas planned for the leasing round in the Celtic Sea. The wind data was taken for 2019. The power curve of the 15 MW IEA reference turbine [13] was used to determine production of a 15 MW wind turbine over a whole year. It was considered that 40 such wind turbines were installed, thus making up a wind farm of 600 MW.

The wind farm production thus used for the PyPSA model can be seen in Figure 3.

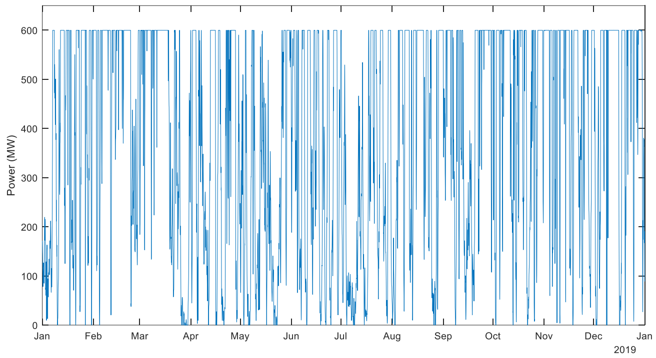

Figure 3 Wind farm production assumed for the PyPSA model

The study assumes that the 600 MW wind farm has been installed and that all electricity produced by the wind farm should be utilised. Optimisation of the infrastructure relating to hydrogen production was performed for a number of scenarios. Collector cables and inter array cables grouping the electricity produced at a central location, were considered to be installed as well. From this central location, electricity was either used for the production of hydrogen via an electrolyser system or sent to shore via an export cable, or both. In that way, the model only considered centralised offshore hydrogen production, as was done in [4]. Decentralised offshore hydrogen production, with electrolysers on the turbine platforms is compared to centralised offshore hydrogen production, where all electrolysers and balance of plant are situated on a dedicated platform, in [14]. Decentralized production could be looked into in the future, in which case in the PyPSA model, the choice between electric cables going from the wind turbine platforms to an offshore substation and individual pipelines going to a central hydrogen storage location can be proposed.

2.2.2 Subsea cable connection: Costs for subsea cables, offshore and onshore substations, as well as for reactive compensation were calculated using data found in [15]. The wind farm was considered to be 60 km from shore. Cost was calculated for six grid connection capacities. A margin of 50 % was taken for the installed capacity of the subsea cable, related transformers and reactive compensation. That is, the grid connection had double the capacity of the maximum power that was expected to be sent through. Cost was calculated for six grid connection capacities. Figure 4 shows those capacities with the cost associated.

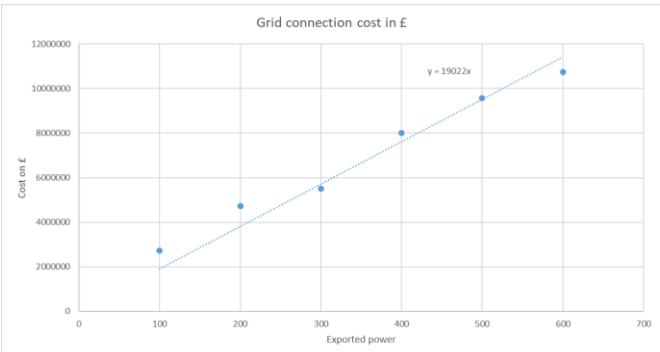

Figure 4 Annual subsea cable connection cost as a function of installed capacity (including 50 % margin)

A linear regression was used to determine the cost of the grid connection per MW (Figure 4). As the simulation was run for only a year, the cost provided to the model had to be divided by the lifetime of the project considered here, which was considered to be 25 years. This approach does not allow the effect of discount rate to be included but is one way to run the simulation over one year, as a first approach. This gave a cost of 19,022 £/MW/year, which was the value given to the variable called “capital_cost” of the “link” representing the subsea cable and further equipment needed to send electricity from the wind farm to shore.

Losses in the subsea cable or transformers were not included in the cost, as was done in the cited article [15]. Rather, the losses were calculated using the formulas provided and included in the PyPSA model as the efficiency of the “link” representing the subsea cable. The efficiency used here was 98 %.

2.2.3 rSOC system cost: Cost for reversible systems have not been found in literature at the point of writing. [4] gives learning curves for SOC electrolyser system CAPEX costs, including the balance of plant, varying between 1588 £/kW in 2017 and 585 £/kW in 2050. However, according to [5], a SOC electrolyser system may be available at a CAPEX of 500 £/kW by 2025. These costs include the cost for the cell stack as well as the costs for the balance of plant for an electrolyser. For a reversible system, costs for the added balance of plant, specific to fuel cell mode, need to be added. Discussion with industry [16] provided a cost range for a reversible system between 350 £/kW and 650 £/kW in 2030. It was found that in certain scenarios (low electricity costs for electricity coming from the grid, low price paid for hydrogen), even the lowest costs found for a SOC electrolyser system were not low enough for hydrogen production to be considered viable. Which is why the lowest cost (160 £/kW) considered was taken even lower than the cheapest electrolyser system cost found (175 £/kW for PEM in 2050). A sensitivity study covering cost assumptions from 160 £/kW to 1500 £/kW with incremental steps of 20 £/kW was done. It was considered that the lifetime of the electrolyser was 20 years (shorter than the lifetime of the project), and so the value used for the “link” representing the electrolyser mode was obtained by dividing the costs above by 20. This gave values for “capital_cost” ranging from 8000 £/MW/year to 75,000 £/MW/year for the “link” representing electrolyser mode. It should be noted that for each of those values, a separate simulation was run. No costs were applied to fuel cell mode, but rather, it was considered that for each MW of electrolyser capacity installed, a corresponding capacity of fuel cell mode was available.

2.2.4 Cost for offshore hydrogen production: [4] provides cost for various components necessary for offshore hydrogen production, such as a desalination system and a central electrolyser platform. In 2030, they predict that platform CAPEX cost would be 167.5 £/kW and water desalination would cost 0.8 £/kW. Including the OPEX costs for desalination, this adds 6752 £/MW/year (25-year project) to the rSOC system cost. This cost was not explicitly provided to the PyPSA model, but rather would need to be included in the total cost of the rSOC system. In future calculations, where offshore hydrogen production would be compared to onshore hydrogen production, this difference in cost due to the costs specific to offshore hydrogen production would need to be taken into account and different costs for onshore and offshore rSOC systems need to be applied.

*2.2.5 rSOC system efficiencies:*Several documents were consulted which describe reversible systems based on solid oxide cell technology. A reversible system described in [17] has an efficiency of 67.1 % in fuel cell mode and of 76 % in electrolyser mode. In this model, the choice was made to have a low fuel utilisation ratio (20 %), but a high recirculation ratio in fuel cell mode. This meant that for a given amount of hydrogen sent into the fuel cell, only 20 % was converted into electricity. However, the left-over hydrogen was recovered and sent back into the system for future use.

In [18], a reversible system is studied with different assumptions. In the system described in that work, diathermic oil was used to store the heat produced in fuel cell mode to be used in electrolyser mode, thus allowing for a high stack efficiency in electrolyser mode (85 % Lower Heating Value, not given in the article but deduced from data given in the article). Furthermore, in fuel cell mode, electricity was produced in addition to the electricity produced by the cell stack thanks to a turbine into which the expanding hydrogen was sent into before being sent into the cell stack. In this way, part of the electricity used for compression in electrolyser mode is recovered in fuel cell mode. This gave different values for efficiency as [17] and illustrates the point that electrolyser efficiency may depend on a number of factors and will be different for different set ups and hence the large variability in efficiency quoted in the literature.

Based on the numbers found in the documents, values of 50 %, 60 % and 70 % were chosen for fuel cell mode efficiency in a sensitivity study. For electrolyser mode, the efficiency was assumed to be 80 %. For some modelling cases an efficiency of 100% in electrolyser mode was required in order to drive necessity for rSOC installed capacity.

2.2.6 Ratio of powers between fuel cell and electrolyser mode: As the system described here was assumed to be reversible, this meant that for every MW of electrolyser capacity, a given capacity of fuel cell mode was available. For the results described here, the ratio between input power of electrolyser mode and input power (hydrogen flow) of fuel cell mode was fixed at 1.0. For a fuel cell mode efficiency of 60 %, the ratio between input power of the electrolyser mode and output power (electricity) of the fuel cell mode was therefore 0.6. This meant that for every 100 kW of electrolyser capacity (defined by electrical power input) installed, 60 kW of fuel cell capacity (defined by electrical power output) was considered to be installed. For future calculations, the ratio between power input in electrolyser mode and power output in fuel cell mode will either be fixed, or varied using the relationship between power output and efficiency similar to those found in [19]. Indeed, in a sensitivity study on the fuel cell mode efficiency, the ratio between power input in electrolyser mode and power output in fuel cell mode would either tend to be independent from fuel cell mode efficiency or tend to go higher when efficiency drops. A higher power output implies high current, which implies higher losses and, as a consequence, lower efficiencies.

2.2.7 Hydrogen storage costs: Hydrogen storage costs were taken from [20]. The CAPEX cost for a salt cavern was indicated to be 180 euros/GJ and the OPEX cost was 0.11 euros/GJ/year. This gave a total of 577 £/MWh (using the conversion rate between euros and £ for the year of publication of the report) for a project lasting 25 years, or 23 £/MWh/year, which was the input value in the model for "capital_cost" of the element "store" which represented hydrogen storage. It is assumed that cushion gas is already available in sufficient amounts in the geological storage and the cost included in the CAPEX of the salt cavern. Cushion gas is "the amount of gas that is permanently stored in a natural gas storage. The main function is to maintain sufficient pressure in the storage to allow for adequate injection and withdrawal rates at all times." ([21]). Any amount of energy stored shown on graphs corresponds to gas present in addition to cushion gas.

Geological storage is a good option for seasonal storage, when large amounts of gas need to be stored at low cost. According to [20], typical storage volume in a salt cavern is 5 PJ (~1389 GWh) of hydrogen.

In the North Sea, depleted gas fields could be an option for geological storage, which is not the case in the Celtic Sea. There are halite (salt) deposits in the Celtic Sea, but no plans yet to exploit salt caverns for storage [22].

2.2.8 Hydrogen price: The element "store" representing hydrogen storage was given a "marginal_cost" of 50.74 £/MWh. This corresponded to a price of 2 £/kg. This meant that any hydrogen left in storage and not used for electricity represented a monetary gain. The value used was voluntarily in the lower range, and the reason for this is provided in the Conclusions section.

2.2.9 Demand: UK Demand for 2021 was used as the basis for the modelling. Seasonal variation of demand in 2021 was found [23, 24] to be typical of the past decade, although it was noted that mean annual demand is slowly reducing over time. In order to localise the demand to the wind farm location the UK demand was scaled to the peak demand registered at the Indian Queens substation which was chosen due to its proximity to the Celtic Sea.

To obtain demand corresponding to local demand, the electricity map produced by nationalgridESO for the Future Energy Scenarios report [25] was consulted. Peak demand for electricity demand around the Indian Queens substation in the scenario called "Leading the way" was taken for the year 2021 and was found to be 413 MW. The demand for the whole of UK was thus multiplied by a factor to correspond to local peak demand. The resulting curve is shown in Figure 5.

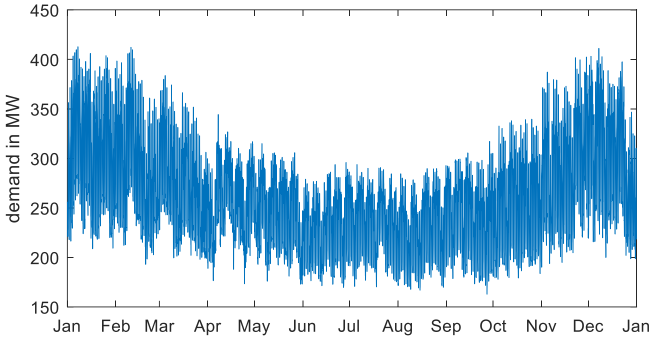

Figure 5 Local demand curve used in PyPSA model

2.2.10 Electricity prices: In order to ensure that demand was met at all times, the model provided the possibility to receive electricity from the grid, rather than directly from the wind farm or stored hydrogen. The grid was represented using a PyPSA network element "store". The storage capacity of this element was not predetermined, but rather calculated by the model. The element was allowed to go into negative values. This would allow to track whether the wind farm-hydrogen system was able to provide energy in excess or deficit over the whole year. In order to not take electricity from this theoretically infinite source of energy preferentially over the electricity from the wind farm-hydrogen system, a price had to be applied for every MWh supplied. This price could have been constant throughout the whole year. However, in order to ensure that electricity would not be taken from the grid at moments when electricity would have been scarce in the rest of the country, it was chosen to use real past electricity prices. That way, at times of high electricity cost, the model would preferentially take energy from the wind farm–rSOC system. It would also provide the model with the possibility to have monetary gain by sending excess electricity to the grid.

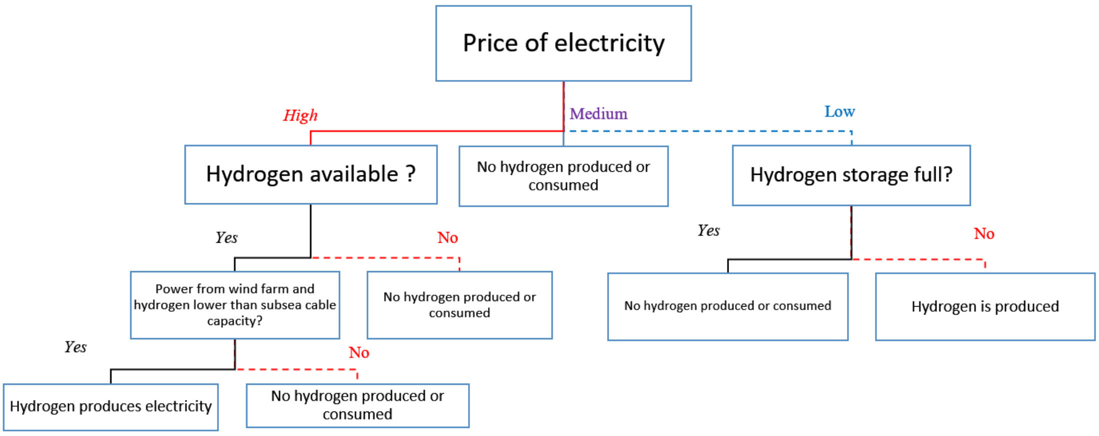

Figure 6 Flow chart of decision-making process for hydrogen production or consumption as a function of the price of electricity

Figure 6 illustrates how the electricity price impacts whether hydrogen is produced, kept in storage or used for electricity production. This decision in the current model is independent of the amount of electricity needed for demand, which is why a simplified flow chart can be presented here. Currently, the price is identical whether electricity is bought or sold. In future versions, a carbon tax will be applied to electricity coming from the grid, in order for the environmentally favourable solution to be prioritized. Furthermore, for now, the amount of electricity which can be sent to or received by the grid is not limited. In future versions, the import/export cable will be priced, and its capacity optimized, just like the subsea cable.

Figure 7 shows a graph typical of the cumulative energy sent to the grid over the year. It is negative when more energy has been taken from the grid than sent to the grid.

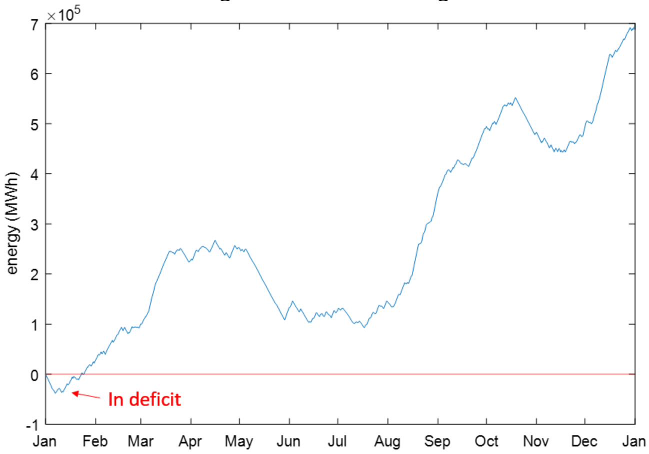

Figure 7 Energy deficit or contribution towards grid (cumulated numbers)

Electricity prices were provided by Nord Pool [26]. 2017 is a year with both relatively low prices, but also low fluctuations over the course of a year. 2021, on the other hand, is a year with exceptional variations. The year starts with relatively low prices, and towards the end of the year, there is a steep increase. This is due to a combination of factors, between strong economic growth in the wake of the Covid-19 pandemic, a cold and long winter in the Northern hemisphere, a weaker than expected increase in supply, and lower-than-expected wind generation in September and October 2021 [27]. Soaring electricity prices are directly linked to increase in gas prices, as peak demand in electricity is met by gas turbines, and spot-market wholesale prices are set by the price of the highest generating costs in that time-slot. In 2022, the average electricity price is exceptionally high, which is strongly linked to the Russian invasion of Ukraine. Fluctuations are also extreme, and several peaks over the year can be identified. This can be observed in Figure 8.

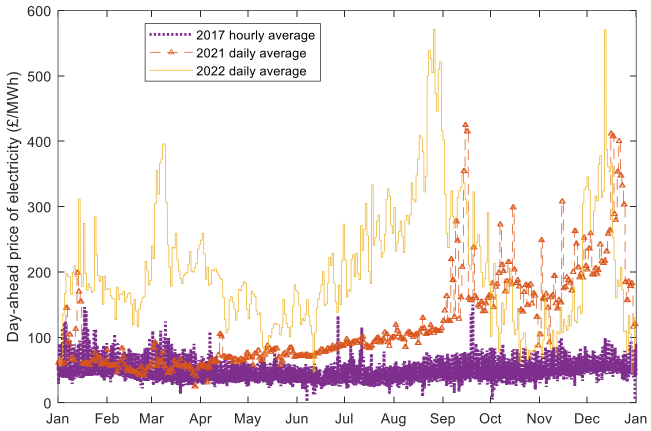

Figure 8 Day-ahead electricity price for 2017, 2021 and 2022. Source: Nord Pool [26]

3 Results

In order to illustrate the workings of the model, a short extract of 6 days is shown here. The graph of Figure 9 shows results obtained for electricity prices from 2021. The cost of the rSOC system in that particular example was assumed to be 500 £/kW. Fuel cell mode efficiency was assumed to be 50 %, and electrolyser mode efficiency was assumed to be 80 %.

This example shows that, when the electricity price is low, and rSOC capacity is sufficient, all wind farm production is dedicated to hydrogen production. Nothing is sent to demand. Instead, demand is provided using electricity from the grid. On days with medium prices, electricity from the wind farm is sent to demand, and excess electricity is sent to the grid for extra revenue. On days with very high electricity prices, even when full wind farm capacity is achieved, hydrogen is converted into electricity to be sent to the grid in addition to the excess electricity from the wind farm. In that way, it can be observed that with a given rSOC system, additional electricity can be obtained at times of scarcity and therefore high cost of electricity.

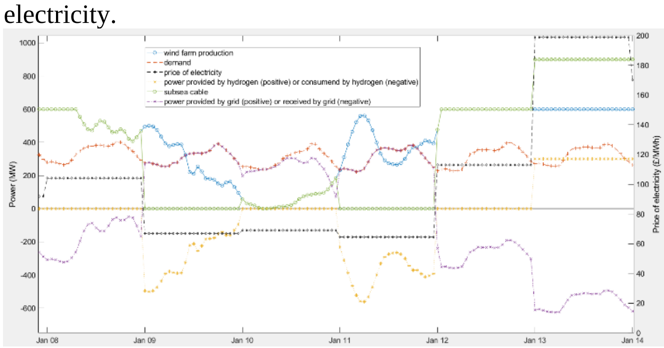

Figure 9 Extract of 6 days of the simulation

To get an idea of the impact of various input variables, several hundred such simulations were run for various combinations of electricity prices, rSOC system efficiencies and rSOC system costs. With the current input variables, for which it should be noted that there is a high level of uncertainty, and using the electricity prices of 2017, it was found that the only range of values for which an rSOC system was recommended by the optimisation, was for an electrolyser mode efficiency of 100 %, a fuel cell mode efficiency of 70 % and rSOC system costs between 160 £/kW and 240 £/kW. These values are unrealistic, so it can be considered that for electricity prices as low as in 2017, it would not be worth it installing an rSOC system, at least not with the assumptions made here. Future calculations will use refined input data and include environmental impact, which could lead to alternative results.

For electricity prices of 2021 and 2022, simulations were run for electrolyser mode efficiencies of 80 %, fuel cell mode efficiencies of 50 %, 60 % and 70 %, and rSOC system costs ranging between 160 £/kW and 1500 £/kW. Optimized electrolyser system capacity for electricity prices of 2021 is shown in Figure 10, and for electricity prices of 2022 is shown in Figure 11. The graphs shown are used to demonstrate the type of information a sensitivity study using the PyPSA model could give and should not be taken as definitive results, due to large uncertainties in the input values.

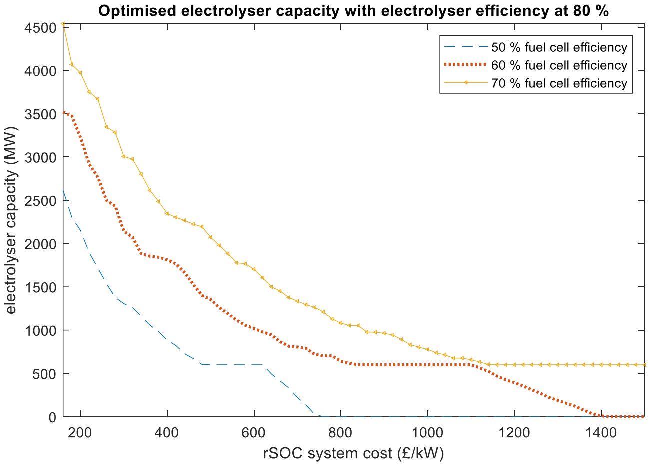

Figure 10 Sensitivity study on fuel cell mode efficiency and rSOC system cost using electricity prices of 2021. Graph only shown for illustration purposes and not showing applicable results.

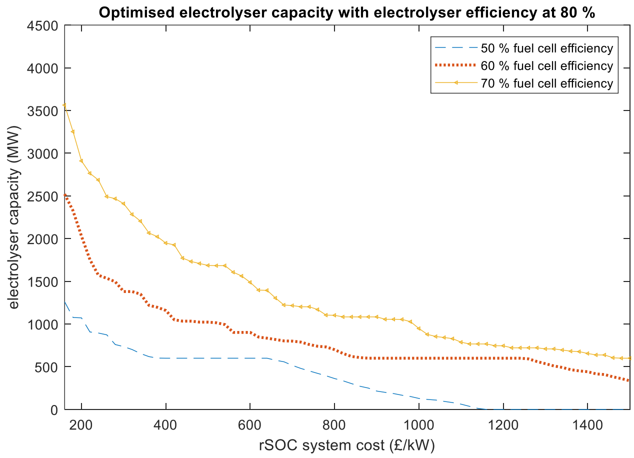

Figure 11 Sensitivity study on fuel cell mode efficiency and rSOC system cost using electricity prices of 2022. Graph only shown for illustration purposes and not showing applicable results.

What can be seen from the graphs, is the range of costs for which the installation of an rSOC system would be worth installing, and its dependency on fuel cell mode efficiency. It is expected that for a lower performing or more expensive system, the model would recommend installing lower rSOC system capacities. It is also very likely that for years with more extreme variations in electricity prices, it is worth it installing extra rSOC system capacity. With a combination of correct conditions, optimized rSOC system capacities may exceed wind farm capacity, in which case, the electrolyser mode becomes redundant. Which is why future iterations of the model will include a choice between a reversible and a fuel cell mode only system.

One interesting observation may be made on how the time between peaks of extremely high prices impacts the optimized hydrogen storage capacity. Figure 12 shows that at the beginning of the year for the simulation using electricity prices for 2021, a considerable amount of hydrogen is stored. Over the summer months, hydrogen storage is untouched, and then, starting in September, hydrogen stored is gradually depleted and fully used up by the end of the year. This decision is coherent with electricity prices for 2021. As can be seen in Figure 14, prices are rather low until September. It seems coherent to use the hydrogen stored towards the end of the year when prices are soaring.

When looking at Figure 13, one can see that for the simulation using electricity prices from 2022, there are three periods throughout the year during which hydrogen is first put into storage, then kept in storage, and then reconverted into electricity. When looking at Figure 15, one can note that the moment when hydrogen starts to be used for electricity coincides with times of the year where electricity prices reach extremely high values.

It is coherent that the simulation using prices of 2021 should require larger storage capacity and most likely also more rSOC system capacity than for 2022, as prices are fairly low for nearly nine months. Hydrogen is stored over a good part of the year and is used up over a shorter period of time. Whereas in 2022, the frequency of the peaks means that periods of hydrogen storage are shorter, thus requiring less storage capacity.

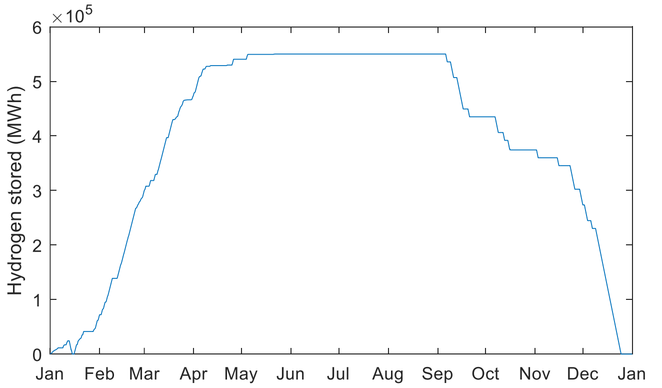

Figure 12 Evolution of hydrogen stored over a whole year for a simulation using electricity prices from 2021, for an rSOC system cost of 500 £/kW, electrolyser mode efficiency of 80 %, and fuel cell mode efficiency of 50 %. Graph only shown for illustration purposes and not showing applicable results.

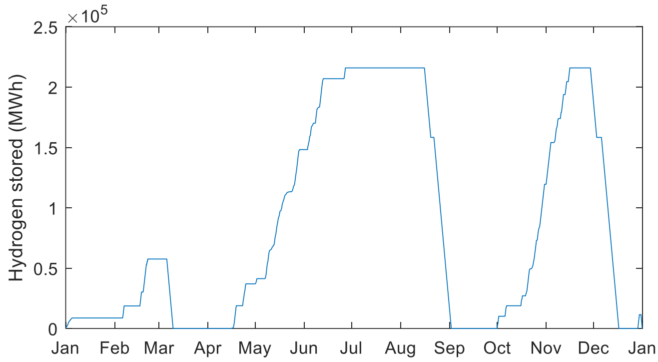

Figure 13 Evolution of hydrogen stored over a whole year for a simulation using electricity prices from 2022, for an rSOC system cost of 500 £/kW, electrolyser mode efficiency of 80 %, and fuel cell mode efficiency of 50 %. Graph only shown for illustration purposes and not showing applicable results.

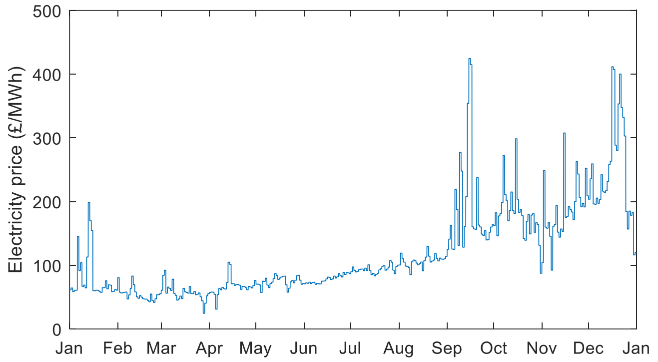

Figure 14 Day-ahead electricity prices for 2021, daily average

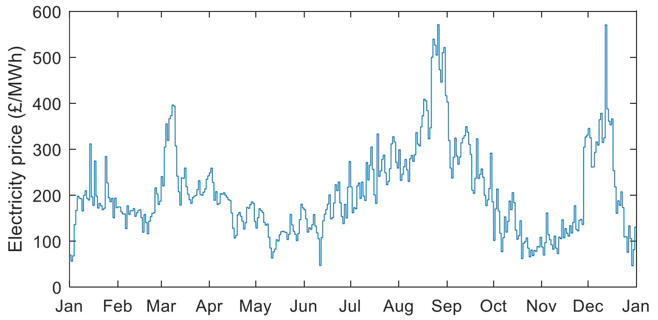

Figure 15 Day-ahead electricity prices for 2022, daily average

4 Conclusion

The preliminary results using the illustrative-only input data described here demonstrate the impact that important parameters have on optimized installed capacities. However, before drawing firm conclusions from the application of the model, it will be necessary to further refine the input data. Nevertheless, the modelling approach is rather well defined and not expected to change significantly with further development.

In Section 2.2.8, it is stated that a relatively low price paid for hydrogen was used. It is indeed thought that there is a threshold price paid for hydrogen beyond which reconverting hydrogen into electricity is not worth doing, as hydrogen would have more value as a gas. This situation was voluntarily avoided, to study a scenario where the rSOC system was used reversibly. Future work will include a sensitivity study on the price paid for hydrogen (not to be confused with LCOH, the cost for producing a kg of hydrogen, whereas the price here corresponds to how much people are ready to pay for it). This would allow the threshold value beyond which reconversion of hydrogen into electricity is not optimal from an economic point of view to be determined. The threshold will of course be different for every assumption made for input values. It would also make sense to run simulations with prices for hydrogen varying over the course of a year, just as gas prices vary depending on the relationship between supply and demand.

In this study, it was assumed that cheap geological storage was available close to the wind farm. This may not necessarily be the case. Simulations with costs for hydrogen storage corresponding to pressurized storage in containers will also be investigated in the future.

Another point for future study is the impact of ramp-up and ramp down time for the rSOC system on the energy dispatch decisions.

So far, it was always considered that the rSOC system was situated offshore. Similar simulations will be run for an onshore rSOC system, in which the subsea cable connection would only transfer electricity to shore coming from the wind farm, and not from the rSOC running in fuel cell mode.

Future studies should also include costs representing environmental impact. For example, the costs of electricity from the grid should include a carbon tax at some point corresponding to the amount of carbon produced per MWh of electricity from the grid.

The results presented here did not make use of the option to consider the hydrogen storage to be “cyclic”, in which case the gas available in storage at the end of the year would have been considered available at the beginning of the year. This will certainly be included in future studies.

5 Acknowledgements

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