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Wind park reliable energy production based on a hydrogen compensation system. Part II: Economic study.

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Abstract

Power production from renewable energy resources is increasing day by day. In the case of Spain, in 2009 it represented 26.9% of installed power and 20.1% of energy production. Wind energy makes the most important contribution to this production. Wind generators are greatly affected by the restrictive operating rules of electricity markets because, as wind is naturally variable, wind generators may have serious difficulties in submitting accurate generation schedules on a day-ahead basis, and in complying with scheduled obligations. Weather forecast systems have errors in their predictions depending on wind speed. Therefore, if wind energy becomes an important actor in the energy production system, these fluctuations could compromise grid stability. In the previous paper in this brief series, [1] we showed technical results of the proposed solution, which consists of combining wind energy production with a biomass gasification system and a hydrogen generation system based on these two sources. In the present paper we show the economic results of the study, considering the most profitable technical configurations and three possible economic scenarios.

Keywords

Hybrid system; Wind energy; Biomass; Fuel cell; Renewable energy; Energy Storage; Economic Viability;

1. Introduction.

The contribution of renewable energy sources to electrical power production is becoming an important part of the energy production mix in many countries. In the case of Spain, in 2009, 26.9% of installed power came from renewable sources (20% corresponding to wind energy), and 20.1% of the electrical energy demand was met with this kind of energy (13.8% corresponding to wind energy) [2]. In the previous paper in this series, we presented a solution for the grid stability problem that appears when wind energy makes up a considerable percentage of the energy production mix. However, it is necessary to find out whether these technical solutions are economically profitable. Thus, in this paper we will show the economic results of the proposed technical scenarios.

Many studies have focused on the economic costs of the hydrogen economy transition. For example, in [3] the authors studied the development of an efficient infrastructure for producing and delivering hydrogen. In [4], a study of the integration of hydrogen in the German energy system is carried out, considering economic aspects of the distribution of hydrogen and the location of its production facilities. In addition, [5] presents the study of cost-minimizing forecasts for the introduction of hydrogen energy technology. It is related to governments' interest in investment by private companies in developing hydrogen technology production and infrastructure.

Hydrogen production from renewable energy sources guarantees that consumption of this energetic vector does not increase CO_2 emissions. In [6] there is an economic study of hydrogen production from different energy sources such as natural gas, coal, nuclear, sunlight, wind and biomass. The considered scenario assumes that the cost of fossil fuels is rapidly increasing, and that nuclear fuel is similar to fossil fuel because it is limited in quantity, although the quantities available are much larger than in the case of fossil fuels. The results of this study showed, of course, that hydrogen production from natural gas or nuclear energy was cheaper than production from coal, biomass or wind energy by means of electrolysis. Nevertheless, biomass gasification is in a very good position, because hydrogen production costs were 2.83 $/kg compared to 3.17 $/kg from coal, 1.84 $/kg from nuclear and 1.38 $/kg from natural gas. Moreover, CO_2 emissions from this technology can be considered to be balanced with the natural collection of biomass.

The use of hydrogen as an energetic vector that could help to increase the penetration of wind energy was studied by the authors in [7]. Later, other authors [8], considered the reduction of network management costs in high wind energy penetration situations. The study was carried out taking into account the energy market in Denmark, where wind already plays an increasingly large role in the energy supply. Current experience identifies a number of impacts from large-scale wind integration. The Danish power system is characterized by large amounts of non-dispatchable power generation (wind and Combined Heat and Power, CHP) and large imbalances in power flows. In the study, two principles were considered: wind energy production in the electricity network represents a considerable share of the total energy demand; and there is demand for hydrogen for energy purposes. The result is four scenarios where different degrees of wind penetration, hydrogen market prices and climate change were considered. Results of the study showed that the market price for wind electricity is a critical factor in the final attractiveness of adopting a wind-hydrogen strategy. Moreover, in a fully competitive market, wind energy prices would vary significantly on an hourly scale. This is an important factor in considering when to sell electricity or when to convert it into hydrogen. The study concludes that a European-wide wind energy strategy is necessary, in order to accelerate the attainment of critical mass in electrolyzer technology, enhancing the perspectives for this pathway in the short term.

Finally, in considering that there is a demand for hydrogen for energy purposes, in [9] the opportunities and challenges of introducing hydrogen as an alternative fuel in the transportation sector are highlighted. The growth of oil demand in the near future (more than one-third by 2030) is considered, as well as the range of benefits that hydrogen offers as a clean energy carrier when it is produced by clean energy sources (for example, the efficiency of the fuel cell system for passenger cars is around 40%, compared with 25-30% for the gasoline-diesel engine, even at partial load when urban driving occurs). The paper considers hydrogen produced by wind energy and biomass, and it concludes that there is a need for a considerable increase in wind energy and up to six times the current global biomass use. As a final conclusion, the evaluation of hydrogen worldwide is positive if the oil price remains above 80-90 $/barrel in the medium and long term, the transport sector has to reduce greenhouse gas emissions significantly, and there is no major technological breakthrough in vehicle batteries.

At least for the moment, these three points are currently active, and, moreover, the Spanish wind plan has not yet been completed. Thus, we can assume that in the next few years the percentage of wind energy production will increase. For these reasons, we have planned our economic study, considering technical scenarios presented in the previous paper and taking into account three economic scenarios: a near-term scenario (NTS), where the current tariff system is applied; a medium-term scenario (MTS), where subsidies in the form of a guaranteed fixed price will be decreased in order to totally incorporate wind energy in the electricity market; and a long-term scenario (LTS) where, as in MTS, electricity from wind energy is sold in a market system, but considering increasing penalties for those producers who do not achieve the previous energy production commitment.

The paper is structured as follows. The second section presents a brief technical system description, considering that a complete description can be found in the previous paper in this series. The third section describes the current Spanish tariff system and the economic scenarios used to complete the study. The fourth section shows the results and discusses them. Finally, the conclusion of the study will indicate the best economic scenarios and proposals for future studies.

2. System description.

As described in the previous section, the objective of the system is to guarantee that energy from the wind park (Sotavento Wind Park: 24 MW_{el} extrapolated to 40 MW_{el}, [10]), promised one day in advance, is delivered to the grid, independently of the error in prediction. Error in one-day advanced predictions was calculated in the same way as in [11]: for low wind speeds (< 6m/s), generated power is highly overestimated by the wind prediction program, so that a 100% estimated error in the predicted power obtained from these speeds is used; for medium wind speeds (> 6m/s and < 9m/s), generated power is also overestimated by the wind prediction program, so that a 45% underestimated error in the predicted power obtained from these speeds is assumed; for high wind speeds (> 9m/s), generated power is underestimated by the wind prediction program, so that a 25% overestimated error in the predicted power obtained from these speeds is used. The compensation system is based on a hydrogen production and conversion system to compensate for the differences between the forecasted energy output and the real energy output. Hydrogen is produced by the electrolysis of water when there is an excess of energy in the wind park (in the valley hours, when energy is not injected into the grid, or when the prediction was lower than the real wind speed) [12,13], and by means of its extraction from the syngas obtained by gasifying biomass with steam water [14]. The chosen base size of the biomass installation is 4.5 MW. This power corresponds to the gasifier, the combustion engine and electrical generator group that is generating energy continuously and injecting it into the grid. Thus, all the systems in this installation are self-funded with the benefits from selling the energy. The increase in energy content of the syngas is not considered because it is obtained by gasifying with steam water. This increment can be used to pay for the maintenance tasks in the gasifier upgrade and its deposit. Upgrading of a biomass installation consists of an over-dimensioning gasifier and a hydrogen separator based on Pressure Swing Absorption (PSA) [15]. The size of the gasifier upgrade is one of the study variables. Hydrogen is stored in a pressurized tank at medium pressure (32 bar) [16]. Figure 1 shows the block diagram of the complete system considered.

In [11] we studied the use of synthesis gas (syngas) from a biomass gasification system to compensate the wind park, establishing synergies between the two energy production systems. Biomass gasification is a mature technology with acceptable conversion efficiency. One of the conclusions of this study was that the syngas deposit (calculated for optimum behavior of the system) remained full during long periods of time, making the use of the gasifier upgrade unnecessary. Moreover, energy produced by the wind park during valley hours (i.e. during the night) might not be profitable for energy storage. These reasons led us to consider hydrogen as a more profitable energetic vector to compensate the wind park. On the one hand, it can be obtained from water electrolysis, taking advantage of the wind park´s excess energy (i.e. during valley hours). On the other hand, it is possible to extract the hydrogen from the syngas obtained by gasifying biomass with steam water.

The compensation factor ($f_{H2,compensation}$) is the parameter that represents the amount of wind park energy that can be compensated with this system. It is possible that the hydrogen stored might not be enough to compensate all the energy required by the wind park, or that the instantaneous power required by the wind park could be greater than the compensation system's installed power. In these cases, the wind park would not be compensated, and the energy commitment would not be met.

To be able to determine a viable economic scenario for the study`s compensation system, the costs have to be considered. Therefore the payback-time t_{pb} will be determined considering capital costs, operation and maintenance costs and feedstock costs.

Regarding capital costs, electrolyzer costs vary between 500 €/kW [17] and 2,000 €/kW [18]. The US department of energy [19] also anticipates electrolyzer costs of 400 $/kW in 2012. Solid oxide fuel cell costs are difficult to determine because they are not yet market-ready and are still under development. The price given by IKA Aachen [20] seems to be reliable because similar costs of 4,100 $/kW or 4,500 $/kW are given by [19]. Studies by the European Union already assume capital costs of 3,000 €/kW [21]. Operation and maintenance costs considered in Table 1 include:

- Maintenance labor
- Ancillary replacement parts and material such as air and fuel filters, reformer igniters or spark plugs, water treatment beds, flange gaskets, valves, electronic components, etc., and consumables such as sulfur absorbent bed catalysts and nitrogen for shutdown purging.
- Major overhauls including shift catalyst replacement (3 to 5 years), reformer catalyst replacement (5 years), and stack replacement (4 to 8 years).

Costs for biomass installation can be seen directly in Pengmei et al. [22], where they are calculated for the specific downdraft gasifier that is also used in this study.

To calculate the hydrogen storage costs, the equation provided by Greiner et al. [23] is used. Low pressure hydrogen storage costs with equation 1 of between 67 €/Nm³ for a small storage vessel and 39 €/Nm³ for a large one are computed, which is consistent with the costs of 50 €/Nm³ used in [11]. Linnemann et al. [24] calculate 111 €/Nm³ for high pressure storage, as in the study by Amos [25], which depicts high-pressure storage costs of 1323 $/kg (119 $/Nm³). Compressor prices of 700 €/kW are also similar to those given by Amos [25] of 1000 $/kW.

$$C_{H2,deposit} = 80\,€ \cdot 2500 \cdot \left(\frac{V_{H2,dep-size}}{2500}\right)^{0.75} \qquad (1)$$

For water storage, a corrugated field-erected water tank offered by the American Tank Company (retrieved 09/ 20/ 2010) is chosen. Due to low costs of about 11,200 €, a standard-sized tank of 10,400 gallons (47,280 liters) was considered. To change dollar prices into Euros, an average exchange of 1 $ = 0.80 € is used, depending on the currency exchange rate.

Costs for tubes and fittings, electrical system and interest are calculated at 5 %. Operation and Maintenance costs are given in percentages of investment costs of each installation or in produced energy in the case of the fuel cell. Table 2 shows a summary of these costs.

Determining a hydrogen price is very difficult because it depends on the process of production and delivery and on energy costs. In 2008, IKA - Inst. für Kraftfahrzeugtechnik (RWTH Aachen) gave several prices between 0.21 €/Nm³ and 0.31 €/Nm³ for delivery by pipeline and by truck in liquid conditions, respectively. The hydrogen is obtained from natural gas or methanol. Natural gas reforming is the cheapest way to obtain hydrogen, whereas electrolysis is the most expensive one. In [26], the hydrogen price at a hydrogen gas station in Munich is given at 0.55 €/Nm³ and 0.33 €/Nm³ in the liquid and gaseous phases, respectively. Also hydrogen production costs of 0.28 €/Nm³ via electrolysis operated with nuclear power are provided in Floch et al. [12]. Considering that the majority of the hydrogen sales will go to the transportation sector, in this study an average price of 0.30 €/Nm³ is considered for hydrogen sale.

The wind park is not included in our system to simplify the study. Due to the fact that in the compensation system consumed energy has to be bought from the wind park company, the company that is running the compensation system has to pay the same prices that the wind park company would get from selling their energy on the market. Hence, the compensation system company can use as much of the energy as they like for hydrogen production as well as for grid feed-in and compensation. The profits now belong only to the compensation system company.

Due to fluctuations in capital costs or non-marketability, these costs and payback-time calculations can only be an estimation used to classify the different technical scenarios.

3. Economic Scenarios.

From an economic point of view, three scenarios are introduced and examined in this study: a near-term scenario (NTS), which applies current regulatory laws; a medium-term scenario (MTS), where subsidies in the form of a guaranteed fixed price will be decreased in order to totally incorporate wind energy in the electricity market; and a long-term scenario (LTS) where, as in MTS, electricity from wind energy is sold in a market system, but considering increasing penalties for those producers who do not achieve the previous energy production commitment.

In today's current Spanish market situation, two electricity selling prices exist. These prices are regulated by law RD 661/2007. On the one hand, there is a fixed price guaranteed by the government to establish still-expensive renewable energies in the electricity sector. In the year 2009, the same year wind park data is given, this fixed price was set at 78 €/MWh. On the other hand, energy can be sold at market price, but for wind energy, the selling price is subsidized to develop a reliable sale of renewable energies. In the same period of time, the subsidized price for electricity from wind parks (average) was 77 €/MWh. In the price regulatory law, there are penalties for failure to meet previous energy commitments (by excess or by defect). This penalty in the year considered was 1.8 €/MWh; the producer has to pay this penalty only if the failure is more than 20% of the promised energy.

Therefore, with this economic situation, NTS is financially not viable because the market price including government subsidies was lower than the fixed price guaranteed by the government. Thus, two more scenarios were considered, assuming the complete integration of wind energy in the electricity market, and making wind energy equal to other non-renewable energy sources. We assume in these two new scenarios that in the future those systems that could be reliable will be boosted.

In a medium-term scenario (MTS), subsidies in the form of a guaranteed fixed price will be decreased in order to use them to increase subsidies on the market price for reliable renewable energies and assure a stable grid. In this case, the currently applicable penalty price for not allocating the committed amount of energy has to be paid. It is considered that the subsidized market energy price varies between79–95 €/MWh and, consequently, the guaranteed fixed price varies between 35–78 €/MWh. The penalty for deviations in committed energy is maintained at 1.8 €/MWh.

In a long-term scenario (LTS), any kind of energy source connected to the grid has to be reliable. Hence, there will be no fixed prices for renewable energies and no subsidies for market prices (35–60 €/MWh). We considered this situation in two LTS scenarios. In the first one (LTS1), penalty prices are increased up to the current lower market price (35 €/MWh). This high penalty is justified by the following argument: if the promised energy cannot be delivered, it has to be bought from other plants at the same price as the market price. In the second long-term scenario (LTS2), penalty prices are increased to the higher market price (60 €/MWh) based on the same justification. Moreover, fuel cell and electrolyzer capital costs are decreased because of ongoing development and production cost reductions. In all of these scenarios, hydrogen's selling price is maintained at a fixed value of 0.3 €/Nm^3, which is the current price in a hydrogen selling station. Table 4 shows a summary of all scenarios.

4. Results and discussion.

In order to calculate payback time (t_{pb}), capital costs, operation and maintenance costs, and feedstock costs are calculated. Profits are calculated using energy or feedstock (like hydrogen or oxygen) sales, and losses are calculated using acquisition of energy or feedstock (like water). In table 4, the system´s profits and costs are listed.

Considering capital costs, prices shown in previous sections are updated to the year 2010 and converted (if necessary) from Dollars into Euros. In the case of electrolyzers, the scale factor shown in table 2 is considered, and a practical equation is obtained to calculate the electrolyzer capital cost (equation 2) and, in the same way, the fuel cell capital cost (equation 3) [12].

$$C_{\mathrm{El}} = -43.69 \cdot \ln(P) + 823.43 \qquad (2)$$

$$C_{\mathrm{FC}} = -43.69 \cdot \ln(P) + 3519.4 \qquad (3)$$

where P is the power of the considered system. Biomass system cost is calculated with the equation given in [22] for a downdraft gasifier.

$$C_{\mathrm{BM}} = C_{\mathrm{BM,spec}} \left[\frac{\$}{\mathrm{Nm^3}/\mathrm{h}} \right] \cdot V_{\mathrm{H2,BM}} \left[\frac{\mathrm{Nm^3}}{\mathrm{h}} \right] \qquad (4)$$

The rest of the costs are calculated as described in previous sections. Thus, to calculate the payback time, first the profits obtained with the compensation system have to be determined. Hence, the wind park energy has to be bought for the same price that the wind park company would get from selling the energy to electricity companies. Now, energy can be used for hydrogen production as well as for direct sale on the energy market, fulfilling the predicted energy outputs. In equation 5, the procedure to calculate the annual benefits (B), which can be achieved by having the compensation system in place, is summarized. Here, $C_{\text{own-demand}}$, $B_{\text{O2,sell}}$ and $B_{\text{H2O,sell}}$ can be profits or costs, depending on the technical scenario. Also, profits from sold hydrogen $B_{\text{H2,sell}}$, and from selling energy to market $B_{\text{E-market-sale}}$, as well as the costs of acquiring wind park energy $C_{\text{WP,acq}}$, are considered. Finally, penalization costs C_{pen} for not fulfilling 100% of compensation are subtracted, as well as annual costs for operation and maintenance and feedstock.

$$B = B_{\mathrm{E-market-sale}} - C_{\mathrm{WP,acq}} - C_{\mathrm{pen}} + B_{\mathrm{H2,sell}} + B_{\mathrm{H2O,sell}} + B_{\mathrm{O2,sell}} - C_{\mathrm{own-demand}} - C_{\mathrm{O\&M}} - C_{\mathrm{feedstock}} \qquad (5)$$

With the sum of all profits and costs, the payback-time is calculated by dividing the sum of all capital costs by the annual profits (Eq. 6).

$$t_{\mathrm{pb}} = \frac{\sum CC}{B} \qquad (6)$$

Taking into account all this information, and considering the situations described for any of the defined scenarios, selling energy, hydrogen, oxygen and water are considered and compared with a wind park without the compensation system described.

In the medium-term scenario, MTS, the very low penalization costs do not affect the profit calculation because the total amount calculated for this concept (penalizations when energy supplied is different from what was promised, Table 3) is 3,600 € at most. The same can be said for the sale of water and oxygen (considering as current costs 1 €/m^3 of water and 0.08 €/kg of oxygen) with maximums of 2,900 € and 116,000 €, respectively. In some technical scenarios (3 Electrolyzers; 4 MW fuel cell; 1.5 MW Biomass; Hourly set-up 12 hours selling energy/12 hours hydrogen production and 14 hours selling energy/10 hours hydrogen production), water even has to be bought because of large consumption by the electrolyzer and the biomass plant and less production by fuel cells. In contrast, the sale of hydrogen is very important; the average is about 2.3 million standard cubic meters, which is equivalent to 690,000 €. Furthermore, scenarios with a 4 MW fuel cell and compensation factors of 76 % to 78 % will be considered because of profits from selling hydrogen of up to 2.1 million € (3 Electrolyzers; 4 MW Fuel Cell; 1.5 MW Biomass; Hourly set-up 12 hours selling energy/12 hours hydrogen production).

Comparing the payback-time results of all the scenarios, the best ones have low fuel cell power, few electrolyzers, a large biomass installation and small storage tanks (for example: 1 Electrolyzer, 2 MW Fuel Cell, 1.5 MW Biomass and hydrogen storage of 5,000 Nm^3). In these scenarios, capital costs of the fuel cell and electrolyzer have less effect on the profits. In addition, a lot of cheap hydrogen is produced by biomass, less is consumed by the fuel cell, and more hydrogen can be sold because of less storage volume. These scenarios have a very poor compensation factor of about 50 % or less; thus, they cannot be considered in this study.

The best scenario for each set-up is shown in figures 2 to 5. As mentioned above, the best ones consist of a 4 MW fuel cell. It is also observed that payback times decrease with hours of hydrogen production via electrolysis. Hence, the best scenario of all the set-ups, with an optimum payback time of 11.42 years, is the one with two electrolyzers, a 4 MW fuel cell, a 1.5 MW biomass plant and a storage tank of 25,000 Nm^3 (set-up 18/06), while still maintaining a compensation percentage of nearly 77 % (figure 5; table 8).

In order to show the important parts in the graph, guaranteed fixed prices are only depicted up to about 50 €/MWh. For higher fixed prices, payback time is increased up to 30 years and more, or it is even negative because of negative benefits. Thus, this part is not economically profitable and does not have to be demonstrated.

In tables 5 to 8, the best payback time for each optimal scenario is shown. These are the optimal payback times for the highest market price and the lowest fixed price. Hence, the time increases for other price adjustments as shown in the graphs in figures 2 to 5. It can be observed that every set-up obtains results with low payback times of between 10 and 20 years.

The long-term scenario was divided into two cases. In both of them, energy has to be sold at market price. As a consequence, payback time becomes greater than in MTS, or is even negative in the majority of the cases. As an example, table 9 shows some cases for a 12 hours selling energy/12 hours hydrogen production technical scenario set-up. Except for the last case, all of them show a negative payback. And in the last case, it takes 51 years to achieve payback.

In LTS1, penalization costs increased up to approximately 115,000 € for 77 % of the compensation factor (hourly set-up 18 hours selling energy/06 hours hydrogen production) and 100,000 € for 85 % of the compensation factor (set-up 16 hours selling energy/08 hours hydrogen production). The total annual profits, including profits from selling energy on the market, penalization costs, and energy acquisition costs can be seen in table 10, where "sum" represents the final benefits for each situation without considering the system´s investment costs. These profits are also given for the different price adjustments. It is observed that there are very few scenarios that also have low profits, and that acquisition costs increase market prices. The higher the market price, the less influence produced by the penalization price, and acquisition costs grow from 1.7 (C_{market} = 35 €/MWh; $C_{pen,spec}$ = 35 €/MWh) to 3.4 million € (C_{market} = 60 €/MWh; $C_{pen,spec}$ = 35 €/MWh). Thus, the best price scenario is the one with 35 €/MWh as the market price, as well as specific penalization costs.

In LTS2, capital costs for the electrolyzer and fuel cell have decreased because of ongoing technical development. They are calculated as 75 % and 50 % of the current costs, respectively. Total capital costs now only vary between 14 and 17 million €, while payback times increase with increasing market prices and penalization costs. Although the set-up with 18 hours selling energy/06 hours hydrogen production, with profits due to energy sales and acquisition up to 600,000 € (table 11), seems to be the best, there are no resulting positive payback times. Annual O&M and material costs are about 1.5 million, and profits from sold hydrogen are only about 600,000 €. However there are still two scenarios with a positive payback time of 173 years (3 Electrolyzers; 4 MW Fuel Cell; 1.5 MW Biomass; Hydrogen storage of 25,000 Nm³; 14 hours selling energy/10 hours hydrogen production) and 51 years (3 Electrolyzres; 4 MW Fuel Cell; 1.5 MW Biomass; Hydrogen storage of 25,000 Nm³; 12 hours selling energy/12 hours hydrogen production) for an optimum price scenario (C_{market} = 35 €/MWh; $C_{pen,spec}$ = 35 €/MWh). In these set-ups, more hydrogen is produced because of more hours with an operating electrolyzer. Thus, profits from selling hydrogen increase up to 2.1 million €, compensating for the negative profits shown in table 11. In the set-up with 18 hours selling energy/06 hours hydrogen production, normally two or three electrolyzers and large hydrogen storage tanks are necessary to achieve acceptable compensation percentages. In this case, in contrast to set-ups of 12 hours selling energy/12 hours hydrogen production and 14 hours selling energy/10 hours hydrogen production, the payback time decreases with increasing market and penalization costs (table 11; 60/60). Payback time is becoming positive, but it is still not economically viable in 51.3 years.

Conclusion.

In this study the economic viability of a wind energy compensation system is shown. Three economic scenarios were evaluated to study technical solutions described in the previous paper in this series. Smaller fuel cells, including compensation percentages of less than 50 %, lead to more cost-efficient systems, but they contradict the study's application, and so they were not considered. The overall most economical scenarios considered in the study were the ones with low fuel cell and electrolyzer power (2 MW and 3.5 MW, respectively), but large biomass installations (1.5 MW). Moreover, very small hydrogen storage tanks (5,000 Nm^3) are included in order to be able to store less H_2 and sell more H_2.

In the near-term scenario, results were negative because the fixed price of energy was greater than the average market price. In a medium-term scenario, the economic viability, considering a system's life-time of 25 years, can only be achieved with governmental support in the form of adequate subsidy policies. Payback times of 16.14 and 12.27 years resulted.

However, in a long-term future without subsidies this wind-hydrogen compensation system is not affordable. Investment costs, especially for fuel cells and electrolyzers, are too high – about 70 % of the system's total capital costs of 23 to 27 million €. Profits resulting from reliable energy feed-in to the grid are quite low. Even capital cost reductions to 50 % and 75 %, respectively, are not economically effective. Thus, total investment costs of only 14 to 17 million € have to decrease even more to make hydrogen production via electrolysis more affordable compared to other methods like biomass gasification. Even at only 50 % of today's fuel cell costs – about 1400 €/kW – they still cost too much compared to the capital costs of a gas combustion engine operated with syngas at 500 €/kW.

Concentrating on profits from the sale of reliable energy, hydrogen production via gasification could be augmented, and daily hours of hydrogen production have to be set at six or eight hours. Thus, electrolyzer power can be lowered to save investment costs, or more hydrogen can be sold.

Thinking of future work, perhaps similar systems can achieve even better economic viability. When a large amount of syngas and only less hydrogen from electrolysis is produced, the fuel cell could be fed with hydrogen-rich syngas. Due to their high operation temperature, SOFCs can be operated with this type of fuel, which would make the hydrogen PSA dispensable. It is also possible to augment the fuel cell's efficiency by installing a combined fuel cell and gas-turbine process. In a gas turbine, leftovers of the fuel cell's gases are mixed with some natural gas or syngas and combusted. This process based on natural gas has already been installed by Siemens AG in a few demonstration plants, and efficiencies of up to 70 % for installations of some MW are expected. Although this would only produce a small improvement, StatoilHydro is investigating "new large scale, alkaline high pressure electrolyzers (some MW, 30 bar) that are able to operate down to 5 – 10 % of their rated capacity".

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Figures.

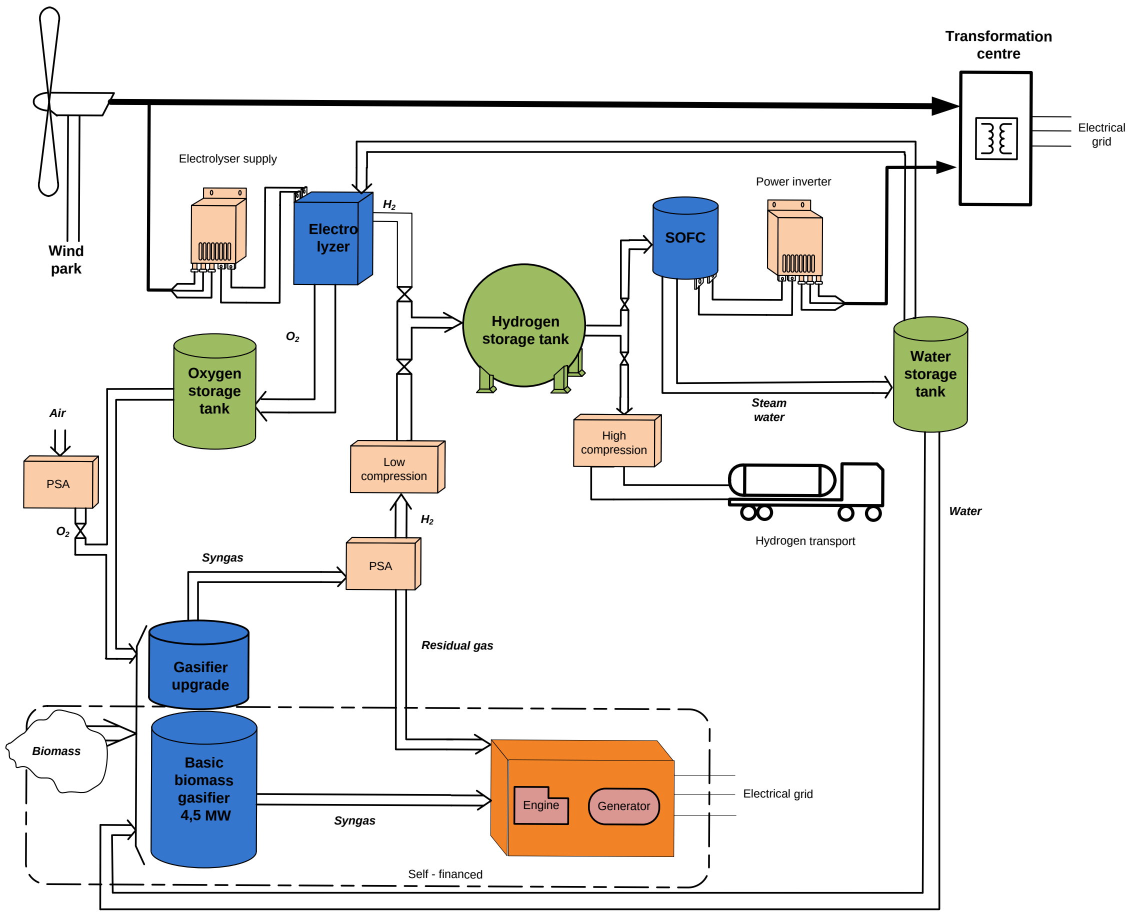

Figure 1: Diagram block of the complete system.

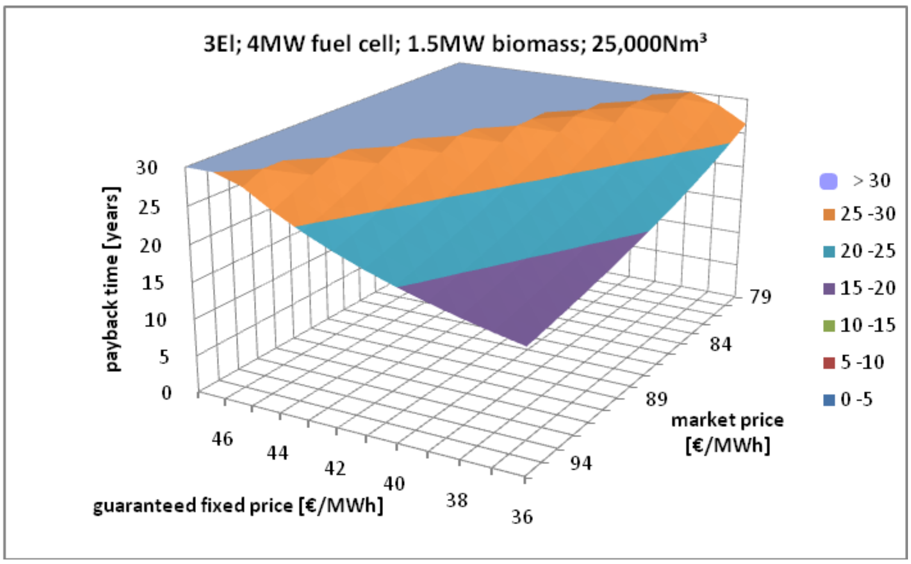

Figure 2: Payback time in the MTS economic scenario of technical scenario: 3 Electrolizers; 4 MW fuel cell; 1.5 MW biomass; Hydrogen Storage of 25,000 Nm³; Hourly Set-up: 12 hours selling energy/12 hours hydrogen production.

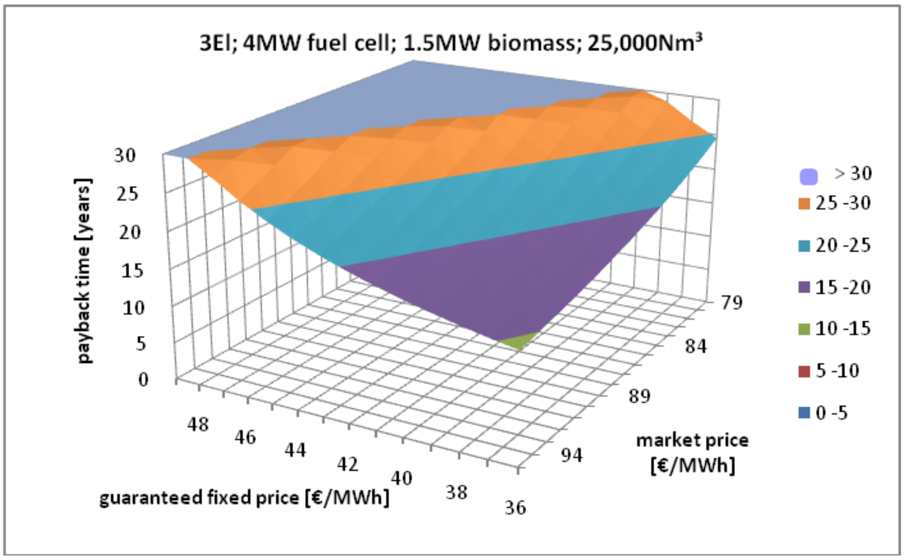

Figure 3: Payback time in the MTS economic scenario of technical scenario: 3 Electrolizers; 5 MW fuel cell; 1.5 MW biomass; Hydrogen storage of 30,000 Nm³; Hourly Set-up: 14 hours selling energy/10 hours hydrogen production.

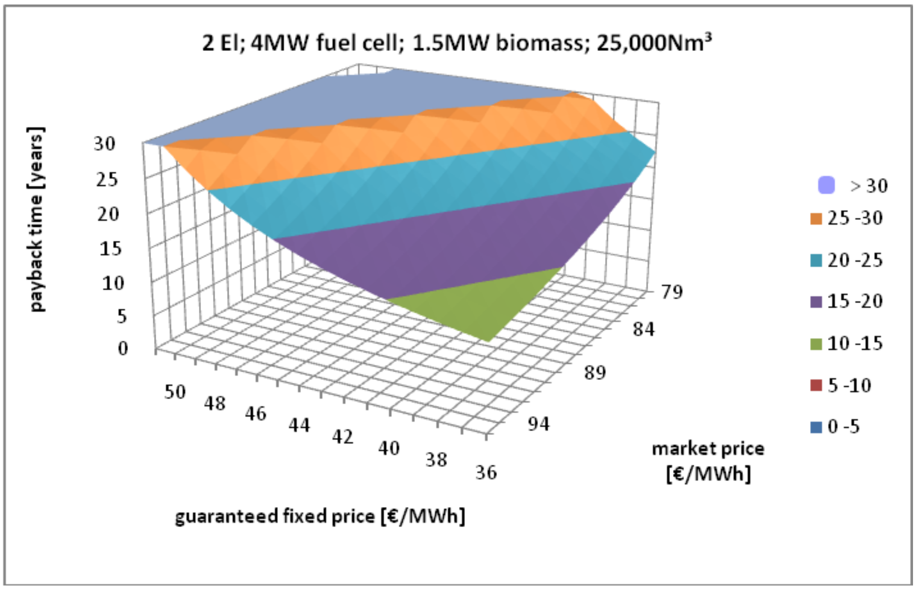

Figure 4: Payback time in the MTS economic scenario of technical scenario: 2 Electrolizers; 4 MW fuel cell; 1.5 MW biomass; Hydrogen storage of 25,000 Nm³; Hourly Set-up: 16 hours selling energy /08 hours hydrogen production.

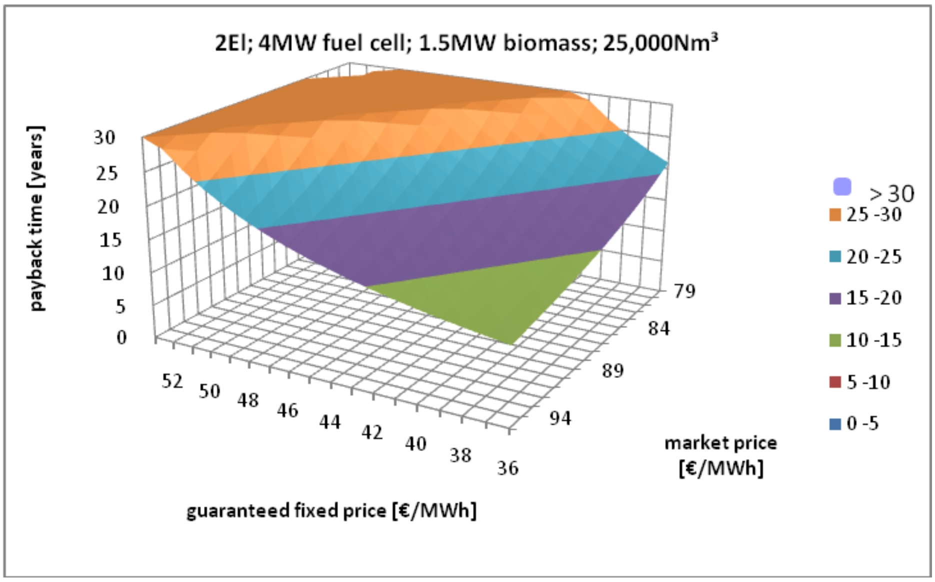

Figure 5: Payback time in the MTS economic scenario of technical scenario: 2 Electrolizers; 4 MW fuel cell; 1.5 MW biomass; Hydrogen storage of 45,000 Nm³; 18 hours selling energy /06 hours hydrogen production.

Nomenclature

Latin symbols

B	€	profits
C	€	costs, price
CC	€	capital costs
E	kWh	energy
f	%	factor
P	W	capacity/power
t	h	time

Volumes

$V_{H2,BM}$	Nm^3	hydrogen produced by biomass gasification and obtained by pressure swing absorption
$V_{H2,dep\text{-}size}$	Nm^3	size of hydrogen deposit

Indexes

acq	acquisition	H2	hydrogen
BM	biomass	O2	oxygen
E	energy	pb	payback
El	electrolyzer	pen	penalization
FC	fuel Cell	spec	specific
fix	guaranteed fixed price	WP	wind park

Tables.

Table 1. Elements of system capital costs.

	Capital costs	Operation and maintenance	Material costs	Bibliography
Fuel cell	3620 $/kW (100 kW system)	0.024 $/kWh	-	[20]
Electrolyzer	see Table 3	4%	-	[23]
Biomass installation	1,328 $/Nm³/h	payed by basic plant	0.15 $/Nm³ H2	[22]
H2 storage	variable: see Eq. 1	2%	-	[20]
Compressors	700 €/kW	4%	-	[20]
Water storage tank	14,000 $ (10,400 gallons)	-	1 €/Nm³	[24]
Tubes and fittings	5%	-	-	-
electrical system	5%	-	-	-
Construction	5%	-	-	-
Interests	5%	-	-	-
Oxygen to sell	-	-	0.08 €/kg	[27]
Hydrogen to sell	-	-	0.30 €/Nm³	[26]

Table 2: Electrolyzer costs.

No. of electrolyzer	[-]	8	32	64	96
Electrolyzers capital costs	[M€]	11.714	42.366	83.555	116.297
Costs of one electrolyzer	[M€]	1.464	1.324	1.306	1.211
Power of one electrolyzer	[MW]	2085.5	2085.5	2085.5	2085.5
Specific capital costs	[€/kW]	702	635	626	581

Table 3: Economical scenarios.

€/MWh	NTS	MTS	LTS 1	LTS 2
Market price	77.05 (avg. 2009) (with subsidies)	79.00 – 95.00 (with subsidies)	35.00 – 60.00 (without subsidies)	35.00 – 60.00 (without subsidies)
Guaranteed fixed price	78.18	35.00 – 78.00	0.00	0.00
Specific penalty price	1.80	1.80	2.00 – 35.00	35.00 – 60.00
Step-range	-	1 €	1 €	1 €
Hydrogen to sell	0.30 €/Nm³	0.30 €/Nm³	0.30 €/Nm³	0.30 €/Nm³
Fuel cell costs	FCCosts*	FCCosts	FCCosts	(CFCosts) · 0.5
Electrolyzer costs	ELCosts**	ELCosts	ELCosts	(ELCosts)· 0.75

*(see Table 1)
**(see Table 2)

Table 4: System profits and costs.

Sales (profits)	Acquisitions (losses)
Wind park energy with compensation system	Purchase of wind park energy
Sell hydrogen to hydrogen industry	Capital costs
Sell water to basic biomass plant	Operation and maintenance
Sell oxygen to basic biomass plant	Feedstock costs
	Energy for system's own consumption

Table 5: Best payback time of optimal technical scenarios in the economic scenario MTS; hourly set up 12 hours selling energy/12 hours hydrogen production.

El [no]	P_FC [MW]	P_BM [MW]	V_H2 [Nm³]	f_comp [%]	market price [€/MWh]	fixed price [€/MWh]	payback-time [years]
1	5	1.5	25000	86	95.00	35.00	38.70
2	5	1	30000	85.8			30.52
1	6	1.5	30000	90.1			57.43
2	6	1	40000	90.4			44.43
2	4	1.5	25000	78.2			17.78
3	4	1.5	25000	78.2			16.14

Table 6: Best payback time of optimal technical scenarios in the economic scenario MTS; hourly set up 14 hours selling energy /10 hours hydrogen production.

El [no]	P_FC [MW]	P_BM [MW]	V_H2 [Nm³]	f_comp [%]	market price [€/MWh]	fixed price [€/MWh]	payback-time [years]
1	5	1,5	40000	85.6	95.00	35.00	26.43
2	5	1,5	30000	86.5			15.71
3	5	1	50000	86			21.86
2	4	1.5	30000	78.3			15.09
3	4	1.5	25000	78.3			14.49

Table 7: Best payback time of optimal technical scenarios in the economic scenario MTS; hourly set up 16 hours selling energy /8 hours hydrogen production.

El [no]	P_FC [MW]	P_BM [MW]	V_H2 [Nm³]	f_comp [%]	market price [€/MWh]	fixed price [€/MWh]	payback-time [years]
2	5	1.5	40000	85	95.00	35.00	16.24
2	6	1.5	35000	85.5			19.00
3	5	1.5	30000	84			15.86
2	4	1.5	25000	76.8			12.35
3	4	1.5	25000	77.2			12.75

Table 8: Best payback time of optimal technical scenarios in the economic scenario MTS; hourly set up 18 hours selling energy /6 hours hydrogen production.

El [no]	P_FC [MW]	P_BM [MW]	V_H2 [Nm³]	f_ comp [%]	market price [€/MWh]	fixed price [€/MWh]	payback-time [years]
2	5	1.5	45000	80			13.86
3	5	1.5	40000	80.9	95.00	35.00	14.56
2	4	1.5	45000	76.7			11.42
3	4	1.5	45000	77			12.27

Table 9: Best payback time of optimal technical scenarios in the economic scenario LTS 2; hourly set up 12 hours selling energy /12 hours hydrogen production.

El [no]	P_FC [MW]	P_BM [MW]	V_H2 [Nm³]	f_comp [%]	market price [€/MWh]	penalization costs [€/MWh]	payback-time [years]
1	5	1.5	25,000	86			-
2	5	1	30,000	85.8			-
1	6	1.5	30,000	90.1	35.00	35.00	-
2	6	1	40,000	90.4			-
2	4	1.5	25,000	78.1			-
3	4	1.5	25,000	78.1			51.31

Table 10: Annual profits of economic scenario LTS 1 considering the following technical scenarios: for 12/12 and 14/10 hourly set-ups, 3 Electrolyzers, 4 MW Fuel Cell, 1.5 MW Biomass, hydrogen storage 25,000 m^3; for 16/08 and 18/06 hourly set-ups, 2 Electrolyzers, 4 MW Fuel Cell, 1.5 MW Biomass, hydrogen storage 25,000 m^3.

Hourly set-up	C_market [€/MWh]	C_pen,spec [€/MWh]	Profits [€]	Penalization costs [€]	Energy acquisition costs [€]	sum [€]
12/12	35	2	1.4E6	4,000	2.3E6	0
	60	2	2.5E6		4.0E6	0
	35	35	1.4E6	70,000	1.7E6	0
	60	35	2.5E6		3.4E6	0
14/10	35	2	1.7E6	4,700	2.3E6	0
	60	2	2.9E6		4.0E6	0
	35	35	1.7E6	80,000	1.7E6	0
	60	35	2.9E6		3.4E6	0
16/08	35	2	1.9E6	5,600	2.3E6	0
	60	2	3.3E6		4.0E6	0
	35	35	1.9E6	100,000	1.7E6	100,000
	60	35	3.3E6		3.4E6	0
18/06	35	2	2.2E6	6,500	2.3E6	0
	60	2	3.7E6		4.0E6	0
	35	35	2.2E6	115,000	1.7E6	385,000
	60	35	3.7E6		3.4E6	185,000

Table 11: Annual profits of economic scenario LTS 2 considering the following technical scenarios: for 12/12 and 14/10 hourly set-ups, 3 Electrolyzers, 4 MW Fuel Cell, 1.5 MW Biomass, hydrogen storage 25,000 m^3; for 16/08 and 18/06 hourly set-ups, 2 Electrolyzers, 4 MW Fuel Cell, 1.5 MW Biomass, hydrogen storage 25,000 m^3.

Set-up	C_market [€/MWh]	C_pen,spec [€/MWh]	Profits [€]	Penalization costs [€]	Energy acquisition costs [€]	sum [€]
12/12	35	35	1.4E6	70,000	1.7E6	0
	60	35	2.5E6		3.4E6	0
	60	60	2.5E6	120,000	2.9E6	0
14/10	35	35	1.7E6	80,000	1.7E6	0
	60	35	2.9E6		3.4E6	0
	60	60	2.9E6	140,000	2.9E6	0
16/08	35	35	1.9E6	100,000	1.7E6	100,000
	60	35	3.3E6		3.4E6	0
	60	60	3.3E6	170,000	2.9E6	230,000
18/06	35	35	2.2E6	115,000	1.7E6	385,000
	60	35	3.7E6		3.4E6	185,000
	60	60	3.7E6	200,000	2.9E6	600,000