UNIVERSITY OF RIJEKA
FACULTY OF ECONOMICS AND BUSINESS

Andrea Dumančić

PROFITABILITY MODELS FOR HYDROGEN PRODUCTION AND ITS INTEGRATION INTO THE GAS NETWORK

DOCTORAL THESIS

Rijeka, 2024

UNIVERSITY OF RIJEKA
FACULTY OF ECONOMICS AND BUSINESS

Andrea Dumančić

PROFITABILITY MODELS FOR HYDROGEN PRODUCTION AND ITS INTEGRATION INTO THE GAS NETWORK

DOCTORAL THESIS

Supervisor: Full Professor Nela Vlahinić, PhD
Co-supervisor: Goran Slipac, PhD

Rijeka, 2024

SVEUČILIŠTE U RIJECI
EKONOMSKI FAKULTET U RIJECI

Andrea Dumančić

MODELI ISPLATIVOSTI PROIZVODNJE VODIKA I NJEGOVE INTEGRACIJE U PLINSKU MREŽU

DOKTORSKI RAD

Mentorica: prof.dr.sc. Nela Vlahinić
Ko-mentor: doc.dr.sc. Goran Slipac, dipl.ing.

Rijeka, 2024.

Mentorica: prof.dr.sc. Nela Vlahinić
Ko-mentor: doc.dr.sc. Goran Slipac, dipl.ing.

Doktorski rad obranjen je dana ____________ ___________ u/na _________________ ____, pred povjerenstvom u sastavu:

1. ____
2. ____
3. ____
4. ____
5. ____

ZAHVALE

Prvenstveno, zahvaljujem suprugu, Marinu Dumančiću, na beskrajnoj podršci koju mi je pružio u svakoj fazi procesa istraživanja i pisanja ovog doktorskog rada. Hvala ti za vrijeme provedeno u razgovoru o temi rada, za sve kritike i savjete kojima si moje nedoumice rješavao, za slušanja o literaturi koju sam pročitala kao i za čitanje svega što sam napisala. Pisanje rada satkano je od mnogobrojnih sati provedenih uz papire i laptop, kao i konstantnih pitanja idem li u dobrom smjeru. Konačan rezultat i doprinos ovoga rada, uz sve navedeno u radu, definitivno je osobno zadovoljstvo i pomicanje granica znanja o novoj i aktualnoj temi. Hvala ti što zajedno pomičemo granice.

Želim zahvaliti svojim roditeljima, bratu, rodbini i prijateljima koji su mi davali podršku, iako im nije bilo jasno o čemu točno pišem.

Nadalje, zahvaljujem mentorici prof. dr.sc. Neli Vlahinić, s kojom je svaki korak doktorskog studija prošao jednostavno i lako. Hvala vam na podršci i savjetima, kao i na dostupnosti u svako doba kada bi se javila sa pitanjima, idejom ili nacrtom dijela rada. Vaša energija i znanje davali su mi poticaj za istraživanje i pisanje.

Zahvaljujem komentoru doc.dr.sc. Goranu Slipcu, dipl.ing na savjetima tijekom pisanja doktorskog rada.

Veliko hvala koautorima na člancima, dr.sc. Goranu Majstroviću na savjetima i podršci za realizaciju i pisanje prvog članka, zatim dr. sc. Lahorku Wagmannu, dipl. ing. na savjetima i angažmanu te podršci za realizaciju za pisanje drugog članka, te dr.sc. Minei Skok na savjetima i podršci za realizaciju i pisanje trećeg članka.

Na kraju, hvala mojoj dječici, na vremenu koje su proveli spavajući u kojem je mama mogla pisati doktorski rad.

Hvala svima što ste vjerovali u mene.

SUMMARY

In the energy transition, hydrogen is considered one of the key elements that could enable the realization of a carbon-neutral economy by 2050. The research within this doctoral dissertation includes an analysis of the profitability of building an electrolyzer for the production of yellow and green hydrogen, making maximum use of the existing infrastructure. The goal is to formulate models that will analyze the potential location of an unpromising thermal power plant, the location of a wind power plant located near the gas transportation network, and the location of a large hydrogen consumer. The production price and quantity of hydrogen as output variables of the models will test the hypothesis about the impact of hydrogen in the energy transition in terms of reduced CO_2 emissions and utilization of the existing gas infrastructure.

Two economic models investigate the possibility of integrating hydrogen into the gas network, i.e. the first model analyzes the justification of investing in an electrolyzer at the location of the thermal power plant, and the second model analyzes the impact of hydrogen production on the total income of the wind power plant. An alternative to the integration of hydrogen into the gas network is a third economic model that calculates the justification of hydrogen production at the point of consumption, i.e. a model where electricity is distributed to the point of hydrogen consumption, instead of transporting hydrogen through the gas system.

Economic models represent a tool that enables the comparison of the production price of hydrogen with the prices of fossil alternatives. If the production price of hydrogen is uncompetitive, the share of necessary subsidies is calculated in terms of the justification of the investment and the achievement of decarbonization goals.

The research results will provide new scientific insights and help in making investment and regulatory decisions on investing in hydrogen production by water electrolysis for greater utilization and efficiency of the existing energy infrastructure, while respecting the goals of climate neutrality

Keywords: Green hydrogen production, Yellow hydrogen production, Proton exchange membrane water electrolysis, Hydrogen colours, Hydrogen economy, Steam methan reforming

SAŽETAK

U energetskoj tranziciji vodik se smatra jednim od ključnih elemenata koji bi mogao omogućiti ostvarenje ugljično-neutralnog gospodarstva do 2050. godine. Istraživanje u okviru ove doktorske disertacije obuhvaća analizu isplativosti izgradnje elektrolizatora za proizvodnju žutog i zelenog vodika maksimalno iskorištavajući postojeću infrastrukturu. Cilj je formulirati modele koji će analizirati potencijalnu lokaciju neperspektivne termoelektrane, zatim lokaciju vjetroelektrane koja se nalazi u blizini plinske transportne mreže te lokaciju velikog potrošača vodika. Proizvodna cijena i količina vodika kao izlazne varijable modela testirat će hipotezu o utjecaju vodika u energetskoj tranziciji glede smanjena emisija CO_2 i iskorištavanja postojeće plinske infrastrukture.

Dva ekonomska modela istražuju mogućnost integracije vodika u plinsku mrežu, odnosno prvi model analizira opravdanost ulaganja u elektrolizator na lokaciji termoelektrane, a drugi model analizira utjecaj proizvodnje vodika na ukupni prihod vjetroelektrane. Alternativa integraciji vodika u plinsku mrežu opisana je ekonomskim modelom koji je dokazao opravdanost proizvodnje vodika na mjestu potrošnje, odnosno model gdje se električna energija distribuira do mjesta potrošnje vodika, umjesto transporta vodika plinskim sustavom.

Ekonomski modeli predstavljaju alat koji omogućuje usporedbu proizvodne cijene vodika sa cijenama fosilnih alternativa. Ukoliko je proizvodna cijena vodika nekonkurentna, izračunava se udio potrebnih subvencija u pogledu opravdanosti ulaganja i ostvarenja dekarbonizacijskih ciljeva.

Rezultati istraživanja pružiti će nove znanstvene uvide te pomoći pri donošenju investicijskih i regulatornih odluka o ulaganju u proizvodnju vodika elektrolizom vode za veću iskoristivost i učinkovitost postojeće energetske infrastrukture, uvažavajući pritom ciljeve klimatske neutralnosti.

Ključne riječi: proizvodnja zelenog vodika, proizvodnja žutog vodika, elektroliza vode na elektrolizatoru s protonski izmjenjivom membranom, boje vodika, ekonomija vodika, parno reformiranje metana

PROŠIRENI SAŽETAK

Energetski sektor nalazi se pred izazovima tranzicije zamjene fosilnih izvora sa obnovljivim izvorima energije, od kojih bi značajnu ulogu trebao imati vodik. Naime, primjena vodika u energetskom sektoru ima potencijal značajno smanjiti emisije CO_2, budući da sagorijevanje vodika ne ispušta CO_2 emisije i ne zagađuje zrak prilikom korištenja, te bi vodik, uz postizanje ciljeva Europskog Green Deal-a i provedbe Pariškog sporazuma, mogao omogućiti ostvarenje ugljično-neutralnog gospodarstva do 2050. godine. Europska Komisija donijela je dva strateška dokumenta za uspješnu energetsku tranziciju: *Strategiju za vodik za klimatski neutralnu Europu* i *Europsku strategiju za integraciju energetskih sustava.* Također, Republika Hrvatska je donijela *Hrvatsku strategiju za vodik do 2050. godine* što dodatno doprinosi važnosti sagledavanja uloge vodika s ekonomskog aspekta. Cilj Europske strategije za vodik jest da se vodik proizvodi iz električne energije dobivene iz obnovljivih izvora energije elektrolizom vode koji se klasificira kao obnovljivi vodik. *Uredbom o unutarnjim tržištima za obnovljive i prirodne plinove i za vodik* dopušta se umješavanje vodika u sustav prirodnog plina do 2 % volumnog udjela kako bi se osigurala usklađena kvaliteta plina između operatora transportnih sustava.

Cilj ove doktorske disertacije bio je formulirati modele isplativosti proizvodnje vodika za više odabranih lokacija te integracijom u plinsku mrežu odrediti utjecaj smanjenja emisija CO_2. Kako bi se ekonomski modeli mogli kreirati i optimirati, bilo je potrebno provesti analizu koja se temeljila na projekcijama cijena električne energije, prirodnog plina i emisija CO_2, zatim na podacima o vrsti i cijeni tehnologije proizvodnje vodika, kao i na specifičnostima odabranih lokacija proizvodnje vodika. Rezultatima modela uspoređene su proizvodne cijene vodika s cijenama fosilnih alternativa u pogledu opravdanosti ulaganja i ostvarenja dekarbonizacijskih ciljeva. Ekonomska isplativost proizvodnje vodika modelirala se za tri odvojena slučaja, odnosno za tri različite lokacije kako slijedi.

1) Za centraliziranu proizvodnju vodika odabrana je opcija na lokaciji postojeće elektrane (lokacija termoelektrane) gdje se električnom energijom iz elektroenergetske mreže u elektrolizatoru proizvodi vodik. U ovome modelu, predviđena je ugradnja elektrolizatora na lokaciji postojeće termoelektrane, koja nije u funkciji ali se može prenamijeniti i uz postojeće priključke na plinsku i elektroenergetsku mrežu smanjuje početno ulaganje. Osim investicije, modelom je predviđeno i uključivanje elektrolizatora u sustav pomoćnih usluga, čime daje sigurnost elektroenergetskom sustavu i dodatnu vrijednost glede proizvodnje

vodika. Cilj modela je zadovoljenje 10% energetskog udjela vodika u plinskoj mreži.

2) Za decentraliziranu proizvodnju vodika odabrana je opcija na lokaciji obnovljivog izvora energije (lokacija vjetroelektrane) gdje se električnom energijom proizvedenom iz vjetroelektrane u elektrolizatoru proizvodi vodik. U ovome modelu, predviđena je ugradnja elektrolizatora na mjestu postojeće vjetroelektrane, koja nema priključak na plinsku mrežu stoga taj dio investicije uvećava početno ulaganje. Cilj modela je proizvodnjom vodika postići dodatan prihod vjetroelektrani, a pritom se cjelokupna proizvodnja vodika umješava u plinsku mrežu.
3) Za proizvodnju vodika na lokaciji potrošnje odabrana je opcija na lokaciji tvornice umjetnih gnojiva, u blizini amonijačnog postrojenja gdje se električnom energijom iz elektroenergetske mreže kupljenom putem PPA ugovora u elektrolizatoru proizvodi vodik. U ovome modelu, predviđena je ugradnja elektrolizatora u blizini amonijačnog postrojenja kako bi se proizvedeni vodik mogao koristiti kao sirovina u daljnjem procesu industrije. S obzirom da se radi o velikoj količini vodika koji bi se proizvodio na lokaciji potrošnje, potrebno je povećati priključak na elektroenergetsku mrežu a koji utječe na povećanje početnog ulaganja. Cilj modela je smanjiti emisije CO_2 koje proizvede industrija u procesu proizvodnje vodika kao sirovine na način da se vodik proizveden iz prirodnog plina zamijeni vodikom proizvedenim iz električne energije iz PPA ugovora sklopljenih sa proizvođačima električne energije iz obnovljivih izvora. Ovim modelom prikazano je alternativno rješenje gdje se vodik koristi kao sirovina u daljnjem procesu, a ne kao energent koji se umješava u plinsku mrežu.

Cilj ovog doktorskog rada bio je istražiti mogućnosti integracije vodika u plinsku mrežu kroz ekonomske modele kojima bi se analizirala opravdanost ulaganja u prenamjenu postojeće energetske infrastrukture na lokaciji termoelektrane i vjetroelektrane. Alternativa integraciji vodika u plinsku mrežu opisana je ekonomskim modelom koji je dokazao opravdanost proizvodnje vodika na mjestu potrošnje, odnosno model gdje se električna energija prenosi do mjesta potrošnje vodika, umjesto transporta vodika plinskim sustavom.

Dva modela disertacije obuhvaćaju umješavanje vodika u plinsku mrežu. U centraliziranom modelu proizvodnje vodika zadan je udio energetskog umješavanja vodika u plinsku mrežu, na način da do 2030. godine zadani udio iznosi 5%, a do 2050. godine iznosi 10%. Kod ovog modela dodatna originalnost bila je postotak umješavanja u energiji a ne u volumnom iznosu, za koje prema saznanju doktoranda, u literaturi ne postoji niti jedna studija koja je analizirala takav učinak. Sve studije se odnose na volumno umješavanje vodika u plinsku mrežu, a koje je za tri puta veće u odnosu na umješavanje u energiji. U decentraliziranom modelu proizvodnje vodika udio umješavanja nije bio zadan, nego se ukupna proizvodnja vodika umješava u plinski sustav, pod pretpostavkom da se sva proizvedena količina vodika može bez ograničenja umješati u plinski sustav.

Istraživanje u okviru ove doktorske disertacije obuhvaćala su proizvodnju različitih boja vodika – tzv. žutog i obnovljivog (zelenog) vodika,s obzirom da boja vodika ovisi o izvoru električne energije kod proizvodnje vodika elektrolizom vode. Na taj način, modelom centralizirane proizvodnje proizvodi se žuti vodik koji će težiti zelenom, obnovljivom vodiku, budući da njegova boja ovisi o energetskom miksu proizvodnje električne energije koja se dobiva iz elektroenergetske mreže, a koja bi do kraja 2050. godine trebala težiti većinskom udjelu obnovljivih izvora energije. U preostala dva modela bila je predviđena proizvodnja obnovljivog vodika iz električne energije proizvedene iz obnovljivih izvora.

Modeli isplativosti proizvodnje vodika prvenstveno su bili fokusirani na proizvodnu cijenu vodika ovisno o specifičnosti lokacije, te ukoliko je cijena vodika bila nekonkurentna naspram cijene prirodnog plina uvećanoj za trošak emisija CO_2, analizirala se potreba za subvencijom koja bi investiciju u proizvodnju vodika učinila isplativom. Iznos subvencija biti će alat s kojim će se moći definirati uspostava poticaja za proizvodnju vodika unutar regulatornog okvira tržišta vodika.

Metodologija koja je korištena u ekonomskim modelima temeljila se na četiri metode: *Monte Carlo* simulacijom napravljena je projekcija satne razrade kretanja tržišnih cijena električne energije, zatim *Merit order* analiza služila je za određivanje optimalne veličine i broja sati rada elektrolizatora temeljem poretka projiciranih tržišnih cijena električne energije ali i krivulje proizvodnje električne energije, *analiza grupa* određivala je grupe vjetroelektrana sukladno dijagramu proizvodnje kod određivanja razine cijena u PPA ugovorima, dok su se *metodom simulacije* izrađivali scenariji ekonomskih modela promjenom ulaznih parametara, odnosno cijena električne energije, prirodnog plina i emisija CO_2.

Ulazni parametri modela koji su se koristili su: cijena električne energije, cijena prirodnog plina, cijena emisija CO_2, CAPEX, OPEX i učinkovitost proizvodnje elektrolizatora. Dodatni ulazni parametri poput krivulje proizvodnje vjetroelektrana te dodatnih ulaganja u infrastrukturu na lokaciji bili su korišteni u pojedinim modelima. Najvažniji izlazni parametri modela su veličina elektrolizatora, proizvodna cijena vodika, utrošak električne energije za proizvodnju vodika, trošak električne energije, količina ušteda u emisijama CO_2. Dodatni izlazni parametri poput prihoda od pomoćnih usluga i prihoda od prodaje električne energije na tržištu bili su prikazani u pojedinim modelima. Koristile su se duge serije satnih podataka u razdoblju od 25 godina. Očekivani rezultat analize koja je povezala više istraživanja je scenariji isplativosti proizvodnje vodika na tri odvojene lokacije, kojima je bio cilj prikazati opravdanost proizvodnje vodika u energetskoj tranziciji.

Rezultati istraživanja pružili su nove znanstvene uvide u donošenje investicijskih odluka o ulaganju u elektrolizatore za proizvodnju vodika za veću iskoristivost i učinkovitost postojeće energetske infrastrukture, uvažavajući pritom ciljeve klimatske neutralnosti.

Contents

1. INTRODUCTION

1.1. Research problem and hypotheses

The energy sector is facing the challenges of the transition from fossil fuels to renewable energy sources, in which hydrogen is expected to play a significant role. This doctoral dissertation will deal with the role of hydrogen as an important factor in the future economic growth of an economy that strives for carbon neutrality. Namely, the application of hydrogen in the energy sector has the potential to significantly reduce CO_2 emissions, since the burning of hydrogen does not emit CO_2 emissions and does not pollute the air during use, and plays an important role in achieving the goal of the European Green Deal and the implementation of the Paris Agreement to achieve a carbon-neutral economy until 2050. This is supported by the fact that the European Commission adopted two strategic documents: The Hydrogen Strategy for a Climate Neutral Europe, in which hydrogen is highlighted as one of the key levers for a successful energy transition, and The European Strategy for the Integration of Energy Systems, which describes how the current framework of European Union policies contribute to the realization of a climate-neutral integrated energy system with a high share of renewable energy sources.

The Republic of Croatia adopted The Croatian Strategy for Hydrogen until 2050 (Official Gazette, 40/2022), which determines the framework possibilities for the development of production, storage, transport, and general use of hydrogen with the aim of reducing CO_2 emissions, as well as the possibilities the inclusion of the economy in the sector of equipment production, which would ensure technological adaptation and participation in the European and world market of hydrogen technologies. According to data from the Hrvoje Požar Energy Institute (2020), the total consumption of natural gas in 2019 in the Republic of Croatia was 2,908.0 million m^3, of which 2,003.4 million m^3 of natural gas was imported. Dependence on the import of natural gas in 2019 amounted to 69%, which indicates the fact that domestic production is declining and that the production of hydrogen from electricity and hydrogen blending into the gas grid with the consequent reduction in natural gas imports and the reduction of CO_2 emissions would enable part of the fulfillment of the energy transition and the goals of the Hydrogen Strategy until 2050.

Among the hydrogen production technologies, the most common is the conversion of electricity into gas, that is, the Power-to-Gas (P2G) process, which uses electricity for electrolysis, which separates water into hydrogen and oxygen molecules through a chemical reaction. At the same time, the share of renewable energy sources in the production of electricity also depends on the color of the hydrogen obtained, i.e.

green, gray, or yellow hydrogen. Hydrogen color depends on the type of production, and if the hydrogen is produced by water electrolysis then the color also depends on the source of electricity. The green hydrogen, often called "pure hydrogen", "renewable hydrogen" or "low carbon hydrogen", is produced by water electrolysis using electricity from wind, water or the sun. Blue hydrogen is production from fossil fuels with capturing the greenhouse gases (Arcos, Santos, 2023.). Turquoise hydrogen is produced by methane pyrolysis. Yellow hydrogen is produced by electrolysis using electricity taken from the power grid (Clifford, 2022). Low-carbon hydrogen includes green, blue, turquoise, and yellow hydrogen (Noussan, 2020). Gray hydrogen is produced by steam methane reforming, partial oxidation, or autothermal reforming, but without capturing the greenhouse gases (National Grid, 2022) and is generally used in the petrochemical industry to produce ammonia. The brown and black hydrogen refer to the type of lignite (brown) and bituminous (black) coal used in production. Although hydrogen from biomass gasification should be considered green, assuming that the entire life cycle of biomass is carbon neutral, the undoubtedly high CO_2 emissions of the production process make it brown hydrogen (Arcos, Santos, 2023.). Pink hydrogen is produced by water electrolysis using electricity from a nuclear power plant. Purple hydrogen is produced using nuclear energy and heat through combined electrolysis and thermochemical splitting of water. Red hydrogen is produced by catalytic splitting of water at high temperatures using nuclear thermal energy as an energy source. White or golden hydrogen, occurs naturally in the continental crust, the ocean, or in volcanic gases, geysers and hydrothermal systems. Hydrogen economy based on white and green hydrogen could be the best combination for the transition to a carbon-neutral economy (Hydrogen Europe, 2024.).

The goal of the European Union's hydrogen strategy is to produce hydrogen from electricity obtained from renewable energy sources by electrolysis of water, the process of which produces green hydrogen, but since the process is still very expensive, hydrogen is produced from natural gas, therefore renewable hydrogen is classified as a priority, while low-carbon hydrogen is necessary in the gradual replacement of fossil sources.

Namely, in this doctoral dissertation, three separate analyses of hydrogen production were carried out, i.e. three different models were created which, through different scenarios of the profitability of hydrogen production, can serve as a tool for making investment decisions. The models refer to the following projects: hydrogen production at the location of an unpromising thermal power plant, hydrogen production at the location of a wind power plant, and hydrogen production at the location of a large consumer industry. The results of the models are primarily focused on the hydrogen production price, which largely depends of electricity, natural gas and CO_2 emissions market prices projection. Given that the goal and aspiration is for the hydrogen price to be competitive with the natural gas price increased by the CO_2 emissions cost, the subsidy option is additionally analyzed, to directly influence the greater use of hydrogen in the energy sector and faster replacement of fossil sources. In addition, to the justification and profitability of hydrogen production projects, as well as an adequate hydrogen market regulation, the replacement of natural gas with hydrogen will also affect end customers in terms of the use of carbon-neutral energy. Following the above, the main and four auxiliary hypotheses were set.

The **main hypothesis** of the thesis is that hydrogen production profitability models formulated for specific locations influence the reduction of CO_2 emissions and the repurposing of the existing energy infrastructure as part of the achievement of energy transition goals.

1) The **first auxiliary hypothesis** tests if investing in an electrolyzer for hydrogen production at the location of an existing thermal power plant is financially justified.
2) The **second auxiliary hypothesis** tests if investing in a hydrogen electrolyzer at the wind power plant site and blending the hydrogen into the gas grid enables a better financial result for the wind power plant.
3) The **third auxiliary hypothesis** tests if investing in an electrolyzer for the production of green hydrogen at the location of a large consumer enables a lower production price of hydrogen than the existing production of gray hydrogen, taking into account the cost of CO_2 emissions.
4) The **fourth auxiliary hypothesis** tests if subsidizing the production of green hydrogen is necessary for projects related to the production of green hydrogen as a substitute for natural gas to be financially justified. The four auxiliary hypotheses will be proved as follows.

The first auxiliary hypothesis will be proven by determining the optimal number of operating hours of the electrolyzer and by activating the provision of ancillary services to the power system. This hypothesis justifies investments in the production of yellow hydrogen at the site of an unpromising thermal power plant. Namely, the greater number of operating hours of the electrolyzer includes hours when the electricity market price is high, while simultaneously, reduces the share of capital investment cost in the total production price. The independent variables that will test the hypothesis are the projection of the hourly electricity market prices according to the Ten-Year Network Development Plans (2022) scenario for a period of 25 years determined by Monte Carlo simulation, the optimal operating hours of the electrolyzer that will be calculated by the model according to the merit order model, the fixed and variable costs of the electrolyzer taken from relevant literature and activation of ancillary services in accordance with the prices taken from Independent Transmission System Operator in Croatia. The dependent variable, i.e. the yellow hydrogen production price, will be calculated using the mentioned independent variables, and the first auxiliary hypothesis will be tested by comparison with the natural gas price increased by CO_2 emissions.

The second auxiliary hypothesis will be proven by calculating the dependent variable of income from hydrogen production. When calculating the green hydrogen production price at the location of the wind power plant, the capital part of the investment is increased by the connection cost to the gas transport network and the cost of chemical preparation of water. However, at the location of the wind power plant, the number of operating hours of the electrolyzer and thus the required installed power of the electrolyzer is limited by the number of operating hours of the wind power plant and the market price of electricity. The independent variables for testing the hypothesis are the following: number of operating hours, installed power and capital and operating costs of the electrolyzer, hourly production of electricity from the wind power plant taken from Independent Transmission System Operator in Croatia, and the hourly electricity market prices projection according to the Ten-Year Network Development Plans (2020) scenario for 25 years determined by Monte Carlo simulation. The independent variables will be used to calculate the dependent variable, i.e. income from hydrogen production, which will test the second auxiliary hypothesis by comparing it with the calculation of income from the sale of electricity on the market.

The third auxiliary hypothesis will be proved by calculating the dependent variable of the amount of hydrogen produced. When calculating the green hydrogen production price at the location of the industry, the capital part of the investment increases the cost of increasing the power grid connection at the location, while at the same time, the cost of electricity is determined by the concluded power purchase agreement contracts (PPA contracts). At the industrial site, the amount of hydrogen produced depends on the amount of available electricity that has been concluded in PPA contracts as well as on the installed electrolyzer capacity. The independent variables for testing the hypothesis are the following: installed power and capital and operating costs of the electrolyzer, hourly electricity production from the wind power plant taken from Independent Transmission System Operator in Croatia, projection of the hourly electricity market prices according to the Ten-Year Network Development Plans (2022) scenario for 25 years determined by Monte Carlo simulation, and the projection of the level of electricity prices concluded in PPA contracts. The independent variables will be used to calculate the dependent variable, i.e. the amount of hydrogen produced, which, by comparison with the same amount of hydrogen produced from the SMR plant, will calculate the ratio of CO_2 emission savings and thus test the third auxiliary hypothesis.

The fourth auxiliary hypothesis will be proven by calculating the subsidy amount for hydrogen production for each analyzed location. Namely, the CO_2 emissions price as a regulatory mechanism already affects the hydrogen price to be competitive. The amount of the subsidy will be calculated in such a way that the natural gas price is increased by the CO_2 emissions price and subtracted from the hydrogen production price. The independent variables used to test the hypothesis are the following: electricity market price projection, natural gas, and emission units projection according to the Ten-Year Network Development Plans (2022) scenario for 25 years, with which the scenarios will be created using the simulation method. Within each scenario, the amount of the necessary subsidy will be calculated depending on the change in the electricity, natural gas, and CO_2 emissions prices. The obtained result of the subsidy amount for each analyzed location and for several presented scenarios will be used to test the fourth auxiliary hypothesis.

1.2. Purpose and goal of the research

Every energy transition is accompanied by investments in new technologies, and for them to be economically justified, is made a techno-economic analysis of the projects that enable the energy transition. A review of the relevant literature found a gap in the existing literature. Therefore the goal of this doctoral dissertation is to create a model that will optimize hydrogen production at specific locations while taking advantage of the existing infrastructure. The review of the literature shows that none of the mentioned studies includes certain assumptions that will be taken into account during modeling in this dissertation, as follows:

1) projection of the movement of hourly electricity market prices for a period of 25 years,
2) choosing the optimal electrolyzer size, so that the excessive capacity of the electrolyzer is not unused and additionally burdens the investment of an individual project,
3) the total amount of the produced hydrogen at a specific location and the impact on the reduction of CO_2 emissions,
4) comparison of the hydrogen production price and the natural gas market price increased by the CO_2 emissions cost for the purpose of competitiveness of the produced hydrogen.

In this doctoral dissertation, the gap is filled with models that, based on the hydrogen production analysis in specific locations, will provide the basis for an optimal scenario of the justification of hydrogen production projects in the energy sector. The main variables of the models are the determination of the optimal electrolyzer size for hydrogen production, and the examination of the competitiveness of the hydrogen production price against the natural gas price increased by the CO_2 emissions cost, which influences the formation of a strategy and basis for the hydrogen market regulation, i.e. the regulation of incentives for hydrogen production, but also incentives for conversion of existing gas infrastructure.

Accordingly, the following research questions were placed:

1) To what extent does the electrolyzer size, the amount of produced hydrogen, and the total cost of the investment correlate?
2) In what period can the return on investment in an electrolyzer for hydrogen production be expected and how much does it depend on the hydrogen production location?
3) Does the location of the production and the electrolyzer size or the ratio of the electricity, natural gas, and CO_2 emissions market prices affect the competitive hydrogen production price?
4) To what extent is the influence of the regulated or subsidized price of hydrogen necessary on the realization of the energy transition in the part of gas infrastructure utilization, taking into account each analyzed location of hydrogen production?

The results of three models will answer questions, which is the purpose of the dissertation; to test the justification of electrolyser construction projects at different existing locations.

1.3. Overview of previous research

A large number of scientific research refer to the examination of the impact of energy, its forms, and energy resources on the economy, at the regional, national, and world levels. In this sense, according to the modern economic theory that future economic development is based on the principles of sustainability, a new economic doctrine called the green economy was created (Ilić, Nikolić, Simeonović, 2018). Given that the topic of the energy transition, and especially the role of hydrogen as one of the carriers of the transition, is new and relevant only in the last few years or even shorter than that, and all existing research on the topic is exclusively of applied significance, the theoretical framework of the model in this doctoral dissertation is the theory of real options. Real options represent the right, but not the obligation, to undertake certain capital projects. They provide flexibility in business and serve to more effectively achieve goals and strategies. With option valuation, the assumption is that traditional methods of investment analysis cannot properly value the potential of the project because they do not consider the possibilities of changes and adaptation to current market conditions. If the economic prospects of the project are favorable, the default option can be realized, for example investing in the construction of an electrolyzer at the wind power plant location. In the opposite case, if there are unfavorable economic conditions, such an option can be abandoned, which means that no investment will be made, for example, in an electrolyzer at the large consumer location until the moment when better market and economic conditions occur.

Ogden (1999) conducted research related to the overview and status of hydrogen production technology along with an assessment of the costs of developing hydrogen infrastructure and the potential for hydrogen use. Li et al. (2020) explained the fundamental principles of hydrogen production technology and the technical advantages of complementary hydrogen production from renewable energy sources in China. In research, Lambert and Schulte (2021) examine the hydrogen development in six European countries with a comparison of approaches in the hydrogen market development in relation to the natural gas market. Each of the countries has a different approach to the introduction of hydrogen, so Great Britain and the Netherlands rely on blue hydrogen, Italy and Spain on green, while Germany and France rely on the hydrogen production from nuclear power plants. The aforementioned authors determined that the production of hydrogen by water electrolysis has limited use due to its current lower competitiveness than hydrogen obtained from fossil fuels. In research, Glenk (2019) analyzed the economics of hydrogen production through the Power-to-Gas process from three perspectives, sustainability, operational synergy, and competitiveness with fossil sources. The author concludes that technological progress and the drop in the price of renewable energy sources will affect the economics of hydrogen production from renewable energy sources through the Power-to-Gas process and that with a competitive price, renewable hydrogen will meet the goals of significantly reducing carbon emissions. From the aforementioned research, it is evident that there is an interest of the author in research on the topic of hydrogen production technology, however, there are still certain obstacles that make hydrogen production unprofitable. Although certain researchers mention factors that would make hydrogen production profitable under certain conditions, no detailed analysis was carried out to confirm this, which will be part of the models in this doctoral dissertation.

Numerous authors in their research have dealt with techno-economic analyzes of hydrogen production technology, of which the following should be singled out: production of gray hydrogen with given natural gas prices and CO_2 emissions was analyzed by Nazir et al. (2021), while Luo et al. (2020) made a comparison of the gray and green hydrogen production costs in China. Although the gray hydrogen production costs are lower, the purification cost and the CO_2 emissions cost are high, so the authors recommend that, when producing green hydrogen, also participate in the transactions of the electricity and emissions units market, which can further reduce the green hydrogen production costs. Furthermore, a techno-economic analysis of hydrogen production from two types of solar technology was carried out by Grimm, Jong and Kramer (2020). Hydrogen production from wind power plants in Ireland was analyzed by Dinh et al. (2021), then Gysels (2018) on the example of Belgium and Walker et al. (2016) on the example of Canada. Comparative analysis and production of gray and green hydrogen was investigated by Navas-Anguita et al. (2020) on the example of Spain, Fu et al. (2020) on the example of Great Britain and Zapantis and Zhang (2020) on the example of Australia. Techno-economic analysis of the green hydrogen production in Germany was processed by Bareiß et al. (2019), Ferrero et al. (2016) on the example of Italy, Kopteva et al. (2021) on the example of Russia, Chaube et al. (2020) on the example of Japan, Siyal (2019) on the example of Sweden, Ruhnau (2022) on the example of Germany and Qolipour, Mostafaeipour, Tousi (2017) on the example of Iran. Jovan, Dolanc and Pregelj (2021) analyzed the potential of green hydrogen production in the existing hydroelectric power plant in Slovenia, as well as the assessment of the implementation of hydrogen production equipment with a comparison of profitability in relation to the sale of electricity on the market. The above-mentioned researches, which dealt with techno-economic analyzes of hydrogen production technology, point to the conclusion that hydrogen can be produced at competitive prices both from renewable energy sources and from fossil alternatives. The analyzes were carried out on individual countries, which are not applicable to other countries and with the limitations with which the profitability of hydrogen production is achieved. The models in this doctoral dissertation try to remove precisely these limitations and obstacles, that is, there are no limitations in the models that make hydrogen production profitable under certain conditions. This is achieved by hourly projections of the long-term period of the models, taking into account the latest forecasts of the electricity, natural gas and CO_2 emissions market prices, then estimates of the operating hours of the wind power plant on a real example, as well as by including in the models the amount of the cost of the complete investment in the electrolyzer at each individual location. The aforementioned results in the analysis in this doctoral dissertation being applicable to other countries as well, along with the calculation of the actual hydrogen production cost at specific locations.

Since the focus of research in this doctoral dissertation is on the production of hydrogen produced by water electrolysis in an electrolyzer, the electrolyzers types were analyzed. Water electrolysis is a chemical process of splitting water molecules into oxygen and hydrogen, which can take place at low and high temperatures, and according to which there are types of electrolyzers that enable this. Based on various studies in which Ayers et al. (2019) gave an overview and technical status of electrolyzers, then Pethaiah et al. (2020) analyzed the efficiency of production depending on the components of the electrolyzer, the assessment of economics and capital costs was made by Ali Khan et al. (2021) while Lappalainen (2019) on the example of Finland made assessments of the technical and economic characteristics for the operation of the electrolyzer as part of the Power-to-X system, in this doctoral dissertation a PEM electrolyzer for hydrogen production was used in all models. The characteristics of the PEM electrolyzers proved to be more efficient and profitable compared to other types of electrolyzers from the mentioned research.

Research on the profitability of green hydrogen production, where hydrogen is produced in an electrolyzer, and which is also used to provide ancillary services to the power system, was done by Jovan and Dolanc (2020) on the example of a Slovenian hydroelectric power plant, Lappalainen (2019) on the example of Finland, Xiong et al. (2021) and Gorre et al. (2020) on the example of Germany. The aforementioned studies include revenues from ancillary services that additionally affect the profitability of hydrogen production from renewable energy sources, therefore, in one model of this dissertation, revenues from tertiary activities are included, for the purpose of which real data from such a system were used. Given that the electrolyzer can provide additional security to the power system by including it in the tertiary activities, it also ensures additional competitiveness in the hydrogen production price.

This doctoral dissertation will also deal with the topic of hydrogen integration into the gas network, therefore the results of significant research on the possibilities and effects of hydrogen injecting into the gas grid are listed below. In research, Eveloy (2018) provides an overview of all scenarios of the implementation of the Power-to-Gas process in the existing and future energy systems through unified research papers and Power-to-Gas projects for selected countries and regions of the world. Also listed are the permitted volume amounts of hydrogen in gas networks in seven European countries, which range from 0.1% in Great Britain to 12% in the Netherlands. The study provides an excellent overview of started and pilot projects across Europe, from which it is clear that these are still not projects with a large installed power of electrolyzers, but rather smaller locations where electrolyzers are installed, and most of the projects relate to examining the profitability of production, storage or transport of hydrogen. Some projects involve the repurposing of part of the industry or gas infrastructure, while there are few projects that include the construction of a completely new hydrogen infrastructure. The aforementioned research provides an overview of countries that have already prescribed the percentage of hydrogen injecting into the gas network in their national strategies, from which it can be seen that there are large differences between countries.

According to research by Pellegrini, Guzzini, and Saccani (2020) and Romeo et al. (2022) on the example of Italy, the concept of combining the Power-to-Gas process and blending hydrogen into the gas grid was presented, which proved to be the most cost-effective solution in the short and medium term with a huge potential for social and environmental benefits if it involves a smaller proportion of blending. Namely, injecting a large amount of hydrogen into the gas network can lead to high concentrations that can degrade materials and generally be unacceptable for correct and safe operation. In addition, the authors highlight numerous technological, economic, and legislative obstacles. Ekhtiari, Flynn, and Syron (2020) analyzed the effects of the inclusion of green hydrogen in the gas network as well as the parameters of the gas network on the example of Ireland, while Huszal and Jaworski (2020) analyzed the blending of hydrogen in the odorization station on the example of Poland and concluded that the possible range hydrogen blending between 8 and 15%. Using the example of Australia, Zapantis, and Zhang (2020) made an analysis of blending up to 10% of gray and green hydrogen into the gas network and concluded that gray is more profitable than green hydrogen, while Zhang et al. (2022) analyzed the example of China and concluded that gas infrastructure has the potential to reduce CO_2 emissions and increase the security of supply in the context of the transmission of all low-carbon gases. Building on the European strategy for hydrogen, in mid-December 2023, the European Commission adopted the draft package for the hydrogen and decarbonized gas market, within which, along with proposals for changes to the directive and gas regulation, the foundation for the development of the hydrogen market is laid. The draft package leaves it to member states to allow hydrogen injecting in their national gas network but sets a blending threshold of up to 2% hydrogen content in gas pipeline at interconnection points to harmonize cross-border natural gas flows.

1.4. Scientific methods

In this doctoral dissertation, the analysis is carried out for electrolyzer construction projects in which hydrogen is produced using the existing energy infrastructure. The models are based on data on the investment in a PEM electrolyzer that produces hydrogen at three specific locations in order to examine the competitiveness of the produced hydrogen in relation to natural gas, but also the effect on reducing CO_2 emissions. The research was conducted on the basis of the available data for the Republic of Croatia, but it is also applicable to Central European and Mediterranean countries with a similar climate and energy mix of electricity production. By changing the input variables of the each model, the results can be obtained for any other region or country examining the feasibility of similar projects. The proposed models will connect multiple researches and provide a new contribution to modeling the profitability of hydrogen production.

The methodology that will be used in the economic models is based on four methods: a Monte Carlo simulation was used to project the hourly projected electricity market prices, then the Merit order analysis was used to determine the optimal size and number of operating hours of the electrolyzer based on the order of the projected market electricity prices, and on electricity production curves, group analysis determines groups of wind power plants in accordance with the production diagram when determining the level price of electricity in PPA contracts, while the simulation method creates economic model scenarios by changing the input parameters, i.e. the electricity, natural gas, and CO_2 emissions price.

1.5. Structure of the dissertation

This doctoral dissertation is written according to the Scandinavian model, which, in addition to the introduction and concluding chapters, includes three published papers focusing on the profitability of hydrogen production, based on available data for the Republic of Croatia, in such a way that each paper forms a separate chapter.

The introduction chapter defines the subject and objective of the research, provides a brief overview of the relevant literature, and along with the research questions and set hypotheses of the thesis, provides the background for making a decision on investment and subsidizing construction projects of electrolyzers for hydrogen production in the energy sector regarding the achievement of energy transition goals.

The concluding chapter presents the most important results of the dissertation, describes the main contributions, and provides background and ideas for future research.

The second chapter deals with the analysis of the profitability of the investment in the project of building an electrolyzer at the unprofitable thermal power plant location.

The third chapter, deals with the analysis of the profitability of the investment in the project of building an electrolyzer at the existing wind power plant location.

The fourth chapter deals with the analysis of the profitability of the investment in the electrolyzer construction project at the existing fertilizer plant location.

After the concluding chapter, there is a list of references and illustrations.

2. CAN HYDROGEN PRODUCTION BE ECONOMICALLY VIABLE ON THE EXISTING GAS-FIRED POWER PLANT LOCATION? NEW EMPIRICAL EVIDENCE

Authors: Andrea Dumančić, Nela Vlahinić Lenz, Goran Majstrović

Title: Can Hydrogen Production Be Economically Viable on the Existing Gas-fired Power Plant Location? New Empirical Evidence

Journal: Energies; EISSN 1996-1073, Published by MDPI

Published: 27 April 2023; Energies 2023, 16(9), 3737; https://doi.org/10.3390/en16093737

Submitted to section: C: Energy Economics and Policy, Energy Economics and Policy Guidance for Renewable and Sustainable Energy Transition

2.1. Introduction

As a part of the energy transition to carbon neutrality, a continuous reduction in natural gas consumption is expected to decarbonize the energy sector and increase energy efficiency, especially the use of gas infrastructure and alternative fuels such as hydrogen. The decline in natural gas consumption combined with the additional supply constraint and decline in domestic production, as well as the increase of CO_2 emission prices, have positioned hydrogen as an alternative to natural gas.

Due to current circumstances, investments in existing production capacities or in the new research to increase the use of hydrogen are being considered in Europe to increase the security of supply and to enable a more effective transition of the economy from fossil-based to RES-based (Renewable energy sources). The topic of hydrogen production and its economics in different scenarios has only been intensively researched in the last few years, although hydrogen production technology by electrolyzers has been known for a long time. The decarbonization of the energy system manifests itself in low-carbon power generation and the use of batteries and Power-to-gas systems.

In view of the above, the authors believe that an analysis of the possibility of replacing natural gas with yellow hydrogen using the existing electricity and gas infrastructure is required, along with an economically justified investment in the Power-to-gas system.

The Power-to-gas system plays an important role, enabling long-term and seasonal storage of electricity and hydrogen production as a substitute for natural gas through water electrolysis (Maeder, et al. 2021.). Although there are four types of water electrolysis processes, alkaline water electrolysis (ALK), solid oxide electrolysis (SOE), microbial cell electrolysis (MEC), and proton exchange membrane (PEM) electrolysis (Kumar, Himabindu, 2019.), two processes are predominantly used for water electrolysis in Power-to-gas systems, called ALK and PEM electrolyzers. In studies, the PEM electrolyzer is more commonly used due to its high output pressure, operational flexibility, and fast start-up time, which is important in intermittent power generation, high efficiency, and lower projected cost (Maeder, et al. 2021., Lahnaoui, et al., 2021.). Alkaline electrolyzers have more mature operational technology and lower initial investment cost (Pellegrini, et al., 2020.). Compared to alkaline electrolyzers, the PEM electrolyzer has higher efficiency, shorter start-up and ramp-up times measured in minutes or even seconds, and a wider range of hydrogen production rates (ENTSO-E, ENTSOG, 2022.). One of the most important features of electrolyzers is their ability to operate at a variable load, which makes them suitable for use in systems with a high percentage of renewable energy sources (Ekhtiari, et al., 2020.). PEM electrolyzers showed excellent dynamic characteristics and stable independent hydrogen production (Lappalainen, 2019.) and better integration with fluctuating and intermittent power generation (Böhm, et al., 2020.). Due to better performance, PEM electrolyzers justify higher initial capital costs than alkaline electrolyzers. Considering the expected price decrease of PEM electrolyzers due to technological innovations and larger implementation, i.e., economies of scale, authors (Ferrero, et al., 2016.) performed a techno-economic evaluation of different Power-to-gas system configurations, confirming that systems with alkaline electrolyzers have significantly higher production costs than PEM electrolyzers (Ferrero, et al., 2016.). The authors (IRENA, 2018.) conducted an analysis of electrolyzers performing water electrolysis technology at low or high temperatures. Alkaline and PEM electrolyzers performing water electrolysis at low temperatures are able to produce hydrogen with high output pressure, while SOE electrolyzers operating at high temperatures are not yet able to do so. In one of the hydrogen utilization options analyzed in the above work, hydrogen with an output pressure of 20 bar from the electrolyzer is directly compressed to a pressure of 75 bar and injected into the gas grid without intermediate storage (IRENA, 2018.).

The overview of research results relevant to the topic of this paper is presented in the following table. The first group of works investigates the possibilities of hydrogen production using different countries and scenarios as examples. Another group of papers relevant to this research relates to the potential of the gas grid to absorb the produced hydrogen.

Blending hydrogen into the existing gas infrastructure is a promising option for transporting renewable energy sources from the production site to the end users using the existing gas grid, thus avoiding congestion in the power grid but also the construction of new energy infrastructure. Existing gas infrastructure can be repurposed for hydrogen technologies, which would significantly reduce infrastructure investment costs (FCH 2 JU, 2017.) and accelerate the development of the hydrogen economy (GIE, 2020.). Blending hydrogen into the existing gas infrastructure at a certain percentage is the key factor enabling hydrogen production in the initial phase of the energy transition.

Within this first group of papers, research related to the methodology is distinguished. Considering the fact that the price of electricity is the largest part of the price of hydrogen, the calculation of the production price of yellow hydrogen in the model applied in this paper is based on the projected hourly electricity prices for the period from 2025 to 2050. In such a way that the given amount of hydrogen for each individual year is produced in the hours when the price of electricity on the market is low, according to the descending order, i.e., the so-called merit order model, which affects the profitability of yellow hydrogen production. Numerous other authors have used a similar methodology, such that the electrolyzer operates when the price in the electricity market is low, i.e., below the marginal profitability price, in order to maximize hydrogen production and reduce operating costs. It means that the electrolyzer does not operate when the price of electricity in the market is high. In their study, authors (Jovan, et al., 2021.) set a limit equal to the production cost of green hydrogen at a fixed cost of electricity. If the selling price of hydrogen were higher than the production price, assuming the price of electricity does not change, it would be profitable to produce hydrogen, while otherwise, it would be profitable to sell electricity in the market (Jovan, Dolanc, 2020.). Another method is to determine the price-duration curve using several historical years of electricity prices from the spot market to determine different possible future electricity prices and flexibility in electrolysis operation (Khan, et al., 2021.). The author (Ruhnau, 2022.) uses the mentioned methods in his study and uses them to determine the minimum market value of RES. In the mentioned study, the merit order model and the price-duration curve were applied to electricity production from renewable sources, i.e., each renewable source is included in the order of its marginal cost (Ruhnau, 2022.).

While in this paper, this method is applied to hours with cheaper electricity prices in the market for the optimal number of operating hours of the electrolyzer in the year it produces yellow hydrogen.

Low-carbon hydrogen includes green, blue, turquoise, and yellow hydrogen (Noussan, et al., 2021.). The color of hydrogen depends on the method of hydrogen production, so green hydrogen is renewable hydrogen that is obtained from electricity produced exclusively from renewable energy sources such as wind, water, or sun. Grey hydrogen is the most common form of hydrogen production, which is produced from natural gas, or methane, using steam methane reforming, but without capturing the CO_2 emissions produced in the process. Yellow hydrogen is obtained from electricity taken from the power grid (Clifford, 2022.), which has a certain share of electricity obtained from a nuclear power plant.

The color of the hydrogen also depends on the time dynamics and structure of the energy sector transformation. In addition, the amount of CO_2 emissions released during hydrogen production depends on the sources connected to the power grid (Clifford, 2022.). Namely, as the share of renewable energy sources increases, the hydrogen produced will move from the “yellow” to the “green” category. Hydrogen blending into the existing gas grid is a technology that allows hydrogen to replace fossil fuels without additional investment costs in the gas infrastructure. In addition, hydrogen blending represents an extraordinary advantage compared to the other energy transition options. The main challenges of hydrogen blending into the gas infrastructure are:

- For the same energy demand, the amount of needed hydrogen is three times larger than the amount of natural gas needed.
- Natural gas infrastructure needs to be changed (reconstructed) to be used for the transport of a higher share of hydrogen.

The objective of this research is to calculate the yellow hydrogen production price for each lifetime year of the Power-to-gas system to evaluate yellow hydrogen competitiveness compared to the fossil alternatives.

Therefore, the paper provides an economic framework for the assessment of the most efficient technology for hydrogen production, which is then integrated into the existing gas grid. The research tests the influence of the optimal number of operating hours of the electrolyzer with its activation as ancillary services provider in the power system on the viability of yellow hydrogen production at the existing gas-fired power plant site and attempts to answer the following research questions:

1) How can the infrastructure of existing gas-fired power plants be used for the energy transition until 2050?
2) At what electricity market wholesale prices can yellow hydrogen production be competitive to the price of natural gas increased by CO_2 costs?
3) What is the impact of ancillary service income on the final production price of yellow hydrogen?

The contribution of this study is multiple. First, this paper considers not only electricity generated from RES but the entire energy mix of the power system. The configuration of the Power-to-gas system, which is located within the existing gas-fired power plant and uses electricity from the power system for hydrogen production, is a new contribution of this research and is a novelty compared to existing research from Table 2-1. Second, this approach differs from the previous research that analyzes the impact of replacing natural gas in volume fraction. This approach is based on the calculation of the impact of natural gas replacement on the energy fraction, which we believe is a better approach. At smaller volume fractions, hydrogen has a lower density and no real impact on the total energy in the gas system, and for the aforementioned reason, the energy fraction can have a real impact on the blending of hydrogen into the gas system. Third, existing papers do not consider the integration of energy systems and the dependence of the production price of yellow hydrogen on the prices of fossil alternatives, and the use of existing gas infrastructure for the production and blending of hydrogen to the desired energy share. Fourth, not a single paper that has addressed the viability of hydrogen production has considered the benefits of providing ancillary services to the power system, considering the limits of scale and activation, which significantly affects the competitiveness of hydrogen production. This paper fills this gap and proposes a calculation model for analysis of the profitability of yellow hydrogen production and blending into the existing gas grid in a certain energy fraction.

Table 2-1. Summary of published analyzes of hydrogen production and blending into the gas grid.

Study	Location	Electrolyzer Technologies, Capacity and Efficiency	Hydrogen End-Use	Color of Hydrogen and Hydrogen Production Price
Jovan et al. (2021)	Slovenian hydropower plant (HPP)	1 MW PEM Electrolyzer with efficiency around 80%	Storage of surplus electricity, feedstock in industries, fuel in the heating and transport sectors	Green hydrogen production price range from 1.36–3.86 EUR/kg with electricity prices ranging from 0.00–50.00 EUR/MWh
Jovan and Dolanc (2020)	Slovenian hydropower plant (HPP)	1 MW PEM Electrolyzer with efficiency around 80%	In industry as a feedstock, for heat generation, transport, and mobility	Green hydrogen production price range from 3.11–7.36 EUR/kg with electricity prices ranging from 35.00–120.00 EUR/MWh
Kopteva et al. (2021)	Russian hydropower plant (HPP)	ALK electrolyzer with efficiency 63–80%; PEM electrolyzer with efficiency 56–74%; SOEC electrolyzer with efficiency 74–90%	For the export of hydrogen through the use of large vessels	Green hydrogen production price range from 3.00–13.99 USD/kg
Lahnaoui et al. (2021)	Wind electricity generation, in France and	PEM electrolyzer with an efficiency of 70%	Hydrogen transport and storage	Green hydrogen production price range from 2.32–6.87

	Germany		infrastructure using the road network	EUR/kg with an electricity price of 55.00 EUR/MWh
Luo et al. (2020)	Production by natural gas, coal, and water electrolysis in China	ALK electrolyzer with efficiency of 65–75%; PEM electrolyzer with efficiency 70–90%	Hydrogen used in fuel cells in the transportation field	Brown/Black hydrogen production price 1.51 USD/kg; Grey hydrogen production price 1.78 USD/kg; Green/Yellow hydrogen production price 4.97 USD/kg
Khan et al. (2021)	Wind and solar generation in Australia	10 MW ALK electrolyzer with efficiency 85%; PEM electrolyzer with efficiency 83%;	In industry as a feedstock	Green hydrogen production price 2.00 AUD/kg with electricity price <30.00 AUD/MWh
Ruhnau (2022)	Wind and solar generation in Germany	ALK/PEM electrolyzers with efficiency 67–74%	For electricity gas heating, cooling, transport and Industry systems	Green hydrogen production price range from 1.50–2.50 EUR/kg
Pellegrini et al. (2020)	Renewable electricity, solar and wind generation in Italy	77.5 MW electrolyzer capacity with an efficiency of 58%	Directly injected into the natural gas grid at a low percentage (10%) for both storage and transportation	Green hydrogen; no information about hydrogen production price
Ekhtiari et al. (2020)	Renewable electricity in Ireland	PEM electrolyzer with an efficiency of 65%	Directly injected into the natural gas grid at 15.8%	Green hydrogen; no information about hydrogen production price
IRENA (2018)	Renewable electricity in Denmark	ALK/PEM electrolyzers with efficiency 57–68%	Transportation and heavy industry, in transmission natural gas grid at 30%	Green hydrogen production price range from 5.00–6.00 USD/kg
FCH 2 JU (2017)	Renewable electricity in France, Germany, Great Britain, Denmark, Sardinia	20 MW ALK with efficiency 77–80% and 6 MW PEM electrolyzers with an efficiency of 65–74%	Mobility and industry, refineries and cooking oil production, gas grid injection of 0.1% in the UK, 9.9% in DE, 6% in FR	Green hydrogen production price of 6.00 EUR/kg with an electricity price of 45.00 EUR/MWh for mobility; hydrogen production price range from 2.60–5.00 EUR/kg with an electricity price range from 26.00–47.00 EUR/MWh
Haeseldonckx and D'haeseleer (2007)	All hydrogen technologies included	-	Hydrogen being directly injected into the natural gas grid at 17%	All types of hydrogen color without information about price
Kanellopoulos et al. (2022)	Renewable electricity in Europe	Approximately 2.00–6.00 GW electrolyzer capacity, efficiency 78%	Hydrogen being directly injected into the natural gas grid at 20%	Green hydrogen production price range from 3.00–5.00 EUR/kg

Romeo et al. (2022)	Renewable electricity surplus to power electrolyzer	300 kW electrolyzer capacity with an efficiency of 65%	Hydrogen being directly injected into the natural gas grid at 14.2%	Green hydrogen; no information about hydrogen production price
Mikovitz et al. (2021)	Wind power generation in Sweden	PEM electrolyzers with efficiency 72%	Long-term storage of hydrogen or backup hydrogen sources	Green hydrogen; no information about hydrogen production price

Note: ALK = alkaline electrolysis. PEM = polymer electrolyte membrane electrolysis.

Source: authors

2.2. Materials and Methods

The idea of this paper is therefore to investigate the viability of investing in a Power-to-gas system and propose a model that could be applicable in any country with similar existing sites and energy mix.

It is necessary to emphasize the two basic assumptions that form the basis of the model. Power-to-gas system located inside the existing gas-fired power plant uses electricity from the power grid and splits water molecules into oxygen and hydrogen in the electrolyzer through a chemical reaction. Resulting in so-called yellow hydrogen blended directly into the existing gas grid at an energy content of hydrogen of 10% by using available electricity and gas infrastructure.

The model includes all parameters required to calculate the production price of yellow hydrogen, as well as projections of electricity, natural gas, and CO_2 prices for the analyzed period. Since variables fluctuate strongly and their fluctuations are very hard to project, sensitivity analysis is applied.

Figure 2-1 shows a data flow chart of input data and assumptions, optimization, and economic analysis used in the model. The following diagram provides a graphical overview of the interdependence of the model parameters.

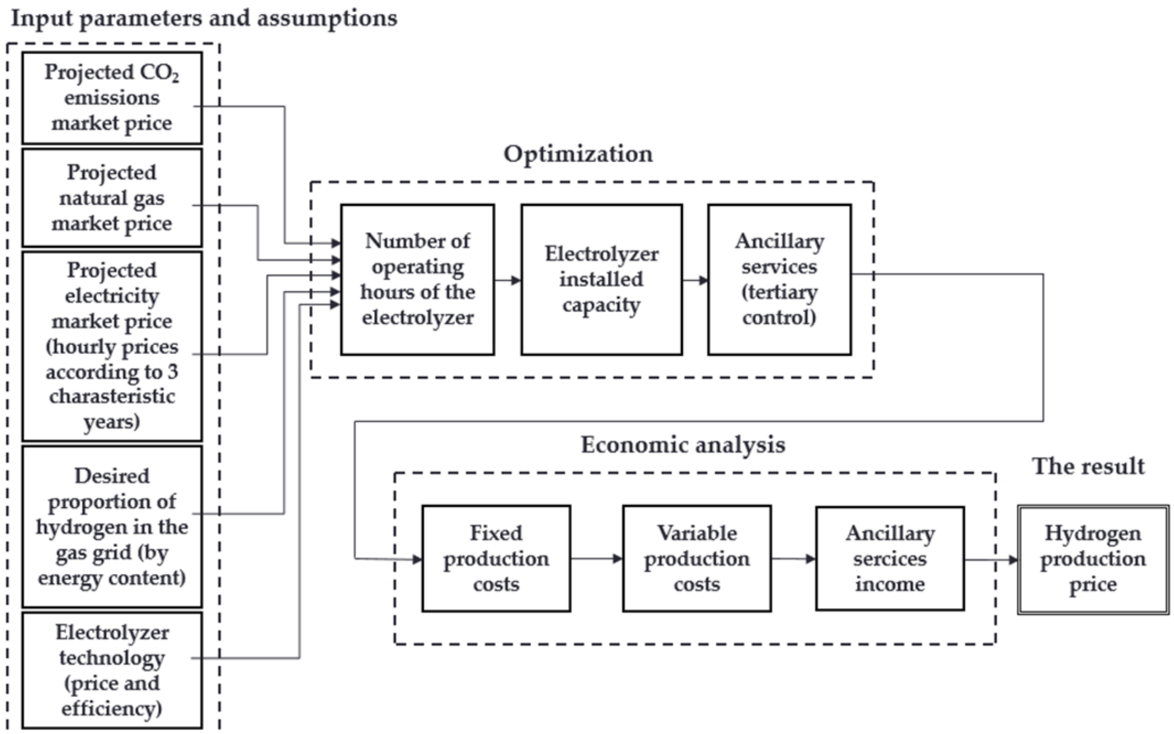

Figure 2-1. Data flow chart.

The total consumption of natural gas in Croatia is taken from the annual energy report of the Energy Institute Hrvoje Pozar, (2020). In 2015, total natural gas consumption in the Republic of Croatia was 23.4 TWh of which 9.8 TWh was imported, respectively in 2017, consumption was 28.0 TWh of which 16.8 TWH was imported. In 2019, total natural gas consumption was 27.0 TWh, of which 18.6 TWh was imported (EIHP, 2020.), which indicates that domestic production is declining and, accordingly, dependence on imports is increasing, threatening the security of supply. Data from the energy sector of the Republic of Croatia were used to investigate the viability of yellow hydrogen production at the site of the existing gas-fired power plant, but the model is fully applicable to other countries and regions by simply changing the input parameters.

The model covers the period from 2025 to 2050, and the assumptions for the standard calculation are as follows:

1) The observed period of 25 years coincides with the lifetime of the Power-to-gas system;
2) The desired percentage of replacement of natural gas with hydrogen is determined in the model based on the natural gas consumption system in Croatia in 2019;

3) According to the system with annual natural gas consumption of 27.0 TWh, the percentage is based on the energy share (10%) of hydrogen injected into the existing gas grid, the amount of 2.7 TWh of replacement of natural gas with hydrogen;
4) Three specific observed years with realized electricity prices were chosen, which were distributed to all years of the model period using Monte Carlo simulation to obtain a more realistic projection of hourly electricity prices;
5) Yellow hydrogen production is carried out with an electrolyzer efficiency of 74% (Fu, et al., 2020.);
6) Providing ancillary services of tertiary regulation for the power system.

Data for the capital (CAPEX) and operating (OPEX) costs of the Power-to-gas system were taken from the literature reviewed and the annual reports of the Croatian national energy institutions to determine the price of yellow hydrogen produced for each year of the model period. The specific values of CAPEX and OPEX Power-to-gas systems from the collected data in the literature vary widely (Kumar, Himabindu, 2019.; Böhm, et al., 2020.; FCH 2 JU, 2017.; Luo, et al., 2020.; Fu, et al., 2020.; Liu, et al., 2017.; Gorre, et al., 2020.; Mayer, et al., 2019.; Zapantis, A.; Zhang, 2020.), and Table 2-2 shows the selected values used for the input parameters in the economic viability model of yellow hydrogen production.

Table 2-2. CAPEX and OPEX of the Power-to-Gas system.

Parameter		**Unit Price**
Capital costs	Electrolyzer	1300.00 EUR/kW
	Compressor	400.00 EUR/kW
Operating costs	Electricity cost	EUR/MWh
	Network usage fee (EUR/MWh)	11.01 EUR/MWh
	Cost of chemical water preparation	0.54 EUR/MWh
	Electrolyzer maintenance (2% of capital costs)	0.38 EUR/MWh

Source: authors

As our model includes the income from the provision of ancillary services to the power system, it needs to be explained in more detail. Ancillary services are necessary for the operation of the power system. Their most important function is to balance the time difference between power generation and consumption, thus ensuring the safe and stable operation of the power system. Ancillary services of power and frequency regulation (P/f) are organized as a hierarchical structure on three-time levels consisting of primary (FCR), secondary (aFRR), and tertiary (mFRR) regulation. For every 100 MW of newly installed variable renewable energy sources, 4–10 MW of reserve power is needed in the ancillary services mechanism to ensure the normal and stable operation of the power system (Jovan, et al., 2021.).

Electrolyzers included in the ancillary services mechanism can lower electricity consumption by decreasing the production when there is a shortage of electricity in the system, and they provide additional electricity consumption by increasing the production and if needed use storage of hydrogen when there is a surplus of electricity in the system. By including the power plant in the system of secondary regulation of ancillary services to the power system, the potential additional revenue from the power plant can be realized, which affects the return on investment in the Power-to-gas system, i.e., lower production costs for hydrogen.

Data on the cost of network charges and the cost of providing ancillary services of tertiary regulation (mFRR) were taken from the Croatian Transmission System Operator report (2022.). The data according to which the income from tertiary regulation is calculated in the model are shown in Table 2-3.

Table 2-3. Input data used in the calculation of the tertiary regulation income.

Input Data	
Transmission system operator's request for mFRR [MW/h]	120.0
Share of the electrolyzer in meeting total system mFRR+ needs	20%
Share of the electrolyzer in meeting total system mFRR- needs	10%
Power system reserve price in the positive direction for 2021 (mFRR+)	EUR 7.41
Power system reserve price in the negative direction for 2021 (mFRR-)	EUR 7.41
Share of activated positive energy in the total offered power reserve in the positive direction mFRR+	1%
Share of activated negative energy in the total offered power reserve in the negative direction mFRR-	1%
Coefficient for positive energy mFRR+	1.3
Coefficient for negative energy mFRR-	0.7

Source: authors

The formula for the calculation of the income from the tertiary regulation provision is as follows:

$$\text{Income from tertiary regulation} = \text{income from tertiary power reserve} + \text{income from activated energy} \tag{1}$$

In this case, income from the tertiary reserve is calculated from reserve price in positive and negative directions as well as a share of electrolyzer in meeting tertiary power reserve as shown in Table 2-3. Income from the activated energy is calculated with hourly electricity prices corrected with the coefficient for energy and share of activated energy in total tertiary power reserve taking into account that negative energy activation carries negative income and lowers total income from tertiary regulation.

The total demand for tertiary regulation in the Croatian transmission system is set to 120.0 MW/h. The model predicts that the electrolyzer will provide 20% of the volume in the positive direction and 10% of the volume in the negative direction. The maximum power of 24.0 MW of the electrolyzer will be used in case of the need to include it in the tertiary regulation. It is also expected that activation will occur in both directions at a rate of 1% per year and that the price will remain the same for the entire model period corresponding to the base year 2021.

The values in Table 2-4 refer to 2028 when the investment is expected to be completed and the electrolyzer is installed at full capacity. Electrolyzer will be built in stages during the first three years, so it will operate with reduced capacity, while in the remaining years of the model period, it will operate at the full required installed capacity. The production efficiency of the electrolyzer is taken from the study by (Fu, et al., 2020.). The fixed costs of the electrolyzer are taken from several different sources as it consists of several separate parts (Kumar, Himabindu, 2019.; Böhm, et al., 2020.; FCH 2 JU, 2017.; Luo, et al., 2020.; Fu, et al., 2020.; Liu, et al., 2017.; Gorre, et al., 2020.; Mayer, et al., 2019.; Zapantis, A.; Zhang, 2020.). The input parameters of the model, which are the same for each year of the period, are listed in Table 2-4. They refer to the number of operating hours of the PEM electrolyzer, its efficiency, and installed power, the desired share and amount of replacement of natural gas with hydrogen relative to the total consumption of natural gas, and the constant hydrogen production cost.

Table 2-4. Input parameters of the model.

Input Parameters	Value
Number of operating hours of the electrolyzer per year	3542
Share of hydrogen in the gas grid (%)	10
Electrolyzer efficiency (%)	74
Fixed costs of hydrogen production (EUR/MWh)	20.12
Total annual consumption of natural gas (TWh)	27.0
Required annual hydrogen production (TWh)	2.7
Required installed power of the electrolyzer (MW)	762.3

Source: authors

The hourly projection of the electricity prices is the most sensitive parameter of the input variables in the model, to which special attention was paid. For each individual year of the observed period, the movement of the electricity price at the hourly level was projected in such a way that the realized electricity price on the Croatian electricity market was taken at the hourly level for the years 2018-2020. For each of the three selected years, the realized hourly electricity price was divided by the average annual realized electricity price to obtain coefficients for the difference between the annual and hourly prices. Using Monte Carlo simulation, three specific years are each selected in a specific ratio and distributed over all years of the future period, while the coefficients of the selected year are multiplied by the projected annual electricity price for each hour of each annual model period. The coefficients are calculated according to the following formula:

$$\text{Hourly electricity price / Average annual realized electricity price = Coefficients} \qquad (2)$$

The electricity market price is included in the model because it reflects the movement of supply and demand, and such a price provides a better and more realistic result in the scenarios. To calculate the coefficients for projecting electricity prices for the selected period of the model, three specific base years of realized electricity market prices at the hourly level were used. Therefore, the fluctuations in electricity prices can be seen, i.e., in this way, the relationship between higher and lower hourly electricity prices can be seen most clearly in a year when climatic conditions (especially hydrology) are better, such as in 2019, then worse, such as in 2018, or in a year when a specific event such as a pandemic occurs, such as in 2020. If the average of three years were used for such a calculation, the larger differences between higher and lower hourly prices would even out, and price fluctuations would not occur as they do in one or three separately observed years. In this way, a more realistic hourly projection of electricity prices was obtained for all model years. The plot of electricity price fluctuations between the three separately observed years is shown in Figure 2-2.

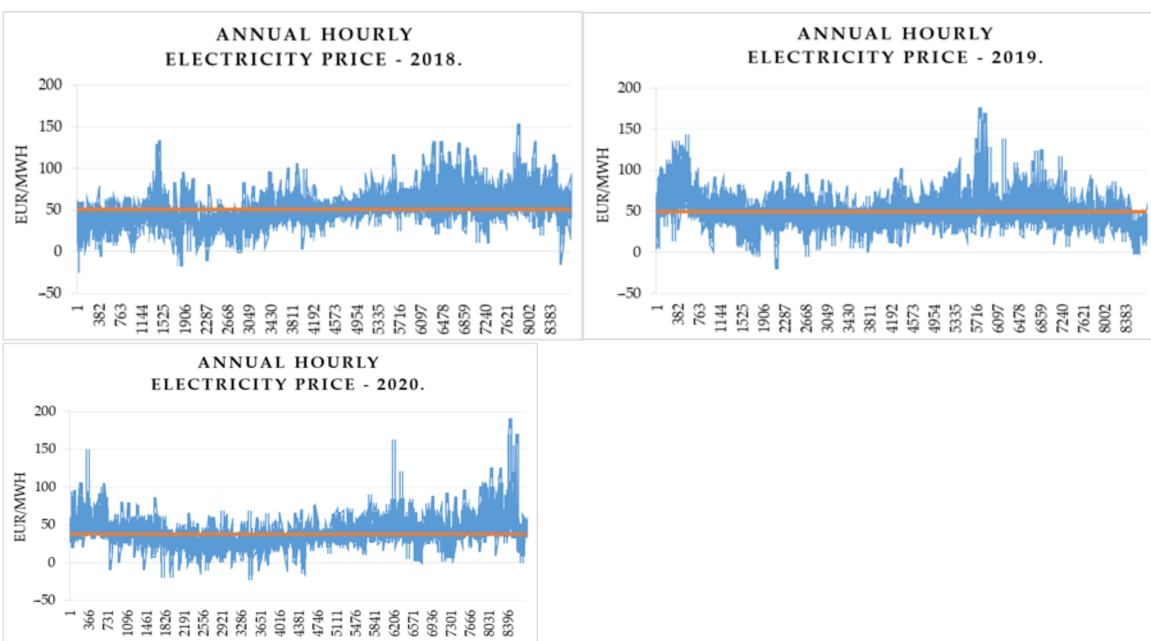

Figure 2-2. Hourly electricity prices for three characteristic years.

According to the results of the Monte Carlo simulations, the model period is distributed in such a way that a 40% share of the years is allocated to the base year 2018, then a 52% share is allocated to the years of the base year 2019, and an 8% share is allocated to the years of the base year 2020. In the Monte Carlo simulation, the year 2020 was limited to a maximum repeatability of 10%, because the authors believe that a given year, like a pandemic, cannot repeat more than three times in the projection of a 25-year period. In this way, the parameter of the input variable of the model, the hourly projection of the electricity price, was determined, reflecting a more realistic approach to the projection according to the specifics of individual years rather than their average.

The projection of electricity prices is a very important parameter for the water electrolysis process, which requires large amounts of electricity. The amount of electricity needed to produce 1 kg of hydrogen depends on the efficiency of the electrolyzer used in the Power-to-gas system. The efficiency of the electrolyzer is defined as the hydrogen production expressed by the lower heating value divided by the electricity consumption of the electrolyzer. For the different electrolyzer efficiency, a different amount of electricity is used to produce 1 kg of hydrogen. For example, with an electrolyzer efficiency of 65%, it takes 60.6 kWh of electricity to produce 1 kg of hydrogen (Gonzalez-Diaz, et al., 2021.), and with an efficiency of 60%, it takes 55.0 kWh of electricity (Bareiß, et al., 2019.). In addition, some authors use electricity prices for industry from the Statistical Office of the European Communities, EUROSTAT, as the basis for calculating the hydrogen production price (Parr, Minett, 2020.).

In the model, the projection of electricity prices at the hourly level is based on coefficients determined using the realized electricity prices of the Croatian Power Exchange. The realized annual electricity price in the Republic of Croatia was 51.00 EUR/MWh in 2018, 49.55 EUR/MWh in 2019, and 38.30 EUR/MWh in 2020. The obtained coefficients for each hour of the selected year are multiplied by the projected annual electricity price resulting from the Monte Carlo simulation, where the selected years are distributed over the entire model period. The formula for the projection of electricity prices at the hourly level is given as follows:

$$\text{Coefficients} \times \text{Projected annual electricity price} = \text{Projection of electricity prices at the hourly level} \quad (3)$$

Data according to the TYNDP under the ENTSO-E and ENTSO-G (2022) baseline scenario were used to project electricity, natural gas, and CO_2 prices in the model. The data includes price projections from 2025 to 2050 for every fifth year, which authors distributed to each year and hour of the period using the linear method according to the previously mentioned coefficients and Monte Carlo simulation.

Table 2-5 shows the projected electricity market price, natural gas price, and CO_2 emission price for the selected observed years.

Table 2-5. Projected prices of electricity, natural gas, and CO_2.

Price Projection	2025	2030	2035	2040	2045	2050
Price of electricity (EUR/MWh)	55.57	70.17	66.00	63.50	58.17	52.13
Price of natural gas (EUR/MWh)	22.79	25.16	26.50	27.84	29.18	26.25
Price of CO_2 emissions (EUR/ton)	40.00	70.00	80.00	90.00	100.00	148.41

Source: authors

The largest contributor to the production price of yellow hydrogen is the electricity cost, followed by the characteristics of the PEM electrolyzer and the constant and variable costs of the Power-to-gas system production. Prices for electricity, natural gas, and CO_2 are taken from the European Ten-Year Plan for the Development of Electricity and Gas Networks (TYNDP), according to the baseline scenario of the European Network of Transmission System Operators for Electricity (ENTSOE), and the European Network of Transmission System Operators for Gas (ENTSO-G) (2022). The formula for the calculation of the yellow hydrogen production price is given as follows:

$$\text{PCVp} = \text{CAPEX} + \text{OPEX} - \text{UPPU} \tag{4}$$

In this case, CAPEX refers to the fixed production costs of yellow hydrogen, which include the price of the electrolyzer and the compressor. OPEX refers to the variable price of electricity and the fees for grid usage, then the cost of chemical water preparation and the cost of maintaining the system. UPPU refers to the total revenues from ancillary services.

Our research results show that incentives for hydrogen production are necessary. The premium incentive system for the development of renewable energies and hydrogen production technology is part of the investment cycle of the energy transition, and such projects are implemented exclusively on a market basis. The amount of the premium for yellow hydrogen production is calculated according to the following formula:

$$\text{S} = \text{PCVp} - (\text{CPP} + (\text{CCO2}/5))\ \text{EUR/MWh} \tag{5}$$

Therefore, the premium is a variable part of the system and depends on the market price: the higher the market price for natural gas and CO_2 emissions, the lower the premium for hydrogen production. If the market price for natural gas and CO_2

emissions is higher than the cost of hydrogen production, then the premium is no longer needed, which is the goal of the energy transition.

2.3. Results

The results of this analysis are applicable to European countries within the same regulatory framework and with a similar energy mix, but for the sake of a more realistic approach in this model, a part of the empirical data is taken from the Croatian electricity and natural gas system and market.

The optimal number of electrolyzer operating hours is an extremely important performance parameter that determines the size (power) of the electrolyzer required to produce a given amount of hydrogen (10%). Therefore, an important part of the electrolyzer size analysis is based on the optimal number of operating hours, which depends on the capital and operating costs, i.e., the unit price of the electrolyzer and the variability of projected electricity prices in the market. The merit order model determines the number of operating hours of the electrolyzer separately for each year of the model based on the ordered forecast electricity prices in the hours when the electrolyzer operates. Then, the optimal number of operating hours of the electrolyzer was determined for the entire period of the model, as shown in Figure 2-3.

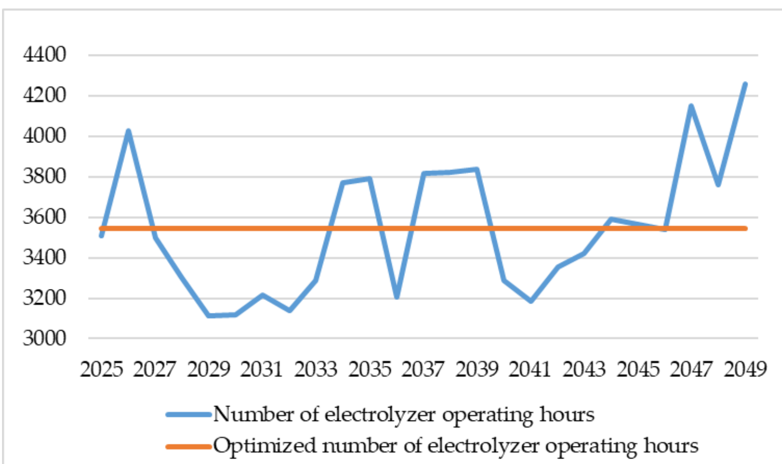

Figure 2-3. Optimal number of operating hours of the electrolyzer.

The calculation of the yellow hydrogen production price considers the time required to build the Power-to-gas system and install the electrolyzer at the gas-fired power plant, as well as to reach the specified percentage of hydrogen in the gas grid. Therefore, in 2028, the model expects to achieve the specified percentage and amount of replacement of natural gas with hydrogen, as well as the total installed capacity of electrolyzers.

The projected data of hourly electricity prices for a period of 25 years reflect the coefficients of the ratio between the realized annual and hourly electricity prices for the three selected years 2019–2021, taken from the Croatian national electricity market. The natural gas and CO_2 prices are taken from the literature (EIHP, 2020.) and are projected in the model on an annual basis. The optimization part of the model refers to the selection of the size of the electrolyzer in such a way that the number of operating hours and the projection of electricity prices are used to select the optimal number of operating hours so that the capacity of the electrolyzer is optimally used. The economic part of the model refers to the fixed and variable production costs and ancillary services income that affect the yellow hydrogen production price. The economic part of the model calculates the return on investment and competitiveness with fossil alternatives.

The obtained research results related to electricity are presented in Table 2-6. The table shows data for the selected six model years.

Table 2-6. Model output data related to electricity.

Output Data	2025	2030	2035	2040	2045	2050
Electricity Consumption * (MWh)	364,762	3,645,558	3,647,619	3,647,619	3,645,558	3,647,619
Annual electricity cost (EUR)	13,919,986	158,450,339	165,334,778	159,072,097	131,351,944	133,603,861
Annual network usage fee (EUR)	4,016,028	40,137,597	40,160,280	40,160,280	40,137,597	40,160,280

* Electricity consumption for the operation of the electrolyzer, per year.

Source: authors

Assuming that the optimal number of operating hours is chosen and thus the installed capacity of the electrolyzer is the same for the entire analyzed period, the fixed costs are the same in all years, while the operating costs change depending on the forecasted electricity market price.

The amount of 2.7 TWh of produced hydrogen, which is replaced by the natural gas in the existing gas network, also reduces CO_2 emissions by 540,000 tons per year. To further reduce the production price of yellow hydrogen, revenue from ancillary services provided by the electrolyzer to the power grid is included in the model. The amount of hydrogen produced, and the unit price of yellow hydrogen produced, expressed in two units of measure (per MWh and per kg), are shown in Table 2-7.

Table 2-7. Price and quantity of produced yellow hydrogen.

Output Data	2025	2030	2035	2040	2045	2050
Produced amount of hydrogen (MWh)	269,924	2,697,713	2,699,238	2,699,238	2,697,713	2,699,238
Production price of hydrogen (EUR/MWh)	83.68	93.24	95.75	93.43	83.20	84.00
Production price of hydrogen (EUR/kg)	2.81	3.13	3.22	3.14	2.80	2.82

Source: authors

The main aim of this paper is to compare the calculated production cost of yellow hydrogen with the natural gas price increased by the CO_2 cost and to determine the profitability of hydrogen production in the observed scenarios. Figure 2-4 shows a comparison of the yellow hydrogen production price shown in Table 2-7 with the natural gas market price shown in Table 2-5, increased by the cost of CO_2.

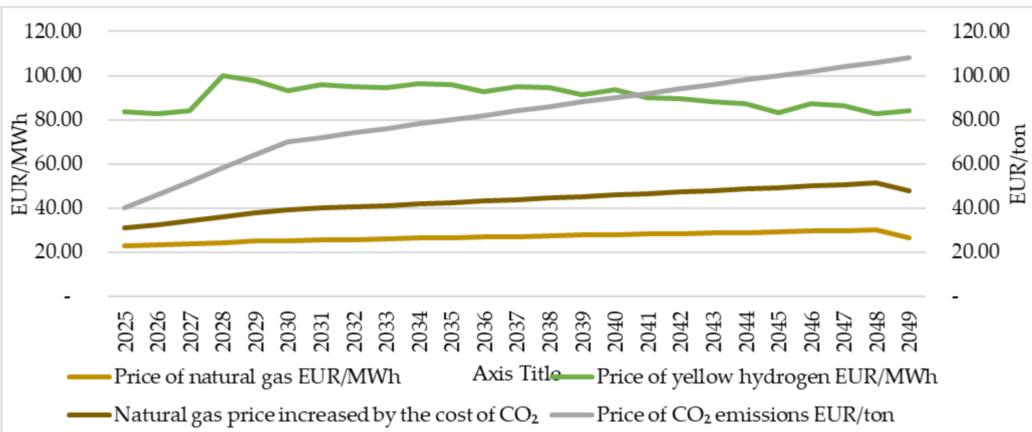

Figure 2-4. Comparison of yellow hydrogen prices with market prices of natural gas and CO_2 emissions.

Although the price of CO_2 emissions is projected to be higher than the price of yellow hydrogen production after 2040, Figure 2-4 shows that the price of yellow hydrogen production is far higher than the projected natural gas market price, which is increased by the cost of CO_2 emissions. The reason is the increase in the price of natural gas by 1/5 of the price of CO_2 emissions. It is clear that the hydrogen price in the given timeframe and scenarios is too high to be a viable substitution for natural gas. Clearly, incentives for hydrogen production are necessary to justify this investment.

Accordingly, with the projected natural gas prices and CO_2 premium, the incentive for hydrogen production should be 52.90 EUR/MWh in 2025 and 36.18 EUR/MWh in 2050.

The sensitivity analysis was performed for the input parameters of the model for two cases: 20% higher and 20% lower electricity price than the reference value. Although the electricity market price affects the natural gas market price, the sensitivity analysis was performed only for the electricity price, while the other parameters remained unchanged. Figure 2-5 shows the results of the sensitivity analysis.

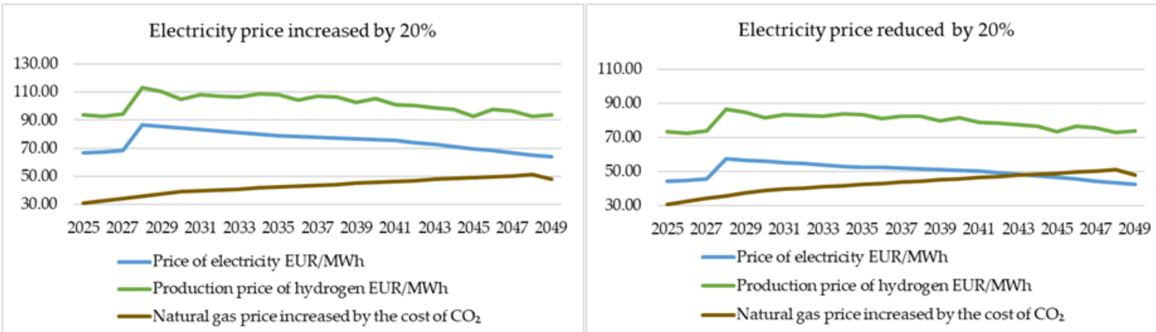

Figure 2-5. Sensitivity analysis related to changes in the electricity price.

According to Figure 2-5, the yellow hydrogen price is higher when the electricity market price is higher, and vice versa. With the same natural gas market price and CO_2 emission price, the yellow hydrogen production price is still not competitive with the fossil alternative natural gas in both cases of the sensitivity analysis, and the application of a premium incentive system is necessary. In this case, the lack of competitiveness of yellow hydrogen production is reflected in the low projected natural gas market prices.

The results are relevant for the hydrogen production technology by water electrolysis with PEM electrolyzers. The results refer to the hydrogen production at the site of an existing power plant that has connections to the electricity and gas networks in order to minimize investment costs. Although the results are based on Croatian data, they are applicable to all countries of the Mediterranean region, given that the energy mixes are similar. The input data can also be easily replaced with data from other countries in order to obtain results for a specific country.

2.4. Discussion

The EU Hydrogen Strategy highlights hydrogen as an important lever for a successful energy transition, especially with regard to the use of existing gas infrastructure. A proposal for a hydrogen and decarbonized gas package, i.e., measures included in the existing regulatory framework for natural gas (European Commission, 2021.), calls on the Member States to allow hydrogen blending in their national gas systems. The blending threshold is set up to 5% hydrogen content in the gas streams at interconnection points, in order to harmonize the cross-border flow of natural gas from 1 October 2025 onwards. The percentage of 10% for the replacement of natural gas with hydrogen, which reflects the energy share of hydrogen in the gas network, was used in this research assuming that the existing gas network can accommodate this without construction changes of the existing gas infrastructure.

The Power-to-gas system is located at the site of an existing, low-potential gas-fired power plant. The repurposing of existing energy infrastructure as part of the decarbonization of the energy sector also affects the fact that investment in repurposing is less intensive than investment in new infrastructure. For the existing gas-fired power plant that is considered economically unviable to operate, i.e., a gas-fired power plant that is no longer competitive due to its traditional power generation, significant investment would be required to decommission the plant. It makes repurposing the gas-fired power plant a better option than complete decommissioning and appropriate management of the infrastructure, i.e., returning to the previous state. The authors believe that the existing gas-fired power plant, with an expected low commitment in the future, is an ideal site to be converted to as it has all the necessary electricity and gas infrastructure. It means that the initial investment costs for conversion are much lower compared to building completely new infrastructure, especially under the conditions of growing spatial planning and environmental requirements.

After the water electrolysis process in the Power-to-gas system, the extracted oxygen and hydrogen are widely used. The oxygen can be compressed into bottles and used as an end product in hospitals, in the chemical industry, or in space missions. In this way, the additional revenue of the Power-to-gas system can be realized. However, in this paper, it is omitted and not considered because this revenue does not directly affect the price of the produced hydrogen, but rather the profit of the Power-to-gas system.

On the other hand, hydrogen can be used in the gas system, in transport, and in industry, it can be stored or re-generated. Considering that each of the possibilities of using hydrogen requires additional and more extensive research, the authors have chosen the possibility of using hydrogen in the gas system to take advantage of the existing energy infrastructure. Natural gas infrastructure can transport large amounts of energy over long distances, provide large seasonal storage capacities, and have larger cross-border capacities compared to electricity infrastructure (Hydrogen Europe, 2019.).

It should also be noted that hydrogen can be used in the gas system directly as a mixture with natural gas, or synthetic natural gas can be obtained through the methanation process and used as such in the gas system. In this analysis, only the direct blending of hydrogen into the existing gas system at a given energy content of 10% is processed. In this way, hydrogen is considered solely as an energy source that is blended into the gas grid to replace natural gas. The existing gas infrastructure can be decarbonized by blending hydrogen, replacing natural gas with biogas, or converting the gas grid to hydrogen (FCH 2 JU, 2017.). The comparison with biogas and the repurposing of the gas grid is not part of this analysis, as the purpose of the paper is the economic viability of replacing the natural gas component with hydrogen while using the existing gas infrastructure.

This paper assumes that the existing gas grid can accept hydrogen blending at the specified ratio at any time. Flexibility in PEM electrolyzer operation is important in this analysis to include the electrolyzer in providing ancillary services to the system to influence the final price of yellow hydrogen with additional income from ancillary services. The efficiency and expected price drop of PEM electrolyzers from the perspective of hydrogen production economics is certainly an important feature that makes the PEM electrolyzer suitable for use in this model compared to others.

The authors are aware of the uncertainties of future electricity price projections and other parameters, especially over a long period of time. Therefore, higher and lower electricity prices were analyzed using a sensitivity analysis. Different prices affect the hydrogen production price in the model, as well as natural gas and CO_2 market prices. However, this reflects current or historical data for electricity prices against which the current competitiveness of hydrogen in the market is measured, whereas in this analysis the authors are interested in projecting electricity prices, i.e., the future competitiveness of hydrogen in the market. The paper presents subsidies for the first and last year of the project, but in the model, it is calculated for each year of the project. The greatest weakness of the research is the input data on the electricity price, natural gas, and CO_2 emissions price.

It should be pointed out that this methodology can be applied in a number of other regions where a similar situation exists with existing gas-fired power plants. The challenge in the energy transition is precisely to use the existing gas infrastructure to replace natural gas with hydrogen, the combustion of which does not release CO_2 and does not harm the environment while meeting decarbonization and climate goals so that the economy will be carbon-neutral by 2050.

The Croatian energy sector is a paradigm for European countries that has a certain share of gas-fired thermal plants and well-developed power systems. The model can be used for other European countries or regions to evaluate future interactions between the hydrogen market, electricity, natural gas, and CO_2. It can also form the basis for future analyses of the use of existing energy infrastructure in the context of decarbonizing the energy sector. The model can be used in practice to assess the profitability of this or similar projects.

2.5. Conclusions

The main conclusion of this paper is that the production of yellow hydrogen with an electrolyzer located inside the existing gas-fired power plant cannot be economically viable and competitive in the observed scenarios and under assumed assumptions. According to the studies in Table 2-1 (Jovan, et al., 2021., Jovan, Dolanc, 2020.), the green hydrogen production price from a hydropower plant is 3.86 EUR/kg at an electricity price of 50.00 EUR/MWh. In our model at the same electricity price, the yellow hydrogen production price is 3.43 EUR/kg. In the study from Table 2-1 (Lahnaoui, et al., 2021.), the green hydrogen production price from a wind farm is 2.32 EUR/kg with an electricity price of 55.00 EUR/MWh. At the same electricity price, in our model, the yellow hydrogen production price is 3.66 EUR/kg.

The number of operating hours of the electrolyzer is optimized here for the whole observed timeframe of 25 years. The amount of hydrogen is given, and due to the installed power of the electrolyzer, it is necessary to have the same number of operating hours for each year. By using the solver, it was calculated that the optimal number of operating hours yearly is 3542. Income from ancillary services reduces the hydrogen production price. From the moment when the electrolyzer operates at full installed capacity, income from ancillary services reduces the hydrogen production price by around 0.5 EUR/MWh.

The competitiveness of hydrogen against natural gas depends on the ratio of the electricity price and natural gas price increased by the CO_2 emission cost. Therefore, it cannot be viewed only through the electricity price without considering the natural gas and CO_2 emission price. It is important to note that the calculations are based on the electricity market prices from the respective ENTSO development plans (ENTSO-E; ENTSOG, 2022.), which are several times lower than the current market prices in Europe during 2023. At current electricity prices, the unviability of yellow hydrogen production is even higher.

The natural gas price should be higher or equal to the hydrogen production price in order to avoid subsidies. In the whole model observed timeframe, the yellow hydrogen production price is not lower than the natural gas price increased by the CO_2 emissions cost. In the first year of the model, the yellow hydrogen price is 83.68 EUR/MWh, and the natural gas price increased by the CO_2 emissions cost is 30.79 EUR/MWh. In the last year of the model, the yellow hydrogen price is 84.00 EUR/MWh, and the natural gas price increased by the CO_2 emissions cost is 47.82 EUR/MWh. There is a strong correlation between the market prices of natural gas and electricity. Hydrogen production from water electrolysis with electricity from the power grid is more expensive than natural gas price increased by the CO_2 emission cost. Because of that, for these cases, it is necessary to create an adequate yellow hydrogen incentive mechanism. The premium incentive system for the development of hydrogen production technology is a part of the investment cycle of the energy transition. Therefore, the premium is a variable part of the incentive scheme and depends on the market price: the higher the market price for natural gas and CO_2 emissions, the lower the premium for hydrogen production. If the market price for natural gas and CO_2 emissions is higher than the hydrogen production cost, the premium is no longer needed, which is the goal of the energy transition.

At the assumed natural gas and CO_2 emission prices, the incentives for hydrogen production need to be 52.90 EUR/MWh in 2025 and 36.18 EUR/MWh in 2050. However, without an appropriate package of incentive measures from European and national energy policies, hydrogen production will not be viable even in a location that does not require large infrastructure investments.

The results of this research clearly show the unviability of such investment, considering that the yellow hydrogen production price is several times higher than the natural gas price increased by the CO_2 emission cost. In the long term timeframe, a solution could be to considerably increase the share of renewable energy sources in the electricity mix to reduce the correlation between electricity and natural gas prices.

Our research on yellow hydrogen production in an existing gas-fired power plant site shows that this is not yet feasible without financial incentives, but in energy terms, it could contribute to decarbonizing the energy system and meeting climate goals, while promoting the sustainability of existing gas infrastructure. Investing in hydrogen production would help reduce dependence on natural gas while decarbonizing the gas sector and leveraging existing gas infrastructure. By avoiding investments in energy infrastructure, i.e., connections to the electricity and gas system and the chemical water preparation, the difference between the hydrogen production price and natural gas market price is significantly reduced.

To date, synthetic gas or hydrogen is not recognized as a green gas eligible for a green gas feed-in tariff. Furthermore, the question of the maximum hydrogen concentration in the hydrogen-natural gas blend is still open. The permissible concentrations for the direct injection of hydrogen into the natural gas grid vary greatly in the individual EU countries, as the possibility of transporting hydrogen through the gas grids was not considered when the existing gas regulations were introduced. It is therefore crucial to remove the legal barriers to blending hydrogen with natural gas by harmonizing blending concentrations and setting limits based on physical constraints. Even if favorable economic conditions exist, Power-to-Hydrogen pathways will only develop if appropriate regulations make this possible. The attention of policymakers should be drawn to this issue. Investigating the incentives and regulatory barriers for the deployment of hydrogen systems is an important policy task to achieve the goals of the EU Green Deal.

The authors are aware of uncertainties in future electricity and CO_2 emission price projections. Still, this is the first attempt to evaluate the viability of hydrogen production at the site of the existing gas-fired power plant, considering the existing infrastructure, the supply of electricity from the power grid, and the inclusion of the power plant in the ancillary service mechanism. Electricity and natural gas price projections are very unclear at the moment due to the energy market crisis, leading to a higher level of uncertainty in any future energy sector scenario analysis. However, the model is developed and tested on the Croatian empirical data and it can be further used to simulate different market conditions and projections. Further research could expand this approach and address the cost-benefit model of hydrogen production at renewable energy plant sites and the integration of hydrogen into the existing natural gas grid.

3. PROFITABILITY MODEL OF GREEN HYDROGEN PRODUCTION ON AN EXISTING WIND POWER PLANT LOCATION

Authors: Andrea Dumančić, Nela Vlahinić Lenz, Lahorko Wagmann

Title: Profitability Model of Green Hydrogen Production on the Existing Wind Power Plant Location

Journal: Sustainability, EISSN 2071-1050, Published by MDPI

Published: 8 February 2024, Sustainability 2024, 16(4), 1424; https://doi.org/10.3390/su16041424

Submitted to section: Energy Sustainability, Energy Economy and Sustainable Energy

3.1. Introduction

A power-to-gas system at the location of an existing wind power plant is one of the promising options for utilizing green hydrogen production technology. Green hydrogen produced at the mentioned location and transported through the natural gas system can contribute to increasing the wind farm profitability and participate in the congestion management of the power grid.

The wind power plant can generate additional income through the power-to-gas system. The power-to-gas process using a polymer electrolytic membrane (PEM) electrolyzer connects the power grid and the gas grid by electrochemically transforming the electricity generated from the wind power plant into green hydrogen, with direct injecting into the gas grid. This process has demonstrated an overall efficiency of over 70%, and the first electrolytically generated hydrogen has been injected into the German gas grid (Chandrasekar, et al., 2021.). One of the motivations for this research is related to the specific climate characteristics of Mediterranean countries, making this research potentially beneficial for many such countries. For instance, the wind power plants in Mediterranean countries have around 2500 equivalent full load hours, indicating relatively low utilization. Therefore, it is important to explore the possibilities of green hydrogen production at the location of an existing wind power plant to increase the profitability and utilization of the wind power plant. When the electricity price on the day-ahead market falls below a certain level, and the wind power plant is producing electricity, the hydrogen produced at the time has a higher value compared to when the electricity is delivered to the grid. There is significant economic and energy potential in such situations, which is insufficiently explored both theoretically and empirically. We believe that this research will provide new insights into increasing the utilization of wind power and will contribute to a greater production of green hydrogen in the energy transition.

This research does not consider the production of a certain amount of green hydrogen to replace a specific percentage of natural gas in the gas grid. Instead, it examines the case where competitive green hydrogen is produced at the location of the wind power plant and injected into the gas grid. This would achieve two goals: increasing the value of the wind power plant production and supporting energy transition in the form of hydrogen production and decarbonization of the gas system. To accomplish this, a universal profitability model for green hydrogen production using wind power plant electricity is defined, which can be applied to all countries with similar climatological characteristics, especially wind characteristics. The model is tested using realistically estimated input parameter values and the optimal electrolyzer capacity at the location of an existing wind power plant in the Republic of Croatia.

An economic model is proposed to determine the profitability of green hydrogen production, considering the hourly production of the wind power plant, hourly electricity prices on the day-ahead market, natural gas prices, CO_2 emissions over an extended period, as well as capital and operational costs of the power-to-gas technology and gas connection. The uncertainty of future variations in hourly electricity prices and wind power plant production curve is modeled by determining hourly coefficients based on previously realized electricity prices in the day-ahead market at the Croatian Electricity Exchange (CROPEX), as well as the production curve, using a Monte Carlo simulation approach. Accordingly, the aim of this research is to test the hypothesis that green hydrogen production at a wind power plant location increases the overall income of the wind power plant. To achieve this, it is necessary to find the critical breakeven point on the curve of hourly electricity prices to produce electricity or green hydrogen.

Analyzing the green hydrogen production potential for almost every wind power plant location requires historical wind power plant production data, electricity specifics data of the day-ahead market, and the natural gas market for the location where the wind power plant is situated, as well as data on the availability and possibility of connection to the gas grid. A model that encompasses all the elements contributing to the introduction of a power-to-gas system tested on a real wind power plant case, according to the available literature, has not been created to date. The production of the wind power plant cannot be influenced, as it depends on climatic conditions, but the amount of electricity delivered to the power system and the utilization of a portion of low-market-value electricity for green hydrogen production can be controlled, thus increasing wind power plant production revenues.

3.2. Literature Review

The production of green hydrogen and its integration into the gas grid has multiple benefits, as discussed by numerous authors who primarily highlight its contribution to achieving climate and decarbonization goals, particularly through the utilization of gas infrastructure, as well as greater efficiency and profitability of investments in renewable energy sources, especially wind power plants.

Several studies have examined the production of green hydrogen from solar and wind power at potential or existing locations. Analyses of the challenges and opportunities related to green, blue, and gray hydrogen are the basis of different perspectives on the potential hydrogen society (Noussan, et al., 2020.). Dinh et al. (2021.) presented an analysis of dedicated offshore wind power plants for hydrogen production and a hypothetical injection into the Irish gas grid. The authors believe that a minimum capacity of 100 MW is required to achieve economically viable hydrogen production from offshore wind power plants. Grimm et al. (2020.) and Li et al. (2023.), using the examples of photoelectrochemical (PEC) and photovoltaic (PV) systems, processed the techno-economic analysis of hydrogen production from solar power plants. They concluded that the photoelectrochemical system is interesting but currently not cost-effective.

Mikovits et al. (2021.) focused on hydrogen production based on potential wind energy production in Sweden. They stated that 46 kWh of electricity is required to produce 1 kg of hydrogen, and additional electricity for hydrogen production comes solely from wind energy. Bareiß et al. (2019.) mentioned that if the energy mix from German's power system in 2017 were used for hydrogen production, 29.5 kg of CO_2 would be emitted per kilogram of hydrogen produced. It is necessary to have a surplus of energy from renewable sources for at least 3000 h per year to reduce the amount of emitted CO_2 to 3.3 kg of CO_2 per kilogram of produced hydrogen to meet climate goals. For comparison, the production of 1 kg of hydrogen from fossil fuels results in 2 kg of CO_2 emissions. Renewable electricity surplus can be used to power water electrolyzers producing green hydrogen to be injected into natural gas pipelines, with the dual effect of solving production–consumption mismatches in the electricity network and decarbonizing the natural gas system (Grossi, et al., 2022.).

Geographical location has a significant impact on the economic and competitive production of green hydrogen. A study by Armijo and Philibert (2020.) analyzed locations in Chile and Argentina with abundant and affordable renewable sources where dedicated solar and wind power plants could produce green hydrogen at competitive prices through the interaction between the variability of renewable energy sources. Ioannou and Brennan (2019.) conducted a techno-economic analysis of costs between a grid-connected floating wind power plant and an off-grid floating wind power plant with an integrated electrolyzer. The results of the model applied to a hypothetical wind power plant in Great Britain located 200 km offshore show that neither system is profitable. For the grid-connected wind power plant, there are high grid connection costs, while for the wind power plant with an integrated electrolyzer, even the higher productivity (full load hours) is not sufficient to cover the costs of hydrogen production infrastructure. However, the investment could become sustainable with higher productivity (>60%).

Power-to-gas has become a promising technology in recent years for connecting the power and gas systems. Eveloy and Gebreegziabher (2018.) present a review of the power-to-gas and power-to-X technologies and European projects dealing with these technologies. A stronger integration between systems is the basis for a more efficient use of existing infrastructure and technology. Installing a power-to-gas system at renewable energy locations enables flexibility and an efficient utilization of the power and gas system. The decentralized injection of hydrogen into the natural gas grid brings the benefits of connecting two energy systems.

The results of the study by Xiong et al. (2021.) show a 12% reduction in renewable energy production constraints due to grid congestion using a power-to-gas system. The main application of a power-to-gas system is to inject hydrogen into the natural gas grid for renewable energy storage or fossil fuel replacement. A study by Gorre et al. (2019.) included the direct connection of the power-to-gas system with a renewable energy source and the occasional delivery of surplus (ancillary services to the power system) produced electricity to the grid.

To reduce CO_2 emissions and decarbonize the energy system, it is necessary to integrate appropriate capacities of renewable energy sources into the power systems. Numerous studies support this idea, analyzing the maximization of variable renewable energy production such as wind and solar in the operation of power systems. The increasing operating costs for the procurement of ancillary services and congestion management in the grid to maximize the integration of renewable energy sources are the price that needs to be paid to achieve the European Union’s goals. However, there are many situations in which maximizing renewable energy production can lead to a simultaneous increase in costs and CO_2 emissions. This can occur due to a frequent redispatching of generation units and congestion management in the grid, power ramping requirements, minimum operating time, or other security constraints (Morales-España, et al., 2021.).

In terms of sustainability and environmental impact, the PEM electrolyzer is the most promising technology for hydrogen production from renewable energy sources, as it only emits oxygen as a by-product without CO_2 emissions. Flexible hydrogen electrolyzers can stabilize renewable market values; additional low-cost renewable supply depresses electricity prices, leading to below-average market revenues (Ruhnau, 2022.). Kumar and Himabindu (2019.) studied and summarized different methods of hydrogen production from renewable energy sources, including the development of electrolyzer efficiency, durability, and cost-effectiveness. The PEM electrolyzer has achieved remarkable results in analyzing the processes of different hydrogen production technologies. It enables faster start-up, greater flexibility, and can operate with intermittent power sources such as renewable sources, achieving an efficiency of up to 85% (Al-Qahtani, et al., 2021.). Hydrogen production by water electrolysis using a PEM electrolyzer is a promising technology for reducing CO_2 emissions if the electrolysis system operates solely on electricity produced from renewable energy sources. The choice of energy source has a significant impact on the results and production costs of hydrogen (Bareiß, et al., 2019.). It is necessary to analyze all the factors affecting the production price of green hydrogen and make a case study for each of the factors in order to calculate the lowest possible price of green hydrogen (Muñoz Díaz, et al., 2023.).

Chandrasekar et al. (2021.) examined low- and high-temperature electrolyzers and their impact on hydrogen production. The study concluded that the operating temperature of the electrolyzer and the nature of the input electricity have a significant influence on maximizing hydrogen production. The modeling results showed that the PEM electrolyzer is more suitable for a variable renewable electricity source, while a Solid Oxide Electrolysis Cell (SOEC) has a higher efficiency when the plant operates continuously. The large capacity of the electrolyzer supporting the wind power plant operation makes the system more stable, especially during hours of reduced electricity demand and favorable wind conditions (Mikovitz, et al., 2021.). Gorre et al. (2019.) conducted an analysis of hydrogen production for three different electrolyzer sizes, assuming continuous plant operation for 8760 h with the average day-ahead market electricity price. Electricity for the electrolyzer operation is secured by purchase through short-term market purchases, long-term contracts, direct connections to renewable energy sources, or occasional surplus delivery.

A large volume of the literature also includes the possibility of injecting green hydrogen into the gas grid (Ferrero, et al., 2016.; Ekhtiari, et al., 2020.; Pellegrini, et al., 2020.; Khan, et al., 2021.; Qiu, et al., 2022.). Hydrogen injection into the gas grid enables the transmission system operator to manage congestions by utilizing the flexibility of energy storage, thereby deferring the necessary investments in the transmission network. This allows for greater integration of renewable sources. Hydrogen produced at renewable energy location can be used for mobility, as well as electricity generation and injection into the natural gas grid (Ferrero, et al., 2016.). Blending green hydrogen produced from electricity generated from wind power plants into the gas grid is possible with control so that the proportion of hydrogen does not exceed the technical limit (Qiu, et al., 2022.). The intertwining of the energy infrastructure through a conversion technology provides the short-term flexibility for the future energy system (Koirala, et al., 2021.).

In a previous study by the authors (Dumančić, et al., 2023.), centralized hydrogen production in a gas-fired power plant with necessary infrastructure was analyzed, resulting in minimal investment. Centralized hydrogen production allows for a larger electrolyzer capacity and a higher amount of produced hydrogen, thereby having a significant impact on replacing natural gas in the gas grid and reducing CO_2 emissions. However, hydrogen is produced from electricity taken from the power grid, and it is not categorized as renewable or green hydrogen. It is necessary to analyze the source of green electricity in order to determine the optimal technology and electrolyzer size and to achieve the lowest hydrogen price (Hassan, et al., 2023.). The economic objective aims to determine the minimum cost, which is composed of the capital costs in the acquisition of units, operating costs of such units, and costs of the production and transmission of energy (Serrano-Arévalo, et al., 2023.).

This paper presents an economic profitability model based on scientific assumptions and principles, aimed at finding the optimal solution for achieving climate and decarbonization goals by testing renewable energy source locations as potential decentralized green hydrogen production sites.

In the above-mentioned studies, the authors did not come across a model in which the electrolyzer capacity was calculated based on the hourly production of the wind power plant. Instead, the electrolyzer capacity was predetermined or the hourly wind power plant production was predefined rather than estimated based on the actual hourly production of an existing wind power plant.

3.3. Description of the Model

Installing a power-to-gas system at the wind power plant location opens the possibility for using produced electricity for green hydrogen production. The green hydrogen is then integrated into the gas grid via the injection station as a substitute for natural gas, thereby additionally influencing the acceleration of the energy transition. This method of production is attractive in the case of low electricity prices on the day-ahead market, but also in cases of congestion in the network when the production of the wind power plant should be limited. Therefore, green hydrogen is produced when electricity prices are low and when there is a need for production flexibility services.

The economic profitability model presented in this paper is designed in such a way that with the historical data of the wind power plant and data from the day-ahead market, it calculates how much of the future share of electricity production can be allocated to the power-to-gas system, without affecting the economy of operating the wind power plant. The results of the model provide answers to three key questions:

1) Is green hydrogen produced from surplus electricity from renewable sources or this surplus does not exist (surplus is manifested through low/negative electricity prices on the day-ahead market)?
2) Can the green hydrogen production at the wind power plant location increase the income from the production of the wind power plant?
3) Is it possible to produce a sufficient amount of green hydrogen that will replace a significant percentage of natural gas in the gas system and, thereby, affect the reduction of CO_2 emissions?

The model shows the concept of connecting the source of electricity with the gas system, so that mutually integrated systems depending on the electricity price and the optimization of the electrolyzer size, and the marginal price of electricity affect the green hydrogen production and the profitability of the production of the wind power plant.

3.3.1. Input Data for the Model

This paper presents an hourly price and electricity production breakdown based on which the electrolyzer size and the marginal price of electricity are calculated to align electricity and green hydrogen production. The horizon of the presented model is set to a period of 25 years (corresponding to the lifetime of the energy plant), and several key input variables (market price of electricity, natural gas, and emission units) subject to uncertainty are presented in sensitivity analysis scenarios.

Given that power-to-gas systems consist of several separate parts, the cost estimate and gas grid connection, i.e., the capital (CAPEX) and operating costs (OPEX) of the whole investment, are shown in Table 3-1.

Table 3-1. CAPEX and OPEX of power-to-gas system and gas grid connections.

Parameter		Unit Price
CAPEX power-to-gas	Electrolyzer	1300.00 EUR/kW
	Compressor	400.00 EUR/kW
CAPEX gas grid connection	Measuring-reduction station (MRS)/Hydrogen injection station	660,000.00 EUR
OPEX	Market value of produced electricity used for hydrogen production	EUR/MWh
	Electrolyzer maintenance (2% of capital costs)	0.58–1.00 EUR/MWh
	The cost of water	2.00 EUR/m^3

Source: Authors, based on data taken from several sources in the literature (Gorre, et al., 2019.; Kumar, Himabindu, 2019.; FCH 2 JU, 2017.; Fu, et al., 2020.; Mayer, et al., 2019.; Plinacro, 2022.).

The total investment cost at the wind power plant site consists of the capital costs of the power-to-gas system and gas infrastructure construction, annual fixed and variable operating costs, and the annual cost of chemical water treatment. The total capital cost of the power-to-gas system and the construction of the gas infrastructure is calculated at the level of the entire life of the plant, i.e., the period of the model, while the rest of the costs are measured on an annual basis. Fixed plant operating costs represent costs that do not depend on system output, while variable costs include costs that vary depending on the system's output.

For the individual CAPEX values used in the model according to the literature, they are adjusted for the specific location. Specifically, the CAPEX for the power-to-gas system is 1700.00 EUR/kW. However, in this case, it is additionally increased by the amount of gas grid connection as part of the overall investment. It should be considered that installing a power-to-gas system in a different location has different costs that make up CAPEX. For the investment case presented in this paper, CAPEX consists of parts of the power-to-gas system and the gas grid connection, i.e., the measuring-reduction station, which is also a hydrogen-injection station. OPEX is the market value of the produced electricity that was used for the green hydrogen production.

The model uses a PEM electrolyzer with a perfectly flexible behavior, i.e., in real time, it follows the variable supply of electricity and maintains a constant efficiency of 74%. The efficiency of the electrolyzer is taken from Fu et al. (2020.) who applied an efficiency of 74%, which is in line with the achievements and progress of water electrolysis technologies (Fu, et al., 2020.). It is assumed that large-scale PEM electrolyzer cost reductions should occur soon, so an amount that supports such a prediction is taken for this study. In terms of flexibility, the PEM electrolyzer technology has the most favorable characteristics and is, therefore, the most suitable for solving variable electricity inputs (Xiong, et al., 2021.). The total installed capacity of the electrolyzer must meet the high efficiency of green hydrogen production, that is, it must work at full capacity during the model's predicted period.

Prices of electricity, natural gas, and CO_2 emissions were estimated on the European Ten-Year Electricity and Gas Grid Development Plan (TYNDP 2022), according to the basic scenario of the European Network of Transmission System Operators, ENTSO-E, and the European Network of Transmission System Operators for Gas, ENTSOG (2022.). Table 3-2 shows estimated prices of electricity, natural gas, and CO_2 emissions, which were used in the model. Certain years were chosen to display prices, although the hourly electricity prices and annual prices of natural gas and CO_2 emissions were used in the model.

Table 3-2. Estimated annual prices of electricity, natural gas, and CO_2 emissions.

Price	2025	2030	2035	2040	2045	2049
Electricity (EUR/MWh)	185.44	127.17	113.58	100.00	95.00	91.00
Natural gas (EUR/MWh) (NCV)	83.81	44.40	41.62	38.85	36.07	33.85
CO_2 emissions (EUR/t)	102.71	127.56	147.97	168.37	188.78	205.11

Source: Authors estimated prices based on data from the TYNDP 2022 Scenario Report (ENTSO-E; ENTSOG, 2022.).

The forecast hourly electricity prices reflect the coefficients of the ratio of realized annual and hourly electricity prices on the day-ahead market for the historical five years, from 2018 to 2022, taken from the day-ahead market at CROPEX. The predicted hourly electricity production data were recalculated from the 15 min readings of the Zelengrad wind power plant production for the historical six years, from 2017 to 2022, taken from the report of the Croatian Energy Regulatory Agency (2022.).

Additionally, an assessment of the value of the power-to-gas system, together with the gas connection, were performed as the overall investment required for green hydrogen production at the wind power plant location. Since the model includes hourly input variable data for all 25 years, all parts of the model are complex and require a significant amount of data and formulas. In this study, a PEM electrolyzer was chosen for hydrogen production using water electrolysis. To calculate the size of the required electrolyzer, the selected operating hours of the wind power plant were optimized to maximize its utilization. The electrolyzer cannot be of the same size as the wind power plant, given that it does not operate at full capacity throughout the year. Therefore, the capacity of the electrolyzer is optimized to avoid excessive investment that would increase the hydrogen production price.

The application of Monte Carlo simulation to energy prices enables uncertainty modeling in such a way that the input variables are predicted through continuous probability density functions, which leads to a more realistic representation of the uncertainty of future price movements, based on collected historical data (Ioannou, et al., 2019.). In addition to the predicted hourly electricity prices, Monte Carlo simulation was also used for electricity production so that the distribution of historical years was more realistically displayed for the entire model period. When predicting electricity prices, each of the five historical years is allocated to model years in a given ratio, while when predicting electricity production, there is no such limitation. To overlook the price of electricity in the Monte Carlo simulation, a limit of 10% was taken for the year 2020 as a specific pandemic year that is considered less likely to recur, while other historical years had an equal proportion of recurrences. The year 2020, with such a restriction, was repeated twice within the 25-year period of the model.

When calculating the coefficients for forecasting electricity prices, a period of five years of realized electricity prices at the hourly level on the day-ahead market was taken, precisely for the sake of the visibility of electricity price oscillations. In this way, the ratio of higher and lower hourly electricity prices can be seen, that is, the influence of climate conditions or other specificities of the covered historical years. By displaying the hourly production of electricity, it is possible to see in which hours of the year the wind power plant produced at maximum installed capacity, reduced capacity, or did not produce.

The hourly display of the expected market price of electricity and the expected production of electricity for a period of 25 years is important when determining the marginal price of electricity. Within the annual hourly realizations of wind power plant production and hourly realizations of electricity prices, it is necessary to determine the breakeven price of electricity based on which green hydrogen or electricity will be produced. The marginal price of electricity is optimized for each model year. It represents the limit above which the wind power plant delivers the generated electricity to the power grid, and below which green hydrogen is produced from the generated electricity in the electrolyzer. Therefore, the hours of the year when the price of electricity is favorable are determined, at the same time considering the hours in which the production of electricity is high, thus optimizing the marginal price of electricity.

The size of the electrolyzer is determined according to the hourly electricity production of the wind power plant and the market price of electricity during those hours. First, the marginal price of electricity, below which hydrogen is produced and above which the wind power plant delivers the generated electricity to the power grid, was determined. The size of the electrolyzer is based on a certain optimized annual marginal value of production in such a way as to consider the total production of electricity below the level of the marginal price of electricity for 25 years. After that, the hourly production of the wind power plant was analyzed in the hours when the price of electricity was below the marginal price, and according to these hours of production, the optimal size of the electrolyzer was calculated using the Excel solver. With this optimal size of electrolyzer, the lowest production price of hydrogen was obtained. This was performed for each individual year of the model, and based on the results for each of 25 years, the size of the electrolyzer was determined, which was closest to the result for each year. According to the realized hourly production of the wind power plant and the expected hourly prices of electricity on the day-ahead market, the optimal size of the electrolyzer was calculated, which increased the economic value of the production of the wind power plant. Therefore, for choosing the size of the electrolyzer, it is important to predict the prices and production of electricity, i.e., the marginal price of electricity.

Part or all the electricity production when the price of electricity on the day-ahead market is lower than the marginal price of electricity was used for the green hydrogen production. The price of green hydrogen consists of the market value of electricity used for the production of green hydrogen, i.e., the variable part of the cost and fixed costs, taking into account the efficiency of the electrolyzer. Finally, the production price of green hydrogen was calculated as follows:

$$GHPP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] = VHP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] + FHP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] \tag{6}$$

where

$GHPP_t$: Green hydrogen production price in year t [EUR/MWh];

VHP_t: Variable cost of hydrogen production in year t [EUR/MWh];

FHP_t: Fixed cost of hydrogen production in year t [EUR/MWh].

Production price of green hydrogen is an annual sum of variable and fixed hydrogen production costs divided by annual hydrogen production for year t.

The component FHP_t is the capital expenditures of hydrogen production and is calculated as follows:

$$FHP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] = \frac{\frac{IC_t[\mathrm{EUR}] + GPCC_t[\mathrm{EUR}]}{25}}{HP_t[\mathrm{MWh}]} \tag{7}$$

where

FHP_t: Fixed cost of hydrogen production in year t [EUR/MWh];

IC_t: Investment cost in year t [EUR];

$GPCC_t$: Cost of connection to the gas pipeline in year t [EUR];

HP_t: Annual hydrogen production in year t [MWh].

The fixed cost of hydrogen production is a sum of investment cost and the cost of connection to the gas pipeline on an annual basis divided by the hydrogen production in year t.

The component VHP_t is the operating expense of hydrogen production and is calculated as follows:

$$VHP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] = \frac{\sum_0^{8760} EHP_t\,[\mathrm{MWh}] * HEPEM_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] + MTC_t[\mathrm{EUR}] + WOC_t[\mathrm{EUR}]}{HP_t[\mathrm{MWh}]} \tag{8}$$

where

VHP_t: Variable cost of hydrogen production in year t [EUR/MWh];

EHP_t: Electricity consumed for hydrogen production in year t [MWh];

$HEPEM_t$: Hourly expected price of electricity on the market in year t [EUR/MWh];

MTC_t: Maintenance cost in year t [EUR];

WOC_t: Cost of water in year t [EUR];

HP_t: Annual hydrogen production in year t [MWh].

The variable cost of hydrogen production is a sum of electricity consumed for hydrogen production, hourly expected price of electricity on the market, maintenance cost, and cost of water divided by the hydrogen production in year t.

To be able to calculate the profitability of the production of green hydrogen, it is necessary to calculate the income from the produced amount of green hydrogen, which is calculated according to the price of natural gas. The income from the produced amount of green hydrogen is calculated as follows:

$$IGHP_t[\mathrm{EUR}] = PNG_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] * HP_t[\mathrm{MWh}] + 0.20196 * \mathrm{PCO2}_t[\mathrm{EUR/t}] * HP_t[\mathrm{MWh}] \tag{9}$$

where

$IGHP_t$: Income from produced green hydrogen in year t [EUR];

PNG_t: Price of natural gas in year t [EUR/MWh];

$PCO2_t$: Price of CO_2 emissions in year t [EUR/t];

HP_t: Hydrogen production in year t [MWh].

The income from produced green hydrogen is calculated with the price of natural gas that is multiplied by hydrogen production, after which the CO_2 emissions cost's equivalent is added. The amount of 0.20196 is multiplied by the price of CO_2 emissions per ton and by the hydrogen production because green hydrogen can be sold at the natural gas price increased by the price of CO_2 emissions and still be competitive to natural gas.

The market value of electricity used to produce green hydrogen is calculated as follows:

$$MEHP_t[\mathrm{EUR}] = \sum_0^{8760} HEPEM_t \left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] * EHP_t[\mathrm{MWh}] \qquad (10)$$

where

$MEHP_t$: Market value of electricity used for hydrogen production in year t [EUR];

$HEPEM_t$: Hourly expected price of electricity on the market in year t [EUR/MWh];

EHP_t: Electricity consumed for hydrogen production in year t [MWh].

The market value of electricity used for hydrogen production is the product of the hourly expected price of electricity on the market and electricity consumed for hydrogen production. The amount of the required premium subsidy for green hydrogen production is calculated as follows:

$$S_t = \frac{MEHP_t[\mathrm{EUR}] - IGHP_t[\mathrm{EUR}]}{HP_t[\mathrm{MWh}]} \qquad (11)$$

where

S_t: Required premium subsidy in year t [EUR/MWh];

$MEHP_t$: Market value of electricity used for hydrogen production in year t [EUR];

$IGHP_t$: Income from produced green hydrogen in year t [EUR];

HP_t: Hydrogen production in year t [MWh].

The required subsidy is calculated as the difference between the market value of electricity used for hydrogen production and the income from the produced green hydrogen divided by the hydrogen production. If the income from the produced green hydrogen is greater than the market value of electricity used for hydrogen production, no premium subsidy is required.

The market value of electricity delivered to the grid is calculated as follows:

$$MVDG_t[\mathrm{EUR}] = \sum_0^{8760} HEPEM_t \left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right] * EPG_t[\mathrm{MWh}] \qquad (12)$$

where

$MVDG_t$: Market value of electricity delivered to the grid in year t [EUR];

$HEPEM_t$: Hourly expected price of electricity on the market in year t [EUR/MWh];

EPG_t: Electricity delivered to the grid in year t [MWh].

The market value of electricity delivered to the grid is the product of the hourly expected price of electricity on the market and electricity delivered to the grid.

The levelized cost of hydrogen (LCOH) is a widely accepted standard for assessing and comparing energy technologies (Kaplan, Kopacz, 2020.). LCOH is a sum of total CAPEX and OPEX divided by the amount of produced hydrogen. LCOH was calculated for the basic scenario as well as for all sensitivity scenarios. The formula for levelized cost of hydrogen is as follows:

$$\mathrm{LCOH}[\frac{EUR}{\mathrm{MWh}}] = \frac{\sum_{t=1}^{n} \frac{FHP_t\left[\frac{EUR}{\mathrm{MWh}}\right] + VHP_t\left[\frac{\mathrm{EUR}}{\mathrm{MWh}}\right]}{(1+d)^t}}{\sum_{t=1}^{n} \frac{HP_t[\mathrm{MWh}]}{(1+d)^t}} \tag{13}$$

where

LCOH: The levelized cost of hydrogen [EUR/MWh];

n: Lifetime of power-to-gas system;

FHP_t: Fixed cost of hydrogen production in year t [EUR/MWh];

VHP_t: Variable cost of hydrogen production in year t [EUR/MWh];

HP_t: Annual hydrogen production in year t [MWh];

d: Discount factor [%].

The rate of the discount factor was adopted from the authors Jovan and Dolanc (2020.), who used a discount factor of 5%, which we consider applicable in our scenarios as well. The fixed cost of hydrogen production was calculated as the sum of fixed costs, which represent costs that do not depend on system output and include costs of power-to-gas system, gas grid connection costs, and hydrogen injection station costs. The variable cost of hydrogen production was calculated using costs that vary depending on the system’s output, such as the market value of the produced electricity that was used for the green hydrogen production, electrolyzer maintenance costs, and water costs.

3.3.2. Structure of the Model

The structure of the economic model shown in Figure 3-1 illustrates the way in which the proposed model works.

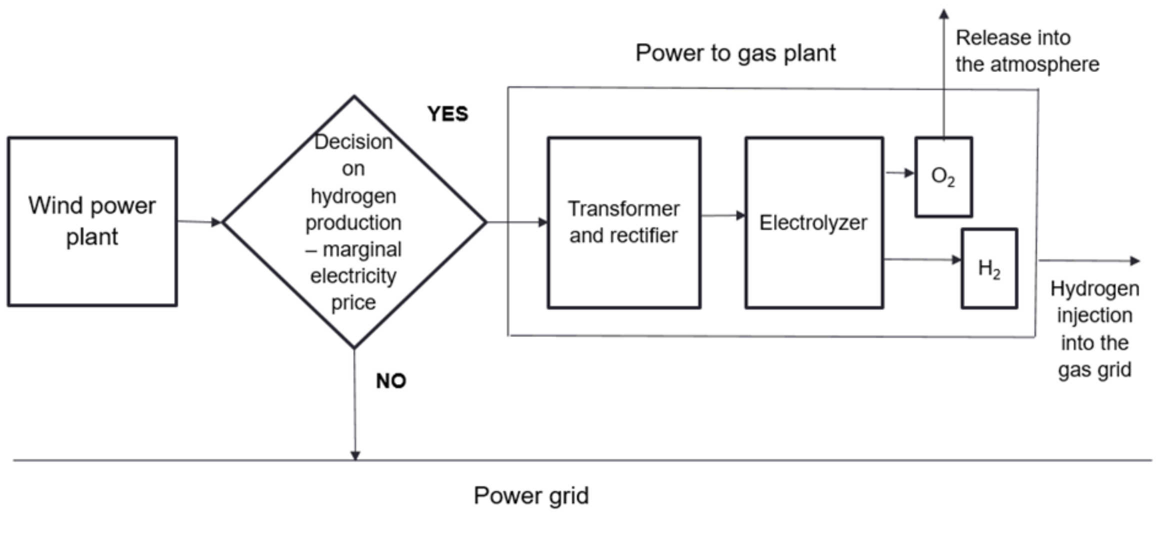

Figure 3-1. Data flow chart.

Depending on the production of the wind power plant and the market price of electricity, the marginal price of electricity is determined, which, along with the type and capacity of the newly installed power-to-gas system, is a decision variable in green hydrogen production. With a positive decision, the green hydrogen production technology is implemented in the power-to-gas system via a PEM electrolyzer that separates water molecules into hydrogen and oxygen. Oxygen is released into the atmosphere while green hydrogen is injected into the gas grid. With a negative decision, green hydrogen is not produced, but the produced electricity from the wind power plant is transferred to the power grid.

Based on data on existing wind power plants in the Republic of Croatia, location, year of construction, installed capacity, and production curve, the Zelengrad wind power plant was selected; its data were used as input parameters of the model, and the model results were applied to it. The input parameters of the price and production of electricity are based on historical data, but their predictions of future trends are an uncertain part of this model. The inclusion of this uncertainty through the change of input variables in the scenario sensitivity analysis results in the basis needed for making an investment decision or providing incentives for investing in green hydrogen production technology at the wind power plant location.

The authors are aware of the following limitations of the model:

1) Predicted price movements of electricity, natural gas, and CO_2 emissions;
2) Predicted trends in electricity production;
3) Determination of low electricity prices, i.e., marginal price of electricity;

4) Optimum electrolyzer size to achieve high efficiency;
5) Accessibility or distance of the gas grid to the renewable energy source.

The output variables of the model are the annual cost of the production price of green hydrogen, the annual consumption of electricity for the green hydrogen production, the capacity of the electrolyzer, the capital and operational cost of the investment, the cost of the chemical preparation of water, and the amount of produced green hydrogen. Based on the amount of produced hydrogen that is injected into the gas grid, the amount of CO_2 emissions is also calculated, which is, thereby, reduced.

3.3.3. Assumptions of the Model

The assumption of the model is the use of power-to-gas technology. When the green hydrogen produced by the electrolysis of water in the power-to-gas system is mixed into the gas grid, it provides a potential solution for storing and transporting a larger amount of energy, achieving the decarbonization of the gas system, and reducing dependence on natural gas. Since the technology of producing and injecting green hydrogen into the gas grid requires considerable investment, it is important to look at the cost effectiveness and justification of the whole investment.

As the aim of this study was to assess the possibility of green hydrogen production at an existing wind power plant location, assumptions were made so that the technical and economic components of the model would contribute to the quality of the results. Below are the model assumptions:

1) The electricity production curve refers to an existing onshore wind power plant, which was selected for its size, location, and historical production data. The capacity of the wind power plant remains constant throughout the model period, and the investment in the wind power plant is amortized;
2) The volatility of the price of electricity at the hourly level for the entire model period is integrated based on five selected historical years of realized electricity prices, which are applied to the future observed period of the model through Monte Carlo simulation with the coefficients of realized prices;
3) The lifetime of the wind power plant is equal to the lifetime of the power-to-gas system, which corresponds to the total period of the developed model;
4) The production of electricity from the wind power plant as well as the green hydrogen production from the power-to-gas system have a zero rate of CO_2 emissions;
5) The price of produced green hydrogen from the power-to-gas system is calculated in such a way that the market value of the produced electricity used for the green

hydrogen production is increased by the efficiency of the electrolyzer and capital costs;

6) The electrolyzer at the wind power plant location will not meet a certain amount of green hydrogen that would replace a certain percentage of natural gas in the grid, but according to the day-ahead market conditions of electricity, it produces green hydrogen when it is profitable. The gas system can accept the produced green hydrogen at any time.

A summary of the basic assumptions for creating an economic model related to the capacity of the wind power plant, the lifetime and depreciation of the power-to-gas system, and the efficiency of the PEM electrolyzer are shown in Table 3-3.

Table 3-3. Assumptions of the economic model.

Wind power plant capacity	42 MW
Lifetime of power-to-gas system	25 years
Straight-line depreciation	25 years
Electrolyzer efficiency	74%

Source: Authors (Fu, et al., 2020.; Croatian Energy Regulatory Agency, 2022.).

The model considers all the costs of the power-to-gas system connected to the gas grid for the specific example of the Zelengrad wind power plant located in the southern part of Croatia.

3.3.4. Site Description

The location of green hydrogen production at the site of an existing wind power plant was chosen for several reasons. The repurposing or expansion of the existing energy infrastructure affects the achievement of part of the goals of the energy transition by reducing the investment intensity and increasing the additional value of the existing gas and electricity infrastructure. The authors believe that the location of the wind power plant with historical electricity production, lower initial investment costs, and the availability of gas infrastructure, in order to increase financial profitability, meet all the conditions for examining the profitability of green hydrogen production. Also, an important part of this analysis is that this model can be applied to other existing wind power plants in the region or the world where there is a similar situation of proximity to gas infrastructure and a relatively low efficiency of wind power plants.

In this study, data from the electricity and gas markets of the Republic of Croatia were used for the input parameters of the model. The installed power of all power plants connected to the transmission system in the territory of the Republic of Croatia at the end of 2022 was 5031 MW, of which wind power plants made up 885 MW. In 2022, wind power plants connected to the transmission system produced 2.1 TWh of electricity, which was 18.4% of the total electricity produced on the transmission system (Croatian Energy Regulatory Agency, 2022.).

The model used data from the wind power plant Zelengrad, which is located within Zadar County, in the town of Obrovac. The electric power of the wind power plant is 42 MW, and it consists of 14 wind turbines V—90 with a power of 3 MW. The Zelengrad wind power plant produced 78,867 MWh in 2022, which is 3.8% of the electricity produced by wind power plants connected to the transmission system. On average, the wind power plant operates between 5500 and 6000 h per year, of which the total annual production is between 75 and 105 GWh of electricity. Converted into equivalent full load hours, the wind power plant operates between 1900 and 2500 h or about 25% per year at full load hours (Croatian Transmission System Operator, 2022.).

3.4. Research Results

The model results do not consider all hydrogen production technologies, but specifically green hydrogen production technology by water electrolysis in a PEM electrolyzer. Furthermore, the model does not include hydrogen storage, but only direct injection into the gas grid. The results provide an overview of the production price and production quantity of green hydrogen calculated using the input variables of electricity price uncertainty, the wind power plant production curve, and capital costs. The probabilities of changes in the input variables within the observed period are calculated separately as a scenario sensitivity analysis by modeling higher and lower initial values of the input variables. Table 3-4 shows the selected years of the model with the results of the income and amount of green hydrogen, the amount and the market value of electricity needed to produce green hydrogen, and the average price of electricity for hydrogen production. Also shown is the amount and average price of electricity delivered to the grid, income from the sale of electricity and total electricity produced, the amount of reduction in CO_2 emissions, as well as the required premium subsidy.

Table 3-4. Presentation of model results for selected years.

Parameter	2025	2030	2035	2040	2045	2049
Income from produced green hydrogen (EUR)	1,425,644	1,199,823	1,494,487	1,631,750	1,662,745	1,780,129
Amount of green hydrogen (MWh)	13,636	17,102	20,901	22,399	22,410	23,648
Electricity for green hydrogen production (MWh)	18,427	23,111	28,244	30,268	30,283	31,957
Market value of electricity used for the production of green hydrogen (EUR)	1,876,266	1,884,391	1,561,556	2,239,727	1,495,198	2,190,288
Average price of electricity for hydrogen production (EUR/MWh)	101.82	81.54	55.29	74.00	49.37	68.54
Electricity delivered to the grid (MWh)	60,440	75,668	75,483	68,510	68,494	66,821
Average price of electricity delivered to the grid (EUR/MWh)	204.75	147.14	150.39	112.05	122.16	102.27
Income from the sale of electricity (EUR)	12,374,926	11,134,121	11,351,609	7,676,500	8,366,890	6,833,479
Total electricity produced (MWh)	78,867	98,779	103,727	98,778	98,778	98,778
Reduction of CO_2 emissions (t)	2727	3420	4180	4480	4482	4730
Required premium subsidy (EUR/MWh)	33.05	40.03	3.21	27.14	0.00	17.34

Source: Authors.

Table 3-4 presents the results of the model according to the input data of the prices shown in Table 3-2 and the input data of the production of the Zelengrad wind power plant. The income from produced hydrogen in 2025 is 8.5 times lower than the income from electricity delivered to the grid. For the same total electricity produced in 2030 and 2049, the electricity delivered to the grid is 12% lower in 2049 than in 2030 due to more favorable market conditions for hydrogen production. The amount of green hydrogen produced represents how much natural gas is replaced by hydrogen in the gas grid. If we compare the amount of produced hydrogen and the annual consumption of natural gas in Croatia, it would be much less than 1% of hydrogen to replace the natural gas in the gas grid. Contrary to that, the effect of reducing CO_2 emissions by replacing natural gas with green hydrogen in the mentioned amount are from 2700 to 4700 tons per year CO_2 emissions. Depending on the prices of electricity, natural gas, and CO_2 emissions, the amount of the required subsidy changes. For example, in 2030, the amount of the subsidy is 40.03 EUR/MWh of produced hydrogen, while in 2045, the subsidy is not required because income from green hydrogen is higher than the market value of electricity used for green hydrogen production.

3.4.1. Base Case

According to the basic scenario, part of the electricity produced from the wind power plant is delivered to the power grid, while part of the electricity is used in the process of water electrolysis for the green hydrogen production. By determining the marginal price of electricity, the level above which electricity is delivered to the power grid, and up to which green hydrogen is produced, is set. The marginal price of electricity is calculated separately for each year, considering that the prices and production of electricity are different every year. By increasing the marginal price of electricity, the share of fixed costs of hydrogen production decreases, while the share of variable costs increases in the price of produced hydrogen. The optimal marginal price of electricity gives the lowest possible price of produced green hydrogen, taking into account the electrolyzer size. The subject of optimization of the proposed model is shown in Table 3-5.

Table 3-5. Optimization of the economic model.

Parameter	2025	2030	2035	2040	2045	2049
Breakeven price of electricity (EUR/MWh)	141.12	115.07	81.13	97.72	74.23	91.18
Optimum electrolyzer size	10 MW					

Source: Authors.

The optimal capacity of the electrolyzer for the green hydrogen production is determined according to the market hourly electricity prices and the wind power plant production curve. After the electrolyzer sizes are determined for each individual model year, one optimal electrolyzer size is calculated for the entire model period. Table 3-6 shows the fixed and variable amounts of green hydrogen production costs, as well as the production price of green hydrogen.

Table 3-6. Production price of green hydrogen.

Parameter	2025	2030	2035	2040	2045	2049
Fixed costs of green hydrogen production (EUR/MWh)	53.42	42.71	35.04	32.73	32.72	31.03
Variable cost of green hydrogen production (EUR/MWh)	137.60	110.18	74.71	100.00	66.72	92.62
Production price of green hydrogen (EUR/MWh) (NCV)	191.02	152.89	109.75	132.73	99.44	123.65

Source: Authors.

Table 3-6 shows the ratio between fixed and variable costs throughout the model period and the total production price of green hydrogen. Fixed costs are affected by the amount of green hydrogen produced, while the forecast movement of electricity prices on the market and the marginal price of electricity affects variable costs. The share of fixed costs in the production price of green hydrogen is 28%. The higher the price, the lower the percentage, and vice versa.

Figure 3-2 shows data on the produced amount of green hydrogen from Table 3-1 and the fixed costs of green hydrogen production from Table 3-5 to see their ratio.

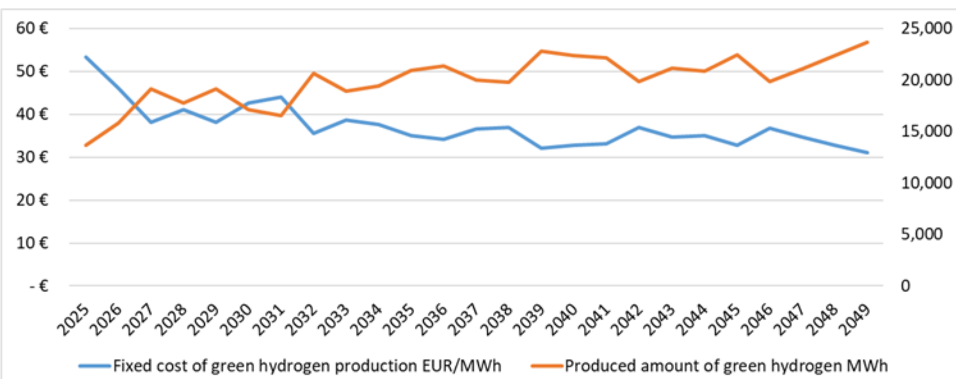

Figure 3-2. Influence of the produced quantity of green hydrogen on unit fixed costs of production.

Figure 3-2 shows the correlation between the fixed costs of production and the amount of green hydrogen, that is, with an increase in the production of green hydrogen, the fixed costs fall. However, the price of green hydrogen is not only affected by fixed costs, but also by variable costs that increase as fixed costs decrease. Therefore, at the optimal marginal price of electricity, the lowest possible production price of green hydrogen is achieved. Figure 3-3 shows a comparison of the price of produced green hydrogen and the price of natural gas increased by the price of CO_2 emissions.

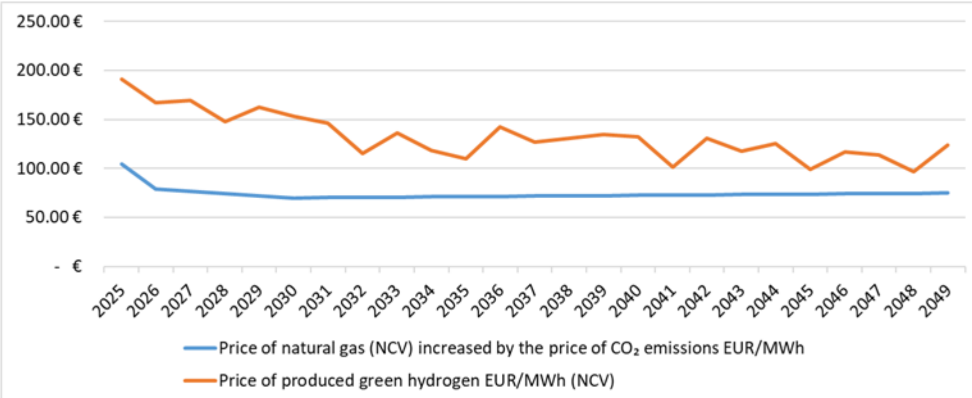

Figure 3-3. Comparison of the price of green hydrogen and natural gas increased by the price of CO_2 emissions (NCV).

It should be noted that burning 1 MWh of natural gas (NCV) emits 201.96 kg of CO_2. Therefore, the amount of 0.20196 is multiplied by the price of CO_2 emissions per ton, which are added to the price of natural gas, as calculated in the model. Figure 3-3 shows that with the current input variables of the model and with the lowest possible price of green hydrogen, it is only competitive 3 out of the 25 years of the model with the price of natural gas increased by the price of CO_2 emissions. In this way, the price of natural gas can be compared to the price of green hydrogen, considering that it does not emit CO_2 during production.

The following figure shows a comparison of the income of produced green hydrogen and the market value of the electricity required for its production.

Figure 3-4 shows that the income from produced green hydrogen in most of the years is lower than the market value of the electricity used for the green hydrogen production. The rising price of CO_2 emission allows for the income from the produced green hydrogen to overtake the market value of electricity used for green hydrogen production in three later years of the model: 2041, 2045, and 2048. The reason for this is the ratio of the price of electricity to the price of natural gas increased by the price of CO_2 emissions, since the income from the produced green hydrogen is calculated according to Formula (4).

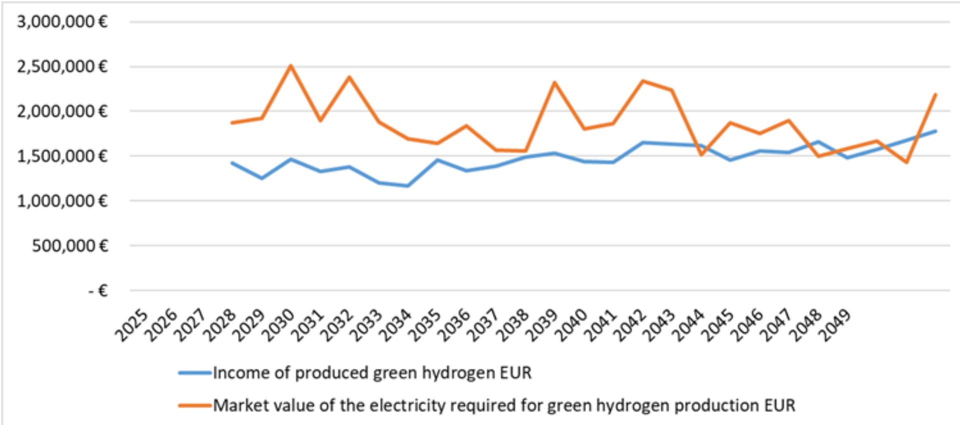

Figure 3-4. Comparison of the income of produced green hydrogen and electricity on the day-ahead market for green hydrogen production.

Figure 3-5 shows a comparison of the income of the wind power plant in the situation when green hydrogen is produced and when green hydrogen is not produced.

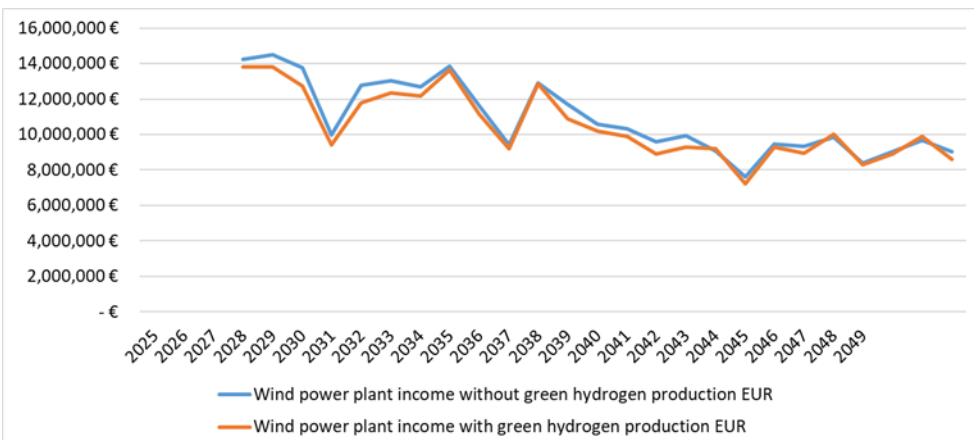

Figure 3-5. Comparison of wind power plant income without and with green hydrogen production.

Figure 3-5 shows that with the construction of the power-to-gas system, the income of the wind power plant does not increase but decreases in most of the analyzed years. According to the projected prices for electricity, natural gas, and CO_2 emissions used in the model, building a power-to-gas facility at the wind power plant site is not financially viable, that is, subsidies are needed for this type of investment.

3.4.2. Sensitivity Analysis

This chapter is dedicated to gaining a deeper insight into how the model works by testing changes in the prices of the input variables, namely, the price of electricity, natural gas, and CO_2 emissions. Therefore, the values were set to a 20% lower predicted hourly price of electricity, 20% higher predicted price of natural gas and CO_2 emissions, and 20% lower predicted electricity prices and simultaneous 20% higher predicted natural gas prices and CO_2 emissions.

The levelized costs of hydrogen calculated for all scenarios are presented in Table 3-7.

Table 3-7. The levelized costs of hydrogen.

Scenario	**LCOH (EUR/MWh)**
Basic scenario	136.56
Scenario of 20% lower electricity price	116.79
Scenario of 20% higher natural gas and CO_2 emissions prices	136.56
Scenario of 20% lower electricity price and 20% higher natural gas and CO_2 emissions prices	116.79

Source: Authors.

Table 3-7 shows that the basic scenario and the scenario where natural gas and CO_2 emission prices are 20% higher have the same result, since natural gas and CO_2 emission prices do not affect the levelized cost of hydrogen. For the same reason, the scenario where the electricity price is 20% lower and the scenario where the natural gas and CO_2 emission prices are 20% higher while electricity price is 20% lower have the same levelized costs of hydrogen.

The above results were derived under the assumption that the Monte Carlo simulation of the historical years of realized electricity prices, as well as the historical years of the wind power plant production curve, follows a normal distribution. The advantage of using Monte Carlo simulation lies in the fact that it allows for assigning a continuous distribution to the selected period of the model based on historical years of wind power plant production, but it also enables the distribution of the historical years of realized electricity prices according to the degree of probability of recurrence, for example a pandemic.

It should be noted that one of the key calculations for the input parameters of the model is precisely the combination of coefficients and Monte Carlo simulation so that each hour of each year of the observed period reflects an exact year and production, and not the average of them. On average, in historical years, major oscillations between electricity prices and production curves would not be visible, which is important when presenting predictions that are more realistic and model results.

3.4.3. Scenarios-Case Study

Considering the presented results of the model, which, according to the predicted prices of electricity, natural gas, and CO_2 emissions, make the green hydrogen production at the tested location unprofitable, an analysis of the sensitivity to changes in the input variables of the model was made. Three price-change scenarios were created: a scenario of a 20% lower electricity price change, and then a scenario of a change in the price of natural gas and CO_2 emissions to 20% more and the scenario where both price changes were made.

Figure 3-6 presents influence of a 20% lower predicted electricity price on income from produced green hydrogen.

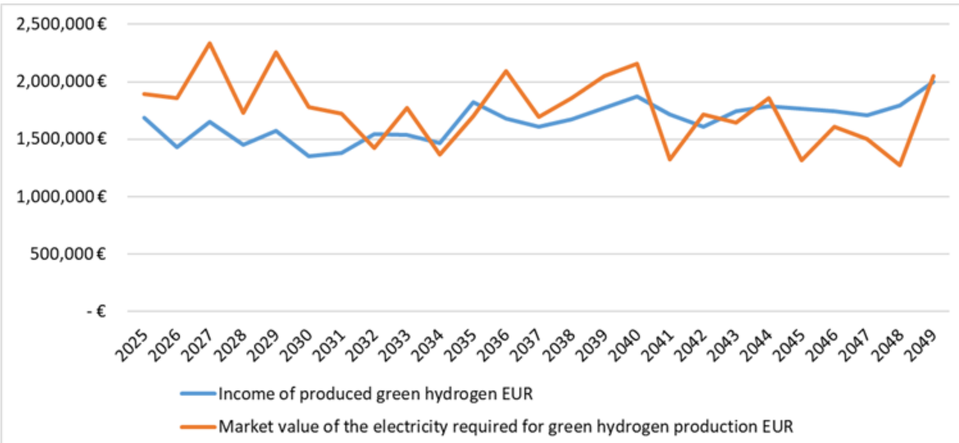

Figure 3-6. Scenario of a 20% lower predicted electricity price.

A new optimization was made, and new marginal electricity prices were calculated for the entire model period. Although there is an increase in the amount of green hydrogen produced, even with the lower price of electricity on the day-ahead market, the production of green hydrogen is still unprofitable for the tested location for most of the years of model. In nine years of the model, specifically 2032, 2034, 2035, 2041, 2043, 2045, 2046, 2047, and 2048, the ratio between the natural gas price increased by CO_2 emissions and the electricity price on an hourly basis was such that it was profitable to produce green hydrogen. Therefore, the subsidy is not required in the mentioned years of the model.

Figure 3-7 presents influence of a 20% higher predicted natural gas prices and CO_2 emissions on income from produced green hydrogen.

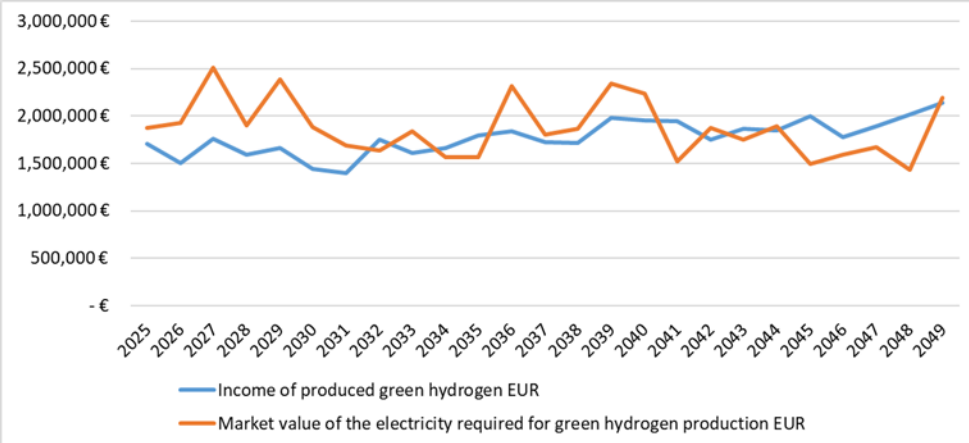

Figure 3-7. Scenario of 20% higher predicted natural gas prices and CO_2 emissions.

From Figure 3-7, it can be concluded that the income from green hydrogen is higher because the price of natural gas increased by the price of CO_2 emissions is higher. Green hydrogen is still more expensive in most of the years of the model than natural gas increased by the price of CO_2 emissions, but the difference in nine years of the model is positive than in the base case without changes in natural gas and CO_2 emissions prices. In those nine years, specifically, 2032, 2034, 2035, 2041, 2043, 2045, 2046, 2047, and 2048, no subsidy is needed because the income from green hydrogen is higher than the market value of the electricity required for green hydrogen production.

Figure 3-8 presents influence of a 20% lower predicted price of electricity and 20% higher predicted price of natural gas and CO_2 emissions on income from produced green hydrogen.

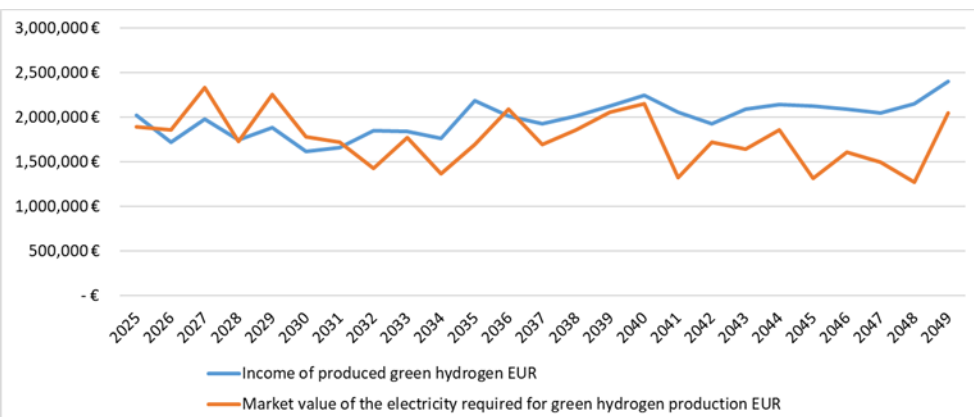

Figure 3-8. Scenario of 20% lower predicted price of electricity and 20% higher predicted price of natural gas and CO_2 emissions.

New marginal electricity prices for all model years were calculated, and the amounts of green hydrogen produced were higher than the base case. In this case, in most years of the model, income from produced green hydrogen is higher than the market value of the electricity required for green hydrogen production. Only in six years of the model, specifically, 2026, 2027, 2029, 2030, 2031, and 2036, is the market value of the electricity required for green hydrogen production higher than the income of produced green hydrogen. So, it is financially justified to invest in a power-to-gas facility at the wind power plant site without subsidies. With the expected increase in the share of renewable energy sources in the future, the ratio between the price of natural gas increased by the price of CO_2 emissions and electricity prices will gradually allow for the replacement of natural gas with green hydrogen.

3.5. Discussion

This paper presents a methodology developed, which can be applied at any location of an existing wind power plant in the world, provided reliable and realistic economic data of wind power plant production and electricity market prices are available, for calculating the costs of green hydrogen production and its integration into the gas grid. The results are primarily relevant for Mediterranean countries with similar climatological characteristics, especially wind specificities.

The study took into account how the variability of electricity production at the wind power plant location can modify the overall structure of the costs of the operation of the wind power plant and the production of green hydrogen. Therefore, special attention was paid to determining the marginal price of electricity that divides the production of electricity into the part that goes to the production of green hydrogen and the part that is delivered directly to the power grid. It is the marginal price of electricity that is important from the aspect of increasing the profitability of wind power plant production, since the calculation of the optimal marginal price of electricity results in the lowest possible production price of green hydrogen. In addition to the marginal cost of electricity, the size of the electrolyzer is also important. Based on the historical data of wind power plant production and realized market prices of electricity, the optimal electrolyzer size for the selected location is determined. It is important that there is no additional investment in an electrolyzer that would not be fully utilized. The utilization of the electrolyzer in a particular year has a great influence on the amounts of fixed costs that affect the production price of green hydrogen.

For example, in dedicated locations that have ideal conditions of wind or sun, it is possible to produce green hydrogen at a price almost competitive with alternatives to fossil fuels (Armijo, Philibert, 2020.). However, the question this paper answers is about the prices at which green hydrogen can be produced at wind power plant locations in Central Europe or the Mediterranean with a predicted production curve based on historical production data.

The results of the selected model show that the green hydrogen production has potential at the wind power plant location and that with the tested predictions of electricity and natural gas prices, the production price of green hydrogen is not yet competitive. It should be noted that the location is also affected by the availability of gas infrastructure, considering that the gas grid connection increases the investment in the construction of the power-to-gas facility, which additionally increases the production price of green hydrogen. The authors believe that the presented results are encouraging and that the price of green hydrogen is not far from being competitive with fossil alternatives, but that a premium subsidy mechanism is needed to start using green hydrogen in the gas sector. This model is a good tool that shows how green hydrogen production is achievable at the location of renewable sources and under what conditions it can affect the decarbonization of the gas system.

From the point of view of the decarbonization of the gas system, this innovative model has an important contribution regarding the realization of the possibility of the decentralized production of competitive green hydrogen at the wind power plant's locations. A wind power plant location, which was situated relatively close to an existing gas infrastructure, was, therefore, tested, which minimized the gas grid connection costs. Only green hydrogen was produced at the wind power plant location, which did not emit harmful CO_2 emissions during production and combustion, which, as renewable gas injected into the gas grid, decarbonized the gas infrastructure.

This paper contributes new knowledge about the possibility of green hydrogen production at an existing wind power plant location in a hybrid energy system. The model connects two systems, power and gas, by setting up a power-to-gas system at a renewable energy location, from which the produced green hydrogen is integrated into the gas grid, which indirectly affects Europe's climate goals by using the existing energy infrastructure. By producing green hydrogen and replacing it with natural gas in the gas grid, CO_2 emissions are also reduced, which is one of the main goals in the energy transition.

3.6. Conclusions

In this study, a universal model was developed for the economic analysis of the future production of green hydrogen in a country or region at the locations of wind power plants. The model considers all the costs associated with the installation of the electrolyzer and the gas grid connection so that the green hydrogen produced at the wind power plant site can be injected with natural gas to meet the energy transition goals. The model takes into account numerous limitations related to the potential of renewable energy, prices of electricity, natural gas and CO_2 emissions, and the costs of building the power-to-gas system.

The model was created based on historical data on the price of electricity and historical data on the wind power plant production through a Monte Carlo simulation, and it predicts future hourly data on the price and production of electricity for a period of 25 years. Although data from the Croatian electricity day-ahead market were used to test the applicability of the model, by changing the input parameters, that is, historical data on the production price of electricity, the model can be applied to any location. The model first calculates the optimal electrolyzer size. The electrolyzer size affects the total investment costs and the amount of green hydrogen production. Then, the model determines the optimal marginal price of electricity, which indicates the limit up to which green hydrogen is produced, i.e., above which electricity is delivered to the grid. The marginal price of electricity directly affects the production price of green hydrogen, which makes its role very important. Numerous results can be obtained with the model, but the authors focused on the following, which they consider interesting to single out.

The model was applied to the base case and in a scenario sensitivity analysis to test the best possible price of green hydrogen production based on changes in the input variables. The option in which the price of electricity is predicted to be lower, the option in which the prices of natural gas and CO_2 emissions are predicted to be higher, and the option in which the price of electricity is lower while the price of natural gas and CO_2 emissions is higher were all tested.

Furthermore, it should be noted that according to the input data on electricity and natural gas prices used in the model, there was no visible surplus of electricity, that is, a sudden and large drop in electricity prices on the market, and for this reason, the model gave mostly negative results. At the time of writing, there was no surplus of electricity from renewable energy sources, but due to the change in the predicted electricity prices and the increase in the share of renewable energy, the authors assume that this surplus will probably occur.

The increased amount of renewable energy sources will lead to increasingly frequent situations when prices on the electricity market are low or even negative. The above would encourage owners of renewable energy systems to invest in electrolyzers in order to use such situations for the green hydrogen production and, thereby, increase the income of their plants. However, what is important from this analysis is the fact that the use of power-to-gas systems for the green hydrogen production is still unprofitable due to the ratio of market prices of electricity and natural gas price increased by the price of CO_2 emissions.

According to the presented model results, taking into account the total consumption of natural gas in the Republic of Croatia and the share of the analyzed wind power plant in the total installed power of renewable energy sources in Croatia, the amount of green hydrogen produced is not significant and would not significantly affect the reduction of CO_2 emissions. However, the amounts of produced green hydrogen shown by the model represent the result of only one wind power plant. If such systems were to be built at several locations of wind power plants, the effect of reducing CO_2 emissions would be more significant because the effect would be multiplied. In addition, by changing the input parameters, the results of the model can be positive as shown in the scenario analysis.

The authors believe that the possible limitations of the model are the lack of technical aspects of injecting hydrogen into the gas grid, and that the analysis of the regulatory framework for the use of hydrogen and the premium subsidy model should be part of further research. Energy infrastructures are natural monopolies, and transmission and transport system operators on liberalized energy markets are regulated entities. Therefore, adjustments to the currently valid regulations regarding the use of power-to-gas systems by the operators are necessary in order to be able to produce green hydrogen without interruption. The presented model shows that the power-to-gas system at the wind power plant location solves the problem of power system congestion and the problem of low hourly electricity prices on the day-ahead market, while contributing to the decarbonization of the gas system.

4. REPLACING GRAY HYDROGEN WITH RENEWABLE HYDROGEN AT THE CONSUMPTION LOCATION USING THE EXAMPLE OF THE EXISTING FERTILIZER PLANT

Authors: Andrea Dumančić, Nela Vlahinić, Minea Skok

Title: Replacing Gray Hydrogen with Renewable Hydrogen at the Consumption Location using the Example of the Existing Fertilizer Plant

Journal: Sustainability, EISSN 2071-1050, Published by MDPI

Published: 27 July 2024, Sustainability 2024, 16(15), 6437; https://doi.org/10.3390/su16156437

Submitted to section: Energy Sustainability, Sustainable Energy Systems: Integrating Renewable Energy Carbon Trading and Electricity Markets

4.1. Introduction

In the last few years, the European Commission adopted several strategic documents for the promotion of hydrogen as an important source of energy that should take its place in production and consumption, as well as other renewable energy sources (RES). Also, the very fact that it is a new energy source that needs its own regulatory framework, the European Commission proposed the establishment of an internal hydrogen market and its implementation in the energy sector.

Hydrogen in the energy sector plays an important role in achieving the goal of the European Green Deal and the implementation of the Paris Agreement to achieve a carbon-neutral economy by 2050. This is supported by the fact that the European Commission adopted two strategic documents in 2020: A hydrogen strategy for a climate-neutral Europe, in which hydrogen is highlighted as one of the key levers for a successful energy transition, and Powering a climate-neutral economy, an EU Strategy for Energy System Integration, which describes how the current political framework of the European Union (EU) will contribute to the achievement of a climate-neutral integrated energy system with a high proportion of RES. The Hydrogen Strategy sets a strategic goal of increasing the installed capacity of electrolyzers to 40 Gigawatts (GW) by 2030 to increase the production of renewable hydrogen and facilitate the decarbonization of sectors dependent on fossil fuels, such as industry or transport. Therefore, the trans-European energy networks policy also includes new and repurposed infrastructure for hydrogen transmission and storage, as well as electrolysis plants.

Hydrogen is a key pillar of the REPowerEU Plan, with the aim of reducing Russian energy imports by diversifying trade partners, increasing energy efficiency, and saving and accelerating the energy transition. Specifically, according to the REPowerEU Plan, the goal is for the EU to reach 10 million tons of domestic renewable hydrogen production and 10 million tons of imported renewable hydrogen by 2030. Although the demand for electricity for hydrogen production is initially expected to be negligible, it is expected to increase by 2030 due to the massive introduction of large electrolyzers. In 2023, the Commission estimates that to fulfill the ambition of the REPowerEU Plan by 2030, about 500 TWh of electricity from renewable sources is needed, which corresponds to 14% of the total electricity consumption in the EU, with the goal of a 45% increase in RES (European Commission, 2023.). In the Integrated National Energy and Climate Plan for the Republic of Croatia for the period from 2021 to 2030 (Ministry of Environment and Energy, 2019.), the installed capacity in 2030 is estimated at 1.36 GW in wind power plants and 0.77 GW in solar power plants, generating approx. 4.5 TWh of electricity from renewable sources in 2030 (Ministry of Environment and Energy, 2019.). According to FCH 2 JU (FCH 2 JU, 2020.), the construction of additional capacities of renewable electricity sources intended for hydrogen production is considered a feasible scenario. Figure 4-1 shows the current state of installed capacities of various renewable sources in 2022 (IEA, 2024.a) and the projection for the period from 2023 to 2028 by individual sources, while the projection for 2030 includes the total planned capacities of renewable sources.

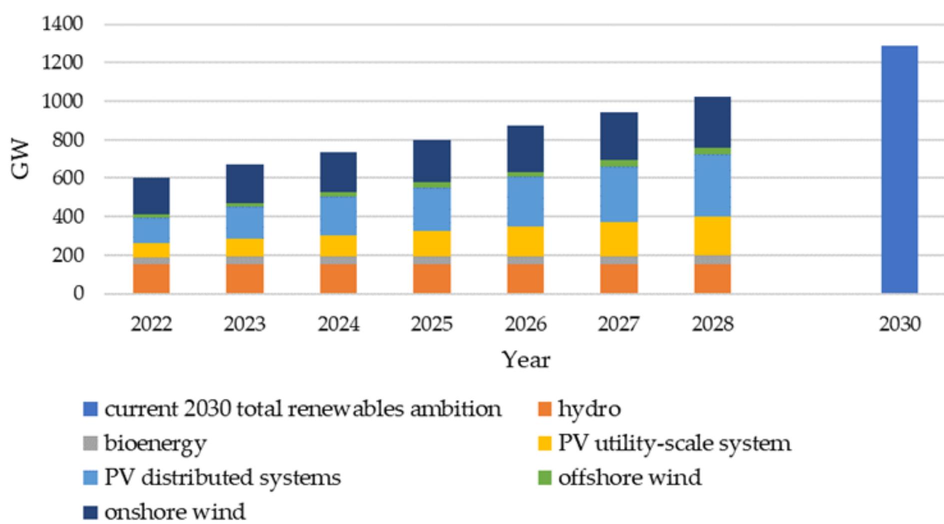

Figure 4-1. Installed capacities of various renewable sources in the EU for the period from 2022 to 2030.

The potential production of electricity from renewable sources by 2028 should reach around 14,400 TWh, which is an increase of almost 70% compared to 2022 (IEA, 2024.b). By producing electricity from onshore and offshore wind power plants instead of from fossil fuels, 95 million tons less of CO_2 were emitted from 2019 to 2023 (IEA, 2024.c), which is shown in Figure 4-2.

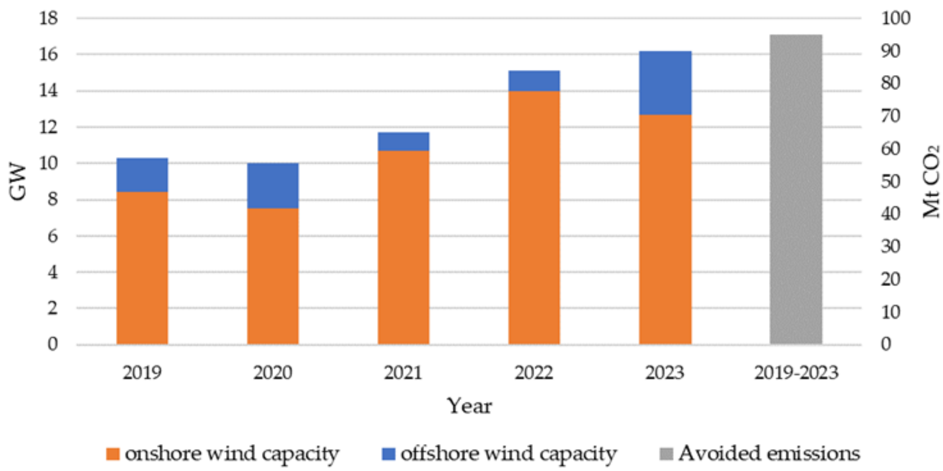

Figure 4-2. Installed capacity from wind power plants and avoided emissions in the EU for the period from 2019 to 2023.

According to the CO_2 emissions avoided by the production of electricity from wind power plants (IEA, 2024.a), shown in Figure 4-2, if the capacity of onshore and offshore wind power plants increased by 130 GW by 2030, this would lead to a further 195 million tons less of emissions CO_2.

The Renewable Energy Directive was the driving force behind the development of renewable energy in the EU. As the EU increased its climate ambitions for 2030 to become the first carbon-neutral continent by 2050, the Directive was revised as part of the package Fit for 55 2021 (RED I) and later in the framework of The REPowerEU plan 2022 (RED II), until it was finally adopted in the fall of 2023 (RED III). In the hydrogen sector, the Directive (RED III) sets clear targets for the use of renewable fuels of non-biological origin (RFNBO), including industry and transport. The industrial sector must increase the use of renewable energy by 1.6% per year. In most countries, this applies to refineries and ammonia production. The largest producers of ammonia in Europe are Germany, Poland, and the Netherlands, which are expected to face significant implications as required by RED III targets to achieve a renewable hydrogen consumption of 42% in industrial applications by 2030 and up to 60% by 2035.

Two Delegated Acts proposed detailed rules for what is considered renewable hydrogen in the EU. These Acts are part of a broad EU regulatory framework for hydrogen that includes energy infrastructure investment, state aid rules, and legislative targets for renewable hydrogen for the industry and transport sectors. Renewable hydrogen should cover 50% of the total hydrogen consumption in the energy sector and industries that use hydrogen as a raw material by 2030. In 2021, with 21.5%, the chemical and petrochemical industry had the largest shares in the final energy consumption of the EU (Eurostat, 2023.). Ammonia production in 2022 was the dominant consumer of hydrogen in Poland, while in Croatia, the shutdown of the only ammonia factory in the country cut the total consumption of hydrogen by half (Hydrogen Europe, 2023.). In 2023, more than 45% of heavy industry plants in the EU were out of operation (temporarily) due to high natural gas and electricity prices.

Numerous papers have studied the reduction of CO_2 emissions in oil refineries, given that oil refining is responsible for 4–10% of global CO_2 emissions and is recognized as an important industrial sector for the implementation of energy efficiency systems and carbon capture and storage technologies. The Authors of (Ma, et al., 2022.) analyzed the development of the green refinery, where they proposed a system for converting “waste” into valuable products that enables an annual CO_2 reduction of 2.80 million tons and increases the energy efficiency of catalytic cracking units by 2.8%, in the example of China. If the refinery replaces the Steam Methane Reforming (SMR) plant with a solid oxide fuel cell (SOFC) system operating at a low fuel utilization factor, it is possible to reduce the refinery’s direct greenhouse gas emissions by at least 60% (Mastropasqua, et al., 2020.). The calculation of the Levelized Cost of Hydrogen (LCOH) from a SOFC system shows a possibility of hydrogen production of 3.3 EUR/kg−1 in the scenario for the oil refining sector. The development of thermo-chemical hydrogen production technologies, which include the gasification and pyrolysis of biomass, steam reforming of methane, and thermal plasma, is reviewed in the previous study in (Das, Peu, 2022.). Technological processes can be further improved using catalysts and sorbents to improve their suitability for continuous clean industrial hydrogen production.

An overview of the various technologies involved in the hydrogen supply chain, including hydrogen production, storage, transport, and utilization technologies, is observed in the study in (Li, et al., 2024.). In the hydrogen production section, a detailed overview of hydrogen production technologies from fossil fuels, biomass, and water is given. Although the production of hydrogen from biomass is preferable to production from fossil fuels since the process emits fewer CO_2 emissions, the gasification of biomass to produce hydrogen faces challenges, primarily due to the complexity and costs associated with the tar removal process.

Hydrogen is a colorless gas, but there are about nine colors that identify the way in which hydrogen is produced, that is, the energy source with which it is produced and how many emission units it produces during this process. In this way, the hydrogen colors green, blue, gray, brown, black, aqua, turquoise, purple, pink, red, yellow, and white were identified.

Green hydrogen, often referred to as “pure hydrogen”, “renewable hydrogen”, or “low carbon hydrogen”, is produced by water electrolysis using electricity from RES. Blue hydrogen is also considered low-carbon hydrogen and is based on the production of hydrogen from fossil fuels but with a carbon capture, use, and storage (CCUS) system. Blue hydrogen is considered an alternative solution during the energy transition because it still offers the possibility of consuming fossil fuels but with a reduction in carbon footprint (Arcos, Santos, 2023.).

Gray hydrogen means hydrogen produced from methane steam reforming, partial oxidation, or autothermal reforming and is generally used in the petrochemical industry to produce ammonia. The brown and black colors of hydrogen refer to the type of lignite (brown) and bituminous (black) coal. For every kg of brown/black hydrogen produced, about 20 kg of CO_2 is released. Although hydrogen from biomass gasification should be considered green, assuming the entire life cycle of the biomass is carbon neutral, the undeniably high CO_2 emissions of the process make it brown hydrogen (Arcos, Santos, 2023.).

Aqua hydrogen technology involves placing oxygen in a sealed fuel deposit between rock grains, using crude oil as fuel and earth as a reactor vessel (Yu, et al., 2021.). Turquoise hydrogen uses methane as a feedstock but is produced by pyrolysis of methane. Pink hydrogen is produced by the electrolysis of water using electricity from a nuclear power plant. Purple hydrogen is produced using nuclear energy and heat by the combined electrolysis and thermo-chemical splitting of water. Red hydrogen is produced by the catalytic splitting of water at high temperatures using nuclear thermal energy as an energy source. Yellow hydrogen is produced by electrolysis using electricity from the energy grid. White hydrogen, also called gold hydrogen, is naturally occurring in the continental crust, oceanic crust, or in volcanic gasses, geysers, and hydrothermal systems. Given that white hydrogen is carbon-free and does not require a large infrastructure, it is believed that a hydrogen economy based on a combination of white and green could be the best answer for the transition to a low-carbon economy (Hydrogen Europe, 2024.).

The aim of this research is to analyze the profitability of replacing the part of natural gas used in the SMR process to produce gray hydrogen with renewable hydrogen, which would be produced in an electrolyzer with electricity from renewable sources. Namely, in the newly built electrolyzer located at the site of the existing fertilizer plant near the ammonia plant, renewable hydrogen would be used instead of gray hydrogen obtained from natural gas.

The goal of the paper is to analyze the profitability of the construction of an electrolyzer at the location of the existing fertilizer plant with the aim of the partial decarbonization of the ammonia production process using the proposed economic model.

The paper aims to answer the following questions:

1) Can Power Purchase Agreement (PPA) contracts ensure the entire need for electricity in the hydrogen production process, or does part of the electricity have to be provided in another way?
2) What are the positive and negative aspects of contracting the purchase and sale of electricity from renewable sources through a PPA contract?
3) In what ratio of replacement of natural gas with renewable hydrogen is the profitability of the investment in an electrolyzer at the location of the existing fertilizer plant achieved?

Does a change in the electricity price or a change in the market price of natural gas and CO_2 emissions have a greater impact on the profitability of the investment?

The purpose of the paper is to analyze the profitability of renewable hydrogen production at the location of the existing fertilizer plant, i.e., at the consumption location. An economic analysis of the profitability of renewable hydrogen production in a newly built electrolyzer near the ammonia plant, which uses electricity purchased through a PPA contract, was performed. Although bilateral contracts have existed for a relatively long time, contracts related to the purchase of renewable energy are quite a novelty on the market. Namely, many customers and producers are deciding to enter contracts for the purchase and sale of renewable electricity. In this way, the producer secures his investment in RES and can safely sell his production at a pre-agreed price. On the other hand, the customer, in this example, the industry, while meeting the conditions of the energy transition, secures electricity from renewable sources at a pre-agreed price. In these cases, when concluding a PPA contract on renewable electricity, both the customer and the producer have multiple benefits.

4.2. Literature Review

Over the past few years, an increasing number of countries have adopted hydrogen-related policies and strategies. What clearly emerges from the ever-increasing ambitions of hydrogen policies in such a short period of time is the widespread recognition that to achieve the set goals, green hydrogen must have a key role in achieving zero emissions from the energy sector. It is the only zero-carbon option for hydrogen production, as carbon capture in carbon capture systems (CCSs) is 85–95% at best and significantly lower to date (IRENA, 2020.).

This is supported by the research of numerous authors on the impact of certain EU policies on hydrogen production. The authors of (Khatiwada, et al., 2022.) made a techno-economic analysis of the obstacles and limitations in EU policies that affect the decarbonization of natural gas. They calculated the LCOH for gray, blue, and green hydrogen for the years 2020, 2023, and 2050. The results show that the cheapest production costs are for grey hydrogen (1.33 EUR/kgH_2) and blue hydrogen (1.68 EUR/kgH_2) in comparison to green hydrogen (4.65 EUR/kgH_2 and 3.54 EUR/kgH_2) from grid electricity and solar power in the proton exchange membrane (PEM) for the year 2020. The costs are expected to decrease to 4.03 EUR/kgH_2 (grid electricity) and 2.49 EUR/kgH_2 (solar electricity) in 2030. With changes in rules by the EU and institutions essential to create market demand, the results of the sensitivity analysis show that investment costs, electricity price, electrolyzer efficiency, and carbon tax (for the SMR process) could play a key role in reducing LCOH, thereby increasing the economic competitiveness of green hydrogen production.

Numerous authors are aware that the production of green hydrogen is an important driver of the energy transition in terms of achieving the goals of energy and climate neutrality; therefore, large amounts of research have been conducted precisely related to such a topic. Hydrogen can be used to produce several fuels and other products such as methane, methanol, ammonia, synthetic aviation fuels, and plastics to replace fossil fuel-based products. The global demand for hydrogen in 2022 was about 95 Mt, a nearly 3% increase from 2021, continuing the growing trend that was only interrupted in 2020 as a consequence of the COVID-19 pandemic and the economic slowdown. From total production, 53 Mt was used in industry, of which 60% was used for ammonia production (IEA, 2023.a). The authors of (Li, et al., 2020.) emphasize that the use of renewable energy to produce hydrogen for the purpose of replacing fossil fuels is the future development trend of the hydrogen economy. The fluctuation of renewable sources can be regulated by hydrogen production through the possibility of long-term energy storage. Namely, the production of green hydrogen requires significant additional production of electricity from renewable sources, which also requires investments in production capacities to produce energy from renewable sources. Green hydrogen is price competitive in regions where the conditions of renewable sources are favorable; however, these locations are usually far from the locations of demand. For example, in Patagonia, wind energy could have a capacity factor of almost 50%, with an electricity cost of 25–30 USD/MWh. This would be enough to achieve a green hydrogen production cost of about 2.5 USD/kg, which is close to the blue hydrogen cost range. In most locations, however, green hydrogen is still two–three times more expensive than blue hydrogen (IRENA, 2020.). However, with the creation of a surplus of renewable sources, the advancement of technology, and the favorable ratio of electricity prices on the market compared to the price of natural gas, green hydrogen could be competitive even at the point of direct consumption. The authors of (Rego de Vasconcelos, et al., 2019.) review technologies for sustainable hydrogen production, with an emphasis on water electrolysis using renewable energy, as well as a review of the challenges for large-scale hydrogen production and integration with other technologies. They stated that using PEM instead of liquid electrolytes allows a quick response to the power input, hence the use of a wide range of power. They concluded that PEM technology has become very promising for hydrogen production due to its compact design, high efficiency, and high hydrogen output pressure, and it provides a good coupling with intermittent energy sources. Investment costs for PEM systems vary between 1400 and 2100 EUR/kW, while the maintenance costs represent 3–5% of the annual investment costs (Rego de Vasconcelos, et al., 2019.).

Power-to-X (P2X) are energy hubs that enable efficient synergy between energy infrastructures, production facilities, and storage capabilities. The authors of (Kountouris, et al., 2023.) investigate the optimal operation of the Danish energy hub by exploiting the flexibility of P2X, analyzing potential revenue streams from the sale of renewable electricity and hydrogen without price incentives, i.e., from the day-ahead market and from the provision of ancillary services. They started with an initial electrolyzer capacity of 12 MW, later extended to a 100 MW capacity for ammonia production, and then the mFRR (tertiary regulation) market income was added. Wind power plants of different sizes in the same area can mitigate dramatic fluctuations in wind power output by complementing and coupling them to increase the utilization rate of wind energy and reduce the extent of energy transmission (Bothun, 2018.).

According to several authors, the production of green hydrogen becomes competitive with additional conditions such as subsidies, but they also prove the greater profitability of hydrogen production through the further process of conversion into ammonia, which is easier to transport than hydrogen. The authors of (Perpinan, et al., 2023.) investigated the possibility of using green hydrogen to obtain synthetic gas used in the iron and steel industry. The use of carbon through the conversion of energy into gas is increased by carbon capture in the iron and steel sector, which affects the reduction in CO_2 emissions. They conducted an economic analysis in search of those combinations of electricity and CO_2 permit prices that enable the conversion of energy into gas to be economically viable. The results of the analysis suggest that profitable scenarios would require either that electricity be obtained at the cost of production, that subsidies be given for purchased electricity, or that PPA be signed. However, sensitivity analysis showed that the concept would become economically feasible under certain conditions, depending on CO_2 taxes, the price of electricity, or the amount of the subsidy, i.e., with electricity prices as low as 40 EUR/MWh, the price of CO_2 emissions have to be over 240 EUR/t to make the investment profitable. The authors of (Rivarolo, et al., 2019.) have conducted an analysis of the economic profitability of hydrogen production by the electrolysis of electricity obtained from a hydroelectric power plant. The specificity of the analysis is the low price of electricity in Paraguay due to the large surplus of renewable electricity, and the increase in the use of electricity is foreseen in the form of ammonia production. The results demonstrated a production-specific cost of 366 EUR/t; this cost is lower than the market price of ammonia synthesis from methane steam reforming, so this analysis confirms the profitability of such an investment. The authors of (Armijo, Philibert, 2020.) state that the production of 1 ton of ammonia from natural gas emits 2.3 tons of CO_2 emissions, while the production of 1 ton of hydrogen from natural gas emits 10 tons of CO_2 emission. The goal of their analysis is to use the interplay of the variability of RES and the flexibility of ammonia production facilities to calculate the optimal size of wind power plants, solar units, and ammonia synthesis units in locations with abundant and cheap renewable sources. The authors calculated the near-term production costs for green hydrogen, around 2 USD/kg, and green ammonia, below 500 USD/t, which are encouragingly close to competitiveness against fossil-fuel alternatives.

However, what is a turning point in incentives for electricity production from renewable sources is certainly the expiration of feed-in tariffs (FITs) or premium incentive models. From the above review, the authors conclude that there are many studies in which other possibilities of incentives for the construction of plants based on renewable sources have been analyzed. The end of FITs for new renewable energy projects in Japan necessitated the research on PPA for the supply of carbon-free energy (CFE), analyzed by the authors of (Kontani, Tanaka, 2024.). The study offers strategic insights focused on the costs and advantages of PPA contracts, as well as increasing the interest of investors in RES, but, on the other hand, also of environmentally conscious energy consumers. The authors of (Mesa-Jiménez, et al., 2023.) proposed long-term forecasts of wind and solar energy production suitable for contracting PPA contracts for the purchase of renewable energy with cost optimization in energy production scenarios. Also, three types of risks were considered to find the optimal match of the production forecast with respect to the target consumption profile. The time horizon of the forecast is one year, so the average of a certain price range within one year was taken for the electricity price. This paper is a simplified version of a real-case scenario. In regular PPA negotiations, many projects would be offered several generators with different price structures. The length of these contracts would be between 10 and 25 years instead of one year or shorter-term periods. Using the example of Spain, the authors of (Arellano, Carrión, 2023.) investigated the best strategy for the procurement of renewable electricity for an existing cement producer, considering the possibility of entering contracts for the purchase of electricity with renewable and traditional power plants and the installation of a photovoltaic unit for its own production. They proposed a formulation that allows contracting decisions to be made considering that contracts can be physical or financial, on-site or off-site, with conventional or renewable energy, and for base or peak periods. This study presents a risk-averse two-stage stochastic programming formulation to decide the contracting decisions of large consumers in PPA contracts. The authors of (Mousavi, Alvarez, 2023.) presented a new flexible electricity trading system based on a short-term bilateral contract called FlexCon between a variable renewable energy producer and an electricity trader. Such a system is managed by a new entity called FlexCon operator that facilitates transactions and is responsible for financial settlement. The operator allocates possible power flexibility transactions based on the surpluses or shortages of the parties. Assuming that the imbalances are not completely resolved with the FlexCon, the remaining deviations are settled in the balancing market. Such a contract can be identified as a PPA contract, which also needs an operator who will balance the system, the producer, and the customer. The authors of (Ghiassi-Farrokhfal, et al., 2021.) investigated how renewable energy producers' (REPs) investment in storage can affect the reliability of predicting future energy production for customers, and this can greatly help when concluding PPA contracts. They studied how owning batteries for a REP affects their own revenues as well as the reliability of their energy forecasts for customers when determining the structure and price of a PPA contract. This shifts the risk of production uncertainty to REPs, increasing the chance that REPs adopt batteries. It has been shown that REPs can have incentives to misreport predicted values. This has discouraged some companies from engaging in PPAs.

Looking at the studied literature and with previous papers of the authors in which the profitability of centralized (Dumančić, et al., 2023.) and decentralized hydrogen production (Dumančić, et al., 2024.) with interference in the gas network was analyzed, in this paper, the profitability of hydrogen production at the location of a large consumer will be measured. Namely, the authors did not come across any literature in which a similar analysis was made, which considers the purchase of renewable electricity through a PPA contract with which hydrogen is produced in an electrolyzer and consumed as a raw material in the same location where it was produced. The authors believe that this kind of research is necessary to analyze the economic profitability of investing in an electrolyzer at the consumption location of the existing fertilizer plant to precisely fulfill the EU decarbonization goals in the industry sector. In this paper, a concept was created in which two sectors, the industry sector and the electricity sector, are intertwined by entering a PPA contract, thereby ensuring the safe production of renewable energy at a predetermined price and influencing the reduction of CO_2 emissions, in terms of achieving the energy transition.

4.3. Basic Assumptions and Structure of the Economic Model

The structure of the economic model and the baseline scenario are shown in Figure 4-3.

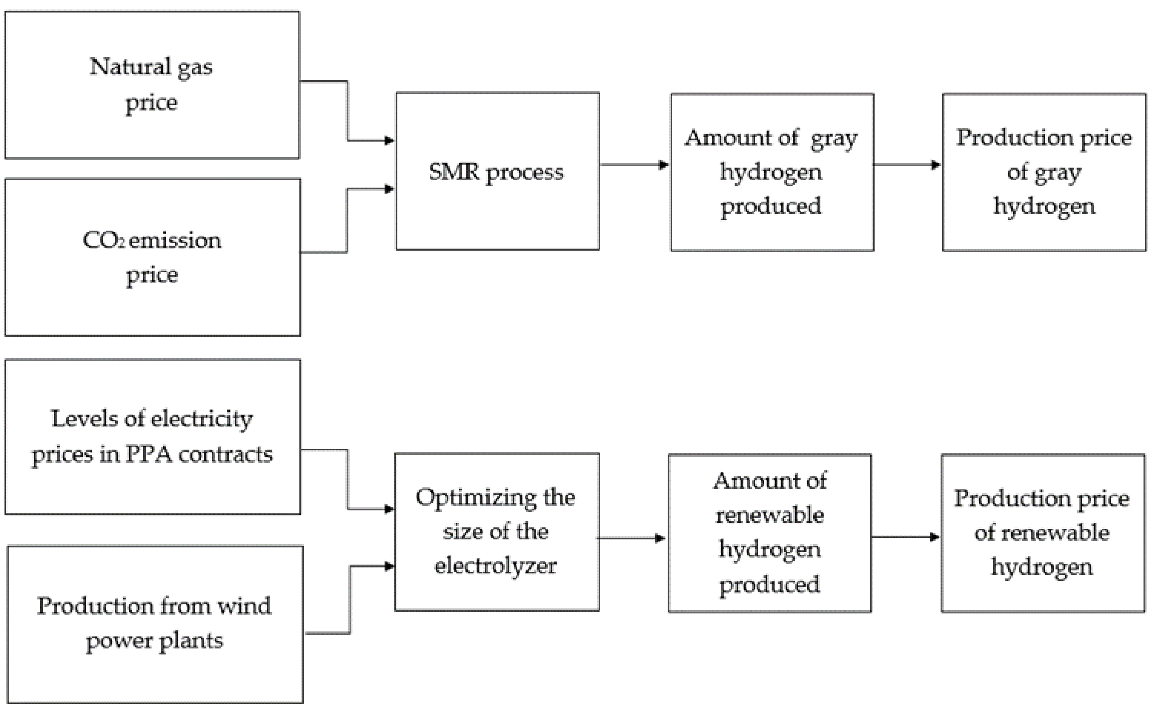

Figure 4-3. Data flow chart.

Figure 4-3 shows a schematic view of the economic model that includes all necessary input parameters (estimated and optimized), objective functions, decision variables, and output parameters. The outcome of the economic model in the part of renewable hydrogen production is influenced by two optimization variables: the size of the electrolyzer and the level of electricity prices in PPA contracts. The above variables affect the total cost of renewable hydrogen production. If the costs of producing renewable hydrogen are higher than the cost of producing gray hydrogen, the investment needs a subsidy. If the costs of producing renewable hydrogen are lower than the costs of producing gray hydrogen, the investment can be achieved without subsidies, and there are no obstacles to decarbonizing part of the process within the operation of the existing fertilizer plant.

The economic model consists of numerous parameters, which are divided into input and output parameters. Input parameters of the model are hourly market prices of electricity, market prices of natural gas and CO_2 emissions, hourly production of electricity from wind power plants, prices of electricity included in PPA contracts, the CAPEX and OPEX of electrolyzers, and the size and efficiency of electrolyzers. The output parameters of the model are the amount and price of renewable hydrogen produced and the income from the sale of excess electricity on the market. The parameters that are the subject of optimization refer to the selection of the size of the electrolyzer and the level of electricity prices in PPA contracts.

The input parameters of the model will be explained below, while the output parameters will be presented in the chapter on the presentation of the research results.

4.3.1. Annual Market Prices of Natural Gas and CO_2 Emissions

In the economic model, the market price of natural gas and CO_2 emissions were used to calculate the production price of gray hydrogen and when comparing it with the price of renewable hydrogen production in terms of competitiveness. Projections of market prices for natural gas were taken from the ICIS platform (Global Petrochemical Market Information Provider) (ICIS, 2024.) for the period up to 2030, while for the remaining years of the model period, data from the TYNDP Scenario Methodology Report was used. Projections of the market prices of CO_2 emissions are taken from the IEA Reports (IEA, 2023.b) and from the TYNDP Scenario Methodology Report (ENTSO-E; ENTSOG, 2024.).

Projections of market prices of electricity, natural gas, and CO_2 emissions were adapted to the projections from the literature for the needs of the economic model, and in Table 4-1, they are shown for the selected years of the model.

Table 4-1. Projection of prices for electricity, natural gas, and CO_2 emissions.

Parameters	2027.	2032.	2037.	2042.	2047.
Electricity (EUR/MWh)	68,28	61,53	62,17	58,42	58,16
Natural gas (EUR/MWh)	33,28	30,50	28,74	27,09	25,53
CO_2 emissions (EUR/t)	90,71	119,23	135,16	151,11	161,90

Source: Authors, based on data taken from several sources in the literature (IEA, 2023.a; ICIS, 2024.; IEA, 2023.b; ENTSO-E; ENTSOG, 2024.).

Figure 4-4 shows the projections of the market prices of electricity, natural gas, and CO_2 emissions on an annual basis for the 25-year period of the economic model.

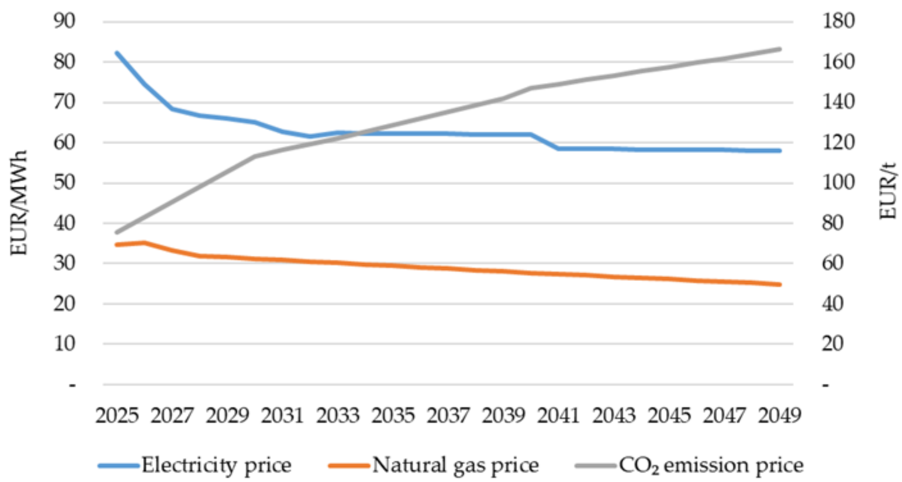

Figure 4-4. Projections of the prices of electricity, natural gas, and CO_2 emissions for the period from 2025 to 2050.

By Figure 4-4, the curves of the projected prices of electricity and natural gas have a similar decline, i.e., they correlate, while the curve of the prices of emission units has a high growth, i.e., it is negatively correlated in relation to the prices of electricity and natural gas. The average price of electricity for a period of 25 years is 62.75 EUR/MWh, while the average price of natural gas for the same period is 29.05 EUR/MWh. The ratio of price projections at the average level is 54%, which means that in the entire period of the model, the price projection of electricity is twice as high as the price projection of natural gas. The price projection of CO_2 emissions ranges from 75.59 EUR/tons in 2025 to 166.43 EUR/tons in 2049. The stable and persistent negative correlation with the EU ETS emission permits market is also confirmed by the coefficient of determination of the stock index ERIX depending on the spot price of natural gas on the TTF with R2 = 0.194, that is, the price of natural gas only affects the price of emission units by 19%. For example, one of the mechanisms used to affect the volatility of electricity prices is the conclusion of long-term electricity supply contracts with producers (PPA contracts), especially bearing in mind that the price of electricity correlates with the price of natural gas (Herbst, 2022.).

4.3.2. Hourly Market Prices of Electricity

The economic model was made on an hourly basis for a period of 25 years. The determined hourly prices of electricity were taken from the Croatian Electricity Exchange Day-ahead Market (DAM) (Croatian Power Exchange, 2024.) for the period from 2019 to 2023. The period of five historical years was taken since a lot of oscillations and specificities of prices that reflect atypical years appeared in that period. To project this period over the next 25 years for each individual year, hourly coefficients were determined based on the determined annual price of electricity. Then, the hourly coefficients were multiplied by annual electricity prices in accordance with the projection from the European Ten-Year Electricity and Gas Network Development Plan (TYNDP 2024), according to the Scenario Methodology Report of the European Network of Transmission System Operators, ENTSO-E, and the European Network of Transmission System Operators for Gas, ENTSOG (ENTSO-E; ENTSOG, 2024.).

In the part of the projection of the market price of electricity, the merit order method was applied to order the historical years to be able to order the frequency of repetitions that are needed in the Monte Carlo simulation, according to which the prices from the historical years were distributed over the total period of the model. The application of Monte Carlo simulation to electricity prices enables an approach to uncertainty modeling in a stochastic way, allowing the input variables of historical years to be represented through continuous years of the future period. This leads to a more realistic representation of the uncertainty of electricity prices without the need to assign a degree of probability to possible scenarios (Ioannou, et al., 2019.). In this way, projected hourly electricity prices were obtained according to precisely determined historical years, which makes it easier and more realistic to present the result than compared to the average of electricity prices, where these oscillations and possible negative electricity prices are not precisely highlighted.

4.3.3. Steam Methane Reforming (SMR) Process

The Steam Methane Reforming (SMR) process is a processing technology used to reorganize the molecular structure of hydrocarbons to produce gray hydrogen. In that process, methane (CH_4) is mixed with steam under high pressure and at high temperatures to obtain hydrogen and carbon dioxide through a catalytic reaction.

Steam reformation of natural gas in industrial plants is the cheapest and most used technology, which generates about 8–10 kg of CO_2 emissions for every 1 kg of gray hydrogen produced (Franchi, et al., 2020.; Fuk, 2023.). The SMR process is the most common and most developed method used for the large-scale production of gray hydrogen, with an energy consumption of 2 kWh/Nm^3 of hydrogen at an efficiency level of 74–85%, but it is not renewable hydrogen because the side product of such a process is carbon dioxide (Komarov, et al., 2021.). The amount of emission unit savings depends on the method of measurement. In the study of (Pivac, et al., 2024.), the authors proposed a mathematical model for calculating CO_2 emission savings, where, on the example of refineries, and in accordance with the RED II methodology, they calculated that the direct reduction of emissions by replacing gray with green hydrogen amounts to 9.58 $kgCO_2/kgH_2$. If all other emissions are included according to the same RED II methodology, the total savings would amount to 21.74 $kgCO_2/kgH_2$. In the analysis of the author's calculations (Hydrogen Europe, 2024.), emissions from the SMR process amount to 11 $kgCO_2/kgH_2$, while in the study in (Kanz, et al., 2023.), the authors state that production from fossil fuels emits 10 $kgCO_2/kgH_2$. The authors of (Langenmayr, Ruppert, 2023.) analyzed the impact of electricity procurement according to the conditions of the RED II on the production of e-fuels using the example of the German energy system. According to the results of the paper, the capacity of the electrolyzer increases, which means a direct reduction in plant operating hours, but also a reduction in CO_2 emissions in the transport sector. The authors of (Klyuev et al., 2020.) developed a mathematical model for calculating and predicting the specific consumption of electricity for hydrogen production, which enables the control of electricity consumption in non-ferrous metallurgy industries.

Component costs as a percentage of total gray hydrogen production costs in the SMR process, according to (Nikolaidis, Poullikkas, 2017.), are divided as follows: 60.7% raw materials (natural gas), 29.1% capital investment, and 10.2% maintenance costs.

4.3.4. Level Price of Electricity in the PPA Contracts

The PPA contract is also presented in the draft of the Delegated Act as one of the important options for the supply of electricity to produce renewable hydrogen. There are a number of renewable electricity procurement options available on the market, including behind-the-meter production, Energy Performance Certificates (EACs) such as the Renewable Energy Certificate (REC) in the United States and the Guarantee of Origin (GO) in Europe or Energy Attribute Certificates (T-EACs), and PPA and green tariffs from renewable electricity suppliers (IEA, 2022.).

This study considers the procurement of electricity through the PPA contracts for the production of renewable hydrogen at the industrial consumer location. A PPA contract for the purchase of electricity from renewable sources is a long-term contract between a producer and a consumer for the physical or financial supply of renewable electricity for a certain period at a pre-agreed price. Such contracts protect large consumers from variations in the price of electricity while at the same time providing producers with a secure income to cover the capital and operating costs of the investment. Most often, such contracts are a particularly suitable choice for those involved in the development of wind power plants on-site (Kontani, Tanaka, 2024.). The typical term in PPAs for wind power is 10–20 years, which not only paves the way for wind investors to build a power plant without government support but also helps industries that buy renewable wind energy to meet sustainability goals (Pinomaa, 2020.). Contracts can be physical (including the actual delivery of electricity to the consumer) or financial (as a price protection instrument) (IEA, 2022.).

There is a wide range of types of PPA contracts, including physical, financial, on-site, off-site, renewable pay-as-produce (PAP) contracts, and non-renewable PPA contracts. The installation of a renewable power plant at the customer's location can be treated as a physical on-site PPA contract, in which the producer is responsible for the installation and operation of the plant and charges a fixed price for the energy produced. A financial PPA, also known as a virtual PPA, is a contract in which the producer transfers a net amount of money instead of delivering energy. This type of contract serves to mitigate price volatility. The most popular is the contract for differences (CFD), in which large consumers must pay or receive an economical amount depending on the differences between the common prices and the reference price established in the contract (Arellano, Carrión, 2023.).

However, it should be noted that with every PPA contract, whether physical or financial, the support of the network operator is important, which enables the fulfillment of the contract in terms of the actual transmission/distribution of electricity. Therefore, when concluding a PPA contract between a producer and a consumer, a contract between the network operator or the energy company that will manage the energy and imbalances between the production of renewable sources and the consumption of large consumers should also be concluded. There are several methods of settling the volume of electricity within the PPA contract, among which the most popular are payment per produced, payment per nominee, guaranteed curve, and base consumption. At the same time, PPA contracts using the pay-as-you-go method do not guarantee the company's electricity consumption (Mesa-Jiménez, et al., 2023.).

Some of the advantages of PPA contracts are the sustainability of companies through savings on the price of electricity as well as long-term protection (hedge) of the price, reducing the carbon footprint, and improving the environmental profile of their products and services by meeting the goals of green energy (Mousavi, Alvarez, 2023.).

In the economic model, a physical PPA contract is applied, and in a smaller part of the deficit of electricity, it is bought on the day-ahead market. Additionally, a certificate of energy properties is acquired for that amount of electricity. Guarantees of Origin (GO) is an electronic document that proves to the consumer that a certain share or quantity of electricity is produced from RES and should be of a standardized size of 1 MWh. In Croatia, the guarantee of origin is issued either for electricity produced from a plant that uses a RES or from a high-efficiency cogeneration plant (Croatian Energy Market Operator, 2023.).

When determining the level of electricity prices in PPA contracts, this study considers the average hourly electricity output produced by 12 wind power plants for the period from 2019 to 2023. Based on electricity production, the number of hours of operation at installed capacity, and the efficiency of production, three groups of four wind power plants were determined, and for each group of wind power plants, the level of electricity prices for PPA contracts was determined. The authors believe that this way of classifying production from wind power plants is fairer and that the electricity price levels in PPA contracts do not have to be the same for all wind power plants. However, in Croatia, there is a premium system for determining the incentive price for wind power plants with an installed capacity of more than 200 kW up to and including 18 MW. According to the last public invitation, the amount is 75.27 EUR/MWh, based on 2800 equivalent hours of operation (Croatian Energy Market Operator, 2024.), and the authors believe that it is not applicable to existing wind power plants with certain production curves. Thus, those wind power plants with lower efficiency and effectiveness would have higher prices for electricity; that is, groups of wind power plants with high efficiency would have lower prices for electricity.

Based on the efficiency of each of the listed groups of wind power plants, three levels of electricity prices are determined for the PPA contract for each group of wind power plants for each model year. Levels of electricity prices in PPA contracts for selected years are shown in the Table 4-2.

Table 4-2. Levels of price of electricity in the PPA contracts for wind power plants groups.

Level of electricity prices in the PPA contracts (EUR/MWh)	2027.	2032.	2037.	2042.	2047.
Wind power plants group 1	71,69	64,61	65,28	61,34	61,06
Wind power plants group 2	68,28	61,53	62,17	58,42	58,16
Wind power plants group 3	64,86	58,45	59,06	55,50	55,25

Source: Authors

The level price of electricity in the PPA contract for all wind power plant groups is determined in relation to the projected average market price of electricity for each individual model year. For calculating the price of green hydrogen in Finland, the authors of (Moradpoor, et al., 2023.) used the level price of electricity for PPA contracts in the years 2019, 2020, and 2021, which corresponds to the market price of electricity in Finland in those years. They used the prices according to the LevelTen Energy platform, which provides information on the renewable energy market. In 2021, the price level for wind PPA was 31 EUR/MWh. At the end of 2022, the price level for wind PPA was 78.50 EUR/MWh, mostly due to the war in Ukraine. At the end of 2023, the level price reached the highest level of 99.82 EUR/MWh, given that in the first quarter of 2024, the level price of the wind PPA was 94.63 EUR/MWh, with a downward trend (LevelTen Energy, 2024.). When calculating the LCOH for the scenario of using the ALK electrolyzer, the authors of (Langenmayr, Ruppert, 2023.) have assumed an amount of 60 EUR/MWh for renewable PPA for the year 2024.

In accordance with the above, the level price of electricity in PPA contracts is determined in accordance with market price expectations. For the second group of wind power plants, a level price of electricity has been set for the PPA contract that reflects the projected average market price of electricity for a certain year. For the first group of wind power plants, the price in the PPA contract is higher by 5%, while for the third group of wind power plants, the price in the PPA contract is lower by 5% compared to the projected average market price of electricity for a certain year. The reason for this is the fact that higher efficiency, that is, a better production curve of wind power plants, is accompanied by a higher-level price of electricity in PPA contracts.

4.3.5. Hourly Production of Electricity from Wind Power Plants

The economic model predicts the hourly production of electricity from wind power plants for two reasons. First, the hourly production is needed to be able to compare with the hourly price of electricity in order to determine the required size of the electrolyzer, and second, so that the production diagram can influence the level price of electricity in PPA contracts. In this part of the model, the historical period of electricity production from 2019 to 2023 is taken. The data was obtained from ITSO (Independent Transmission System Operator in Croatia, 2024.) in the form of 15 min production readings for each wind power plant for each year during the period from 2019 to 2023. Namely, the 15 min production readings for each wind power plant were converted into hourly production for easier analysis. At the end of 2022, there were 19 wind power plants in Croatia with a total capacity of 1021 MW. Wind power produced 2.3 TWh of electricity, which covers 12.5% of the total production of renewable electricity in Croatia.

For the annual amount of hydrogen between 29,000 and 33,000 tons, which is produced in the electrolyzer at the location of the existing fertilizer plant, between 1.2 and 1.5 TWh of electricity from renewable sources is needed. Therefore, 12 wind power plants with a total power of 595 MW, whose total annual production is about 1.5 TWh, and which are located in various locations within Croatia, were taken into the analysis. After that, according to the hourly production, they were distributed into groups of wind power plants, with which different PPA contracts were determined, depending on the production diagram.

A classification of the efficiency of each individual wind power plant was made according to the five historical years of electricity production from 12 wind power plants. The hourly annual production of individual wind power plant is divided into four sections, according to the production hours of operation: the number of hours of operation with less than 20% of the installed power, then the number of hours of operation between 20 and 50% of the installed power, then the number of hours of operation between 50 and 80% of the installed power, and the number of hours of operation with more than 80% of the installed power. By looking at the production diagrams of all 12 wind power plants for the mentioned four sections by the number of operating hours according to installed power, four wind power plants were selected in group 1, which have the best production diagram; that is, the best ratio of electricity production in relation to installed power. In the same way, four wind power plants were selected for group 2, and four wind power plants were selected for group 3. In this way, the grouping of wind power plants was made based on the group analysis and wind power plants production diagram so that the size of the electrolyzer would not have a large installed power with a small number of operating hours of use of that installed power. The production curves of wind power plants of group 1 are shown as average hourly production for the period of 2019–2023.

Figure 4-5 shows the average hourly production of four wind power plants of group 1 that have higher efficiency compared to the other eight selected wind power plants shown in Figure 4-6 and Figure 4-7. This is supported by the fact that the wind power plants of group 1 participate with 274 MW of total installed power, while the wind power plants of group 2 and group 3 participate with 153 MW and 168 MW of installed power, respectively. The production efficiency for the group 1 wind power plants is 32%, with 2845 equivalent hours of operation. From Figure 4-5, it can be concluded that with 2703 h of operation, wind power plants produce electricity in a range from 62.5 to 92.5 MWh of total installed capacity. Only 3 h in a year produces electricity at the full installed capacity, while 93 h in a year produces at minimum installed capacity.

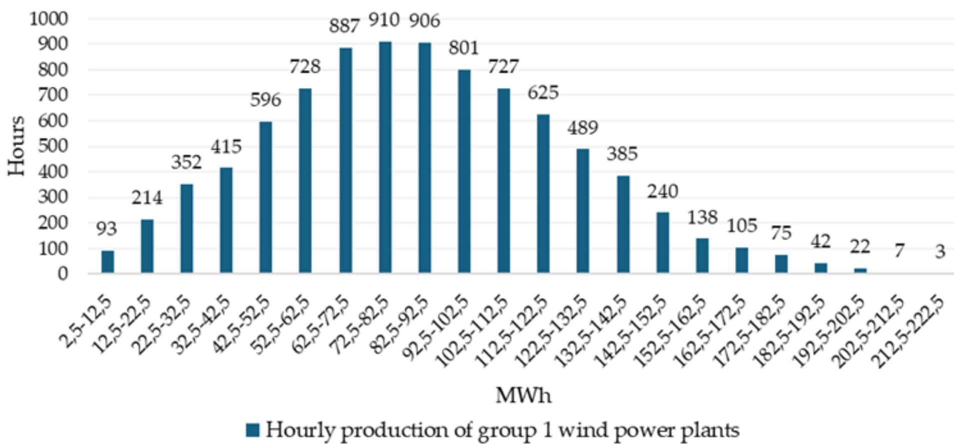

Figure 4-5. Average hourly production of group 1 wind power plants for the period 2019–2023.

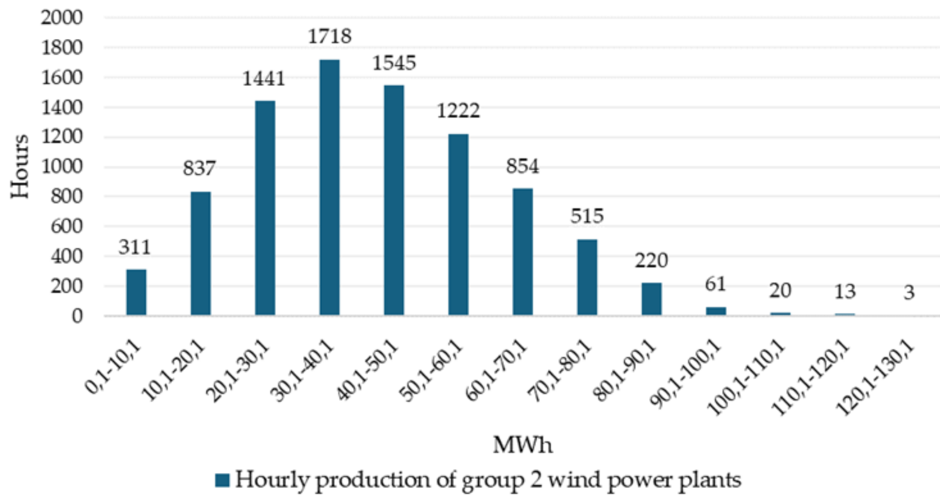

Figure 4-6. Average hourly production of group 2 wind power plants for the period 2019–2023.

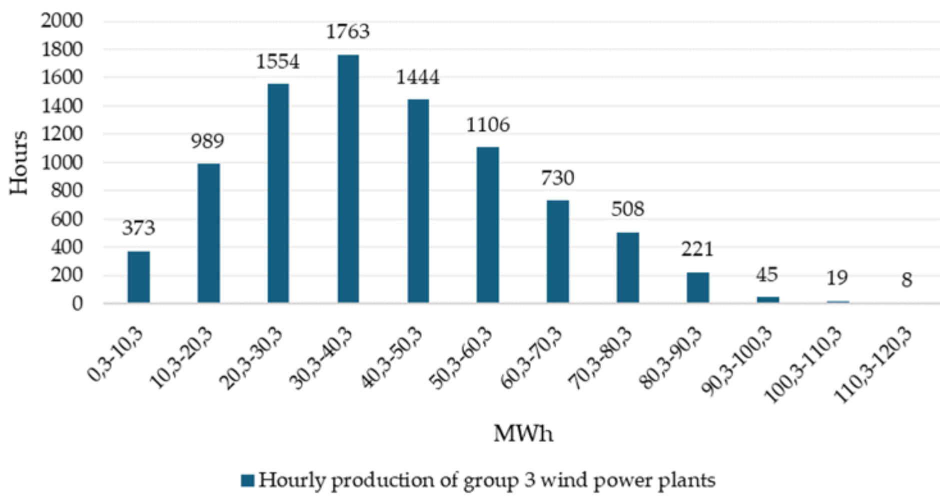

Figure 4-7. Average hourly production of group 3 wind power plants for the period 2019–2023.

The production efficiency for the group 2 wind power plants is 28% with 2424 equivalent hours of operation. Figure 4-6 shows that for 1718 h of operation, wind power plants produce electricity in a range from 30.1 to 40.1 MWh of the total installed capacity. Only 3 h in a year produces electricity at full installed capacity, while 311 h in a year produces at minimum installed capacity.

The production efficiency for group 3 wind power plants is 24% with 2126 equivalent hours of operation. Figure 4-7 shows that for 1763 h of operation, wind power plants produce electricity in a range from 30.3 to 40.3 MWh of total installed capacity. Only 8 h in a year produces electricity at full installed capacity, while 373 h in a year produces at minimum installed capacity. The difference between group 2 and group 3 is that in a range from 20 to 60 MWh of total installed capacity, group 2 wind power plants have 5926 operating hours of electricity production, while group 3 wind power plants have 5867 operating hours of electricity production.

4.3.6. Optimal Size of Electrolyzer

Each of the electrolyzer technologies has its own set of advantages and disadvantages. Alkaline (ALK) electrolyzers have a long record of accomplishment and long duration and do not require critical raw materials such as platinum group metals (PGM). The PEM electrolyzers have high flexibility in load changes and a high power density, which enables a compact design and high output pressure. Solid oxide (SOE) electrolyzers have the highest energy conversion efficiency of up to 84%, and they use cheap ceramics to operate; on the other hand, they require high temperatures (above 600 °C), which makes them particularly suitable for industrial applications with access to waste heat sources. Anion exchange membrane (AEM) electrolyzers combine high load flexibility, compact design, and low reliance on critical raw materials but suffer from emerging technology status and short material life (Hydrogen Europe, 2024.). When producing hydrogen from water, besides ALK, PEM, and SOE electrolyzers, it is also worth mentioning the photocatalytic production of hydrogen. However, most research in this area does not achieve 10% solar-to-hydrogen (STH) efficiency. Therefore, further research on the improvement of photocatalyst efficiency is necessary for the wide commercial application of photocatalytic hydrogen production.

A PEM electrolyzer has a more flexible power operation when starting and stopping, which is especially important when fluctuating production of renewable energy. This allows the PEM electrolyzer to provide frequency reserve capacity to transmission system operators for additional revenue. PEM technology has a high potential for high-pressure operation (up to 200 bar), and technological innovations show a greater impact on reducing capital costs (Lappalainen, 2019.). The authors of (Kumar, Himabindu, 2019.) confirm that in terms of sustainability and environmental impact, the PEM electrolyzer is a promising technique for producing pure hydrogen from RES while only emitting oxygen as a by-product without any carbon emissions. The flexibility in operation of the PEM electrolyzer, the efficiency, and the expected drop in price from the perspective of the economics of hydrogen production are important characteristics that make the PEM electrolyzer suitable for use in this model.

The model uses a PEM electrolyzer with perfectly flexible behavior, i.e., it follows the variable power supply in real time and maintains a constant efficiency of 74%. The efficiency of the electrolyzer was taken from the study in (Fu, et al., 2020.), in which it was applied with an efficiency of 74%, which is in line with the achievements and progress of water electrolysis technologies. The electrolysis process itself emits no pollution, and oxygen is its only by-product. However, all electrolysis process plants have high capital costs, while the overall efficiency of hydrogen production is lower than that of the SMR process. The efficiency of the electrolyzer is defined as the production of hydrogen expressed by the lower calorific value divided by the consumption of electricity in the electrolyzer. Therefore, the efficiency of the electrolyzer determines the amount of electricity used to produce 1 kg of hydrogen. For example, with an electrolyzer efficiency of 65%, the production of 1 kg of hydrogen requires 60.6 kWh of electricity (Gonzalez-Diaz, et al., 2021.). With an electrolyzer efficiency of 60%, 55.0 kWh of electricity is required (Bareiß, et al., 2019.), while with an electrolyzer of 72% efficiency, 46 kWh of electricity is required per kg of hydrogen (Mikovitz, et al., 2021.).

In the model, 9 kg of water was used to produce 1 kg of hydrogen, according to the study in (Bareiß, et al., 2019.). The lower calorific value of hydrogen is 33.6 kWh/kg. An electrolyzer consumes 1 L of water for every 3.73 kWh of hydrogen produced; that is, 268 L of water is consumed for 1 MWh of hydrogen production. For hydrogen production, the minimum amount of water that electrolysis can consume is about 9 kg of water per kg of hydrogen. However, taking into account the water demineralization process, the ratio can range between 18 kg and 24 kg of water per kg of hydrogen or even up to 25.7–30.2, according to (Blanco, 2021.). For the SMR process of hydrogen production, the minimum water consumption is 4.5 kgH_2O/kgH_2 (required for the reaction). Water consumption depends on the production method and the specifics of the process; that is, water consumption can vary between technologies for hydrogen production (Ramirez, et al., 2023.).

In order to show the real value of the investment, the selected electrolyzer parameters in this study were taken from various published references (Kumar, Himabindu, 2019.; Fu, et al., 2020.; Mayer, et al., 2019.; FCH 2 JU, 2017.; Gorre, et al., 2019.; Christensen, 2020.; Government of the Republic of Croatia, 2006.). The technical and economic parameters of the PEM electrolyzer are shown in Table 4-3.

Table 4-3. Parameters of the PEM electrolyzer.

Parameters		Unit Price
CAPEX	Electrolyzer and Compressor	1700.00 EUR/kW
	The cost of connection to the power grid	179.28 EUR/kW
OPEX	The level of electricity prices from the PPA contract	EUR/MWh
	Electrolyzer maintenance (2% of capital costs)	0.58–1.00 EUR/MWh
	The cost of water	2.00 EUR/m^3
Electrolyzer efficiency		74%
Lifetime of the electrolyzer		25 years
Electrolyzer size		370 MW

Source: Authors

The total cost of building an electrolyzer consists of the amount of capital cost and annual fixed and variable operating (O&M) costs. The total capital cost is calculated on an annual basis for the assumed lifetime of the electrolyzer. Fixed costs represent operation and maintenance costs that do not depend on the capacity of the electrolyzer, while variable costs vary depending on the production capacity of the electrolyzer (Ioannou, et al., 2019.). The lifetime of the PEM electrolyzer configuration is 25 years (Kanz, et al., 2023.).

When choosing the size of the electrolyzer, it is necessary to compare the projection of electricity prices and the hourly load of the electrolyzer according to the projection of electricity production. Namely, CAPEX decreases with increasing full load hours of electrolyzer while at the same time, electricity costs increase. For example, for the determined electricity prices in Germany in 2019, the authors of (Lambert, Schulte, 2021.) calculated the optimum electrolyzer size between 5000 and 6000 full load hours. The author of (Lappalainen, 2019.) considers the price of electricity to be the dominant parameter for calculating the cost of hydrogen production in the PEM electrolysis system.

When optimizing the size of the electrolyzer in the model, the hourly electricity prices and the total hourly production of 12 wind power plants were analyzed. According to historical data for the period from 2019 to 2023, the highest production of 12 wind power plants in one hour was 548 MWh. Figure 4-8 shows the average hourly production of 12 wind power plants based on the historical period.

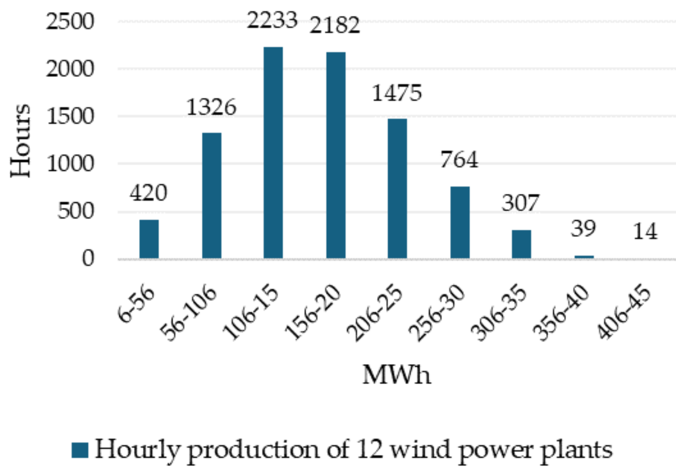

Figure 4-8. Total average hourly production of selected wind power plants for the period 2019–2023.

Figure 4-8 shows the average production of 12 wind power plants according to annual operating hours for the period from 2019 to 2023. By analyzing the hourly production of 12 wind power plants for each of the five historical years, it was determined that out of 8760 h, there were between 40 and 230 h with production below 1 MW and between 550 and 1250 h with production over 370 MW. With that data, it was determined that the optimal size of the electrolyzer should be 370 MW, which would use all available electricity for about 7300 h and part of it for about 1200 h of operation. Decreasing the size of the electrolyzer decreases the production price of hydrogen by a small margin but decreases the amount of hydrogen produced sharply. Also, increasing the size of the electrolyzer increases hydrogen production but also sharply increases the price of hydrogen. With the selected power of the electrolyzer, the production curves of wind power plants can be used, without a large part of the capacity being unused for most of the year and without the CAPEX of the electrolyzer becoming too high in the total production price of renewable hydrogen.

4.4. Materials and Methods

The optimization of the size of the electrolyzer was calculated depending on the need for the ammonia production process in the existing fertilizer plant and the available amounts of renewable electricity. Electricity for the hydrogen production process is provided through a PPA contract on the purchase and sale of electricity from renewable sources. The level of the electricity prices of the PPA contract is determined according to the expected average annual electricity prices, dividing the sources, i.e., wind power plants, according to the generation efficiency diagram into three groups.

This study investigates the impact of the construction of an electrolyzer at the location of an existing fertilizer plant on the production cost of renewable hydrogen. In response to the research questions, the authors conducted a group analysis and a Monte Carlo simulation when optimizing the size of the electrolyzer, as well as a sensitivity analysis in price change scenarios using mathematical and techno-economic methods based on available data. In the period from 2019 to 2023, the electricity market experienced different prices, from extremely high to extremely low and even negative prices. For the same five-year period, production curves were observed for 12 selected wind power plants at an hourly level, whose total average annual production is approximately 1.5 TWh of electricity. ITSO publishes a monthly report on the production of wind power plants in the Republic of Croatia, which includes the installed capacity of individual wind power plants (Independent Transmission System Operator in Croatia, 2024.). The following 12 wind power plants were used in the model: WPP Bruška, WPP Jelinak, WPP Katuni, WPP Krš Pađene, WPP Lukovac, WPP Ogorje, WPP Rudine, WPP Velika Glava, WPP Velika Popina, WPP Voštane, WPP Vrataruša, and WPP Zelengrad. Hourly electricity prices and hourly production curves of wind power plants are the basis for optimizing the size of the electrolyzer as well as for setting the level of electricity prices in PPA contracts.

The combustion of 1 MWh of natural gas (NCV) emits 201.96 kg of CO_2. When calculating the price of natural gas increased by the cost of emission units, the amount of 0.20196 is multiplied by the price of CO_2 emissions per ton, which are added to the price of natural gas, and which is compared to the price of produced hydrogen, as shown in the baseline and sensitivity scenarios. The results of the model show a comparison of the total cost of renewable hydrogen production with the total cost of gray hydrogen production, as well as the comparison of the electricity price and price of natural gas increased by CO_2 emissions with an effect on the correlation between renewable and gray hydrogen production price.

In the continuation of this paper, the selection of the renewable hydrogen production location, the mathematical formulation of the calculation for the economic model, the presentation of the results of the baseline scenario, and the sensitivity analysis are presented.

4.4.1. Location of Renewable Hydrogen Production

This research analyzes the production of renewable hydrogen at the consumption location. This reduces the costs of transporting hydrogen and storing and converting hydrogen, and hydrogen is consumed directly at the location where it is produced. For such an analysis, the location of a large consumer, i.e., an existing fertilizer plant, was chosen since, along with the refinery industry, it is one of the largest consumers of natural gas. However, apart from the purpose of carrying out activities, the existing fertilizer plant uses part of the natural gas to produce gray hydrogen, from which ammonia is further produced to produce mineral fertilizers.

The chosen location for analyzing the profitability of renewable hydrogen production, apart from the amount of natural gas that would be replaced by a renewable source, has numerous other advantages. The location was primarily chosen because of the existing hydrogen consumption. Namely, the production of artificial fertilizers is a process that has three phases that take place at different times; therefore, there are hydrogen tanks on the site. In the first phase, the petrochemical industry produces gray hydrogen for a certain period in the plant, which is stored in tanks. In the second phase, it produces ammonia in the ammonia plant, while in the third part of the process it mixes and packs mineral fertilizers. These separate stages of production and the existing tanks enable the easier implementation of renewable hydrogen. In this way, the fertilizer plant can adapt its period of fertilizer production to the profile of electricity production from wind power plants. At that location, there is a space where an electrolyzer can be installed without entering the investment of buying additional land. In addition, the existing location of the petrochemical industry was tested precisely because of all the connections necessary for the achievement of such a project. Namely, near the industry, a 400 kV line can connect a 370 MW electrolyzer, and the connection cost to the power grid of 179.28 EUR/kW is included in the overall investment, as shown in Table 4-3. The existing industry uses natural gas as an energy source and as a raw material, and it has a direct connection to the transport gas system because it takes in a large amount of natural gas. The authors consider all the above to be advantages of a location suitable for research into the possibility of the partial decarbonization of the industry sector.

4.4.2. Economic Model

The economic model consists of numerous formulas used to calculate the profitability of an investment in an electrolyzer at the location of an existing fertilizer plant. The investment includes capital and operating costs. Namely, the existing connection of the fertilizer plant to the electric power system does not have a capacity sufficient to connect a 370 MW electrolyzer; therefore, it is necessary to increase the existing power of the connection. Considering that it is a large part of the cost of the total investment, this connection cost is added to the capital costs of the electrolyzer. In this way, the capital cost of the electrolyzer investment is shown by the following formula:

$$CAPEXe = \frac{INVe + INVc + CC}{25} \tag{1}$$

where the following are defined:

CAPEXe – capital cost of the electrolyzer (EUR),

INVe – investment cost of the electrolyzer (EUR),

INVc – investment cost of the compressor (EUR),

CC – cost of increasing connection capacity to the power grid (EUR).

The operating cost of the electrolyzer includes the cost of electricity prices from the PPA contract, the cost of equipment maintenance, and the cost of water. The calculation is complex and presented as follows:

$$OPEXe_n = \left(\sum_{8760}^{0}\left(\left(\frac{\sum_3^{t=1} PPAEp_t * HWPe_t - (HWPS * MEp)}{HWPe}\right) + NFC\right) * HWPe\right) + MWC \tag{2}$$

where the following are defined:

$OPEXe_n$ – operating cost of the electrolyzer for year n (EUR),

n – year for which the calculation is made within the lifetime of the electrolyzer (year),

t – group of wind power plants,

$PPAEp_t$ – level of electricity prices in PPA contracts for each group of wind power plants (EUR/MWh),

$HWPe_t$ – hourly wind power production for each group used per electrolyzer (MWh),

HWPe – total hourly electricity production of all groups of wind power plants used on the electrolyzer (MWh),

HWPS – hourly amount of surplus electricity sold on the day-ahead market (MWh),

MEp – hourly market price of electricity (EUR/MWh),

NFC – network fee cost (EUR),

MWC – annual cost of maintenance and water (EUR).

The operating cost of the electrolyzer for year n is calculated as the sum of the cost of electricity for hydrogen production, considering the price difference from the PPA contract between the groups of wind power plants and the hourly production of the groups. Amounts of electricity below the minimum consumption of the electrolyzer, which is 1 MW, as well as those over the installed power of the electrolyzer, are counted as excess electricity that is sold at market prices, and that income is deducted from variable costs to reduce the price of the produced hydrogen.

The amount of hydrogen produced is between 29,000 and 33,000 tons annually. This amount is the same for both renewable and gray hydrogen, given that it refers to the given amount of hydrogen that is replaced in the production process in the existing fertilizer plant. The production price of renewable hydrogen consists of a constant and a variable part, considering the efficiency of the electrolyzer. The fixed part of the production price of renewable hydrogen is calculated according to the following formula:

$$FrH = \frac{CAPEXe}{QrHn} \tag{3}$$

where the following are defined:

FrH – fixed part of the production price of renewable hydrogen (EUR/MWh),

CAPEXe – capital cost of the electrolyzer (EUR),

QrH_n – amount of produced renewable hydrogen (MWh).

The variable part of the production price of renewable hydrogen is calculated according to the following formula:

$$VrH = \frac{OPEXe_n}{QrHn} \tag{4}$$

where the following are defined:

VrH – variable part of the production price of renewable hydrogen (EUR/MWh),

$OPEXe_n$ – operating cost of the electrolyzer (EUR),

QrH_n – amount of produced renewable hydrogen (MWh).

Finally, the production price of renewable hydrogen can be represented by the following formula:

$$PprH = FrH + VrH \tag{5}$$

where the following are defined:

PprH – production price of renewable hydrogen (EUR/MWh),

FrH – fixed part of the production price of renewable hydrogen (EUR/MWh),

VrH – variable part of the production price of renewable hydrogen (EUR/MWh).

The production price of renewable hydrogen reflects the sum of all hourly production prices that are included in the total annual operating cost of the electrolyzer, the total annual capital cost of the electrolyzer, and the connection to the power grid, which is divided by the total produced amount of renewable hydrogen. The production price of renewable hydrogen is calculated in the measurement unit EUR/MWh, as well as the measurement unit EUR/kg.

The levelized cost of hydrogen (LCOH) represents the sum of the total fixed and variable parts of the production cost of hydrogen divided by the amount of hydrogen produced in the lifetime of the electrolyzer. The LCOH for renewable hydrogen was calculated for the baseline scenario and for all sensitivity scenarios. The levelized unit cost of renewable hydrogen production (LCOH) is shown by the following formula:

$$LCOH = \frac{\sum_{t=1}^{n} \frac{FrH_t + VrH_t}{(1+d)^t}}{\sum_{t=1}^{n} \frac{QrH_t}{(1+d)^t}} \qquad (6)$$

where the following are defined:

LCOH – levelized cost of renewable hydrogen production (EUR/MWh),

n – year for which the calculation is made within the lifetime of the electrolyzer,

FrH – fixed cost of renewable hydrogen production in year t (EUR),

VrH – variable cost of renewable hydrogen production in year t (EUR),

QrH_n – amount of produced renewable hydrogen in year t (MWh),

d – interest rate of return on investment (%).

In the formula for calculating the LCOH, the payback time is 25 years, which reflects the lifetime of the electrolyzer, while the interest rate of 6% is taken from the literature (Moradpoor, et al., 2023.).

The production price of gray hydrogen was calculated for the same amount of produced renewable hydrogen, considering the projected market prices of natural gas and CO_2 emissions and the investment cost for a plant where hydrogen from natural gas is produced from the SMR process. The production price of gray hydrogen is shown by the following formula:

$$PpgH = \frac{pNG}{1000} * Hd * 3{,}5 + pCO_2 * QCO_2 + \frac{INVsmr}{QgHn} \qquad (7)$$

where the following are defined:

PpgH – production price of gray hydrogen (EUR/MWh),

pNG – price of natural gas at lower calorific value (EUR/MWh),

Hd – lower calorific value of gas (kWh/kg),

pCO_2 – price of CO_2 emissions (EUR/MWh),

QCO_2 – amount of CO_2 emissions for the production of 1 kg of hydrogen (kg), INVsmr – Investment cost of SMR process plant (EUR),

QgH_n – amount of produced gray hydrogen (kg).

The production price of gray hydrogen is expressed in the unit of measure EUR/MWh, but it is also converted into the unit of measure EUR/kg. When producing 1 kg of gray hydrogen, about 3.5 kg of natural gas is needed for the SMR process, while about 9.3 kg of CO_2 emissions are emitted into the atmosphere (Badrov, 2022.).

The production price of renewable hydrogen is compared to the production price of gray hydrogen, and if the price is higher, subsidies on the price of renewable hydrogen are required. The subsidy amount is calculated according to the following formula:

$$S = PprH - PpgH \tag{8}$$

where the following are defined:

S – subsidy for the price of renewable hydrogen (EUR/MWh),

PprH – production price of renewable hydrogen (EUR/MWh),

PpgH – production price of gray hydrogen (EUR/MWh).

Based on all the mentioned formulas, what follows are the results of the economic model for the baseline scenario.

4.4.3. Baseline Scenario Results

The results of the analysis are shown in Table 4-4. The price of produced renewable and gray hydrogen was calculated, as well as the amount of produced hydrogen. Savings in the amount of CO_2 emissions, income from the sale of excess electricity on the market, and subsidy amounts are shown.

Table 4-4. Presentation of model results for selected years.

Parameters	2027.	2032.	2037.	2042.	2047.
Fixed part of the hydrogen production price (EUR/MWh)	24,94	26,31	25,18	24,94	27,25
Variable part of the hydrogen production price (EUR/MWh)	104,54	96,00	99,66	91,36	92,42
Production price of renewable hydrogen (EUR/MWh)	129,48	122,31	124,83	116,30	119,67
Amount of hydrogen produced (MWh)	1.100.763	1.043.458	1.090.486	1.100.763	1.007.409

Amount of hydrogen produced (tons)	32.760,81	31.055,29	32.454,95	32.760,81	29.982,40
Savings in the amount of CO_2 emissions (tons)	304.675	288.814	301.831	304.675	278.836
Income from the sale of excess electricity on the market (EUR)	6.761.875	5.561.081	1.592.222	6.324.864	4.082.443
Production price of gray hydrogen (EUR/MWh)	76,10	80,44	82,19	84,26	85,56
Required subsidy amount (EUR/MWh)	53,38	41,87	42,65	32,04	34,11

Source: Authors

The annual amount of hydrogen produced ranges from 29,000 to 33,000 tons, with the consumption of 1.3 to 1.5 TWh of electricity produced by selected wind power plants. The annual amount of produced renewable hydrogen is about 31,000 tons, which contributes to savings of 300,000 tons of CO_2 emissions per year. The amount of production is affected by the installed power of the electrolyzer. The excess electricity does not depend on the production of hydrogen, which can be seen more clearly in Figure 4-9, where the relationships between the amount of hydrogen produced, the amount of electricity used for hydrogen production, and the amount of electricity sold are shown.

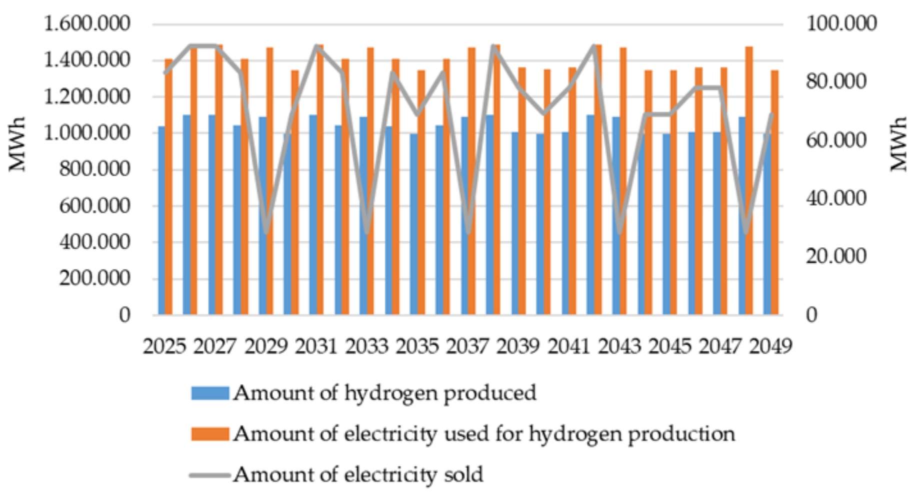

Figure 4-9. The amount of hydrogen produced, the consumption of electricity to produce hydrogen, and the amount of electricity sold for the period from 2025 to 2050.

From Figure 4-9, it can be observed that the amount of hydrogen produced depends on the electricity used for hydrogen production; however, excess electricity does not only appear in years when the amount produced is high. Namely, the amount of hydrogen produced depends on the installed capacity of the electrolyzer, and all the hourly electricity production of wind power plants greater than the installed capacity of the electrolyzer is sold as excess electricity. This is a smaller amount in some years and a larger amount in others, and it depends on the production curve of the wind power plants and the installed power of the electrolyzer.

In addition to the amount of hydrogen produced, Table 4-4 shows that the price of gray hydrogen production is around EUR 82.00/MWh, which is 33% lower than the price of renewable hydrogen production, whose price is around 122.00 EUR/MWh. According to the projection of electricity and natural gas prices from Table 4-1, it can be seen that the price of electricity is 54% higher than the price of natural gas, which affects the lower price of gray hydrogen production. If the price of natural gas were to be increased by one-fifth of the price of CO_2 emissions, the ratio of projected prices would still be lower by 12% compared to the price of electricity. Therefore, the production price of gray hydrogen would still be lower compared to the price of renewable hydrogen. It can be concluded that without subsidies, the ratio of the price of natural gas increased by the cost of CO_2 emissions and electricity prices on the market is unfavorable for an investment in an electrolyzer at the location of the existing fertilizer plant since the electricity prices from the PPA contract are directly derived from the electricity market prices. From the above, subsidies are needed, which on average amount to around 40 EUR/MWh per year for renewable hydrogen.

The price of green hydrogen is strongly influenced by the price of electricity and the type of energy source that supplies the electrolyzers. The authors of (Moradpoor, et al., 2023.) analyzed the price of green hydrogen produced in different electrolyzers with different electricity procurement strategies. Progress in green hydrogen production technologies through various types of electrolyzers and different sources of renewable energy is presented in the study in (Ikuerowo, et al., 2024.). The authors conclude that using PEM electrolyzer technology with electricity obtained from wind power plants achieves the best LCOH between 5.3 and 9.29 USD/kg. According to (Mahajan, et al., 2022.), the price of hydrogen generated from renewable energy is about 5 USD/kg, while the price of hydrogen generated from the SMR process is 1.40 USD/kg. The volatility of electricity prices is important for optimizing operational strategies. The total price of electricity consists of the price of energy, network fees, and taxes. The average spot price on the day-ahead market in Croatia in 2023 was 104.03 EUR/MWh. The LCOH is 126.98 EUR/MWh calculated for the baseline scenario. The production price of renewable and gray hydrogen calculated in the measurement of EUR/kg is shown in Table 4-5.

Table 4-5. Price and amount of produced renewable and gray hydrogen.

Parameters	2027.	2032.	2037.	2042.	2047.
Amount of hydrogen produced (tons)	32.760,81	31.055,29	32.454,95	32.760,81	29.982,40
Production price of renewable hydrogen (EUR/kg)	4,35	4,11	4,19	3,91	4,02
Production price of gray hydrogen (EUR/kg)	2,56	2,70	2,76	2,83	2,87

Source: Authors

From Table 4-5, it can be seen that with the parameters of baseline scenario production, the price of gray hydrogen is lower than the production price of renewable hydrogen. The best ratio between prices is in 2042.

Figure 4-10 compares the production price of gray and renewable hydrogen and the total cost of production of gray and renewable hydrogen as shown for the baseline scenario of the entire model period.

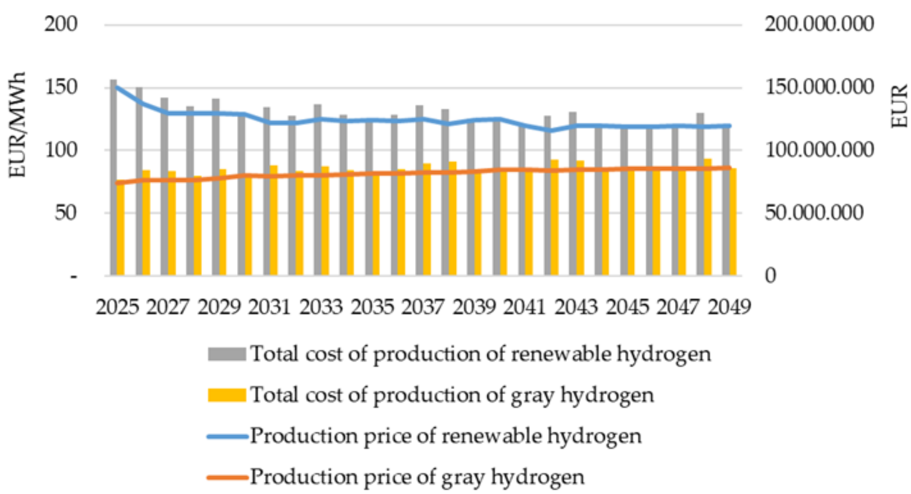

Figure 4-10. Comparison of the production price of renewable and gray hydrogen, and the total cost of renewable and gray hydrogen for the period from 2025 to 2050.

From Figure 4-10, it can be concluded that the production costs of renewable and gray hydrogen in the first years of the model are high, and there is a greater difference between them, while in the last years of the model, this difference decreases. The same happens with the price of produced renewable and gray hydrogen, i.e., the price difference decreases towards the end of the model period. The difference is mostly influenced by the relationship between the prices of electricity and natural gas, as well as the investment costs for the production of renewable or gray hydrogen.

4.4.4. Sensitivity Analysis

When calculating the production price of renewable hydrogen, there are values of input parameters estimated with uncertainty, which can significantly affect the result of the analysis. In this section, a sensitivity analysis is carried out to determine the sensitivity of the production price of renewable hydrogen to changes in the input parameters whose values have been estimated, i.e., the market price of electricity, natural gas, and CO_2 emissions. The sensitivity analysis is carried out in percentage changes (±20%) of increase and decrease in the estimated values in the variable input parameter and then the effect on the profitability of the investment is analyzed as the target parameter of the analysis.

Two sensitivity analysis scenarios are foreseen: the scenario of a change in the input parameter of the price of electricity by 20% higher or lower values compared to the baseline scenario, and a scenario of a change in the input parameter of the price of natural gas and CO_2 emissions by 10% higher or lower values compared to the baseline scenario.

4.4.4.1. Scenario of Changes in the Market Price of Electricity

In the scenario of a change in the projection of the market price of electricity, two options were made. In the first option, the electricity price projection is 20% higher than the market value of the price in the baseline scenario, and in the second option, the electricity price projection is 20% lower than the market value of the price in the baseline scenario.

Figure 4-11 shows the ratio of the production price of gray and renewable hydrogen and the total cost of production of gray and renewable hydrogen under the assumption that the projection of the market price of electricity is 20% higher compared to the baseline scenario.

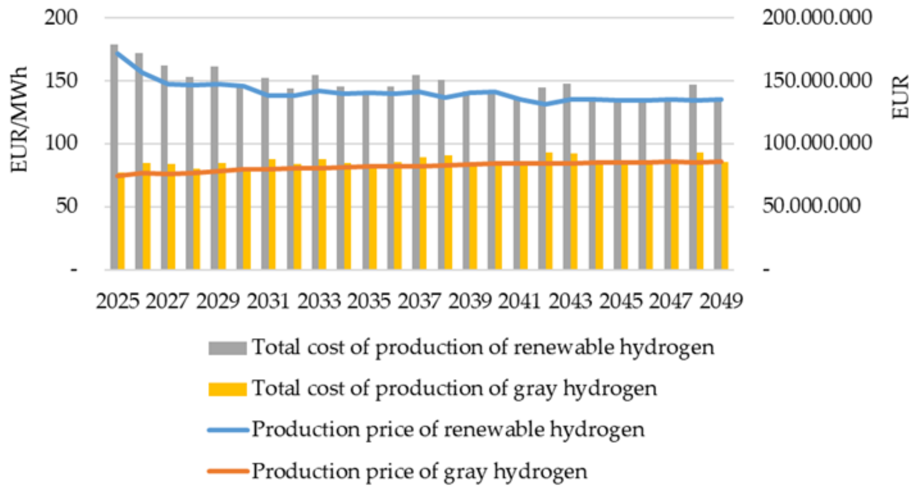

Figure 4-11. Scenario of changing the electricity price projection by 20% higher compared to the baseline scenario.

According to Figure 4-11, it is evident that the total cost of gray hydrogen production is lower than the cost of renewable hydrogen production; that is, the difference in the costs of renewable and gray hydrogen production is much higher compared to the baseline scenario. Namely, a higher price of electricity directly increases the costs of producing renewable hydrogen, while the price of electricity has no such effect on the costs of gray hydrogen production. Consequently, the ratio of production prices of gray and renewable hydrogen is higher than in the baseline scenario. The average price of electricity is 61% higher than the average price of natural gas, according to the projection for the entire model period. The LCOH calculated for this scenario is 143.99 EUR/MWh, which is higher than the amount in the baseline scenario. Therefore, in this scenario, higher subsidies for the production price of renewable hydrogen would be required.

In the second option, the change in the electricity price projection is 20% lower compared to the baseline scenario, and the comparison of the prices and costs of production of gray and renewable hydrogen is shown in Figure 4-12.

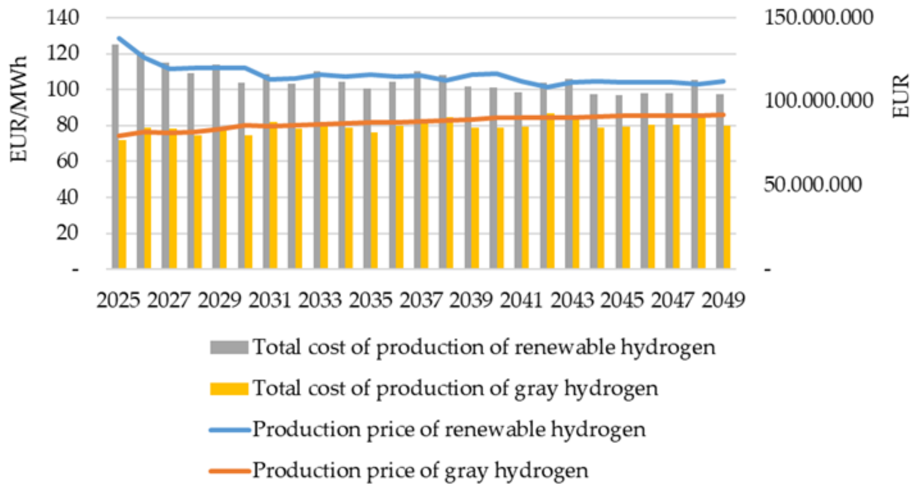

Figure 4-12. Scenario of changing the electricity price projection by 20% lower compared to the baseline scenario.

According to Figure 4-12, the ratio of gray and renewable hydrogen production costs is much lower than in the baseline scenario. Namely, the projection of a lower electricity price affects the lower production costs of renewable hydrogen, which makes it almost competitive in the later years of the model compared to the production costs of gray hydrogen. The production price of renewable hydrogen is still higher compared to the production price of gray hydrogen, but this difference is much smaller compared to the baseline scenario. According to this option, the average price of electricity is still higher than the average price of natural gas, according to the projection for the entire period of the model, by 42%. Therefore, despite the lower projection of the price of electricity, the production price of renewable hydrogen is still uncompetitive with the production price of gray hydrogen, and subsidies are needed even in this price change scenario. The LCOH calculated for this scenario is 109.98 EUR/MWh, which is less than the amount in the baseline scenario.

4.4.4.2. Scenario of Changes in the Market Price of Natural Gas and CO_2 Emissions

In the scenario of changes in the projection of the market price of natural gas and CO_2 emissions, two options are made. In the first option, the projection of natural gas prices and CO_2 emissions is higher by 10% than the market value of prices in the baseline scenario, and in the second option, the projection of natural gas prices and CO_2 emissions is 10% lower than the market value of the price in the baseline scenario.

Figure 4-13 shows the production price and the production costs of gray and renewable hydrogen due to changes in the price of natural gas and CO_2 emissions by 10% higher than the market value of prices from the baseline scenario.

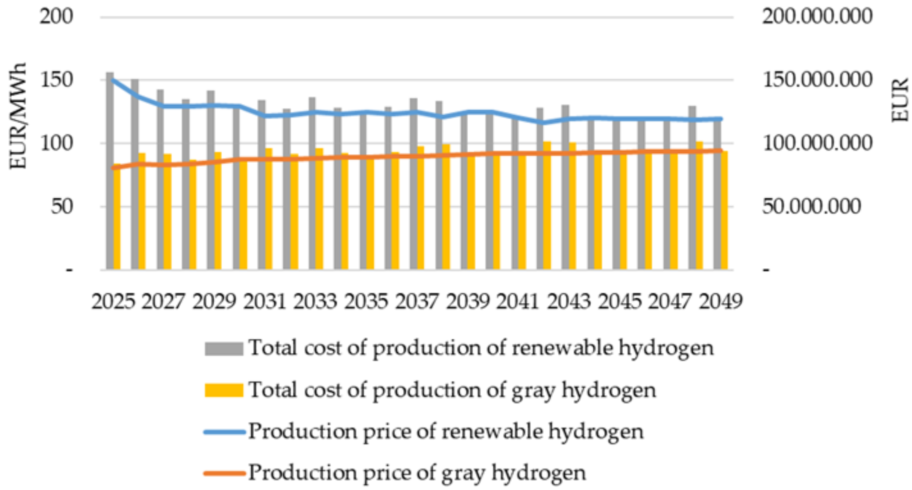

Figure 4-13. Scenario of a change in the projection of the price of natural gas and CO_2 emissions by 10% higher compared to the baseline scenario.

The cost of gray hydrogen in the entire model period is lower than the cost of production of renewable hydrogen, although the difference in production costs is smaller than in the baseline scenario. The average price of electricity is 3% higher than the price of natural gas, increased by the price of CO_2 emissions. Hence, the lower natural gas prices and CO_2 emissions can reduce the difference between gray and renewable hydrogen production costs; however, renewable hydrogen production costs are still higher than gray hydrogen production costs. In this scenario, a subsidy is required for the production price of renewable hydrogen, but in a lower amount than in the other scenarios.

Figure 4-14 shows the production price and the production costs of gray and renewable hydrogen due to changes in the price of natural gas and CO_2 emissions by 10% lower than the market value of prices from the baseline scenario.

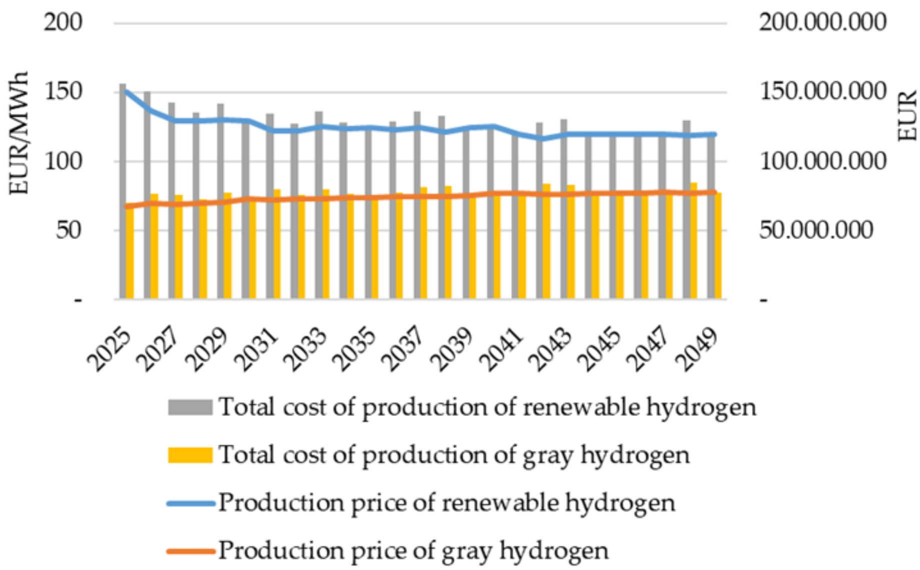

Figure 4-14. Scenario of a change in the projection of the price of natural gas and CO_2 emissions by 10% lower compared to the baseline scenario.

The cost of gray hydrogen in the entire model period is lower than the cost of production of renewable hydrogen, and this difference is higher than in the baseline scenario. The average price of electricity is 21% higher than the price of natural gas, increased by the price of CO_2 emissions. Therefore, the difference between the production costs of gray and renewable hydrogen is higher. Consequently, the production price of renewable hydrogen is higher compared to the production price of gray hydrogen, and in this scenario as well, a subsidy is needed for the production of renewable hydrogen to be competitive.

4.5. Discussion

This paper is a continuation of the author's research in the direction of the profitability of hydrogen production in the energy transition. Namely, in the author's previous work (Dumančić, et al., 2023.), an analysis of the profitability of hydrogen production at a centralized location was performed. A model was presented that examines the profitability of hydrogen production by building an electrolyzer at the location of an existing thermal power plant that is no longer in operation. This makes use of the existing infrastructure, and the produced hydrogen is mixed into the gas grid. Electricity for hydrogen production is taken from the power grid, whereby the obtained hydrogen is designated as yellow hydrogen due to the energy mix from which the electricity is produced. In the model, the energy share of blending hydrogen into the gas grid is 10%, and the electrolyzer provides ancillary services to the power system to reduce the total price of produced hydrogen. The following results were obtained with the model: with the optimal size of the electrolyzer at 762 MW, which works at full capacity 3542 h per year, an amount of 2.7 TWh of hydrogen is produced, which affects the reduction of CO_2 emissions by 540,000 tons per year. Although the best production price of yellow hydrogen was achieved in 2045, which was 83.20 EUR/MWh, this type of investment still requires a subsidy to make hydrogen production economically viable. The author's second research (Dumančić, et al., 2024.) is based on a model that examines the profitability of hydrogen production at a decentralized location. The location of the existing wind power plant where an electrolyzer would be built was analyzed, which would produce hydrogen with electricity from the wind power plant and blend it into the gas grid. The model is set up in such a way that green hydrogen production enables investors in wind farms to earn higher incomes at times when electricity prices are low on the electricity market. The results of the model show that with a 10 MW electrolyzer, which works for 2500 h at full capacity, it is possible to produce 22,410 MWh of green hydrogen, which affects the reduction of CO_2 emissions by 4.482 tons per year. In 2045, the best production price of green hydrogen reached 99.44 EUR/MWh; however, a subsidy is still needed to make this investment profitable.

The analysis of the presented research is based on the fact that the part of gray hydrogen obtained by the SMR process is replaced by renewable hydrogen produced from electricity in the electrolyzer. In this way, the partial decarbonization of the existing fertilizer plant was analyzed. The authors believe that the location of the existing fertilizer plant is interesting and worthy of research, given that a large amount of hydrogen is produced and consumed further as a raw material, and its replacement from gray to renewable hydrogen affects the achievement of the goals of EU energy policies in the industry sector.

After analyzing the cost-effectiveness of hydrogen production in centralized and decentralized locations, the authors decided to analyze the cost-effectiveness of building an electrolyzer at the direct consumption location, i.e., at the location of a large industrial consumer. In the literature review, we did not come across a similar work concept and model that tests the profitability of hydrogen production, including the very method of replacing the SMR plant with an electrolyzer. The model also includes the procurement of renewable energy through PPA contracts that are concluded with groups of electricity producers from wind power plants in accordance with their production diagram, which we consider an additional contribution and novelty in the calculation of the profitability of green hydrogen production. Likewise, PPA contracts concluded between industry and producers of RES can influence a faster process of energy transition (i.e., integration of RES). Such contracts can be used to finance new projects in renewable sources or existing projects that are approaching the end of preferential tariffs. In this way, producers of electricity from renewable sources are protected in terms of energy distribution and payment of obligations to creditors, while the industry is protected by such contracts from the volatility of green energy prices but also participates in meeting the set energy and climate goals of the EU.

Accordingly, this research deals with the current challenges faced by the industry. The authors believe that this analysis and model will provide a deeper insight into the real state of the possibility of changing the existing work process of the industry and that all aspects of investment in an electrolyzer at the consumption location will be taken into account. By comparing decentralized and centralized hydrogen production with hydrogen production at the consumption location, we believe that this type of green hydrogen production is the basis of the decarbonization of the natural gas sector. With such an approach, a much larger amount of hydrogen can be produced and used compared to the production of hydrogen at a centralized or decentralized location where hydrogen is blended into the gas system or transported in some other way.

The specificity of the industry sector is that a large amount of natural gas is used in very few locations in Europe, so the partial decarbonization of it is the focus of this study. The premise discussed in this paper is based on the idea of which form of energy is easier to translate or transport to the location of use. With the limitation of the location of certain industries and the need for a large amount of energy from renewable sources, there is a doubt as to which energy to transport. Should renewable hydrogen be transported to the location of a large consumer by trucks, railways, or pipelines, or is it a better option to transport electricity and produce hydrogen directly at the consumption location? The authors believe that the transport of a large amount of renewable hydrogen, which is needed by the industry, is more expensive than the transmission of electricity. Additionally, the transport of hydrogen by road or rail would create large crowds at the site, while new pipelines should be built for the purposes of transport, given that the percentage of hydrogen mixing in the gas system is very limited. The transmission of a large amount of electricity is faster and more favorable than the transport of renewable hydrogen, and it is also possible to transfer a larger amount of energy through the existing infrastructure. Based on the above, the authors decided to analyze the construction of an electrolyzer with the transmission of electricity to the location of a large consumer.

With the mentioned models, the basis for the decision to invest in an electrolyzer for the production of hydrogen for specific locations is formed, considering that in each presented model, only by replacing the input parameters can the calculation of the production price of hydrogen be obtained. We believe that it is important to test existing locations and obtain realistic calculations that can help both regulators in terms of subsidizing and creating a framework for the development of the hydrogen market, and investors in terms of return on investment. The contribution of the research is visible in terms of achieving the goals of the energy transition through hybrid models in which the power and gas systems are combined. The calculation of CO_2 emission savings, the hydrogen production volume and prices, and the calculation of subsidies necessary for the justification of projects also affect the value of utilization of the existing energy infrastructure.

One of the goals of the energy transition is to increase the use of green hydrogen and replace gray hydrogen and fossil fuels in the most demanding economic sectors, where electrolysis will play a key role. Water electrolysis is considered the most promising method of hydrogen production when it is based on renewable electricity. Hydrogen is considered one of the vectors of the energy transition; therefore, its source is important. In 2022, 11.3 Mt of hydrogen was produced in Europe, of which 95.9% was produced by the method of reforming, partial oxidation, gasification, and as a by-product, while 3.7% was produced as a by-product of electrolysis, of which only 0.25% was produced by water electrolysis (European Hydrogen Observatory, 2022.). The European Commission estimates that between 9 and 14% of energy demand could be covered by pure hydrogen by 2050. It is believed that in regions with cheap electricity from renewable sources, hydrogen from electrolyzers will compete with hydrogen produced from fossil fuels by 2030. These elements will be the most important factors for the introduction of green hydrogen into the EU economy. For the achievement of REPowerEU's goals of producing 10 million tons of hydrogen per year, if between 100 and 120 GWel of the planned capacity of electrolyzers are built by 2030, the potential production of hydrogen would amount to about 16–17 Mt of hydrogen per year, which would achieve the goals of REPowerEU.

4.6. Conclusions

From the presented results of the economic model, it can be concluded that the production price of renewable hydrogen at the location of the existing fertilizer plant is uncompetitive with the production price of gray hydrogen and that without subsidies, the decarbonization of the industry will not be viable. At the location of the existing fertilizer plant, an investment in an electrolyzer was analyzed, which, with electricity procured through PPA contracts with wind power plants, produces renewable hydrogen, which is needed for the further process of ammonia production. The economic analysis determined the annual production price of renewable and gray hydrogen given the projection of the prices of electricity, natural gas, and CO_2 emissions for a period of 25 years.

PPA contracts formed with renewable energy producers are relatively new on the market, but they are beneficial for both parties when entering into them. The industry provides renewable energy in this way, thus meeting the goals of energy neutrality, while producers of renewable energy have a less risky placement of all produced energy at a pre-agreed price. The installed capacity of the wind power plants under the PPA and used in the model is 595 MW. Their efficiency is relatively low, and the production of electricity covers only half of the hydrogen needs of the existing fertilizer plant. If the production of all wind power plants in the Republic of Croatia were included in the model, there would still not be enough electricity to cover the entire hydrogen requirement of the existing fertilizer plant, which needs about 60,000 tons of hydrogen per year, or 2.7 TWh of electricity.

In the additional analysis of the sensitivity scenario, in which the change in the input parameters of the prices of electricity, natural gas, and CO_2 emissions was tested, it was found that despite increasing or decreasing the value of the parameter, the production price of renewable hydrogen was still not competitive without subsidies. The best-performing scenario was the one in which the price of natural gas and CO_2 emissions changed by 10% lower than the projected market value from the baseline scenario, in which the difference between the production prices of gray and renewable hydrogen was the lowest. Therefore, a premium model is needed to cover the difference in production price each year. Due to the volatility of the market prices of electricity, natural gas, and CO_2 emissions, the amount of the necessary subsidy is determined each year separately so that the production price of renewable hydrogen is competitive with the production price of gray hydrogen.

The cost of gray hydrogen production is also analyzed in the model. Existing industries already have facilities where the SMR process takes place in which gray hydrogen is produced, but in the model, the cost of investment in the SMR facility is included in the production price of gray hydrogen. Therefore, industries without adequate incentives will find it difficult or will not decide to build an electrolyzer, that is, to decarbonize part of the process.

The limitation of the model is certainly the unpredictability of future market prices of electricity, natural gas, and CO_2 emissions. Namely, the model was made for a period of 25 years, which is inconvenient for predicting prices, given the fact of what has happened in the market in the last few years, such as the pandemic and the war in Ukraine. Energy prices are the biggest limiting factor in the decision, given that existing industrial consumers who have SMR plants for the production of hydrogen have a hard time deciding on investing in an electrolyzer and replacing gray with green hydrogen due to the electricity price unpredictability. This is supported by the fact that precisely because of the high prices of natural gas in 2022, the production of ammonia in the petrochemical industry in Croatia was stopped until the prices stabilized again, i.e., at the end of 2023, production continued.

What should be highlighted from the presented economic analysis is the amount of hydrogen produced and the amount of savings in CO_2 emissions. The results of the model show the unprofitability of the investment; the authors believe that it is necessary to subsidize the construction of electrolyzers at the locations of large consumers due to the extremely large savings in CO_2 emissions. With the electrolyzer used in the analysis, about 31,000 tons of renewable hydrogen would be produced, which would reduce CO_2 emissions by about 300,000 tons per year. It is precisely because of these amounts of CO_2 emissions that the investment in the electrolyzer should be subsidized, but the amount of the subsidy on the annual production price of renewable hydrogen should also be determined using a premium model.

Since this paper analyzes the replacement of an SMR plant with an electrolyzer at the location of the fertilizer industry, we believe that future research should examine the production of hydrogen at the location of an oil refinery, given that refineries are one of the largest producers of gray hydrogen. Furthermore, future research should analyze subsidies for the construction of electrolyzers and then the mediation of contracts for the purchase of electricity, but also, in general, the establishment of a regulation for the hydrogen market, which will allow hydrogen to be implemented more quickly in the energy sector.

5. CONCLUDING REMARKS

The contribution of this dissertation can be viewed from a theoretical and applied perspective. In a theoretical sense, this dissertation contributes to climate and economic sustainability through the development and formulation of models that test the profitability of hydrogen production in different locations through several scenarios, thereby influencing CO_2 emissions reduction and climate goals. In an applied sense, this dissertation makes a contribution through a cost-economic analysis of hydrogen production, and given that such research does not exist for the Republic of Croatia, or beyond, the results can benefit future research on the use of hydrogen as a cost-effective energy source in the electric and gas networks with which it is possible to achieve part of the decarbonization goals. The research results provide insights into making investment decisions about investing in electrolyzers for greater utilization and efficiency of unpromising thermal power plants, locations of renewable energy sources, or industrial consumers.

In the second chapter of the dissertation, a model is presented that examines the profitability of hydrogen production by building an electrolyzer at the location of an existing thermal power plant that is no longer in operation. This makes use of the existing infrastructure, and the produced hydrogen is blended into the gas grid. Electricity for the production of hydrogen is provided from the power grid, whereby the obtained hydrogen is designated as yellow hydrogen due to the energy mix from which the electricity is produced. In the model, the energy share of blending hydrogen into the gas network is 10%, and the electrolyzer provides ancillary services to the power system in order to reduce the total price of produced hydrogen. The following results were obtained with the model: with the optimal size of the electrolyzer of 762 MW, which operates at full capacity 3542 hours per year, an amount of hydrogen of 2.7 TWh is produced, which affects the reduction of CO_2 emissions by 540,000 tons per year. Although the best production price of yellow hydrogen was reached in 2045, which amounted to 83.20 EUR/MWh, this type of investment still requires a subsidy to make hydrogen production economically profitable.

Research on the production of yellow hydrogen at the location of the existing thermal power plant shows that it is not yet feasible without financial incentives, but in terms of energy, it could contribute to the decarbonization of the energy system and the fulfillment of climate goals, while promoting the sustainability of the existing gas infrastructure. Investing in hydrogen production would help reduce dependence on natural gas while decarbonizing the gas sector and leveraging existing gas infrastructure. By avoiding investments in energy infrastructure, that is, connections to the electricity and gas systems and chemical water treatment, the difference between the price of hydrogen production and the market price of natural gas is significantly reduced.

Limitations in the research are primarily the impossibility of an accurate assessment of future electricity prices and CO_2 emission prices, but this is the first attempt to assess the profitability of hydrogen production at the location of an existing thermal power plant, taking into account the existing infrastructure, the supply of electricity from the power grid, and the inclusion of the power plant in the system of tertiary ancillary services regulation. Electricity and natural gas price projections are currently very unclear due to the crisis in the energy market, leading to a higher level of uncertainty in any future analysis of the energy sector scenario. However, the model was developed and tested on Croatian empirical data and can be further used to simulate different market conditions and projections. Further research could expand this approach and address the profitability model of hydrogen production in renewable energy plants and the integration of hydrogen into the existing natural gas network.

However, the question of the maximum concentration of hydrogen in the mixture of hydrogen and natural gas in the gas network is still open. Permitted concentrations for direct injection of hydrogen into the gas network differ greatly in individual EU countries since the possibility of transporting hydrogen through gas networks was not considered during the introduction of the existing gas regulation. Therefore, it is crucial to remove legal barriers to blending hydrogen with natural gas by harmonizing blending concentrations and setting limits based on physical limitations. Researching the incentives and regulatory obstacles for hydrogen production and application is an important political task for achieving goals of the EU Green Deal.

In the third chapter of the dissertation, a model is presented that examines the profitability of hydrogen production at a decentralized location. The location of the existing wind power plant was analyzed, where the electrolyzer produces hydrogen with electricity from the wind power plant and injecting it into the gas grid. The model is set up in such a way that the production of green hydrogen enables investors in wind power plants to earn higher incomes at a time when electricity prices are low in the electricity market. The model results show that with a 10 MW electrolyzer, which operates at full capacity for 2,500 hours per year, it is possible to produce 22,410 MWh of green hydrogen, which affects the reduction of CO_2 emissions by 4,482 tons per year. The best production price of green hydrogen was reached in 2045 and is 99.44 EUR/MWh. However, a subsidy is still needed to make this investment profitable.

According to the presented model results, taking into account the total consumption of natural gas in the Republic of Croatia and the share of the analyzed wind power plant in the total installed capacity of renewable energy sources in Croatia, the amount of green hydrogen produced is not significant and would not significantly affect the reduction of CO_2 emissions. However, the amounts of green hydrogen produced shown by the model are the result of only one wind power plant. If such systems were to be built at several locations of wind power plants, the effect of reducing CO_2 emissions would be more significant, as the effect would increase many times over. In addition, by changing the input parameters, the model results can be positive as shown in the scenario analysis.

Possible limitations of the model are the lack of technical aspects of injecting hydrogen into the gas grid, and the analysis of the regulatory framework for the use of hydrogen and the subsidy model should be part of further research. Energy infrastructures are natural monopolies, and operators of transmission and transport systems on liberalized energy markets are regulated entities. Therefore, adjustments to the currently valid regulations on the use of Power-to-Gas systems by operators are necessary to enable the smooth production of green hydrogen. The presented model shows that the Power-to-Gas system at the location of the wind power plant solves the problem of power system congestion and the problem of low hourly electricity prices on the market, and contributes to the decarbonization of the gas system.

After analyzing the profitability of hydrogen production in centralized and decentralized locations, the profitability of building an electrolyzer at the location of direct consumption, i.e. at the location of a large industrial consumer, was analyzed in the fourth chapter of the dissertation. In the review of the literature, no similar research concept and model that examines the profitability of hydrogen production, including the method of replacing the SMR plant with an electrolyzer, was found. The analysis of this model is based on the fact that gray hydrogen obtained by the SMR process is replaced by green hydrogen, produced from electricity in the electrolyzer. In this way, the partial decarbonization of the existing fertilizer plant is affected, by replacing a part of natural gas with electricity, i.e. replacing gray with green hydrogen. From the aforementioned analysis, the selection of the location of the existing fertilizer plant is interesting and worth research, considering that a large amount of hydrogen is produced and consumed further as a raw material, and its replacement from gray to green hydrogen affects the achievement of the goals of EU energy policies in the industry sector.

The model includes the procurement of renewable energy sources through PPA contracts concluded with groups of electricity producers from wind power plants in accordance with their production diagram, which is considered an additional contribution and novelty in the calculation of the profitability of green hydrogen production. Likewise, PPA contracts concluded between industry and producers of renewable energy sources can influence a faster process of energy transition (i.e. integration of renewable energy sources). Such contracts can be used to finance new projects in renewable sources or existing projects that are approaching the end of preferential tariffs. In this way, producers of electricity from renewable sources are protected in terms of energy distribution and payment of obligations to creditors, and the industry is protected by such contracts from the volatility of green energy prices but also participates in meeting the set energy and climate goals of the EU. Accordingly, this model addresses the current challenges facing the industry. This analysis and model provide a deeper insight into the real state of the possibility of changing the existing work process of the industry, in which all aspects of investment in the electrolyzer at the point of consumption are taken into account. Comparing decentralized and centralized hydrogen production to point-of-use hydrogen production, this type of green hydrogen production is the foundation of the decarbonization of the natural gas sector. With such an approach, a much larger amount of hydrogen can be produced and used compared to hydrogen production at a centralized or decentralized location where the hydrogen is injected into the gas system or transported in some other way.

The specificity of the industrial sector is that large quantities of natural gas are used in very few locations in Europe, so its partial decarbonization is the focus of this model. The premise discussed in this part of the dissertation is based on the idea of which form of energy is easier to translate or transport to the place of use. With the limited location of certain industries and the need for a large amount of energy from renewable sources, the question arises as to which energy to transport. Should green hydrogen be transported to a large consumer site by truck, rail or pipeline, or is it a better option to transport electricity and produce hydrogen directly at the point of consumption? Transporting a large amount of green hydrogen, which is needed by industry, is more expensive than transporting electricity. Additionally, the transportation of hydrogen by road or rail would create large crowds at the location, and new pipelines need to be built for transportation purposes, given that the percentage of hydrogen blending in the gas system is very limited. The transmission of a large amount of electricity is faster and more favorable than the transport of green hydrogen, and it is also possible to transfer a larger amount of energy through the existing infrastructure. On the basis of the above, an analysis was made of the construction of an electrolyser for which electricity is procured and leads to the location of a large consumer.

The contribution of the research is visible in terms of achieving the goals of the energy transition through hybrid models in which electric power and gas systems are combined. The models formed the basis for the decision to invest in an electrolyzer for the production of hydrogen for specific locations, considering that in each model shown, only by replacing the input parameters can the calculation of the production price of hydrogen be obtained. The value of the utilization of the existing energy infrastructure is also affected by the calculation of CO_2 emission savings, the volume and price of hydrogen production, and the calculation of the subsidies necessary for the justification of the projects. Analysis of existing locations and realistic investment calculations can help both regulators in terms of subsidizing and creating a framework for the development of the hydrogen market, and investors in terms of return on investment.

For further research, it is recommended to include a techno-economic analysis of alternative technologies to water electrolysis for the production of hydrogen without CO_2 emissions, since the planned use of green hydrogen as a substitute for gray hydrogen and fossil fuels in the most demanding economic sectors requires amounts of electricity from RES that may not be available. In 2022, 11.3 Mt of hydrogen was produced in Europe, of which 95.9% was produced by the method of steam reforming, partial oxidation, gasification, and as a by-product, while 3.7% was produced as a by-product of electrolysis, i.e. of which only 0.25% produced by water electrolysis. By 2030, it is planned to build between 100 and 120 GW_{el} electrolyzer capacity with the production of hydrogen by electrolysis of water to amount between 16-17 Mt of hydrogen per year, achieving the goals of REPowerEU. The reason for proposing alternative technologies to water electrolysis is the large number of other uses of electricity from renewable sources. Electrification of traffic, replacement of electricity produced from thermal power plants and transition of heating from fossil sources to heat pumps are planned with electricity from RES. Each of the listed renewable energy uses represents competition for the production of hydrogen by water electrolysis.

A techno-economic analysis for an alternative to water electrolysis is required in the situation when the amounts of electricity from RES required for hydrogen production are not available. In that case, hydrogen for critical industries such as the production of fertilizers will continue to be produced from fossil sources or alternatives to water electrolysis will have to be found if CO_2 emissions from hydrogen production has to be removed.

The technology of hydrogen production that needs to be techno-economically analyzed is the hydrogen production by thermolysis, i.e. the use of thermal energy from nuclear reactors and the sulfur-iodine cycle for the production of red hydrogen.

The use of new nuclear reactors or conversion of existing ones and the use of the sulfur-iodine cycle offers the possibility of efficient and economically justified production of hydrogen in significant quantities. The sulfur-iodine cycle is a pure thermochemical water separation process consisting of three steps in which all chemicals are recycled, i.e. it is a closed cycle where hydrogen and oxygen are obtained from water. Although one part of the process requires high temperatures of 850ºC, satisfactory efficiency can be achieved with the use of thermal energy from a nuclear reactor. The potential of this technology is a large amount of hydrogen production at a relatively low cost, although with the extremely high cost of construction, later maintenance and fuel cost represent a small share of the price of the produced hydrogen. The infrastructure for the production of red hydrogen can be built within a decade and provide an alternative to water electrolysis and further accelerate the decarbonization of industry, transport, and energy. The proposed analysis of the production of red hydrogen is ahead of the much more frequently mentioned production of pink hydrogen, i.e. the production of hydrogen by electrolysis from electricity obtained from nuclear power plants due to efficiency. In the production of pink hydrogen, two energy conversions are required, which significantly lowers the efficiency of the entire process, while the production of red hydrogen is theoretically twice as efficient as the production of pink hydrogen. A techno-economic analysis of the production of red hydrogen would be a continuation of this research because it would enable a comparison of the price of red hydrogen with the prices of green and yellow hydrogen from this dissertation and provide insight into the potential quantities of hydrogen that could be produced and in which cases gray hydrogen could be replaced by red instead of green hydrogen.

REFERENCES

1) Ali Khan, M.H. et al. (2021) “Designing optimal integrated electricity supply configurations for renewable hydrogen generation in Australia”, iScience, 24(6)
2) Al-Qahtani, A.; Parkinson, B.; Hellgardt, K.; Shah, N.; Guillen-Gosalbez, G. Uncovering the true cost of hydrogen production routes using life cycle monetization. Appl. Energy 2021, 281, 115958.
3) Arcos, J.M.M.; Santos, D.M.F. The Hydrogen Color Spectrum: Techno-Economic Analysis of the Available Technologies for Hydrogen Production. Gases 2023, 3, 25–46.
4) Arellano, J.; Carrión, M. Electricity procurement of large consumers considering power-purchase agreements. Energy Rep. 2023, 9, 5384–5396.
5) Armijo, J.; Philibert, C. Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina. Int. J. Hydrogen Energy 2020, 45, 1541–1558.
6) Ayers, K. et al. (2019) “Perspectives on Low-Temperature Electrolysis and Potential for Renewable Hydrogen at Scale”, Annual review of chemical and biomolecular engineering, 10(1)
7) Badrov, V. Cost Analysis of Hydrogen Production from Different Sources; University of Zagreb, Faculty of Mining, Geology and Petroleum Engineering: Zagreb, Croatia, 2022.
8) Bareiß, K.; de la Rúa, C.; Möckl, M.; Hamacher, T. Life cycle assessment of hydrogen from proton exchange membrane water electrolysis in future energy systems. Appl. Energy 2019, 237, 862–872.
9) Blanco, H. Hydrogen Production in 2050: How Much Water Will 74EJ Need? 2021. Available online: https://energypost.eu/hydrogen-production-in-2050-how-much-water-will-74ej-need/ (accessed on 15 July 2024).
10) Böhm, H.; Zauner, A.; Rosenfeld, D.C.; Tichler, R. Projecting cost development for future large-scale power-to-gas implementations by scaling effects. Appl. Energy 2020, 264, 114780.
11) Bothun, G. Offshore Wind Power: A Promising and Scalable Future Electricity Source. In The Energy and Sustainability 2018 Symposium; Springer: Cham, Switzerland, 2019; pp. 125–148. [Google Scholar]
12) Chandrasekar, A.; Flynn, D.; Syron, E. Operational challenges for low and high temperature electrolyzers exploiting curtailed wind energy for hydrogen production. Int. J. Hydrogen Energy 2021, 46, 28900–28911.
13) Chaube, A. et al. (2020) “The Role of Hydrogen in Achieving Long Term Japanese Energy System Goals”, Energies, 13(4539)

14) Christensen, A. Assessment of Hydrogen Production Costs from Electrolysis; United States and Europe, International Council on Clean Transportation: Washington, DC, USA, 2020.
15) Clifford, C. Hydrogen Power Is Gaining Momentum, but Critics Say It's Neither Efficient nor Green Enough. Clean Energy. CNBC. 2022. Available online: https://www.cnbc.com/2022/01/06/what-is-green-hydrogen-vs-blue-hydrogen-and-why-it-matters.html?recirc=taboolainternal (accessed on 12 January 2022).
16) Croatian Energy Market Operator. Energy Origin Guarantee System in the Republic of Croatia. Annual Report for 2023. The Sector of Renewable Energy Sources and the Implementation of the Incentive System, Croatia. 2024. Available online: https://www.hrote.hr/registar-jamstava-podrijetla (accessed on 14 April 2024).
17) Croatian Energy Market Operator. State Aid Program for the System of Stimulating the Production of Electricity from Renewable Energy Sources and High-Efficiency Cogeneration with a Market Premium and a Guaranteed Purchase Price. Croatia. 2024. Available online: https://www.hrote.hr/javni-poziv-za-javno-prikupljanje-ponuda-s-uvjetima-za-sudjelovanje-na-javnom-natjecaju-za-dodjelu-trzisne-premije (accessed on 14 April 2024).
18) Croatian Energy Regulatory Agency. Report on the Work of the Croatian Energy Regulatory Agency for the Year 2021; Ministry of Economy and Sustainable Development of the Republic of Croatia: Zagreb, Croatia, 2022. [Google Scholar]
19) Croatian Power Exchange. Electricity Prices. 2024. Available online: https://www.cropex.hr/en/ (accessed on 14 April 2024).
20) Croatian Transmission System Operator. Annual Report 2021; Ministry of Economy and Sustainable Development of the Republic of Croatia: Zagreb, Croatia, 2022.
21) Das, A.; Peu, S.D. A Comprehensive Review on Recent Advancements in Thermochemical Processes for Clean Hydrogen Production to Decarbonize the Energy Sector. Sustainability 2022, 14, 11206. [Google Scholar] [CrossRef]
22) Dinh, V.N.; Leahy, P.; McKeogh, E.; Murphy, J.; Cummins, V. Development of a viability assessment model for hydrogen production from dedicated offshore wind power plants. Int. J. Hydrogen Energy 2021, 46, 24620–24631.
23) Dumančić, A.; Vlahinić Lenz, N.; Majstrović, G. Can Hydrogen Production Be Economically Viable on the Existing Gas-Fired Power Plant Location? New Empirical Evidence. Energies 2023, 16, 3737.

24) Dumančić, A.; Vlahinić Lenz, N.; Wagmann, L. Profitability Model of Green Hydrogen Production on an Existing Wind Power Plant Location. Sustainability 2024, 16, 1424.
25) Ekhtiari, A.; Flynn, D.; Syron, E. Investigation of the multi-point injection of green hydrogen from curtailed renewable power into a gas network. Energies 2020, 13, 6047.
26) Energy Institute Hrvoje Požar. Novi Izazovi u Energetici: Ekonomska Perspektiva; Ministry of Economy and Sustainable Development of the Republic of Croatia: Zagreb, Croatia, 2020.
27) ENTSO-E; ENTSOG. TYNDP 2020 Scenario Report. 2020. Available online: https://2020.entsos-tyndp-scenarios.eu/ (accessed on 4 February 2022).
28) ENTSO-E; ENTSOG. TYNDP 2022 Scenario Report. 2022. Available online: https://2022.entsos-tyndp-scenarios.eu/ (accessed on 21 April 2022).
29) ENTSO-E; ENTSOG. TYNDP 2024 Scenarios Methodology Report. 2024. Available online: https://2024.entsos-tyndp-scenarios.eu/ (accessed on 23 May 2024).
30) European Commission. Commission Sets Out Rules for Renewable Hydrogen. 2023. Available online: https://ec.europa.eu/commission/presscorner/detail/en/IP_23_594 (accessed on 14 April 2024).
31) European Commission. Proposal for a Regulation of the European Parliament and of the Council on the Internal Markets for Renewable and Natural Gases and for Hydrogen; COM(2021) 804 final. 2021/0424(COD); European Commission: Brussels, Belgium, 2021. [Google Scholar]
32) European Hydrogen Observatory. Hydrogen Production. 2022. Available online: https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/production-trade-and-cost/hydrogen-production (accessed on 8 July 2024).
33) Eurostat. Industry Relied Mostly on Natural Gas & Electricity. 2023. Available online: https://ec.europa.eu/eurostat/web/products-eurostat-news/w/ddn-20230512-1 (accessed on 20 April 2024).
34) Eveloy, V.; Gebreegziabher, T. A Review of Projected Power-to-gas Deployment Scenarios. Energies 2018, 11, 1824. [Google Scholar] [CrossRef]
35) Ferrero, D.; Gamba, M.; Lanzini, A.; Santarelli, M. Power-to-Gas Hydrogen: Techno-economic Assessment of Processes towards a Multi-purpose Energy Carrier. In Energy Procedia; Elsevier Ltd.: Amsterdam, The Netherlands, 2016; pp. 50–57.

36) Franchi, G.; Capocelli, M.; De Falco, M.; Piemonte, V.; Barba, D. Hydrogen Production via Steam Reforming: A Critical Analysis of MR and RMM Technologies. Membranes 2020, 10, 10.
37) Fu, P.; Pudjianto, D.; Zhang, X.; Strbac, G. Integration of Hydrogen into Multi-Energy Systems Optimisation. Energies 2020, 13, 1606.
38) Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU). In Study on Early Business Cases for H2 in Energy Storage and More Broadly Power to H2 Applications; Tractebel Engineering SA: Brussels, Belgium, 2017.
39) Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) Study on Opportunities Arising from the Inclusion of Hydrogen Energy Technologies in the National Energy & Climate Plans (Ref. FCH/OP/Contract 234). Consortium led by: Trinomics B.V. Westersingel 34 3014 GS, Rotterdam the Netherlands. August 2020. Available online: https://trinomics.eu/wp-content/uploads/2020/09/Final-Report-Hydrogen-in-NECPs.pdf (accessed on 14 April 2024).
40) Fuk, B. The future of hydrogen as a fuel in Croatia. Sigurnost 2023, 65, 453–458. Available online: https://hrcak.srce.hr/file/452088 (accessed on 20 April 2024).
41) Gas Infrastructure Europe (GIE). The European Gas Infrastructure Can Help Deliver the EU Hydrogen Strategy; Gas Infrastructure Europe (GIE): Brussels, Belgium, 2020.
42) Ghiassi-Farrokhfal, Y.; Ketter, W.; Collins, J. Making green power purchase agreements more predictable and reliable for companies. Decis. Support Syst. 2021, 144, 113514.
43) Glenk, G.C. (2019) "Economics of Renewable Hydrogen", Tehničko sveučilište u Münchenu, Ekonomski fakultet, Katedra za kontroling
44) Gonzalez-Diaz, A.; de Guevara, J.C.S.L.; Jiang, L.; Gonzalez-Diaz, M.O.; Díaz-Herrera, P.; Font-Palma, C. Techno-Environmental Analysis of the Use of Green Hydrogen for Cogeneration from the Gasification of Wood and Fuel Cell. Sustainability 2021, 13, 3232.
45) Gorre, J.; Ortloff, F.; van Leeuwen, C. Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-gas system with intermediate hydrogen storage. Appl. Energy 2019, 253, 113594. [Google Scholar] [CrossRef]
46) Gorre, J.; Ruoss, F.; Karjunen, H.; Schaffert, J.; Tynjälä, T. (2020) „Cost benefits of optimizing hydrogen storage and methanation capacities for Power-to-Gas plants in dynamic operation". Applied Energy, 257, 113967

47) Government of the Republic of Croatia. Decision on the Amount of the Fee for Connection to the Electric Power Network and for Increasing the Connection Power. Official Gazette, 52/2006-1249. 2006. Available online: https://narodne-novine.nn.hr/clanci/sluzbeni/2006_05_52_1249.html (accessed on 14 April 2024).
48) Grimm, A.; de Jong, W.A.; Kramer, G.J. Renewable hydrogen production: A techno-economic comparison of photoelectrochemical cells and photovoltaic-electrolysis. Int. J. Hydrogen Energy 2020, 45, 22545–22555.
49) Grossi, G.; Arpino, F.; Bertone, M.; Canale, C.; Canale, L.; Cortellessa, G.; Dell'Isola, M.; Ficco, G.; Moretti, L. Natural gas system decarbonization by green hydrogen injection: A distributed approach. In IOP Conference Series: Earth and Environmental Science; IOP Publishing: Bristol, UK, 2022; Volume 1106.
50) Gysels E. (2018) "The role of green hydrogen in Belgium's future energy system", Aalborg University
51) Haeseldonckx, D.; D'haeseleer, W. The use of the natural-gas pipeline infrastructure for hydrogen transport in a changing market structure. Int. J. Hydrogen Energy 2007, 32, 1381–1386.
52) Hassan, Q.; Abdulrahman, I.S.; Salman, H.M.; Olapade, O.T.; Jaszczur, M. Techno-Economic Assessment of Green Hydrogen Production by an Off-Grid Photovoltaic Energy System. Energies 2023, 16, 744.
53) Herbst, T. The Impact of Energy Price Movements on the European Economic and Energy Sector; University of Zagreb, Faculty of Mining, Geology and Petroleum Engineering: Zagreb, Croatia, 2022.
54) Croatian Parliament (2022) "Croatian strategy for hydrogen until 2050", Official Gazette, 40/2022. Ministry of Economy and Sustainable Development. Zagreb, March 2022. Available online: https://mingo.gov.hr/ (accessed on 14 March 2022).
55) Huszal, A., Jaworski, J. (2020) "Studies of the Impact of Hydrogen on the Stability of Gaseous Mixtures of THT", Energies, 13(6441)
56) Hydrogen Europe. Clean Hydrogen Monitor 2023. 2023. Available online: https://hydrogeneurope.eu/in-a-nutshell/reports/ (accessed on 15 July 2024).
57) Hydrogen Europe. Clean Hydrogen Production Pathways. Report 2024. 2024. Available online: https://hydrogeneurope.eu/wp-content/uploads/2024/06/2024_H2E_CleanH2ProductionPathwaysReport.pdf (accessed on 23 May 2024).
58) Hydrogen Europe. Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy; European

Hydrogen and Fuel Cell Sector; Hydrogen Europe Secretariat: Bruxelles, Belgium, 2019.
59) Hydrogen Europe. The Colors of Hydrogen. Available online: https://hydrogeneurope.eu/in-a-nutshell/ (accessed on 19 April 2024).
60) ICIS Forward Prices—Natural Gas. 2024. Available online: https://www.icis.com/Dashboard (accessed on 24 May 2024).
61) Ikuerowo, T.; Bade, S.O.; Akinmoladun, A.; Oni, B.A. The integration of wind and solar power to water electrolyzer for green hydrogen production. Int. J. Hydrogen Energy 2024, 76, 75–96.
62) Ilić B., Nikolić M., Simeonović N. (2018) “Ekološka ekonomija i održivi razvoj”, International Symposium on Natural Resource Management, University of Belgrade, Faculty of Management, Zaječar
63) Independent Transmission System Operator in Croatia. Reports WPP. 2024. Available online: https://www.hops.hr/en/reports-wpp (accessed on 19 April 2024).
64) International Energy Agency. Advancing Decarbonisation through Clean Electricity Procurement. IEA Publications. 2022. Available online: https://www.iea.org/reports/advancing-decarbonisation-through-clean-electricity-procurement (accessed on 20 April 2024).
65) International Energy Agency. Clean Energy Market Monitor 2024. IEA Publications. 2024. Available online: https://www.iea.org/reports/clean-energy-market-monitor-march-2024 (accessed on 15 July 2024).
66) International Energy Agency. Global Hydrogen Review 2023. IEA Publications. 2023. Available online: https://www.iea.org/reports/global-hydrogen-review-2023 (accessed on 13 May 2024).
67) International Energy Agency. Renewable 2023. Analysis and Forecasts to 2028. IEA Publications. 2024. Available online: https://www.iea.org/reports/renewables-2023 (accessed on 15 July 2024).
68) International Energy Agency. Renewable Energy Progress Tracker. IEA Publications. 2024. Available online: https://www.iea.org/data-and-statistics/data-tools/renewable-energy-progress-tracker (accessed on 12 July 2024).
69) International Energy Agency. World Energy Outlook 2023. IEA Publications. 2023. Available online: https://www.iea.org/reports/world-energy-outlook-2023 (accessed on 13 May 2024).
70) International Renewable Energy Agency (IRENA). Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5 °C Climate Goal. Abu Dhabi. 2020. Available online: www.irena.org/publications (accessed on 20 April 2024).

71) International Renewable Energy Agency (IRENA). Hydrogen from Renewable Power: Technology Outlook for the Energy Transition; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2018.
72) Ioannou, A.; Brennan, F. A Preliminary Techno-Economic Comparison between a Grid-Connected and Non-Grid Connected Offshore Floating Wind Power Plant; Department of Naval Architecture, Ocean & Marine Engineering University of Strathclyde: Glasgow, UK, 2019.
73) Ioannou, A.; Fuzuli, G.; Brennan, F.; Yudha, S.W.; Angus, A. Multi-stage stochastic optimization framework for power generation system planning integrating hybrid uncertainty modelling. Energy Econ. 2019, 80, 760–776.
74) Jovan, D.J.; Dolanc, G. Can Green Hydrogen Production Be Economically Viable under Current Market Conditions. Energies 2020, 13, 6599.
75) Jovan, D.J.; Dolanc, G.; Pregelj, B. Cogeneration of green hydrogen in a cascade hydropower plant. Energy Convers. Manag. X 2021, 10, 100081.
76) Kanellopoulos, K.; Busch, S.; De Felice, M.; Giaccaria, S.; Costescu, A. Blending Hydrogen from Electrolysis into the European Gas Grid; Joint Research Centre, Publications Office of the European Union: Luxembourg, 2022.
77) Kanz, O.; Brüggemann, F.; Ding, K.; Bittkau, K.; Raua, U.; Reinders, A. Life-cycle global warming impact of hydrogen transport through pipelines from Africa to Germany. Sustain. Energy Fuels 2023, 7, 3014–3024.
78) Kaplan, R.; Kopacz, M. Economic Conditions for Developing Hydrogen Production Basec on Coal Gasification with Carbon Capture and Storage in Poland. Energies 2020, 13, 5074.
79) Khan, M.H.A.; Daiyan, R.; Han, Z.; Hablutzel, M.; Haque, N.; Amal, R.; MacGill, I. Designing optimal integrated electricity supply configurations for renewable hydrogen generation in Australia. iScience 2021, 24, 102539.
80) Khatiwada, D.; Adithya Vasudevan, R.; Henrique Santos, B. Decarbonization of natural gas systems in the EU—Costs, barriers, and constraints of hydrogen production with a case study in Portugal. Renew. Sustain. Energy Rev. 2022, 168, 112775.
81) Klyuev, R.; Madaeva, M.; Umarova, M. Mathematical Modeling of Specific Power Consumption of Electrolyzers. In Proceedings of the International Ural Conference on Electrical Power Engineering (UralCon), Chelyabinsk, Russia, 22–24 September 2020.
82) Koirala, B.P.; Hers, S.; Morales-Espana, G.; Ozdemir, O.; Sijm, J.; Weeda, M. Integrated electricity, hydrogen, and methane system modelling framework: Application to the Dutch Infrastructure Outlook 2050. Appl. Energy 2021, 289, 116713.

83) Komarov, I.I.; Rogalev, A.N.; Kharlamova, D.M.; Naumov, V.Y.; Shabalova, S.I. Comparative analysis of the efficiency of using hydrogen and steam methane reforming storage at combined cycle gas turbine for cogeneration. J. Phys. Conf. Ser. 2021, 2053, 012007.
84) Kontani, R.; Tanaka, K. Integrating variable renewable energy and diverse flexibilities: Supplying carbon-free energy from a wind turbine to a data center. Urban Clim. 2024, 54, 101843.
85) Kopteva, A.; Kalimullin, L.; Tcvetkov, P.; Soares, A. Prospects and Obstacles for Green Hydrogen Production in Russia. Energies 2021, 14, 718.
86) Kountouris, I.; Langer, L.; Bramstoft, R.; Münster, M.; Keles, D. Power-to-X in energy hubs: A Danish case study of renewable fuel production. Energy Policy 2023, 175, 113439.
87) Kumar, S.S.; Himabindu, V. Hydrogen production by PEM water electrolysis—A review. Mater. Sci. Energy Technol. 2019, 2, 442–454.
88) Lahnaoui, A.; Wulf, C.; Dalmazzone, D. Optimization of Hydrogen Cost and Transport Technology in France and Germany for Various Production and Demand Scenarios. Energies 2021, 14, 744.
89) Lambert, M.; Schulte, S. Contrasting European Hydrogen Pathways: An Analysis of Differing Approaches in Key Markets; Oxford Institute for Energy Studies: Oxford, UK, 2021.
90) Langenmayr, U.; Ruppert, M. Renewable origin, additionality, temporal and geographical correlation—eFuels production in Germany under the RED II regime. Energy Policy 2023, 183, 113830.
91) Lappalainen, M. Techno-Economic Feasibility of Hydrogen Production via Polymer Membrane Electrolyte Electrolysis for Future Power-to-X Systems; Tampere University, Faculty of Natural Sciences: Tampere, Finland, 2019.
92) LevelTen Energy. PPA Price Index. Available online: https://www.leveltenenergy.com/tags/ppa-price-index (accessed on 5 July 2024).
93) Li, F.; Liu, D.; Sun, K.; Yang, S.; Peng, F.; Zhang, K.; Guo, G.; Si, Y. Towards a Future Hydrogen Supply Chain: A Review of Technologies and Challenges. Sustainability 2024, 16, 1890.
94) Li, Z.; Fang, S.; Sun, H.; Chung, R.; Fang, X.; He, J. Solar Hydrogen. Adv. Energy Mater. 2023, 13, 2203019.
95) Li, Z.; Zhang, W.; Zhang, R.; Sun, H. Development of renewable energy multi-energy complementary hydrogen energy system (A Case Study in China): A review. Energy Explor. Exploit. 2020, 38, 2099–2127.

96) Liu, W.; Wen, F.; Xue, Y. Power-to-gas technology in energy systems: Current status and prospects of potential operation strategies. J. Mod. Power Syst. Clean Energy 2017, 5, 439–450.
97) Luo, Z.; Hu, Y.; Xu, H.; Gao, D.; Li, W. Cost-Economic Analysis of Hydrogen for China's Fuel Cell Transportation Field. Energies 2020, 13, 6522.
98) Ma, Q.; Chang, Y.; Yuan, B.; Song, Z.; Xue, J.; Jiang, Q. Utilizing carbon dioxide from refinery flue gas for methanol production: System design and assessment. Energy 2022, 249, 123602
99) Maeder, M.; Weiss, O.; Boulouchos, K. Assessing the need for flexibility technologies in decarbonized power systems: A new model applied to Central Europe. Appl. Energy 2021, 282, 116050.
100) Mahajan, D.; Tan, K.; Venkatesh, T.; Kileti, P.; Clayton, C.R. Hydrogen Blending in Gas Pipeline Networks—A Review. Energies 2022, 15, 3582.
101) Mastropasqua, L.; Pegorin, A.; Campanari, S. Low fuel utilisation solid oxide fuel cell system for CO2-free hydrogen production in oil refineries. J. Power Sources 2020, 448, 227461.
102) Mayer, T.; Semmel, M.; Morales, M.A.G.; Schmidt, K.M.; Bauer, A.; Wind, J. Techno-economic evaluation of hydrogen refueling stations with liquid or gaseous stored hydrogen. Int. J. Hydrogen Energy 2019, 44, 25809–25833.
103) Mesa-Jiménez, J.J.; Tzianoumis, A.L.; Stokes, L.; Yang, Q.; Livina, V.N. Long-term wind and solar energy generation forecasts, and optimisation of Power Purchase Agreements. Energy Rep. 2023, 9, 292–302.
104) Mikovits, C.; Wetterlund, E.; Wehrle, S.; Baumgartner, J.; Schmidt, J. Stronger together: Multi-annual variability of hydrogen production supported by wind power in Sweden. Appl. Energy 2021, 282, 116082.
105) Ministry of Environment and Energy. Integrated National Energy and Climate Plan for the Republic of Croatia for the Period from 2021 to 2030. 2019. Available online: https://mingor.gov.hr/ (accessed on 14 April 2024).
106) Moradpoor, I.; Syri, S.; Santasalo-Aarnio, A. Green hydrogen production for oil refining—Finnish case. Renew. Sustain. Energy Rev. 2023, 175, 113159.
107) Morales-España, G.; Nycander, E.; Sijm, J. Reducing CO2 emissions by curtailing renewables: Examples from optimal power system operation. Energy Econ. 2021, 99, 105277.
108) Mousavi, M.; Alvarez, M. A contract-based trading of power flexibility between a variable renewable energy producer and an electricity retailer. Sustain. Energy Grids Netw. 2023, 34, 101067.
109) Muñoz Díaz, M.T.; Chávez Oróstica, H.; Guajardo, J. Economic Analysis: Green Hydrogen Production Systems. Processes 2023, 11, 1390.

110) National Grid (2022) “The hydrogen colour spectrum”, Available online: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum, (accessed on 12 January 2022).
111) Navas-Anguita Z. et al. (2020) “Prospective techno-economic and environmental assessment of a national hydrogen production mix for road transport”, Applied Energy, 259
112) Nazir S.M. et al. (2021) “Pathways to low-cost clean hydrogen production with gas switching reforming”, International Journal of Hydrogen Energy, 46(38), pp. 20142-20158
113) Nikolaidis, P.; Poullikkas, A. A comparative overview of hydrogen production processes. Renew. Sustain. Energy Rev. 2017, 67, 597–611.
114) Noussan, M.; Raimondi, P.P.; Scita, R.; Hafner, M. The Role of Green and Blue Hydrogen in the Energy Transition—A Technological and Geopolitical Perspective. Sustainability 2020, 13, 298.
115) Ogden, J.M. (1999) “Prospects for building a hydrogen energy infrastructure”, Annual Review of Energy and the Environment, vol. 24, pp. 227–279
116) Parr, M.; Minett, S. What Is the Real Cost of Green Hydrogen? Euractiv. 2020. Available online: https://www.euractiv.com/section/energy/opinion/what-is-the-real-cost-of-green-hydrogen/ (accessed on 23 February 2022).
117) Pellegrini, M.; Guzzini, A.; Saccani, C. A preliminary assessment of the potential of low percentage green hydrogen blending in the Italian Natural Gas Network. Energies 2020, 13, 5570.
118) Perpinan, J.; Bailera, M.; Pena, B.; Romeo, L.M.; Eveloy, V. Technical and economic assessment of iron and steelmaking decarbonization via power to gas and amine scrubbing. Energy 2023, 276, 127616.
119) Pethaiah, S.S. et al. (2020) “Methanol Electrolysis for Hydrogen Production Using Polymer Electrolyte Membrane: A Mini-Review”, Energies, 13(5879)
120) Pinomaa, M. Long-Term Wind Power Purchase Agreements Are the Foundation of Wind Farm Investments. Castren & Snellman. 2020. Available online: https://www.castren.fi/long-term-wind-power-purchase-agreements-are-the-foundation-of-wind-farm-investments/ (accessed on 12 July 2024).
121) Pivac, I.; Šimunović, J.; Barbir, F.; Nižetić, S. Reduction of greenhouse gases emissions by use of hydrogen produced in a refinery by water electrolysis. Energy 2024, 296, 131157.
122) Plinacro. Ten-Year Plan for the Development of the Gas Transportation System of the Republic of Croatia 2021–2030; Ministry of Economy and Sustainable Development of the Republic of Croatia: Zagreb, Croatia, 2022.

123) Qiu, Y.; Zhou, S.; Chen, J.; Wu, Z.; Hong, Q. Hydrogen-Enriched Compressed Natural Gas Network Simulation for Consuming Green Hydrogen Considering the Hydrogen Diffusion Process. Processes 2022, 10, 1757.

124) Qolipour, M., Mostafaeipour, A., Tousi, O.M. (2017) “Techno-economic feasibility of a photovoltaic-wind power plant construction for electric and hydrogen production: A case study”, Renewable and Sustainable Energy Reviews, vol.78, pp. 113-123

125) Ramirez, K.; Weiss, T.; Kirk, T.; Gamage, C. Hydrogen Reality Check: Distilling Green Hydrogen’s Consumption. 2023. Available online: https://rmi.org/hydrogen-reality-check-distilling-green-hydrogens-water-consumption/ (accessed on 15 July 2024).

126) Rego de Vasconcelos, B.; Lavoie, J.M. Recent Advances in Power-to-X Technology for the Production of Fuels and Chemicals. Front. Chem. 2019, 7, 392.

127) Rivarolo, M.; Riveros-Godoy, G.; Magistri, L.; Massardo, A.F. Clean Hydrogen and Ammonia Synthesis in Paraguay from the Itaipu 14 GW Hydroelectric Plant. ChemEngineering 2019, 3, 87.

128) Romeo, L.M.; Cavana, M.; Bailera, M.; Leone, P.; Peña, B.; Lisbona, P. Non-stoichiometric methanation as strategy to overcome the limitations of green hydrogen injection into the natural gas grid. Appl. Energy 2022, 309, 118462.

129) Ruhnau, O. How flexible electricity demand stabilizes wind and solar market values: The case of hydrogen electrolyzers. Appl. Energy 2022, 307, 118194.

130) Serrano-Arévalo, T.I.; Tovar-Facio, J.; Ponce-Ortega, J.M. Optimal Incorporation of Intermittent Renewable Energy Storage Units and Green Hydrogen Production in the Electrical Sector. Energies 2023, 16, 2609.

131) Siyal S.H. (2019) “Techno-economic assessment of wind energy for renewable hydrogen production in Sweden”, KTH Royal Institute of Technology, Industrial Engineering and Management, Sweden

132) Walker, S. et al. (2016) “Economic analysis with respect to Power-to-Gas energy storage with consideration of various market mechanisms”, International Journal of Hydrogen Energy, 41(19), pp. 7754–7765

133) Xiong, B.; Predel, J.; del Granado, P.C.; Egging-Bratseth, R. Spatial flexibility in redispatch: Supporting low carbon energy systems with Power-to-gas. Appl. Energy 2020, 283, 116201.

134) Yu, M.; Wang, K.; Vredenburg, H. Insights into low-carbon hydrogen production methods: Green, blue and aqua hydrogen. Int. J. Hydrogen Energy 2021, 46, 21261–21273.

135) Zapantis, A.; Zhang, T. Replacing 10% of NSW Natural Gas Supply with Clean Hydrogen: Comparison of Hydrogen Production Options; Global CCS Institute: Melbourne, Australia, 2020.

136) Zhang, J. et al. (2022) “Potential role of natural gas infrastructure in China to supply low-carbon gases during 2020–2050”, Applied Energy, 306

LIST OF FIGURES

LIST OF TABLES