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Technical – economic comparative analysis of energy storage systems equipped with a hydrogen generation installation

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Abstract

This paper presents the results of a technical-economic comparative analysis of two energy storage systems integrated with a wind farm: Power-to-Gas-to-Gas Grid (Case A) and Power-to-Gas-to-Power (Case B). The aim of the technical analysiswhich was to determine the power characteristics of particular installations forming the storage systems and to assess the impact of the nominal power of hydrogen generators on basic technical indicators, which can influence investment decision-making. The economic analysis included factors such as the impact of grants, the sale price of the product and the purchase price of electricity on the NPVR (Net Present Value Ratio), depending on the nominal power of hydrogen generators. The break-even unit investment costs were determined for both cases with nominal power of the hydrogen generators of 5 MW depending on the purchase price of electricity and the sale price of the main product .

Keywords: Power-to-Gas, wind farm, hydrogen generator, economic analysis,

1. Introduction

Despite attempts to increase the share of renewable energy sources in Poland, 85% of electricity is still generated from conventional sources, based on hard coal and lignite. The greatest changes in the structure of electricity generation were observed in the case of wind and gas power. Wind power production grew by 23.4% in 2014 y-o-y. The main forms of renewable energy in Poland rely on wind turbines and photovoltaic panels. The popularity of these technologies is stimulated by support mechanisms, whose role is to direct the national economy to meet the obligations arising from the 20:20:20 package. The basic mechanism, based on so-called green certificates, is guaranteed priority access to the network. It has to be noted that this mechanism creates a situation in which the large, unadapted coal-fired units working in the largest centrally organized systems take on a regulatory role. The Polish energy system is characterized by a relatively low level of flexibility. In addition, the renewable energy sources are characterized by contrasting electricity generation potentials, which rarely correlate, especially in the case of wind energy, with end-user electricity demand [1–3]. The large variations in the power supplied by wind farms and the lack of flexible energy systems will lead to substantial fluctuations in the price of electricity on the national energy market [4]. A further increase in the installed power of wind farms could lead to a situation in which coal-fired units hit their regulatory limits and the power system becomes unstable. The negative situation caused by the increase in the share held by wind energy could be compensated by improving certain operational features of coal-fired power plants. This could come about through commissioning new units with supercritical parameters. It is also important to increase installed capacity in power plants based on gas turbines. However, analysts from power grid operators Polskie Sieci Elektroenergetyczne S.A. predict that the dynamics of startup of new wind farms will contribute to insecurity in the system by 2025. In addition to investment in modern power plant units, it is also very important to implement energy storage systems as a measure to avoid this scenario. Energy storage systems could draw power during off-peak demand periods and produce during peak periods [5, 6]. Energy storage is a basic method of reducing inequalities in production and consumption of electricity. The literature mentions a large number of methods, which can be divided into five categories: mechanical, electrical, chemical, electrochemical and thermal. In the framework of these methods technologies can be identified which, together with the already existing hydro-pumped storage in Poland, can provide the basis for building systems [7] with high potential for reducing adverse effects of changes in the productive potential

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of the country's largest wind farm. In addition to Compressed Air Energy Storage technologies (CAES) [8–12], Power-to-Gas has been a dynamically developing technology in recent years. This technology is based on the electrolysis of water. PEM [13–15], alkaline [16–18] and solid oxide [19–22] elecrolyzers are under development in many research institutions. Although it is now over 120 years since the alkaline electrolyzer emerged, and over 50 years since PEM and solid oxide electrolyzers were developed, technologies are now being developed for implementation in energy applications [23]. The main product of the electrolysis process is hydrogen. The hydrogen produced during energy valleys could be injected into the gas grid, used in the transport or chemical industry, e.g., in the methanation process or at the place of production, during the peak period of demand and can be re-converted into electrical energy.

This article presents the results of a comparative analysis of the two systems. The basis for the production of hydrogen in electrolysis is electricity, which in this study is taken from a particular wind farm during the night-time energy valley. The first system (Case A) is an energy storage system in which the hydrogen produced by electrolysis is sold to the natural gas transmission network. This type of solution is generally classified as a Power-to-Gas-to-Gas Grid system. In the second system (case B), the hydrogen, during off peak demand, is supplied to a fuel cell installation [24], and finally, the electricity generated in the fuel cells is sold to the electricity grid. The group of solutions which use fuel cells, gas turbines and piston engines to generate electricity is classified as a Power-to-Gas-to-Power system[25–28].

2. The characteristics of the analyzed systems

In this article two energy storage systems are analyzed: Power-to-Gas-to-Gas Grid (Case A) and Power-to-Gas-to-Power (Case B). The basic common elements of both systems are a hydrogen generator installation and a water treatment installation, ensuring appropriate quality water is supplied for the process of electrolysis. Both cases involve hydrogen tanks. In Case A the tanks perform the function of buffer tanks, accumulating hydrogen prior to it being fed into the natural gas grid, while in Case B the tanks' function is to collect and store the produced hydrogen until the fuel cell installation starts work. In Case A, in view of the need to maintain pressure at a level above that in the gas grid, a hydrogen compressor has been provided. In Case A the produced hydrogen is injected into the high pressure gas grid, and in Case B it is supplied to the fuel cell installation. Fig. 1 presents a schematic diagram of the analyzed systems.

It was assumed that the system is integrated with a wind farm with nominal power of 50 MW. In the analysis the size of the energy storage system was amended by changing the installed power of the hydrogen generators. It was assumed that the energy storage system operates in a daily cycle. The electrolysis installation is supplied by electricity produced by

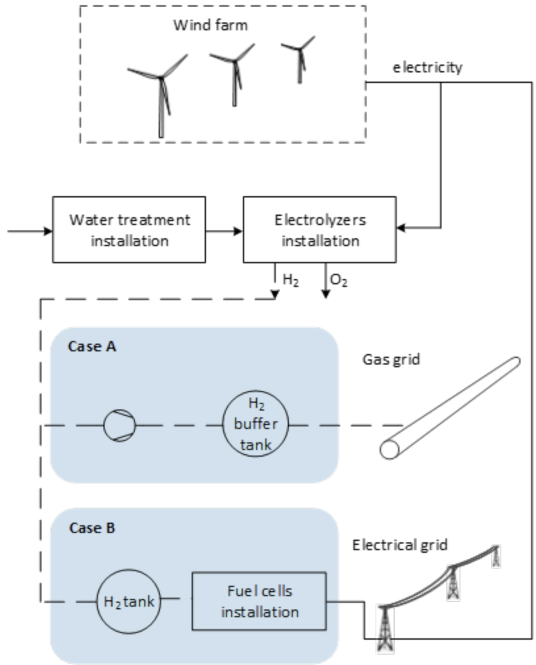

Figure 1: A schematic diagram of the two analyzed storage system cases

the wind farm during the period of reduced demand for electricity. Both analyzed systems consist of a determined quantity of hydrogen generators with the input power of each being 1 MW. It was decided that the efficiency of generators is 57%. This quantity is defined as:

$$\eta_{HG} = \frac{\dot{m}_{H_2} \cdot LHV}{N_{HG}} \tag{1}$$

where: $\dot{m}_{H2}$ – the mass flow of produced hydrogen, LHV – the lower heating value, N_{HG}– input power of hydrogen generator.

The input power of the electrolysis installation is limited by the installed power of hydrogen generators or current potential of the wind farm. In the period of reduced demand that part of the electricity which is not supplied to the electrolysis installation is directed to the electrical grid. Thus, if the wind farm is producing little power, the limited number of hydrogen generators work in the energy storage system. As the power of the wind farm increases or decreases more units can be turned on or off in cascade. The hydrogen generators used for the analysis produce hydrogen at a total pressure of 3.5 MPa.

In Case A the produced hydrogen is compressed from 3.5 to 15 MPa and directed to buffer tanks. The isentropic efficiency value of the compressor was assumed at 0.8. In both cases the battery of tanks includes devices with a capacity of 100 m^3 each, and their number depends on the installed power of the hydrogen generators and the maximum pressure in the tank. The maximum pressure in the tank for Case A was assumed at 8 MPa, while the minimum pressure ensuring unbroken operation of the system was set at 3 MPa. It was assumed that the injection of hydrogen into the natural gas network takes place 24 hours a day.

Under Case B the produced hydrogen is collected in tanks and after the charging period it is stored until the start of the contractual period of peak demand for electricity. The maximum storage pressure in the tanks is 1.8 MPa, while the minimum pressure of storage is 0.4 MPa. At the stage of discharge of the system, the hydrogen pressure supplying the fuel cell installation is reduced to 0.2 MPa. Together with the start of the period of peak demand of electricity, the fuel cell installation starts work. The installation consists of modules with a power of 100 kW each. It was assumed that the installation of fuel cells operates at constant power throughout the period of peak demand and enables full utilization of the accumulated hydrogen potential. The efficiency of the fuel cell modules was assumed at 48%. The efficiency of the module is defined by the equation:

$$\eta_{FC} = \frac{N_{FC}}{\dot{m}_{H_2} \cdot LHV} \tag{2}$$

where: $\dot{m}_{H2}$ – the supply mass flow of hydrogen, LHV – the lower heating value, N_{FC}– the power generated by the fuel cell installation.

The installed power of the fuel cells (the number of modules) is selected for the maximum amount of hydrogen which can be stored in tanks during the off-peak period.

It was assumed that the periods of reduced demand and peak demand occur every day of the year; the off-peak period runs from 22:00 to 06:00, and the peak demand period from 12:00 noon to 20:00.

The oxygen produced in the electrolysis installation is sold in both cases directly to a local recipient.

3. Determination of the characteristics for cooperation of the energy storage system with a wind farm

The decision variable in the analyses was the number of installed hydrogen generators and thus the nominal power of the electrolysis installation (from 1 to 15 MW). Calculations in both cases were made based on established schedules of cooperation between a wind farm and an energy storage system, as described in section 2 above and with the adopted characteristics of the wind farm power shown in Fig 2.

On this basis the power characteristics of the electrolysis installation were defined and in consequence the chemical energy flux of produced hydrogen, the power of the fuel cell installation and the chemical energy flux of injected hydrogen for the entire annual cycle. The power characteristics as a function of time for the analyzed year and for the selected week are shown in Fig. 3.

In the analyses the indicators for assessing the technical energy storage system were calculated: the degree of storage (γ) and the utilization rate of nominal power (δ_N). The basic indicator, determining the scale of connection of the energy storage system with the wind farm is the degree of storage, which is the ratio of the amount of electricity directed to storage to the annual total amount of electricity generated in the wind farm.

The selection of nominal power of the hydrogen generators installation is the main task when planning the investment in the analyzed energy storage system. On the one hand, a high power installation can store large amounts of energy produced in periods of unfavorable prices on the market. Unfortunately, the higher the nominal power installed generators, the longer the period of the year in which the generators work with lower input power than would result from their potential. In addition, given the relatively low capacity of the series of hydrogen generators available on the market, the installation of higher capacities requires more devices to be equipped. Accordingly, the economies of scale of the system do not generally result in a reduction of the per-unit investment cost (e.g., per kW of installed power). A similar situation exists in with the hydrogen tanks and the modules of fuel cells available on the market. An indicator which can be used to assess the validity of the selection of the power of hydrogen installation cooperating with a given wind farm is the utilization rate of nominal power, defined as the ratio of average power of the hydrogen generator installation achieved in the annual cycle to the nominal power of the hydrogen generator installation. The values of the degree of storage and the utilization rate of nominal power with changed nominal power of the electrolysis installation is shown in Fig. 4.

The comparison of these two indicators, shown in Fig 4. indicates contrary effects of increasing the power of hydrogen generators installed within the energy storage system. On the one hand, an increase in power allows a beneficial growth in the degree of energy storage, but on the other hand, there is an adverse effect on the utilization rate of the nominal power of the installation.

4. Economic analysis

Power-to-Gas technologies are characterized by relatively low efficiencies. Nevertheless, the main advantages of these technologies are the small requirements for built-up space and lack of requirements regarding site conditions (suitable height differences or geological conditions are required, e.g., in storage systems such as CAES or pumped-storage power plants). Recently there has been increasing interest in energy storage technologies. This is a very interesting area of study for scientists and has attracted interest from enterprises in the power and gas sectors.

This chapter reports on a comparative economic analysis of two energy storage systems. As in the technical analysis, the economic analysis was carried out on installations of variable nominal power of electrolysis. In the economic analyses the NPVR (Net Present Value Ratio) was used, calculated using the formula:

$$NPVR = \frac{\sum_{t=0}^{t=N} \frac{[(-J+D)-K+S-T+A+L]}{(1+r)^t}}{J_0} \tag{3}$$

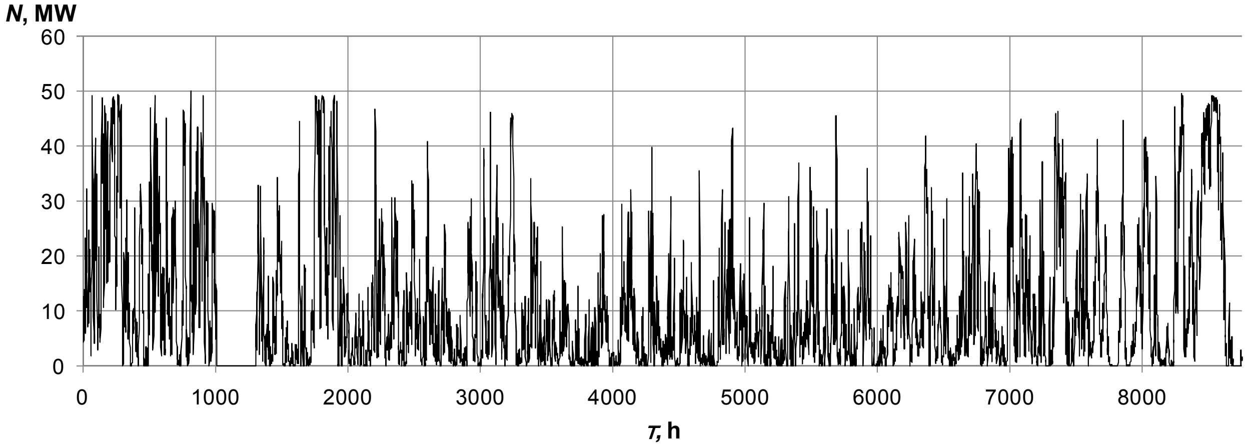

Figure 2: The power characteristics of the analyzed wind farm during the year

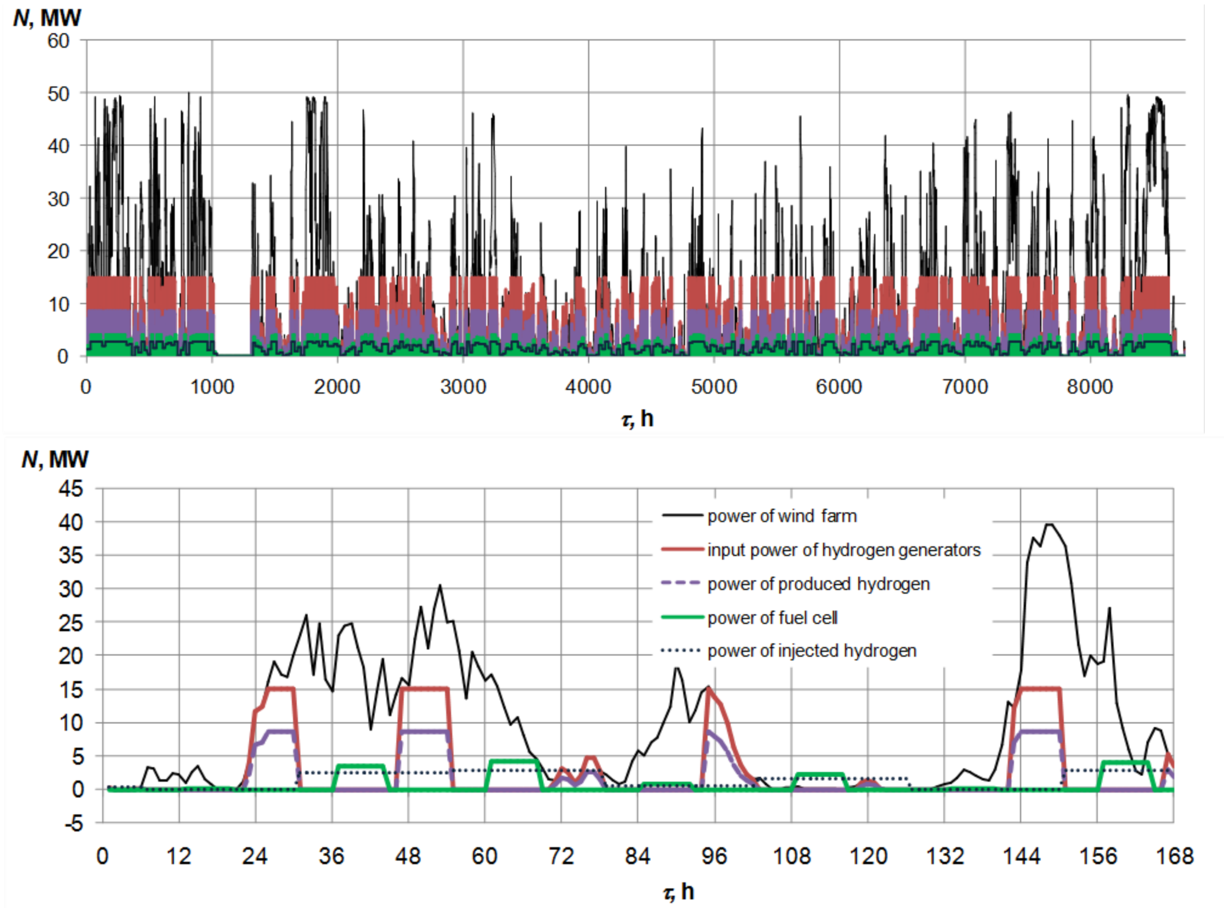

Figure 3: The characteristics of the power of the wind farm, hydrogen generator installation, produced hydrogen, fuel cell installation and in the injected hydrogen as a function of time for the whole analyzed year and for the selected week of that year

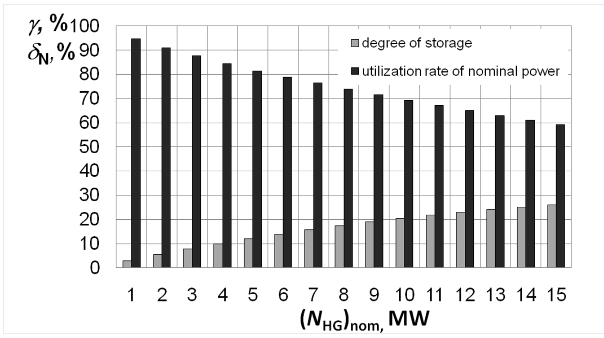

Figure 4: The degree of storage and the utilization rate of nominal power as a function of nominal power of the hydrogen generators included in energy system storage

where: J – investment cost, J_0 – present investment cost, D – grants, K – operating costs, S – revenue from sale of products, T – taxes (on income and property), A – depreciation, L – liquidation value, r – discount rate, t – another year of analysis, from $t = 0$ (the start of construction) to $t = N$ (last year of operation)

The investment J has been calculated as the sum of the cost of purchase and installation of individual machines and devices (K_i) included in the cases of the system:

$$J = \sum_i K_i \tag{4}$$

The common elements of both cases are hydrogen generators and tanks.

The purchase cost of hydrogen generators can be expressed as the product of nominal power of the battery of generators $(N_{HG})_{nom}$, and the unit cost of the purchase referred to the installed power of hydrogen generators (k_{HG}):

$$K_{HG} = (N_{HG})_{nom} \cdot k_{HG} \tag{5}$$

The purchase cost of hydrogen tanks is the product of number of tanks (l) and the unit cost of the purchase of single tank with defined volume (k_{TANK}):

$$K_{TANKS} = l \cdot k_{TANK} \tag{6}$$

In Case A the cost of buying a hydrogen compressor should also be taken into account . This cost is the product of mass flow of compressed hydrogen ($\dot{m}_{H2}$) and unit cost related to mass flow of hydrogen (k_{COMP}):

$$K_{COMP} = \dot{m}_{H2} \cdot k_{COMP} \tag{7}$$

In Case B the purchase cost of the fuel cell modules was taken into account, which is the product of the nominal power of installed modules and unit cost of purchase per kW nominal power (k_{FC}):

$$K_{FC} = (N_{FC})_{nom} \cdot k_{FC} \tag{8}$$

See Fig. 5 for a comparison of distribution of the investment cost on particular machines and devices for the two analyzed cases, at the nominal power of the electrolysis installation of 5 MW .

The construction time was assumed at 2 years, at which time the costs are distributed: 30% in the first and 70% in the second year. The lifespan of the system was assumed at

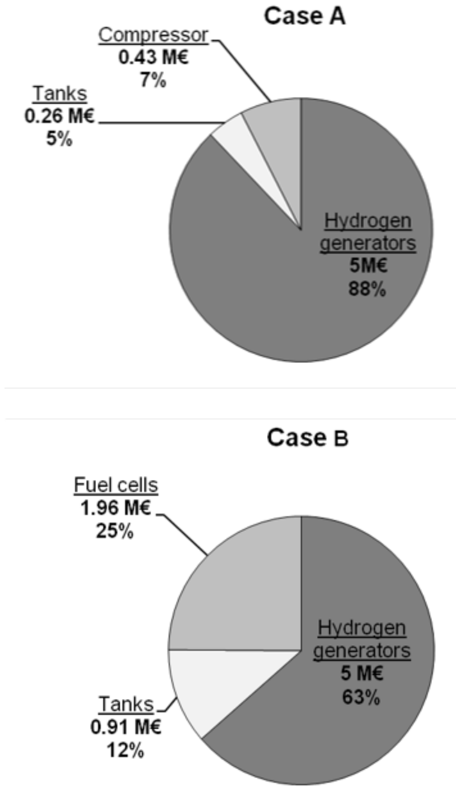

Figure 5: A comparison of distribution of the investment cost in the two cases at $(N_{HG})_{nom}$ = 5 MW

20 years. The following maintenance costs were assumed: 0.3% of the investment costs for the first 4 years of operation, 0.6% for years 5-8 , 0.9% during years 9-12, 1.2% for years 13-16 and 1.5% for years 17-20. Property tax was assumed at 2% of the capital expenditures incurred on the property in the period in which the property is subject to depreciation, and 2% of the market value of the property on 1 January of the year in the last year of depreciation. The liquidation value of the installation was assumed at 20% of the investment. The other main assumptions for the economic analysis are presented in Table. 1.

Due to the delay between publication of the article regarding purchase cost of the compressor and the presented studies, the calculations have been revised on the basis of the Chemical Engineering Plant Cost Index (CEPCI). Moreover, it was assumed that the investment is being realized from internally generated funds and three variants of grant - 0%, 50% and 100%. In addition, the two purchase prices of the electricity in the off-peak period (${C_{el}}^{off-peak}$) were analyzed: 0 €/MWh, and the average price between 22:00 and 06:00 calculated on the basis of data from Towarowa Giełda Energii S.A of 2015, equal to 28.8 €/MWh. The nominal sale price of hydrogen (C_{H2}) in Case A, was assumed at 8 €/GJ. The nominal price of electricity sales (C_{el}^{peak}) for Case B, was assumed at 41.42 €/MWh and it is the average price of electricity between 12:00 and 20:00 calculated on the basis of data from Towarowa Giełda Energii S.A for 2015. The results

Table 1: The main assumptions for the economic analysis [25, 29, 30]

	Quantity	Value
1.	k_{HG}, €/kW	1000
2.	k_{TANK}, €/pcs	130 000
3.	k_{COMP}, €/kg/h	5000
4.	k_{FC}, €/kW	1400
5.	Operating cost of electrolysis installation, €/GJH_2	3.5
6.	Operating cost of fuel cell installation, €/MWh	1.5
7.	Sale price of oxygen, €/$m^3{}_n$	0.06
8.	Price of water, €/m^3	1.1
9.	Nominal sales price of hydrogen (Case A), C_{H2}, €/GJ_{H2}	8
10.	Nominal sale price of electricity (Case B), $C_{el}{}^{peak}$, €/MWh	41,42
11.	Discount rate, %	5
12.	Average depreciation rate, %	6.7

of a comparative analysis of NPVR for both cases as a function of nominal power hydrogen generators for three variants of the grant and for three levels of sale prices of products in the case of $C_{el}^{off-peak} = 0$ €/MWh are presented in Fig. 6. Similar results of analysis for $C_{el}^{off-peak} = 28.8$ €/MWh are presented in Fig. 7.

The results show that Case A has an advantage over Case B. In the case of nominal sale price of products at 0 €/MWh Case B does not generate a positive financial result whereas Case A shows a profit with 100% subsidies and takes on an extreme for the 8 MW installation. With an increase in sale prices of the product, the values of $NPVR$ for both variants increase. In Case A, with financing of 100%, the investment profitability increases with increasing power of the electrolysis installation. In the case of a high sale price of hydrogen of 24 €/GJ, with financing of 50%, the extreme occurs at the power of 10 MW and in the absence of funding at the power of 2 MW. In Case B the first return on investment is achieved at the sale price of electricity of 82.84 €/MWh and with financing of 100%. In this case, the maximum value of $NPVR$ occurs at $(N_{HG})_{nom} = 6$ MW.

In a situation when the cost of electricity is 28.8 €/MWh only Case A with a high sale price of hydrogen $C_{H2} = 24$ €/GJ and grants 100% shows the profitability.

The economic efficiency of the investment, as presented in the economic analyses of the storage energy systems, will depend to a large extent on the off-peak prices of electricity and on the market prices of the commercial products. The results clearly show that the investment in the analyzed energy storage systems cannot exist without the appropriate support mechanisms. The support mechanisms could take the form of grants or certificates, which are well known on the Polish market. The certificates could be granted as an equivalent to the amount of energy storage in the balance period. In addition, the investment cost seems a key factor determining the economic efficiency. In this aspect, the high prices of commercially available hydrogen generators and of the fuel cell units are exceptionally unfavourable. However, the prices of these components have been falling in recent years. Hopefully, this trend will continue in future. The analyses presented in this paper were carried out for specific values of unit prices. The next section presents the results of the economic analysis, aimed at determining the break-even point [31, 32] for the analyzed cases. In this regard, unit investment cost was determined from a condition:

$$NPV = 0 \tag{9}$$

In both analyzed cases the unit investment cost indicator was determined as a ratio of total investment cost to installed power of hydrogen generators:

$$i = \frac{J}{(N_{HG})_{nom}} \tag{10}$$

In determining the investment cost the relationship (4) - (8) was used. The unit investment cost indicator in Case A, for the entire test range of the installed power of the hydrogen generators, ranged from 1132 to 1215 €/kW, and for Case B in the range of 1557 to 1680 €/kW.

The break-even unit investment cost, referred to installed power of the hydrogen generator installation in both cases, is determined by the general formula:

$$i^{b-e} = \frac{\sum_{t=0}^{t=N} \frac{[-D+K-S+T-A-L]}{(1+r)^t}}{\sum_{t=0}^{t=N} \frac{(N_{HG})_{nom}}{(1+r)^t}} \tag{11}$$

The analyses aimed at determining the break-even unit investment cost index were carried out only for a system with installed power of hydrogen generators of 5 MW. The grants were assumed at 50%. The values of the indicator were investigated with variable off-peak price of electricity and the prices of products, i.e., the price of hydrogen injected to the gas grid in Case A, and the price of electricity at peak demand in Case B. The results of analyses for Case A are shown in Fig. 8. In addition, the range of changes in the price of electricity in off-peak periods in Poland in 2015 was marked. The average price of electricity, i.e., 28.8 €/MWh with sale price of hydrogen of 8 €/GJ was marked with a dot. The determined unit investment cost (shown in a broken line) of the analyzed energy storage system, referred to nominal power of hydrogen generators, was 1137.5 €/kW.

The results of analyses for Case B are shown in Fig. 9 The range of maximum and minimum of prices of electricity in peak and off-peak periods in Poland in 2015 was marked in gray, while the average values of those prices were marked with a dot. The estimated unit investment cost (shown in a broken line) of the analyzed energy storage system in Case B, referred to nominal power of hydrogen generators, was 1574 €/kW.

The results of analyses show that Case A has a clear advantage over Case B. In the case of the purchase price of electricity at 0 €/MWh with nominal values of the prices of products, the break-even unit investment cost for Case A was

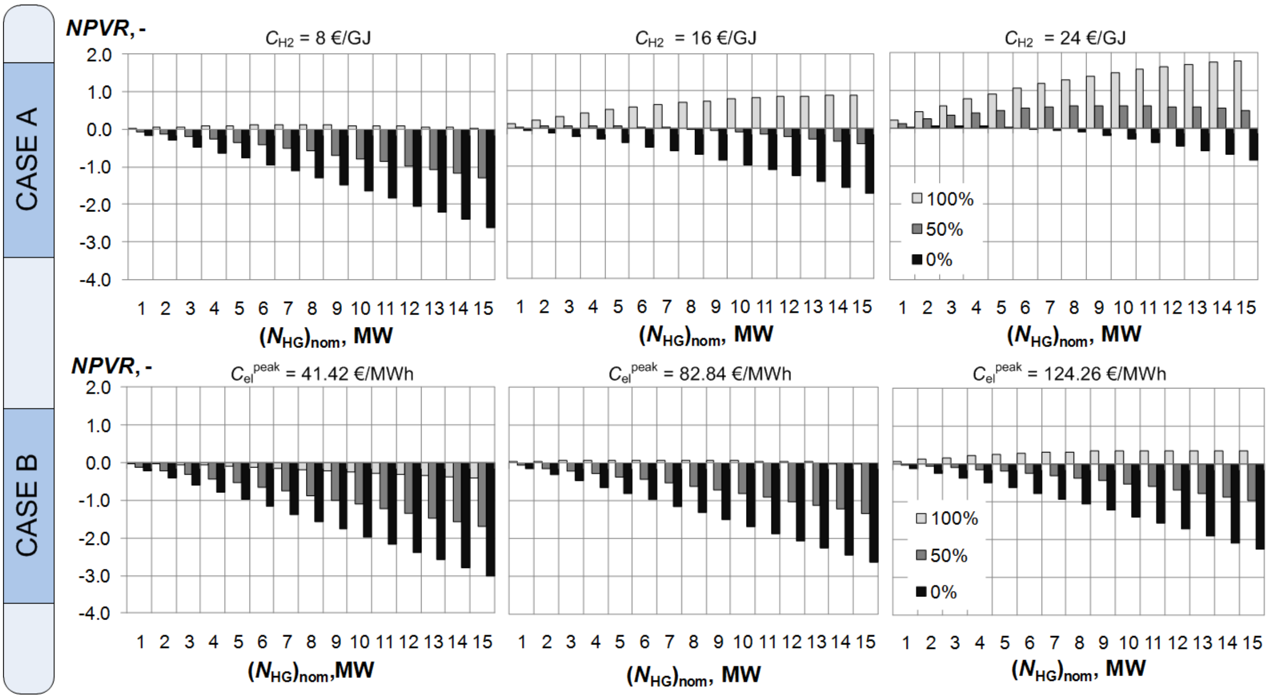

Figure 6: The values of NPVR for both cases depending on nominal power of hydrogen generators, the sale price of main product and the grant at $C_{el}^{off-peak} = 0$ €/MWh

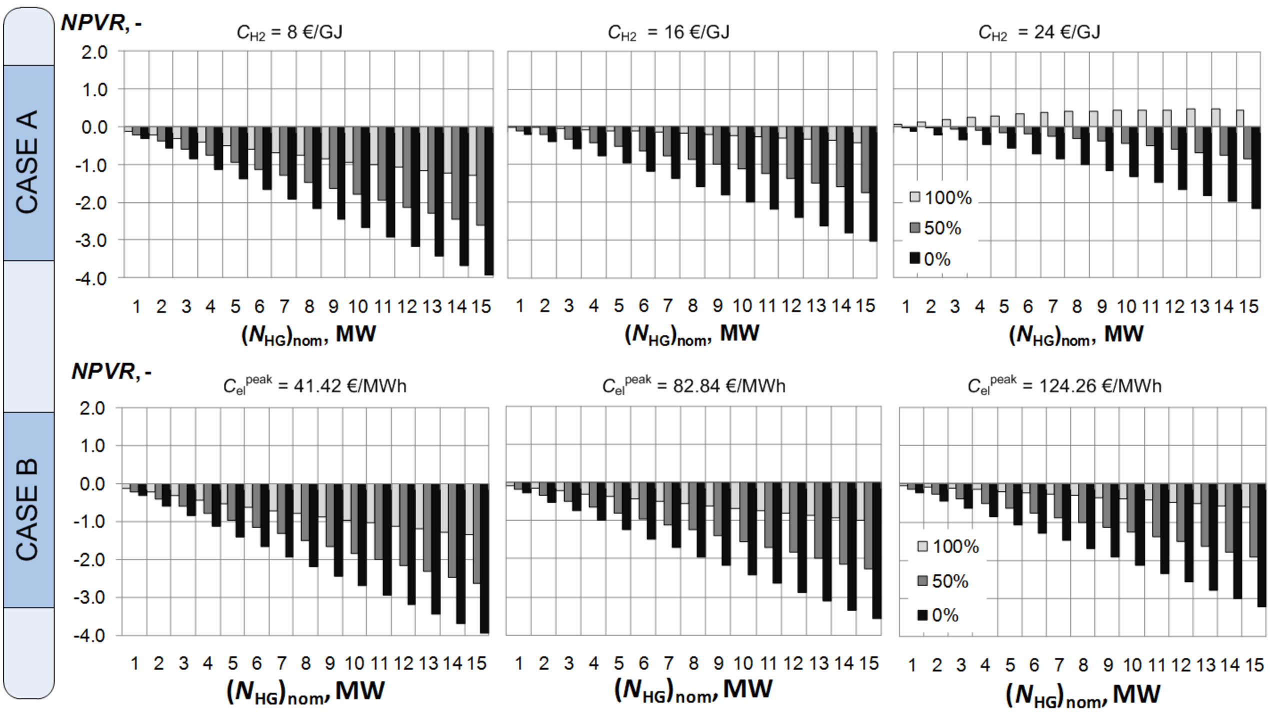

Figure 7: The values of $NPVR$ for both cases depending on nominal power of hydrogen generators, the sale price of main product and the grant at $C_{el}^{off-peak} = 28.8$ €/MWh

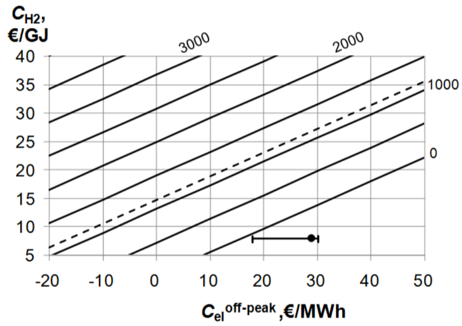

Figure 8: The break-even unit investment cost for Case A, depending on the price of electricity in the off-peak period and the sale price of hydrogen for the system with nominal power of hydrogen generators of 5 MW with financing of 50%

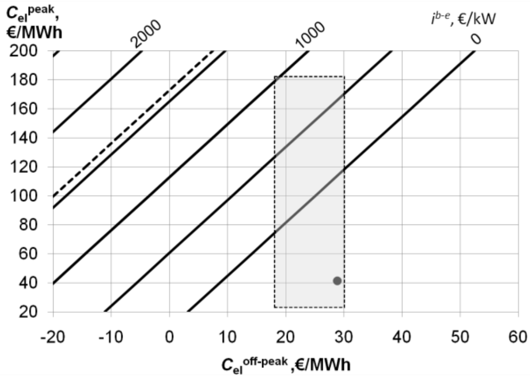

Figure 9: The break-even unit investment cost for Case B, depending on the price of electricity in the off-peak period and the sale price of electricity in the peak period for the system with nominal power of hydrogen generators of 5 MW with financing of 50%

about 568 €/kW, and for Case B about 317 €/kW. It means that to achieve break-even the investment cost would have to be reduced by 50% in Case A and by almost 80% in Case B. As shown in Fig. 5 the level of investment in both systems depends largely on the cost of purchase of hydrogen generators and additionally in Case B on the cost of purchase of the fuel cell installation. As indicated in [33] in the coming years we can expect a significant decrease in the price of these devices. For the given assumptions, Case B enjoys lower economic efficiency. However, in the coming years systems with fuel cells can benefit from an expected increase in the difference between the price of electricity in peak and off-peak demand periods. This is the expected result of a growth in power installed in unstable energy systems, primarily wind farms. In Case B the increase in hydrogen price may be a result of growth in the hydrogen automotive market. In this case, the hydrogen produced in the storage system may be distributed to fuel stations, instead of to the natural gas grid.

5. Summary

Energy storage systems based on electrolysis are currently characterized by low efficiencies of storage and high investment costs. These factors mean the technology has low application potential. Technologies such as Compressed Air Energy Storage and Pumped Hydro Storage are characterized by higher application potential, as is shown by their widespread use. It seems that technology based on electrolysis, too, has great potential for development. The one great advantage of this technology is that it has no special requirements regarding location.

The need to develop energy storage systems is highly dependent on the development of renewable energy technologies and in turn the direction of development of power plants based on fossil fuels. The importance of energy storage systems will grow hand-in-hand with the evolution of wind energy. The large potential of coal energy will favor these systems in Poland. This is due to the lower flexibility of coal-fired units, for example relative to the flexibility of natural gas-fired units. An unfavorable energy mix in terms of the system's ability to adjust electricity production to current demand will result in an increase in the difference between the average price of electricity during off-peak demand periods and electricity prices during peak demand periods. The results of the analysis showed that regardless of the system studied (Power-to-Gas-to-Gas Grid and Power-to-Gas-to-Power), implementation of storage systems in Poland cannot take place without adequate support mechanisms. The expected fall in prices of hydrogen generators and fuel cells over time will benefit the economic efficiency of investments in this field.

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