The feasibility of Power-to-X fuels for power generation

Decarbonising power systems requires technology that enables greater flexibility and facilitates the integration of renewable energy. Engine power plants running on sustainable fuels produced through the Power-to-X (P2X) process in combination with energy storage offer an ideal solution to meet this need. The main P2X fuel options for power generation are green hydrogen, synthetic methane, ammonia and methanol. Wärtsilä's continued research on P2X has led to a comprehensive economic feasibility analysis of the cost of using sustainable fuels for reliable power generation and long-term storage in the future.

In order to understand the total levelised cost of using these fuels, this analysis employs a holistic approach by assessing the cost of the production inputs and process, the conversion process (such as liquefaction or compression) depending on the transportation pathway and finally the storage mechanism required onsite of the end-use application. Conducting this analysis increases our understanding and our customers' understanding of which fuel could be predominantly used for different applications in the future.

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Introduction

Decarbonising the power sector is one of the biggest challenges we face today. The transition towards a 100% carbon-neutral energy system is a stepwise process which first requires investing in low-cost renewable sources like wind and solar, phasing out inflexible coal power plants and, finally, steadily integrating the usage of cleaner fuels into power generation.

Given the intermittent nature of these sources, a renewables-dominated future requires system flexibility for balancing in both the short-term and long-term (seasonal). Engines powered by carbon-neutral and sustainable fuels have emerged as a viable option to provide balancing power that is dynamic with a quick response to load fluctuations. The choice of sustainable fuel that is best suited for power generation applications is a contentious topic. Fuels produced through the P2X process such as hydrogen or its derivatives are frontrunners among the sustainable fuels currently available. The P2X process involves using renewable electricity to split water into hydrogen and oxygen through electrolysis. Hydrogen can be stored and then used as as a fuel in power generation. It can also be further converted into synthetic methane, ammonia or methanol. In this white paper, we will take a closer look at the financial and technical feasibility of these green P2X fuels including hydrogen, methane, methanol and ammonia.

The emergence of P2X

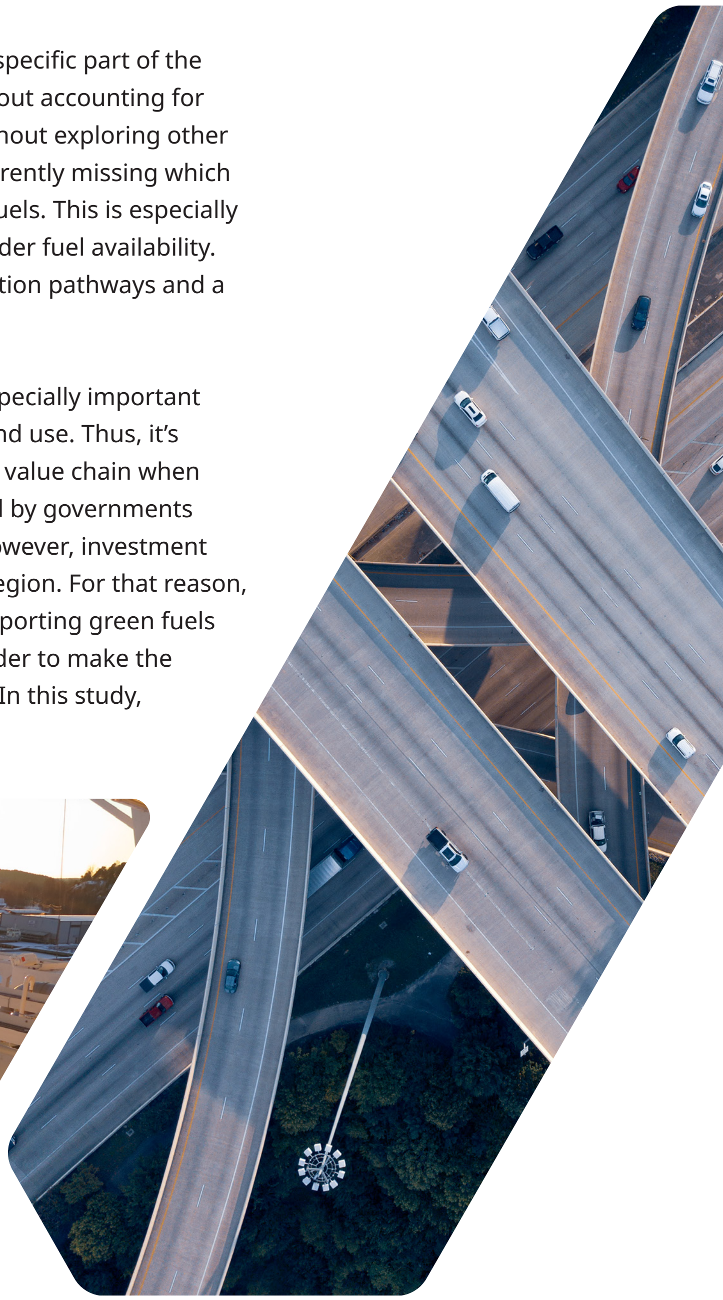
There are many types of sustainable fuels that will play a critical role in the complete phase-out of fossil fuels. These fuels can be divided into three categories based on the input source of energy. First are P2X fuels, which use renewable electricity to produce green hydrogen. Second is Bio-to-X (B2X), which includes producing gaseous fuels like biomethane or liquid biofuels such as hydrotreated vegetable oils (HVO) from biomass, mostly agricultural or forestry by-products. B2X fuels are carbon neutral and are commonly used in blends in the transportation sector. Third is Waste-to-X (W2X), which includes producing recycled carbon neutral fuels from for example plastic waste or gasified municipality waste.

As mentioned, P2X fuels are a promising choice for power generation in the long term. However, the scale and adoption of these fuels is highly dependent on the financial and environmental costs of producing these fuels. Some of the factors that have a direct bearing on the cost of sustainable fuel include the input cost of energy for producing the fuel, the cost of storing and transporting them from the production source to the end-user and the policy support for these fuels.

Analysing the value chain of P2X fuels

The current literature on sustainable fuels is broadly focused on a specific part of the value chain – in other words, assessing the cost of production without accounting for the cost of storage or transportation or just the cost of storage without exploring other aspects of the sustainable fuel value chain. A holistic analysis is currently missing which considers the cost associated with the entire value chain of these fuels. This is especially important since there are location specific bottlenecks that can hinder fuel availability. Adoption of P2X fuels for power generation relies on viable production pathways and a supply chain that supports it.

Considering the transportation and storage costs of P2X fuels is especially important because of the need to either compress or liquify the fuel before end use. Thus, it's necessary to take into consideration the cost associated across the value chain when calculating the total levelised cost. Incentives and subsidies offered by governments can have a significant impact on the production cost of the fuel. However, investment subsidies can vary substantially and are specific to a country or a region. For that reason, subsidies are excluded from the analysis. Furthermore, when transporting green fuels across borders, some countries are considering CO2 taxation in order to make the least carbon intensive fuels as commercially attractive as possible. In this study, these taxes have not been included.

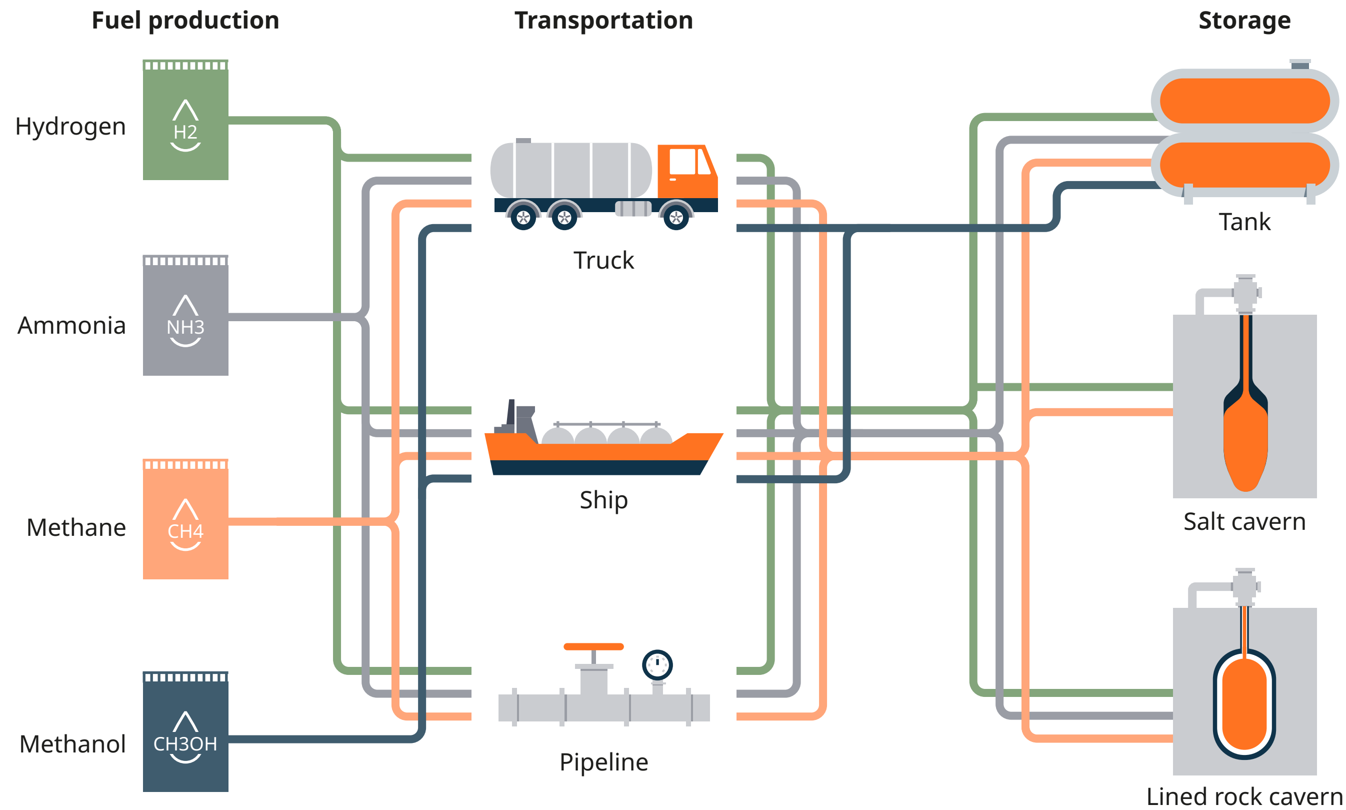


The value chain of P2X fuels

The value chain of P2X consists of three main components: production, transportation, and storage. The first step in the value chain for all P2X fuels is the production of green hydrogen using electricity generated from renewable energy sources.

Transportation options for fuels from production facilities to terminals and end-users over shorter or longer distances include trucks, pipelines, tankers and trains. Trucks and small distribution networks are typically used to cover last mile connectivity to the end users, whereas other options such as ships equipped with tankers are typically used for transporting fuels in large volumes over long distances.

Storage is the last stage in the P2X value chain. There are three main types of storage options: tank storage, salt cavern and lined rock cavern. Tank storage, a mature and common technology, can be used to store fuels in gaseous and liquid form. Geological formations such as salt caverns and lined rock caverns are attractive options for large-scale and long-term energy storage. Depending upon the type of storage available, P2X fuels can be stored for later use either on or offsite.



Multiple pathways for producing P2X fuels

The production of P2X fuels begins with Power-to-Hydrogen, in which renewable electricity is used to decompose water into hydrogen and oxygen via the water electrolysis process. There are three electrolysis methods for producing green hydrogen – alkaline (AEL), polymer exchange membrane (PEM), and solid oxide electrolysis (SOE). All electrolysers are composed of a stack where the chemical splitting of water occurs and auxiliary equipment which includes power supply, water supply, oxygen and hydrogen buffer units and hydrogen processing units.

Out of the three technologies, AEL is the cheapest and most mature technology, but has a long start-up time due to the inflexibility of its auxiliary equipment. PEM is currently a more costly technology due to its expensive catalysts. Despite being relatively expensive, PEM is considered to be the best-suited technology for P2X applications because of its fast load-change capability. SOE has a higher electrical efficiency than the latter two technologies. The disadvantage of SOE is the high heat requirement for the process and the fact that it's currently only available at a demonstration level.

COMPARISON OF POWER-TO-HYDROGEN PROCESSES

	AEL	PEM	SOE
Electrical efficiency (Lower heating value, lhv)	63 – 70%	56 – 63%	74 – 81%
Ramp rate	20%/s	10 – 100%/s	-
Minimum load	15%	0 – 5%	0%
Stack lifetime (h)	50,000 – 90,000	30,000 – 90,000	10,000 – 30,000
Maturity	Mature	Commercial	Demonstration

Hydrogen can be further processed to produce other fuels, and these derivatives have their own specific production processes. Besides hydrogen, either nitrogen or carbon dioxide is also required as feedstock in the production processes of hydrogen derivatives. An air separation unit is used to produce pure nitrogen from the other constituents of air at a sufficient flow rate. Carbon dioxide can be captured from point sources such as exhaust gases or obtained directly from air via direct air capture technologies.

Power-to-Ammonia is based on using hydrogen and nitrogen to produce ammonia, which occurs at extremely high temperature and pressure. Produced ammonia is then separated from the unreacted gases in separation units and recovered for storage. The ammonia synthesis loop also consists of recirculation equipment for unreacted gases.

Power-to-Synthetic Methane can be based on the chemical or biological conversion of hydrogen and carbon dioxide, depending on the type of gas that is needed. The catalytic methanation process takes place in the presence of the catalysts at very high temperature and pressure. The process is characterised by high overall conversion but is sensitive to changes in thermodynamic conditions and impurities. Biological methanation is based on an anaerobic process in which microorganisms are utilised. Additionally, the process has a high tolerance for impurities in the feed-in gas but is a slow process.

Power-to-Methanol is performed with catalysts that enable a very high overall conversion. Reverse water gas shift and hydrogenation reactions take place in the reactor. After synthesis, crude methanol must be purified in a distillation unit to produce pure liquid methanol and to recover and recirculate unreacted gases back to the reactor.

COMPARISON OF POWER-TO-X PROCESSES

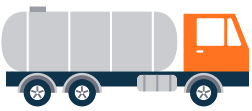
		Power-to-Hydrogen	Power-to-Ammonia	Power-to-Methane	Power-to-Methanol
Use case	Industry	✓	✓	✓	✓
	Power generation	✓	✓	✓	✓
	Mobility	✓		✓	✓
	Building	✓		✓	
	Marine		✓		✓
Process inputs		Water	Hydrogen Nitrogen	Hydrogen Carbon dioxide	Hydrogen Carbon dioxide
Process outputs		Hydrogen Oxygen	Ammonia	Methane Water	Methanol Water
Electrical efficiency (LHV)		60 – 70%	45 – 55%	45 – 55%	45 – 55%

Modes of transporting hydrogen over short and long distances

The transportation costs associated with different P2X fuels depend on the need for compression or liquefaction before transportation, the distance the fuels need to be transported and the location of the production source with respect to the end consumer – for example, whether the location can be accessed by land or sea.

High volumetric density is an important characteristic of fuel that requires transportation over long distances. Achieving this for hydrogen at standard temperature and pressure conditions is very challenging due to hydrogen's low molecular mass and volumetric density.

COMPARISON OF TRANSPORT OPTIONS



Physical state
Gas

Distance
<100km

Transport by truck
Transportation by road is a universal method for delivering fuel produced in a centralised hub to multiple demand sources connected via a local distribution network.

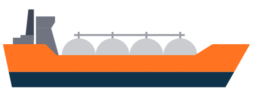
Typically, hydrogen can be transported by road either in a compressed gaseous form through gas trucks or in liquefied form through cryogenic tube trailers. Both are novel methods of transportation that have yet to reach commercial maturity due to the lack of appropriate infrastructure. This includes refuelling stations and liquefaction plants, as well as challenges attributed to the low volumetric density of the gas and thus the large vessel capacities required.

Physical state
Gas

Distance
>500 km (highly location specific)

Transport by gas grid
Pipelines enable the delivery of large volumes of fuel over long-distances. It also enables import and export of fuel across jurisdictions. It's possible to inject hydrogen into natural gas pipelines. However, blending mandates differ depending on the location. This is because hydrogen can cause embrittlement of steel pipelines and lead to an increased risk of leakage.

The two main methods of utilising pipelines to transport pure hydrogen are repurposing existing natural gas pipelines to transport hydrogen and implementing new pipeline capacity for hydrogen. The former will require extensive structural testing and modification of compressor technology.



Physical state
Liquid

Distance
Overseas

Transport by ship
Sea transportation is a viable solution for transferring large amounts of LNG, ammonia and methanol over long distances if other transportation options are not technically possible or economically viable. Shipping is characterised by a non-continuous transfer due to the limited storage volume and the number of ships as well as delays in both loading and unloading terminals.

Due to the low energy density of hydrogen, it is economically challenging to transport by ship. There are no commercial solutions available for compressed gaseous hydrogen, and the first solutions for liquid hydrogen are only just emerging.

Types of hydrogen storage

Among the fuels analysed in this paper, hydrogen fuel faces the most challenges when it comes to storage due to the gas's chemical properties as well as a lack of commercially available storage options. Hydrogen molecules have a low molar mass and small size, meaning the gas can diffuse through materials that are considered impervious to most gases. Thus, the likelihood of gas leakage associated with hydrogen is higher.

Moreover, hydrogen's low vapour density and high buoyancy – combined with its colourless and odourless nature – complicate its detection and increases the risk of gas accumulation at high points especially indoors. Hydrogen's low flame temperature also poses a risk if it leaks from storage containers as the likelihood of explosion is high.

Tank storage

There are several types of pressure vessels currently utilised for bulk storage of hydrogen.

COMPARISON OF PRESSURE VESSELS

Type I vessels are all-metal cylinders usually made from carbon steel or low-alloy steel. These types of vessels are an economical and mature technology. Moreover, type 1 vessels are commonly utilised in industrial and commercial applications. Hydrogen is usually stored at 200–300 bar with a maximum limit of 500 bar. The main problem with conventional tanks for high-pressure hydrogen storage is the cracking and blistering of steel, thereby making it less ductile (a process known as embrittlement), especially after multiple charging and discharging cycles.

Cost	**$**
Maximum pressure	**≤500 bar**
Gravimetric density	■
Application	**Stationary**

Type II vessels are a lighter, more durable alternative to type I vessels and can withstand a similar amount of pressure. They are partially reinforced with a composite material.

Cost	**$$**
Maximum pressure	**Unlimited**
Gravimetric density	■■
Application	**Stationary**

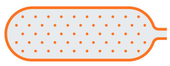
Type III vessels are more expensive and are fully wrapped in a high-strength composite liner. This type of vessel has a maximum operating pressure of 450 bar.

Cost	**$$$**
Maximum pressure	**≤450 bar**
Gravimetric density	■■■
Application	**Industry, mobility**

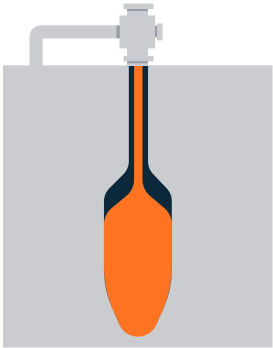
Type IV vessels are more expensive and lightweight than the previous vessels, and they can withstand pressures of 700 bar. These vessels consist of a polymer liner that is wrapped with a fibre-resin composite.

Cost	**$$$$**
Maximum pressure	**≤1,000 bar**
Gravimetric density	■■■■
Application	**Industry, mobility**

Type V vessels are linerless, fully composite vessels and are lighter than the composite vessels mentioned above. However, they are still in development and currently very expensive.



Building pressure vessels near a hydrogen production facility reduces transportation costs. Pressure vessels also enable retaining the purity of hydrogen over time. However, they are infeasible for the large-scale storage of hydrogen due to the sheer material cost associated with the quantity of vessels that would be required to meet hydrogen demand on a TWh-scale. High land area requirement is another factor that decreases the competitiveness of pressure vessels, given the scarcity and cost of land.



Salt cavern

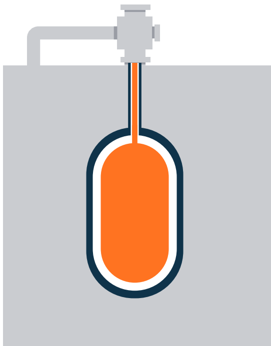
Underground gas storage is a state-of-the-art technology that has been utilised for storing natural gas in geological formations for several decades. Underground storage enables the storage of enormous volumes of gas (upwards of 500,000 m3) at a high pressure (200–300 bar). These features make it one of the most economical methods of storing large amounts of energy, and perhaps the cheapest way of storing hydrogen at a large scale.

Underground reservoir capacity is divided into cushion gas and working gas. Cushion gas is defined as the minimum amount of gas required to maintain adequate pressure within the reservoir to enable efficient injection and prevent water intrusion. It acts as a buffer and is non-recoverable, so it accounts for a significant part of the capital cost of the reservoir. The working gas capacity of the reservoir is the maximum amount of gas that can be injected and withdrawn from the reservoir repeatedly.

Salt caverns are artificially mined cavities created within salt domes or bedded salt deposits through salt leaching. They are considered the most suitable form of storing hydrogen underground due to the gas tightness provided by the inert salt lining of the cavern, the relatively large volumes that can be attained (typical geometrical volumes of 100,000 m3 to a maximum of 1,000,000 m3) and high operating pressures of 300 bar. The inertness of the salt offers a tight, sealed space for hydrogen, thus preventing any risks to the external environment and ensuring a negligible risk of leakage. Moreover, the ratio of working gas to cushion gas is usually 80:20, which is much higher than with other types of underground storage.

Lined rock cavern

Rock caverns are excavated underground facilities that are built in areas which have hard rock but lack salt domes. Given the permeability of hydrogen, these formations do not have the desired level of imperviousness to reduce the risk of a leak. However, a recent development in rock cavern storage – the concept of lined rock cavern storage (LRC) – has been developed to overcome this limitation.



LRC involves encasing a rock cavern with a lining that has three main components: a sheet of stainless steel to contain the gas, a concrete layer between the steel and the surrounding rock and the rock mass which absorbs the load from the working gas pressure. The purpose of the concrete is to ease the pressure load on the liner and transfer the load smoothly to the surrounding host rock. The first LRC facility was built in Skallen, Sweden in 2004 to store natural gas. The storage is 51 metres high and 35 metres in diameter, with a volume of 40,000 m3. The working gas capacity is approximately 90% and the cushion gas level is 10%.

COMPARISON OF UNDERGROUND STORAGE

	Lined rock cavern (LRC)	Salt caverns	Depleted oil and gas reservoirs*	Aquifer storage*
Description	Excavated rock cavern, lined with steel and reinforced with concrete	Mined cavities within salt domes or bedded salts, formed by leaching salt	Gas/oil in existing reservoir is displaced utilising working gas	Ground water bearing reservoirs
Operating pressure (bar)	20 – 200	Up to 275	200	Up to 200
Injection cycles	Multiple (>3) cycles a year, high deliverability	Multiple (>3) cycles a year, high deliverability	Suitable for 1–2 cycles a year, low deliverability	Suitable for 1–2 cycles, low deliverability
Maximum volume (m^3)	Up to 200,000 (hard rock)	Up to 1,000,000	Up to 500,000	Up to 10^9 for NG
Leakage tendency	Lack of data	Negligible due to inertness of salt	Hydrogen loss through chemical reaction	High risk due to permeability of porous rock
Undesirable characteristics	• Intensive capital costs • No commercial cases	Severely limited by geographical availability	Bacteria that can lead to methane production	• Very permeable • Contamination of ground water • Geographically limited
Cushion gas requirement	10%	20–30%	50–60%	80%

*These geological storage types have not yet been proven as feasible for storing hydrogen.

The most feasible form of hydrogen storage is still unclear. There are several important non-cost related parameters to consider when assessing the feasibility of hydrogen storage technology. These include:

- The ability to retain hydrogen for long periods of time (low leak risk)
- The purity of the stored hydrogen
- The ability to withstand fluctuations caused by intermittent power
- Damage to the environment
- The number of required charging and discharging cycles
- Safety and handling of fuel

Determining P2X fuel costs

A thorough analysis of various cost elements across the P2X fuels value chain is required to understand the impact of various cost structures on the total levelised cost of P2X fuels. The variation in cost across the value chain depends on the feedstock and equipment required for the production process and the end-use application.

Costs also vary substantially depending on location-specific details, such as the distance from the fuel production site to end-use customers, the feasibility of transportation and the need for storage on fuel production or consumption sites.

COMPARISON OF COST FACTORS

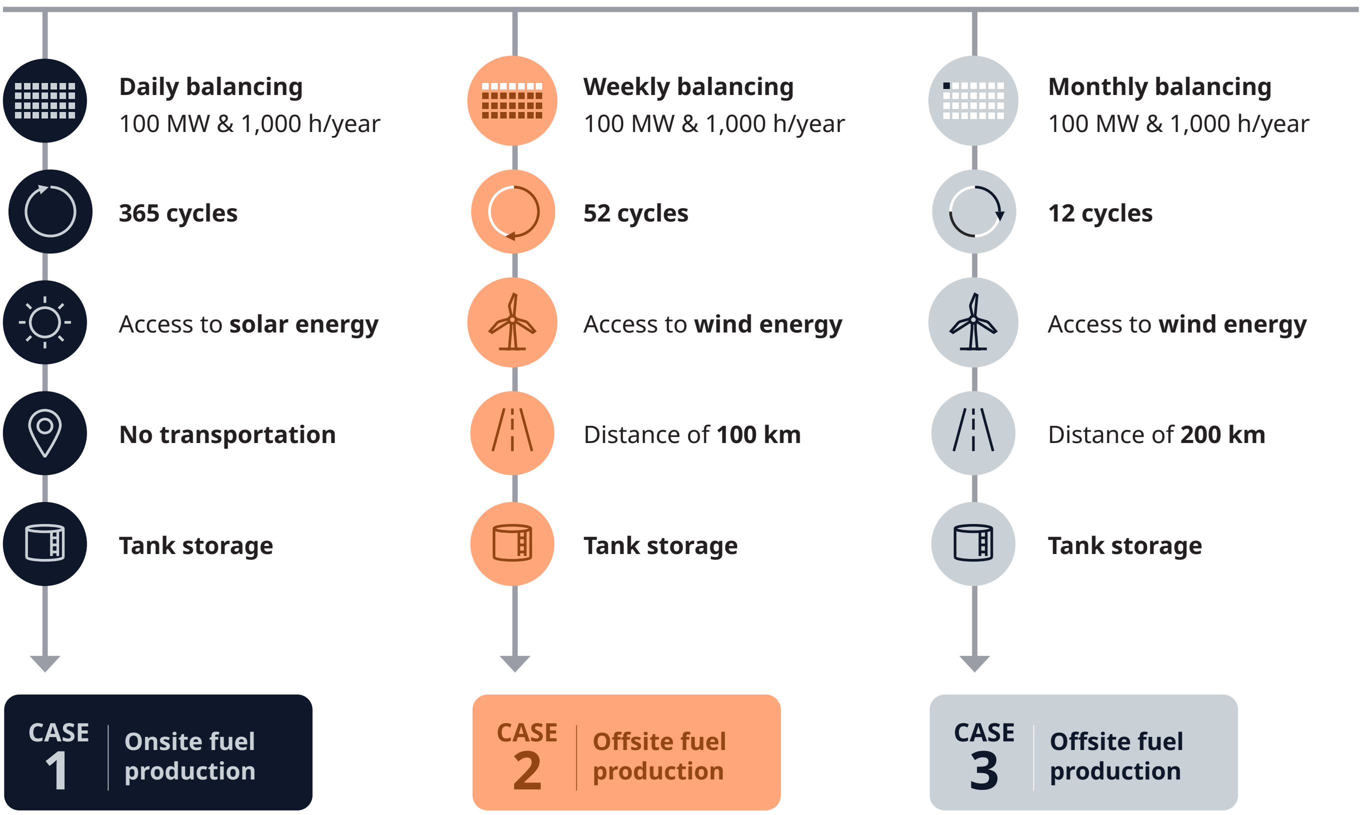
Production	Transportation	Storage
• Cost of renewable electricity • CAPEX of electrolyser • Efficiency of electrolyser • Utilisation rate • Conversion cost • Liquefaction requirement	• Transport distance • Transportation method • Compression requirement • Leakages and boil-off costs	• Short duration storage vs long duration storage (daily vs monthly cycles) • Available storage methods and volume • CAPEX and OPEX of storage • CAPEX and OPEX of compression (decompression is excluded from the model)

P2X case studies

> In order to compare different P2X fuels depending on the end-use application, Wärtsilä has studied onsite and offsite fuel production process case examples. These cases are discussed below.

The three main cases for determining P2X cost factors
These case examples assume that P2X fuels and flexible power generation are required to meet electricity demand when there is a shortage in renewable energy. The estimated net power output and annual running hours requirements for flexible power generation are 100 MW and 1,000 hours, respectively.

AIM TO CALCULATE LEVELISED COST OF FUELS FOR VARIOUS ASSUMPTIONS



Case 1 assumes that P2X fuel production facilities are located at the same site as flexible power generation, meaning there is no transportation. The location in question has abundant renewable energy sources (especially solar power), and renewable energy is utilised to produce P2X fuels for later use. The fuel production plant has approximately 2,600 running hours per year. Storage tanks are the only option for storing the fuels onsite, and the size of the pressure vessel is defined so that there are 365 full-empty cycles in a year.

CASE 1 Onsite fuel production

Case 2 assumes that P2X fuels are not produced in close proximity to flexible power generation, so fuels must be transported to the site. The distance between fuel production and the power plant is 100 km. Additionally, it has been assumed that there is an existing natural gas pipeline between the fuel production and the power plant site – and that it can be utilised for synthetic methane or be retrofitted for hydrogen. For ammonia and methanol, trucks are the only reasonable option to transport fuels to the power plant as there are no existing pipelines for them. The location has excellent conditions for wind production and running hours for fuel production processes are assumed to be 4,400 hours per year. It's assumed that wind power can generate more stable power during the day, but there are longer periods of time when production is low. Due to irregular flexible power, there is a need for a large storage tank and there are 52 full-empty storage cycles in a year.

CASE 2 Offsite fuel production

Case 3 assumes that the fuel production case is identical to case 2 except the distance between fuel production and the power plant is 200 km, and flexible power generation is needed for seasonal balancing only. Due to seasonal balancing, a large tank is required and there are 12 full-empty storage cycles per year.

CASE 3 Offsite fuel production

There are many input parameters and defaults that are required for the calculations used for each case.

SELECTED INPUTS FOR CASE STUDY CALCULATIONS

Electricity
€50/MWh

Nitrogen
€10/metric ton

Carbon dioxide
€40/metric ton

Weighted average cost of capital (WACC)
7%

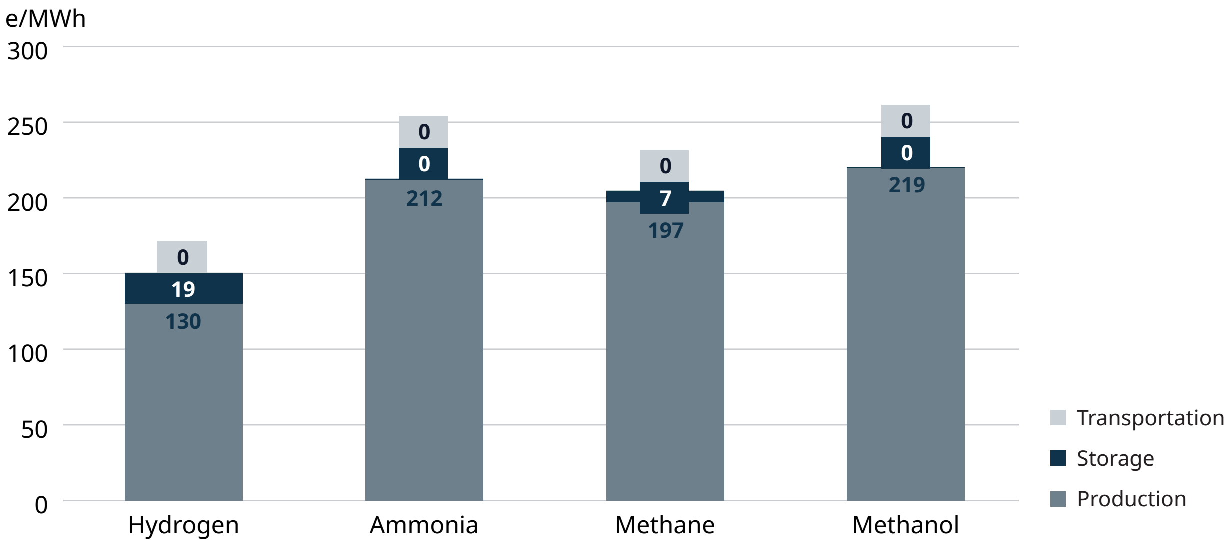
	Hydrogen	Ammonia	Methane	Methanol
Electrical efficiency (LHV)	64%	51%	53%	50%
Reference CAPEX	€10M	€56M*	€7.5M*	€16M*
Capacity	12 MW	65 MW	10 MW	18.5 MW
Scaling factor	0.8	0.82	0.82	0.82
OPEX	3% of CAPEX	4% of CAPEX	2.5% of CAPEX	3% of CAPEX

*These numbers do not include the CAPEX of hydrogen

CASE 1 Onsite fuel production | CASE 2 Offsite fuel production | CASE 3 Offsite fuel production

The first case example deals with onsite fuel production where transportation is not needed.

LEVELISED COST OF VARIOUS FUELS FOR CASE 1



Based on these assumptions, hydrogen is the most affordable fuel. The levelised cost of hydrogen is roughly €150/MWh H2 (LHV), or €5/kg H2 and the required size of the electrolyser is almost 85 MW H2 (LHV) in order to meet the fuel demand requirement for the given running hours.

The results indicate that production of hydrogen accounts for over 86% of the total cost while the rest comes from storage as transportation is excluded.

Hydrogen production costs can be divided into three main categories: the electricity cost (electricity utilised by the electrolyser), the CAPEX cost and OPEX cost. In this example, electricity costs account for 60% of the total hydrogen production cost. The CAPEX component includes electrolysers as well as other related cost additions and covers 25% of the total cost. The rest is allocated for OPEX, which consists of maintenance, electrolyser stack replacement and water costs.

The cost of hydrogen storage accounts for less than 14% of the total cost and consists of the cost of the pressure vessel and the compression cost to reach the operating pressure of the tank. The CAPEX component is the main cost contributor for storage as it covers approximately 60% of the storage cost.

Besides hydrogen, the levelised cost of ammonia, synthetic methane and methanol are approximately 212, 204 and 220 EUR/MWh (LHV) respectively. Production costs for hydrogen derivatives are significantly higher in comparison to hydrogen, and ammonia and methanol production costs account for over 99% of the total costs since producing hydrogen is the precursor step for all the fuels in question. The additional production step requires capital and leads to a decrease in electrical efficiency due to losses and conversion rates. On the other hand, it is easier to store hydrogen derivatives, which is why the cost of storage is much lower.

KEY TAKEAWAYS

Hydrogen has the **lowest levelised cost of fuel** when onsite fuel production and short-term storage are considered.

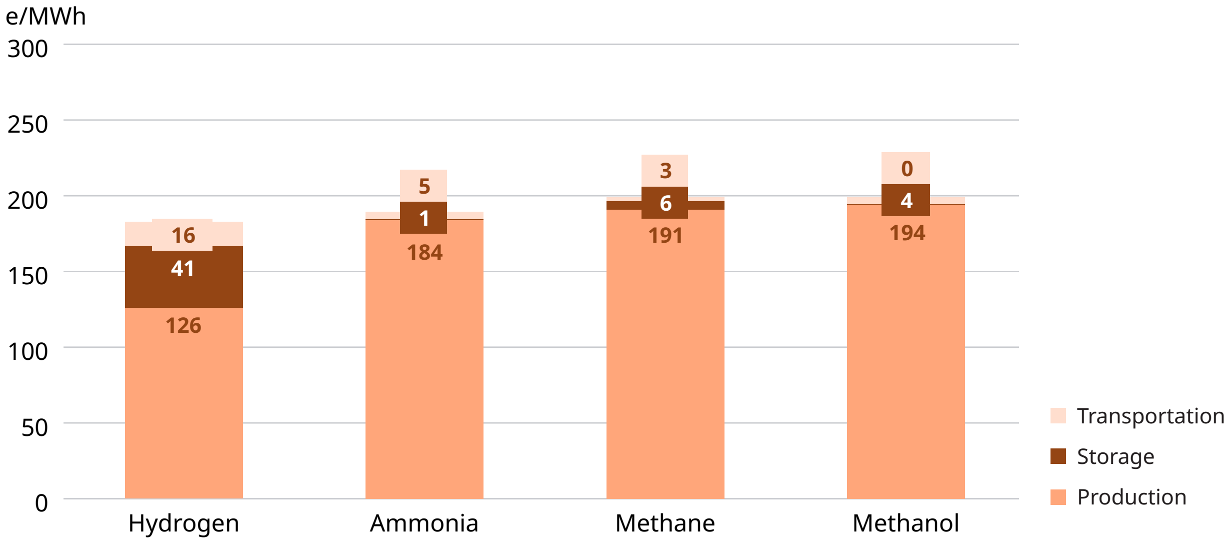
Electricity accounts for **60%** of hydrogen production costs and approximately **50%** of total hydrogen cost.

Hydrogen derivatives are **more expensive** due to significantly higher production costs.

CASE 1 Onsite fuel production | CASE 2 Offsite fuel production | CASE 3 Offsite fuel production

The second case example covers offsite fuel production and the entire value chain of P2X fuels.

LEVELISED COST OF VARIOUS FUELS FOR CASE 2



KEY TAKEAWAYS

Hydrogen derivatives become more competitive when offsite fuel production and longer-duration storage are considered.

Storage of hydrogen derivatives is more affordable as compared to hydrogen

According to the results, hydrogen is still the most affordable fuel, and the levelised cost of hydrogen is approximately €174/MWh H2 (LHV) or €5.8/kg H2. However, the cost difference between fuels is now roughly 10% due to the increased cost of hydrogen storage and transportation. The required size of the electrolyser is approximately 50 MW H2 (LHV).

Transporting and storing hydrogen is very expensive, which means that hydrogen production accounts for 70% of the total cost. For hydrogen derivatives, production costs account for over 95% of the total costs.

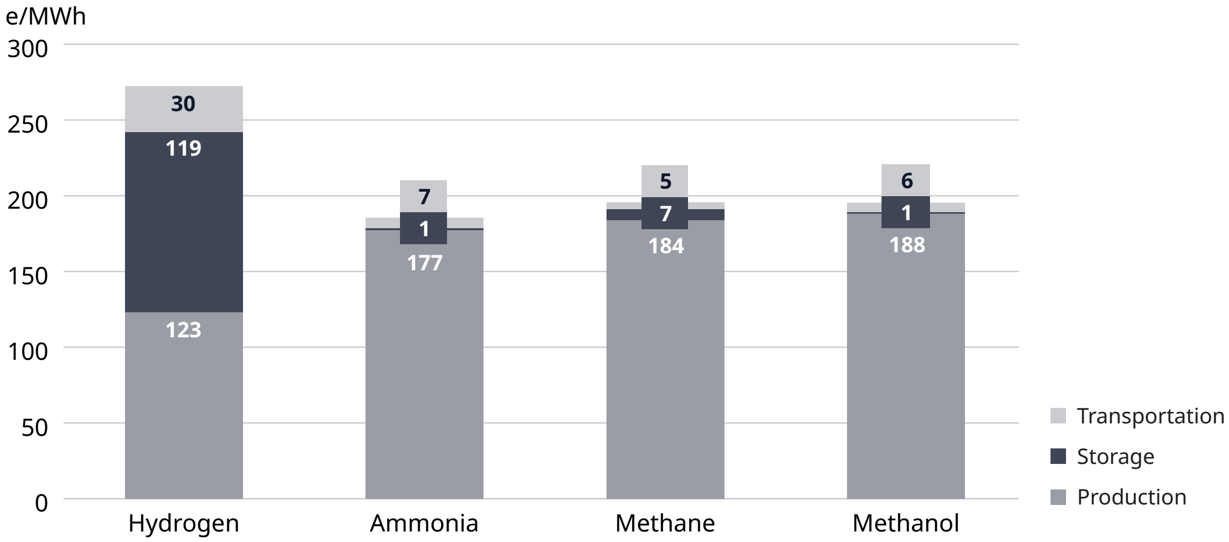
Synthetic methane transportation via an existing natural gas pipeline is the cheapest way to transport fuel, and the cost difference increases as the transportation distance increases. To transport fuel with trucks requires hundreds of truck deliveries per year – which is infeasible as a long-term solution, especially on a large scale.

Correspondingly, methanol is the cheapest fuel when looking at storage costs, which account for less than 1% of the total cost of methanol. Ammonia is another fuel that can be stored very cheaply, with synthetic methane costing slightly more to store.

In this case, utilising truck transportation for hydrogen would require thousands of truck deliveries in a year with a net payload of 400kg (200 bar) to meet the required fuel demand and the levelised cost of hydrogen would increase by over 5%.

Lastly, let us consider monthly storage cycles and a transportation distance of 200 km.

LEVELISED COST OF VARIOUS FUELS FOR CASE 3



The results indicate that ammonia is the most affordable fuel, with a levelised cost of approximately €186/MWh NH3 (LHV). Furthermore, the levelised cost of synthetic methane and methanol is approximately €195/MWh (LHV). There is a very narrow cost gap between the fuels.

Contrary to the other cases, hydrogen is the most expensive fuel, and the levelised cost of hydrogen is about €273/MWh (LHV). In this case, hydrogen storage costs are especially expensive, and hydrogen production costs account for less than 50% of the total costs. By reducing the number of storage cycles per year, the CAPEX costs of the hydrogen tank increase significantly which makes the hydrogen case less attractive.

KEY TAKEAWAYS

Challenges associated with transporting and storing hydrogen make it more expensive in comparison to hydrogen derivatives.

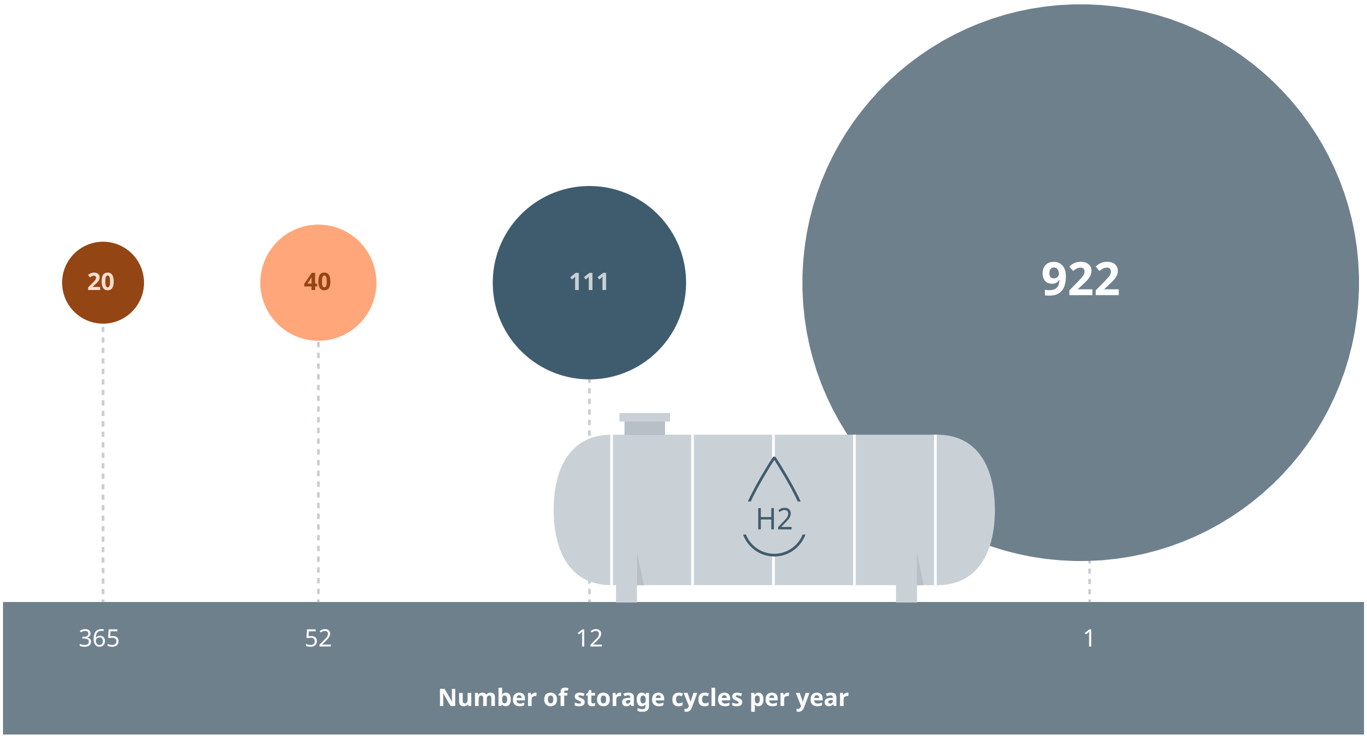
Using steel pressure vessels to store hydrogen is not a cost-effective solution for seasonal, large-scale energy storage.

Sensitivity analysis

Hydrogen storage
The case studies highlight the importance of considering the costs associated with each part of the P2X fuels value chain when choosing which fuel is best suited for power generation, especially when the location of the power generation source is not located near the fuel source. In the case of hydrogen, transportation and storage costs vary significantly between the cases and also account for a sizeable portion of the total levelised cost. Between the transportation and storage section of hydrogen's value chain, the utilisation of the storage (number of full-empty cycles in a year) has a greater impact on the total levelised cost as is evident from case 3.

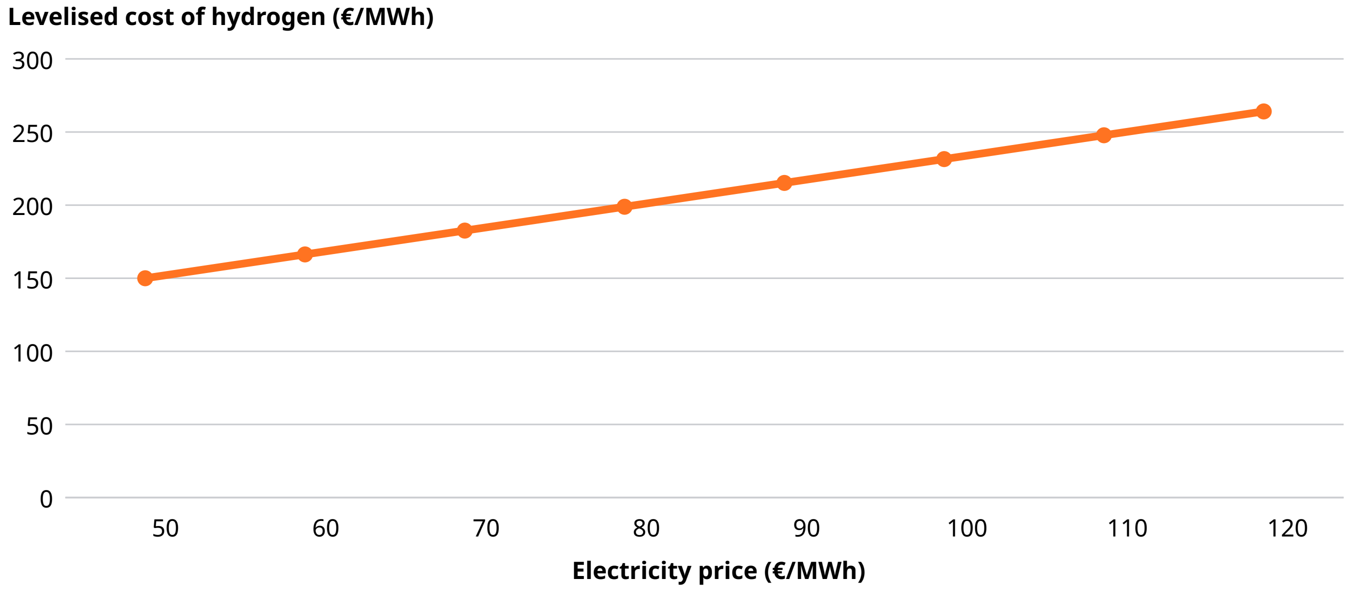
The graph below illustrates the impact of changing the number of hydrogen storage cycles in a year on the levelised cost of storage for hydrogen for case 1 (onsite fuel production and power generation). Due to the high CAPEX cost of the tank storage, utilising it as a seasonal storage once per year is not cost effective. In this case, the optimal storage method would be utilising a geographical storage option such as a salt cavern that can store large volumes of gas. Tank storage is best suited for applications where daily or weekly storage is needed.

LEVELISED COST OF STORAGE, HYDROGEN (€/MWh)



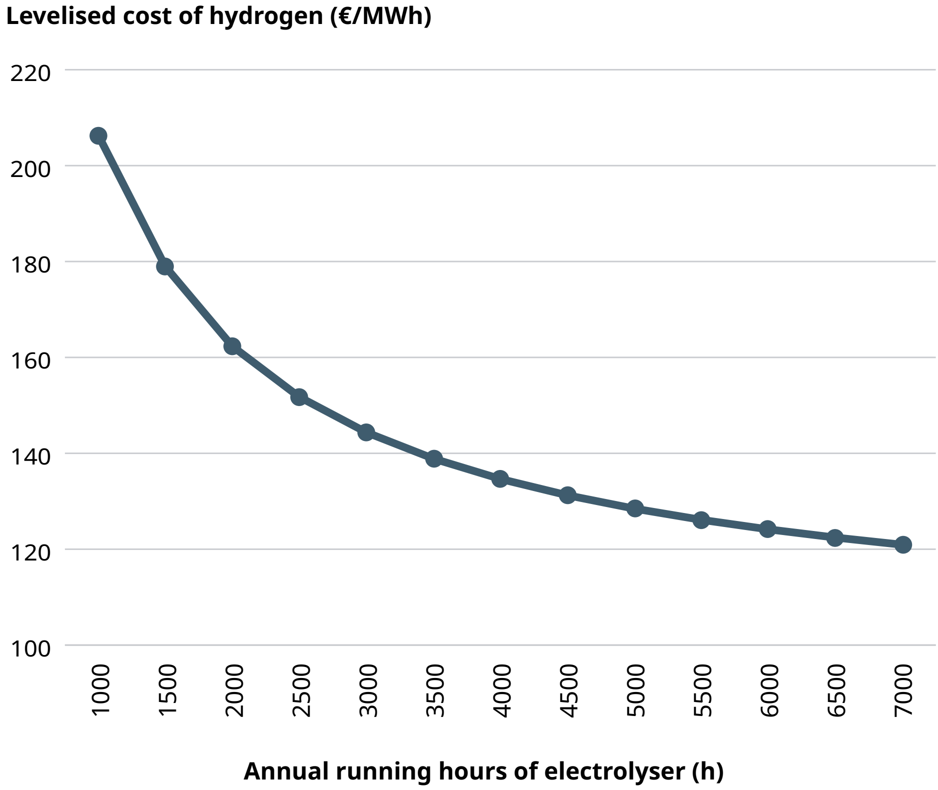
Cost of electricity and electrolyser running hours
The cost of renewable electricity is a significant driver of the total levelised cost of P2X fuels. This is evident from case 1, where electricity costs accounted for 60% of the total production costs of hydrogen. As the figure below depicts, increasing the cost of electricity can have a severe negative impact on the levelised cost of hydrogen. Thus, access to cheap renewable energy and water resources play a key role in the production of P2X fuels and there needs to be a significant push towards increasing renewable energy integration in order to enable large scale production of P2X fuels.

IMPACT OF THE ELECTRICITY PRICE IN LEVELISED COST OF HYDROGEN, IN CASE 1.



The most suitable locations for production would be those with high-capacity factors for wind and solar. In addition to the cost of electricity, it’s also important to consider electrolyser efficiency, CAPEX and the annual running hours of the electrolyser. The graph below shows that increasing the number of running hours of the electrolyser (assuming a fixed cost of electricity) also leads to a decrease in the cost of hydrogen. This indicates that utilising the electrolyser in a baseload operation with higher running hours is the most suitable for cheaper hydrogen. However, this does not mean that utilising the electrolyser in a flexible manner does not have its advantages, such as capitalising on price fluctuations on the day ahead and balancing markets.

IMPACT OF CHANGING ELECTROLYSER RUNNING HOURS, IN CASE 1.



Modelling P2X in energy systems

Aside from evaluating the cost of sustainable fuels, it's also important to assess the feasibility of utilising P2X in the broader perspective of an energy system. Power system modelling can play a critical role here. Power system modelling tools can highlight the role that P2X may play in the transition towards achieving a carbon-neutral energy system.

Wärtsilä conducts country-level modelling using a techno-economic optimisation software called PLEXOS, which employs chronological modelling to assess the least-cost pathway for a country to achieve its decarbonisation targets over a long-term horizon. The software enables Wärtsilä to assess the feasibility of utilising P2X and energy storage in combination with balancing power to reduce renewable curtailment and overcome supply-side volatility caused by higher renewable integration. On a project level, the software can also assess the degree to which a P2X system can be used for demand response operation or evaluate the optimal size of a P2X system participating on the day-ahead or balancing (real-time) markets.

Building a real-world P2X2P system

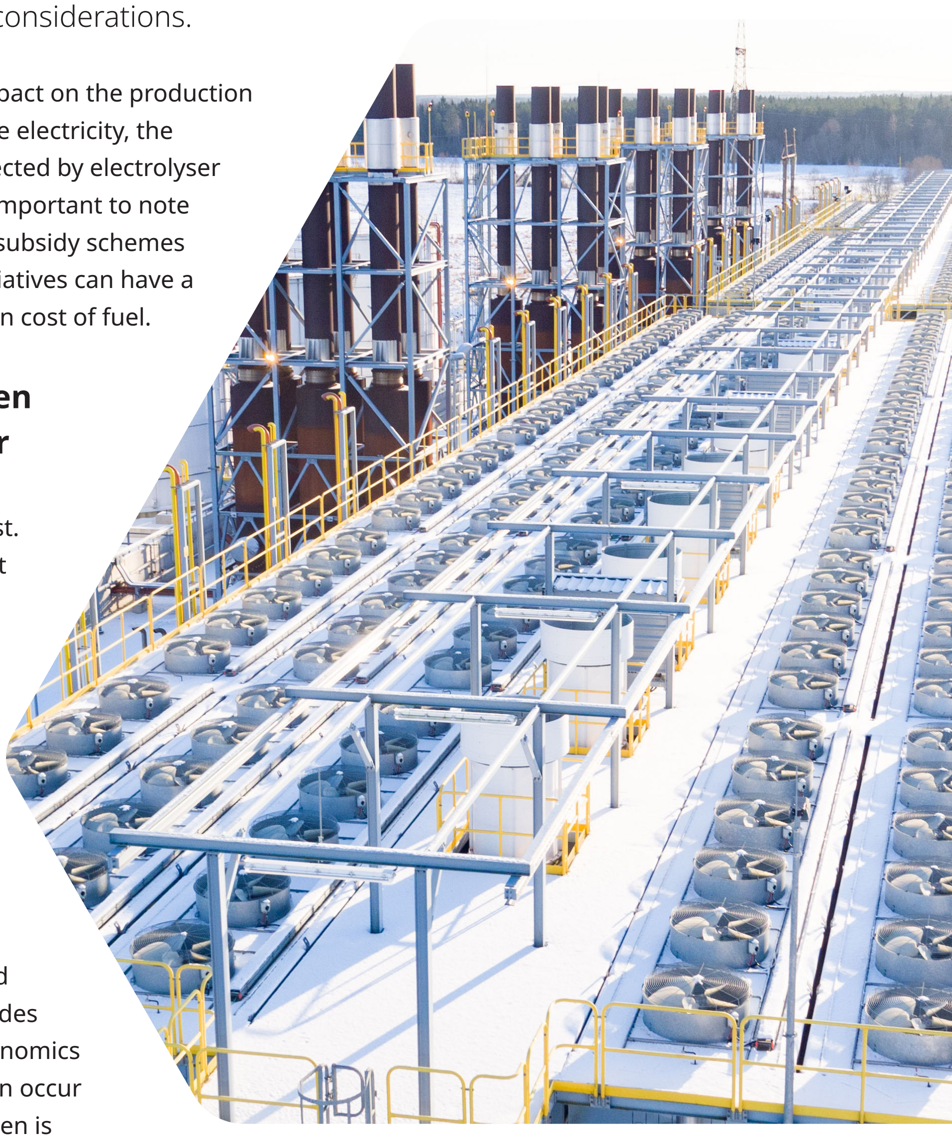
At the end of 2021, Wärtsilä – along with energy companies EPV Energia and Vaasan Sähkö – announced plans to build a pilot Power-to-X-to-Power (P2X2P) system to capitalise on the dynamics of the electricity market by producing and storing hydrogen. The proposed solution will produce hydrogen using P2X when electricity prices are low on the day-ahead market and store it in a hydrogen tank to be consumed for electricity generation by an engine when electricity prices are high. Moreover, the excess heat generated as a by-product from the engine can be channelled into underground thermal storage caverns for use in the local district heating network.

For this project, Wärtsilä used PLEXOS to conduct a sensitivity analysis of what impact varying the electrolyser size in the system will have on the hydrogen storage utilisation, offtake of hydrogen by the engine and the overall participation of the system on the real-time and day-ahead electricity market.

A final investment decision will be made in 2023 and the project has a completion schedule in 2025. The plant will have capability to run on hydrogen and methane - either natural gas or biogas/biomethane. The aim of the project is to showcase an engine power plant that runs on 100% hydrogen by the end of 2026.

Conclusions

P2X fuels will play a key role in the decarbonisation of the energy sector. In the power sector, P2X fuels will prove essential to meet the seasonal and balancing requirements of the grid. Our analysis demonstrates that the choice of P2X fuel, particularly in the power sector, will be case specific and will depend on the available transportation and storage technology as well as safety, operation, and maintenance considerations.



The input cost of electricity has the biggest impact on the production cost of P2X fuels. Besides the cost of renewable electricity, the overall production cost is also significantly affected by electrolyser efficiency, CAPEX and the utilisation rate. It is important to note that geographical considerations, investment subsidy schemes and carbon legislation among other policy initiatives can have a significant impact on the choice and production cost of fuel.

Green hydrogen is attractive when onsite fuel production and power generation is considered

Green hydrogen has the lowest production cost. This makes it an attractive fuel option amongst available P2X fuels. Besides this, there are other factors that make green hydrogen an attractive option. First, converting green hydrogen into one of its derivatives results in a loss of energy which makes hydrogen derivatives relatively costly in terms of production cost. Second, green hydrogen is more suitable when the production and consumption of fuel are close together, thereby minimising the need for additional investment in transportation and storage. For example, a power plant that provides daily balancing or peaking will have better economics when fuel production and electricity production occur on the same site. Under this condition, hydrogen is probably the preferred option given the cost of fuel.

It's important to note that hydrogen storage can have a huge impact on the cost of green hydrogen. This is because as the number of storage cycles decreases, the investment requirement in a larger storage tank increases, increasing the overall investment cost which impacts the levelised cost of green hydrogen. In case of pressure vessel storage, it's fair to say that hydrogen is competitive and suitable for short-term energy storage and related applications – however the availability of geological formations can enable cost-effective long-term, large-scale hydrogen storage.

The case for hydrogen derivatives

Ammonia, synthetic methane and methanol production are more competitive compared to green hydrogen when long-distance transportation and seasonal energy storage is required. In the case of ammonia, synthetic methane and methanol, production costs cover most fuel costs and they are competitive when long-distance transportation and more seasonal energy storage are required. Furthermore, the cost advantage of locally produced green hydrogen can erode and the competitiveness of synthetic fuels, even imported, can increase when hydrogen is used to produce hydrogen derivatives at large-scale. In this case, the cost of green hydrogen has an impact on the results.

Even though the levelised cost of fuel is an important factor, there are other key factors that have a significant impact. Fuel availability is one thing that must be secured – this depends on the scale, mode of supply and local regulations. Hydrogen and hydrogen derivatives have different characteristics and require that specific CAPEX, OPEX, emissions and safe operation and maintenance measures are taken into consideration. Lastly, to obtain financing, many rules need to be followed to ensure that the investment is sustainable. Thus, it's important to acknowledge that the most affordable fuel on paper does not necessarily guarantee the lowest levelised cost of electricity. Overall, it's important to not exclude any fuel from consideration as a contender for power generation applications. The choice of fuel that is the most cost-optimal is highly dependent on the specifications of the entire value chain as mentioned previously.

Looking to the future

The adoption of sustainable fuels in the energy sector is not without its challenges. Significant investment in infrastructure and transformation in policy is required to develop the P2X fuels ecosystem.

Wärtsilä has recently launched a major test programme at the company's engine laboratory in Vaasa, Finland with the purpose of defining the most feasible internal combustion engine-based solutions for power plant applications using 100% hydrogen and ammonia as carbon-free fuels. The results so far have been encouraging, and the programme is expected to have a power plant concept for ammonia in the first quarter of 2024, and for methanol in the second quarter. Wärtsilä engines can currently run-on natural gas, biogas, synthetic methane, or hydrogen blends of up to 25% hydrogen. Another target of the ongoing testing is to achieve a plant concept for pure hydrogen by 2025. Wärtsilä has the capabilities to conduct concrete economic feasibility analysis at a project level and support customers with adopting sustainable fuels in their energy system. This includes a combination of cost and operational analysis of different energy assets and financial analysis such as cash flow modelling.

About Wärtsilä

Wärtsilä leads the transition towards a 100% renewable energy future. We help our customers to decarbonise by developing market-leading technologies. These cover future-fuel enabled balancing power plants, hybrid solutions, and energy storage and optimisation technology, including the GEMS energy management platform. Wärtsilä Energy's lifecycle services are designed to increase efficiency, promote reliability and guarantee operational performance. Our portfolio comprises 76 GW of power plant capacity and more than 110 energy storage systems delivered to 180 countries around the world.

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