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A Pragmatic Approach to the Economic Assessment of Green Synthetic Methane Power in the Baltics

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Abstract: The synthesis of methane from hydrogen and carbon dioxide creates an energy resource that is suitable for long-term storage. Once this process is powered by renewable electricity, it produces a clean fuel for producing electricity and heat and supports large-scale renewable energy deployment, energy transition and climate change mitigation. This paper proposes a pragmatic approach to assessing the economic potential of synthetic methane-based power. Today, natural gas plays an important role in the Baltic region due to the existing infrastructure, which includes a transmission and distribution pipeline network, gas power plants and a large underground storage reservoir. Replacing natural gas with synthetic methane would fulfil carbon emission reduction ambitions. In this paper, we simulate electricity producers' actions at market conditions and consider the generation portfolio in the Baltics and the interconnections with Scandinavia and Poland operating in the NORDPOOL electricity market. As a result of these calculations, we obtain the volume of the synthetic gas, the production costs, the volume of gas storage, the installed capacity of the gas power plant, and the investments required to ensure energy transition and system adequacy. These results are essential for the informed decisions made by policymakers, investors and system operators.

Keywords: energy storage; electricity market; hydrogen and methane production; renewables; climate change mitigation

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1. Introduction

The climate crisis calls for immediate action for introducing mitigation measures and diminishing the amount of greenhouse gas emissions into the atmosphere. The European Union's (EU) objective is to reduce greenhouse gas emissions by 80–95 percent by 2050, compared to 1990 levels [1]. That requires severe restriction or full abandonment of fossil fuels. A massive development of renewable energy resources (RES) is a natural consequence of this strategy. Nevertheless, a further proliferation of renewable energy resources necessitates effort and investments in ensuring system adequacy, namely, available energy generation at all times. Flexible generation and controllable load properties are central to supporting further renewable deployment around the world. However, this potential is limited. The intermittent generation and varying, poorly controllable consumption create a need for storage. The required energy storage capacity would be in the range of tens of terawatt-hours. This challenge is even more pronounced in the case of limited power capacity of interconnecting lines [2].

While the world practice combines multiple strategies, measures and implementations, experts unanimously agree on green hydrogen being an inevitable part of the future solution. The European Union has already set a goal of 40 gigawatts of electrolyser capacity to be deployed by 2030. It should supply up to 32 million tonnes of hydrogen per year.

At the same time, it should be noted that hydrogen as a highly reactive element poses challenges such as hydrodynamic, geochemical, physiochemical, bio-chemical or microbial impacts on storage. In addition, technologies for energy conversion from hydrogen are under development: hydrogen burns at higher temperatures and the turbines capable of handling it are in the testing stage [3]. The problems of hydrogen storage and energy conversion can be avoided by turning hydrogen into synthetic methane.

Methanation transforms hydrogen and carbon dioxide (CO_2) into synthetic methane (CH4), which is also the main component of natural gas. Here, CO_2 is consumed in the process, which supports carbon neutrality. A vast amount of CO_2 can be collected from the atmosphere, using direct carbon capture (CC) technology [4]. CC technology exists; this is a technically feasible path forward.

Methane can be used as a fuel to generate heat and electricity in power plants or at home. Synthetic methane can be directly used at existing gas-fired power plants, at existing district heating plants and in numerous households. Using synthetic methane can alleviate the need for investments into infrastructure in the order of billions of euros, which would be necessary for hydrogen use.

Synthetic methane produced from green hydrogen and captured carbon dioxide would meet sustainability requirements. Methane placed in underground gas reservoirs that reach billions of cubic meters in volume can provide the necessary amount of storage for an all-renewable system. Such storage would enable renewable proliferation, potentially shifting energy even seasonally, for example, from high solar power seasons to high demand seasons.

This scenario, which entails a weakly interconnected system, high renewable proliferation and availability of gas infrastructure, is exactly what is expected to happen in the energy systems of the Baltic States [5,6], where a large amount of construction of solar and wind power plants is being carried out and, in the coming years, the decommissioning of conventional power plants is planned.

This article investigates the economic viability of a fully renewable system with energy storage based on synthetic methane. Aiming at a fully renewable energy-independent power system in the Baltics, we require synthetic methane plants to fully cover inflexible load, to absorb excessive renewable production and to be price capped. Thus, electrolysers are to produce hydrogen, hydrogen and captured carbon dioxide [7] are to be used to produce synthetic methane, and methane is to be stored and used for electricity generation in our study. Such an energy conversion and storage system will consume energy and generate hydrogen as well as methane during the low-price periods and electricity during the high-price periods.

What are the quantitative economic implications of such a scenario? To answer that question, firstly, we develop a model of the power system, which includes sub-models of energy storage units. Secondly, we model the electricity market and the behaviour of the players. The result of the calculations consists of the volume and costs of the produced gas, the capacity of a gas power plant required to ensure system adequacy, the necessary number of investments and the resulting energy costs. This investigation requires the development of mathematical models and the implementation of optimisation algorithms. These models are generic enough to be applied in similar studies for other regions and will be described in this paper in detail. The results should be of particular interest to energy policymakers, investors and implementation bodies.

1.1. The Innovative Contribution

This paper proposes an innovative framework and a methodology for assessing the use of hydrogen and synthetic methane in the conditions of an electricity market, while considering the physics of the energy system.

The main objectives and contributions of this paper are as follows:

- To analyse whether RES being supported by the production and storage of hydrogen and synthetic methane can ensure system adequacy and energy supply to the consumers in the Baltic States; i.e., whether it is possible to fulfil the commitments on the reduction in greenhouse gas emissions into the atmosphere with that strategy.

- To propose a methodology and a modelling framework to define the required installed capacity of the renewable power plants, electrolysers, gas power plants using synthetic methane as well as the capacity of the gas reservoir in a system. The methodology contains a complex optimisation problem, for the solution of which acceptable simplifications were introduced, which made it possible to greatly reduce the amount of input data and use linear programming, and ensured the synthesis of an efficient algorithm.
- To calculate revenues and profitability during a year of operation. To evaluate the rate of return on the investments and the electricity market prices in 2050.

For this purpose, first, we created hourly forecasts of the demand and electricity generation based on historical weather data, such as water inflow into rivers, solar and wind generation, statistical data on electricity consumption, etc. Then, we developed simplified models of the electricity market, the transmission grid and the power plants and their operation in the market. We emulated both the market paradigm and the actions of the players and formulated the optimisation problem. The formulation is suitable for the application of linear programming solvers. Finally, we estimated the costs of the system adequacy, the return on assets and other economic criteria. To quantify the impact of uncertainty, a few scenarios were analysed by means of the software tools developed.

To the best knowledge of the authors, this kind of approach and case have not been addressed in the literature.

1.2. The Organisation of the Paper

The rest of the article is organised as follows: Section 2 provides a literature review; Section 3 describes specifics and the conditions of a future interconnected energy system in the Baltic States and formulates the problem; Section 4 describes the modelling framework for a case of maximising the players' benefits and the socioeconomic welfare [8]; and Section 6 focuses on the calculations the investments required, the capacities of the plants and their impact on zonal electricity market prices.

2. Literature Review

2.1. Technologies

Prina M.G. et al. [9] consider and underline that the increase in the power of renewables is not enough to decarbonise the power system. Storage systems, particularly power-to-gas storage systems, are a must.

Hannes Lange et al. [10] and Lin, Y et al. [11] investigate the flexibility of water electrolysis and energy storage systems. They show that current electrolysers are already able to manage load changes between 10 and 90% per second. Thus, in combination with suitable control strategies, intermittent power output of renewable generation can be partly balanced by a flexible green hydrogen production load.

Many research papers (a comprehensive review is provided in [12]) discuss different paths to renewable hydrogen production and storage. The authors underline that hydrogen can be generated and stored by means of various technologies. Green hydrogen production assumes electrolysis of the water supplied by renewable energy. Production by means of the alkaline electrolysis method provides 61–82% energy efficiency and is ready for industrial applications [12] with the technology readiness level at 9–10. However, hydrogen storage in gaseous or liquid form in tanks is neither cost-effective nor safe for large-scale long-term use. Therefore, there is a need to design a cost-effective, reliable and safe solution.

Davood Zivar et al. [13] note that underground storage is an established way to store a significant volume of energy once it is converted to hydrogen. We argue that the use of hydrogen presents a number of technological challenges and requires significant adjustments to the infrastructure.

The round-trip efficiency of power-to-gas storage was well below 50%, with the hydrogen path being able to reach a maximum efficiency of ~43%, and that of methane, a maximum efficiency of ~39% by using combined-cycle power plants. If methane is to be used by combined heat and power plants, which produce both electricity and heat, the efficiency can be above 60%, yet that is still below the efficiency of a pumped hydro or battery storage [14–16]. At the same time, the potential of both pumped hydro and battery storage is limited by the availability of natural resources. On the other hand, there is a potential to increase the efficiency of power-to-gas storage. A 2018 study found that using pressurised reversible solid oxide cells and a similar methodology may lead to round-trip efficiencies (power-to-power) of up to 80% [14,15,17,18].

On the path to a sustainable energy system, there is another challenge to be solved, namely, the capture and concentration of carbon dioxide. Hao Zhang [4] notes that the large-scale capture of CO_2 from industrial activities has been successfully running in several countries. For example, Tokyo Gas is beginning a synthetic methane trial by using green hydrogen [19]. Yuka concludes that the biggest challenge lies in reducing costs, because the methanation cost in around 2030 would still be much higher than the prices of liquefied natural gas (LNG).

Analysis of technologies brings us to the conclusion that the readiness of the Hydrogen Extraction, Conversion to Methane and back to Electricity (HECME) technology (Figure 1) is close to final industrial readiness for the applications of energy storage and electricity generation.

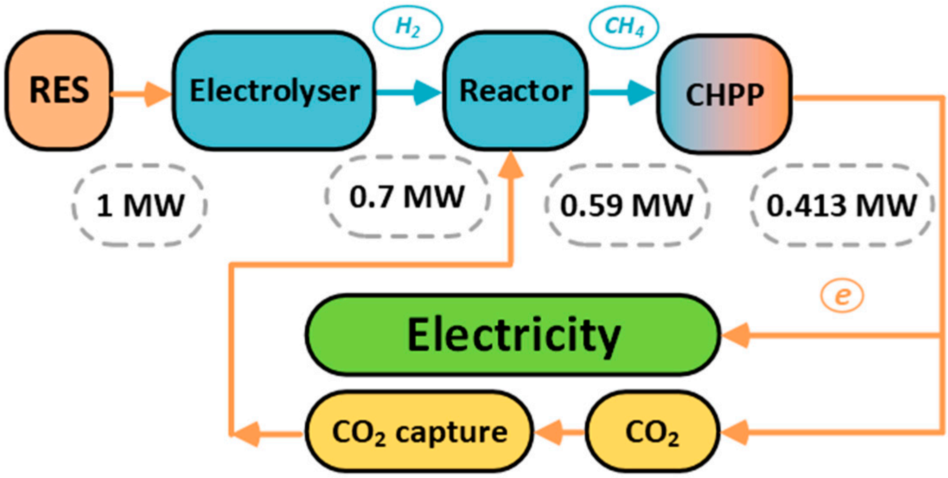

Figure 1. Energy conversion and efficiency in a hydrogen energy conversion to methane energy power plant (HECME PP).

2.2. Economic Performance

The cost analysis of hydrogen and synthetic methane technologies has been extensively covered in the literature [20–24].

Guerra, Omar et al. [21] estimate the cost-effectiveness of different types of storage technologies, including pumped hydro, compressed air and seasonal hydrogen storage. The avoided-costs approach is used without considering market rules.

Simon Morgenthaler et al. [22] estimate electrolyser investment costs to be between 650 EUR/kW and 1000 EUR/kW (2020). The levelised cost of synthetic natural gas is predicted to be between 0.24 and 0.30 EUR/kWh.

Al-Qahtani et al. [23] compare the most common hydrogen generation approaches from an economic aspect, namely, steam methane reforming, gasification of coal or biomass, and methane pyrolysis with or without carbon capture vs. storage technology. Carbon capture, utilisation and storage (CCUS) applications do not all have the same cost. Looking specifically at carbon capture, the cost can vary greatly by CO_2 source, from 15–25 USD/t CO_2 for industrial processes producing "pure" or highly concentrated CO_2 streams (such as ethanol production or natural gas processing) to 40–120 USD/t CO_2 for processes with "diluted" gas streams, such as cement production and power generation [24]. The paper [25] presents a rich literature survey and a detailed assessment of the levelised cost of hydrogen as a function of the prices of electricity consumed. Unfortunately, these data cannot be used directly, since the price in electricity markets varies and is influenced by a number of factors.

Paul E. Dodds and Stéphanie Demoullin [26] investigate the feasibility of the UK gas system to transport hydrogen. The authors conclude that hydrogen can be transported safely in low-pressure pipes but the capacity of the pipeline has decreased in this case. New hydrogen meters and sensors would have to be fitted to every building and appliances would have to be adapted. Real-world data have been used to estimate the investments. It must be emphasised that, unlike the use of hydrogen, utilisation of synthetic methane does not lead to significant modifications of existing gas infrastructure.

Zhang J. et al. [27] explore the benefits of long-term energy storage in 2050 in the Western Interconnection power system with an 85% renewable proliferation level. A two-stage optimisation model is applied, where the first stage applies a price-taker model to optimise the generators' operation profile, and the second stage uses a production cost model to simulate the unit commitment (UC) problem for an entire year. The authors conclude that solving the UC problem in a computationally efficient manner for a large power system across timescales ranging from one year to one hour poses challenges. To overcome these challenges, the problem formulation assumes that there are no links with other energy systems and that the capacities of the generators and the storage capacities are known beforehand.

Michael Mazengarb [28] predicts a sharp drop in the costs of hydrogen technology. The prices may fall from 600 EUR/kW in 2030 to 120 EUR/kW in 2050.

Kharel, S. et al. [29] discuss studies that use real-world data for the application of hydrogen as a large-scale energy storage solution in multiple renewable energy input scenarios. The case study includes a feasibility analysis of an energy storage system that is dimensioned to support four days of autonomous operation. The authors observe that a limited number of studies focus on the applications of hydrogen as an energy storage solution in large-scale long-term energy scenarios.

A review of the literature on the economic feasibility of hydrogen and synthetic methane power plants shows that the profitability of HECME technologies depends on many factors, including the particularly strong influence of electricity market prices [25,27], whose impact on the efficiency of long-term energy storage systems is computationally complex and has not been sufficiently studied.

3. Problem Definition and the Modelling Framework

3.1. The Nord Pool Market

The Baltic States, Poland, Sweden and Finland are part of the Nord Pool market. Nord Pool is Europe's leading power market and offers trading and associated services in both day-ahead and intraday markets across 16 European countries and more than 350 participants [30,31]. We recognise that the producers and the consumers of the interconnected power systems shown in Figure 2 participate in the day-ahead electricity market [32].

Acceptance of bids in the Nord Pool market is based on the market price formation and is managed by the Electricity Market Operator (EMO). The EMO and all market players contribute to a fair balance between the interests of power consumers and producers. That is, all players, namely, power generators and consumers, have to submit to the EMO their bids for selling and buying electricity [33,34]. The market bids indicate what amount the seller or the buyer is willing to sell or buy, respectively, and at what price. The bids to the market need to be prepared by using the results of generator operation optimisation and considering the marginal costs of production (MCP) as well as the generation resource availability forecasts [35].

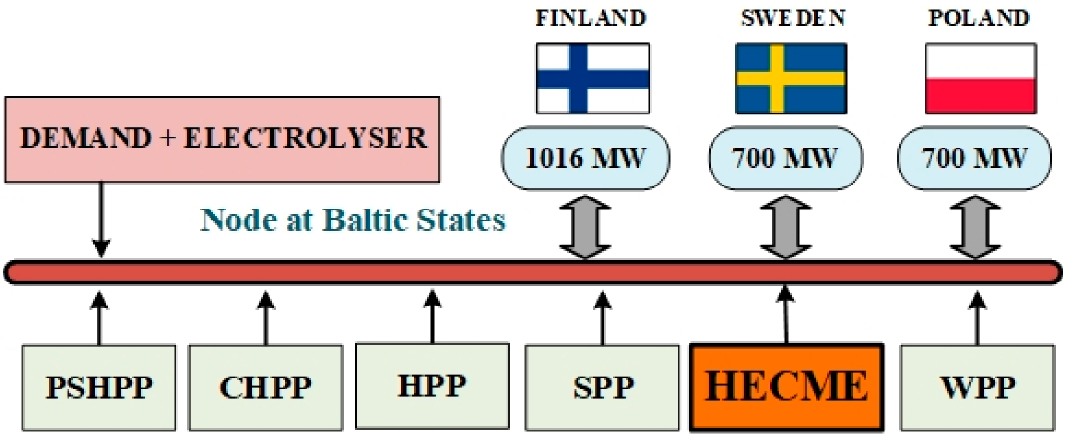

Figure 2. The portfolio of the power plants and the interconnections: a pumped storage hydropower plant (PSHPP), a hydropower plant (HPP), small HPPs (sHPP), a solar power plant (SPP), a wind power plant (WPP), a power plant based on hydrogen production, conversion to methane and back to electricity (HECME), a combined heat and power plant (CHPP), electricity loads (Demand) and interconnecting DC and AC power lines between the Baltic States and Finland, Poland, Sweden.

EMOs aggregate all the bids and create a single cumulative picture for generation and consumption for each hour [36]. A market clearing price (MCP), or a systems price, defines the accepted/rejected generation and consumption bids. Generators bid with a price lower than the forecasted MCP. Purchase bids with a price higher than the MCP are accepted, whereas the remaining bids are rejected. In this auction scheme, all the accepted participants are paid a market clearing price. Thus, the MCP determines the income of the power plants and the costs of the power consumers. The socioeconomic welfare created by the market price formation is the sum of the extra income received by the generators . . . and the extra savings of the consumers in comparison to the price at which they were ready to sell/buy the power according to their bids [37]. The MCP is calculated daily for every hour. The forecast of RES availability as well as the MCP guide the decision-making of the players regarding their offers to the market.

Several approaches to market clearing with limited transmission line capacities are practised. In the Nord Pool market, the limited capacity of the power transmission line is addressed by splitting the electricity market into price zones. In the Nord Pool market, day-ahead market coupling uses the Single Price Coupling Algorithm called Euphemia [38,39]. Euphemia solves the market coupling optimisation problem for supply and demand bids, maximising the social welfare of the market players subject to operational, reliability, stability and security constraints, which arise due to power flow limits over the congested transmission lines.

3.2. The Baltic Power System

The Baltic Power System (BPS) combines the power systems of the three Baltic States, namely, the Estonian, Latvian and Lithuanian power systems. The schematic structure of the energy system is presented in Figure 2. The BPS has connections, via DC and AC transmission lines, with the power systems of Finland, Sweden and Poland. The electricity generation mix of the power systems of the Baltic Sea region includes hydro, gas, coal, wind and solar power plants, comprising large hydro pump plants and natural-gas-fired combined heat and power plants. In the future, up to 2050, a major transformation of the existing system is planned: high-capacity solar, wind and synthetic methane power plants will be built and plants producing atmospheric CO_2 emissions will be shut down.

The natural gas transmission and storage system of the Baltic States includes an underground gas storage (UGS) in Incukalns [40], a gas transmission pipeline system with an overall length of 1191 km, a gas distribution pipeline system with an overall length of 4950 km, consisting of a network of natural gas pipelines, gas regulation devices, and electrical protection devices. The UGS is one of the most important elements of the natural gas infrastructure. The existing international connections of the gas transmission system allow exchanges between the Baltic States, on the one hand, and Finland and Poland, on the other. The gas transmission system also includes a large regional liquefied natural gas terminal (LNG), which is suitable both for natural and synthetic gas import or export.

The capacity of the existing gas storage is 2.32 billion m^3 and can even be expanded in the future. Apart from the existing UGS, there also are other sites in Latvia that can potentially be used for gas storage. As the ground in Latvia has a suitable geological structure, this permits for a natural gas storage with a total capacity of up to 50 billion cubic meters [40]. This might become particularly valuable once the gas pipeline interconnections with the EU networks are reinforced. We assume that a synthetic methane plant will be constructed in proximity to the large underground gas reservoir and should complement and further reinforce the existing strong gas storage, and the transmission and distribution system. It is important to note that Latvia's/the Baltic States' Baltic Sea ports and LNG terminals are connected to the underground gas storage. Such an infrastructure [41] opens access to the global synthetic methane market and enables extensive gas import and export for the Baltic States.

3.3. The Modelling Framework

Electricity consumers require energy for their activities and are willing to pay for it. At market conditions, plant operators aim to maximise their profits, while adhering to the electricity market rules and fulfilling the technical constraints imposed by the plants and the network. The main responsibility of the power system operator is to ensure system adequacy and energy balance—sufficient generation in every possible state of the power network, which is especially challenging in a structure with a high share of renewables.

The variable pattern of RES generation significantly complicates the adequacy of the power system, namely, the provision and further maintenance of power balance. The excessive power generated by wind and solar plants can be converted into synthetic methane production with the goal of accumulating energy in underground gas reservoirs.

The greatest difficulties, and the most expensive challenge, occur during the periods when renewable resources are not available and the capacity of the interconnection lines is limited. In these cases, HECME plants convert previously stored methane into electric power.

To successfully maintain the balance of the power system through the potential of synthetic methane, a mathematical model of the energy market is required in order to assess the impact of the energy strategy for operating the HECME power plant. Modelling hourly market clearing prices for a one-year-long planning period is the central and most challenging task in this problem.

Our solution involves the main steps as follows:

1. *Creating a scenario and a forecast*, namely, electricity prices, energy demand, water inflow, solar irradiation, wind and the generating interconnection. We will use multiple deterministic scenarios and time series data collected or forecasted at regular hourly intervals over the course of one year.
2. *Preparation of generator and consumer bids*, i.e., the energy and the prices for each hour [42–44]. This is an optimisation problem to be solved by the individual generators and consumers and is described in many publications, for example, Refs. [6,7,45–48]. During this step, we should simulate the behaviour of each market participant.

3. *Market clearing and the accepted generator and load energy.* In this step, we simulate the actions of a market operator whose task is to choose the cheapest generators, considering energy balancing and interconnection constraints. The result of this step contains hourly schedules for every energy generator, consumer and interconnection, and the MCP for every price zone.
4. *Calculation of the economic indicators and performance.* The previous step provides basic information for calculating economic performance indicators, such as annual energy import and export costs, consumer spending, installed and used capacity and volume of investments, which will show us the revenue for each power plant.

3.4. Assumptions, Heuristic Approximations and Definitions

Figure 2 shows the consumers as well as the portfolio of power plants and interconnections to the neighbouring countries in the future. To simplify the analysis of the depicted system, we will use a series of assumptions:

1. We assume a "copper plate system" within the Baltic States. The Baltic network can be reduced to one node, see Figure 2.
2. We acknowledge that the capacities of the interconnections of the Baltics to Sweden, Poland and Finland are limited, while these countries have significantly larger consumption/production amounts [49], and are strongly linked to the larger energy systems of other European countries. Therefore, we assume the following: (a) the Baltics function as a "price taker" in those markets; (b) the neighbouring systems can always provide import/export power at full interconnection capacity.
3. The HECME PP should guarantee system adequacy and provide peak/reserve power and should absorb the residual renewable energy in surplus of the consumption and the exports. We require the total installed capacity of the HECMEs to cover the residual system demand. Additionally, we require that the electrolysers can ensure energy balance at any hour when the consumption is too low otherwise; i.e., all the available renewable generation can be used.
4. The capacities of the hydrogen PP and the electrolysers are not limited.
5. We consider that electrolysis is the source of green carbon-free hydrogen fed by renewable energy resources. Hydrogen will only be produced when abundant renewable energy is available, when it exceeds domestic demand and a limited export. The electrolyser will only be activated when the market prices are very low.
6. The price of HECME energy is higher than that of any other plant. Thus, the generation from the HECME is economically justified at hours when the active power balance can only be provided with the help of gas from a storage reservoir.
7. The methane storage is large enough to store any available energy, regardless of the reservoir's usage schedule in the past or in the future, i.e., an infinite storage; it is assumed that the HECME plant will be located in proximity to the large underground gas reservoirs and will support the operation of the already existing and well-developed gas transmission and distribution system. Thus, there are no extra costs for gas transmission.
8. We assume that the consumers' LBSs are inflexible and are forced to buy energy, at worst, even at the maximum Nord Pool market price, or in its absence, to buy energy at the even higher price of the HECME plant.
9. We assume that in compliance with the decisions of the regulator and the government, there is a price cap on the market.

The above assumptions provide a simplified mathematical description of the problem under consideration and the possibility of using the structure reflected in Figure 3.

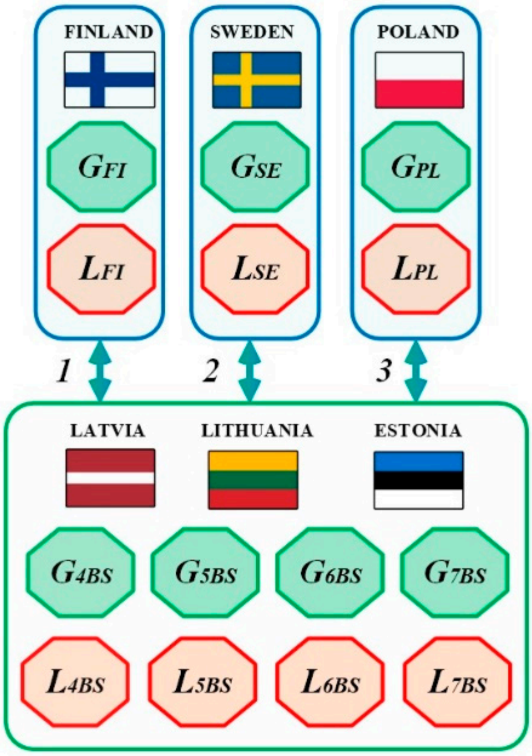

Figure 3. A simplified structure of the interconnected energy systems of the Baltic region.

Considering the above heuristics and the simplifications, we can now formulate the socioeconomic welfare maximisation problem [8]. We will show in the following that the adopted simplifications allow for a dramatic reduction in the optimisation problem, since no detailed models of the power systems of countries neighbouring the Baltic States are used. The electricity market model forming process considers the following transformation and designations:

The interconnections. We are modelling Finland, Sweden and Poland by equivalent generators—G_{FI}, G_{SE} and G_{PL}—respectively (see Figure 3). The combined installed capacities in these countries, or equivalent generators, W_{1r}, W_{2r} and W_{3r} at hour t, allow exporting $w_G^{t,1}$, $w_G^{t,2}$ and $w_G^{t,3}$ (MWh/h), accordingly.

We are replacing the high-voltage lines that connect the Baltic States with their neighbours with three equivalent lines with a defined capacity. The maximum export cannot exceed the interconnection capacity and can be represented by a load equivalent—L_{FI}, L_{SE} and L_{PL}, while the energy demand at hour t is $w_L^{t,1}, w_L^{t,2}, w_L^{t,3}$ (MWh/h).

The domestic generation and loads. We are replacing the Baltic States by the equivalent generators G_{4BS}, G_{5BS}, G_{6BS} and G_{7BS} (see Figure 3), with the rated capacities W_{4r}, W_{5r}, W_{6r} and W_{7r} and possible generation $w_G^{t,4}, w_G^{t,5}, w_G^{t,6}$ and $w_G^{t,7}$ in hour t. These capacities, together with the generation costs, are supply bids to the market, while the equivalent loads L_{4BS}, L_{5BS}, L_{6BS} and L_{7BS} consume energy $w_L^{t,4}, w_L^{t,5}$, $w_L^{t,6}$ and $w_L^{t,7}$ in hour t, accordingly. A demand price cap has to be introduced by the market operator [38].

4. The Mathematical Formulation of the Tasks

4.1. Creating a Scenario and a Forecast

We will use time series data collected or forecasted at regular hourly intervals over the course of one year. We form an N-dimensional time series, which would mean N-many different time series where each series contains T-many observations (8760 h). The vector autoregression (VAR) approach [50] is used to capture the relationship between multiple quantities as they change over time. Historical data are denoted as follows:

$$Y_T^H = (Y_{1,\ldots}, Y_{T,\ldots}, Y_{8760,\ldots}). \quad (1)$$

where Y_t are the measurements results (samples) recorded at hours t = 1, . . ., 8760. Each Y_t contains n different components Y_{nt}; n = 1, . . . N:

$$Y_t = (Y_{1t}, \ldots, Y_{nt,\ldots}, Y_{Nt}). \quad (2)$$

The forecasts for year $T + K$ will include time series, which are denoted as Y_{T+K}^F.

Firstly, based on the data collected, we estimate the N-dimensional vector of time average Y_{TA}^H:

$$Y_{TA}^H = (Y_{TA1,\ldots}, Y_{TAN})^T = ((Y_{1,1}+, \ldots, +Y_{1,8760})/8760, \ldots, (Y_{N,1}+, \ldots, +Y_{N,8760})/8760)^T \quad (3)$$

Then, we calculate the deviations of a random variable Y_i from its average Y_{TA}^H, i.e.,

$$Y_T^{HC} = ((Y_1 - Y_{TA}^H), \ldots, (Y_{8760} - Y_{TA}^H)). \quad (4)$$

And, finally, we forecast the time series at year $T + K$, using the model as follows:

$$Y_{T+K}^F = Y_{TA}^H (K_1 \cdot D_1) + Y_T^{HC} (K_2 \cdot D_2) \quad (5)$$

The first component of (5) can be interpreted as the result of applying the naïve forecasting method with drift [51], because we assume that towards the future, the historical average Y_{TA}^H will linearly increase (the base of the drift method) over the years. The second component is inspired by both random walk and naïve models [51]. This component defines deviation from the forecasted average (the main idea of the random walk model). The deviations are modelled by using the centred random variables "naïvely", assuming that future deviations will repeat historical samples with drift ($K \cdot D$).

4.2. Preparation of Generator and Consumer Bids

Preparation of the domestic bids. The first group of domestic bids includes dispatchable thermal and hydroelectric power plants. In the second group, we include the production by the solar and wind farms, whose power output is defined by the weather conditions.

Every generator in the first group, apart from the HECME PP, defines its generation schedule based on MCP forecasts, seeking to maximise its benefit $B(T_{pl})$, which can be obtained during the planned period Tpl.

In the most complex cases of maximising the benefits$B(Tpl)$ of units with energy storage capability (HPP and PSPP), the objective can be formulated as follows:

$$B(T_{pl}) = (\sum_{t=1}^{T_{pl}} P_{prf}^t \cdot w_G^t - \sum_{t=1}^{T_{pl}} P_{prf}^t w_L^t) \rightarrow \text{max}. \quad (6)$$

where w_G^t and w_L^t are the decision variables, which define the generation w_G^t and storage w_L^t over time t, and P_{prf}^t is a forecasted MCP.

The constraints include maximum installed capacity limits for the generation, the capacity of the storage, the maximum pumping power and similar. It is important to add that unless the power plant contains medium-term storage, one can split long planning horizons into relatively short periods, such as weeks. Thus, the problem is decomposed into a set of much simpler sub-problems because of a significantly reduced planning horizon and a reduced number of optimization variables [5,52,53]. Such an approach has proven to be highly efficient, despite the necessity to repeat the optimisation many times. Applying (6) will determine the arguments of the $B(Tpl)$ maxima:

$$\text{argmax } (B(Tpl)) = \{\{w\hat{\ }_G^t, P_{prf}^t\}, \{what_L^t, P_{prf}^t\}\}, \quad (7)$$

which have to be used as bids for the market operator.

The modelling of HECME PP offers is fundamentally different, as this plant has to perform an energy-balancing task.

Defining the offers to be submitted by the renewable generation plants, such as wind and solar power plants, permits a significantly different approach. In these cases, the marginal production costs are zero and the traders are interested in selling the energy even at a very low positive price. Thus, we assume that the bids of these PPs contain the forecasts using five time series of solar and wind power output and a zero price.

4.3. Market Clearing and the Accepted Generator and Load Energy

Now it is possible to formulate the problem from the market operator's point of view, who is pursuing maximisation of socio-economic welfare ($SWBS(t)$):

$$SWBS(t) = (-\sum_{n=1}^{N} (P_{prbG}^{t,n} \cdot W_G^{t,n}) + \sum_{k=1}^{K} P_{prbL}^{t,k} W_L^{t,k}) \rightarrow \max. \tag{8}$$

where

$w_G^{t,n}$—production by generator n in hour t, MWh/h; N—total number of generators;

$P_{prbG}^{t,n}$—the price bid by the generator n in BS price zone in hour t (EUR/MWh);

$w_L^{t,l}$—the energy demand of load l in hour t; K—total number of loads;

$P_{prbL}^{t,l}$—the price bid by load l to the market in hour t (EUR/MWh).

The market operator can only consider bids submitted to the market—$W_{Gb}^{t,n}$, $W_{Lb}^{t,k}$. Thus, the following constraint must be introduced:

$$\{P_{prbG}^{t,n}, W_G^{t,n}, P_{prbL,}^{t,k} W_L^{t,k}\} \subseteq \{P_{prbG}^{t,n}, W_{Gb}^{t,n}, P_{prbL,}^{t,k} W_{Lb}^{t,k}\} \tag{9}$$

$$k = 1, \ldots, K;\ n = 1, \ldots, N;$$

The maximisation (8) must be performed for each hour of the planning period:

$$t = 1, \ldots, Tpl,$$

while ensuring that the following conditions are met:

- The equality constraint for power balance in each hour:

$$\sum_{n=1}^{N} w_G^{t,n} = \sum_{k=1}^{K} w_L^{t,k}, \tag{10}$$

- The inequality constraints for the interconnections' capacity:

$$w_G^{t,n} \leq W_{max}^n \tag{11}$$

$$w_L^{t,n} \leq W_{\max}^n \tag{12}$$

where W_{max}^n—maximum allowed capacity (see Figures 2 and 3) of interconnecting power line n.

Inequalities (11) and (12) must hold for all the generators and loads in Finland, Sweden and Poland and in each hour t:

$$n = 1, \ldots, 3$$

$$t = 1, \ldots, 8760.$$

It is particularly important to add that there is no need for multiperiod optimisation, which would be bounded by such constraints as state of charge (SoC) [52]. By relaxing the size of gas storage, we significantly simplify the solution and address single-period optimization, thereby spending much less computational resources.

Finally, applying (8) will determine the arguments of the SWBS maxima:

$$S(t) = \text{argmax}\,(\text{SWBS}(t)) = \{w\hat{}_{G}^{t,n}, P_{prG}^{t,n}\}, \{w\hat{}_{L}^{t,k},\ P_{prL}^{t,k}\}\}. \tag{13}$$

Thus, $w\hat{}_{G}^{t,n}$ is the production by generator n in hour t, MWh/h, corresponding to optimal social welfare.

4.4. Calculation of the Economic Indices and Performance

The set $S(t)$ contains irrelevant elements that are linked to rejected bids of the generators and the loads, i.e., ones with $w\hat{}_{L}^{t,k*}$ or $w\hat{}_{G}^{t,n\hat{}}$ equal to zero. We will calculate the economic performance indices only for the bids accepted to the market. Thus, to extract the maximum price, i.e., the market clearing price, it is necessary to perform the transformation TR1 of the set $S(t)$ excluding losing bids:

$$TR1:\quad S(t) \to S*(t) = \{\{w\hat{}_{G}^{t,n\hat{}}, P_{prG}^{t,n\hat{}}\}, \{w\hat{}_{L}^{t,k*} P_{prL}^{t,k*} : w\hat{}_{G}^{t,n\hat{}} > 0, w\hat{}_{L}^{t,k*} > 0\}, \tag{14}$$

where n* and k* are the generators and loads accepted to the market in hour t.

From the subset $P_{prG}^{t,n\hat{}}$, the market clearing price $P_{pr}^{t,MCP}$ can be extracted performing an operation as follows:

$$P_{pr}^{t,MCP} = \max\left\{P_{prG}^{t,n} : n = 1, \ldots NM\right\}, \tag{15}$$

where $P_{pr}^{t,MCP}$represents the market clearing price of the BS and NM denotes the total number of generators accepted by the market in hour t.

Knowledge of $P_{pr}^{t,MCP}$ and capacities $w\hat{}_{G}^{t,n}$, $w\hat{}_{L}^{t,l}$ of generators and loads in each hour of the year permits calculation of important economic and technical indices. It is crucial to determine the peak power of the HECME and the electrolysers, as these capacities determine the amount of investment required. In order to evaluate the economic attractiveness of the considered scenarios to the generators, we use a simplified criterion, namely, the Return On Assets (ROA) [54]. The ROA is one of the simplest financial criteria, which specifies how profitable is a company in relation to its total value [55]. ROA can be calculated by means of a formula as follows:

$$\text{ROA} = \text{Net Income}/\text{Invested Capital} \tag{16}$$

The income of power plants can be estimated easily, by using time series that are formed by applying (14).

We calculate invested capital as the overnight [56–58] construction costs (OCC), using data from [56–58].

$$\text{OCC} = \text{Power plants capacity(kW)} \times \text{Investment cost (EUR/kW)} \tag{17}$$

5. The Case Studies

5.1. Scenario Description

Table 1 displays the power system parameters for five specific scenarios expected in 2050. The maximum value of total power consumption, total generation and rated capacity of each kind of power plant is depicted.

Table 1 presents only fully renewable generation: a pumped storage hydropower plant (PSHPP), a hydropower plant (HPP), a solar power plant (SPP) and a wind power plant (WPP). These scenarios account for a moderate increase in energy demand, the shutdown of all natural gas and coal-fired power plants, upkeeping existing capacities of hydro and biomass power plants and the rapid building and deployment of solar and wind plants.

Additionally, we will include the HECME power plant, using the following parameters of hydrogen and synthetic methane technology.

- The efficiency of the electrolyser equals 0.7.
- The efficiency of the H2PP is 0.59.
- The initial state of synthetic methane storage equals the current storage capacity of the underground reservoir—2.32×10^9 m^3.
- The density of synthetic methane at 25 °C equals 0.657 kg/m^3 [16].
- The thermal capacity of synthetic methane at 25 °C is 39 MJ/m^3 = 10.833 kWh/m^3 [16].

Table 1. Basic parameters of the Baltic 2050 future development scenario.

Scenario	Demand	SPP	WPP	HPP	PSHPP	BPP
S1	6629 [a] 39.83 [b]	1600 [a] 1.87 [b]	5000 [a] 14.92 [b]	1727 [a] 2.24 [b]	1625 [a] 2.85 [b]	522 [a] 3.52 [b]
S2		2200 [a] 2.57 [b]	7000 [a] 20.88 [b]			
S3		2800 [a] 3.27 [b]	9000 [a] 26.85 [b]			
S4		3400 [a] 3.97 [b]	11,000 [a] 32.82 [b]			
S5		4000 [a] 4.67 [b]	12,000 [a] 35.80 [b]			

[a]—peak consumption (BPS demand) and peak generation, MWh/h. [b]—annual energy demand (BPS demand) and annual energy supply, TWh.

5.2. Creating Forecasts

Figure 4 reveals forecasts of electricity market prices and the volatility of the market. The forecasting is based on historical data collected before the COVID-19 pandemic and calibrated by an average annual price forecast from [5] and using (4). The forecasting methodology is described in our previous publications [5,52].

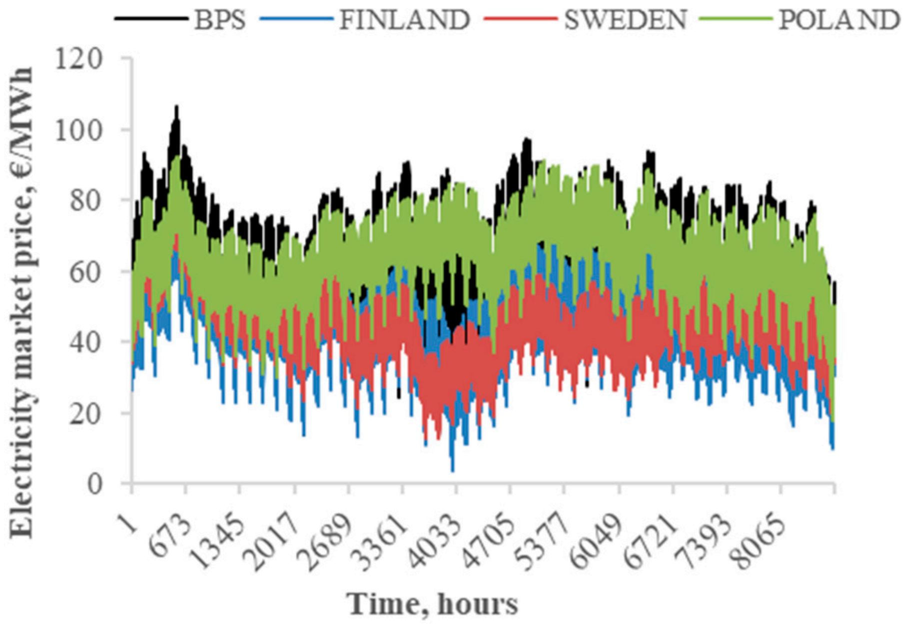

Figure 4. Forecasts of electricity market prices in 2050.

Figure 5 shows an example of the foreseeable generation of solar and wind power plants, with plant capacities corresponding to scenario S3.

To create forecasts of electricity generation from RES, we processed hourly power outputs of many real randomly selected plants located in the Baltic region. These historical data values are scaled using (5) to account for the expected growth of capacities. The details of the methodology are described in [5,36,52,53,59,60].

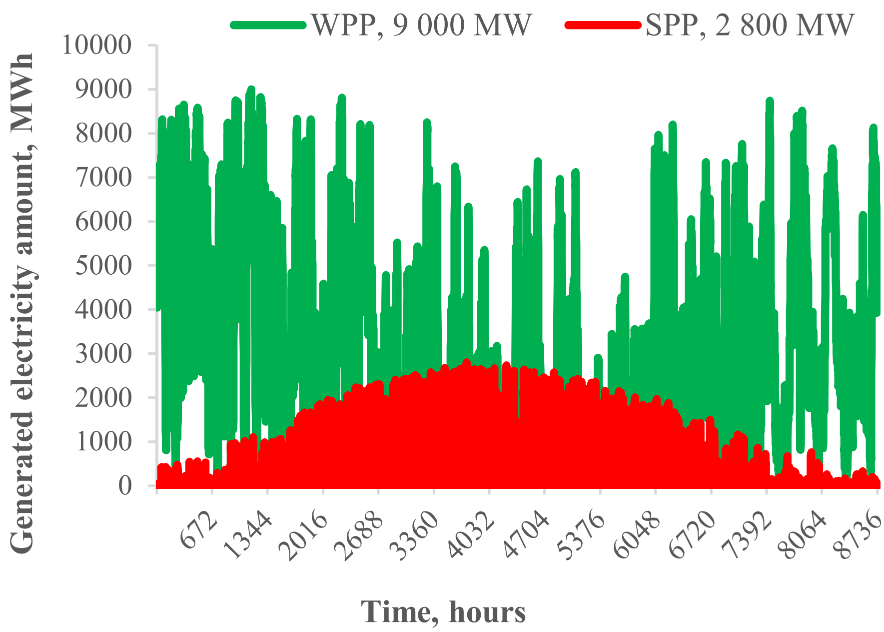

Figure 5. Hourly forecasts of RES-generated energy in the BPS in 2050.

To form forecasts of electricity consumption, we processed the hourly power consumption of many real randomly selected consumers. These historical time series are scaled to account for the expected consumption growth with an augmentation drift of 3% per year. Figure 6 reflects an actual historical data of electricity demand in BPS 2019 and prediction of electricity demand in BPS 2050. The details of the methodology are described in [5,36,52,53].

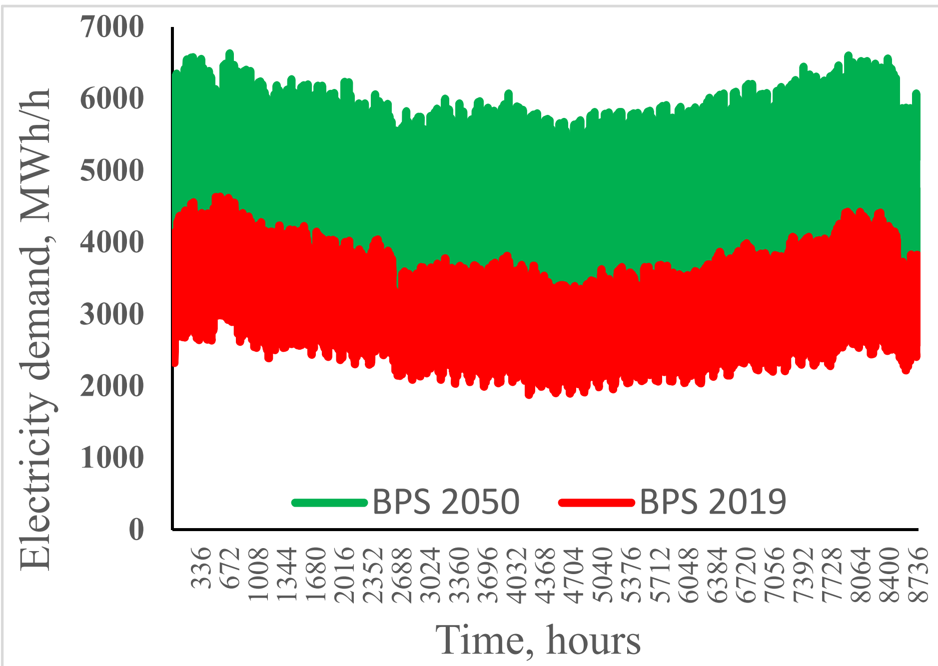

Figure 6. Hourly consumption in the BPS in 2019 (27.56 TWh/year) and in 2050 (39.83 TWh/year).

5.3. Results

5.3.1. BPS in an Islanded Mode

First, let us consider an unrealistic yet helpful complement to the S1, . . ., S5 (Table 1) scenario—the Baltic power system operates in an islanded mode; i.e., the interconnections are missing. Figure 7 shows the results of the simulations.

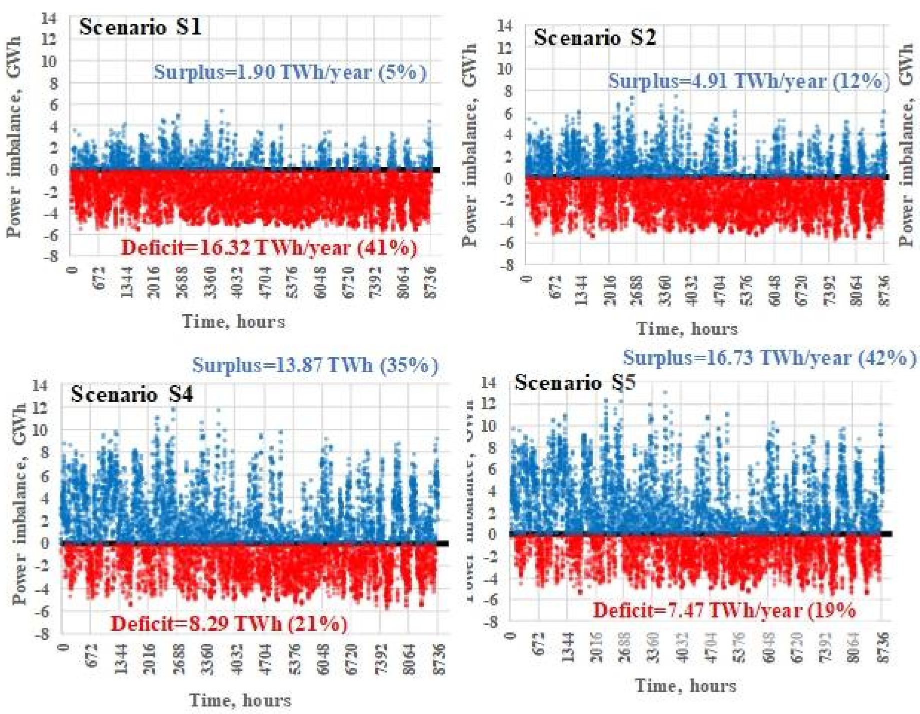

Figure 7. The energy balance of BPS 2050 in an islanded mode for scenarios S1, S2, S3, S4 and S5.

Two distinct states are displayed in Figure 7:

- The "Surplus" shows the amount of energy that must be used by the electrolyser to achieve the balance or wasted otherwise;
- The "Deficit" shows the energy that needs to be produced by using synthetic methane.

Figure 7 demonstrates a significant energy surplus or deficit at most hours of the year. For this imbalance to be covered by the HECME, it will require significant investments. Fortunately, the energy balance can be achieved with much lower HECME PP capacities through cooperation with neighbouring countries, as seen in Figure 8 for the same case, showing the power system with enabled interconnecting transmission lines.

We can observe that export/import of energy diminishes the imbalance. Indeed, the power surplus has diminished in all scenarios; for example, in scenario S5, the surplus decreased from 42% to 19%. The energy deficit decreased from 19% to 3%.

5.3.2. The Energy Balance of BPS after HECME Construction

The imbalance numbers shown in Figure 8 indicate the installed capacity and energy production of the HECME power plant and the volume of synthetic methane that must be used. For example, in scenario S3, we can conclude that an energy amount of 1.90 TWh would eliminate the annual deficit. Could this energy be generated from a surplus renewable energy by HECME power plants? Considering the efficiency of the conversion stages as in Figure 1, the energy input electrolysers (EIE) shall be as follows:

$$\mathrm{EIE} = 1.9/0.41 = 4.63\ \mathrm{TWh} \tag{18}$$

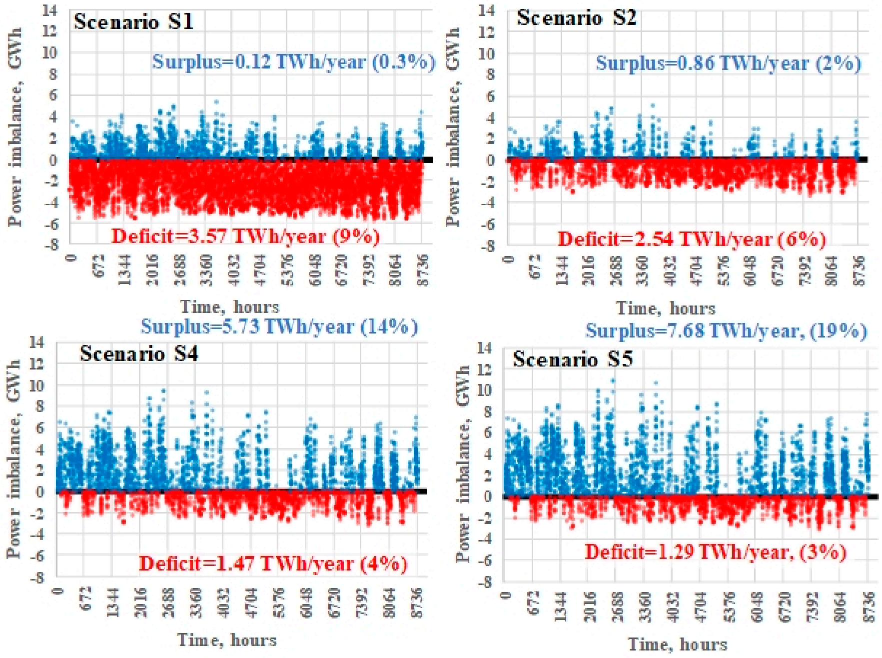

Figure 8. The power imbalance of the BPS in 2050, assuming operational interconnections but no HECME power plants. Results of the scenarios S1, S2, S3, S4 and S5 modelling.

We conclude that the surplus energy does not suffice to produce the required volume of methane because only 2.7 TWh of surplus renewable energy is available. In this case, the energy deficit can be made up by methane import as in Table 2, GCH. The deficit of locally produced gas can be observed for three scenarios S1–S3. In scenarios S4 and S5, we detect gas surplus, which can be stored, exported or used, for example, for district or residential heating.

Table 2. Energy needs for annual balance: $ED_{\text{-HECME}}$, $ES_{\text{-HECME}}$ is the energy deficit and surplus, respectively, without HECME, $ED_{\text{+HECME}}$, $ES_{\text{+HECME}}$ —the energy deficit and surplus with HECME operation, $E2CH_4$—the energy required for synthetic methane production, GCH—the gas consumption by HECME, Mm^3/year.

Scenario	$ED_{\text{-HECME}}$	$ES_{\text{-HECME}}$	$ED_{\text{+HECME}}$	$ES_{\text{+HECME}}$	$E2CH_4$	GCH
	TWh/Year, % of Total Demand in BPS				TWh/Year	Mm^3/Year
S1	3.57 (9%)	0.12 (0.3%)	0.00 (0%)	−8.53 (−21%)	8.65	798.43
S2	2.54 (6%)	0.86 (2%)	0.00 (0%)	−5.30 (−13%)	6.16	568.61
S3	1.90 (5%)	2.75 (7%)	0.00 (0%)	−1.86 (−5%)	4.61	425.51
S4	1.47 (4%)	5.73 (14%)	0.00 (0%)	2.17 (5%)	3.55	328.22
S5	1.29 (3%)	7.68 (19%)	0.00 (0%)	4.55 (11%)	3.12	288.14

The calculation results as presented in Figure 8 define the selection of the capacity of the HECME generator and electrolyser. That is the maximum deficit or, correspondingly, surplus of power in each scenario; thus, we obtain capacities of HECME units as in Table 3.

Table 3. Optimal capacities of HECME units, GW.

Scenario	S1	S2	S3	S4	S5
Capacity of generator, GW	3.313	3.265	3.218	3.170	3.146
Capacity of electrolyser, GW	3.041	5.148	7.254	9.518	10.901

The determined capacities of the units will ensure an electrical balance of the generation and consumption of electricity. However, as Figure 9 shows, the balance of produced and consumed gas is not achieved.

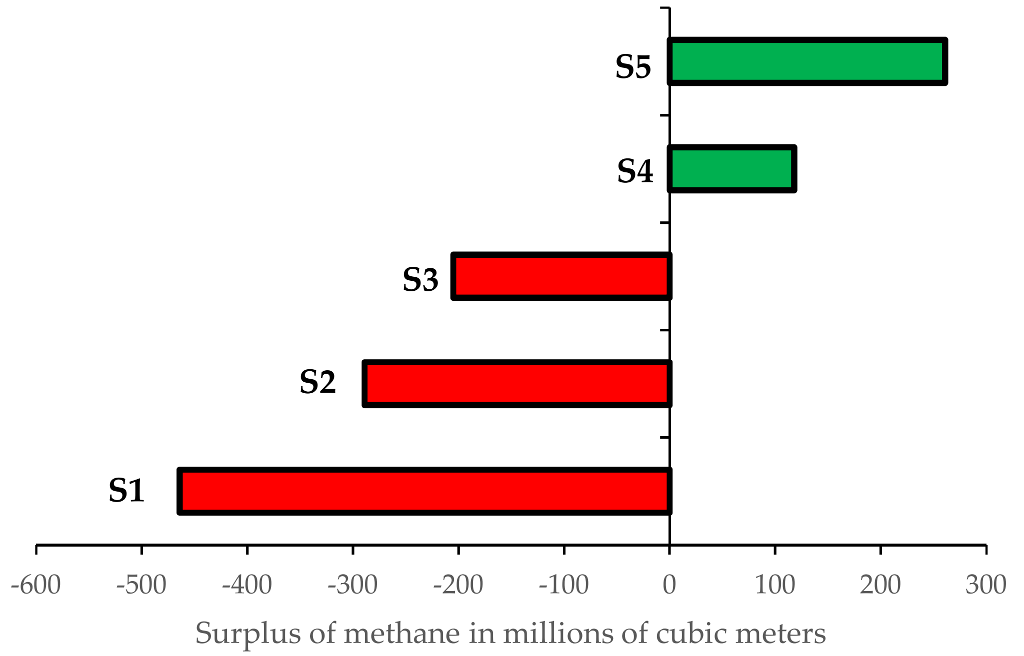

Figure 9. The surplus of methane in the considered scenarios (positive—green bars, negative—red bars).

It was assumed that the gas storage is large enough to accumulate any volume of gas to satisfy power generation requirements. However, it is interesting to understand what those assumptions imply for realistic implementation. Therefore, we calculated the gas volume in the reservoir. The results are provided in Table 4 and in Figure 10.

$$V_{res,T_{pl}} = V_{res,0} - \sum_{t=1}^{T_{pl}} (+V_t^{charge} - V_t^{discharge}). \tag{19}$$

where $V_{res,T_{pl}}$ stands for the final reservoir capacity value (m^3); $V_{res,0}$ is the initial capacity of the gas reservoir (m^3); T_{pl}—planning period (hours); V_t^{charge}—the charging procedure of the HECME power plant (m^3); $V_t^{discharge}$—the discharging procedure of the HECME power plant (m^3).

At the same time, variables V_t^{charge} and $V_t^{disckarge}$ are mutually exclusive.

$$\begin{cases} if\ V_t^{charge} > 0\ then\ V_t^{discharge} = 0 \\ if\ V_t^{discharge} > 0\ then\ V_t^{charge} = 0 \end{cases} \tag{20}$$

Table 4. Gas volume in the reservoir according to the scenarios.

Scenario	The Initial State (TWh, Mm^3, Percentage)			The Final State (TWh, Mm^3, Percentage)			Maximal Level (TWh, Mm^3, Percentage)		
S_1	25.13	2320	100%	20.10	1856	80%	25.13	2320	100%
S_2	25.13	2320	100%	22.00	2031	87%	25.14	2321	100%
S_3	25.13	2320	100%	22.91	2115	91%	25.14	2321	100%
S_4	25.13	2320	100%	26.42	2439	105%	26.69	2464	106%
S_5	25.13	2320	100%	27.96	2581	111%	27.96	2581	111%

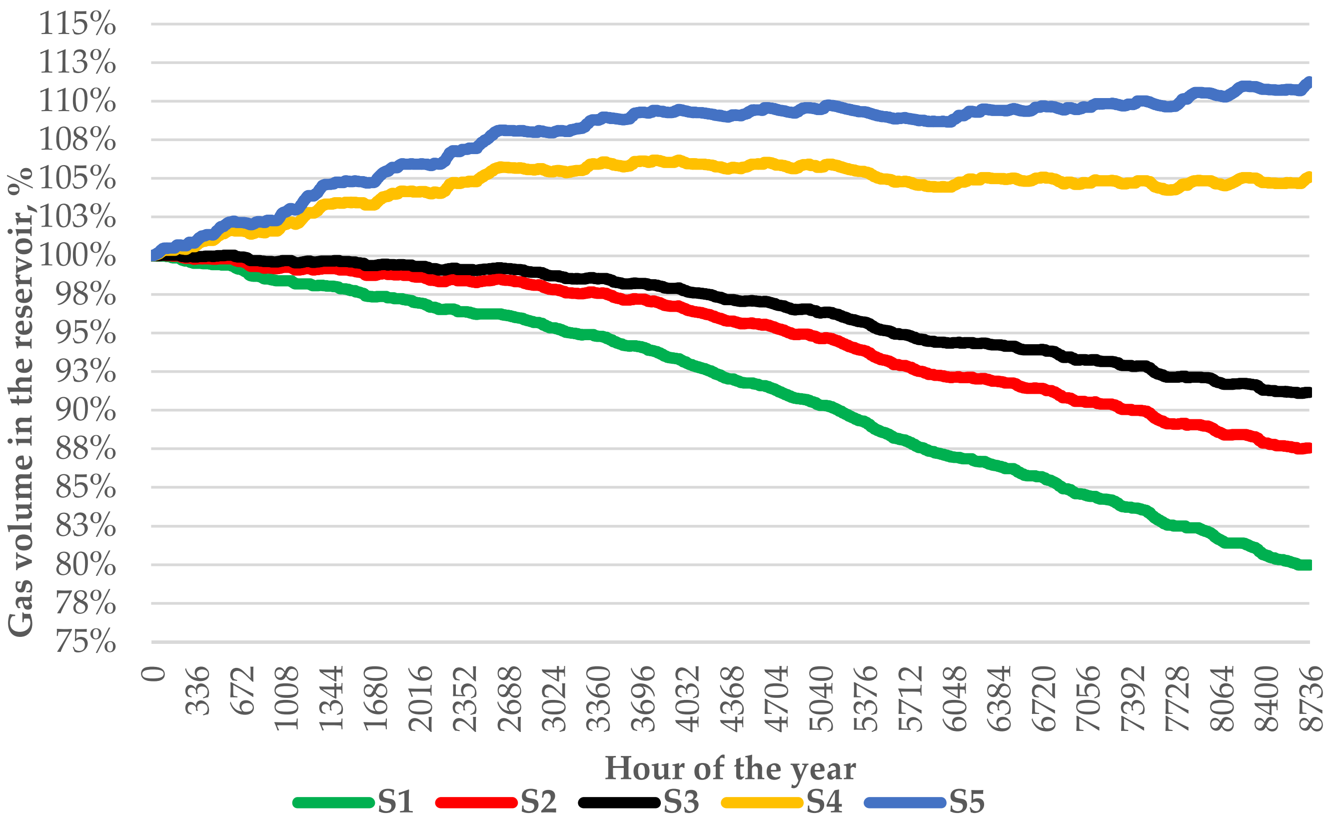

Figure 10. Evolution of gas volume in the reservoir over a year.

Figure 10 shows that there is a significant reserve in the volumes of the reservoir already in use. Depending on the scenario, the volume of stored gas varies between 80% and 111% of the initial volume, which allows setting additional tasks, for example, to increase gas production and expand gas exports.

5.3.3. The Impact on the Market Prices

The calculations performed so far show the technical feasibility of the operation of an all-renewable system supported by HECME power plants and gas storage. Economic feasibility is similarly essential for the decision-making; thus, we focus our efforts on relevant economic calculations in the following paragraphs.

We begin with the calculations of market prices in the price zone of the Baltic States using the proposed methodology. Figures 11–15 show the variations in the market clearing price in the Baltic zone depending on the development scenario and assuming that the price of the electricity generated by the HECME will be capped at 300 EUR/MWh. This price defines the upper bound of the price in the zone. In the hours when the renewable generation produces abundant energy that can only be used to run the electrolyser, the price becomes close to zero. The average price will be impacted by all the bids in the interconnected energy systems.

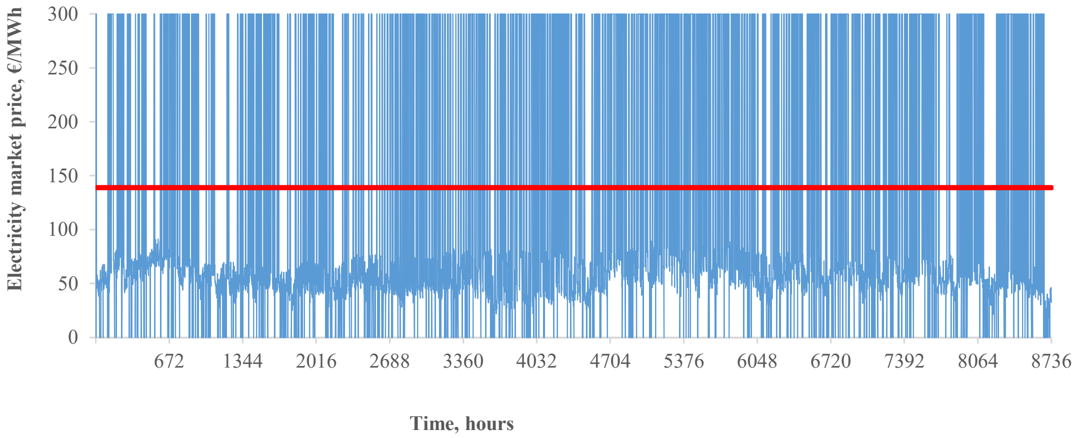

Figure 11. Zonal market clearing prices of BPS. Scenario S1. The average electricity market price is 138.77 EUR/MWh (red curve). The cumulative duration of zero electricity market price is 5.51%.

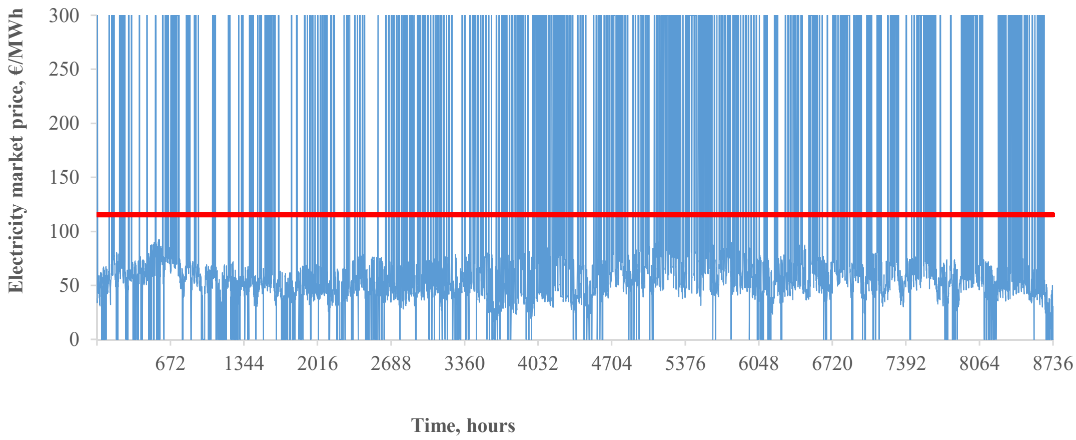

Figure 12. Zonal market clearing prices of the BPS. Scenario S2. The average electricity market price is 115.42 EUR/MWh (red curve). The cumulative duration of zero electricity market price is 8.86%.

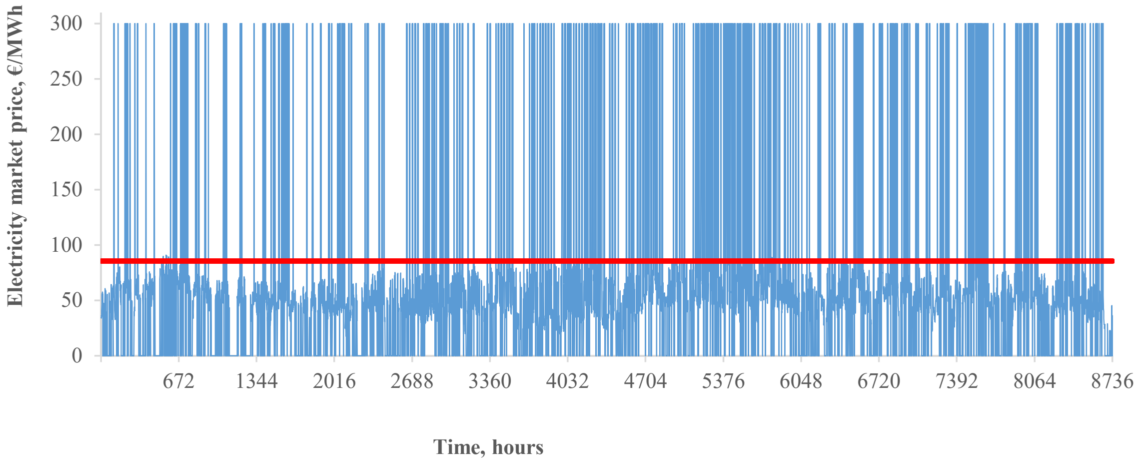

Figure 13. Zonal market clearing prices of the BPS. Scenario S3. The average electricity market price is 85.40 EUR/MWh (red curve). The cumulative duration of zero electricity market price is 23.45%.

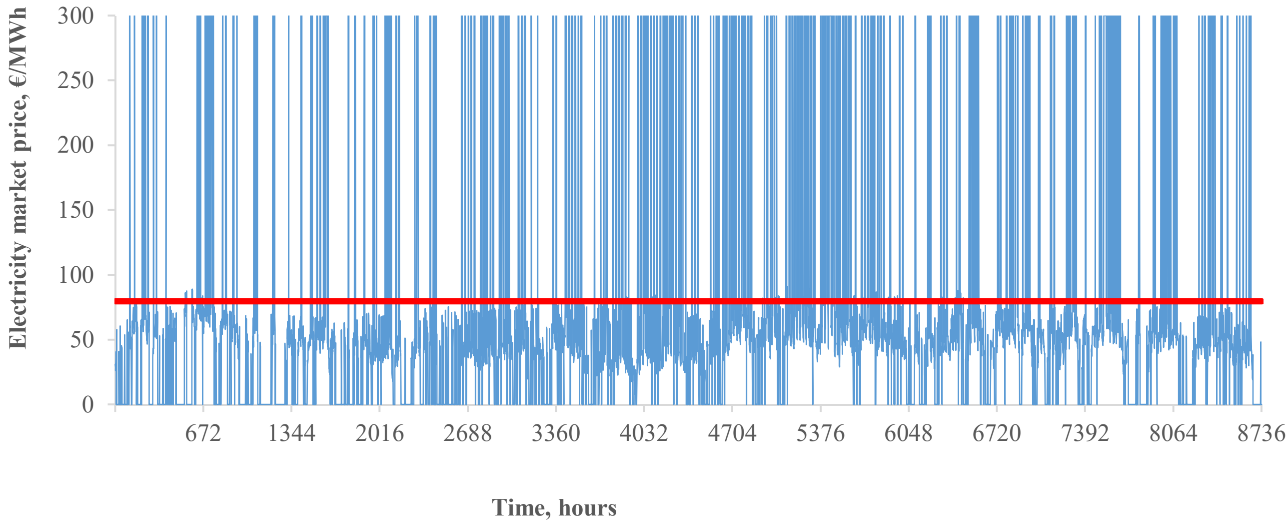

Figure 14. Zonal market clearing prices of the BPS. Scenario S4. The average electricity market price is 79.67 EUR/MWh (red curve). The cumulative duration of zero electricity market price is 27.23%.

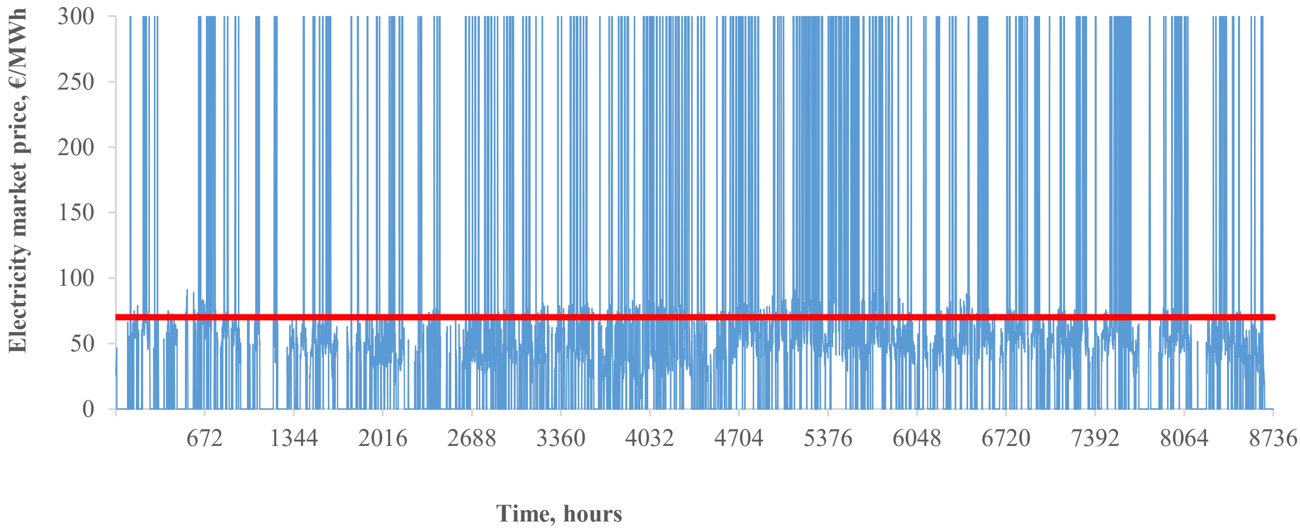

Figure 15. Zonal market clearing prices of the BPS. Scenario S5. The average electricity market price is 70.06 EUR/MWh (red curve). The cumulative duration of zero electricity market price is 33.71%.

Table 5 shows the incomes of all simulated power plants and the average annual prices. S1–S3 show that the HECME will be buying additional volumes of gas and, thus, has negative income, which is compensated by the electricity sales by the HECME.

Table 5. Income from the sales of electricity in BPS, per type of power plant.

Scenario	SPP (MEUR/Year)	WPP (MEUR/Year)	HPP (MEUR/Year)	PSPP (MEUR/Year)	BPP (MEUR/Year)	HECMEe (MEUR/Year)	HECMEg (MEUR/Year)	AvPr (EUR/MWh)
S_1	119	1002	142.40	173.77	482.94	1071.66	−610	139
S_2	160	1308	114.54	143.27	400.25	763.19	−370	115
S_3	202	1656	93.86	116.74	329.70	571.13	−129	95
S_4	249	2013	78.51	101.45	275.22	440.54	+188	79
S_5	323	2504	67.74	91.43	242.03	387.76	+360	70

In a free market, with limited competition and limited interconnection capacities, the HECME PP will be defining market prices and seeking to maximise profits in the deficit hours. Therefore, intervention by the regulator will be necessary.

The average price in 2050 is almost three times smaller than the ones historically observed in 2022 and, therefore, can be acceptable for consumers.

5.3.4. Profitability of Green Power Generation

In order to assess the economic criterion ROA, we need to estimate the investments into the HECME plant, which have two parts:

- Methane production facility.
- Gas power plant with carbon dioxide capture. The construction costs for various power plants are adopted from [56].

The results are summarised in Table 6.

Table 6. The costs, income and ROA of renewable power plants in the BPS in S5 and S5*, where the capacity of electrolysers is diminished.

Power Plant Type	Investment (EUR /kW)	Overnight Construction Costs, S5 (MEUR)	Overnight Construction Costs, S5*, (MEUR)	Annual Income, S5 (MEUR)	Annual income, S5* (MEUR)	ROA, S5 (%)	ROA, S5* (%)
SPP	800	3200	3200	323	323	10.1	10.1
WPP (onshore)	1500	18,000	18,000	2504	2504	13.9	13.9
HECME (Electrolyzer + methanation)	1200	13,080	2400	-	-	-	-
HECME (Gas PP with CC)	1400	4410	4410	747	387	4.3	5.7
A set of all power plants	-	38,690	28,010	3574	3214	9.24	11.5

We only discuss the results of the analysis in scenario S5—the one with the highest economic performance, which, in our view, is still rather low. The implementation of the synthetic-methane-fired plants will require investment, in the range of EUR 17 billion for scenario S5. That is a significant number for the economies of the Baltic States; for comparison, the GDP of Latvia in 2023 was USD 41.15 billion. That is why, when looking for ways to increase performance without raising the prices of the energy produced by the HECME, we investigated additional cases that require a lower capacity of the electrolyser and, therefore, a reduced amount of investment. Such a case for scenario S4 is shown in Figure 16. From the diagrams, it follows that even if the electrolyser's power is noticeably reduced, it can deliver enough hydrogen to cover for an energy deficit—when the total installed capacity of the electrolysers is above 2 GW, it can still provide enough hydrogen and, therefore, methane to support the energy balance.

However, it should be taken into account that such a strategy will lead to waste/spillage of solar or wind energy. If the available production of the renewable power plants exceeds the total system demand, including the electrolysers, market operators will be forced to reject a part of the generation bids. Scenario S5* requires approximately 7 billion EUR. A significant drop in investment is associated with a bulky decrease in the capacity of the electrolyser.

Unfortunately, in this case, the income of the HECME plants also decreases, but as a result, the ROA of scenario S5* is only slightly higher. Let us note that in both scenarios, the ROA of solar and wind generators exceeds 10%, which allows us to consider that the construction of these generators is economically attractive. The last conclusion determines the possibility of combining projects, financing a set of all RES and HECME power plants, which would allow achieving the winning profitability (the average value of ROA is approximately 10%) of the power system's green transition in line with the goal of reaching net zero emissions by 2050.

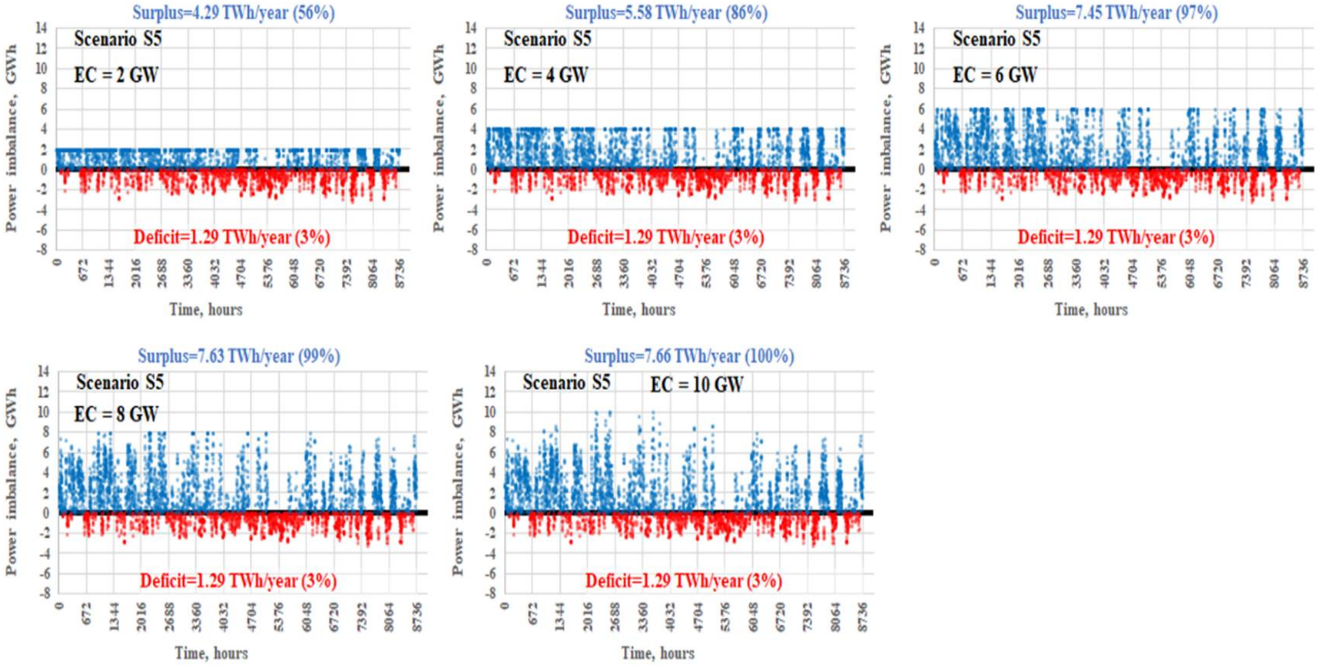

Figure 16. Power imbalance in the BPS in S5 that is addressed by the HECME with varying installed capacities of electrolysers (EC). The annual deficit is specified in TWh/year and in percent of total power demand in the BPS. The annual energy consumption by the electrolysers (the surplus) is shown in TWh/year and in percent from the total energy surplus in the BSP.

From the diagrams in Figure 16, it follows that even if the electrolyser's power is slightly reduced, it can deliver enough hydrogen to cover for energy deficit—when the total installed capacity of the electrolysers is above 2 GW, it can still provide enough hydrogen and, therefore, methane to support the energy balance.

However, it should be taken into account that such a strategy will lead to waste/spillage of solar or wind energy. If the available production of the renewable power plants exceeds the total system demand, including the electrolysers, market operators will be forced to reject a part of the generation bids.

Summarising the results presented in Table 6, we conclude that the return on assets (ROA) of HECME power plants is close to 5%, and, therefore, the project of such a plant is of little attraction economically. At the same time, taking into account that the ROA when implementing solar and especially wind projects is significantly higher, we can raise the issue of combining projects. The ROA of the combined project would reach 10% and such a return can be considered more than moderately attractive [61].

6. Conclusions and Directions for Future Work

Further proliferation of renewable energy is challenged by the ability to ensure power system adequacy. The problem can be resolved by the application of green hydrogen production, carbon capture and conversion to synthetic methane and further generation of electricity. The energy infrastructure of the Baltic system includes a large gas storage, a bulk gas transmission and distribution network, and gas-fired power plants; thus, it is particularly suitable for the deployment of synthetic methane technology.

Our analysis shows that the energy transition in the BPS can be achieved by building about 15 GW of solar and wind power plants, about 3.2 GW of synthetic methane plants and about 2 GW capacity of electrolysers. The existing 2.4 billion m^3 gas storage is sufficient to ensure adequacy in the energy system throughout the year.

The implementation of RES (capacity—about 16 GW) and the synthetic-methane-based plants (approximately 14 GW) will require investments in the range of EUR 38 billion. That is a significant number for the economy of the Baltic States (the GDP of Latvia in 2023 was USD 41.15 billion). However, ROA of such combined project is 10% and such a return can be considered more than moderately attractive. The scale of the above investments corresponds to the huge amount of restructuring of the energy system, as well as to the significance of the global goal of reducing millions of tonnes of emissions per year [62].

The proposed framework and approach are suitable for a pragmatic simplistic assessment of the techno-economic feasibility of the new technologies. In the future, additional scenarios have to be considered, including the construction of nuclear power plants and expansion of interconnections. Considerations of system reliability and stability, in addition to an in-depth analysis of the economic performance, must be taken into account.

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Conflicts of Interest: The authors declare no conflict of interest.

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