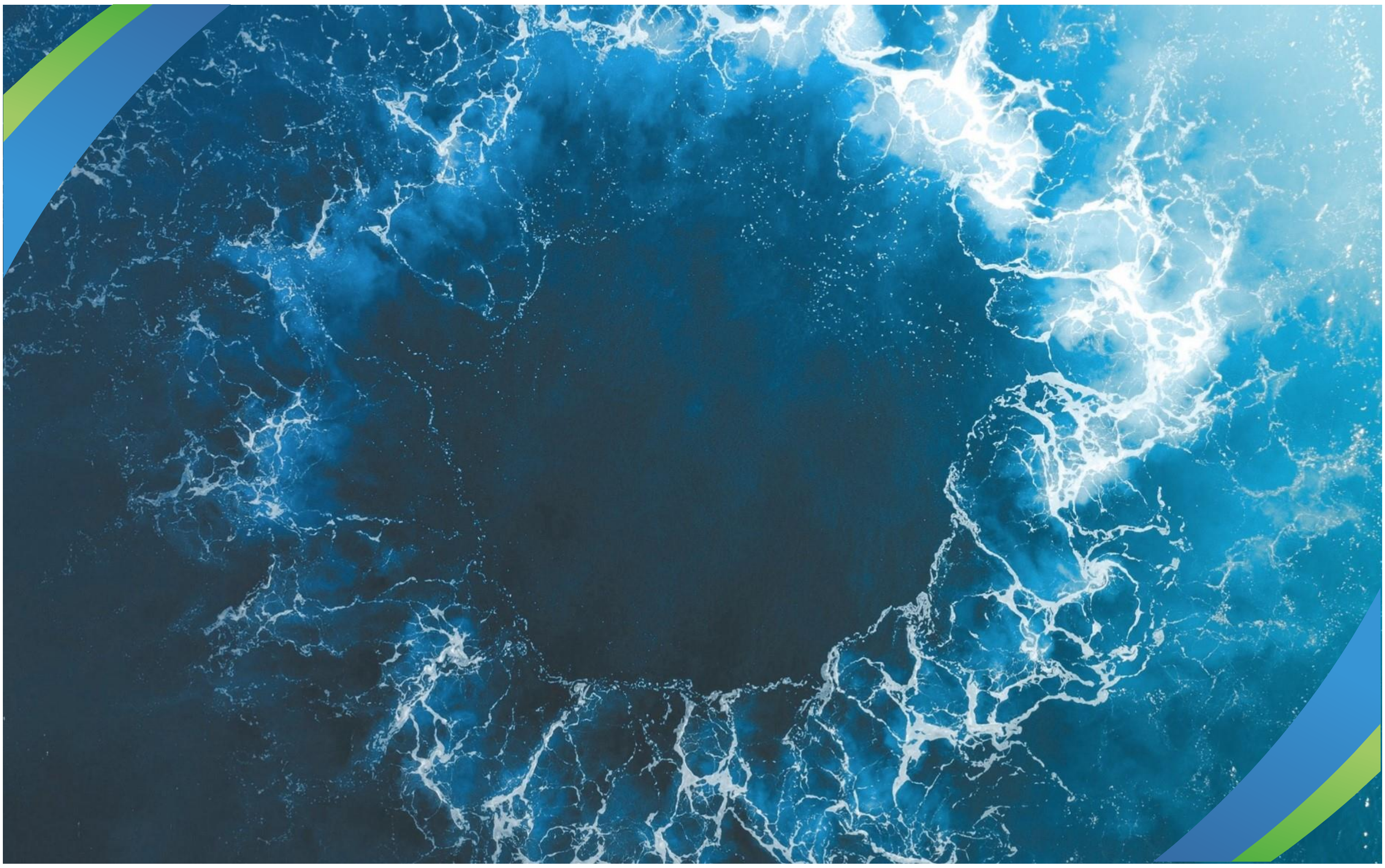
Trans4ReaL



Challenges of the Living Labs of the Energy Transition in the Context of Hydrogen

Discussion Paper from the Transfer Research of the Living Labours of the Energy Transition

Imprint

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1 Introduction

The Trans4ReaL project consortium consists of the Forschungsstelle für Energiewirtschaft e.V., DECHEMA e.V., the Zentrum für BrennstoffzellenTechnik gGmbH, Agora Energiewende, the Stiftung Umweltenergierecht, Ruhr-Universität Bochum and the Hochschule für Politik at TU München. As part of the Transfer Research Hydrogen project, it closely and trustfully accompanies the living labs of the energy transition with a focus on hydrogen and sector coupling, thereby gaining insights into some of the most important implementation projects for the market ramp-up of hydrogen in Germany. In order to classify the insights from the living labs, the consortium also seeks regular exchange with other players from industry and science. The project is supported by the German Energy Agency (dena) in the preparation of external communication and the organization of specialist events. This creates a comprehensive understanding of the status, development and current challenges for implementation projects in the market ramp-up of hydrogen.

In 2023, many important decisions were made in the context of hydrogen. At the regulatory level, one of the most important steps was the adoption of the Delegated Act on Article 27(3) of the second version of the Renewable Energy Directive II (RED II), which sets out the electricity purchase criteria for the production of renewable hydrogen. In the living labs, it was primarily investment decisions that received the most attention. For example, the living lab Energiepark Bad Lauchstädt made a positive investment decision and began construction of a 50 MW wind farm and a 30 MW electrolysis plant, among other things[1]. However, the negative investment decision on the 30 MW electrolysis plant at the WESTKÜSTE100 living lab attracted much more public attention[2]. Even though it was known that the economic viability of electrolyzers poses major challenges for companies, many experts were still surprised that such a pioneering project was canceled. This is particularly true in light of the fact that the two living labs mentioned appear very similar at first glance.

The challenges of hydrogen projects in general and electrolysis projects in particular therefore appear to be more differentiated and cannot generally be transferred from one project to another. The purpose of this paper is to present and explain these challenges. In doing so, the authors rely on the findings that have been gathered during the monitoring of implementation projects. An evaluation and weighting of the individual aspects is not carried out, but is necessary for a final evaluation of an investment. This depends on the individual case and can only be assessed by the actors involved.

The following paper will first discuss the living labs of the energy transition and their technologies. The living labs are representative of large implementation projects in the context of hydrogen. Chapter 3 then describes the current challenges of the projects. These are divided into the sections on business models, cost structures and regulation. Finally, chapter 4 summarizes the most important points and provides an outlook. In addition to the chapters written by the authors, actors from the living labs give their assessment of the challenges mentioned in the appendix, thus providing an insight into the perspective of those implementing the hydrogen ramp-up.

[1] Energiepark Bad Lauchstädt geht in die Umsetzung
[2] Entscheidung des Joint Ventures: Elektrolyseur im WESTKÜSTE100 Reallabor wird nicht gebaut

2 Location and Structure of the Living Labs

The living labs of the energy transition are implementation projects funded by the Federal Ministry for Economic Affairs and Climate Protection of Germany (BMWK), the first of which were launched in 2020. These are projects designed to accompany the market entry and ramp-up of technologies by implementing them on an industrial scale and under real conditions. In addition to living labs that deal with the topic of "energy-optimized districts", there are other living labs that deal with the topics of hydrogen and sector coupling and to which the topics described here relate.

The living labs are project consortia consisting of several companies and research institutes, each of which invest their own funds to implement the project ideas and also receive public funding. While quite extensive public sector funding is often available for the research and testing of new technologies in the areas of basic and applied research, this funding often decreases in the subsequent area of industrial demonstration in comparison to the increasing funding requirements with the size of the plant. However, as long as there is no commercially successful application in the area of industrial demonstration, the investments from the private sector are still manageable, especially for capital-intensive technologies. In this situation, which is also referred to as the "valley of the death of innovation", the living labs of the energy transition come into play as a public-private cooperation format. The transfer of knowledge and networking between these two areas is another essential component of the concept. These interrelationships are shown schematically in Figure 1.

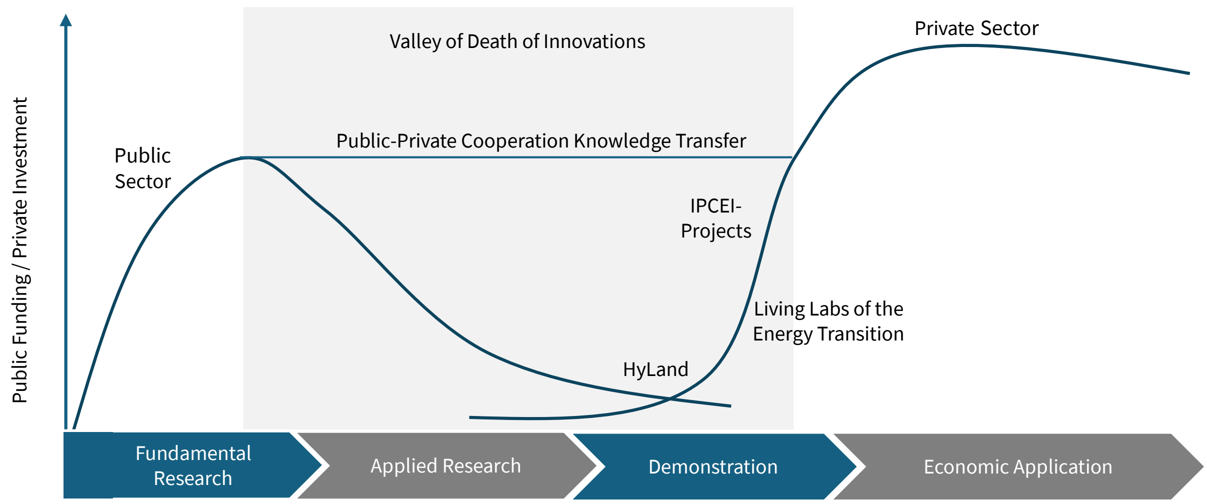

Figure 1: The living labs of the energy transition as a bridge between applied research and commercial application

By demonstrating important hydrogen technologies along the entire process and value chain on an industrial scale and under real conditions, the living labs are intended to ensure Germany's technical connectivity and contribute to the ramp-up of the hydrogen economy. Several new processes and business models along the hydrogen process chain are being tested simultaneously in many living labs. Figure 2 below provides an overview of these applications and their location in the individual living labs.

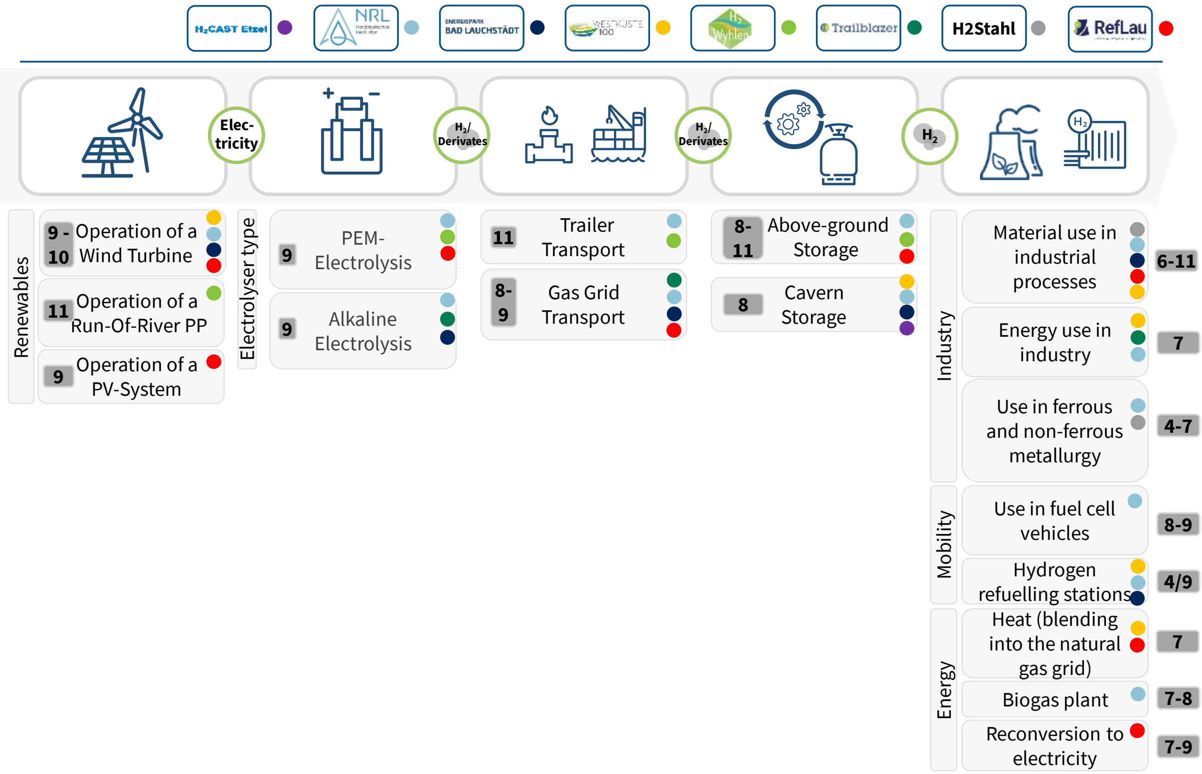

Figure 2: Overview of tested process chains and applications in the living labs as well as the respective Technology Readiness Level (TRL)[3]

With the project start of a living lab, which already took place in 2020 for the first living labs, the planning phase begins as the first of the project phases shown schematically in Figure 3. The aim here is to ensure the technical and economic feasibility of the project so that an investment decision can then be made. Economic feasibility in particular represents a hurdle for a positive investment decision due to various challenges with regard to business model development, cost structures and the development of the regulatory framework.

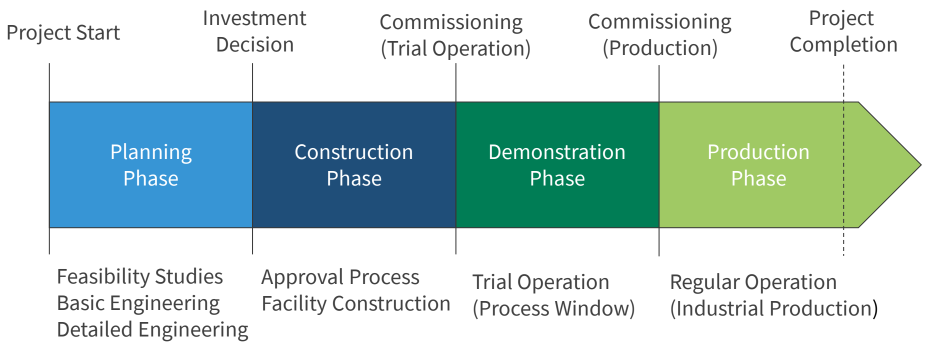

Figure 3: Schematic representation of the project phases of the living labs

In the following, we will now look at the points that caused the planning phase up to the investment decision to take longer than initially anticipated in many of the projects. The focus here is on the electrolysis plants planned in the living labs.

[3] IEA: ETP Clean Energy Technology Guide

3 Challenges for the Living Labs

The living labs that want to realise electrolysis plants in their projects face various challenges that have been subject to strong dynamics over the last few years up to the present day. In the following chapters, these are structured into the aspects of business models, cost structures and regulatory.

3.1 Business Models

In a viable business model, the refinancing of the electrolysis project must be ensured. Factors influencing this include the purchase of green electricity, securing transport from the electrolyser to the point of use and a source of revenue that is as secure and profitable as possible. For the purchaser of the hydrogen as a stakeholder in the chain, the security of supply is paramount. Developers of electrolysis projects face numerous challenges in these contexts when designing and implementing them.

Lack of willingness to pay for green hydrogen makes economic operation difficult

Green hydrogen can be used for decarbonisation in many applications, such as in the chemical and steel industries or in mobility and heat generation. There is general interest in the use of green hydrogen, particularly in the context of avoiding greenhouse gas emissions. In all applications, however, green hydrogen competes with established technologies that are available at low cost due to the externalisation of costs, economies of scale already achieved and high technological maturity, as well as with alternative decarbonisation technologies such as battery-electric vehicles.

Potential users therefore face multiple burdens when switching to green hydrogen: On the one hand, the investment costs that are incurred when switching from the previous technology to hydrogen have to be met. Secondly, the additional costs for the procurement of green hydrogen must be included in the running costs. In addition, the end user expects a secure supply when needed.

There are financial incentives on the utilisation side: the greenhouse gas quota (GHG quota) and emissions trading offer additional sources of revenue or increase the costs of fossil alternatives. However, the respective certificate or quota prices are currently not at a sufficiently high level. They are also subject to uncertainties in the form of fluctuations that cannot currently be hedged for GHG quotas. The prices of GHG quota certificates have fallen from 430 €/t CO_2 to 130 €/t CO_2 in 2023[4], which means a drop in potential revenue from 8.6 €/kg H_2 to 2.6 €/kg H_2[5]. In emissions trading, on the other hand, prices are expected to rise, but these are currently not sufficient to finance a corresponding business model: Current prices for ETS certificates are still below those of the fallen GHG quota prices at around 85 €/t CO_2. The potential revenue from this is around 1.7 €/kg H_2, meaning that there is only an effective financial incentive in the mobility sector, and even then only to a limited extent.

The framework conditions for the GHG quota are set out in the 37th Ordinance on the Implementation of the Federal Immission Control Act (37th BImSchV), which is currently being amended. Changes to the basis for calculating the GHG reduction quantity and, as a result, an increase in the expected revenue were also recently discussed here.

[4] Klima-Quote.de: [Markteinblicke für THG-Quoten]
[5] Calculation according to the version of the 37th BImSchV still valid in 2023

There are also other, often more cost-effective alternatives to fossil technology for applications, particularly in the heating and mobility sector. Finally, it is only possible to pass on additional costs to the end customer in a few market segments. With high hydrogen prices, this makes the switch to green hydrogen economically unattractive for potential users.

This unwillingness to pay in turn has an impact on potential manufacturers and infrastructure operators of green hydrogen. Electrolyser operators have difficulties concluding purchase agreements that provide for a cost-covering hydrogen price in the medium term. At the same time, the transport and storage of hydrogen often has to be co-financed. In the expectation of long-term cost reductions or revenue increases, a hydrogen project can still be worthwhile, but it harbours clear uncertainties. If, on the other hand, long-term refinancing is not foreseeable, this stands in the way of realisation. For the investor of plants as a "First Mover", this results in an enormous entrepreneurial risk, which is exacerbated by the developing regulatory framework.

Lack of infrastructure leads to high complexity

Hydrogen is often not utilised at the same location as production. The gas must therefore be transported. Pipelines are the only realistic option for large quantities of hydrogen[6]. Apart from geographically limited, privately operated networks in the Ruhr region (Ruhrgebiet), the Middle German Chemical Triangle (Mitteldeutsches Chemiedreieck) and in Schleswig-Holstein, there is currently no pipeline infrastructure for transporting hydrogen[7,8].

When realising a hydrogen project, this means additional expenditure to enable the transport of hydrogen. Possible options include the construction of a dedicated pipeline or the conversion of former natural gas pipelines, transport by lorry or - if a rail network is available - by train and, to a limited extent, feeding into the natural gas grid. The cost estimates for transporting hydrogen by lorry are around 1-2 €/kg[6], which would be a relevant proportion at the current index price of 7.2 €/kg[9].

Furthermore, production and consumption do not always coincide. Hydrogen storage is therefore also necessary to guarantee a constant supply. Pressurised gas tanks can be used for smaller storage volumes, while cavern storage facilities can be considered for large quantities. The latter require considerable planning, authorisation and development work. It can therefore take up to 15 years between the start of a project and the commissioning of a new cavern storage facility.

Additional technical and business expertise is required for hydrogen transport and storage in order to guarantee the commissioning and operation of hydrogen transport. It therefore usually makes sense to integrate additional partners into the projects.

High and difficult to assess risks increase financing costs

Electrolysis projects are affected by numerous risks. In addition to the risk of default by anchor customers or unfavourable developments in the prospective hydrogen market, these also include the risk of unforeseen failures of as yet untested technology components and the unpredictability of political developments. In extreme cases, there is a risk that the business model will fail and thus become insolvent.

This makes it more difficult to raise capital. Banks and other lenders expect higher returns to compensate for the high risk of default. This increases the financing costs, which must be factored into the business model.

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[6] Hydrogen Council: Hydrogen Insights 2021
[7] TÜV NORD: Wasserstoff-Pipelines und Wasserstoffnetze
[8] Chemie Technik: Wie sieht das neue Wasserstoffnetz für Deutschland aus?
[9] EEX Hydrix, retrieved on 17.01.2024

Financiers face a further challenge that makes the financing of green hydrogen projects unattractive. Before financing, they must assess the risk of insolvency in order to determine an appropriate return and to manage the risk to which they themselves are exposed. However, as green hydrogen is largely new both technologically and economically, there is a lack of data to adequately assess the above risks. This reduces the supply of capital for green hydrogen, which also increases the cost of financing for green hydrogen projects.

It cannot be ruled out that the ownership structure of the partners in a project consortium plays a relevant role in the context of financing risks. This makes it easier for larger, financially strong companies to take risks to the extent currently required or to offer potential investors collateral.

Individual contracts lead to additional administrative work and delayed project starts

For the construction and operation of an electrolyser as part of a viable business model, the supply of green electricity, the transport and storage of the hydrogen and, ideally, the long-term purchase of the hydrogen must be contractually guaranteed. In addition, purchase agreements must be concluded for the plants.

With regard to purchase agreements for capital-intensive electrolysis plants, there is a lack of experience, particularly in the context of guarantees and warranties. The plants in the sizes in which they are being pursued in the real laboratories either hardly exist or do not yet exist in Germany. As a result, neither manufacturers nor buyers want to assume the warranty in the event of premature failure. The purchase agreements for the hydrogen to be produced are also complex. For example, in addition to quantities and prices, a contract for the purchase of hydrogen must also describe delivery modalities, obligations and guarantees in the event of delivery failure by both parties. Currently, the lack of hydrogen transport infrastructure also limits the transferability of contracts, meaning that an individual solution must be found for each customer.

With regard to the lack of experience of all parties in negotiating such contracts, consulting by external service providers is an option. While there is already a limited range of green power purchase agreements (PPAs), hydrogen transport and purchase are new territory even for specialised service providers. In principle, the contractual structures of public natural gas supply can provide a basis. However, the lack of infrastructure and the regulatory framework, which has yet to be finalised, limit transferability. As a result, contract negotiations can be complex and lengthy. If the financial situation or the priorities of the partners change in the course of the contract negotiations, this can make it more difficult to reach an agreement. Due to the interdependence of the process steps, the failure of an individual contractual relationship often means the failure of the entire project.

Lack of green electricity supply prevents projects in the conception phase

The availability of renewable electricity is an essential prerequisite for the production of green hydrogen. EU regulations - one of the prerequisites for eligibility for the GHG quota - stipulate that only fully renewable electricity can be used for production if the hydrogen is to be counted towards the targets. As a rule, this must either come from a renewable energy plant (RE plant) directly connected to the electrolyser or be purchased from a RE plant operator via a PPA. From 2028, the electricity-producing plants must not have been commissioned more than three years before the electrolyser is commissioned.

The use of a directly connected plant requires the availability of appropriate land in the vicinity of the electrolyser. This is one of the reasons why PPAs are the standard for many projects. However, the supply of qualified PPAs is limited. In view of the high electricity prices in Germany, it is attractive for many renewable energy plant operators to sell their electricity on the electricity market. At the same time, there is also demand for green PPAs from other industries. Furthermore, there is currently no transparent market for PPAs.

As a result, there is a supply market in which prices can be determined primarily by the suppliers of green electricity. This makes it difficult for many project developers of electrolysers to secure PPAs. This is particularly true if they cannot draw on experience in electricity trading from other business areas.

One alternative is the joint project development of a renewable energy plant and electrolysis. This ensures the availability of green electricity, but requires additional expertise in the project consortium and ties the success of the electrolysis project to the approvability and success of the renewable energy project.

3.2 Cost Structures

There are challenges on the cost side, as the production costs for green hydrogen are high despite subsidies. The reasons for this lie in both the investment costs and the operating costs.

For an electrolysis business model to work, the trading price must be higher than the supply costs

The possible market ramp-up and further penetration of green hydrogen depends on how the prices for green hydrogen develop relative to the possible alternatives, e.g. grey hydrogen or coal. From the perspective of a green hydrogen producer, in addition to the market on which pricing takes place, the question of the costs at which green hydrogen can be provided is relevant. A possible business model only arises when the production costs, taking into account other sources of revenue such as the GHG quota, are below the prices to be achieved for the producer.

There is currently no liquid market for green hydrogen, meaning a market in which green hydrogen can be made available everywhere in sufficient quantities and at transparent prices by a large number of competing producers. Pricing is therefore a free negotiation between the producer and the customer. In addition to the actual price, aspects such as security of supply, quality and other conditions also play an important role in negotiations, meaning that it is not possible to draw conclusions about pricing in the event of a liquid market from individual contracts, which are generally confidential.

Irrespective of pricing, however, the producer can determine his production costs and use them to try to position himself in the market. As part of a techno-economic analysis, the production costs of green hydrogen, the total expenditures (TOTEX) allocated to the product quantity, can be described. The total costs can in turn be broken down into a part that results from the expected return on invested capital (capital expenditures, CAPEX) and a part that can be described as the costs of ongoing operation (operational expenditures, OPEX).

Capital costs remain a relevant component of production costs - especially after the development of recent years

CAPEX essentially represents the investment costs for the construction of the production plant. However, other costs such as planning and authorisation costs, connection costs to infrastructure and contract costs can also be included. In the case of electrolysers, the investment costs for the electrolyser and its peripheral equipment represent by far the largest part of the CAPEX and the following discussion will refer to these for the sake of simplicity.

As already described, an investor expects an additional profit over the period of an investment in addition to recovering the capital invested and compensating for inflation. The investment costs are therefore assessed taking into account the capital employed, the assumed accounting life of the investment and a discount rate that includes the cost of capital and inflation, as well as an assessment of the risk of the investment coupled with the investor's profit expectations. The latter is always in global competition with other investment opportunities. The individual assumptions regarding the parameters are highly dependent on each individual case and it is difficult to derive universally valid statements. Typical assumptions from the chemical industry[10] are 15-20 years for the accounting life of the plant with a final residual value of 0 € and a discount rate of 8 %. This means that an investor invests his capital in the construction of the plant. He expects an interest rate of 8 % on his capital and full repayment over the accounting life. Expected inflation must also be taken into account. This expectation and the resulting value is distributed over the production of the accounting life. A higher discount rate and a lower amortisation period lead to a higher CAPEX value in the product costs, while a lower discount rate and a longer amortisation period result in a lower CAPEX value and thus a lower cost burden on the product. The public subsidisation of the investment in strict compliance with the EU state aid guidelines is part of the living lab concept. A total subsidy of up to 15 million euro per company is possible under state aid law. Such support directly reduces the capital requirements of the entire investment and thus reduces CAPEX.

The effect of flexible operation on the degradation of the electrolysers and thus their technical service life is currently still uncertain. Ideally, the technical service life should be equal to or longer than the accounting service life. However, it is becoming apparent that essential parts of the electrolyser (in particular the galvanic cells) must be replaced before the end of the accounting service life of the entire system. This replacement cycle is determined, among other things, by the way the system is operated and can presumably be between 5 and 10 years, depending on the individual constellation. The replacement costs must therefore also be taken into account in the CAPEX.

It should also be noted that the investment costs of the entire system, i.e. the electrolyser and ancillary systems, must be taken into account here. There is much discussion about how a possible cost degression of electrolysers will develop in the future and there are good reasons to assume that mass production of stacks will lead to a significant cost degression. In addition to the actual stack, however, there are many components that are necessary for the industrial production of hydrogen, e.g. power electronics, gas and water management, safety technology, etc., which will not benefit from the same cost degression, as they are either already produced under mass production conditions and therefore only limited degression is to be expected, or they are customised products anyway, such as the costs for the concrete foundation of the plant.

[10] FutureCamp Climate GmbH, DECHEMA e. V.: Roadmap Chemie 2050

The construction price index for chemical plant construction in Figure 1 shows how the various services in plant construction have developed over the past few years. The graph also shows that, compared to a relatively constant trend before 2017, prices for chemical plants have risen significantly since then. This is particularly relevant for the living labs of the energy transition, as these were designed for the tender in 2019 and the assumptions made at the time have resulted in a cost increase of around 20 % by 2023. The increased demand for these components, supply bottlenecks due to the coronavirus crisis and high capacity utilisation in plant construction mean that further cost increases can be expected even after 2023.

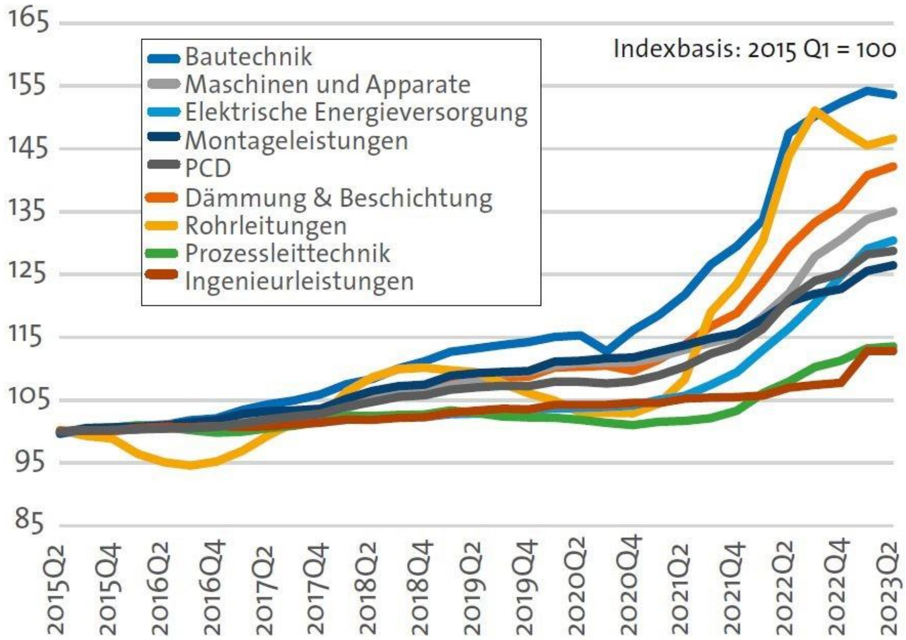

Figure 1: Development of costs in chemical plant construction relative to 2015[11]

As the costs for peripherals, auxiliary equipment and balance-of-plant are significant, it generally makes sense to implement electrolysers in an existing industrial environment (so-called "brownfield" plants) in order to synergistically utilise any existing plants, infrastructure and services. This can reduce this cost component. In addition, an existing industrial environment provides better conditions for the utilisation and thus valorisation of the by-products waste heat in the low-temperature range and oxygen. In contrast, greenfield plants are at the upper end of these costs, as all the necessary equipment, infrastructure and services have to be provided additionally. In this case, it will generally not be possible to utilise the by-products, or only at increased expense.

Figure 2 shows reported investment costs for projected systems. These are not necessarily the costs incurred in the livings labs of the energy transition. The costs shown are significantly higher than existing forecasts. Nevertheless, strong scaling effects can already be derived here. As a result, the costs for electrolytically produced hydrogen will remain significantly higher than expected in the forecasts for the time being. This discrepancy represents a considerable risk for the ramp-up of a hydrogen economy, as this uncertainty generally leads to reluctance to invest or must be compensated for by a correspondingly higher profit expectation for investors.

[11] CHEMIE TECHNIK: CT-Preisindex für Chemieanlagen PCD Q2 2023

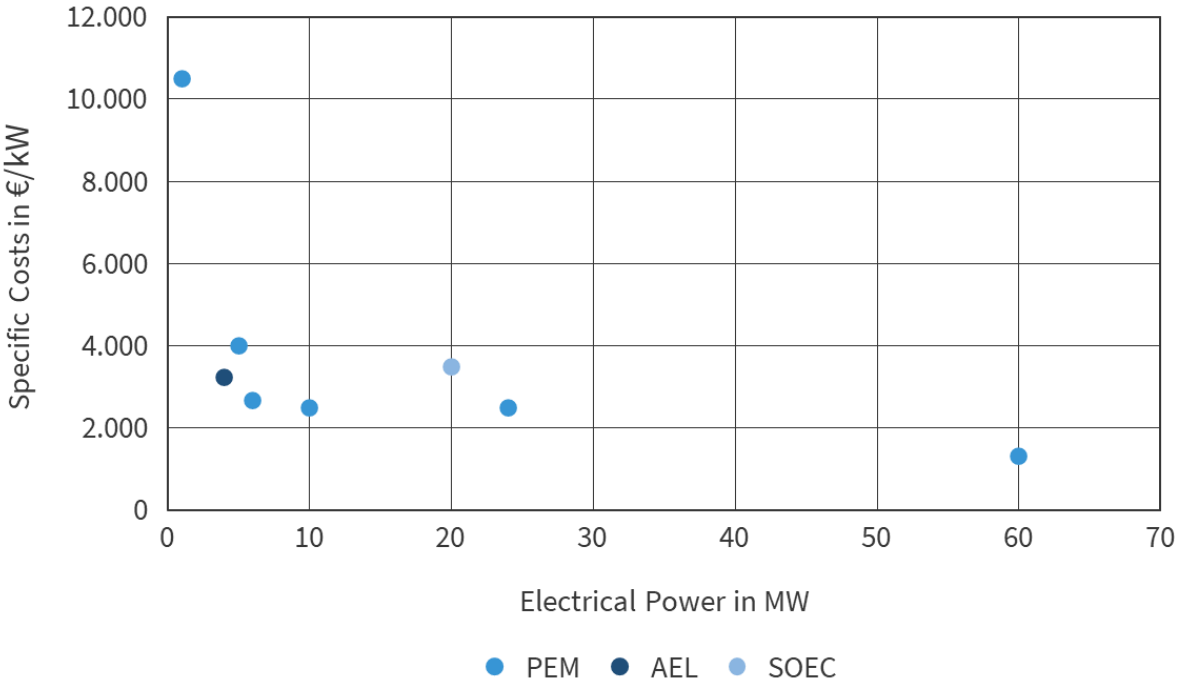

Figure 2: Investment costs for electrolysers; projects do not necessarily and exclusively correspond to the living labs of the energy transition

Another important factor for the allocation of CAPEX costs is plant utilisation. An industrial plant is designed for a certain maximum annual production. If this plant were operated at full capacity all year round without interruption (8760 h/a), it would produce this amount of product. Actual production is almost always lower. This is due, among other things, to temporary shutdowns for maintenance and repair or underutilised production due to a lack of demand or availability of green electricity.

In the case of green hydrogen as defined by EU regulations, there are also the criteria for electricity procurement that must be met by the Delegated Act (DA) for RED II and now also RED III. These include the aforementioned additionality, i.e. the new installation of the renewable energy system, as well as the local and temporal correlation of the electricity purchase. In practice, electricity procurement must be secured through PPAs between the renewable electricity generation provider and the electrolysis operator. For example, a maximum output, a total amount of energy, a number of hours, the duration of the contract and a price (fixed-price PPA) or a price reference, e.g. to the exchange electricity price (variable-price PPA) are agreed.

Due to the legal constraints, continuous operation of the electrolyser at full load to produce green hydrogen is therefore not possible. The term "full load hours" describes the nominal number of hours that the plant would have to be operated at full production capacity in order to produce the corresponding amount of product. It does not contain any information about the distribution of production over time. For comparison: typical full-load hours of fluctuating renewable electricity generation in Germany are around 1000 h/a for photovoltaics, 2000 h/a for onshore wind and 3500-4000 h/a for offshore wind. The PPA provider will therefore generally bundle a portfolio of renewable electricity generation providers in order to guarantee the contractually agreed supply. With regard to the possible bundling of PPAs and the permitted role of aggregators, there is still uncertainty in the interpretation of the DA of RED II.

Since the total amount of product produced is proportional to the plant utilization over the period under consideration, the CAPEX contribution to the production costs of the product is a function of the full load hours, assuming a constant electricity price (see Figure 3). The CAPEX contribution to the total production costs for production at 5500 full-load hours is ≈160 %, around 60 % higher than it would be the case if the plant was theoretically operating at full capacity. Put simply, the system is only used around 2/3 of the time, but requires the same investment as if it could produce 1/3 more at full load.

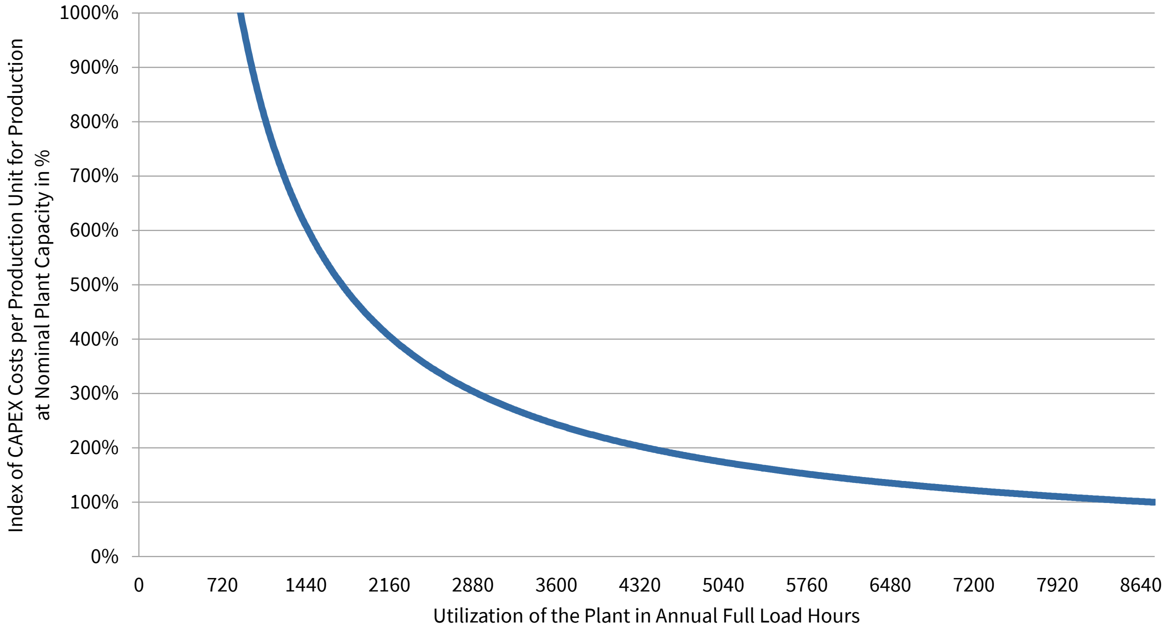

Figure 3: Dependence of the CAPEX contribution on the full load hours at a constant electricity price (reference value full load or 8760 hours per year)

Operating costs are the biggest driver of production costs for domestic hydrogen production

In addition to CAPEX, operating costs - also known as OPEX - are incurred when operating an electrolyzer. These include electricity costs, personnel costs, maintenance and water costs. For electrolysers, their electricity procurement costs make up the largest share of OPEX.

The largest electricity consumer in the electrolysis plant is the galvanic process (splitting of water) in the stack. In addition, in pressureless electrolysis systems there is a non-negligible demand for electricity in the compression of the product gases. Furthermore, the electricity consumption required to maintain the controlled and safe operation of the system and for ancillary consumption (compressed air, cooling water, etc.) must also be taken into account.

Since the Russian war of aggression against Ukraine, electricity prices and market volatility have risen sharply. The costs for the power supply therefore represent the largest cost item, also due to the current electricity prices. From the plant operator's point of view, a long-term fixed-price PPA with a correspondingly low price would be preferable. As the living labs report, fixed-price PPAs are currently only available at rather unfavorable conditions, as the market prices of the PPAs are derived from current exchange electricity prices and future exchange electricity price expectations, among other things, and the demand for PPAs exceeds the scarce supply. Electrolysis operators are in direct competition with other consumers of PPAs for renewable energy, such as data centers, some of which may have a higher willingness to pay. According to Art. 5 lit. b)

DA, subsidized plants for the generation of renewable electricity (e.g. under the Renewable Energy Sources Act, Erneuerbare-Energien-Gesetz, EEG) are generally not permitted for PPAs. However, Art. 11 DA provides for an exception to this until January 1, 2038, provided that the plant for the production of green hydrogen is commissioned before January 1, 2028. In view of the uncertainties in the electricity market, electricity supply contracts are currently often variable, that is, linked to the average exchange electricity price. This can lead to uncertainties as you are exposed to potential price fluctuations on the electricity market.

In addition, users oversize PPAs in order to achieve a higher number of full-load hours and thus a lower CAPEX share of the electrolyser (see above). This means that the maximum output of the PPA exceeds the rated output of the electrolyser. The peak electricity that is not required usually occurs at times of high renewable electricity supply. During these times of high electricity supply, the prices on the exchange at which the surplus electricity can be sold are generally low. This effect will be particularly relevant from 2030, as the production of RFNBOs will then require the generation of the renewable energy plant and the consumption of the electrolyser to take place in the same hour. This therefore also affects the operating phase of electrolysers that are currently in operation. If the green hydrogen has to be continuously made available to the customer, this results in additional expenses for the times when no or insufficient renewable energy is available, e.g. through intermediate storage of the hydrogen produced. Cheaper storage options in caverns connected by pipeline will not be available before 2030, which is why more expensive storage methods will have to be used.

In simple terms, the prices on the electricity market are formed using the marginal power plant in the merit order. This means that the price of all traded electricity in an hour is the price that the most expensive power plant needed to cover the electricity load can offer. With the increasing phase-out of lignite and hard coal-fired power plants, combined cycle gas turbine power plants or gas turbines are increasingly becoming the price-setting power plants in this system. This means that the price of gas will initially have a greater influence on the price of electricity. The production of grey (or blue) hydrogen from natural gas requires approximately the same amount of energy as the electrolytic production of green hydrogen. However, the conversion efficiency of natural gas into electricity must be taken into account: Taking into account the conversion efficiency of natural gas in power plants and other state-induced or regulated electricity price components or privileges, there is an average factor of 2.5-3 between the costs of grey and green hydrogen. Green hydrogen is therefore significantly more expensive to produce than grey hydrogen as long as natural gas prices strongly define the price of electricity.

One way to reduce the procurement costs of renewable electricity is to build up and utilise your own renewable electricity generation as an electrolyser operator. However, the use of renewable electricity in electrolysis and the sale or use of hydrogen competes with the opportunity to sell the electricity generated on the market, which - for the reasons mentioned above - potentially offers a higher margin for a company than the production of hydrogen. With the company's own plants, electricity can therefore be generated at a cost price below market value and additional electricity price components can be largely avoided. Operating your own plant generally also reduces the number of available full-load hours, as these are only fed from a few plants with a high correlation of generation and cannot be smoothed to the same extent as would be possible with external procurement from a large number of generation plants.

Another way to reduce the electricity procurement costs of an electrolyser is to operate it in a strongly price-dependent manner. This means that the electrolyser is only operated at times of very low electricity prices, which increases the CAPEX share per unit of hydrogen produced - as shown in Figure 3- but can significantly reduce the average electricity purchase price per kWh. Overall, this can lead to more favourable total costs

(TOTEX), but the plant operation must be very dynamic. In addition, an electrolyser can also be used to provide system services. Proof that today's electrolysers on the scale of the living labs are technically capable of this has yet to be provided, which means further uncertainties for project realisation.

If the by-products of water electrolysis can be utilised, the corresponding equivalent value can be credited to the operating costs. The marginal costs of the corresponding alternative can be used as a possible value for simplification. For example, the utilisation of low-temperature waste heat could partially replace the use of a gas boiler or heat pump at the site. This aspect also speaks in favour of installing the system in an industrial or urban environment where, for example, a heating network can absorb and distribute the heat. The utilisation of oxygen, on the other hand, poses a greater challenge.

The TOTEX are allocated to the quantity of products produced during the period under consideration. In the case of proton exchange membrane electrolysis (PEM electrolysis) or alkaline electrolysis, oxygen and heat are produced at a low temperature level of around 70 - 90 °C in addition to the main product hydrogen. If the by-products can be sold, the corresponding costs must be allocated to the products on a weighted pro rata basis. If only the hydrogen can be commercialised, the entire costs must be attributed to it. Therefore, those plants that also provide for the utilisation of by-products can potentially supply hydrogen at more favourable conditions. Figure 4 shows the respective potential cost reduction for an exemplary plant through the use of by-products, through a public CAPEX subsidy of €15 million and the availability of more favourable electricity procurement costs. This shows how strongly OPEX and in particular electricity costs dominate TOTEX.

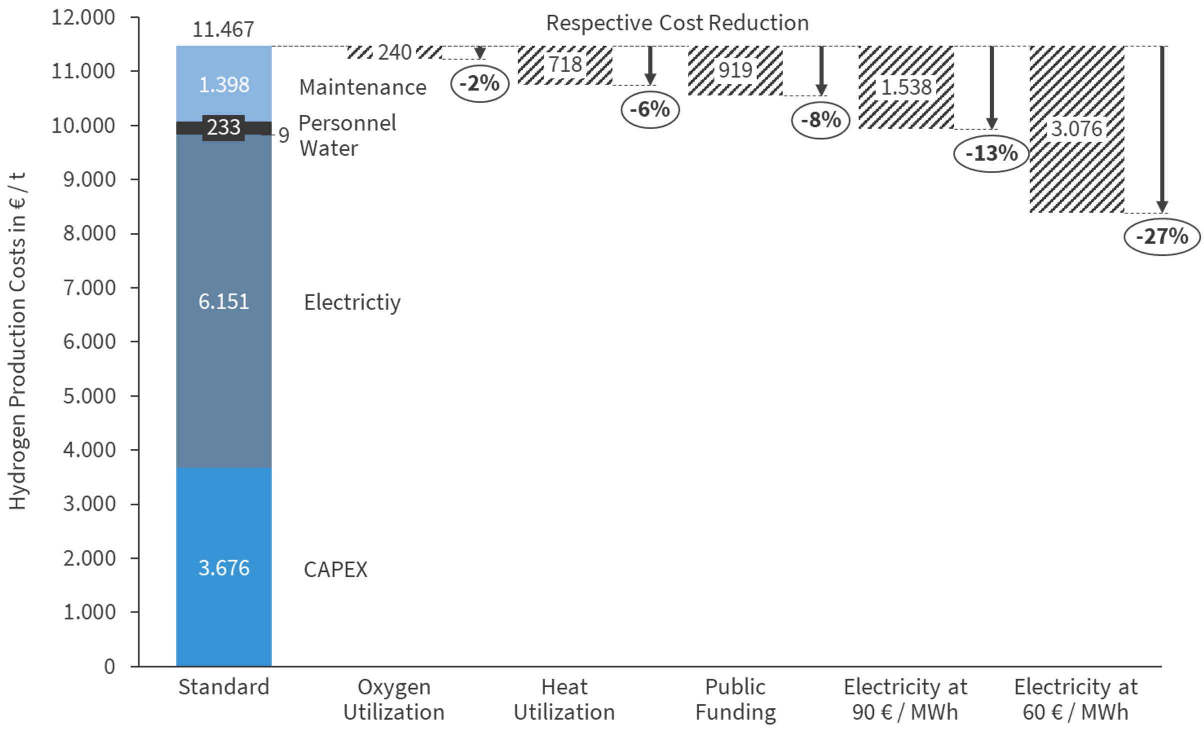

Figure 4: H2 production costs for an example plant with 20 MW; parameters: Efficiency 65 % (based on calorific value), investment costs 3,000 €/kW, discount rate 12 %, amortisation period 20 years, standard electricity costs 120 €/MWh, full load hours 5,500 h/a, fixed OPEX (maintenance) 5 % of CAPEX, water costs 1 €/t, oxygen price 30 €/t, public funding 15 million €

3.3 Regulatory

There are also regulatory challenges that lead to delays and sometimes negative investment decisions for green hydrogen projects - especially living labs.

Late revision of the 37. BImSchV leads to late investment decisions and more expensive projects

Due to the low willingness to pay for green hydrogen (see section 2.1), manufacturers of green hydrogen are currently reliant on financial incentives for economic operation. The regulatory design of such incentive systems has a major effect on the economic viability of green hydrogen projects, so that investment decisions can often only be made with reliable and precise knowledge of the incentives.

The GHG quota is an existing incentive system for the mobility sector. It can be considered as a source of revenue for projects that use hydrogen in refineries or in the mobility sector. As described above, very high revenues can be generated from the GHG quota. It is therefore a central component of the business model of most living labs.

In order for hydrogen to be counted towards the GHG quota, it must fulfil certain criteria. These criteria were only published by the EU Commission as part of the DA for RED III in February 2023 and therefore with a significant delay. The criteria have been valid throughout the EU since July 2023 and will only be implemented in German law as part of the revision of the 37th BImSchV, a version of which has been approved by the cabinet since December 2023. Legal certainty will only be provided once the Bundestag and Bundesrat have given their approval (as of February 2024) and the EU Commission has given its subsequent notification.

In the course of the lengthy process, the investment decisions of many living labs had to be postponed (see Figure 5). This not only means that the production of green hydrogen will start later, but also makes the realisation of the projects more expensive: the high energy prices, especially in 2022, have led to strong inflation. In addition, there are supply difficulties for many of the components and the supply of electrolysis stacks is only increasing slowly. The combination of these factors resulted in significantly higher implementation costs compared to what was calculated for many of the projects in 2020 and 2021.

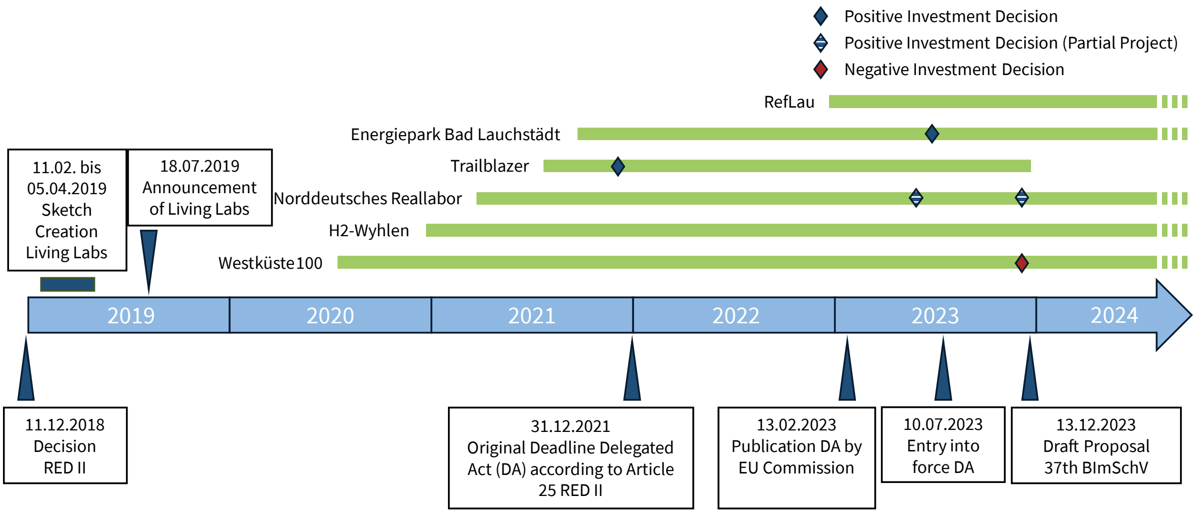

Figure 5: Dates and project durations of the living labs with planned electrolysers as well as the timeline of the necessary regulatory framework for the amendment of the GHG quota; investment decisions are entered if they have been made public

As of February 2024, positive investment decisions had been made in some living labs: Since it was already largely clear when the Hydrogen DA came into force what substantive legal requirements would be placed on green hydrogen - including in national law - it was possible to assess the economic viability here even before the new version of the 37th BImSchV. In some other projects, the final decision has not yet been made. This shows that there is a grey area here. Nevertheless, the more concrete and certain the legal situation is, the easier it is to assess the economic viability of a project.

Pending implementation of RED III and ReFuelEU initiative at national level must create the necessary clarity for investment decisions

With the revision of the Renewable Energy Directive (RED III) and the ReFuelEU Aviation Regulation, two further European legal acts were adopted at the end of 2023 that provide for the increasing use of green hydrogen.

In addition to tightening the requirements for the transport sector, RED III contains a mandatory minimum quota for the industrial sector. In 2030, at least 42 % and in 2035 at least 60 % of the total hydrogen used in industry must be completely renewable. However, a member state can reduce the target for 2030 by 20 % under certain conditions. It is not yet entirely clear what requirements will be placed on green hydrogen in order for it to be counted towards the minimum quota. At present, the criteria of the DA can only be applied to the transport sector due to clear definitions. However, the industry expects the requirements there to be transferred to the industrial sector and can already be legally implemented through minor adjustments to the DA.

The ReFuelEU Aviation Regulation focuses on the aviation sector and stipulates a minimum share of 2 % of Sustainable Aviation Fuels (SAF) from 2025 and a minimum share of 6 % from 2030. SAFs can be produced on the basis of green hydrogen, but there are also other options. However, a minimum proportion of 0.7 % of synthetic aviation fuels must also be met from 2030. Synthetic aviation fuels refers to green hydrogen and derivatives obtained from it within the meaning of RED III (such as synthetic kerosene), whereby the (additional) requirements in the DA for the electricity used for production are probably not applicable here. The minimum shares increase dynamically up to 2050 and a minimum share of 20 % of SAF and at least 5 % of synthetic aviation fuels must be made available from 2035.

While RED III addresses the member states to ensure compliance with the industry quota, the ReFuelEU Aviation Regulation directly regulates obligations for aviation fuel suppliers and aircraft operators (refuelling obligation). As a European regulation, the ReFuelEU Aviation Regulation already applies directly to economic operators and does not necessarily require a further legal act. In contrast, RED III still needs to be transposed into national law, as RED III, as a European directive, does not apply directly to economic operators. Such implementation is still pending. It will also be necessary to answer the question of how the use of green hydrogen in industry can be incentivised in such a way that the target is met. In particular, the introduction of a GHG quota system is also under discussion.

A rapid concretisation of the outstanding legal framework can now help to create legal and investment security. Delays such as with the DA, which only came into force around 1.5 years after the original deadline, should be avoided wherever possible. At present, the minimum quotas provide an assurance of increasing demand. However, as long as there is uncertainty about the exact implementation, the economic evaluation of a project can only be carried out to a limited extent, which exposes investment decisions to additional risk.

Price fluctuations for GHG quota and emission allowances make long-term revenue forecasts difficult

The GHG quota and the EU Emissions Trading System (EU-ETS) offer additional financial incentives for the production of green hydrogen. Depending on the system, the provision of certificates results in additional revenue (GHG quota) or avoided costs due to the reduction in CO_2 emissions (EU-ETS).

The prices for the certificates of both mechanisms, and thus the financial incentive for green hydrogen, are market-based and result from supply and demand. This design is intended to incentivise savings in CO_2 emissions in those applications with the lowest CO_2 avoidance costs.

However, market-based pricing also ensures that prices - and therefore the financial incentive to use green hydrogen - can only be predicted to a limited extent in the long term. The market prices of the two certificate types depend on many factors. These include the cost of biofuels and other renewable alternatives to green hydrogen, the spread of electromobility, changes in regulation and the speed at which the energy transition develops. For example, an early phase-out of coal-fired power generation in the absence of cancellation of the corresponding ETS certificates can cause certificate prices to fall.

All in all, there is a lack of long-term planning security through market-based instruments for the economic viability of projects and protection for "First Movers", which makes financing more expensive and investment decisions more difficult.

Long approval procedures delay project progress

Before the construction of an electrolyser and its infrastructure can begin, it must be authorised. The authorities responsible for this, as well as the relevant regulations, vary from state to state. This can make it difficult for developers of electrolysis projects to find a responsible contact person and compile the necessary documents. Staff shortages and a lack of experience on the part of those submitting and processing applications can also lead to delays.

In addition to the situation for applicants, the authorising authorities are also faced with new challenges during the approval process. This is particularly the case in areas that were previously less industrially characterised and where the authorities have little experience with corresponding approval procedures. These authorisation procedures require professional processing for which further training may be necessary, which can lead to further bottlenecks for authorities that are already working to capacity.

Public interests can also make authorisation more difficult. This is the case to a greater extent than with electrolysers in the case of newly constructed hydrogen pipelines or renewable energy plants for green electricity production. A lack of authorisation at these locations can also be critical for the construction of the electrolyser itself, as it is not possible to operate the electrolyser without a green electricity supply or consumer.

The authorisation of infrastructure elements, in particular for cavern storage facilities, is particularly complex. In addition to environmental impact assessments, planning approval procedures and authorisation in terms of spatial planning, issues of mining law are also relevant here.

In general, it should be noted that the approval processes for projects that are implemented in industrialised areas present fewer hurdles, as both applicants and approving authorities are more familiar with the procedures.

Open design of certification leads to ambiguities

In order to prove the green properties of renewable hydrogen, functioning certification systems must be created and established. Although voluntary certifications already exist, there is as yet no certification recognised by the EU Commission for proving the regulatory green properties of hydrogen. The framework in which the verification of green hydrogen takes place is also crucial. In Germany, there are currently two regulatory developments relating to the verification of green hydrogen. On the one hand, the certification requirements in the DA of RED II are currently being implemented in the 37th BImSchV. In addition, it will be possible in future to provide proof by means of guarantees of origin. This is regulated, among other things, by the Ordinance on Guarantees of Origin for Gaseous Energy Sources, Heating and Cooling (GWKHV), which (as of February 2024) still has to be passed by the Bundestag.

The certification of biofuels already exists and serves as a blueprint for hydrogen certification: voluntary and national certification systems are applying to be recognised by the EU Commission[12,13]. Proof must be provided as part of mass balancing. This certification must be distinguished from the guarantees of origin under the GWKHV, as it will be organised differently and, among other things, follows a book-and-claim approach. With this book-and-claim approach, the certificates can be traded independently of the physical delivery, whereas this is not possible in the case of mass balancing. As things stand at present, guarantees of origin cannot be used to prove compliance with the requirements for eligibility for the RED target. This requires certification, as set out in the draft amendment to the 37th BImSchV.

For some business models, it is currently unclear how it will be possible to trade hydrogen on the balance sheet as green together with a corresponding certificate. One example is the feeding of hydrogen into the natural gas grid. If this is not the case, such business models would not be economically viable.

Until corresponding certification systems are set up and established, uncertainties remain regarding the exact form of certification. This creates ambiguity regarding the certification of green hydrogen, the underlying business models and relationships, as well as the effort required for certification.

Lack of norms and standards increase costs for early projects

Hydrogen technology is currently being developed in parallel with research and standardised in parallel with development. In addition, hydrogen technology is multimodal and multidisciplinary along the value chain. In such a developing business field, there is an enormous need for standards in order to harmonise quality features such as safety, performance or product characteristics for all market participants. In the field of hydrogen technology, standardisation in Germany is lagging conspicuously behind in international comparison.

For market players, however, questions of quality understanding are crucial for market entry. For example, there are legal requirements for safety and product quality that operators must fulfil. Without standards or technical regulations, the required verification is difficult and requires a complex case-by-case decision, which hinders the market ramp-up. Various experts, specialists and notified bodies must therefore be consulted. Their expertise must be meticulously coordinated during the approval and certification process to avoid a conflicting situation. This harmonisation process requires a great deal of knowledge transfer from all those involved and generates enormous frictional losses when it is initiated for the first time by market

[12] https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/voluntary-schemes_en
[13] https://www.certifhy.eu/news/certifhy-rfnbo-vs-for-recognition-eu-commission/

participants in an innovative business field. Furthermore, the knowledge gained in the process is not subsequently available to the general public, but must always be built up anew.

4 Summary and Outlook

In the past, especially before the publication of the DA on Art. 27(3) of RED II, the lack of or sluggish development of regulation was often criticised. However, this discussion paper shows that the challenges faced by demonstration and implementation projects in the hydrogen ramp-up are both individual and complex. Figure 6 shows the aforementioned building blocks summarised and categorised in the topics of regulatory, cost structures and business models.

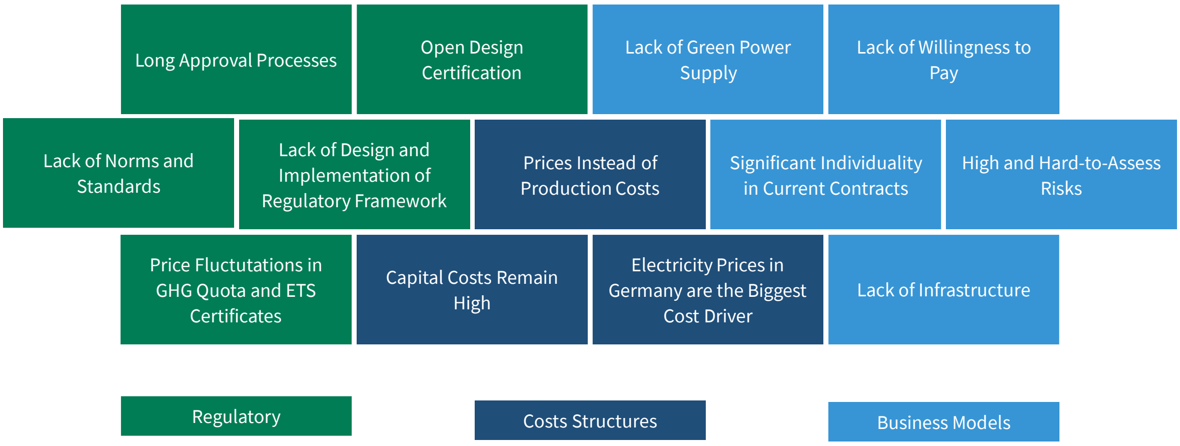

Figure 6: Summary of the most important current challenges in the realisation of hydrogen projects in Germany

The categories mentioned are not exactly clear-cut and are often mutually dependent, which brings additional complexity to the realisation of projects. All of the challenges mentioned have a direct or indirect impact on the profitability of the projects. For example, the direct correlation between capital costs, which remain high or have even risen in recent years, and profitability is quickly apparent. The situation is different, for example, when it comes to risks that are difficult to assess, which only have an indirect impact on profitability in the form of high interest rates for borrowed capital. The level of risk, in turn, is influenced by strong price fluctuations in potential sources of revenue such as the sale of GHG quota certificates.

To summarise, it can be said that the companies involved in a hydrogen project have to deal with all of the points mentioned and assess them individually. The assessment may vary depending on the project, for example because of the existence of purchase agreements or because the projects do not have to be financed via the capital markets. In order to put industry, politics and research in a position to support the market ramp-up of hydrogen, it would be helpful to be able to track investment decisions that have already been made.

In the following, the individual challenges are to be sharpened, where possible more clearly separated from each other and their mutual relationships presented. Based on this, a questionnaire will be drawn up with which the living labs and other implementation projects will be approached. The aim is to develop an information base as comprehensive as possible so that the challenges can be addressed in a socially responsible manner.

A Assessments from the Living Labs

The following assessments were written by the actors in the living labs of the energy transition and provide an insight into their view of the challenges mentioned in the previous chapters. The content of these assessments has been adopted unchanged.

A.1 Energiepark Bad Lauchstädt

From the perspective of the living lab Energiepark Bad Lauchstädt, the localisation of the living lab projects (see Figure 1) is very accurate. As "First Movers" for a very new technology, the living labs face a very high risk. On the one hand, in a highly regulated energy market, not all regulatory framework conditions are fixed or are in the process of being developed. On the other hand, the investments to be made are in the mid to high 3-digit million range. Business models for both the operators of the hydrogen infrastructure and the future customers cannot be clearly defined. Added to this is the comparatively long planning and construction period, which is also characterised by uncertainties with the approving authorities. This requires a strong and visionary decision and a high degree of trust in the legislature in order to bear this entrepreneurial risk.

The Energiepark Bad Lauchstädt benefited from the relatively long preparation time, during which basic technical and scientific issues and an exemplary approval procedure could be worked on in preliminary projects. This means that some of the authorisation issues as a basis for an investment decision could be prepared together with the authorities and key agreements were already in place at the start of the project. This meant that the planning and authorisation period within the living lab project could be streamlined.

A key prerequisite for the Final Investment Decision (FID) was the adoption of RED II and the resulting Delegated Act. These regulatory requirements were the basis for the long-term business models. In addition, the conclusion of a supply contract for the majority of the hydrogen produced was a prerequisite for the commissioning of the main plants.

The current market situation, with high utilisation of the few capacities currently being built up in the area of plant construction for electrolysis systems and other peripheral plants, poses an additional challenge. This is compounded by sharp price increases in the event of delays due to external influences on FID with coordinated delivery schedules.

Despite the sometimes critical circumstances mentioned, the consortium of the Energiepark Bad Lauchstädt has made a positive FID and thus paved the way for a ground-breaking reorganisation of the energy infrastructure, not least in the expectation of the implementation of the hydrogen strategy specified by the German government and continued support for the "First Movers".

A.2 Norddeutsches Reallabor

The North German Real-World Laboratory (NRL) welcomes the fact that the transfer research has summarised and processed the challenges of the living labs of the energy transition with a focus on hydrogen in a discussion paper. Many of the challenges mentioned in the paper also affect parts of the NRL in which hydrogen is to be produced or utilised. Depending on the project, however, the effects of the challenges mentioned will vary. In the following, these challenges will be categorised from the perspective of NRL.

From a regulatory perspective, the delays in connection with the Delegated Act RED II and its transposition into national law have led to significant delays in investment decisions. In order to create planning certainty, implementation via the 37th BImSchV should therefore take place as quickly as possible, whereby intermediaries (middlemen) should be permitted as PPA contracting parties. Clarity should also be created with regard to the applicable certification systems for green hydrogen.

From an economic perspective, we at NRL can emphasise the challenges with regard to the increase in investment costs, the purchase of green electricity and the revenue side. With regard to the latter, the drop in THQ quota prices is particularly relevant. In order to accelerate the market ramp-up of hydrogen, we see great potential in the use of climate protection contracts, which should extend to various industrial sectors. There should also be stronger incentives for the system-friendly operation of electrolysers, the flexibilisation of industrial processes on the electricity side and the use of otherwise curtailed electricity.

With regard to the technical challenges, we were able to hear from associated partners in our consortium with existing plants that the issue of degradation and the associated costs and liability aspects certainly play a role and can make electrolysis projects more expensive. In the case of new plants, the liability risk has apparently not yet been completely resolved and is partly transferred by the manufacturers to the buyers. As long as this situation does not change and the manufacturers are not fully liable, the corresponding costs must be taken into account in terms of economic viability or CAPEX funding.

The large number of challenges shows that the market ramp-up of hydrogen in Germany has not yet reached the envisaged speed. Nevertheless, we at the NRL remain certain that hydrogen will play an important role in the future energy system and that it is therefore important to help develop solutions in response to the challenges. In terms of economic policy, we believe it is necessary not only to rely on potentially favourable imports, but also to quickly ramp up production in Germany and Europe. This is not only necessary in order to achieve greater independence from energy imports, but also to keep technology production and expertise in Germany. Pioneering projects and companies that invest here at an early stage should definitely be supported in order to ensure the economic operation of the plants until a market develops. The "Reallabore der Energiewende" (living labs of the energy transition) funding programme is an important tool for this, which at least promotes the high investment costs, enables technological experience and identifies regulatory obstacles. However, the biggest hurdles currently lie in the area of operating costs and achievable generation costs and prices.

A.3 WESTKÜSTE100

The project partners of the WESTKÜSTE100 living lab can confirm the challenges described in the discussion paper. The key element of the WESTKÜSTE100 living lab is the main work package (Hauptarbeitspaket, HAP) 1, in which a 30 MW electrolysis plant for the production of green hydrogen using electricity from renewable energy sources is to be planned, built and put into operation. The joint venture "H2 Westküste GmbH" was founded for this purpose. However, for the reasons described above, the joint venture was unable to make a positive investment decision for HAP 1, i.e. the construction of the planned 30 MW electrolyser (see the joint venture's press release on this from 16 November 2023). The other sub-projects had to contend with many other challenges, which are not addressed in this paper.

From the perspective of HAP 1, the incentive system for green hydrogen is currently not yet sufficient to make the emerging market attractive. This is due, among other things, to the following points, which we would like to summarise here once again from the discussion paper and supplement with our experience:

The GHG quota price has fallen so sharply in the past year that the incentives to buy "expensive" green hydrogen have been cancelled out. According to the calculations within the framework of WESTKÜSTE100, the following values were obtained for green hydrogen (theoretical additional willingness to pay on the part of those obliged to pay the quota), depending on the GHG quota price:

Table 1: Calculated greenhouse gas reduction value of green hydrogen in [€/kg H_2] depending on the GHG quota price in [€/t CO_2] with a credit factor of 3 according to the current draft of the 37th BImSchV from December 2023 (value of green hydrogen solely through GHG quota)

	Unit	Low	Medium	High
GHG quota price on the market	€/t CO_2	130	280	430
GHG value of green H_2	€/kg H_2	4,40	9,47	14,55

The production costs of green hydrogen determined in the WESTKÜSTE100 project are in the double-digit range, so that a GHG quota of at least 380 to 420 €/t CO_2 would have to be achieved in order to ensure economic operation of the electrolyser.

We can confirm that the investment costs are significantly higher than initially expected. In WESTKÜSTE100, we are in the mid four-digit range per kW of installed capacity at 30 MW and thus slightly above the reference values in Figure 2.

The difficulty in procuring RED II-compliant electricity and the resulting demand and supply situation caused prices to rise to unusually high values in the three-digit range in 2022. PPA prices are currently between €55 and €85/MWh. With an efficiency of 65 kWh/kg H_2, this leads to a price of €3.58 to €5.53 for a kilogramme of hydrogen based on real electricity prices. Other price components for the investment and operation of the 30 MW electrolysis plant are added accordingly.

Due to RED II and the associated necessary temporal correlation between electrolysis operation and the renewable energy generated, a lower utilisation of the electrolyser far from 100 percent is unavoidable. This significantly increases the investment costs (CAPEX), which are otherwise estimated to be low, and thus makes green hydrogen even more expensive.

To counteract the previous point, an attempt was made to achieve higher utilization of the electrolyser by oversizing the power supply agreements (PPAs). For example, 40 to 60 MW of renewable electricity would be contracted for a 30 MW electrolyzer by concluding long-term PPAs. Due to the time correlation, the electricity must be used when it is generated. If a lot of renewable energy is now generated, 10 to 30 MW would have to be sold on the market again. It is assumed that, depending on the renewable electricity sources and the electricity procurement strategy, around 15 to 35 percent of the total electricity volumes per year will have to be sold back on the market. However, the market price will differ significantly from the purchase price during these periods of surplus electricity, meaning that unpredictable losses can be expected.

In addition, there are time-related components that have significantly prolonged the development of the WESTKÜSTE100 project:

The complex contractual structures of hydrogen projects are still uncharted territory for everyone involved. A new market is currently emerging in which companies from a wide range of sectors are negotiating with each other. The WESTKÜSTE100 project also brings together various players with different corporate philosophies. This leads to additional challenges in the already complex negotiations.

The uncertain and delayed regulatory situation has also caused the joint venture H2 Westküste GmbH to postpone the final investment decision for the construction of the planned 30 MW electrolyser several times. The adoption of the delegated acts based on RED II was scheduled for the end of 2021 in accordance with Article 27 of the directive. This was delayed until February 2023, followed by a further two months (which were extended by another two months) for examination by Parliament and the Council. The amendment of the 37th BImSchV at German level has not yet been completed. During this period, investment costs have risen by a further around 40 percent compared to the initial offers at the start of the project. The project partners of WESTKÜSTE100 hoped to obtain a certain regulatory freedom and special status as a living lab in order to test the regulatory framework and thus be able to make recommendations to the German government.

A.4 Referenzkraftwerk Lausitz

The Referenzkraftwerk Lausitz attempts to present a business case for hydrogen in five ways:

1. Reconversion to electricity in times of dark doldrums
2. Sales of hydrogen via the natural gas grid
3. Sales of hydrogen via trailers
4. Sales of hydrogen to local industrial customers
5. Sales to the mobility sector

Each of these sales channels has specific challenges that make a final investment decision considerably more difficult. Below are the individual stumbling blocks for the respective points:

1. Conversion back into electricity will result in costs of 70-100 ct/kWh and will only work on a significant scale if hydrogen fed into the gas grid can be bought back at a later date. It should be noted that it is currently unclear how exactly H_2-reconversion is to be promoted and whether it is possible to buy back hydrogen from the natural gas grid at different times while retaining the green properties of the hydrogen.
2. It is currently not clear whether the hydrogen fed into the natural gas grid can be traded on the balance sheet while retaining its green properties. However, this would be absolutely necessary in order to benefit from incentive systems such as CFDs or GHG quotas and to demonstrate economic viability.
3. Hydrogen sales by trailer are currently viewed very critically, as the additional costs for trailer transportation alone are 2-4 €/kg, making hydrogen considerably more expensive.
4. Industrial consumers of hydrogen will probably only settle here once it is available. In other words, we have the classic chicken-and-egg problem here again.
5. Sales in the mobility sector are considered to be extremely critical because there are currently massive lock-in effects for battery electric drives. Hydrogen will presumably only be used for niche applications in the mobility sector, meaning that the sales channel for the Referenzkraftwerk Lausitz is essentially reduced to trailers. The construction and operation of its own hydrogen filling station currently seems rather inopportune.

A.5 H_2CAST Etzel

Cavern storage facilities are enablers of the energy transition - thoughts and suggestions on the necessary infrastructure by 2030:

- STORAG's H2CAST research project is running according to plan, the announced milestones are expected to be reached and the first H2 cavern of the Lower Saxony lighthouse project will be transferred to approval-compliant operation by 2027. Further caverns can be made available from 2028. STORAG needs the certainty that the hydrogen market and the hydrogen infrastructure will also be implemented so that its own hydrogen storage facilities can go into operation and fulfill their function as part of the hydrogen value chain. A storage facility will only work if the SSOs' above-ground operating facilities and the TSOs' pipeline infrastructure are in place.
- Approval procedures under mining law must be conducted in parallel or accelerated. In the event of a conversion of existing caverns or for already approved cavern sites and their above-ground facilities, complex planning approval procedures with environmental impact assessments should be omitted.
- Underground spatial planning procedures must be carried out at local authority level in order to develop and designate priority areas for mining projects. Mining projects, such as cavern storage mining, are tied to existing deposits.
- H_2 storage will not have a business case for years to come, which means that in addition to hedging investment risks (CAPEX), it is also essential for energy storage operators (SSOs) to support fixed operating costs (OPEX).
- The contracts for differences (CfD) proposed by INES, for example, offer the possibility of implementing the development and operation of hydrogen storage systems by 2030 by commissioning companies to do so.
- The core idea of a contract for differences is that the difference between actual revenues and reference revenues, i.e. the shortfall in revenues, is compensated by the state, while excess revenues are repaid to the state. The reference revenues must inevitably include both capital costs (CAPEX) and fixed operating costs such as rent to the cavern and mine owner (OPEX). Reference revenues could be determined by the regulator on the basis of a comprehensive project-specific cost review.
- The announced H_2 storage strategy and the BMWK's H2 power plant strategy are still pending. A consultation is still required in 2024.

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