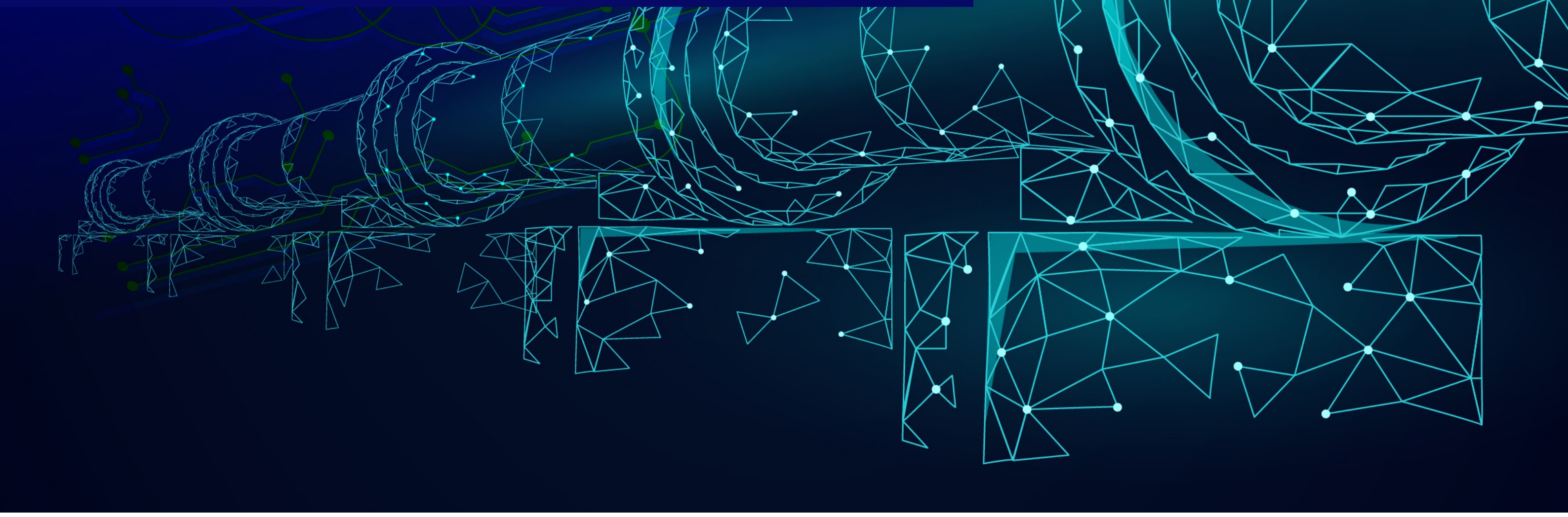
INFRASTRUCTURE FINANCE REPORT

Bridging the gap: Mobilizing investments in hydrogen infrastructure

December 2024



H2Global Stiftung

Authors

Julian Reul, Program Lead, H2Global Foundation

Hanna Graul, Research Associate, H2Global Foundation

Contributions

Jan Klenke (H2Global Foundation), Martin Lambert (OIES), Joseph Cordonnier (OECD), and Moongyung Lee (OECD).

Publisher

Department — Analysis and Research
Trostbrücke 1
20457 Hamburg

H2Global Knowledge Hub reports

ISSN: 2944-7801

Table of contents

List of figures and tables

Acknowledgements

This report was developed by the research team of the H2Global Foundation. It is part of the H2Global Knowledge Hub, a research program sponsored by the 7th Energy Research Program funded by the German Federal Ministry of Education and Research. The authors were Julian Reul and Hanna Graul, with support from Jan Klenke and Matteo Massera. Victor Ponsford provided editing and communications support and Anne Sorkamo design expertise.

Sincere thanks are extended to Martin Lambert (Oxford Institute for Energy Studies), Moongyung Lee (OECD), and Joseph Cordonnier (OECD), whose invaluable contributions have significantly enriched this work. Their expertise, insight, and diligent efforts have greatly improved the quality of our output.

Gratitude is also extended to esteemed peer reviewers, Mathias Koch (Agora Energiewende), Manuel Villavicencio (Deloitte), and Ichiro Kutani (Institute of Energy Economics, Japan) for their important feedback on the report that greatly helped to enhance its quality.

The donors to the H2Global Foundation that so graciously provided feedback throughout the “Bridging the Gap: Mobilizing Investments in Hydrogen Infrastructure” working group meetings are appreciatively acknowledged. It is through their comments that H2Global has been able to make the report speak to practitioners in the field.

Lastly, the team greatly appreciates the input and guidance of Susana Moreira.

H2Global Stiftung

Federal Ministry
of Education
and Research

Glossary

Term	Definition
ACB	Anchor capacity booking
BOT model	Build-operate-transfer model
CAPEX	Capital expenditure, i.e., funds used by a company to acquire, upgrade, and maintain physical assets.
CfD	Contract-for-difference: subsidy model in which both positive and negative deviations from a fixed reference price are paid out to the contractual partner.
Claw back	Money or benefits that have been given out but are required to be returned (clawed back) under specific circumstances.
CCUS	Carbon capture, utilization and storage
CEF	Connecting Europe Facility
CNG	Compressed natural gas
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Sources Act), Germany
Energy carrier	A substance or system that contains energy which can be converted to useful work. For example, hydrogen, which can carry/store energy until it is converted into other forms such as electricity.
EMDC	Emerging markets and developing countries: nations characterized by lower income levels and industrialization stages, with potential for rapid economic growth.
e-SAF	Sustainable aviation fuel, produced from clean hydrogen
FID	Final investment decision: a decision by the board of directors that officially sanctions and allows for the commitment of funds to a project or investment.
FP funding	Fixed-premium funding
GHG	Greenhouse gas
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	Internal rate of return: annual growth rate that makes the net present value of a project zero.
LH2	Liquid hydrogen
LOHC	Liquid organic hydrogen carrier: compound that can reversibly absorb and release hydrogen, enabling compact hydrogen storage and transportation.

Term	Definition
LNG	Liquified natural gas
NH3	Ammonia
NPV	Net-present value
NZE	Net zero emissions: NZE scenario is a comprehensive pathway developed by the IEA outlining how the global energy sector can achieve net zero CO2 emissions by 2050 while ensuring stable and affordable energy supplies.
Offtaker	Entity that agrees to purchase hydrogen from a producer.
OPEX	Operating expenditure: i.e., the ongoing costs for running a product, business, or system.
PPP	Public private partnership: collaborative agreements where the public and private sectors jointly fund, develop, or operate projects, sharing risks and resources to efficiently deliver public services or infrastructure.
RAB	Regulated asset base: the value of a company's assets, determined by a regulatory authority, on which it can earn a specified rate of return through regulated prices or tariffs.
ROI	Return on investment: a measure that compares the gain or loss from an investment relative to the initial amount invested.
SD	Standard deviation
SNG	Synthetic natural gas
SPV	Special purpose vehicle: separate legal entity created to isolate financial risk for specific assets or projects.
TRL	Technology readiness level
TPA	Third-party access: the right granted to third parties to use infrastructure or services owned by another entity, typically regulated to promote competition and fair access.
UHS	Underground hydrogen storage
VaR	Value-at-risk: statistical measure that estimates the potential loss in value of an asset over a defined period for a given confidence interval.
WACC	Weighted average cost of capital: the average rate that a company is expected to pay to finance its assets, factoring in the cost of equity and the cost of debt, weighted by their respective proportions in the capital structure.

Foreword

H2Global is committed to addressing the challenge of climate change with its unique double-auction mechanism, international stakeholder engagement, and research on the clean hydrogen economy. In 2024, the H2Global Pilot Auction delivered first results in the form of a renewable ammonia offtake agreement worth EUR 300 million for a project delivering renewable ammonia from Egypt to Europe due to start in 2027. Four new H2Global tenders totaling EUR 4.43 billion, committed and/or earmarked by Germany, the Netherlands, Canada and Australia, are to be launched in the coming months.

H2Global's mission extends beyond auctions to identifying and alleviating market development barriers. As part of this endeavor, H2Global is building the H2Global Knowledge Hub, which is financially supported by a research grant issued by the German Federal Ministry of Education and Research. With the Knowledge Hub's support, H2Global has engaged its current 72 private sector supporters in producing valuable insights into market creation for clean hydrogen and its derivatives. The result is a series of reports in 2024 addressing three key challenges: the clean hydrogen infrastructure investment gap, the lack of clean hydrogen demand commitments, and the need to optimize auction designs.

Infrastructure is critical in developing a robust and reliable hydrogen supply chain. A well-developed hydrogen infrastructure, comprising production, transport, storage, and distribution facilities, enables sufficient physical deliveries and will promote efficiency and reduce end-user costs, helping to increase adoption.

Developing hydrogen infrastructure, however, faces several significant challenges including extensive permitting, uncertainty regarding what volumes of hydrogen need to be delivered to where and in what form, and cost. The investment required to develop hydrogen infrastructure can at times be prohibitive, particularly when compared to conventional energy sources. In an effort to address the uncertainties, costs and associated risks for companies, this report assesses instruments that can be used to encourage investment in midstream infrastructure.

If successful, the adoption of new tools to unlock investment in midstream infrastructure would not only enable physical deliveries of hydrogen (derivatives), but would—in the process—support other measures designed to facilitate the creation of a market for clean hydrogen (derivatives) such as "hydrogen demand hubs" (addressed in-depth in H2Global's second report in 2024, "Unlocking potential: Scaling demand through hydrogen hubs") and "auctions" (discussed in its third report, "Keep it simple: Aligning auction objectives for success").

With the 2024 reports, H2Global is working towards becoming a center of excellence in clean fuels' market creation, reinforcing its role as a green market maker and its commitment to protecting the climate and the environment.

"This report is extremely timely. As initial, large scale, clean hydrogen projects start to reach final investment decisions and operations, hydrogen infrastructure will be critical to allow a rapid scale up of the industry, beyond these "first mover" projects. The report provides an excellent overview of some of the challenges, but also solutions, to financing this vital part of the value chain. Congrats to the H2Global Foundation team for this valuable contribution to moving the dialogue forward."

Ignacio de Calonje
Chief Investment Officer,
Global Co-Lead, Green Hydrogen
IFC

Executive summary

The need for hydrogen infrastructure

The transition to a global hydrogen economy is critical for achieving net-zero emissions and decarbonizing hard-to-abate sectors. Midstream hydrogen infrastructure—including pipelines, import terminals, reconversion facilities, and underground hydrogen storage—is projected to be the backbone of this transition, enabling large-scale trade and supply chain integration. However, this infrastructure faces a particularly large investment gap, in advanced economies and even more so in emerging markets and developing countries (EMDCs).

Financing energy infrastructure

Investments into clean hydrogen remain marginal, with only USD 1 billion directed toward hydrogen infrastructure in 2024—less than 0.1% of the total USD 2 trillion in clean energy investments. Comparatively, renewable power (38%), energy efficiency (19%), and electricity grids and storage (23%) have attracted the bulk of funding, largely due to their bankable risk-return profiles. Hydrogen infrastructure investments, by contrast, are perceived as being high risk and having low returns, further inhibiting capital flow into this nascent market.

The challenges are compounded by several critical risks unique to infrastructure projects:

— **Market risks**: Uncertain demand, pricing, and utilization.

— **Political and regulatory risks**: Evolving and inconsistent regulations.

— **Macroeconomic risks**: Volatility in currency, inflation, and interest rates.

— **Permitting and compliance risks**: Delays in acquiring land and necessary permits.

— **Design, construction, and completion risks**: Cost overruns and technical delays.

— **Technology risks**: Low readiness levels for certain solutions.

— **Operational and maintenance risks**: Underperformance and skill shortages.

A survey of H2Global donors ranked market risks, political and regulatory risks, and permitting and compliance risks as the most critical barriers to hydrogen infrastructure development. These risks demand targeted de-risking strategies to enhance the risk-return profiles of projects and attract private investment.

While conventional de-risking approaches—such as public-private partnerships (PPPs), regulated asset base (RAB) models, and special-purpose vehicles (SPVs)—have been successfully implemented globally for energy infrastructure, they fail to address the unique challenges of hydrogen projects. Consequently, innovative financial support instruments are needed to bridge the hydrogen infrastructure investment gap.

Finance support instruments to de-risk hydrogen infrastructure

To close the investment gap, the report identifies and evaluates four financial support mechanisms:

— **Capital expenditure (CAPEX) support**: Upfront subsidies to reduce initial investment costs.

— **Fixed premium (FP)**: Operational-phase subsidies linked to capacity utilization.

— **Contracts-for-difference (CfDs)**: Guaranteed returns on investment to mitigate revenue risks.

— **Anchor capacity bookings (ACBs)**: Revenue floors to ensure stable income during early operations.

Each mechanism is evaluated for its funding efficiency, ability to mitigate risks, administrative ease, and suitability for different project types. Archetypal projects—including pipelines, terminals, reconversion facilities, and storage—were analyzed to test the effectiveness of these mechanisms under various scenarios. Findings highlight the need for tailored solutions to address specific project needs, market conditions, and regional contexts.

Key recommendations

The report offers tailored recommendations to address the challenges of financing hydrogen infrastructure:

— Develop tailored funding mechanisms for specific types of infrastructure, prioritizing CfDs for high-risk, long-term projects like pipelines and underground storage, and CAPEX support for simpler, lower-cost projects like terminals and reconversion facilities.

— Leverage CAPEX support to reduce initial investment costs for midstream hydrogen infrastructure, particularly in EMDCs. CAPEX support is administratively simple and efficient, but should be combined with additional financial support mechanisms to address future revenue risks.

Leverage CAPEX support to reduce initial investment costs for midstream hydrogen infrastructure, particularly in EMDCs. CAPEX support is administratively simple and efficient, but should be combined with additional financial support mechanisms to address future revenue risks.

— Deploy CfDs to guarantee stable returns and mitigate market risks for high-cost, high-risk infrastructure, such as pipelines and underground storage.

— Introduce ACBs to provide revenue floors during early operational phases, offering stability for investors while balancing simplicity and risk mitigation.

— Use fixed-premium instruments selectively to incentivize operational performance by linking financial support to capacity utilization. While these instruments are effective for reducing the risk of stranded funding, they rank lower in terms of funding efficiency and risk mitigation compared to CAPEX support, CfDs, and ACBs.

— Adopt competitive auctions to allocate financial support instruments, such as CfDs and FPs, effectively. Tailored auction designs can address project-specific or regional needs and ensure that funding targets the most impactful initiatives.

The report provides recommendations that extend beyond financial support instruments, aiming to foster the overall development of hydrogen infrastructure:

— Enhance regulatory certainty through clear and practical frameworks that address third-party access, unbundling rules, and permitting processes. Long-term stability and transparency are crucial to fostering investor confidence.

— Coordinate supply-chain activities to mitigate market risks and compensate for the lack of liquidity and market signals in the nascent hydrogen economy. Explore vertical integration across different stages of the hydrogen value chain to smooth revenue disparities and create sustainable business cases, even in less profitable segments.

— Explore centralized development of funding instruments to streamline application processes, standardize eligibility criteria, and reduce administrative burden. This approach can enhance accessibility, minimize duplication, and improve efficiency, saving time and resources for both funding authorities and project developers.

— Link public financial support to demonstrable social and environmental benefits to enhance public acceptance. Emphasize third-party access to privately operated infrastructure and communicate the broader societal value of hydrogen projects.

— Support EMDCs by combining financial instruments with capacity building, international cooperation, and guarantees from development financial institutions to address higher financing costs and risk profiles.

IMAGE CREDIT: HAYOSHKA / ADOBE STOCK

The need for hydrogen infrastructure

The Paris Agreement has shaped global energy policies since its announcement in 2015 and lays out the paradigm for the transformation of global energy systems from fossil-dependent to greenhouse gas (GHG)-neutral sources of energy by 2050. An inevitable component of GHG-neutral energy systems is hydrogen[1], as it facilitates the decarbonization of "hard-to-abate" sectors,[2] while also having the potential to balance renewable energy production by offering large-scale storage and transport options.

International Energy Agency (IEA)'s Net Zero Emissions (NZE) scenario estimates that the global supply of clean hydrogen needs to increase to 70 Mt-H2-eq.[3] in 2030 and to 420 Mt-H2-eq. in 2050, respectively, up from 1 Mt-H2-eq. in 2022, to meet climate goals. In this scenario, 14 Mt (=21%) of global hydrogen production would be traded internationally by 2030.[4] The existing project landscape suggests that the world will fall severely short of the 2030 targets. There is therefore an urgency for the global hydrogen economy to develop rapidly, from production to offtake. A core challenge in the creation of the clean hydrogen economy is the so-called chicken-and-egg problem, whereby supply, infrastructure and demand creation all depend on each other being in place, creating a situation where none can develop independently. Established markets, such as the electricity or natural gas market, provide enough liquidity for market participants to identify long-term business opportunities with sufficient certainty. However, in nascent markets, such as the clean hydrogen market, there is limited liquidity, no market prices, legal uncertainty, and multiple barriers to entry. Clean hydrogen costs are high when compared to their carbon-intensive counterparts, which inhibits demand. Without demand, investments remain too risky for wide-scale clean hydrogen production that would, in turn, reduce costs.

Infrastructure is critical in developing a robust and reliable hydrogen supply chain. A mature hydrogen infrastructure, comprising production, transport, storage, and distribution facilities, will promote efficiency and reduce end-user costs, helping to increase adoption. However, there are several significant challenges in developing hydrogen infrastructure projects. For one, due to their complexity, infrastructure projects typically require long lead times and substantial labor. They often necessitate coordination across multiple sectors, span large geographical areas, and involve lengthy permitting processes. Another key hurdle is the uncertainty associated with developing networks to satisfy future demand—i.e., identifying what volumes of hydrogen need to be delivered to where and in what form. This uncertainty leads to higher financing costs compared to conventional energy projects, which are typically seen as less risky. The investment required to develop hydrogen infrastructure is substantial. Estimates suggest that the total investment needed to ramp up the hydrogen economy in line with net-zero targets is USD 1 trillion globally by 2030, of which USD 335 billion has yet to be allocated. Hydrogen infrastructure accounts for the largest share of the investment gap at USD 190 billion.[5]

Hydrogen infrastructure accounts for the largest share of the investment gap at

USD 190 billion.

The significant gap in investment in hydrogen infrastructure build-up has been highlighted as a major source of delay in the ramp up of the hydrogen economy. While it affects both developed countries and emerging markets and developing countries (EMDCs), most of the discussion so far has been focused primarily on how to bolster infrastructure investment in developed countries.

The aim of this report is to explore financial support instruments that can sufficiently de-risk hydrogen infrastructure projects in this early phase of the market to reduce the investment gap in both developed countries and EMDCs.

Figure 1: Hydrogen infrastructure investment gap

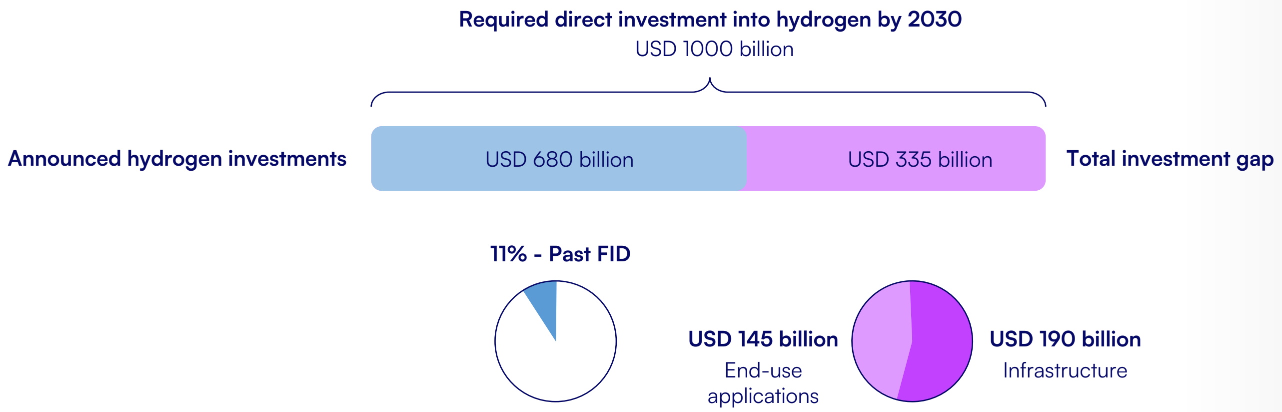


IMAGE CREDIT: ЕЛЕНА БИОНЫШЕВА-АБРА / ADOBE STOCK

IMAGE CREDIT: ANDREI / ADOBE STOCK

2

Financing energy infrastructure

Energy and hydrogen infrastructure—an overview

What is energy infrastructure? The European Commission defines it as technical equipment or facilities to transport and store electricity, oil and gas.[6] In this definition, it includes transmission and distribution grids, electricity storage linked to high-voltage power lines, smart grid infrastructure, as well as transmission and distribution pipelines and storage facilities for oil and gas, and facilities for the reception, storage and regasification of gas, i.e. liquefied natural gas (LNG) and compressed natural gas (CNG) terminals.

This definition of energy infrastructure captures what is typically referred to as midstream energy infrastructure. It is extended by upstream and downstream infrastructure. Upstream infrastructure refers to all auxiliary infrastructure that facilitates the generation of electric power or the production of chemical energy carriers. Downstream infrastructure involves last-mile transportation of chemical energy carriers via distribution pipelines, inland ships, trucks, and railways, along with on-site storage and reconversion facilities at the places of final consumption.

Figure 2 transfers the concepts of up-, mid-, and downstream infrastructure to the supply chain of clean hydrogen and its derivatives.

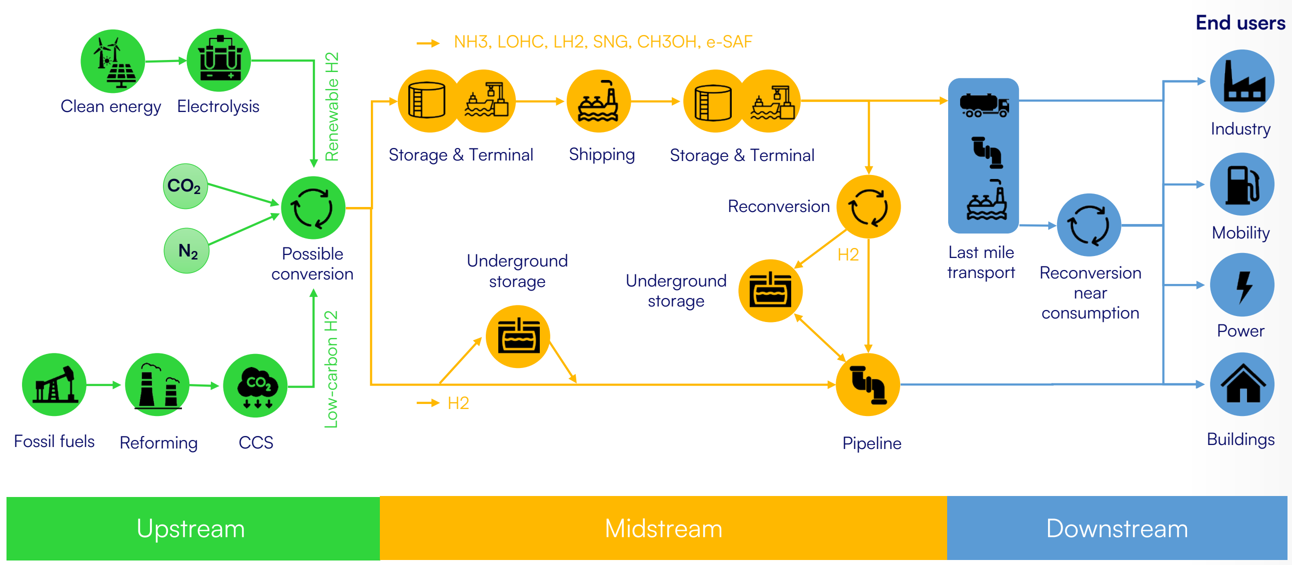
Clean hydrogen can be produced in various ways, including electrolysis powered by renewable energy resources (so-called renewable hydrogen) or steam reforming of natural gas with carbon capture, utilization and storage (CCUS) (so-called low-carbon hydrogen). After its production, hydrogen is typically either fed into a pipeline network for transportation or is converted for shipping. Options for ship transport include liquid hydrogen (LH2), liquid organic hydrogen carriers (LOHCs), or chemical energy carriers, such as ammonia (NH3), synthetic natural gas (SNG), synthetic methanol, or synthetic kerosene (e-SAF). Upon the shipped hydrogen's arrival at the import terminal, in any of the above-mentioned forms, it is either directly transported to the end user or converted back into gaseous hydrogen and fed into a pipeline network. Underground hydrogen storage is another crucial element of midstream hydrogen infrastructure. It serves the purpose of balancing supply and demand in case of regional mismatches and—more importantly—in case of various temporal mismatches, by bridging hourly to seasonal supply shortages, and managing oversupply or disruption of imports.

This report focuses on midstream hydrogen infrastructure because, on the one hand, it will serve as the backbone of hydrogen trade in a future global hydrogen economy and, on the other hand, it is associated with the largest investment gap both at project and system levels.

Midstream infrastructure connects supply and demand and thereby facilitates national and international trade of hydrogen and its derivatives on a large scale. In contrast, up- and downstream infrastructure is tied to the development and location of hydrogen supply- and demand-side projects. As such, this infrastructure is inherently more regionally dispersed and granular. This report focuses on **midstream hydrogen infrastructure** because, on the one hand, it will serve as the backbone of hydrogen trade in a future global hydrogen economy and, on the other hand, it is associated with the largest investment gap both at project and system levels.

The report specifically examines four types of midstream hydrogen infrastructure: **hydrogen pipelines, import terminals, reconversion facilities (e.g., ammonia crackers, dehydrogenation facilities)** and **underground hydrogen storage facilities.**[7] Furthermore, this report takes a **global perspective** when assessing hydrogen infrastructure.

Figure 2: Overview of the clean hydrogen value chain with necessary infrastructure components



NH3: Ammonia, LOHC: Liquid organic hydrogen carrier, LH2: Liquid hydrogen, SNG: synthetic natural gas, CH3OH: methanol, e-SAF: Synthetic aviation fuel

Box 1: Piloting clean ammonia transport

How Fertiglobe is solving the infrastructure challenge under Hintco's first purchase agreement

In July 2024, Fertiglobe PLC was announced as the winning bidder of H2Global's pilot auction for renewable ammonia. As a result of this auction, Hintco, H2Global Foundation's subsidiary, entered into a long-term offtake agreement with Fertiglobe at a fixed purchase price of EUR 1,000 per ton of ammonia. This includes the delivery of the product to an import terminal in Western Europe—Rotterdam—where the first deliveries are expected in 2027. With an ex-factory price of EUR 811 per ton of ammonia, the transport from the place of production in Egypt to the import terminal in Rotterdam was priced at EUR 189 per ton. The purchase price equals EUR 0.036 per kWh ammonia or EUR 0.041 per kWh hydrogen after cracking, assuming a hydrogen recovery rate of 78%.

The renewable ammonia will be produced in Northern Egypt close to the port of Ein El Sukhna in the Suez Canal. From the production facility, it will be transported via an existing seven km ammonia pipeline to the export terminal located in the port and stored in two permanent ammonia tanks with a capacity of 40,000 tons each. The seaborn transport from Egypt to the target location in Western Europe via the Mediterranean Sea is overseen by Fertiglobe International Trading, a subsidiary of Fertiglobe PLC. Ammonia tankers with a capacity of 15,000 to 20,000 tons will be used for shipping. On arrival in Rotterdam, the ammonia will be stored in ammonia tanks until it is contractually transferred to the final offtaker. The offtaker will be determined in upcoming sales auctions conducted by Hintco and will be given the responsibility of handling the transport of the ammonia from the import terminal to the place of final consumption.

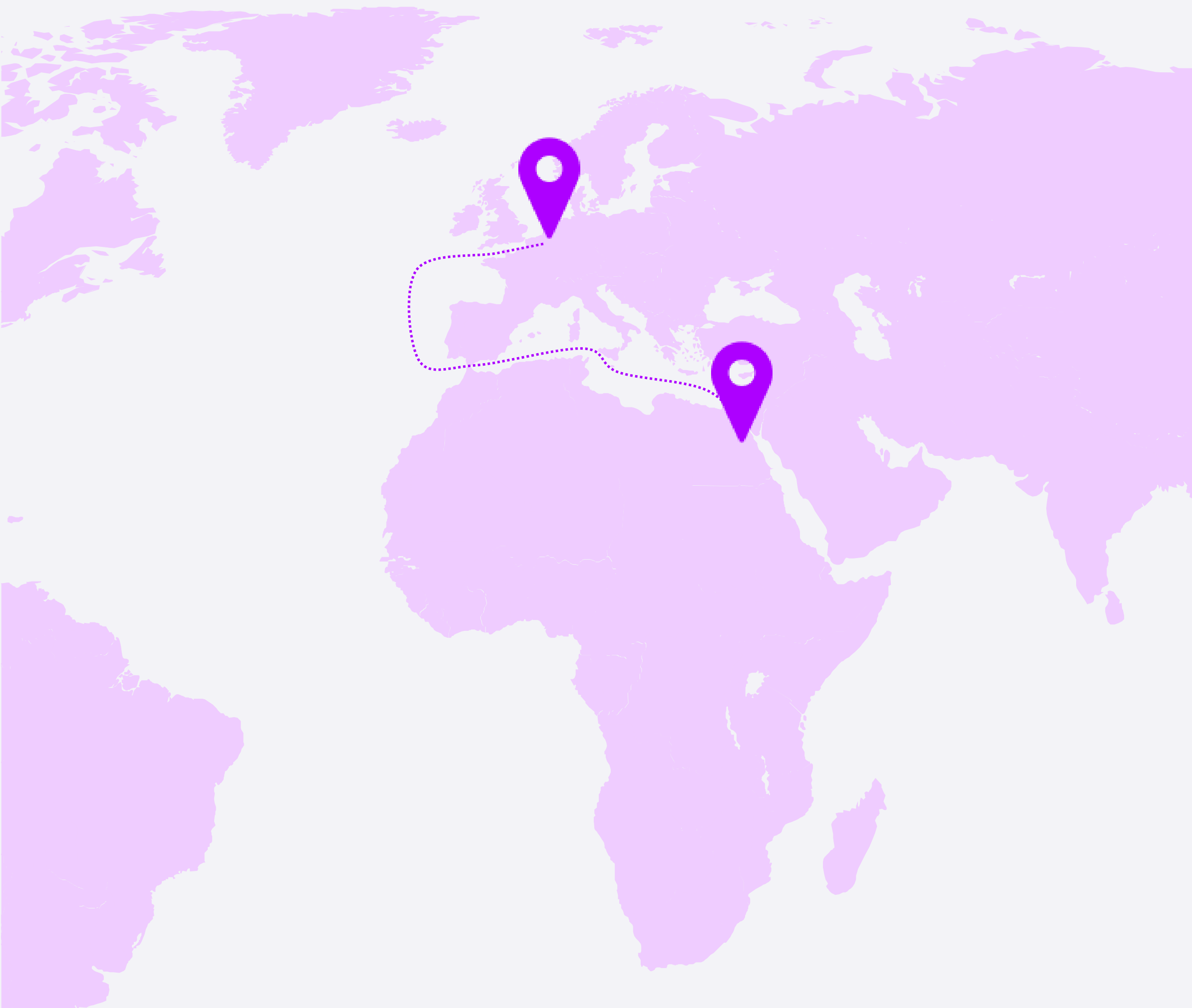


Table 1 compares the current global status of midstream hydrogen infrastructure projects with the International Energy Agency's (IEA's) global net zero emissions targets (NZEs) for 2035, pointing towards significant gaps in project realization.

It also presents the technology readiness levels (TRLs) of each type of midstream hydrogen infrastructure analyzed in this report. The TRL assessments, based on IEA evaluations, range on a scale from 1 (initial idea) to 11 (proof of stability reached)[8].

Table 1: Status quo of selected midstream hydrogen infrastructure and IEA-NZE global targets for 2035.[9]

Hydrogen infrastructure	Status quo	IEA-NZE target 2035
Pipelines	• Cheapest transport option < 2,000-2,500 km. • 5,000 km operational hydrogen pipelines in chemical parks; 994 km hydrogen pipelines (8 projects) at final investment decision (FID) or beyond • New hydrogen pipelines: TRL 9 (market uptake) • Repurposed natural gas pipelines: TRL 8 (demonstration)	45,000 km operational hydrogen pipelines.
Terminal	• Transport of hydrogen derivatives via ship, including reconversion at a terminal becomes cost competitive with pipelines for distances > 2,500 km. • Ammonia: ca. 150 ports, ca. 240 tankers, ammonia trade: 3.5 Mt H2-eq.; TRL 9 (market uptake) • Liquid hydrogen: TRL 4 (small prototype) • Methane: ca. 150 ports; TRL 11 (mature) • LOHC: can be transported using existing ships and port infrastructure; TRL 11 (mature)	No specific targets.
Reconversion facilities	• No commercial reconversion projects for clean hydrogen derivatives with FID. However, reconversion of methane and ammonia are established processes in the chemical industry. • Ammonia cracker: TRL 4 (small prototype) • Steam methane reformation: TRL 9 (market uptake) • LOHC dehydrogenation: TRL 6-7 (demonstration)	No specific targets.
Underground storage	• The first salt cavern projects for hydrogen storage date to 1972. Size: 500 GWh. • Three large-scale commercial underground hydrogen storage projects at FID or beyond. • Salt cavern storage: TRL 9-10 (market uptake) • Depleted gas fields storage: TRL 4 (small prototype) • Aquifer storage: TRL 3 (concept)	230 TWh of usable capacity.

Global landscape of clean energy finance

Investment into clean energy amounted to USD 2 trillion in 2024, according to the IEA.[10] Clean energy investments include renewable power, energy grids, storage, low-emission fuels, energy efficiency, nuclear, and end-use renewables, as well as electrification. The largest share of investment went into renewable power (38%), energy efficiency measures (19%), and electricity grids and storage (23%). More specifically, solar, and onshore and offshore wind power projects attracted 91% of all investments into renewable power in 2024, primarily due to their bankable risk-return profiles.

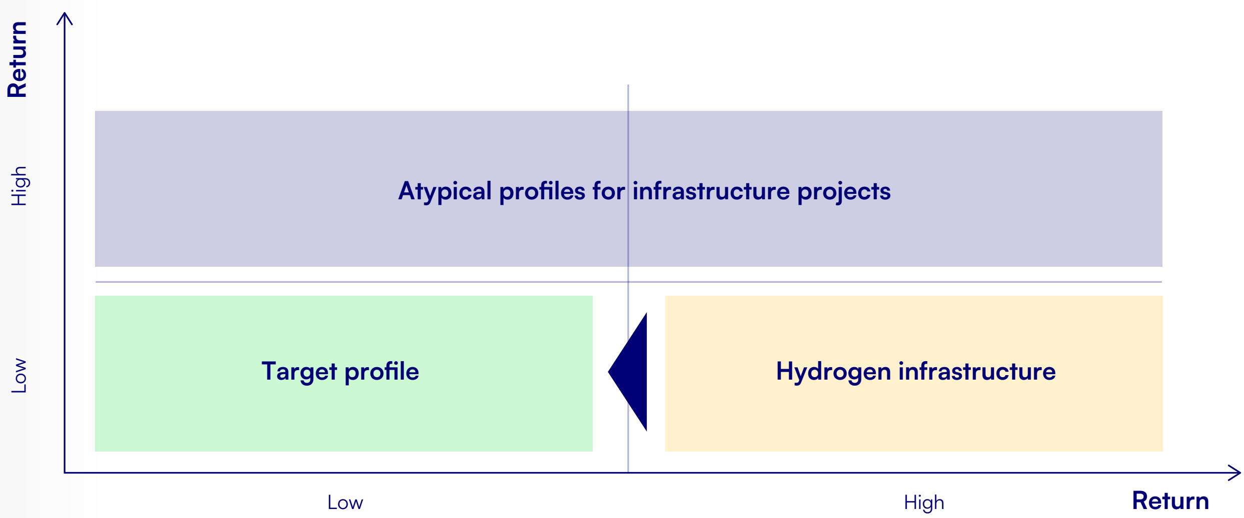
Mitigating risks—de-risking—to improve risk-return ratios of projects is critical to attract capital. De-risking hydrogen infrastructure projects can be achieved with financial support instruments.


IMAGE CREDIT: KITREEL / SHUTTERSTOCK

In contrast, only USD 1 billion, or less than 0.1% of total clean energy investment, was directed towards clean hydrogen. This is largely explained by the fact that investment in hydrogen and hydrogen infrastructure is currently associated with relatively high perceived risks and low returns compared to other investment opportunities, e.g. in clean energy, infrastructure, and conventional energy, making them less attractive to investors.[11] This is a structural financing gap that characterizes most of the initial investments in hydrogen infrastructure.[12]

Lastly, mitigating risks—de-risking—to improve **risk-return ratios** of projects is critical to attract capital. De-risking hydrogen infrastructure projects can be achieved with financial support instruments, as detailed in Section 3.

Figure 3: Schematic risk-return profile of hydrogen infrastructure



Box 2: Key risks impacting clean hydrogen midstream infrastructure projects

Market risks: These involve uncertainties in the price and volume of capacity bookings for pipelines, terminals, reconversion and storage facilities. For conventional infrastructure projects, price risks are typically mitigated by regulatory authorities through defined tariffs. Uncertainty about future capacity bookings, especially in the early post-commissioning phase, remains a key risk in the nascent hydrogen economy.

Political and regulatory risks: These stem from the evolving nature of hydrogen regulations, which are still under development in many regions. Consistent and clear regulatory frameworks are essential for project success, providing certainty about future cashflows and permitting processes. Political stability is also crucial, as regulatory environments must remain stable over the project's lifespan to avoid disruptions, particularly in emerging markets and developing countries (EMDCs) prone to regime change or social unrest.

Macroeconomic risks: These include volatile currency exchange rates, interest rates, and inflation. Changes in these factors have a significant impact on the capital costs of hydrogen projects. These costs are even higher in EMDCs, due to additional country risks related to medium to low credit ratings.

Permitting and compliance risks: Delays in land acquisition and obtaining necessary social and environmental permits pose significant challenges. These risks are particularly relevant for projects involving cross-border pipelines, which must navigate diverse national jurisdictions.

Design, construction, and completion risks: These encompass potential underestimations of project scope, planning errors, as well as time and cost overruns during construction and commissioning. Such risks are typically managed through engineering, procurement, construction and commissioning contracts with third parties.

Technology risks: These are especially high for technologies with low technology readiness levels (TRLs). These projects face increased risks of underperformance and failure. In contrast, commercially available technologies, like hydrogen pipelines and ammonia terminals, have higher TRLs and lower associated risks.

Operational and maintenance (O&M) risks: These arise after project commissioning and include performance failures and a lack of skilled workforce to operate the infrastructure. O&M risks are often linked to technology risks, which can cause hydrogen infrastructure underperformance.

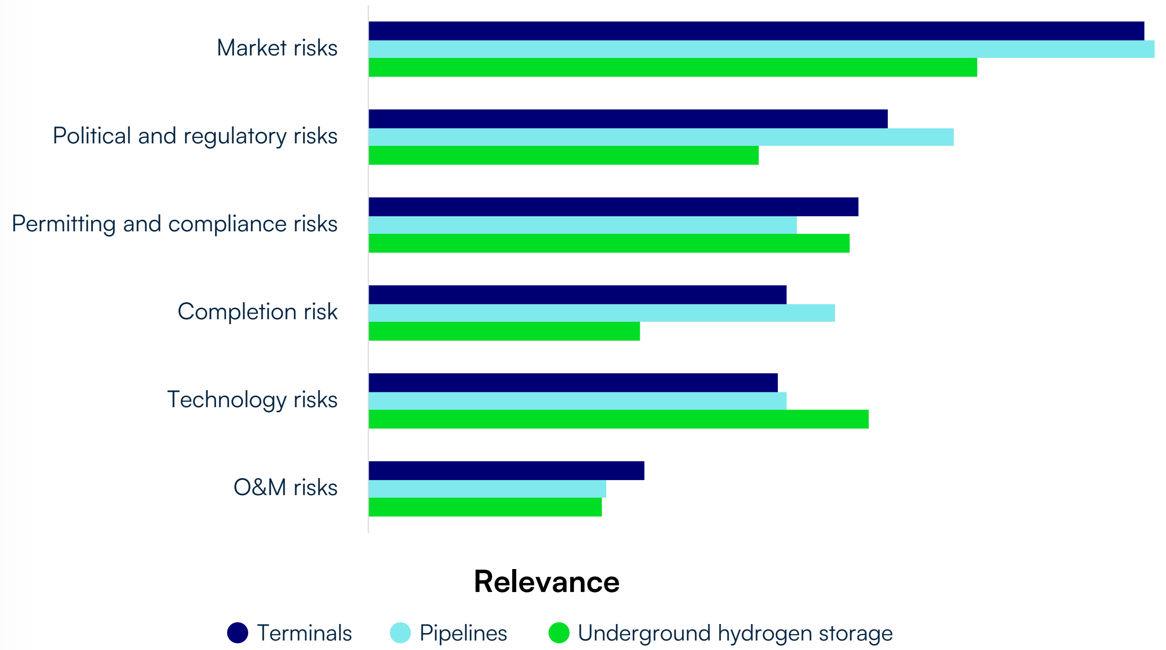
Risks and how they shape hydrogen infrastructure investments

Risk refers to the probability that a project will deviate from its expected outcome. In an investment context, risks include all circumstances that may change the timing or volume of an expected cashflow in an unfavorable or favorable manner. Risks that lack effective mitigation strategies can hinder equity investment, increase the cost of debt, and therefore negatively impact the weighted average cost of capital (WACC) of the project and, ultimately, the decision to invest.

All infrastructure projects face a variety of risks. Detailed discussions of these can be found in several sources.[13] Midstream hydrogen infrastructure projects are particularly susceptible to risks impacting their financial evaluation and feasibility.

The clean hydrogen economy is still in an early development stage characterized by limited liquidity, information asymmetry, high transaction costs, and market entry barriers. These factors contribute to substantial uncertainty regarding demand for infrastructure services among project developers and operators. In this report, this uncertainty is referred to as **market risk**. A crucial element of this risk, particularly in non-monopolistic infrastructure sectors such as reconversion technologies and storage facilities, is the threat posed to early adopters by second- and third-generation technologies. As newer, more cost-effective, and efficient technologies and facilities emerge, whether by leveraging economies of scale or through advancements in technology, they may outcompete first-generation technologies, potentially leading to the underutilization of infrastructure developed by first movers. This dynamic leads to significant aversion to early movement in the market.

Figure 4: Risk ranking from H2Global survey. Completion risks: Includes design and construction risks. O&M: Operation and maintenance.



Risks associated with the enabling environment of a hydrogen infrastructure project include **political and regulatory uncertainty, permitting and compliance risks, and macroeconomic risks**. The remaining risks are linked to on-site activities, such as **design, construction and completion risks, technology risks, and operational and maintenance risks**, including **safety risks**.

The clean hydrogen economy is still in an early development stage characterized by limited liquidity, information asymmetry, high transaction costs, and market entry barriers.

H2Global conducted an internal, non-representative industry survey among 22 of its donors, covering companies along the entire hydrogen value chain, to rank the described risks from 1 (most critical) to 6 (least critical) according to their perceived influence on the successful development of hydrogen infrastructure projects. The risks **ranked most critical were market risks, political and regulatory risks**, as well as **permitting and compliance risks**. Completion risks, technology risks and operational and maintenance (O&M) risks ranked lower.

Conventional de-risking strategies for energy infrastructure

Conventional energy infrastructure is typically associated with low to medium returns. In order to facilitate its construction and operation, several risk-sharing and mitigation strategies have been developed to realize sufficient risk-return ratios, including but not limited to:

— **Public-private partnerships (PPPs):** These involve collaboration between public and private stakeholders to finance, build, and operate projects.[14] In these constructs, the public side takes on a portion of the risk involved with the infrastructure project to build a viable economic case for the private side.

— **Build-operate-transfer (BOT) model:** This is a prominent example of a PPP. In this model, the private sector builds the infrastructure and operates it for a period of time before it is transferred to the public side. For the public side, this approach bears the advantage that risks associated with the construction and operation of the infrastructure are transferred to the private side. For the private side, BOT models hold the advantage of a foreseeable business case until the infrastructure is finally transferred to the public side.

IMAGE CREDIT: RJANKOVSKY SHUTTERSTOCK

- **Regulated asset base (RAB) model:** This model is particularly important for natural monopolies, where high entry barriers limit competition and ensure stable returns,[15] as these assets face minimal market-driven threats. However, this characteristic can also restrict discrimination-free access to the infrastructure, leading to unequal opportunities. In the RAB model, the public side regulates the fees for infrastructure users to guarantee a regulated return rate for the private side and fair pricing for users.

- **Special-purpose vehicles (SPVs):** These involve risk mitigation that can be conjointly leveraged in PPP and RAB constructs. Non-recourse SPVs are legal entities, which are separated from the balance sheets of the private entities that form the SPVs to invest in infrastructure assets. The advantage for private investors is that the infrastructure is financed only against the cashflows of the infrastructure assets themselves, protecting the balance sheets of the investing private entities.

An example of energy infrastructure which is currently being planned under a PPP scheme is the LNG import terminal in Brunsbüttel, Germany, with a maximum import capacity of 10 bcm per year, equivalent to 105 TWh per year.[16] For this project, the German Federal Government, together with the public entity Gasunie and private sector entity RWE AG, formed the SPV German LNG Terminal GmbH in order to plan, build and operate the terminal.

Although conventional de-risking strategies are successfully implemented to finance energy infrastructure globally, they are—as of now—failing to address the specific de-risking needs of hydrogen infrastructure projects, due to the unique circumstances of these projects. As detailed in earlier sections, the nascent hydrogen market and its associated risks and uncertainties are significantly different from those of other energy infrastructure projects. Therefore, the remainder of this report assesses variants of conventional and newer financial support instruments as innovative strategies to build viable business cases for investment in hydrogen infrastructure to close this investment gap.

Although conventional de-risking strategies are successfully implemented to finance energy infrastructure globally, they are—as of now—failing to address the specific de-risking needs of hydrogen infrastructure projects.

IMAGE CREDIT: TAVIPHOTO / ISTOCKPHOTO

IMAGE CREDIT: BELYAAA / ADOBE STOCK

3

Financial support instruments to de-risk hydrogen infrastructure

Financial support instruments are a key lever for increasing the economic viability of hydrogen infrastructure projects, as they mitigate associated market risks and lower investment needs.

This section outlines four key financial support instruments and discusses their impact on closing or narrowing the investment gap for midstream infrastructure projects. These instruments were identified through working group discussions with the H2Global Foundation's donors and are closely aligned with the publication by H2eart for Europe and Guidehouse, which, while focused on underground hydrogen storage (UHS), presents a toolbox of financial support mechanisms that are applicable to all midstream infrastructure projects in this report.[17]

The **four most promising instruments identified are capital expenditure (CAPEX) support, fixed premium, contracts-for-difference (CfDs), and anchor capacity bookings (ACBs)**.

Additionally, other strategies aimed at indirectly supporting the growth of hydrogen infrastructure, particularly by supporting the demand sector, are discussed in detail in the associated H2Global report, "Unlocking potential: Scaling demand through hydrogen hubs". These strategies include the benefits of demand aggregation through hydrogen hubs and the positive impacts of supply chain coordination.

Furthermore, this assessment of the four instruments focuses solely on their financial impact on individual infrastructure projects; how different design elements of the award procedure have impacted on their effectiveness is not examined here. Instead, the influence of the award procedure—particularly auction design—is covered in detail in the H2Global report, "Keep it simple: Aligning auction objectives for success". This section will first describe the four identified financial support mechanisms and will follow this description with a quantitative analysis of their funding efficiency for archetypal infrastructure projects. The section concludes with a qualitative discussion of other relevant metrics that influence the suitability of these mechanisms for financing infrastructure projects, including administrative ease, market risk mitigation, and mitigation of stranded funding resources.

CAPEX support

Direct capital expenditure (CAPEX) support is the simplest financial support mechanism, as it comes as a one-time subsidy before the construction and operation phase of a project, in order to lower the upfront investment costs. Examples at the European level include the Connecting Europe Facility (CEF), which has granted EUR 4.7 billion of financial support to energy-related infrastructure projects since its start in 2013, thereby contributing up to 50% of the total investment costs to each project.[18]

Fixed premium

In contrast to CAPEX support, a fixed premium (FP) subsidy is provided during the operational phase of a hydrogen infrastructure project. Projects are awarded an FP per sold unit of capacity booking, e.g., cubic meters of booked gas transport capacity in the case of a pipeline. This type of financial support mechanism creates an add-on to the revenue stream from selling capacity to the users. Germany's Renewable Energy Sources Act, *Erneuerbare-*

Germany's Renewable Energy Sources Act has been a prominent example of an FP scheme, where fixed payments are provided to renewable energy producers for every kilowatt-hour of electricity they generate.

Figure 5: Revenue and funding over capacity utilization for the financial support instrument "fixed premium"

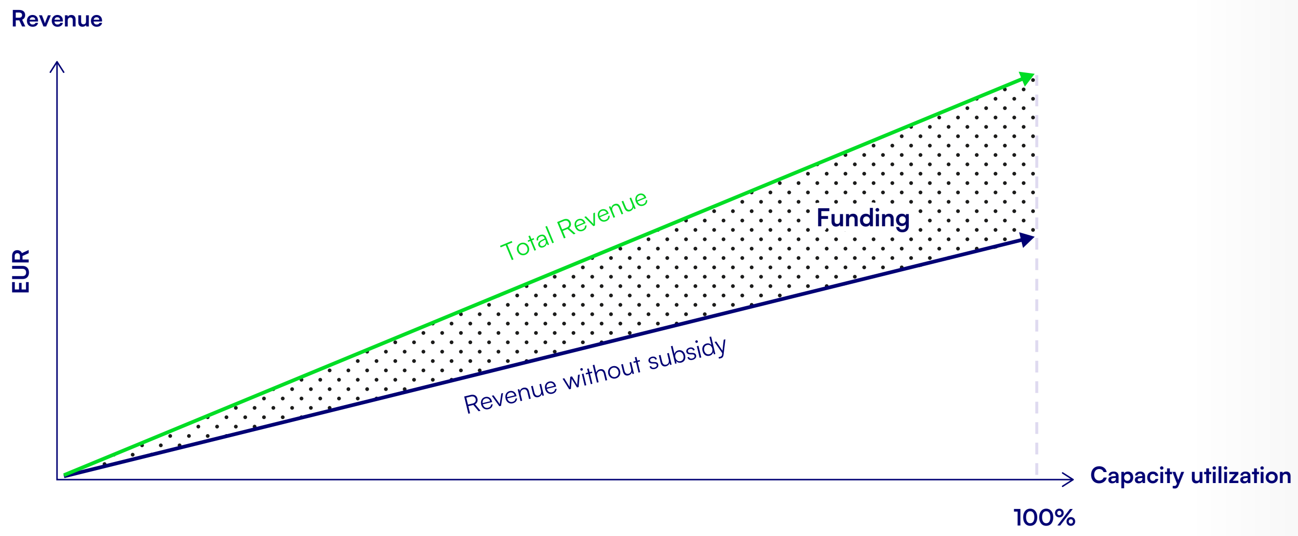
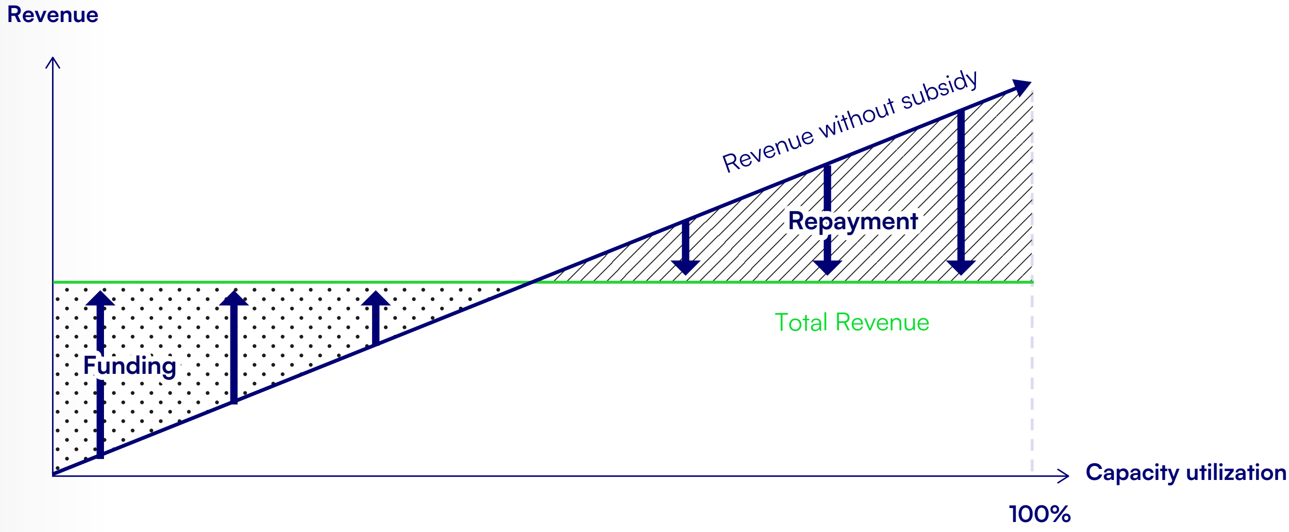


Figure 6: Revenue and funding over capacity utilization for the financial support instrument "contracts-for-difference"



Energien-Gesetz (EEG), has been a prominent example of an FP scheme, where fixed payments are provided to renewable energy producers for every kilowatt-hour of electricity they generate.[19] Financial support with an FP has also been applied to fund hydrogen production in recent tenders of the European Hydrogen Bank's pilot auction and the Danish Power-to-X (PtX) tender.[20] Figure 5 visualizes the development of the revenue and funding cashflows for the infrastructure operator, showing that revenues increase proportionally with rising capacity utilization until the capacity is fully booked. For simplicity, the figure assumes a constant fee for capacity utilization, resulting in a linear increase in revenue, as capacity utilization increases. This approach, however, does not account for potential fluctuations in pricing or network fees, thus neglecting the associated price risk.

One option to limit the funding expenses is to set a cap, beyond which the total revenue remains constant. As capacity utilization increases, the FP is continuously decreased to ensure that the total revenue from capacity utilization matches the cap. This cap is defined during the procurement process, either through auctions, negotiations, or directly through the funding body.

CfDs

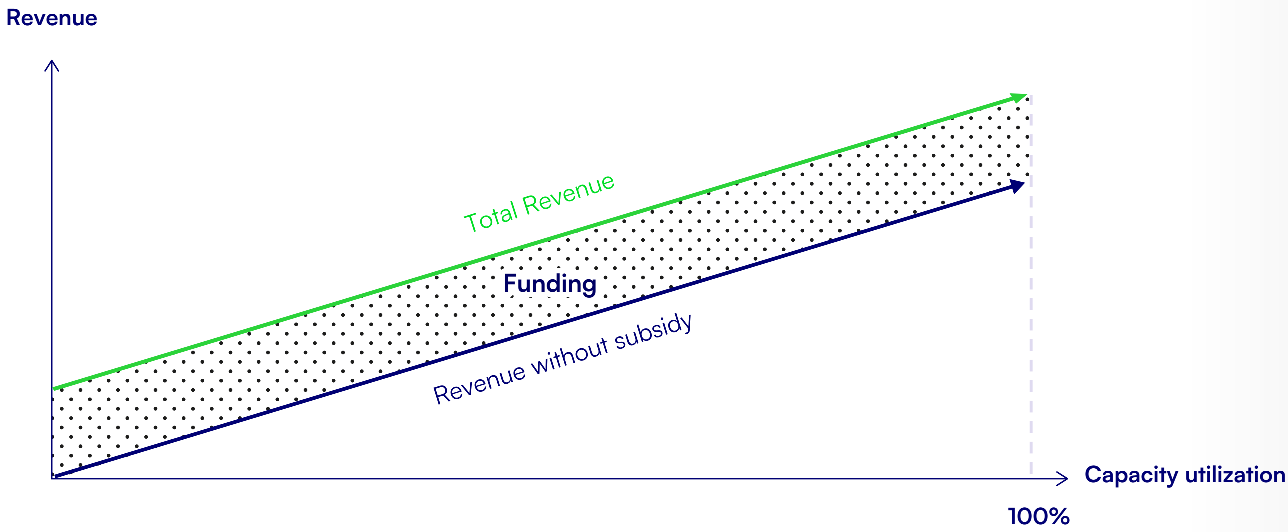
Contracts-for-difference (CfDs) are another type of financial support instrument applied during the operational phase of infrastructure projects. The presented design of a CfD is revenue-based, guaranteeing private investors of infrastructure projects a constant return on their investment (ROI), as opposed to the common price per unit-based understanding of CfDs. In the allocation phase of this mechanism, the projects' target ROIs are defined through auctions, negotiations, or directly through a regulatory body. Subsequently, awarded projects receive funding if revenues from capacity utilization result in a lower ROI than guaranteed by the instrument. In the reverse case, i.e., that revenues from capacity utilization exceed the constant ROI, awarded projects are obliged to make payments back to the funding body. This is called the "claw back" in CfD mechanisms and results in a potentially more effective usage of public funds.

In the context of infrastructure financing, revenue-based CfDs are derived from the regulated asset-based business model, which also predefines the maximum allowed ROI and regulates the tariffs for infrastructure users accordingly.

This is different from price-per-unit-based CfD schemes, which are typically applied outside of infrastructure financing to provide price support for renewable energy projects, for example in the United Kingdom and Denmark,[21] and to decarbonize industrial sectors in Germany under the carbon-contracts-for-difference (CCfD) concept.[22] These schemes stabilize the price received per unit of output, rather than focusing on overall revenue.

Because CfDs guarantee an ROI independent from capacity utilization, projects may lack the incentive to market and sell capacity. To address this, CfD mechanisms could either be designed with an ROI that increases as capacity utilization rises or include a joint risk-sharing arrangement between the project operator and the funding body. In the latter case, if the project's cash balance ends up being negative, the remaining debt is shared between the investors and the funding body.

Figure 7: Revenue and funding over capacity utilization for the financial support instrument "anchor capacity bookings"



ACBs

The concept of anchor capacity bookings (ACBs) is derived from the notion that uncertainty regarding the future utilization of infrastructure is the largest single impediment to private investments. The proposed ACBs guarantee a revenue floor over the funding period via constant annual payments. This financial support scheme is also referred to as a "revenue floor". Examples include the Capacity Investment Scheme, introduced in Australia in 2023 to support investments in renewable energy generation and storage,[23] and the proposed Hydrogen Storage Business Model in the UK, which includes a revenue floor for underground storage in its first allocation round set to be launched in Q3 of 2024.[24]

The ACB mechanism is presented in Figure 7. The instrument provides constant annual funding—the so-called "anchor capacity bookings"—which is independent of the actual utilization of the infrastructure. This ensures that even if there is no capacity utilization, the infrastructure operator receives revenue from these ACBs. When actual capacity utilization increases, the operator can earn additional revenue on top of the guaranteed income from them.

One option to limit the overall funding amount is to set a cap, beyond which the ACBs are reduced, thereby only providing funding in the cases of low-capacity utilization. This cap is defined during the allocation process, either through auctions, negotiations or directly through the funding body.

IMAGE CREDIT: STEVE TRITTON / SHUTTERSTOCK

Box 5: Examples of financing mechanisms for hydrogen infrastructure

Currently, there are only a few existing or proposed financial support mechanisms specifically for hydrogen infrastructure projects. Notable examples include Germany's amortization account for hydrogen pipelines and the UK's proposal for supporting underground hydrogen storage (UHS) and hydrogen pipelines, which are similar to the instruments proposed in this report: CfDs and ACBs.

Germany's amortization account

In the ramp-up phase for the core network of hydrogen pipelines, the gap between high investment costs and low revenue generated from network fees is covered by an amortization account. As more users connect to the network and the revenues from network fees surpass the network costs, the deficit in the amortization account will be offset. If the amortization account is not balanced out by 2055, network operators will contribute a co-payment of up to 24% of the remaining shortfall.[25]

UK's "minded to" position to support UHS and hydrogen pipelines

The UK has outlined its proposals for supporting UHS and hydrogen pipelines in their "minded to" positions for the Hydrogen Storage Business Model and Hydrogen Transport Business Model, respectively.[26] While the final designs of the allocation processes are not yet published, the first allocation rounds are planned for 2024.

The Hydrogen Storage Business Model includes a revenue floor to ensure UHS operators receive minimum revenue, covering total capital costs, fixed operational costs, and a modest return on capital investment, but not variable operating costs. To encourage operators to maximize revenue from users, the system is designed so that, as user revenue increases, the subsidy decreases—but the reduction in subsidy will be less than the increase in user revenue. The UK government is also considering mechanisms to profit from potential high revenues, such as a revenue cap or gainshare, but a specific approach has not yet been determined.

The Hydrogen Transport Business Model proposes using a regulated asset base (RAB) to support hydrogen pipelines. An external subsidy mechanism will be established alongside the RAB to keep user charges affordable while allowing operators a reasonable return on investment. During the ramp-up phase, user charges will be capped to avoid being prohibitive. If operators cannot recover all allowed revenue via the RAB, the subsidy mechanism will cover the shortfall between the allowed revenue and the fair user charges.

IMAGE CREDIT: FUTUROPROSSIMO

Hydrogen infrastructure archetype projects: Testing alternative financial instruments

Financial support instruments are key to mitigating risks associated with midstream hydrogen infrastructure projects. This report tests whether the instruments described above can help mobilize the large-scale investments needed in hydrogen infrastructure, using archetypal projects of hydrogen pipelines, terminals, reconversion technologies (e.g., ammonia crackers) and underground hydrogen storage. Each archetypal midstream project is evaluated as an independent business case, focusing on individual economic viability from the project developer's perspective. For an assessment of integrated value chains, the reader may refer to other existing studies.[27]

The archetype projects were developed in collaboration with industry stakeholders and academic partners, and parametrized with respect to: (a) capacity; (b) financial metrics, such as capital expenditure (CAPEX), operational expenditure (OPEX), capital structure, depreciation period, cost of capital, and pricing; (c) the future utilization of hydrogen infrastructure projects; and (d) associated project risks. A discounted cashflow analysis was conducted for all archetypal projects to analyze financial support mechanisms under different pricing scenarios. The general economic assumptions on depreciation, cost of capital, debt-to-equity ratio and the project's utilization rate over the depreciation period are detailed in Table 2.

Project-specific risks are accounted for by conducting a Monte-Carlo simulation, assuming normal distributions for the investment costs, operational costs, and the future utilization of the project. The Monte-Carlo simulation provides a probability distribution of the expected return

This report tests whether the financial support instruments can help mobilize the large-scale investments needed in hydrogen infrastructure, using archetypal projects of hydrogen pipelines, terminals, reconversion technologies (e.g., ammonia crackers) and underground hydrogen storage.

and enables the calculation of the value-at-risk (VaR). In turn, the VaR is considered as a premium to the cost of equity to account for potential losses due to project-specific risks. The calculation of the weighted average cost of capital (WACC) is described in detail in Annex II.

Table 2: General financial assumptions

Financial parameter	Value
Depreciation period	25 years
Share of debt financing	0.7
WACC*	10.06% + VaR* share of equity financing
Utilization during operational phase	Ramp-up phase (8 years for hydrogen pipelines and underground hydrogen storage, 5 years for terminals and reconversion): Linear increase from 50 to 80% Constant phase (>8 years for pipelines, underground hydrogen storage, >5 years for terminals, reconversion): 80%
Probabilistic assumptions	Standard deviation (SD) of investment costs: 10% SD of operational costs: 20% SD of utilization rate: 20%

*Both the WACC and the VaR are calculated using the open-source Python package PROFIN, developed by the H2Global Foundation.[28]

Pricing scenarios

Individual pricing scenarios are assumed for the analyzed archetypal hydrogen infrastructure, oriented at the levelized costs of providing the infrastructure service. Because each type of infrastructure provides different services, the unit of the fee also varies, as listed below.

— **Pipeline fee**: charged per kWh of hydrogen transported across the total pipeline distance.

— **Terminal fee**: charged per kWh of hydrogen unloaded and stored, assuming a maximum storage duration of six days.

— **Reconversion fee**: charged per kWh of hydrogen reconverted from its carrier, including associated energy costs for heat and electricity.

— **Underground storage fee**: charged per kWh of hydrogen stored, assuming a maximum storage duration of 50—180 days.

Maximum storage duration is assumed for the archetypal terminal and underground hydrogen storage projects to facilitate the required storage cycles per year to achieve the assumed utilization rate of the infrastructure. Real-world business models may differ from the assumed pricing scenarios (e.g., business models for storage might be based on monetizing intertemporal price differences); however, revenues can be converted to the assumed pricing scenarios to allow for theoretical analyses.

Three distinct pricing scenarios are established for each infrastructure archetype to assess economic viability under different conditions:

— **Base scenario**: pricing aligns with levelized costs, resulting in a net-present value (NPV) near zero.

— **Reduced fee scenario**: a 25% fee reduction from the base, simulating conditions of unprofitability.

— **Increased fee scenario**: a 25% fee increase from the base, representing a profitable outlook.

Archetype hydrogen pipeline project

The archetype project of a hydrogen pipeline has a length of 1,500 km, with 60% being newly built and 40% repurposed, consistent with the European Hydrogen Backbone plans,[29] a 48-inch pipeline diameter, and a compressor station every 500 km. This results in a transport capacity of 9,200 tons of hydrogen per day or a daily throughput capacity of 307 GWh.[30] With an annual import capacity of max. 112 TWh or 3.3 Mt-H2 per year, this archetypal pipeline is at the upper end of currently discussed pipeline dimensions and could serve large shares of future national hydrogen demands. Comparable pipeline projects are the South2 corridor connecting North Africa with Italy over a length of 3,300 km, with an annual import capacity of >4 Mt-H2 per year, or the HY-FEN pipeline leading through France over a length of 1,200 km, with an annual capacity of >2 Mt-H2 per year.[31] The investment (CAPEX) and operational (OPEX) costs for the archetype hydrogen pipeline are derived from the latest European Hydrogen Backbone report.[32]

In this analysis, the business model of the archetypal hydrogen pipeline project is simplified to a single revenue stream for transporting hydrogen through the pipeline. The transport fee depends on the pricing scenario and varies between 0.86 EUR-ct./kWh, 1.15 EUR-ct./kWh, and 1.44 EUR-ct./kWh. The results of the financial analysis are depicted in Table 4.

Table 3: Techno-economic assumptions for the archetype pipeline project

Parameter	Value
Capacity (1,500 km pipeline, 60% new, 40% repurposed, compressor stations every 500 km)	9,200 t-H2 per day
CAPEX pipeline	EUR 4.488 billion
CAPEX compressor	EUR 1.280 billion
OPEX	EUR 67 million per year

Table 4: Simulation results archetypal pipeline project. NPV: net-present value. IRR: internal rate of return. WACC: weighted average cost of capital

Pricing scenario	0.86 EUR-ct./kWh (Base — 25%)	1.15 EUR-ct./kWh (Base)	1.44 EUR-ct./kWh (Base + 25%)
Archetypal pipeline project			
NPV [Mio. EUR]	-1,370	+170	+1,720
IRR	7.7%	11.8%	15.7%
WACC	11.1%	11.3%	11.4%

In the base case pricing scenario, a fee of 1.15 EUR-ct/kWh (equivalent to 0.38 EUR/kg H2) for transported hydrogen is sufficient to achieve a slightly positive net present value. The WACC rises with the assumed fee due to increased volatility of the revenue, which amplifies the project's VaR and subsequently raises financing costs.

Archetype terminal projects

The archetypal terminal project encompasses four different energy carriers: ammonia (NH3), liquid hydrogen (LH2), synthetic methane (SNG), and liquid organic hydrogen carrier (LOHC), detailed in Table 5. The import capacity is oriented at the size of two currently planned German terminal projects in Brunsbüttel[33] and Wilhelmshaven[34] and defined to 5 TWh H2-eq. per year, assuming the arrival and offloading of cargo occurs every six days. The required tank volumes for NH3 and SNG are designed to include additional capacity, accounting for losses incurred during the subsequent reconversion to hydrogen. The largest cost component of the archetypal terminal projects is the storage tank for the energy carrier. Additionally, investment and operational costs are assumed for required piping, compressors, pumps, and boil-off gas systems. The specific costs for the terminal projects are derived from literature[35] and validated in expert interviews.

Terminals, and in this case specifically import terminals, serve the purpose of unloading cargo and storing the energy carrier for a given period until it is further transported to the place of final consumption. In real terminal projects, all services are charged. In this simplified analysis, a combined fee for the unloading and storage services per kWh-H2-eq. are assumed in the different pricing scenarios. An additional service being provided by the terminal operator or an associated third party might optionally be the reconversion of the stored energy carrier into another. This reconversion step is analyzed in a separate scenario. Table 6 presents the results of the financial analysis for the archetypal storage terminals.

Table 5: Techno-economic assumptions for the archetypal terminal projects

Parameter	Value	
Capacity	Import: 5 TWh-H2-eq. per year Tank volumes: NH3: 38,000 m³ SNG: 33,000 m³	 LH2: 57,000 m³ LOHC: 81,000 m³
CAPEX for a depreciation period of 25 years	NH3: EUR 220 million SNG: EUR 355 million	LH2: EUR 497 million LOHC: EUR 34 million
OPEX	NH3: EUR 11 million per year SNG: EUR 23 million per year	LH2: EUR 15 million per year LOHC: EUR 1 million per year

Table 6: Simulation of results of archetypal terminal projects. NPV: net-present value. IRR: internal rate of return. WACC: weighted average cost of capital

NH3 terminal			
Pricing scenario	0.90 EUR-ct./kWh	1.20 EUR-ct./kWh	1.50 EUR-ct./kWh
NPV [Mio. EUR]	-66	+7	+78
IRR [%]	6.7%	12.0%	17.1%
WACC [%]	11.0%	11.4%	11.8%
SNG terminal			
Pricing scenario	1.54 EUR-ct./kWh	2.05 EUR-ct./kWh	2.56 EUR-ct./kWh
NPV [Mio. EUR]	-117	+5	+120
IRR [%]	6.2%	11.8%	17.0%
WACC [%]	11.0%	11.4%	11.9%
LH2 terminal			
Pricing scenario	1.80 EUR-ct./kWh	2.40 EUR-ct./kWh	3.00 EUR-ct./kWh
NPV [Mio. EUR]	-135	+11	+153
IRR [%]	7.2%	11.9%	16.3%
WACC [%]	11.1%	11.4%	11.7%
LOHC terminal			
Pricing scenario	0.15 EUR-ct./kWh	0.20 EUR-ct./kWh	0.25 EUR-ct./kWh
NPV [Mio. EUR]	-8	+2	+12
IRR [%]	7.7%	12.6%	17.2%
WACC [%]	11.1%	11.5%	11.8%

In the base case pricing scenario, which yields a net present value close to zero, fees range from 0.20 to 2.40 EUR-ct/kWh-H_2-equivalent. The LOHC terminal is at the lower end of this range, the NH3 terminal in the middle, and the SNG and LH2 terminals are at the upper end. The capacities of the archetypal carrier reconversion projects in the following section are aligned with the capacities of the presented terminal archetypes.

Archetype carrier reconversion project

The design of archetype carrier reconversion projects is oriented at the associated terminal projects for NH3, SNG, and LOHC. There is no reconversion project analyzed for LH2, since the carrier is already in its final form—hydrogen. The reconversion technologies convert the energy carrier into gaseous hydrogen with a purity of 99.97%, in accordance with the ISO 14687:2019 standard,[36] at ambient temperature and 80 bar, suitable for feeding into a hydrogen pipeline network and for use in fuel cells. All analyzed reconversion technologies (NH3: ammonia cracking, SNG: steam reforming, LOHC: dehydrogenation) are endothermic processes, requiring external thermal energy (e.g., from the hydrogen carrier or from waste heat), or electric energy input. In this analysis, for ammonia cracking and steam reforming, the energy is derived directly from the energy carriers involved in the process, whereas LOHC dehydrogenation relies on external electric energy. Table 7 lists investment and operational costs for the different reconversion technologies with respect to the assumed capacity of 5 TWh-H2 per year. The techno-economic assumptions are based on expert interviews with technology providers and relevant literature.[37]

Table 7: Techno-economic assumptions for the archetype reconversion projects

Parameter	Value
Capacity	Import: 5 TWh-H2 per year
CAPEX for a depreciation period of 25 years	NH3: EUR 160 million SNG: EUR 423 million LOHC: EUR 169 million
OPEX—excluding thermal energy demand	NH3: EUR 7.5 million per year SNG: EUR 35 million per year LOHC: EUR 4.2 million per year

As outlined above, the process of reconverting an energy carrier to hydrogen can be part of the services offered by an import terminal or an associated third party. However, the reconversion unit can also be co-located with the offtaker. The results of the financial assessment are presented in Table 8.

Table 8: Simulation of results of archetypal reconversion projects. NPV: net-present value. IRR: internal rate of return. WACC: weighted average cost of capital

NH3 reconversion			
Pricing scenario	3.15 EUR-ct./kWh	4.20 EUR-ct./kWh	5.25 EUR-ct./kWh
NPV [Mio. EUR]	-250	+2	+196
IRR [%]	<5%	13.3%	32.0%
WACC [%]	11.1%	12.8%	14.8%
SNG reconversion			
Pricing scenario	12.45 EUR-ct./kWh	16.60 EUR-ct./kWh	20.75 EUR-ct./kWh
NPV [Mio. EUR]	-1,002	-9	+662
IRR [%]	<5%	13.9%	39.2%
WACC [%]	11.1%	13.5%	16.7%
LOHC reconversion			
Pricing scenario	3.90 EUR-ct./kWh	5.20 EUR-ct./kWh	6.50 EUR-ct./kWh
NPV [Mio. EUR]	-307	+1	+239
IRR [%]	<5%	13.6%	34.8%
WACC [%]	11.1%	13.1%	15.2%

In the base case pricing scenario, which yields a net present value close to zero, fees range from 4.20 EUR-ct./kWh-H2-produced for the archetypal ammonia cracker, to 5.20 EUR-ct./kWh-H2-produced for LOHC dehydrogenation, and 16.60 EUR-ct./kWh-H2-produced for steam methane reforming of SNG. The economics of all archetypal reconversion projects are primarily driven by OPEX, due to the significant external energy requirements needed to operate the endothermic reconversion processes.

Archetype underground hydrogen storage project

Underground hydrogen storage project types vary depending on the specific use case and the geological pre-conditions at the project site. The use cases can generally be separated into three types: (1) Storage to balance intra-day to intra-month mismatches between the supply of renewable energy to the grid and the demand side. These mismatches can occur due to the inherent short-term temporal volatility of renewable energy generation or regional imbalances of supply and demand; (2) Seasonal storage to cover long-term imbalances in the power sector due to seasonal weather fluctuations, e.g., less solar power generation in winter months; (3) Strategic storage to bridge periods of unexpected supply shortages.

Underground hydrogen storage projects can be developed in salt caverns, depleted gas fields and aquifers. Salt cavern projects involve higher specific investment costs compared to depleted gas fields and aquifer projects.

However, they offer the advantage of enhanced cyclability and have been a proven technical solution for gas storage for decades.

In this analysis, four different archetypal underground hydrogen storage projects are defined, drawing from Lin et al.[38] and discussion with industry experts. The first two archetypal projects are termed "single-turn" to depict seasonal hydrogen storage, and are analyzed for a depleted gas field and a salt cavern project. The storage of these types of projects is usually filled and withdrawn from relatively continuously, following seasonal supply and demand. In total, it is assumed that the working gas is fully cycled[39] once per year. The second two archetypal projects are named "multi-turn" and serve the purpose of balancing the production of volatile renewable energy sources over the year, with changing periods of filling and withdrawal.

This archetype is also evaluated for a depleted gas field and a salt cavern project. In total, the working gas is cycled 3.5 times per year in the multi-turn project.

The energy costs associated with compressing the working gas during injection make up a major portion of the total operational expenses. Therefore, a higher OPEX-to-CAPEX ratio is assumed for multi-turn projects compared to single-turn projects.

The storage capacity of an underground hydrogen facility can range from approximately 1 GWh for pilot projects to several TWh for large-scale installations that combine multiple underground hydrogen storage sites located near one another.[40] Storage capacity is influenced by the intended use, geological conditions, and the overall hydrogen market development. For this analysis, mid-term capacities of 145 GWh for depleted gas field projects and 25 GWh for salt cavern projects are assumed.

The investment and operational costs are detailed in Table 9 and derived from a report by Gas Infrastructure Europe, published in April 2024,[41] and discussions with industry experts.

Table 9: Techno-economic assumptions for the hydrogen underground storage archetype project

Parameter	Value
Capacity	Depleted gas field: 145 GWh
	Salt cavern: 25 GWh
CAPEX for a depreciation period of 25 years	Depleted gas field: EUR 65 million
	Salt cavern: EUR 23 million
OPEX	Single-turn: 4% of CAPEX
	Multi-turn: 10% of CAPEX

In the case of the single-turn project, the maximum storage duration would be ~180 days to allow for one full storage cycle per year. In the case of the multi-turn project, the maximum storage duration would decrease to ~50 days to facilitate 3.5 storage cycles per year. Hence, the maximum revenue for the single-turn project is 145 GWh * storage fee, while the multi-turn project has a maximum revenue of 25 GWh * 3.5 cycles * storage fee. The results of the financial evaluation of the underground hydrogen storage projects are shown in Table 10.

Table 10: Simulation of results of archetypal underground hydrogen storage projects. npv: net-present value. irr: internal rate of return. wacc: weighted average cost of capital

Single-turn			
Depleted gas field			
Pricing scenario	8.5875 EUR-ct./kWh	11.45 EUR-ct./kWh	14.3125 EUR-ct./kWh
NPV [Mio. EUR]	-19	1	20
IRR [%]	7.3%	11.5%	15.6%
WACC [%]	10.9%	11.2%	11.5%
Salt cavern			
Pricing scenario	16.875 EUR-ct./kWh	22.50 EUR-ct./kWh	28.125 EUR-ct./kWh
NPV [Mio. EUR]	-7	0	6
IRR [%]	7.1%	11.2%	15.3%
WACC [%]	10.8%	11.3%	11.5%
Multi-turn			
Depleted gas field			
Pricing scenario	3.30 EUR-ct./kWh	4.40 EUR-ct./kWh	5.50 EUR-ct./kWh
NPV [Mio. EUR]	-26	0	25
IRR [%]	6.0%	11.4%	16.8%
WACC [%]	11.0%	11.3%	11.7%
Salt cavern			
Pricing scenario	6.60 EUR-ct./kWh	8.80 EUR-ct./kWh	11.0 EUR-ct./kWh
NPV [Mio. EUR]	-9	0	9
IRR [%]	6.0%	11.5%	16.8%
WACC [%]	10.8%	11.4%	11.6%

IMAGE CREDIT: STANDRET / ADOBE STOCK

In the base case pricing scenario, which achieves a near-zero net present value, the storage fee for single-turn archetypes is 11.45 EUR-ct./kWh-stored for depleted fields and 22.50 EUR-ct./kWh-stored for salt cavern projects. The higher fee for salt cavern projects reflects their greater initial investment costs compared to depleted fields. Due to these lower costs and potentially larger capacities, depleted fields are more likely to be used for seasonal and strategic storage projects—provided their scalability and reliability can be demonstrated. For multi-turn archetypes, the fees decrease to 4.40 EUR-ct./kWh-stored for depleted fields and 8.80 EUR-ct./kWh-stored for salt caverns, as increased storage cycles per year enhance project revenue.

Sensitivity analysis: country risk premium and utilization

The evaluation of the economic viability of archetypal hydrogen infrastructure projects builds on the assumptions of no country risk and relatively high utilization, which increases from 50% to 80% during the first years of operation.

In the base case scenarios, the cost of capital (WACC) without project-specific risks is calculated to 10.06%, assuming no country risk premium. This assumption holds true for Central Europe, North America, Japan, South Korea, Australia, New Zealand, and parts of the Middle East. In order to depict the economic viability of projects in emerging markets and developing countries (EMDCs) with higher associated risks, the archetypal projects have been additionally evaluated in a sensitivity analysis assuming a **country risk of 6.5%**, equal to a Moody's B1 ranking (e.g., Namibia, Albania, Jordan). **This increases the WACC without project-specific risks to 15.7%**. Thus, hydrogen infrastructure projects in EMDCs face significantly higher financing costs while at the same time having more limited access to capital. Governments can play a vital role in decreasing the perceived country risk by enhancing the investment environment for hydrogen projects. Additionally, development financial institutions and multilateral development banks can help bridge the gap through direct guarantees and loans, knowledge sharing, capacity building, and international cooperation.[42]

A second sensitivity analysis assumes a **lower, constant utilization of 20%** over the depreciation period for the archetypal infrastructure projects. Under this scenario, **projects across all pricing scenarios become unprofitable**, indicating a heightened risk of these assets becoming stranded if actual utilization falls short of projections.

Assessing the efficiency of financial support instruments

Financial support instruments, such as CAPEX funding, ACB, FP funding and CfD can be adopted to enhance the economic viability of hydrogen infrastructure projects. To assess their efficiency, they were tested under different **funding scenarios**: CAPEX, ACB and FP funding were set to 40% of the total CAPEX across all scenarios; the CfD funding volume was set depending on varying annual cashflows.

Figure 8 depicts the efficiency of diverse financial support instruments, measured by the increase of the NPV in relation to the total amount of received funding. Furthermore, Figure 8 distinguishes between the defined pricing scenarios, highlighting projects that are—without funding—on the verge of economic viability (NPV~0), the ones that are profitable, and the ones that are unprofitable.

CAPEX funding is evaluated to be the most efficient instrument for projects with an NPV below or above zero, while it is the second most efficient instrument for projects with an NPV close to zero after CfD funding. The high funding efficiency of 90%, on average, is explained by the fact that the time value of financial support is higher the earlier it is received. This effect is best leveraged by CAPEX support instruments, as the financial support is given before the project goes into operation.

CfD funding is found to be the second most efficient instrument, with an average efficiency of 64% for projects with an NPV below zero and 98% for projects with an NPV close to zero. In this case, the high funding efficiency is primarily due to the fact that CfD funding alleviates all project-specific risks associated with future cashflows and thereby lowers the WACC to the baseline of 10.06%. In contrast, the minimum WACC for CAPEX-funded projects is 11.1%. This emphasizes the key advantage of CfD funding to mitigate project-specific market risks.

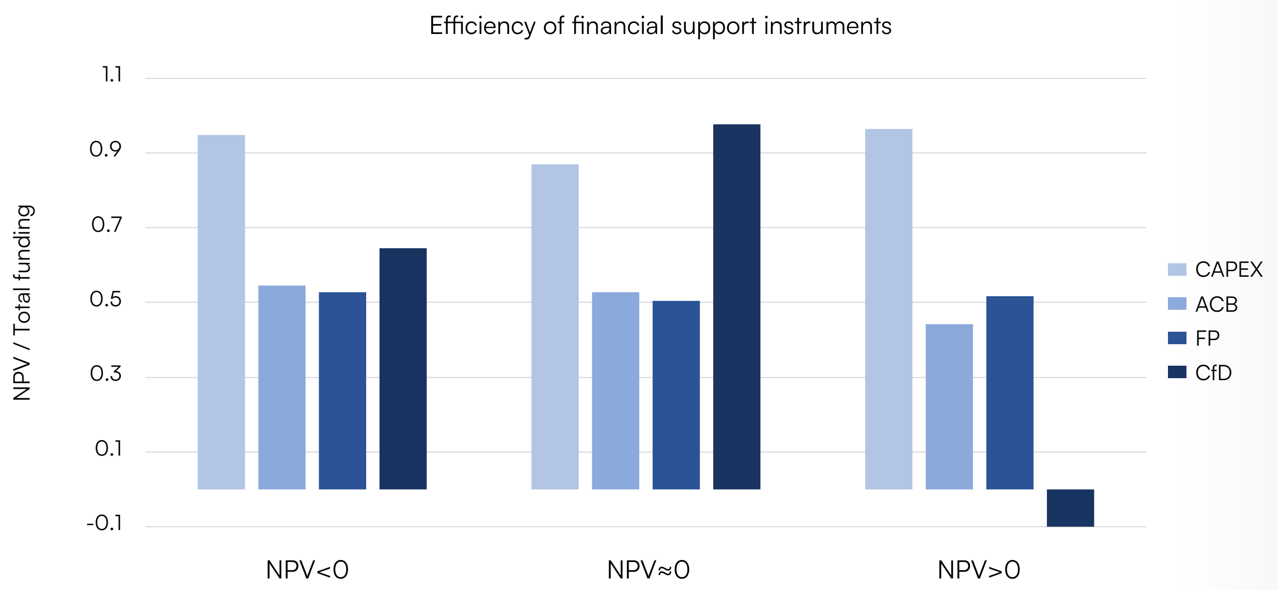
ACB and FP funding come out of the analysis as the least efficient for projects with an NPV below or close to zero, with ACB funding being slightly more efficient than FP funding.

In some cases, it might also make sense to apply funding instruments to projects with already high economic viability in order to mitigate associated risks. For these types of projects, the financial efficiency of CAPEX funding remains the highest, with an average of 97%, while ACB and FP funding yield 44% and 52%, respectively. At the same time, the efficiency of CfD funding turns negative. This is because projects become so profitable that the repayments to the funding institution within the CfD scheme exceed the payments from the funding institution to the project.

Overall, CAPEX and CfD funding are found to be the most efficient instruments for projects prior to receiving funding with an NPV below or close to zero. ACB and FP are least efficient, with ACB being slightly more efficient than FP as it also contributes to risk mitigation.

Financial efficiency is a valuable tool to assess the suitability of a financial support instrument. However, there are also practical reasons that can influence the choice of a support instrument, as detailed on page 39.

Figure 8: Funding efficiency given as increase of NPV per EUR billion funding



Evaluation of financial support instruments

In addition to the funding efficiency calculated for the archetypal projects in the previous section, several other metrics are crucial for evaluating the suitability of different financial support instruments. A spider-web style visualization is used to illustrate the assessment of various metrics, enabling a comprehensive comparison and aiding in the decision-making process for selecting the most appropriate support instrument.

These metrics were identified and qualitatively ranked through working group discussions with H2Global Foundation's donors, reflecting the collective perspectives of both the authors and working group participants. The metrics closely align with a publication by Frontier Economics, which, while focusing on UHS, provides a qualitative assessment of various financing instruments using five metrics.[43] Each metric is rated on a scale of 1 to 4, with 1 being the highest and 4 the lowest. The instruments are ranked relative to one another, ensuring that each is assigned a unique rating from 1 to 4.

It is important to note that certain shortcomings identified in this ranking could be addressed through alternative measures, such as thoughtful adjustments to auction design. This ranking is based on an "all other things being equal" approach, meaning that external factors or potential improvements were not accounted for in the assessment.

Funding efficiency measures the increase in NPV relative to the total amount of funding received, as calculated in the previous section. The qualitative evaluation is based on the data in Figure 8, specifically for the cases where the IRR is smaller than 5% or between 5-10%.

Funding efficiency: evaluation	
CAPEX support	1
Fixed premium	4
Contracts-for-difference	2
Anchor capacity bookings	3

Market risk mitigation refers to the extent to which a financial support instrument can protect investors from uncertainties and fluctuations in market conditions, thereby making it easier to obtain the necessary total funding to fully finance a hydrogen infrastructure project. This includes the instrument's effectiveness in reducing financial risks, enhancing investor confidence, and ensuring the project's

IMAGE CREDIT: GOLDEN HOUSE IMAGES / ADOBE STOCK

financial stability. Importantly, it also ensures that the project is built, as securing adequate financing is crucial for the project's development and completion.

Fixed premium (FP) schemes provide financial support based solely on actual infrastructure usage, providing no protection against market risks. As a result, infrastructure operators face uncertainty regarding their future total revenues, which could lead to a higher WACC compared to other financial support instruments. CAPEX support reduces the initial capital required through an ex-ante fixed level of funding, but still leaves significant revenue risk, depending on the hydrogen market ramp up. ACBs provide a level of certainty during the critical ramp-up phase, helping secure financing by assuring investors of a stable revenue stream early in the project's life. CfDs provide the strongest support by guaranteeing a pre-defined ROI, fully mitigating market risk and significantly facilitating the securing of full project financing. CfDs, FPs, and ACBs can incorporate design elements that allow them to adapt to changing project conditions during the operational project phase, possibly reducing the market risk. For instance, these instruments can include mechanisms to adjust financial support according to inflation rates or other economic indicators and include provisions for renegotiation based on actual market demand and project performance.

Market risk mitigation: evaluation	
CAPEX support	3
Fixed premium	4
Contracts-for-difference	1
Anchor capacity bookings	2

Mitigating stranded funding resources refers to a financial support instrument's ability to reduce the risk that allocated funds from the funding authority become ineffective due to shifts in project viability, market conditions, regulatory frameworks, or technological advancements. This metric qualitatively evaluates how much funding could be lost if an asset gets stranded or has limited infrastructure utilization throughout its operational phase.

CAPEX support provides upfront capital, but it offers limited flexibility to adapt if market conditions or project needs change after the initial allocation of funds. This rigidity can lead to stranded funding resources in the event of stranded assets, as the funding does not adjust to evolving project conditions. CfDs ensure a fixed revenue during the operational phase, independent of infrastructure utilization. However, if an asset becomes stranded, the intended claw back at high utilization rates will not occur, potentially resulting in greater financial losses than with CAPEX support, as funding resources will continue to flow into an ineffective project. FP schemes provide support proportional to the actual infrastructure utilization, making them highly effective at mitigating stranded funding resources in the event of a stranded asset. ACBs ensure a certain revenue, even with no infrastructure utilization. However, as the operator can generate excess revenue above these bookings, the guaranteed level is most likely lower than for CfDs. In the event of a stranded asset, this would still result in ineffective funding spent, but at a lower level compared to CfDs. One way to mitigate the risk of stranded funding resources is through a risk-sharing approach between the funding provider and the infrastructure operator. A notable example is Germany's amortization account, where network operators have agreed to contribute a co-payment of 24% if a financial deficit remains in the amortization account by 2055.

IMAGE CREDIT: FOTOKALEINAR / SHUTTERSTOCK

Mitigation of stranded funding resources: evaluation	
CAPEX support	3
Fixed premium	1
Contracts-for-difference	4
Anchor capacity bookings	2

Administrative ease for funding authority refers to the simplicity, efficiency and minimal complexity with which the funding authority can develop, implement, and manage the financial support instrument. This includes the effort required to establish guidelines, create application processes, set evaluation criteria, and manage the overall framework of the support instrument. The assessment and ranking of administrative ease for funding authorities may similarly apply to the project developers benefiting from the funding. Additionally, this metric is linked to the speed to market, as simpler administrative instruments tend to expedite project timelines.

CAPEX support is administratively simple for the funding authority, with the main effort focused on the initial setup of criteria. It requires no ongoing management, which is advantageous compared to other instruments. In contrast, CfDs, FP, and ACBs require a continuous administrative process to ensure proper disbursement of payments. CfDs, in particular, involve complex administrative management due to the nature of two-way financial flows between the

CAPEX support requires no ongoing management, which is advantageous compared to other instruments.

funding authority and the project developers. This involves considerable administrative effort, such as defining and implementing the process for setting the guaranteed annual revenue and regularly assessing the project's financial performance to determine actual project revenues. The FP model offers a simpler administrative setup than CfDs, as it primarily requires periodic evaluation of capacity utilization (instead of a detailed project revenue evaluation) to determine the premium payments. However, it still involves some administrative effort to define what the premium should be based on, particularly since there isn't as yet a standard market price for hydrogen infrastructure usage. ACBs require the definition of a constant annual funding amount, which may require some initial administrative effort. During the operational phase, the need for project evaluation is minimal.

Administrative ease for funding authority: evaluation	
CAPEX support	1
Fixed premium	3
Contracts-for-difference	4
Anchor capacity bookings	2

Well-known and established instrument refers to the degree to which a financial support instrument is widely recognized, accepted, and relied upon by stakeholders in the industry, including investors, developers, and regulators, particularly in the context of hydrogen infrastructure projects. This metric evaluates whether similar instruments have been used in hydrogen infrastructure financing or other related areas, such as infrastructure projects or hydrogen production projects.

CAPEX support is a commonly used instrument for financing hydrogen and infrastructure projects, such as those under the EU's Connecting Europe Facility (CEF). The concept of ACBs lacks a standardized definition and is sometimes referred to as a "revenue floor". Examples of support schemes that include a similar concept to ACBs, as proposed in this report, include the Transmission Facilitation Program in the US for interregional electricity transmission lines,[44] the proposed Hydrogen Storage Business Model in the UK for UHS and the Capacity Investment Scheme in Australia for renewable energy generation and storage. However, due to the absence of a clear and widely accepted definition, it was ranked lowest. FP schemes are widely employed in financing renewable energy and hydrogen projects, such as the European Hydrogen Bank auction and the Danish PtX auction, as explained in detail in the WG3 report. However, they have not been applied to infrastructure financing. In contrast, CfD mechanisms are currently being developed, albeit in a limited number of projects, for hydrogen infrastructure financing, such as Germany's amortization account for hydrogen pipelines. This practical application of CfDs in hydrogen infrastructure gives them a higher rating than FP schemes, which lack such use cases. Additionally, price per unit-based CfDs (contrary to the proposed revenue-based CfDs) are being widely applied for renewable energy projects.

Well-known and established instrument: evaluation	
CAPEX support	1
Fixed premium	3
Contracts-for-difference	2
Anchor capacity bookings	4

The spider web visualization in Figure 9 below combines the evaluation of these five different metrics.

CAPEX funding has the highest funding efficiency, while being a well-known and established instrument that is comparably easy to implement.

A downside of CAPEX support is that it does not mitigate risks associated with future project cashflows. In addition, if the business case for the infrastructure financed with CAPEX support turns out worse than expected, it has a higher risk of being associated with stranded assets.

In contrast, CfD mechanisms can be designed such that the funding is tied to the positive development of the funded infrastructure, decreasing the risk of stranded funding resources. Furthermore, it mitigates most risks associated with future cashflows, by guaranteeing a minimum return. The downside of CfD mechanisms is that they are comparably complex to implement.

ACBs are ranked between CAPEX and CfD instruments in terms of administrative ease and their potential to mitigate market risks: They are easier to implement compared to CfD mechanisms, however they contribute less to the mitigation of market risks. The funding efficiency of ACBs is generally lower compared to CfD and CAPEX instruments, but higher than for FP schemes.

FP instruments fall short of the above-mentioned instruments in most dimensions, except for the potential to mitigate stranded funding resources.

Figure 9: Evaluation of financial support instruments

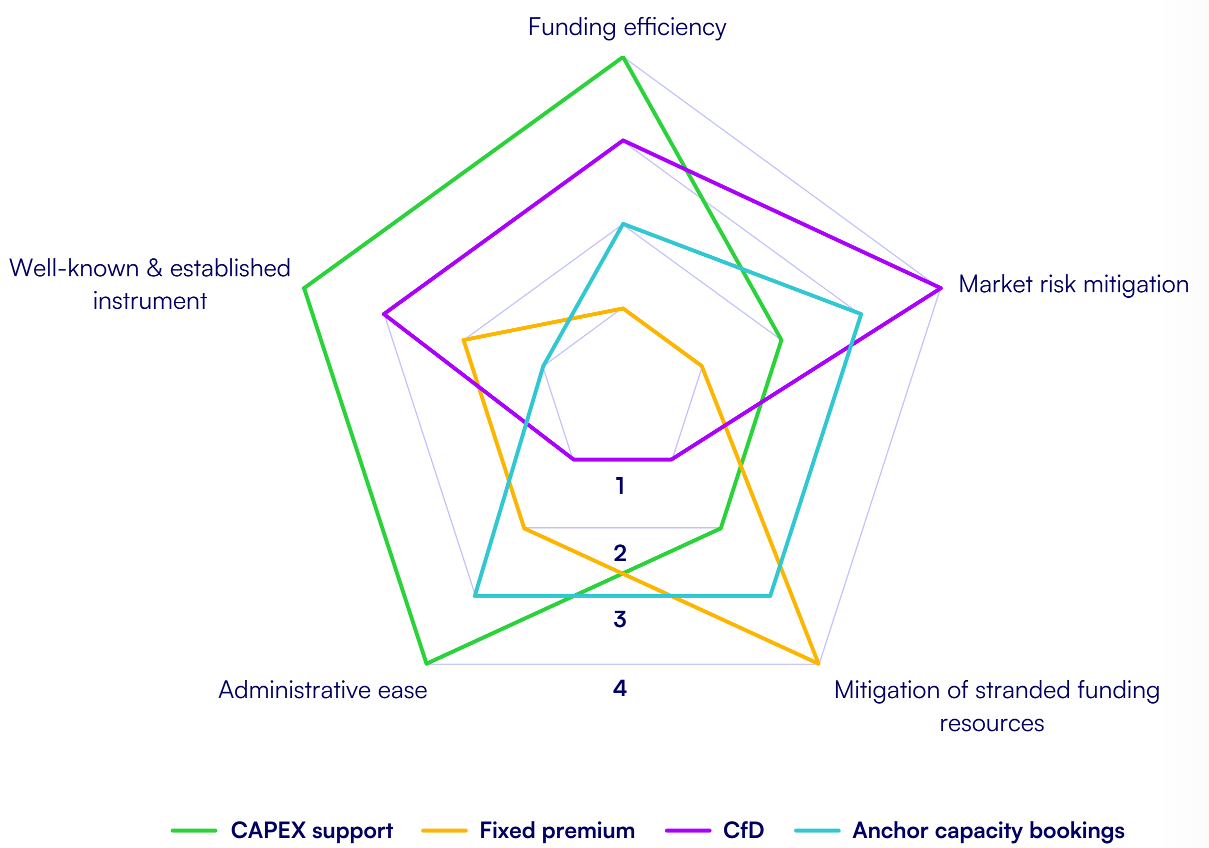



IMAGE CREDIT: KNABODINI / SHUTTERSTOCK


IMAGE CREDIT: KITTIRAT ROEKBURI / SHUTTERSTOCK

4

Recommendations

This report explores four different financial support instruments to de-risk investments into hydrogen infrastructure that can be applied to support the financing of hydrogen pipelines, import terminals, reconversion facilities, and underground hydrogen storage. These financial support instruments are analyzed along five dimensions: (1) funding efficiency, their ability to (2) mitigate market risks and to (3) avoid stranded funding resources, (4) administrative ease, and (5) whether they are already a well-known and established instrument. Figure 9 visually compares the assessment of each instrument across the key dimensions.

This analysis has led to the following conclusions:

- **CAPEX support is advantageous when prioritizing funding efficiency and minimizing administrative complexity.** This includes situations where infrastructure projects are not expected to be economically viable, and the increase of the project's net present value has highest priority. Because CAPEX support instruments are comparatively simple to implement, they are also suitable for smaller-scale projects with rather complex business models.

- **CfD instruments are favorable when mitigating market risk is key.** This includes situations where projects are already approaching economic viability, and the highest priority is to de-risk future cashflows.

Since the costs of reconversion projects are largely driven by variable operational expenses, i.e., external energy demand, CAPEX support is a suitable funding mechanism due to its high funding efficiency and straightforward implementation.

Because CfD mechanisms are comparatively complex to implement, they are more suited to being applied to large-scale infrastructure projects and to projects with focused business models, where revenue is derived from a single infrastructure service.

- **ACBs are well suited to addressing market risks and stranded funding resources.** They borrow favorable characteristics from CAPEX and CfD mechanisms, albeit with less efficiency. As such, this instrument is a favorable alternative—especially to CfD mechanisms—in situations where de-risking of future cashflows has priority, and yet the administrative burden of developing a CfD mechanism is disproportionate to the size of the infrastructure project.

- **FP instruments are best used if stranded funding concerns take precedence over funding efficiency and market risk mitigation.** While FPs are most useful for avoiding stranded funding, they come with trade-offs, as they perform lower in terms of market risk mitigation, funding efficiency, and administrative ease compared to other instruments. It should be carefully evaluated as to whether the focus on stranded funding justifies the use of FPs, given their lower performance across these other dimensions.

Table 11 provides an overview of the recommended financial support instruments for each type of midstream infrastructure, based on their specific characteristics.

Pipelines are expected to form the backbone of large-scale hydrogen transmission and distribution infrastructure, both domestically and internationally. Our analysis of a representative 1,500 km hydrogen pipeline project shows it achieves economic viability at a transport fee of 1.15 EUR-ct./kWh-H2-transported. Reducing future cashflow uncertainties is essential for pipeline projects, making CfD mechanisms the most effective form of financial support, followed by ACBs. Initial financing models for hydrogen pipeline networks, primarily utilizing CfD-like mechanisms, are already being developed in Germany and the UK.

Table 11: Suitability of financial support instruments by infrastructure

	CAPEX	Fixed premium	Contracts-for-difference	Anchor capacity bookings
Pipeline	Medium	Low	High	Medium
Terminal	High	Low	Medium	Medium
Reconversion	High	Low	Medium	Medium
UHS	Medium	Low	High	Medium

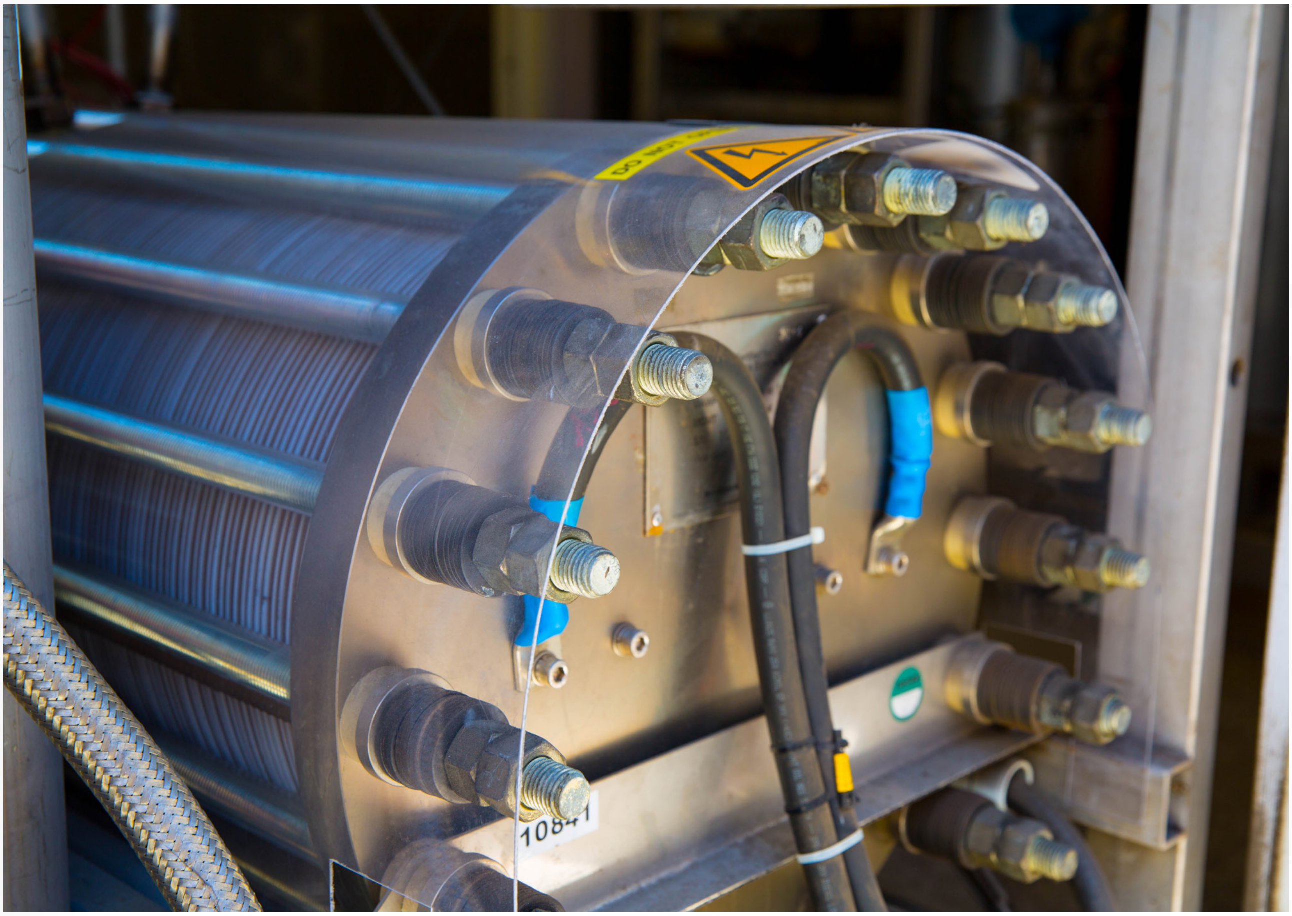


IMAGE CREDIT: JEREMYISWILD-

Import terminals for hydrogen and its derivatives are essential for a globally integrated hydrogen economy. The economic viability of these terminals—excluding the reconversion of carriers to hydrogen—varies according to the type of hydrogen derivative. Due to their technical similarity to conventional petroleum storage, LOHC terminals are economically viable at a low fee of 0.17 EUR-ct./kWh-H2-equivalent for unloading and temporary storage. NH_3 terminals reach viability at 1.2 EUR-ct./kWh-H2-equivalent, SNG terminals at 2.05 EUR-ct./kWh-H2-equivalent, and LH2 terminals are the costliest at 2.4 EUR-ct./kWh-H2-equivalent. Although the initial investment costs for terminal projects are generally lower than for pipeline infrastructure, their business models can be more complex. Given these characteristics, CAPEX support schemes are generally the most suitable, while ACBs can serve as an alternative, if future cashflows are particularly uncertain.

Reconversion technologies serve the purpose of reconverting hydrogen derivatives to gaseous hydrogen. Technologies include ammonia crackers, steam reformers for reconverting synthetic methane, and dehydrogenation facilities to reconvert LOHC. Reconversion projects can either be co-developed with import terminals on a large scale or be more decentralized and close to the place of final consumption. The economic viability of these projects varies depending on the reconversion technology and is characterized by an increased OPEX intensity due to the external energy demand to operate endothermic reconversion processes. This characteristic may also lead to a competitive disadvantage for first movers; competitors who enter the market at a later stage may profit from technological improvements in reconversion technologies, leading to a decreased external energy demand and thus lower reconversion costs. This market risk poses a significant barrier for early entrants. In our analysis, ammonia crackers approach economic viability at a fee of 4.2 EUR-ct./kWh-H2-converted and LOHC dehydrogenation facilities at 5.2 EUR-ct./kWh-H2-converted, while steam reformers are most costly at a fee of 16.6 EUR-ct./kWh-H2-converted. Since the costs of reconversion projects are largely driven by variable operational expenses, i.e., external energy demand, CAPEX support is a suitable funding mechanism due to its high funding efficiency and straightforward implementation.

To enhance public acceptance, financial support for hydrogen infrastructure should be linked to demonstrable social value.

Underground hydrogen storage facilities play a vital role in addressing temporal mismatches between supply and demand in a future hydrogen economy, while also serving as a safeguard against import shortages. They provide essential systemic value that extends beyond individual business cases by ensuring security of supply. The business model for underground hydrogen storage varies based on geological conditions, the scale of the temporal mismatches to be bridged (ranging from hours to months), and the required injection and withdrawal periods for the stored hydrogen. These facilities can be used to bridge short-term supply and demand mismatches associated with variable renewable energy sources, address long-term imbalances due to seasonal weather fluctuations, or serve as strategic reserves. Each of these use cases presents different requirements for the number of storage cycles an underground hydrogen facility can accommodate, with the annual number of storage cycles significantly influencing the modeling results in this analysis. Single-turn archetypal projects, such as those intended for seasonal hydrogen storage, achieve economic viability at a storage fee of 11.45 EUR-ct./kWh-H2-stored for depleted fields and 22.5 EUR-ct./kWh-H2-stored for salt caverns. In contrast, multi-turn archetypal projects, designed to balance renewable energy supply, become viable at lower fees of 4.4 EUR-ct./kWh-H2-stored for depleted fields and 8.8 EUR-ct./kWh-H2-stored for salt caverns. Given the high exposure of underground hydrogen storage projects to supply and demand uncertainties, managing market risks is a top priority. As such, CfD support is identified as the most suitable funding instrument.

Given the high exposure of underground hydrogen storage projects to supply and demand uncertainties, managing market risks is a top priority.

Beyond specific midstream hydrogen infrastructure, more general recommendations and observations have been derived to mitigate project risks, to optimize the application of financial support instruments, and to ultimately improve the investment environment.

— **Clear, practical, and stable regulatory frameworks** for hydrogen infrastructure are essential to mitigate regulatory risks. These frameworks should address critical areas such as third-party access, unbundling rules, central planning, and the designation of responsible authorities. Regulations should also clearly define types of hydrogen infrastructure and provide tailored guidance for different market phases. Striking a balance between fostering market competition and enabling risk mitigation is key, while also ensuring long-term predictability, stability, and transparency for all market participants.

— The financial analysis of various archetypal infrastructure projects revealed a heterogeneous distribution of revenue streams and profitability across the hydrogen value chain. **Vertical integration of individual midstream infrastructure projects** has the potential to smooth out these disparities in revenue and create viable business cases, even if certain segments of the value chain remain unprofitable on their own.

— **Coordination of supply chain activities across different stakeholders** should be encouraged to mitigate market risks. Mature markets provide liquidity and price signals to inform investment decisions. In the absence of a mature market for clean hydrogen, midstream hydrogen infrastructure carries increased market risks. Centralized or bilateral coordination of supply chain activities can help compensate for the lack of market signals, fulfilling the informative role typically provided by a developed market.

— Options for **centralizing the development of funding instruments** should be explored to decrease individual administrative burden. A centralized approach could streamline application processes, improve accessibility, and create standardized criteria for funding eligibility, making it easier for projects to secure financing. By consolidating efforts at a central level, duplication of administrative work can be minimized, ensuring greater efficiency and reducing the time and resources required for project developers to navigate funding mechanisms.

— To **enhance public acceptance,** financial support for hydrogen infrastructure should be linked to demonstrable social value. This could include ensuring third-party access to privately operated infrastructure and transparently communicating the social and environmental impacts and benefits of each project. By highlighting these values, stakeholders can better understand the strategic importance of hydrogen infrastructure—such as pipelines, terminals, reconversion facilities, and underground storage—and its contributions to society as a whole.


IMAGE CREDIT: MARIOGUTI / ISTOCKPHOTO

Literature and sources

Agnieszka Ason, and Julio Dal Poz, *Contracts for Difference the Instrument of Choice for the Energy Transition* (The Oxford Institute for Energy Studies, April 2024) <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/04/ET34-Contracts-for-Difference.pdf> [accessed 3 May 2024]

Bernhard, Lorentz, Trüby Johannes, Philip Pradeep, Shirizadeh Behrang, Clémence Lévêque, and Vincent Jacamon, *Financing the Green Energy Transition: Innovative Financing for a Just Transition* (Deloitte, May 2024) <https://www2.deloitte.com/content/dam/Deloitte/de/Documents/sustainability/Deloitte_Financing_the_green_energy_transition_Report_2024.pdf>

Bothe, David, Matthias Janssen, Jasmina Biller, and Anna Lane, *Finanzierungsmechanismus Für Den Aufbau von Wasserstoffspeichern* (Frontier Economics, 30 August 2024) <https://www.frontier-economics.com/media/mkkhfxeq/frontier-economics-finanzierungsmechanismus-fuer-wasserstoffspeicher-studie-fuer-den-bdew_final_20240830_stc_docx.pdf> [accessed 16 September 2024]

Brändle, Gregor, Max Schönfisch, and Simon Schulte, 'Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen', *Applied Energy*, 302 (2021), p. 117481, doi:10.1016/j.apenergy.2021.117481

Bruno Alves, 'Do Infra Investments Really Need to Be Monopolistic?', *Infrastructure Investor*, 2016 <https://www.infrastructureinvestor.com/do-infra-investments-really-need-to-be-monopolistic/> [accessed 9 August 2024]

Chema Zabala and Alfa Diallo, *Study on the Performance of Support for Electricity from Renewable Sources Granted by Means of Tendering Procedures in the Union 2022.* (European Commission, 2022) <https://data.europa.eu/doi/10.2833/93256> [accessed 4 June 2024]

Damodaran, Aswath, 'Equity Risk Premiums (ERP): Determinants, Estimation, and Implications — The 2023 Edition Updated: March 23, 2023', 2023, doi:http://dx.doi.org/10.2139/ssrn.4398884

Danish Energy Agency, 'The First PtX Tender in Denmark Has Been Determined: Six Projects Will Establish Electrolysis Capacity on More than 280 MW', *Energistyrelsen*, 2023 <https://ens.dk/en/press/first-ptx-tender-denmark-has-been-determined-six-projects-will-establish-electrolysis-capacity> [accessed 28 November 2023]

David Bothe, Gregor Brändle, and Johanna Reichenbach, *Kompakte Analyse Der Importkosten von Synthetischem Methan Nach Deutschland* (Frontier Economics, 30 September 2024)

Department for Energy Security and Net Zero, 'Contracts for Difference', 2023 <https://www.gov.uk/government/collections/contracts-for-difference>

ENTSOG, GIE, EUROGAS, CEDEC, GD4S, and GEODE, 'Hydrogen Infrastructure Map' <https://www.h2inframap.eu/> [accessed 1 November 2024]

European Commission, 'Energy Infrastructure: Projects of Common Interest (CEF Energy)' <https://cinea.ec.europa.eu/programmes/connecting-europe-facility/energy-infrastructure-connecting-europe-facility-0/energy-infrastructure_en> [accessed 5 June 2024]

———, 'European Hydrogen Bank Auction Provides €720 Million for Renewable Hydrogen Production in Europe' <https://ec.europa.eu/commission/presscorner/detail/en/IP_24_2333> [accessed 30 April 2024]

———, *Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on Common Rules for the Internal Markets in Renewable and Natural Gases and in Hydrogen, COM/2021/803 Final* <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803&qid=1640002501099> [accessed 4 June 2024]

———, *Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the Internal Markets for Renewable and Natural Gases and for Hydrogen (Recast), COM/2021/804 Final* <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A804%3AFIN&qid=1640001545187> [accessed 4 June 2024]

European Hydrogen Backbone, 'European Hydrogen Backbone Maps' <https://ehb.eu/page/european-hydrogen-backbone-maps> [accessed 24 September 2024]

European Hydrogen Backbone: Implementation Roadmap - Cross Border Projects and Cost Update (European Hydrogen Backbone, November 2023) <https://www.ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf> [accessed 8 December 2023]

Federal Ministry for Economic Affairs and Climate Action, 'FAQ - Hydrogen Core Network' <https://www.bmwk.de/Redaktion/EN/FAQ/Hydrogen-Core-Network/faq-hydrogen-core-network.html> [accessed 6 August 2024]

———, 'First Round of Carbon Contracts for Difference Launched' <https://www.bmwk.de/Redaktion/EN/Pressemitteilungen/2024/03/20240312-first-round-of-carbon-contracts-for-difference-launched.html> [accessed 12 March 2024]

German LNG Terminal, 'Terminal Overview' <https://germanlng.com/overview/?lang=en> [accessed 2 August 2024]

GRTgaz, 'HY-FEN' <https://www.grtgaz.com/en/our-energy-transition/hydrogen-transport/hyfen> [accessed 24 September 2024]

Guidelines on State Aid for Environmental Protection and Energy 2014-2020, Official Journal of the European Union (European Commission, 28 June 2014) <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0628%2801%29>

H2Global Stiftung, 'PROFIN: A Python Package for Project Finance in the Energy Sector' (H2Global Stiftung, 2024) <https://github.com/H2Global/profin/tree/master/profin>

Helena Lönnberg, Jeroen Wegh, and Jaap Peterse, *A European Underground Hydrogen Storage Roadmap: H2eart for Europe's Recommendations to Secure the Scale up of Underground Hydrogen Storage* (H2eart for Europe; Guidehouse, July 2024) <https://h2eart.eu/wp-content/uploads/2024/07/H2eart-for-Europe_European-UHS-Roadmap.pdf> [accessed 9 July 2024]

Hydrogen Council and McKinsey & Company, *Hydrogen Insights 2024* (Hydrogen Council, McKinsey & Company, 17 September 2024) <https://hydrogencouncil.com/wp-content/uploads/2024/09/Hydrogen-Insights-2024.pdf> [accessed 19 September 2024]

Hydrogen Storage Business Model: Market Engagement on the First Allocation Round (UK Department for Energy Security & Net Zero, December 2023)

IEA, 'ETP Clean Energy Technology Guide' <https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide> [accessed 29 October 2024]

———, 'Germany's Renewables Energy Act' <https://www.iea.org/policies/12392-germanys-renewables-energy-act> [accessed 5 June 2024]

———, *Global Hydrogen Review 2023* (International Energy Agency, 2023) <https://iea.blob.core.windows.net/assets/8d434960-a85c-4c02-ad96-77794aaa175d/GlobalHydrogenReview2023.pdf>

———, *Global Hydrogen Review 2024* (International Energy Agency, October 2024) <iea.blob.core.windows.net/assets/89c1e382-dc59-46ca-aa47-9f7d41531ab5/GlobalHydrogenReview2024.pdf>

———, *World Energy Investment 2024*, June 2024 <https://iea.blob.core.windows.net/assets/60fcd1dd-d112-469b-87de-20d39227df3d/WorldEnergyInvestment2024.pdf> [accessed 1 November 2024]

Imperial College Business School, International Energy Agency, *Climate Infrastructure Investing: Risks and Opportunities for Unlisted Renewables* (International Energy Agency, March 2022) <https://www.iea.org/reports/climate-infrastructure-investing-risks-and-opportunities-for-unlisted-renewables>

IRENA, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part I - Trade Outlook for 2050 and Way Forward* (International Renewable Energy Agency, 7 July 2022) <https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook> [accessed 5 December 2023]

———, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal. Part II: Technology Review of Hydrogen Carriers* (IRENA, 2022) <https://www.irena.org/%20%20%20%20Publications/2022/Apr/Global-hydrogen-trade-Part-II>

ISO, 'ISO 14687:2019(En) Hydrogen Fuel Quality — Product Specification' <https://www.iso.org/obp/ui/en/#iso:std:iso:14687:ed-1:v1:en>

Kate Axup, Skye Kirby, Julia Arrighi, and Jun Chong, 'Capacity Investment Scheme Kicks off: What You Need to Know' <https://www.allens.com.au/insights-news/insights/2023/10/capacity-investment-scheme-kicks-off-what-you-need-to-know/> [accessed 18 October 2023]

Kerr, William R, and Ramana Nanda, 'Financing Innovation', *Annual Review of Financial Economics*, 7 (2015), pp. 445—62, doi:10.1146/annurev-financial-111914-041825

Khan, Mohd Adnan, Cameron Young, and David B Layzell, 'The Techno-Economics of Hydrogen Pipelines', *Transition Accelerator Technical Briefs*, 1.2 (2021)

Lee, Moongyung, and Deger Saygin, *Financing Cost Impacts on Cost Competitiveness of Green Hydrogen in Emerging and Developing Economies*, OECD Environment Working Papers (OECD, 29 November 2023), CCXXVII, doi:10.1787/15b16fc3-en

Lin, Ning, Liying Xu, and Lorena G. Moscardelli, 'Market-Based Asset Valuation of Hydrogen Geological Storage', *International Journal of Hydrogen Energy*, 49 (2024), pp. 114—29, doi:10.1016/j.ijhydene.2023.07.074

Max Distel, 'Large-Scale H2 Storage and Transport with Liquid Organic Hydrogen Carrier Technology: Insights into Current Project Developments and the Future Outlook', *Energy Technology*, 2301042 (2024), doi:10.1002/ente.202301042

Mazzucato, Mariana, and Gregor Semieniuk, 'Financing Renewable Energy: Who Is Financing What and Why It Matters', *Technological Forecasting and Social Change*, 127 (2018), pp. 8—22, doi:10.1016/j.techfore.2017.05.021

Mehran Ghasemi and Hidemichi Iizuka, *Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy* (Black & Veatch, 2022)

Merten, F.; Scholz, A., *Metaanalyse Zu Wasserstoffkosten Und -Bedarfen Für Die CO2-Neutrale Transformation* (Wuppertal Institut, June 2023)

Moongyung Lee, Joana Argemí Ribalta, Joseph Cordonnier, and Dolf Gielen, *Leveraging Enhanced De-Risking Instruments and International Co-Ordination to Catalyse Investment in Clean Hydrogen* (OECD, Forthcoming)

Natalia Fabra and Juan Pablo Montero, *DP15554 Technology-Neutral vs. Technology-Specific Procurement*, 13 December 2020 <https://cepr.org/publications/dp15554> [accessed 31 May 2024]

Scaling Hydrogen Financing for Development (The World Bank, ESMAP, OECD, Global Infrastructure Facility, Hydrogen Council, Breakthrough Agenda, 15 February 2024), doi:10.1787/0287b22e-en

Schreiner, Florian, Matia Riemer, and Jakob Wachsmuth, *Conversion of LNG Terminals for Liquid Hydrogen or Ammonia* (Fraunhofer Institute for Systems and Innovation Research ISI, 3 November 2022)

South2 Corridor, 'South2 Corridor' <https://www.south2corridor.net/> [accessed 24 September 2024]

The World Bank, 'Energy and Power PPPs', 2024 <https://ppp.worldbank.org/public-private-partnership/sector/energy>

UK Hydrogen Strategy (Department for Energy Security & Net Zero, UK, 24 July 2024)

Uniper, 'LNG Terminal Wilhelmshaven' <https://www.uniper.energy/solutions/energy-transformation-hubs/energy-transformation-hub-northwest/lng-terminal-wilhelmshaven> [accessed 1 November 2024]

U.S. Department of Energy, 'Transmission Facilitation Program' <https://www.energy.gov/gdo/transmission-facilitation-program> [accessed 31 July 2024]

Why European Underground Hydrogen Storage Needs Should Be Fulfilled (Frontier Economics; Artelys, 9 April 2024) <https://www.gie.eu/publications/studies/> [accessed 17 April 2024]

World Energy Outlook 2023 — Analysis (International Energy Agency, October 2023) <https://www.iea.org/reports/world-energy-outlook-2023> [accessed 1 March 2024]

Annex I: Calculation of NPV and WACC

The calculation of a project's net-present value (NPV) is based on the concept of discounting all future cashflows—positive and negative—that are forecast over the depreciation period of the project to the year of the initial investment:

$$NPV = S_0 - I_0 + \sum_{t=0}^{T} \frac{R_t - I_t + S_t}{(1 + WACC)^t} \qquad \text{Eq. 1}$$

with:

T : Depreciation period

I_0 : Initial investment costs (CAPEX)

S_0 : CAPEX subsidy

R_t : Revenue in year t

S_t : Subsidy in year t

$WACC$: Weighted average cost of capital

The WACC reflects the financing costs of a project. Its calculation is based on an estimation of the associated project risks.

$$WACC = C_e * \alpha_e + C_d * \alpha_d \qquad \text{Eq. 2}$$

with:

C_e, C_d : Cost of equity and cost of debt

α_e, α_d : Share of equity capital (assumed to 30%) and share of debt capital (assumed to 70%).

And:

$$C_e = R_{free} + \beta * ERP + CRP + SP \qquad \text{Eq. 3}$$

with:

R_{free} : Risk-free rate of return. Assumed to 4.5%[45].

β : Beta-factor, indicating the risk premium of the sector compared to the overall market. Assumed to 1.54[46].

ERP : Equity-risk premium, indicating the risk premium of the overall market. Assumed to 6.5%

CRP : Country-risk premium, indicating the risk premium due to additional country-specific risk factors such as political stability, etc. Assumed to 0.0% (Europe, US, Japan).

SP : Specific-risk premium, quantifying the risks associated with project-specific uncertainties. Calculation is based on Deloitte (2024) [47]:

$$SP = VaR = IRR(P = 50\%) - IRR(P = 10\%) \qquad \text{Eq. 4}$$

with:

VaR : Value-at-risk

$IRR(P=X)$: Internal rate of return, which is achieved with a probability of X%. The respective $IRR(P = X)$ is calculated using Monte-Carlo simulation of 2,000 market scenarios, based on the assumed standard deviation of defined project risks. These project risks include volatile utilization rates and a deviation of the upfront investment costs from the expected values. Both risks are simulated with a standard deviation of 20% for all archetype hydrogen infrastructure projects.

Finally, the cost of debt is calculated as follows:

$$C_d = (R_{debt} + CRP) * (1 - Tax) \qquad \text{Eq. 5}$$

with:

R_{debt} : Interest rate. Assumed to 4%.

Tax : Corporate tax rate. Assumed to 20%.

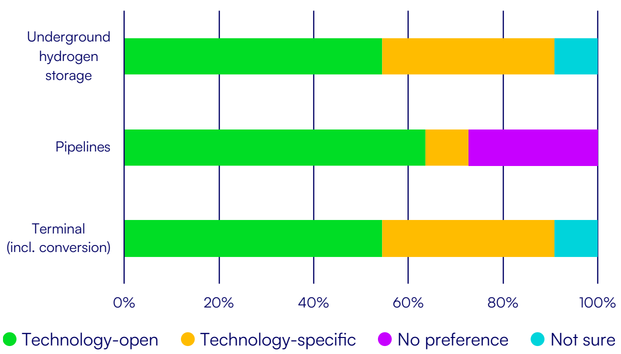
Annex II: Trade-offs in the design of financial support instruments

When designing financial support mechanisms to stimulate hydrogen infrastructure investments, there are some trade-offs that need to be contemplated, including whether to be technology-neutral, to be region- or project-specific, to have constant or dynamic subsidies, to have regulated or open third-party access (TPA), or to maximize for returns or for risk mitigation.[48]

Technology neutral vs. technology specific

An H2Global survey of industry representatives points to a clear preference for financial support instruments that are technology neutral, allowing for competition between alternative technology solutions (⌀ 58%). This is particularly true when talking about hydrogen pipelines, with over 60% of respondents opting for competition among distinct technological solutions. While technology neutral is also preferred for underground storage and terminals, around 30% of respondents would like to see financial support mechanisms support specific technologies. According to the industry representatives, this is because it is too early to define a winning technology, and competition fosters innovation. They believe terminals and pipelines are crucial in the early stages of the hydrogen economy, enabling diverse technological developments. However, they argue that specific support is needed for hydrogen storage to ensure scalability, as only salt caverns are currently suitable. Additionally, they suggest that terminals need targeted support, with ammonia being the most promising for large-scale import.

Figure 10: Survey results of preferences regarding technology-specific vs. technology-open design

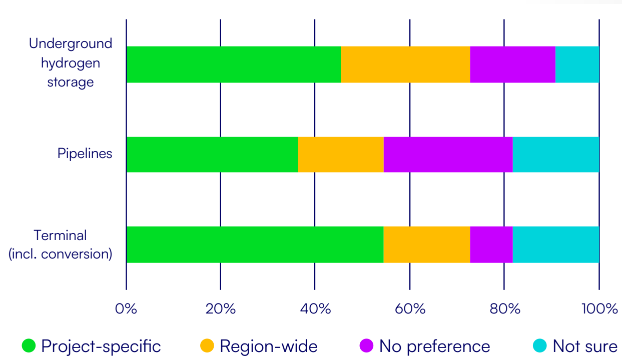


The technology-neutral approach favors established technologies because the technology-risk involved is lower.[49] Established technologies' advantage could lead to long-term technological path-dependencies, particularly for terminals. To support technologies with lower maturity but with the potential to be more advantageous (e.g., to have higher efficiency, lower overall supply costs), technology-specific financial support instruments can play an important role.

Project-specific vs. region-wide funding

When asked by H2Global, 45% of industry stakeholders expressed a preference for financing support mechanisms that target specific projects, 33% indicated "no preference" and "not sure", while the rest (21%) showed a preference for targeted support to territories (e.g., all terminal projects in one country). Project planning and quality are expected to be better when support targets specific projects, since it will be easier to oversee the beneficiaries of the financial assistance.

Figure 11: Survey results of preferences regarding project-specific vs. region-wide design



Project-specific funding of infrastructure projects typically requires a *central planning process*, conducted by public and/or private stakeholders. A central planning process provides recommendations for the optimum state of a future energy system and determines which projects are needed to achieve this systemic optimum. Key considerations in designing a systemic optimum include balancing total system costs and strategic diversification of the technologies and energy sources used. Examples of central planning processes in the domain of hydrogen infrastructure include the planning for the European Hydrogen Backbone pipeline network[50] and for hydrogen underground storage facilities by Gas Infrastructure Europe.[51] In project-specific funding, competition occurs between project developers, who are competing for the project being procured, with incumbents often having the upper hand.

When financial support mechanisms are not project specific, but instead target certain areas/regions, competition tends to emerge between projects that have been planned and/or initiated within the chosen region. Examples of region-wide support schemes include the national tendering processes for electricity from renewable energy sources in the European Union.[52] Competition may optimize for individual business cases, but the ultimate outcomes may diverge from the systemic optimum. There are also limits to this approach, as not all regions/territories can support all different types of infrastructure projects. Terminals cannot be built inland, nor hydrogen underground storage projects built anywhere, since they rely on geological preconditions, such as the availability and suitability of salt caverns or depleted gas fields.[53]

Constant vs. dynamic subsidies

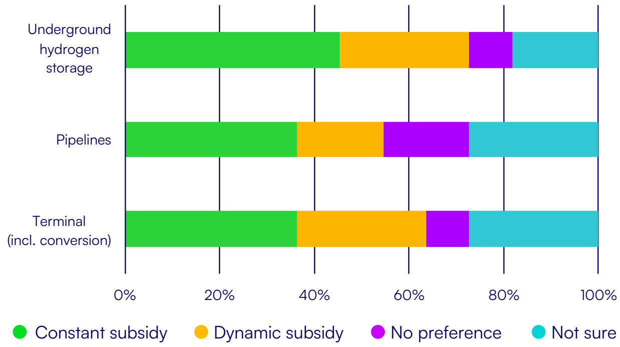
All the financial support instruments discussed earlier in the report, apart from CAPEX funding, provide cashflows over longer periods. During this funding period, key factors influencing the operational and non-operational cashflows of infrastructure projects might change. This includes inflation, interest, currency exchange rates, and the price for handled hydrogen derivatives. To account for this volatility, financial support can be linked to reference indexes.

In the industry survey, conducted by H2Global, financial support instruments with constant subsidy schemes (⌀ 39%) were generally preferred over dynamic subsidy schemes (⌀ 24%) due to the perceived uncertainty of future subsidy cashflows. Still, ⌀ 36% of industry representatives had “no preference” or were “not sure”.

Constant subsidies are not responsive to any kind of change in economic conditions. This means that, when constant subsidies are provided, their real value may decrease over time due to inflation. Some try to compensate for this volatility by including a buffer, but there is a limit to this approach, because of the uncertainty and added cost. Ultimately, constant subsidies offer a predictable and straightforward financial contribution, which is key to project developers and commercial funding providers.

Dynamic subsidies can be designed to reflect changes in critical economic factors such as inflation. They can

Figure 12: Survey results of preferences regarding constant vs. dynamic subsidy

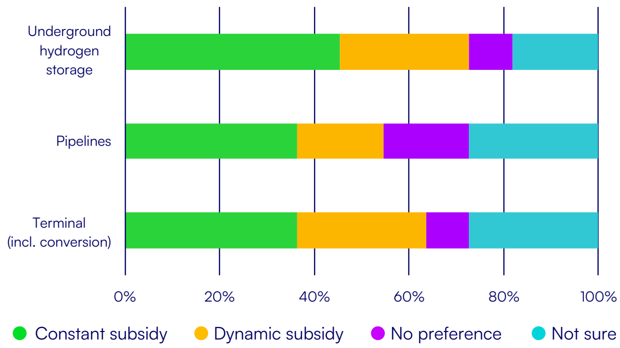


also buffer market volatility by linking financial support to hydrogen-specific indicators, such as the price of hydrogen or its derivatives. Dynamic subsidies are more complex and demanding from an administrative point of view than constant subsidies, requiring regular checks and adjustments.

Regulated TPA vs. negotiated TPA

The H2Global survey results for hydrogen pipelines and terminals were aligned with the EU directive 2021/0425(COD) and EU regulation 2021/0424(COD), which foresees regulated third-party access (TPA) for pipelines and negotiated TPA for terminals in the long term.[54] For underground storage, there were slightly more diverse opinions among industry respondents, though many ended up leaning towards regulated TPA.

Figure 13: Survey results of preferences regarding regulated vs. negotiated TPA



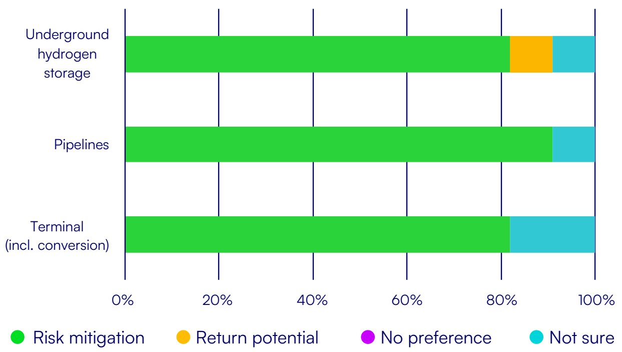
Under regulated TPA, the terms and conditions for accessing hydrogen infrastructure are set by national regulatory authorities. The fees, terms of use, and other operational aspects are predefined by these regulators. This model promotes transparency and non-discrimination, as all potential users have access to the infrastructure under the same conditions. Standardized conditions, however, might not fit all business models. Regulated TPA also places an administrative burden on regulatory bodies to continuously oversee and adjust terms of access.

Under a negotiated TPA regime, the infrastructure owner and the entity seeking access negotiate terms and conditions bilaterally. However, the regulatory authority may still play a role in overseeing these agreements to ensure they are fair and non-discriminatory. This approach allows for greater flexibility and can be better adapted to the specific needs of the parties involved. It can foster innovative contracts and partnerships that might be stifled under a more rigid regulatory framework. Disadvantages entail a higher risk of discriminatory practices, as dominant infrastructure owners often favor certain users over others.

Risk mitigation vs. return potential

The H2Global industry survey highlighted a strong preference for risk mitigation. Support to enhance return potential was only mentioned with respect to underground storage. Stated reasons include that the mitigation of market risks must be prioritized in this early phase of the market for hydrogen infrastructure, as potential excess returns due to market upside risks cannot be properly estimated due to the inherent market uncertainties.

Figure 14: Survey results of preferences regarding risk mitigation vs. return potential



The core objective of the financial support instruments[55] discussed in this report is to mitigate market risks to shift the risk-return profiles of hydrogen infrastructure investments from high-risk/low-return to low-risk/low-return investments. CAPEX support mechanisms, ACBs, and fixed premium support schemes mitigate market risks only to a limited degree but allow for excess returns in the case of favorable utilization rates of the infrastructure. The possibility of a higher return can attract investors looking for growth opportunities rather than secure investments.

CfD schemes clear market risks for the project developer by compensating for missing revenues in the case of low utilization rates of the infrastructure. However, excess returns above a pre-defined return on equity must be paid back to the funding body. As CfD mechanisms reduce market risks, alternative incentives must be introduced for project developers to maximize utilization rates. Such measures include risk-sharing among the funding body and project developers or a coupling of return and utilization. Designing a CfD scheme with an increasing ROI with increasing utilization is one option to incentivize the operator to bring customer-oriented and competitive products onto the market. Complete market risk mitigation, as in conventional CfD schemes, leads to a high investment security that is attractive for investors with lower risk tolerance, like pension funds. However, these projects offer lower returns. Furthermore, without any market risk, the project operator may stifle innovation and efficiency improvements, as financial support compensates for any potential inefficiencies.

Endnotes

1 IEA, *Global Hydrogen Review 2023* (International Energy Agency, 2023) <https://iea.blob.core.windows.net/assets/8d434960-a85c-4c02-ad96-77794aaa175d/GlobalHydrogenReview2023.pdf>; IRENA, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part I - Trade Outlook for 2050 and Way Forward* (International Renewable Energy Agency, 7 July 2022) <https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook> [accessed 5 December 2023]; Merten, F.; Scholz, A., *Metaanalyse Zu Wasserstoffkosten Und -Bedarfen Für Die CO2-Neutrale Transformation* (Wuppertal Institut, June 2023).

2 Industries that face significant challenges in reducing carbon emissions. Examples include heavy industries like steel, cement, and chemicals, as well as transportation sectors such as aviation, shipping, and heavy-duty road transport.

3 H2-eq. refers to hydrogen equivalent, standardizing different forms of hydrogen derivatives based on their energy content.

4 *World Energy Outlook 2023 — Analysis* (International Energy Agency, October 2023) <https://www.iea.org/reports/world-energy-outlook-2023> [accessed 1 March 2024].

5 Hydrogen Council and McKinsey & Company, *Hydrogen Insights 2024* (Hydrogen Council, McKinsey & Company, 17 September 2024) <https://hydrogencouncil.com/wp-content/uploads/2024/09/Hydrogen-Insights-2024.pdf> [accessed 19 September 2024].

6 *Guidelines on State Aid for Environmental Protection and Energy 2014-2020*, Official Journal of the European Union (European Commission, 28 June 2014) <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0628%2801%29>.

7 This report focuses on built infrastructure, thereby excluding ships, trailers, and trains from the analysis. Built infrastructure inherently incorporates different characteristics regarding scalability and typically employed business models.

8 IEA, 'ETP Clean Energy Technology Guide' <https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide> [accessed 29 October 2024].

9 IEA, *Global Hydrogen Review 2024* (International Energy Agency, October 2024).

10 IEA, *World Energy Investment 2024*, June 2024 <https://iea.blob.core.windows.net/assets/60fcd1dd-d112-469b-87de-20d39227df3d/WorldEnergyInvestment2024.pdf> [accessed 1 November 2024].

11 *Climate Infrastructure Investing: Risks and Opportunities for Unlisted Renewables* (Imperial College Business School, International Energy Agency, March 2022); *Scaling Hydrogen Financing for Development* (The World Bank, ESMAP, OECD, Global Infrastructure Facility, Hydrogen Council, Breakthrough Agenda, 15 February 2024), doi:10.1787/0287b22e-en.

12 William R Kerr and Ramana Nanda, 'Financing Innovation', *Annual Review of Financial Economics*, 7 (2015), pp. 445—62, doi:10.1146/annurev-financial-111914-041825; Mariana Mazzucato and Gregor Semieniuk, 'Financing Renewable Energy: Who Is Financing What and Why It Matters', *Technological Forecasting and Social Change*, 127 (2018), pp. 8—22, doi:10.1016/j.techfore.2017.05.021.

13 *Scaling Hydrogen Financing for Development*; Moongyung Lee and Deger Saygin, *Financing Cost Impacts on Cost Competitiveness of Green Hydrogen in Emerging and Developing Economies*, OECD Environment Working Papers (OECD, 29 November 2023), CCXXVII, doi:10.1787/15b16fc3-en; Lorentz Bernhard and others, *Financing the Green Energy Transition: Innovative Financing for a Just Transition* (Deloitte, May 2024) <https://www2.deloitte.com/content/dam/Deloitte/de/Documents/sustainability/Deloitte_Financing_the_green_energy_transition_Report_2024.pdf>; Moongyung Lee and others, *Leveraging Enhanced De-Risking Instruments and International Co-Ordination to Catalyse Investment in Clean Hydrogen* (OECD, Forthcoming).

14 The World Bank, 'Energy and Power PPPs', 2024 <https://ppp.worldbank.org/public-private-partnership/sector/energy>.

15 Bruno Alves, 'Do Infra Investments Really Need to Be Monopolistic?', *Infrastructure Investor*, 2016 <https://www.infrastructureinvestor.com/do-infra-investments-really-need-to-be-monopolistic/> [accessed 9 August 2024].

16 German LNG Terminal, 'Terminal Overview' <https://germanlng.com/overview/?lang=en> [accessed 2 August 2024].

17 Helena Lönnberg, Jeroen Wegh, and Jaap Peterse, *A European Underground Hydrogen Storage Roadmap: H2eart for Europe's Recommendations to Secure the Scale up of Underground Hydrogen Storage* (H2eart for Europe; Guidehouse, July 2024) <https://h2eart.eu/wp-content/uploads/2024/07/H2eart-for-Europe_European-UHS-Roadmap.pdf> [accessed 9 July 2024].

18 European Commission, 'Energy Infrastructure: Projects of Common Interest (CEF Energy)' <https://cinea.ec.europa.eu/programmes/connecting-europe-facility/energy-infrastructure-connecting-europe-facility-0/energy-infrastructure_en> [accessed 5 June 2024].

19 IEA, 'Germany's Renewables Energy Act' <https://www.iea.org/policies/12392-germanys-renewables-energy-act> [accessed 5 June 2024].

20 European Commission, 'European Hydrogen Bank Auction Provides Million for Renewable Hydrogen Production in Europe' <https://ec.europa.eu/commission/presscorner/detail/en/IP_24_2333> [accessed 30 April 2024]; Danish Energy Agency, 'The First PtX Tender in Denmark Has Been Determined: Six Projects Will Establish Electrolysis Capacity on More than 280 MW', *Energistyrelsen*, 2023 <https://ens.dk/en/press/first-ptx-tender-denmark-has-been-determined-six-projects-will-establish-electrolysis-capacity> [accessed 28 November 2023].

21 Department for Energy Security and Net Zero, 'Contracts for Difference', 2023 <https://www.gov.uk/government/collections/contracts-for-difference>; Agnieszka Ason and Julio Dal Poz, *Contracts for Difference the Instrument of Choice for the Energy Transition* (The Oxford Institute for Energy Studies, April 2024) <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/04/ET34-Contracts-for-Difference.pdf> [accessed 3 May 2024].

22 Federal Ministry for Economic Affairs and Climate Action, 'First Round of Carbon Contracts for Difference Launched' <https://www.bmwk.de/Redaktion/EN/Pressemitteilungen/2024/03/20240312-first-round-of-carbon-contracts-for-difference-launched.html> [accessed 12 March 2024].

23 Kate Axup and others, 'Capacity Investment Scheme Kicks off: What You Need to Know' <https://www.allens.com.au/insights-news/insights/2023/10/capacity-investment-scheme-kicks-off-what-you-need-to-know/> [accessed 18 October 2023].

24 *Hydrogen Storage Business Model: Market Engagement on the First Allocation Round* (UK Department for Energy Security & Net Zero, December 2023).

25 Federal Ministry for Economic Affairs and Climate Action, 'FAQ - Hydrogen Core Network' <https://www.bmwk.de/Redaktion/EN/FAQ/Hydrogen-Core-Network/faq-hydrogen-core-network.html> [accessed 6 August 2024].

26 *UK Hydrogen Strategy* (Department for Energy Security & Net Zero, UK, 24 July 2024).

27 Gregor Brändle, Max Schönfisch, and Simon Schulte, 'Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen', *Applied Energy*, 302 (2021), p. 117481, doi:10.1016/j.apenergy.2021.117481; David Bothe, Gregor Brändle, and Johanna Reichenbach, *Kompakte Analyse Der Importkosten von Synthetischem Methan Nach Deutschland* (Frontier Economics, 30 September 2024); IEA, *Global Hydrogen Review 2024*.

28 H2Global Stiftung, 'PROFIN: A Python Package for Project Finance in the Energy Sector' (H2Global Stiftung, 2024) <https://github.com/H2Global/profin/tree/master/profin>.

29 *European Hydrogen Backbone: Implementation Roadmap - Cross Border Projects and Cost Update* (European Hydrogen Backbone, November 2023) <https://www.ehb.eu/files/downloads/EHB-2023-20-Nov-FINAL-design.pdf> [accessed 8 December 2023].

30 Mohd Adnan Khan, Cameron Young, and David B Layzell, 'The Techno-Economics of Hydrogen Pipelines', *Transition Accelerator Technical Briefs*, 1.2 (2021).

31 South2 Corridor, 'South2 Corridor' <https://www.south2corridor.net/> [accessed 24 September 2024]; GRTgaz, 'HY-FEN' <https://www.grtgaz.com/en/our-energy-transition/hydrogen-transport/hyfen> [accessed 24 September 2024]; European Hydrogen Backbone, 'European Hydrogen Backbone Maps' <https://ehb.eu/page/european-hydrogen-backbone-maps> [accessed 24 September 2024].

32 *European Hydrogen Backbone: Implementation Roadmap - Cross Border Projects and Cost Update*.

33 German LNG Terminal, 'Terminal Overview'.

34 Uniper, 'LNG Terminal Wilhelmshaven' <https://www.uniper.energy/solutions/energy-transformation-hubs/energy-transformation-hub-northwest/lng-terminal-wilhelmshaven> [accessed 1 November 2024].

35 IRENA, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal. Part II: Technology Review of Hydrogen Carriers* (IRENA, 2022) <https://www.irena.org/%20%20%20%20Publications/2022/Apr/Global-hydrogen-trade-Part-II>; Mehran Ghasemi and Hidemichi Iizuka, *Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy* (Black & Veatch, 2022); Florian Schreiner, Matia Riemer, and Jakob Wachsmuth, *Conversion of LNG Terminals for Liquid*

Hydrogen or Ammonia (Fraunhofer Institute for Systems and Innovation Research ISI, 3 November 2022).

36 ISO, 'ISO 14687:2019(En) Hydrogen Fuel Quality — Product Specification' <https://www.iso.org/obp/ui/en/#iso:std:iso:14687:ed-1:v1:en>.

37 IRENA, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal. Part II: Technology Review of Hydrogen Carriers*; Mehran Ghasemi and Hidemichi Iizuka, *Hybrid LNG & Ammonia Infrastructure: Key to a Green Economy*; Schreiner, Riemer, and Wachsmuth, *Conversion of LNG Terminals for Liquid Hydrogen or Ammonia*; Max Distel, 'Large-Scale H2 Storage and Transport with Liquid Organic Hydrogen Carrier Technology: Insights into Current Project Developments and the Future Outlook', *Energy Technology*, 2301042 (2024), doi:10.1002/ente.202301042.

38 Ning Lin, Liying Xu, and Lorena G. Moscardelli, 'Market-Based Asset Valuation of Hydrogen Geological Storage', *International Journal of Hydrogen Energy*, 49 (2024), pp. 114—29, doi:10.1016/j.ijhydene.2023.07.074.

39 A full cycle consists of filling the storage to its total capacity and subsequently withdrawing all the working gas.

40 ENTSOG and others, 'Hydrogen Infrastructure Map' <https://www.h2inframap.eu/> [accessed 1 November 2024].

41 *Why European Underground Hydrogen Storage Needs Should Be Fulfilled* (Frontier Economics; Artelys, 9 April 2024) <https://www.gie.eu/publications/studies/> [accessed 17 April 2024].

42 *Scaling Hydrogen Financing for Development*; Moongyung Lee and others, *Leveraging Enhanced De-Risking Instruments and International Co-Ordination to Catalyse Investment in Clean Hydrogen*.

43 David Bothe and others, *Finanzierungsmechanismus Für Den Aufbau von Wasserstoffspeichern* (Frontier Economics, 30 August 2024) <https://www.frontier-economics.com/media/mkkhfxeq/frontier-economics-finanzierungsmechanismus-fuer-wasserstoffspeicher-studie-fuer-den-bdew_final_20240830_stc_docx.pdf> [accessed 16 September 2024].

44 U.S. Department of Energy, 'Transmission Facilitation Program' <https://www.energy.gov/gdo/transmission-facilitation-program> [accessed 31 July 2024].

45 Based on the return of 10y-US Treasury Bonds

46 Based on Damodaran Aswath Damodaran, 'Equity Risk Premiums (ERP): Determinants, Estimation, and Implications — The 2023 Edition Updated: March 23, 2023', 2023, doi:http://dx.doi.org/10.2139/ssrn.4398884.

47 Bernhard and others, *Financing the Green Energy Transition: Innovative Financing for a Just Transition*.

48 There are additional critical trade-offs closely associated with the process of determining which projects receive financial support—such as auctions, negotiated procurement, or first come, first served mechanisms. However, these aspects are beyond the scope of this report. For more comprehensive insights into the trade-offs involved in setting eligibility criteria for auctions, please refer to another report by H2Global entitled, "Keep it simple: Aligning auction objectives for success".

49 Natalia Fabra and Juan Pablo Montero, *DP15554 Technology-Neutral vs. Technology-Specific Procurement*, 13 December 2020 <https://cepr.org/publications/dp15554> [accessed 31 May 2024].

50 *European Hydrogen Backbone: Implementation Roadmap - Cross Border Projects and Cost Update*.

51 *Why European Underground Hydrogen Storage Needs Should Be Fulfilled*.

52 Chema Zabala and Alfa Diallo, *Study on the Performance of Support for Electricity from Renewable Sources Granted by Means of Tendering Procedures in the Union 2022.* (European Commission, 2022) <https://data.europa.eu/doi/10.2833/93256> [accessed 4 June 2024].

53 *Why European Underground Hydrogen Storage Needs Should Be Fulfilled*.

54 European Commission, *Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on Common Rules for the Internal Markets in Renewable and Natural Gases and in Hydrogen, COM/2021/803 Final* <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803&qid=1640002501099> [accessed 4 June 2024]; 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 (Recast), COM/2021/804 Final* <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A804%3AFIN&qid=1640001545187> [accessed 4 June 2024].

55 The financial support instruments discussed in this report only address involved market risks for hydrogen infrastructure projects. Other risks, as pointed out in Section 2, remain with the project developer.

H2Global-Stiftung
Trostbrücke 1
20457 Hamburg

T: +49 40 36197500
E: info@h2-global.org

www.h2-global.org

H2Global Stiftung