Dynamic modeling of a power-to-gas system for green methane production from wind energy

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Abstract:

Despite the impact of global warming on the living conditions of the Earth, fossil fuels still dominate the global energy scenario. The precariousness of our energy system requires the use of more reliable and less polluting energy sources, but a greater penetration of intermittent renewables implies the need for large-scale flexible energy storage. This need, combined with the growing interest in the use of hydrogen in mobility and industry, makes the prospect of including this energy vector in our daily lives tangible. However, the problems related to the development of dedicated infrastructures make its positioning on the market complex. In a transition phase, power-to-gas systems constitute an emerging solution that allows the use of existing structures for natural gas and, at the same time, solves the problem of hydrogen storage. In this study, a power-to-gas system producing synthetic methane from wind energy was modelled. Management strategies for both the electrolysis system and the hydrogen storage tank were tested to assess the flexibility and versatility of the system. Particular attention was dedicated to the analysis of the impact of the storage on the mitigation of the operating condition fluctuation of the methanation unit. Results of the simulations showed similar performances of the four electrolyzers and a limited number of methanation unit shutdowns. Nevertheless, the annual utilization factor of the subsystems was low, and this suggests a further investigation of the subsystems' sizing. Overall, the effectiveness of the management strategies developed for the power-to-methane system makes the proposed model a good instrument to be used for further analysis and evaluations.

Keywords:

Dynamic operations; Hydrogen; Modeling; Management strategies; Methane; Power-to-Gas.

1. Introduction

Decarbonizing the world's energy system requires the use of green and renewable energy sources (RES). However, a high penetration of renewable sources in the global energy mix creates additional challenges related to the more complex management of energy flows and the difficulty of synchronizing energy demand and production. This problem can be solved using energy storage systems. In this context, hydrogen has been identified as a sustainable energy vector for electricity and heat generation; nevertheless, today 96% of the produced hydrogen is obtained from fossil fuels and only 3.9% comes from electrolysis [1] due to the elevated costs associated with its entire supply chain.

Although some hydrogen production technologies (e.g.: alkaline electrolysis) alternative to fossil fuel-based ones are already mature, the lack of dedicated infrastructures makes the introduction of hydrogen in the market difficult [2]. Using hydrogen for the synthesis of various hydrocarbons, including methane [3,4], could be considered a promising solution to foster hydrogen economy while using the existing infrastructure. Lewandowska-Bernat & Desideri [4] identify various opportunities for the power-to-methane systems (both in off-grid and on-grid systems) that are considered promising for the development of more efficient and flexible energy systems, the reduction of polluting emissions, and the increase of sustainability in sectors such as industry and mobility. After a comparison among short-term storage systems, Belderbos et al. [5] conclude that power-to-fuel systems can play a significant role in scenarios with a high share of renewable energy. In particular, they analyze four case studies each of which characterized by a different type of RES (onshore wind, offshore wind or solar). Their study illustrates the different trends of methane production and how power-to-gas systems play a more important role when the renewable energy production profile has a seasonal trend. Furthermore, Walker et al. [6] identify power-to-fuel as an attractive solution to implement, especially for seasonal storage.

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Some issues arise and should be considered when electrolysis systems are directly coupled with variable RES. In particular, alkaline electrolyzers have some limitations on the lower operating load because of safety reasons, and they can generally operate in a range of 20-100% of the nominal power [7].The variability of these sources might affect the system operation by causing frequent shutdowns, part-load and dynamic operation. However, frequent shutdowns can speed up the stack degradation and should be limited. In addition, the intermittent RES availability causes a low number of annual equivalent operating hours that negatively affects the specific production cost of hydrogen. Several studies investigated techno-economic aspects of electrolysis systems coupled with RES. Liponi et al. [8] investigate the effect of the electrolyzer size on the levelized cost of hydrogen in the case of PV-electrolyzer coupling. The choice of the electrolyzer size should be a trade-off between the maximization of hydrogen production and the needs of limiting shutdowns and having sufficiently high electrolyzer utilization factors to minimize the specific production costs. The possibility of adopting an electric storage [9] and/or grid-electricity support [10] to mitigate wind variability has also been investigated. On one side, by allowing grid support, the electrolyzer operation can be more continuous and annual operating hours are increased, resulting in a reduction of specific production costs. However, on the other side, if the electricity grid is not completely decarbonized, CO_2 emissions are associated with hydrogen production. In another study [11] Liponi et al. perform a techno-economic comparison of different configurations of an electrolysis system consisting of multiple electrolysis units that can operate separately for hydrogen production from wind sources.

In this study, an electrolysis system composed by several separated units is adopted and a management strategy is implemented to limit the number of electrolyzers shutdowns.

Several models for power-to-gas systems were proposed in the literature. In particular, Baccioli et al. [12] analyze the costs associated with the production and sale of liquefied methane and oxygen from a power-to-gas plant associated with a CO_2 source from a geothermal plant. This study reveals that using hydrogen storage does not increase the cost-effectiveness of the plant, while "only small storage systems will be needed for managing the different dynamic behavior of the components" [12]. Gorre et al. also published two studies in this subject [13,14]. In the first study, they observe that the production costs of methane in a power-to-gas system can be reduced by releasing the operation of electrolyzer and methanation unit by using an intermediate storage system. They also assert the importance of optimizing the size of the methanation unit. In the second study, they underline the importance of using an intermediate storage to decouple the electrolysis system and the methanation unit, but also the need to optimize its size to reduce production costs, depending on the operation strategy and the case study.

In a 2009 study [15] Frate et al. investigate the use of electric storage systems to counter the problem of wind power fluctuations in small-sized wind farms. In particular, they study the effectiveness of Li-Ion batteries and flywheels in managing the rates of power output from a wind turbine. Nevertheless, the impact of the management strategy of hydrogen and electricity surplus on the mitigation of the operating condition fluctuation of the methanation unit have not been deeply investigated.

In the present work, a mathematical model to simulate the operation of a power-to-gas system with wind-energy source is proposed. The problems related to the variability of the energy source will be addressed by developing a management strategy for both the electrolysis system and the hydrogen storage tank, in order to limit the number of shutdowns (and consequently the equipment degradation) and, at the same time, to exploit to the maximum the electricity produced by the wind farm.

2. Modeling

A schematic representation of the power-to-gas system modelled in this study is given in Figure 1. The first step is the production of hydrogen (and oxygen) through an electrolysis system (composed of four alkaline electrolyzers of equal nominal power) powered by a dedicated wind farm. The produced hydrogen is partly sent to the methanation unit and partly injected in a storage system before the methanation unit. The conversion of hydrogen and CO_2 to methane takes place in a catalytic methanation reactor. The main components of the system are modelled (wind farm, electrolyzers, and methanation unit) as described below.

2.1. Alkaline electrolyzer

Several models for the simulation of the operation of an alkaline electrolyzer are provided in literature. The foundations of "semi-empirical" alkaline electrolyzers models are built by Ulleberg [16], whose model is based on a combination of fundamental thermodynamics, heat transfer theory and empirical electrochemical relationships. An extension of this model is proposed in the study of Amores et al. [17] in which the effect of electrolyte concentration and cell architecture is also studied. Sánchez et al. published two other relevant studies on this subject [18,19] in which a semi-empirical mathematical model based on the polarization curve and the Faraday efficiency in dependence of pressure, temperature and current density is proposed. Dièguez et al [20] develop a thermal modeling of the electrolyzer focusing on coupling the stack with a renewable energy source.

Whereas the above-mentioned studies use a simplified lumped parameter configuration for the description of the electrolyzer, in which stack, gas-liquid separators and heat exchangers are treated as a single component,

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in this study a more detailed modelling is performed, paying greater attention to individual elements and control systems. The baseline study used is from Sakas et al. [21], in which a model based on energy and mass balances with adjustable parameters with a zero-dimensional approach is proposed.

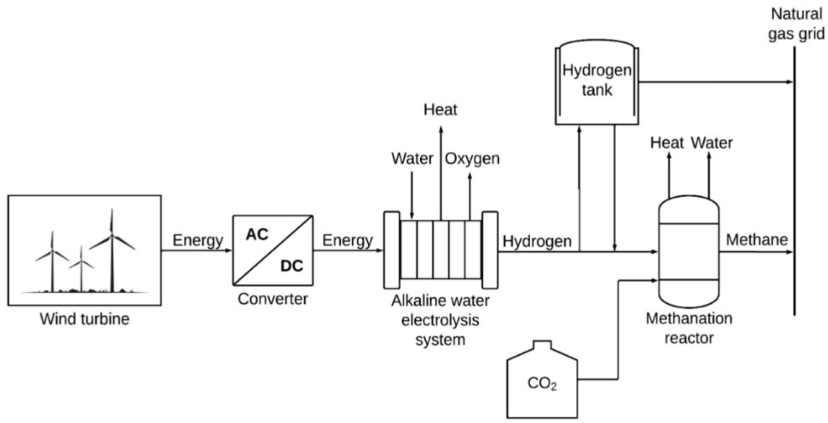

Figure 1. Schematic representation of the power-to-gas system.

Electric current powers the stack for the production of gaseous hydrogen and oxygen. At the stack outlet, a mixture of electrolyte (25wt% KOH) and hydrogen on one side, and oxygen on the other side, are sent to the horizontal gas-liquid separators. Hydrogen and oxygen are removed from the separator, while the electrolyte mixture is sent to the mixer where it is mixed with the make-up water. The oxygen leaving the separator is just flushed from the process, while the produced hydrogen is sent to the methanation unit (see Figure 2).

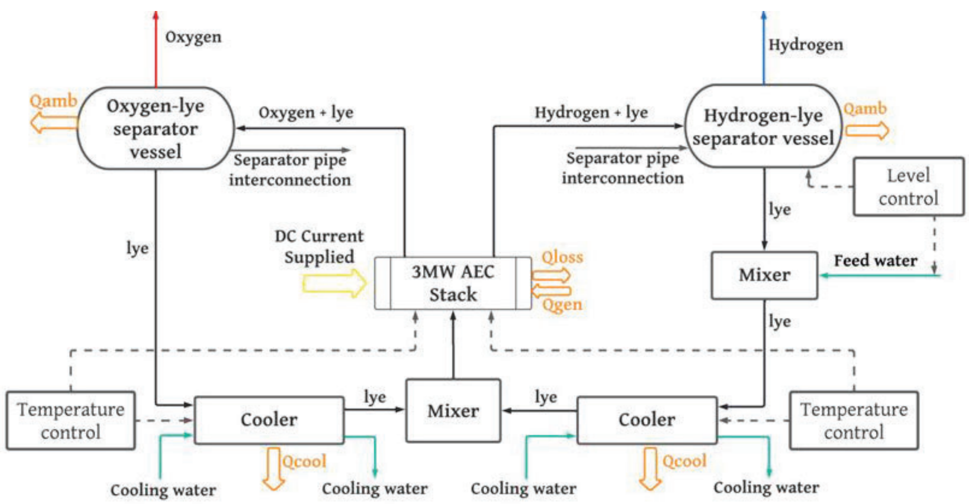

Figure 2. Alkaline water electrolyzer plant process diagram.

The stack is modeled in Matlab assuming the parameters listed in Table 1.

Table 1. Stack model parameters [21]

Parameter	Unit	Value
Number of cells	-	326
Cell lateral area	m^2	2.66
Cell block diameter	m	1.84
Free cell volume	m^3	0.027
Distance between bipolar plates	m	0.01
Stack length	m	5.85

A thermal model and an electrochemical model are used to calculate the production of hydrogen, the trend of flow rates, temperatures, energy losses, cell voltage and cell current.

2.1.1. Electrochemical model

The cell voltage is calculated as the sum of the reversible potential and overvoltage terms:

$$E_{cell} = E_{rev} + E_{act} + E_{ohm} + E_{conc} \quad (1)$$

The reversible potential is the minimum voltage necessary for the water splitting reaction to take place and depends on the temperature and pressure according to Nerst equation. Overvoltage are expressed through semi-empirical expressions as a function of temperature and current density [21].

The polarization curve is defined as a function of the cell current, which is calculated through Newton's iterative method using the parameters adopted by Sakas et al. [21] for a 3 MW alkaline electrolyzer.

2.1.2. Thermal model

The stack temperature of an alkaline electrolyzer is one of the parameters that most affects its performance. In this paper, internal temperature gradients in the stack are assumed spatially uniform, according to Sakas et al.'s lumped thermal capacitance model [21].

The overall thermal energy balance is expressed by:

$$C_{stack} \cdot \frac{dT_{stack}}{dt} = Q_{gen} - Q_{loss} + \dot{m}_{lye,stackin} \cdot \bar{c}_{p,lye} \cdot T_{stackin,cooled} - \left(\dot{m}_{lye} + \dot{m}_{cons,wat}\right) \cdot \bar{c}_{p,lye} \cdot T_{stack} \quad (2)$$

The term on the left in Equation (2) represents the rate of change of the electrolyzer temperature over time, while Q_{gen} is the heat generated inside the stack, Q_{loss} is the total heat loss to the ambient and the other two terms are the enthalpy flows of the incoming and outgoing electrolyte mixture from the stack.

Since the flow rates of hydrogen and oxygen are very low compared to the flow rate of the electrolytic mixture circulating in the system (0.0138 kg/s, 0.12 kg/s and 19.68 kg/s respectively at nominal conditions), they can be neglected in the energy balances.

The hydrogen and oxygen produced by the electrolysis process exit from the stack in the form of a mixture of gas and electrolytic solution, therefore it is necessary to separate them from liquid phase through two horizontal gas-liquid separator vessels. In the present study, for simplicity, the separation efficiency is considered unitary.

To prevent gas-liquid separators from excessively emptying or filling, an on/off control of their liquid level is applied to the water make-up pump to keep the separators' level within a certain range (0.4 m – 0.6 m) for the entire duration of the simulation.

After gas separation, the electrolytic mixture enters the mixer where the consumed water is refilled. Although mixing with low temperature water (15°C) results in a lowering of the temperature of the electrolyte mixture, this is not enough to reach the target temperature of the stack. Therefore, a cooling system with a temperature control is required. The regulation has the aim to keep the stack temperature always near the target value (70°C).

The efficiency of the electrolyzer was defined as:

$$\eta_{ele} = \frac{\dot{m}_{H_2} \cdot LHV_{H_2}}{P_{stack}} \quad (3)$$

2.1.3. Operation at nominal conditions

The simulation is performed using a 5-minute time discretization. By simulating the operation of a single electrolyzer fed with nominal power, the results obtained were very close to those obtained in the reference study [21], whose model was validated. In Table 2, the main operating parameters of the electrolyzer are given.

2.2. Hydrogen storage tank

The storage system was considered an ideal component, and it was modeled as a variable volume at constant pressure (16 bar). Its storage capacity is 4,434 Nm^3 of hydrogen, corresponding to the amount of hydrogen required by the methanation unit to operate continuously for two-and-a-half hours at nominal conditions. The State of Charge (SOC) of the tank is defined as:

$$SOC(t) = \frac{V_{H_2,tank}(t-1)}{V_{H_2,tank,cap}} \quad (4)$$

Where $V_{H2,tank}$(t-1) is the hydrogen volume content inside the tank at the timestep "t-1" and $V_{H2,tank,cap}$ is the storage capacity of the tank.

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2.3. Methanation unit

The methanation unit is modelled in Matlab without going into the thermodynamic details of its operation. The model provides the methane flow rate on the basis of the produced hydrogen according to stoichiometry.

The methanation unit is assumed to operate in a range of 40-100% of the nominal flow rate, without major changes in the quality of the produced gas, with a maximum load change rate of ±10%/min [13]. Since the electricity input might fluctuate strongly and electrolyzers and the methanation unit work at different loads, it is necessary to decouple the two components. For this purpose, a hydrogen storage tank is installed between the electrolyzer and the methanation unit, and it is modeled as an ideal component. In this study, the methanation unit, the electrolysis system and the storage system are considered at the same pressure (16 bar), but compressing the hydrogen after the electrolysis system could significantly decrease storage volume. The methane flow rate is retrieved from the methanation efficiency according to the Eq. (5).

$$\eta_{\mathrm{met}} = \frac{\mathrm{LHV}_{\mathrm{CH_4}} \cdot \dot{m}_{\mathrm{CH_4}}}{\mathrm{LHV}_{\mathrm{H_2},} \cdot \dot{m}_{\mathrm{H_2,in}}} \cdot 100 \tag{5}$$

Table 2. Alkaline electrolyzer operating parameters at nominal conditions.

Parameter	Unit	Value
Stack target temperature	°C	70
Ambient temperature	°C	25
Stack nominal power	MW	3
System efficiency	%	92
Average electrolyzer efficiency	%	60
Stack pressure	bar	16
Faraday efficiency	%	86
Water consumption	kg/s	0.125
Hydrogen production	Nm^3/h	554
Oxygen production	Nm^3/h	277
Specific energy consumption	kWh/Nm^3	4.45

Table 3. Methanation unit operating parameters.

Parameter	Unit	Value
mol H_2 : mol CO_2	-	4:1
Pressure	bar	16
Methanation efficiency at nominal conditions	%	80 [13]
Load of methanation	%	40 – 100 [13]
Load change rate of methanation	%/min	± 10 [13]
Nominal hydrogen molar flow	Nm^3/h	1,773

3. Management algorithms

3.1. Electrolysis system

The power generated by the wind farm is sent to an electrolysis system composed of four alkaline electrolyzers, each of which has a nominal power of 3 MW. During the simulations, due to the variability of the renewable source, the wind farm rarely produces its nominal power. For this reason, a management algorithm is developed to ensure that the four electrolyzers have similar operating conditions and, at the same time, a limited number of shutdowns.

Three operating states are defined: on, off and standby. The management algorithm ensures the electrolysis system to work always within its operative range (20-100% of its nominal power). Based on the input power, which is fairly divided among the operating machines, the electrolyzers state is established at each timestep according to the following parameters:

- the state of the electrolyzer at the previous timestep.
- the equivalent operating hours.
- the duration of the off and the standby states.

The aim of the management algorithm is to ensure that the four electrolyzers have averagely similar performances in terms of number of shutdowns, equivalent operating hours and hydrogen production.

3.2. Methanation unit and hydrogen storage system

The hydrogen flow rate feeding the methanation unit is often different than the nominal flow rate depending on the power supplied by the wind farm. In particular, if the inlet hydrogen flow rate from the electrolysis system exceeds the value of methanation unit nominal feed flow rate, the methanation unit works at maximum load, and the storage tank provides the missing amount of hydrogen (Figure 3, timesteps "i+1”). On the other hand, if the produced hydrogen is lower than the minimum flow rate of methanation, the methanation unit is set to its minimum load, and the storage tank stores the surplus hydrogen (Figure 3, timesteps “i-1”). When the electrolysis system has greater load change rates than those tolerable by the methanation unit, the storage system acts as a “ramps mitigator” (Figure 3, timestep "i+2"). When the methanation unit operates within the load range, it does not only convert into methane the produced hydrogen flow from the electrolysis system, but the hydrogen feed flow rate could be increased or decreased (if $SOC > SOC_{target}$ or $SOC < SOC_{target}$ respectively). The SOC_{target} is set to 50%.

Then, when the methanation unit operates within the load range, the inlet flow rate is calculated as:

$$\dot{m}_{met}(t) = \dot{m}_{ele}(t) + \dot{m}_{SOC}(t) \tag{6}$$

Where $\dot{m}_{SOC}(t)$ depends on the SOC at the timestep “t-1”.

The storage system, therefore, has the function of absorbing the off-range hydrogen production peaks, keeping the ramps within the constraints imposed to the load change rate of methanation, and methane production support.

Depending on the size of the methanation unit, during the simulations the electrolysis system could produce a certain amount hydrogen which cannot be converted into methane. However, the storage tank can store hydrogen until it reaches the full status, after which the surplus hydrogen can no longer be stored. In this case, we could have hydrogen losses.

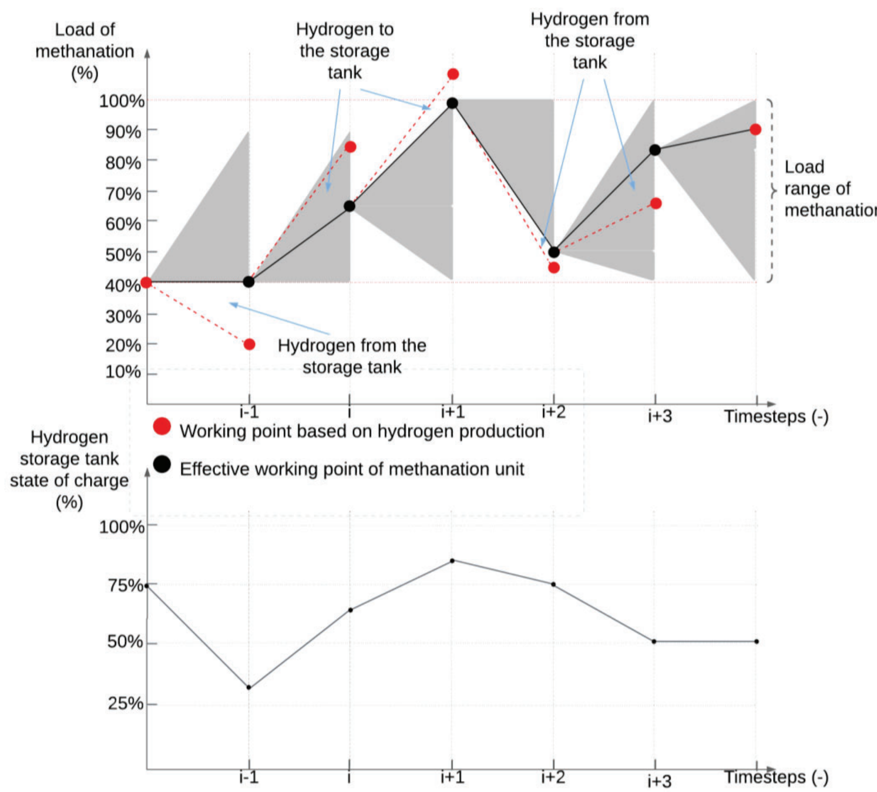

Figure 3. Example of operating of the methanation unit management strategy. The grey area represents the permissible operating points of the methanation unit at each timestep [15].

In order to avoid excessive shutdowns, a minimum SOC is imposed to allow the methanation unit to extract the required hydrogen from the storage tank to ensure operation at the minimum load. This constraint is needed only if the methanation unit was in the “off” state at the previous timestep. In fact, especially during less windy seasons, the hydrogen production is not enough to ensure the operation at minimum load. Therefore, allowing an uncontrolled adsorption of hydrogen from the tank would cause excessive on/off cycles of the methanation unit, since the low hydrogen production and the low SOC of the tank are not able to support continuous operation. Setting a minimum SOC (SOC_{min} = 50%) to be achieved to withdraw from the hydrogen storage tank

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allows it to reach the conditions for supporting the methanation unit for a certain period, limiting its shutdowns and, consequently, its degradation.

4. Results and discussion

In a first phase, simulations of the single electrolyzer operation powered by a 3 MW wind farm were carried out on four typical days characterizing the seasonal trend of the wind: December 21, September 25, March 22, June 21 (solstices and equinoxes, or, when the wind data for those specific days seemed to have an untypical trend, days close to solstices and equinoxes). Figure 4 and Figure 5 show the performance of the cooling system and the separators level control system, respectively. During windy days (December 21 and September 25) the cooling system was in the "on" state for almost all the day. This happens because a greater windiness results in a most intensive use of the electrolyzer and then in a greater heat generation.

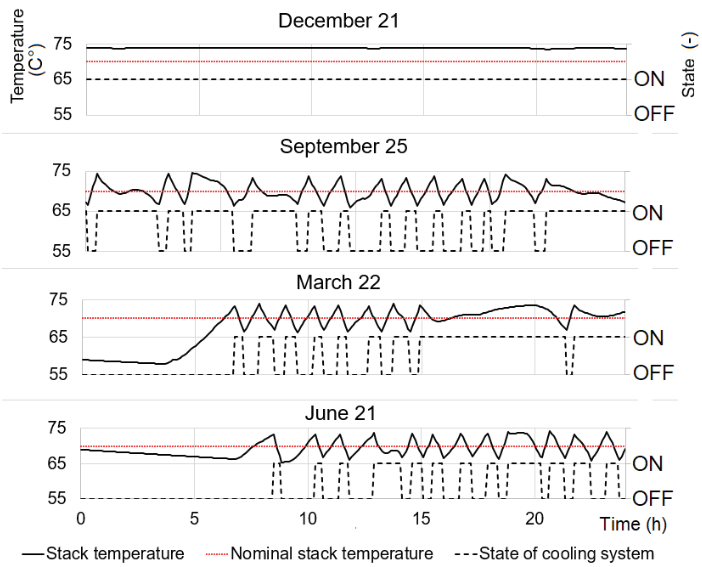

Figure 4. Performance of the cooling system during four seasonal characteristic days.

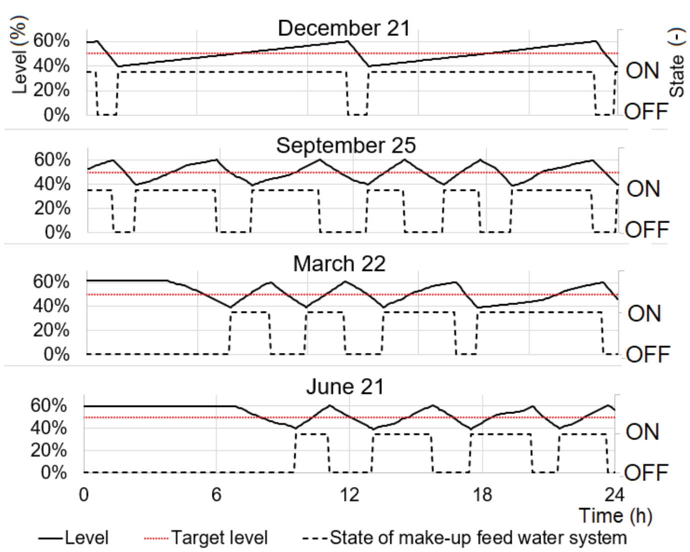

Figure 5. Performances of the separators level control system during four seasonal characteristic days.

Similarly, the separators level control system showed a longer working time of the make-up feed water system in winter and autumn (Figure 5). However, both the stack temperature and the separators level were always within the required range (70 ± 5°C and 50 ± 10% of the separator height, respectively), which is a sign that the applied control systems ensure the desired management of the alkaline electrolyzer.

Figure 6 shows the power distribution between the four electrolyzers of the electrolysis system during a daily simulation (September 25). The sizing of the electrolyzers was such as to ensure the utilization of all the renewable power and, on the other hand, the respect of the constraints imposed to the electrolyzers.

The four electrolyzers exhibited different performances in terms of hydrogen production, number of shutdowns and utilization factor (Table 5). However, the duration of a daily simulation is not enough to observe the efficacy of the proposed management algorithm.

Regarding to the whole power-to-gas system, Figure 7 shows the operation of the management algorithm for the methanation unit and hydrogen storage during a two-days simulation. Until 4 pm of the first day the the SOC of the hydrogen storage tank was under 50%; then, a certain share of the produced hydrogen incoming from the electrolysis system was used to fill the storage tank, while the remaining flow rate was sent to the methanation unit to be converted in methane.

Table 4. Performances of the alkaline electrolyzer for four seasonal typical days.

Day	Feed water system at the "on" state (%)	Stack average temperature (°C)	Average efficiency (%)	Cooling system at the "on" state (%)	Hydrogen production (Nm^3)	Utilization factor (%)
21-Dec	100	73.9	60	89	13,316	100
25-Sep	64	70.0	62	63	9,380	69
22-Mar	52	68.0	62	52	7,964	59
21-Jun	33	69.2	63	38	5,569	42

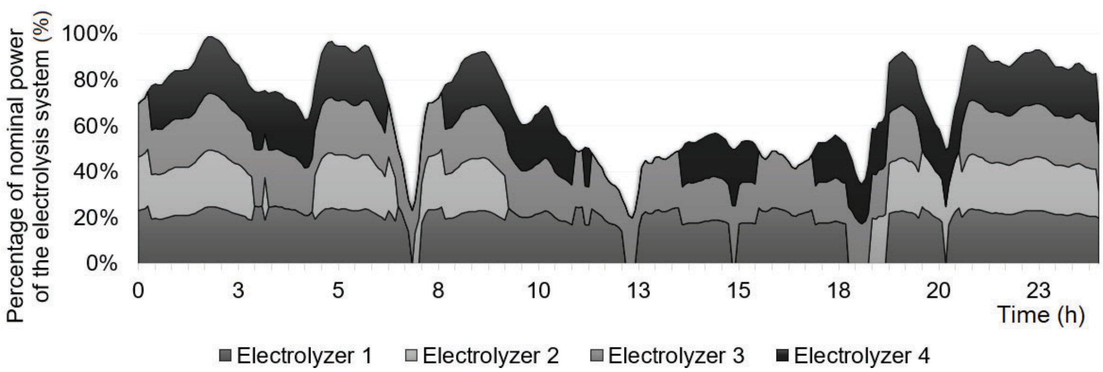

Figure 6. Power distribution between the four electrolyzers during a daily simulation.

From 4 pm of the first day the SOC of the hydrogen storage tank was over 50%; in particular, approximately from 8:30 pm to 10 pm of the first day and 2:30 am to 5 am of the second day the produced hydrogen and a certain share from the storage tank are sent to the methanation unit. During the remaining period, the produced hydrogen was out of the constraints of the methanation unit; in fact, the methanation unit was set to the maximum load or switched off, and the surplus hydrogen was stored up to the filling limit of the storage tank.

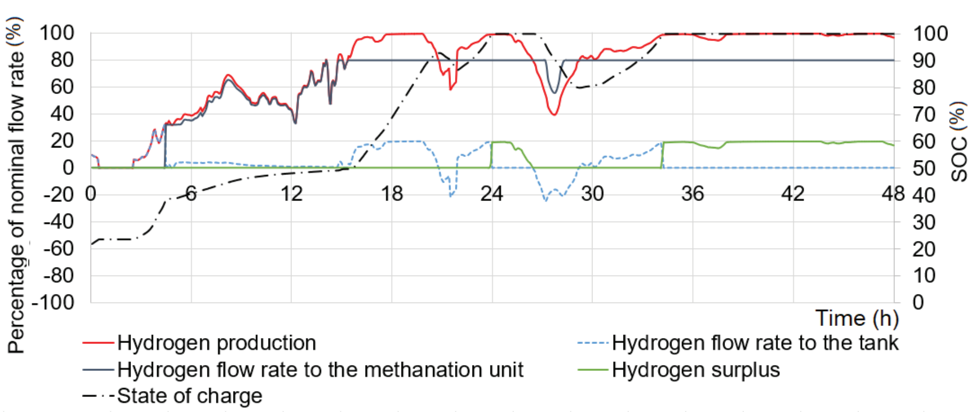

Figure 7. Performance of the management strategy for the methanation unit and hydrogen storage during a two-days simulation.

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Table 5. Performances of the four electrolyzers in a daily simulation.

Electrolyzer	Efficiency (%)	Hydrogen production (Nm^3)	Utilization factor (%)	Number of shutdowns (-)	Oxygen production (Nm^3)	Water consumption (kg)	Average tack temperature (°C)	Maximum duration of the off period (h)
1	60	10,619	80	1	5,283	8,532	70.5	0.5
2	60	6,388	48	2	3,171	5,133	67.9	8.6
3	60	10,993	82	1	5,470	8,833	70.1	0.5
4	60	8,716	65	3	4,333	7,003	69.6	1.8
Electrolysis system	-	36,716	-	-	18,258	29,500	-	-

In Figure 8 the characteristic variable trends of the power-to-gas system during four seasonal characteristic days are shown. The hydrogen flow rates and the methane production were expressed as percentages of the nominal hydrogen production of the electrolysis system ($\dot{V}_{H_2,nom,ES} = 2{,}216\ Nm^3/h$) and the nominal production of the methanation unit ($\dot{V}_{CH_4,nom} = 439\ Nm^3/h$), respectively.
The methane production and the utilization factors for the methanation unit and the storage tank for four seasonal typical days are given in Table 6.

Table 6. Methane production and utilization factors for the methanation unit and the hydrogen storage system for four seasonal typical days.

Day	Methane production (Nm^3)	Storage utilization factor (%)	Methanation unit utilization factor (%)	Surplus hydrogen (Nm^3)	Number of shutdowns (-)	Average load (%)
21-Dec	10,538	80	100	10,539	0	100
25-Sep	8,831	45	84	0	0	84
22-mar	6,952	43	66	76	1	66
21-Jun	5,014	26	48	0	1	47

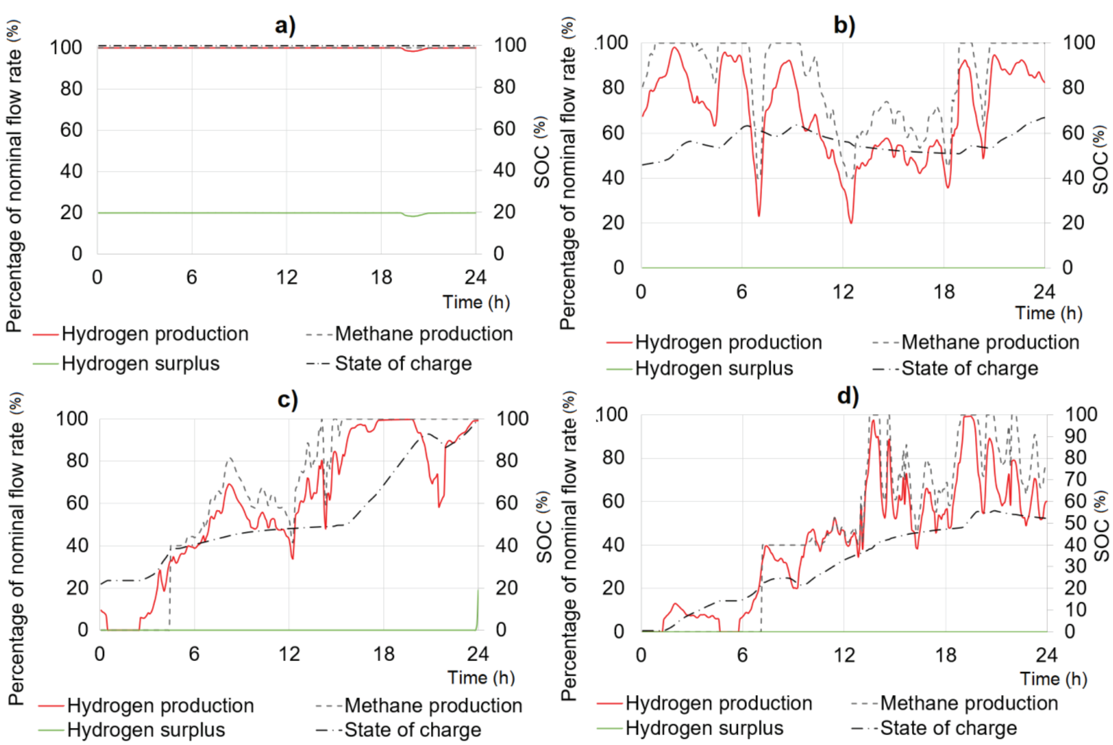

Figure 8. Performances of the power-to-gas system during four seasonal characteristic days: a) December 21; b) September 25; c) March 22; d) June 21.

Similarly to the electrolysis system, the results for the daily performances of the power-to-gas system showed a seasonal trend with a higher methane production in the windiest season, from which derives a most intensive use of the methanation unit.

During the summer, the SOC of the hydrogen storage tank was very low. This is due to the poorer wind conditions typical of this season, which makes the methanation unit work at relatively low load, even below the minimum limit value. In this condition, the methanation unit needs the support of the storage tank to be able to continue to work at his minimum load. When the storage tank is empty, it can no longer support the methanation unit. This could result in frequent shutdowns and a non-continuous operation ot the methanation unit.

On the other hand, on windy days the methanation unit worked at higher average loads, and, in some period, also exceeding the upper limit value. When the methanation unit is set to the nominal working point, and the storage tank SOC is 100%, a certain share of the produced hydrogen can't be converted in methane or stored. This condition mainly occurred during the winter, when the highest share of surplus hydrogen can be detected.

Table 7. Performances of the four electrolyzers at the end of a one-year simulation.

Electrolyzer	Efficiency (%)	Hydrogen production (Nm^3)	Utilization factor (%)	Number of shutdowns (-)	Water consumption (kg)	Stack temperature (°C)	Maximum duration of the off period (h)
1	61	1,597,493	33	537	1,283,546	66.5	62
2	61	1,598,248	33	548	1,284,152	66.3	62
3	61	1,595,090	33	541	1,281,615	66.2	64
4	61	1,597,295	33	546	1,283,387	66.6	56
Electrolysis system	-	6,388,126	-	-	5,132,700	-	-

In a second phase of this study an annual simulation on the power-to-gas system was carried on. Contrary to what results of the daily simulations suggested, the electrolyzers exhibited similar behavior and comparable performances in terms of all the observed variables on a yearly basis.In Table 8 and Table 9 the performance of the methanation unit and the hydrogen storage tank at the end of the one-year simulation are shown. Only the 2.4% of the produced hydrogen was in surplus. In addition, the management strategy effectively minimized the number of shutdowns.The use of an hydrogen storage, in fact, decreased the annual number of methanation-unit shutdowns from 1,006 within a year to only 301. Also, the imposed value of the SOC_{min} was essential to achieve this purpose. Indeed, without this constraint the annual number of methanation-unit shutdowns have been 5,950.

Nevertheless, the utilization factor of the subsystems at the end of the simulation was low, and this suggests that the sizing may not be optimal.

Table 8. Performances of the methanation unit at the end of a one-year simulation.

Methane production (Nm^3)	Surplus hydrogen (Nm^3)	Utilization factor (%)	Number of shutdowns (-)	Maximum duration of the OFF period (h)	Percentage of time in the ON state (%)	Percentage of time at the minimum load (%)	Percentage of time at the maximum load (%)
1,542,389	154,949	40	301	114	63	37	23

Overall, the management strategies performed both for the electrolysis system and for the methanation unit adequately managed to operate the power-to-fuel system minimizing the yearly surplus of hydrogen while ensuring a limited number of shutdowns that would otherwise increase the system degradation.

Table 9. Performances of the storage tank in a one-year simulation.

Percentage of time that SOC < SOC_{target} (%)	Utilization factor (%)
77	34

5. Summary and conclusions

In this study, a mathematical model of a power-to-methane system has been developed. An electrolysis system composed of four alkaline electrolyzers, each of which has a nominal power of 3 MW, is powered by a wind

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farm with a nominal power of 12 MW. A hydrogen storage tank was designed for two-and-a-half hours of independent operation of the methanation unit, which nominal production of the methane is 438 Nm^3/h.

A management strategy of the electrolysis system, hydrogen storage and methanation unit to limit fluctuating and discontinuous operation of both the electrolysis system and the methanation unit was adopted. The management strategy of the electrolysis system was conceived to averagely ensure similar operating conditions of the four electrolyzers. The management strategy proposed for the methanation unit and the hydrogen storage tank effectively kept the operation of the methanation unit within the imposed constraints, and, at the same time, ensured a limited number of shutdowns while minimizing the surplus of hydrogen.

The simulated results over four seasonal typical days revealed a more intensive use of the electrolyzers, the methanation unit and the storage tank in windy seasons; however, the on/off control systems developed for the stack temperature and the separators level kept both the variables within the established range.

In addition only the 2.4% of the hydrogen producing during the year was in surplus and the number of shutdowns of the methanation unit turned out to be drastically reduced then without any storage tank (from 1,006 to 301). Nevertheless, the utilization factor of the subsystems at the end of the simulation was low (40% for the methanation unit and 34% for the storage system), and this suggests to explore different sizes of the subsystems. A sensitivity analysis should be carried out to determine the optimal value of the parameters (SOC_{min} and SOC_{target}) impacting the management strategy and the optimal size of the subsystems.

In addition, the influence of different management strategies on the operation of the power-to-methane system could be investigated in future studies.

Nomenclature

RES renewable energy sources

SOC state of charge

LHV Lower heating value, J/kg

Symbols

C thermal capacity, J/K

$\bar{c}_p$ average specific heat at constant pressure, J/(kgK)

E voltage, V

I current intensity, A

$\dot{m}$ mass flow rate, kg/s

n number, -

p pressure, bar

P power, W

Q heat flow, W/s

T temperature, °C

$\dot{V}$ volumetric flow rate, m3/s

Greek symbol

η efficiency, %

Subscripts

act activation

amb ambient environment

cap capacity

cooled at the heat exchanger outlet

cons consumed at the stack

ele electrolyzer

ES electrolysis system

Far faraday

gen generated inside of the stack

in at the methanation unit inlet

loss losses

nom nominal value

ohm ohmic

rev reversible

sys system

stack within the stack

stackin at the stack inlet

target target value

tn thermoneutral

wat water

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