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Power-to-hydrogen-to-power: Technology, efficiency, and applications

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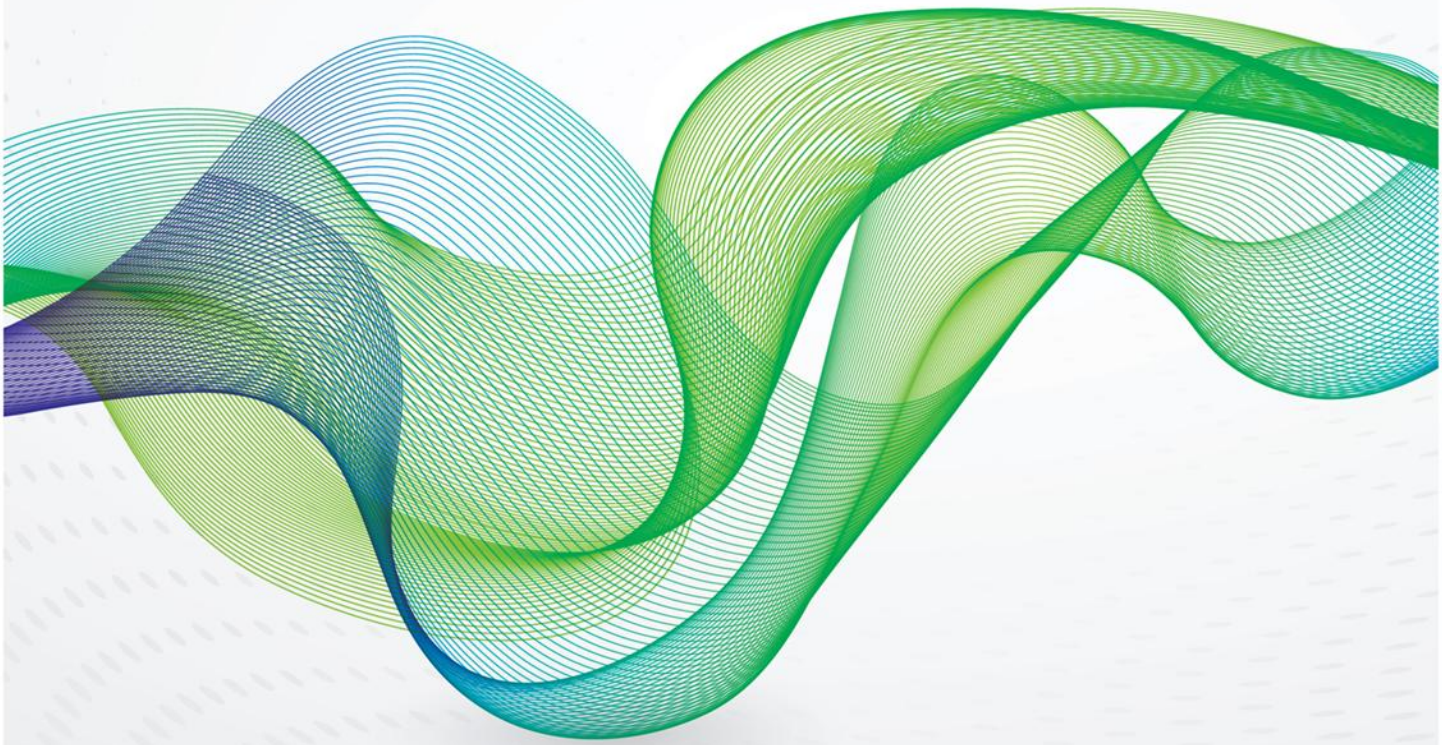
Power-to-Hydrogen-to-Power: Technology, Efficiency, and Applications



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1. Introduction

The transition to clean power is the most critical step in closing the emissions gap by 2030. According to the IPCC, in pathways compatible with limiting global warming to 1.5°C, phasing out fossil-based electricity generation accounts for approximately 40% of emission reductions in the 2020s, while expanding clean electricity to other sectors contributes to another 10%. This means that about half of the emissions reductions needed by 2030 depend on decarbonising the power sector.

Nonetheless, the transition to clean power is not without its challenges. The endeavour to increase the integration of Variable Renewable Energy (VRE) sources to curtail greenhouse gas (GHG) emissions is complicated by the need to synchronise energy demand and supply effectively. This complexity arises from the unpredictable output of weather-dependent generators such as solar panels and wind turbines. To mitigate this issue, various strategies can be employed, including the implementation of energy storage systems, optimisation of demand patterns, and enhancement of flexibility and connectivity between different energy grids at a regional level (Shaikh, et al., 2024). In other words, the power system needs to be flexible. According to IEA, power system flexibility is defined as "the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales" (IEA, 2018).

Energy storage is essential for electricity grids, particularly as the generation of renewable energy continues to rise. Technologies such as batteries and pumped-storage hydro plants facilitate the integration of VRE sources and contribute to the management of increasing electricity demand. Research indicates that VRE will constitute a significant proportion of the energy mix; however, without sufficient storage capacity, approximately 20% of installed VRE capacity may remain unused, leading to stranded investments. For example, in Germany, it is projected that the volume of curtailed electricity could reach around 270 TWh. This situation underscores the critical importance of implementing energy storage solutions on a large scale (Robinius, et al., 2018).

Hydrogen could assume a critical role within the power sector, offering flexibility, storage and a fuel source. Power-to-Power (PtP) is a process that enables the storage of surplus renewable energy as chemical energy in the form of hydrogen. This hydrogen can either be utilised on-site or transported to the appropriate consumption location if infrastructure is in place. When there is a demand for power, the hydrogen can be converted back into electricity for power generation. It is important to note that each step in this process incurs energy losses, resulting in a specific round-trip efficiency. Notably, select nations, including Japan, Korea, and Germany, have established specific targets for integrating hydrogen or hydrogen-based fuels within the power sector. For example, Japan has a target of 1 GW of power capacity based on hydrogen by 2030. Moreover, numerous other countries have acknowledged the viability of hydrogen as a low-carbon alternative within the power sector (IEA, 2019).

This paper aims to assess to estimate the round-trip efficiency of utilising renewable energy for hydrogen production, which is subsequently stored for future power generation, a process commonly referred to as Power-to-Power (PtP)[1]. Furthermore, it investigates the possible applications of PtP and the specific contexts in which they could be implemented, comparing it with alternative energy storage systems, including batteries and pumped-storage hydro plants. While PtP may play a significant role in providing critical services for the power sector such as adequacy capacity and flexibility and help mitigate electricity market risks, the value derived from these services can fluctuate greatly depending on various factors. These include specific system requirements, prevailing market conditions, and the overarching policy frameworks that govern energy markets.

[1] There are many abbreviations used for this process. In this paper, PtP will be used.

The paper is divided into three sections. Section 2 discusses the efficiency ranges from Power to Hydrogen and from Hydrogen to Power and the technologies that could utilise hydrogen for power generation and their associated challenges. Section 3 makes a comparison of efficiencies and characteristics of storage technologies. Section 4 briefly addresses the grid flexibility needs and discusses how hydrogen can contribute to grid flexibility and compare it to other alternatives. The final section contains the conclusion and limitations of the study.

2. PtP concept: Efficiencies, Technologies and Economics

To estimate the round-trip efficiency of utilising renewable energy for hydrogen production, which is subsequently stored for future power generation, it is imperative to assess the efficiency of each individual step within this process. This evaluation is crucial for effectively comparing this methodology with alternative technologies, such as batteries.

2.1 Efficiency ranges from Power to Hydrogen (P2H)

Hydrogen production in the current landscape remains predominantly dependent on unabated fossil fuels. The growth of low-emission hydrogen production has been marginal over the past two years, with output totalling less than 1 million tons per annum (Mtpa), constituting less than 1% of global hydrogen production. This low-emission hydrogen primarily derives from fossil fuel sources coupled with carbon capture, utilisation, and storage (CCUS) technologies (IEA, 2024). Hydrogen production using electrolysis, meanwhile, represents a minimal share of the overall market, remaining below 100,000 tons of hydrogen in 2023. This form of production is primarily concentrated in China, Europe, and the United States, which collectively account for approximately 75% of global electrolytic hydrogen output (IEA, 2024). As of the end of 2023, the installed capacity of water electrolysers reached 1.4 GW, nearly doubling the capacity from the end of 2022.

Alkaline technology remains the dominant choice, comprising over 60% of the installed electrolyser capacity in 2023, followed by proton exchange membrane (PEM) technology at 22% (IEA, 2024). By the year 2030, it is anticipated that the share of alkaline technology will decline to approximately 55% of the announced capacity, down from more than 70% of facilities currently in operation, the majority of which are situated in China. The rest will be accounted by PEM technology (concentrated in Europe) followed by solid oxide electrolysers (SOECs). Based on existing announcements and advancement, SOECs currently represent about 6% of the total capacity and are expected to sustain this proportion through 2030. Anion exchange membrane (AEM) technology has a minimal share of the current manufacturing capacity; however, this could potentially exceed 10% by 2030, provided that all proposed projects are realised (IEA, 2024).

Significant differences exist between the four electrolyser technologies in terms of cost, efficiency, and technological readiness (TRL), among other characteristics. Alkaline and PEM electrolysers are the most mature technologies, while SOEC is less mature (IEA, 2023). When discussing efficiency, it is vital to distinguish between electrolyser, system, and plant efficiency. The boundaries for defining system or plant efficiency are often set arbitrarily. Depending on the scope of supply, losses may also encompass factors such as AC/DC conversion, medium voltage transformation, water treatment, cooling systems, the electrical energy required for buildings and auxiliary packages, and hydrogen compression and purification. Defining these boundaries is essential for accurately comparing efficiency data and calculations (Lettenmeier, 2019). The IRENA 2020 report defines the system boundary as extending from the electricity transformer's inlet to the compressor's inlet, which is responsible for compressing hydrogen for storage (IRENA, 2020). However, this does not consider the processes of water purification and compression for storage, which would lead to lower efficiency.

Table 1 presents the estimated system efficiency of various electrolyser technologies as defined by IRENA. The efficiency of alkaline electrolysers ranges from 50.5% to 78.8%. For PEM electrolysers, the efficiency spans from 47.5% to 78.8%. In contrast, AEM electrolysers exhibit efficiencies ranging from 57.1% to

69.1%. SOEC demonstrates a broader efficiency range of 71.6% to 87.6%. One contributing factor to the variation in the efficiency of electrolysers is that enhancing the performance of the electrolyser stack in one dimension often correlates with a decrease in other critical parameters, such as overall efficiency, cost, operational lifetime, mechanical strength, and manufacturing feasibility (IRENA, 2020). However, other processes should also be considered, such as seawater desalination and hydrogen compression for storage. Nevertheless, seawater desalination can be used with limited impact on cost and efficiency (IRENA, 2020). To produce 1 kg of hydrogen, approximately 28.6 litres[2] of seawater are needed (IRENA, 2023). The purification of 1 m^3 of seawater for electrolysis requires about 7 kWh of energy (EuroWater, 2022). Consequently, this process consumes around 0.2 kWh per kg of hydrogen[3], which has a negligible impact on overall efficiency.

Hydrogen compression is crucial for its utilisation. Despite its high specific energy of 120 MJ/kg, as indicated by its lower heating value (LHV), its low energy density per unit volume—approximately 10.8 MJ/Nm^3—poses significant challenges for its utilisation, transportation, and overall application (Franco & Giovannini, 2024). Hydrogen compression is an energy-intensive process and can consume more than 25% of the hydrogen energy. The significant energy consumption involved in hydrogen compression can considerably decrease overall process efficiencies (Franco & Giovannini, 2024). The compression levels commonly referenced in academic literature include 350 bar and 700 bar. Presently, the highest pressure attained by commercially available compressors is approximately 450 bars, with 350 bars being the most prevalent operating pressure. These compressors are typically volumetric and consist of three or four stages. Notably, compressors with maximum output pressures of 700 bars are not available in the market (Franco & Giovannini, 2024). According to the available commercial data and utilising a total compression ratio of 350, the specific work involved in compression varies from approximately 2.78 kWh/kg for larger compressors to over 10.9 kWh/kg for smaller ones (Franco & Giovannini, 2024). This equates to approximately 7% to 27.8% of hydrogen's higher heating value, which could reduce the PtH efficiency by a few percentage points.

Table 1: Efficiency of different types of electrolysers

	Alkaline	PEM	AEM	SOEC
	Current			
Efficiency (HHV)	50.5% - 78.8%	47.5% - 78.8%	57.1% - 69.1%	71.6% - 87.6%
Efficiency (HHV) after considering Compression	48.8% - 74.6%	45.9% - 74.6%	54.9% - 65.9%	68.2% - 82.5%
	2050			
Expected efficiency (HHV)	<87.6	<87.6	<87.6	<98.5

Source: IRENA, 2020. *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal,* Abu Dhabi: International Renewable Energy Agency and own calculations.

Electrolyzer efficiency is projected to experience substantial improvements. IRENA anticipates that the efficiencies of alkaline, PEM, and AEM systems will surpass 87.6%, while SOEC's apparent efficiencies based on electricity may approach or exceed 100% if waste heat is used[4] (see Table 1, (IRENA, 2020)). Such efficiency levels have already been demonstrated in controlled laboratory environments. For instance, an alkaline capillary-fed electrolysis cell has exhibited water electrolysis performance that exceeds that of

[2] The actual quantities of water withdrawn and consumed are site-specific. They could vary based on factors such as the source water type and its quality, specific hydrogen production technology, and cooling technology. The figures used are inductive only

[3] See the above footnote.

[4] The waste heat energy is not considered as input in efficiency calculations.

conventional commercial electrolysis cells, achieving an impressive 98% energy efficiency alongside an energy consumption of 40.4 kWh per kilogram of hydrogen (Hodges, et al., 2022). This incremental enhancement in efficiency is expected to play a critical role in reducing the cost of low-carbon hydrogen production.

2.2 Efficiency ranges for Hydrogen to Power (H2P)

Various technological options are available for generating power from hydrogen, including fuel cells, internal combustion engines, and gas turbines. Fuel cells account for 60% of the installed hydrogen-fueled capacity, with gas turbines and combined-cycle gas turbines making up the remainder. Looking ahead to the announced projects in the pipeline, it is anticipated that by 2030, gas turbines and combined-cycle gas turbines will comprise two-thirds of the hydrogen-fueled capacity (IEA, 2024). To assess the efficiency of H2P, each technology must be evaluated individually due to its distinct characteristics and varying levels of effectiveness.

Hydrogen Powered Internal combustion engine (H2ICE)

The hydrogen-powered internal combustion engine has a long history and is highly researched, mainly for the automotive industry. While several hydrogen-powered engines are currently available for automotive applications, only a limited number of original equipment manufacturers (OEMs) provide hydrogen-ready internal combustion engines (ICE) for stationary power generation. OEMs presently offer engines designed to operate on hydrogen blends with varying hydrogen proportions. Furthermore, some manufacturers have developed hydrogen-ready engines that can be modified to utilise hydrogen as a fuel source in the future. According to various manufacturers, fully operational 100% hydrogen engines are anticipated to be available in the coming years (Srna, 2023).

As a step for 100% operated hydrogen engines, OEMs are actively engaged in the development of engines that utilise blended hydrogen fuel first. For example, Wärtsilä successfully conducted tests on an engine operating with blended fuel (25% hydrogen and 75% natural gas) in October 2022, achieving a remarkable 95% of engine maximum capacity with this mixture (Wärtsilä Corporation, 2023). Furthermore, Mitsubishi Heavy Industries Engine & Turbocharger, Ltd. (MHIET) has successfully implemented test operations as part of a collaborative project aimed at demonstrating mixed-fuel combustion. This initiative involves the use of city gas and hydrogen in a commercial gas engine for a cogeneration system, achieving the rated output with a burning ratio of 35% hydrogen mixed fuel (by volume) (MHIET, 2021). Other prominent OEMs involved in this sector include MAN, Caterpillar, Jenbacher, MWM, and MTU[5].

Hydrogen fuel possesses several advantageous properties contributing to a highly efficient combustion process. Key characteristics include a wide flammability range, a rapid combustion rate, a very low ignition energy requirement, a high auto-ignition temperature, excellent diffusivity, and a high octane number (Stepien, 2024). The effectiveness of H2ICEs in achieving clean combustion and efficient operation is attributed to hydrogen's distinctive combustion properties. These properties facilitate ultra-lean combustion, significantly reducing NO*x* emissions and enabling efficient performance during low engine loads. However, these characteristics pose technical challenges when the engine operates at higher loads (White, et al., 2006).

Despite these benefits, the operation of hydrogen-powered internal combustion engines encounters various challenges, particularly concerning reliability. These issues must be addressed as development progresses. Notable concerns include maintaining low lubricating oil consumption and further refining combustion strategies to mitigate premature fuel ignition. Moreover, it is essential to consider the adverse effects of hydrogen on metals and their alloys, including hydride formation, hydrogen embrittlement,

[5] Data were collected from OEMs' websites.

cracking from hydrogen leakage, and hydrogen bubble formation. Another challenge is hydrogen's low lubricity, which can result in premature wear of critical components in contact with it, such as intake valves, engine valve seat seals, and injector needles, potentially leading to a loss of airtightness. Additionally, problems related to the engine lubrication system and the lubricating oil itself require attention, as the oil can quickly become diluted with the substantial amounts of water generated during hydrogen combustion (Stepien, 2024).

Hydrogen Powered Gas Turbine

By incorporating hydrogen into gas turbines, the combustion process becomes a more environmentally friendly alternative to traditional fossil fuels, significantly lowering greenhouse gas emissions linked to power generation. Existing gas-fired power plants can cofire hydrogen in varying proportions, from 10% up to 100%, depending on the specific design of the gas turbine. Based on manufacturer data regarding the performance of current gas turbines and their maximum hydrogen blending capacities, the potential for hydrogen-fired generation could surpass 80 GW globally (IEA, 2024).

Gas turbine OEMs have carried out several projects to demonstrate the ability of their equipment to run on blended or pure hydrogen. The HYFLEXPOWER project, funded by the EU's Horizon 2020 program, seeks to showcase renewable hydrogen as a clean energy source for electricity and heat. Located at Smurfit Kappa's Saillat-sur-Vienne paper packaging plant in France, the project features a modified Siemens Energy gas turbine capable of running on 100% hydrogen. After initial testing with a 30% hydrogen blend in 2022, it has now achieved using 100% hydrogen with low emissions, demonstrating that gas-fired power plants can be effectively converted to hydrogen (Choudhury, 2023).

Another example is in Lingen, in northern Germany, which is set to launch a pilot power station powered entirely by green hydrogen, providing a carbon-free electricity solution. Kawasaki Heavy Industries (KHI) and RWE are collaborating to implement advanced hydrogen gas turbine technology for this 34 MW facility, expected to start operations in 2024. This technology was previously tested in a 1 MW hydrogen gas turbine co-generation system in Kobe, Japan, in 2018. This system was the first of its kind to supply heat and power from pure hydrogen in an urban setting. The 'H2GT-Lingen' project showcases the potential of hydrogen-based electricity generation to decarbonise energy production on an industrial scale (Nature Portfolio, 2024).

Using blended hydrogen in gas turbines is a well-established technology that has been effectively employed for many years. For example, GE has developed a fleet of gas turbines specifically designed to run on high-hydrogen fuels, with over twenty units currently in operation. Many of these turbines have successfully operated on fuels with hydrogen concentrations ranging from 50% to 80% (by volume) for over two decades, achieving maximum hydrogen levels surpassing 90%. Notably, one of these units has accrued more than 180,000 operational hours on high-hydrogen fuel. Enel’s Fusina facility in Italy, inaugurated in 2010, also features a gas turbine that generates approximately 11.4 MW of net electrical power using fuel containing around 97.5% (by volume) hydrogen (Goldmeer & Catillaz, 2022).

Mitsubishi Power has accumulated more than 3.5 million hours of operations on hydrogen fuels across 29 units since the 1970s, with a blending ratio ranging from under 10% up to 90%. Mitsubishi Power is currently developing dry low NOx combustion technology for 100% hydrogen firing and targeting March 2025 for the rig tests completion, which will be a monumental step towards the goal of carbon-free gas turbines (Mitsubishi Power , 2024).

Using 100% hydrogen as fuel in a gas turbine can substantially decrease CO2 emissions compared to natural gas or other hydrocarbons. Although hydrogen generates no CO2, a trace amount may originate from atmospheric CO2 (approximately 0.04% by volume). While gas turbine fuel flows are generally measured volumetrically, the critical factor for emissions lies in the relative heat input of the different fuel components since methane and hydrogen possess distinct energy densities. Consequently, merely adding

small amounts of hydrogen will have a limited impact on CO2 reduction. To attain a 50% reduction in CO2 emissions, a fuel blend must comprise around 75% hydrogen by volume. This requirement arises from the nonlinear relationship between fuel composition and CO2 emissions (Goldmeer & Catillaz, 2022).

One of the critical advantages of gas turbines is their capacity to be reconfigured for operation with alternative fuels, including those that contain higher levels of hydrogen. Given the distinct physical and chemical properties of hydrogen, integrating this fuel into a gas turbine may require modifications to the turbine itself, its associated components, and the overall system balance of the plant. The extent of the necessary modifications directly correlates with the proportion of hydrogen in the fuel.

Higher hydrogen flame temperatures can increase NOx emissions. A more extensive, efficient Selective Catalytic Reduction (SCR) system can mitigate emissions in new plants. Hydrogen presents operational safety challenges as it is more flammable than methane. Furthermore, hydrogen flames are less visible. These factors increase safety risks and may require updates to plant safety procedures as most existing hazardous gas detection systems are designed for hydrocarbons, making them less sensitive to elevated hydrogen levels. Due to its smaller molecular size, hydrogen affects materials and systems uniquely compared to other gases. It can diffuse through seals designed for other gases, requiring welded connections or enhanced seals instead of conventional natural gas seals. Furthermore, hydrogen can permeate certain solids, causing hydrogen embrittlement. Some materials, such as Stainless-steel alloys like 316L, exhibit more excellent resistance to this embrittlement (Goldmeer & Catillaz, 2022). Also hydrogen has unique properties that can cause flashback when mixed with air. A flashback happens when flames move back along the fuel line, escaping the combustion chamber, which can damage hardware and the fuel nozzle. Upgrading to a hydrogen-specific combustor is essential to reduce flashback risk. (Mitsubishi Power , 2024). Following a thorough review of data sheets from various original gas turbine equipment manufacturers (OEMs) concerning hydrogen gas turbines, it was observed that higher heating was calculated to facilitate a meaningful comparison with other technologies. It is essential to note that these efficiency figures are based on ISO conditions[6]. Gas turbines typically experience derating as ambient temperatures rise, resulting in decreased efficiency.

Hydrogen-Powered Fuel Cell

Fuel cells generate electricity through electrochemical reactions, eliminating the emission of harmful substances, including carbon dioxide. This technology facilitates a unique one-step energy conversion process, transforming chemical energy directly into electricity, as opposed to traditional heat engines, which operate through a more intricate four-step conversion process involving chemical, thermal, mechanical, and subsequently electrical energy (Ahmed, et al., 2020).

Although fuel cells could use hydrogen as a fuel, other types could use other substances, such as natural gas, syngas, ammonia, and methanol. The different types of fuel cells are outlined below, and Table 2 exhibits the characteristics of each type.

- Proton-exchange membrane fuel cell (PEMFC)
- Direct methanol fuel cell (DMFC)
- Fuel cell using molten carbonate (MCFC)
- Phosphoric acid fuel cell (PAFC)
- Solid oxide fuel cell (SOFC)
- Alkaline fuel cell (AFC)

[6] The standard environmental design point of any gas turbine system is 15 °C, 60% relative humidity, and sea level elevation.

Fuel cells demonstrate various applications within the power sector, notably serving as power units for residential users and as auxiliary and backup power sources, with capacities typically ranging from 1 to 500 kW. In contrast, distributed power plants are considerably larger and engineered to accommodate megawatt-scale capacities. Moreover, a notable trend has emerged regarding technology transfer from manufacturers to end users within commercial markets, specifically for fuel cells uniquely designed for stationary applications (Arif, et al., 2025).

Fuel cells are recognised as a competitive alternative to established technologies, including batteries, internal combustion engines, and generators. The transfer of this technology, which entails the provision of fuel cell equipment to the stationary industry, was valued at 395,000 units in 2014 and increased to 575,000 units by 2018. The success of Japan's home fuel cell initiative, known as "ENE-FARM," coupled with the growing utilisation of fuel cells in practical applications as energy backup systems, has substantially contributed to this expansion (Arif, et al., 2025).

PEMFC, SOFC, and PAFC fuel cells hold the largest shares of installed megawatts (MW). PEM fuel cells lead in both shipment volume and MW capacity. In 2022, of nearly 90,500 fuel cells shipped, over 55,000 were PEM, consistent with the previous year and representing 61% of total shipments. PEM fuel cells produced 2,151 MW, accounting for 86% of the total volume, similar to 2022 (ERM, 2023). SOFC increased from over 25,000 units in 2021 to nearly 27,000 in 2022, with capacity rising from 207 MW to 249 MW, mainly due to stronger sales from Bloom Energy. While suppliers like Ceres and Bosch are still developing their products, few units have made it to market. SOFC is gaining traction as a prime mover for ships and is expected to grow, though not rapidly (ERM, 2023). Sales of PAFC units dropped from an estimated 95 MW in 2021 to just 56 MW in 2022.

Table 2 illustrates the efficiency of various fuel cell types. The highest efficiencies are observed in the Proton Exchange Membrane Fuel Cell (PEMFC) and Solid Oxide Fuel Cell (SOFC), representing the largest share of installed power capacity. The Molten Carbonate Fuel Cell (MCFC) exhibits the second-highest efficiency, ranging from 45% to 50%.[7]

[7] The maximum theoretical limit for electrical efficiency in a fuel cell system is defined by the ratio of Gibbs free energy to the heat of combustion of the fuel. In the case of hydrogen fuel cells, this is calculated by dividing the Gibbs free energy (237.2 kJ/mole) by the higher heating value (HHV) of hydrogen (285.8 kJ/mole), yielding an efficiency of 83% (Harrison, et al., 2010). However, practical fuel cells often fall short of this theoretical maximum due to internal resistance losses. For instance, a fuel cell operating near its peak power output may produce approximately 154 kJ of electricity per mole of hydrogen consumed, while the remainder of the energy from the heat of combustion is released as heat (Harrison, et al., 2010).

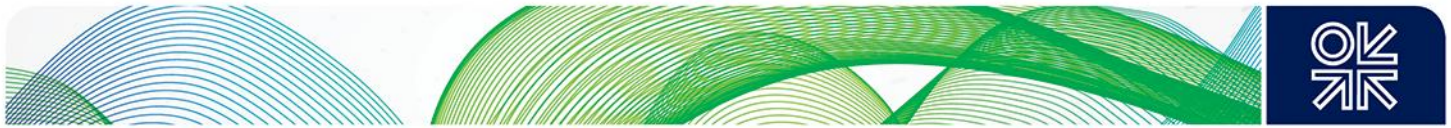


Table 2: Technical characteristics of different fuel cell types

Fuel Cell Types	Alkaline	Phosphoric Acid	Molten Carbon	Solid Oxide	Proton Electrolyte Membrane Direct	Direct Methanol
Common electrolyte	Potassium hydroxide solution drenched in a matrix	Phosphoric acid immersed in a matrix	Lithium, sodium, and/or potassium carbonates in solution	Zirconia stabilised by yttria	Perfluoro sulfonic acid	Polymeric membrane
Operating temperature	90°C–100°C	150°C–200°C	600°C–700°C	700°C–1,000°C	50°C–100°C	60°C–130oC
Efficiency	60%	40%	45%–50%	60%	60%	40%
Power generation	<20 kW	>50 kW	>1 MW	>200 kW	< 250 kW	<10 kW
Applications	Military, Space	Distributed generation	Electric utility, Distributed generation	Auxiliary power, Distributed generation, Electric Utilities	Transportation, Distributed generation, Specialty vehicles, Backup power, Portable power	Transportation
Advantages	• High performance is achieved by the cathode reaction occurring more quickly in an alkaline electrolyte • Low-cost components	• CHP is made possible by higher temperatures, which also increases fuel impurity tolerance	• Solid electrolyte lessens concerns with corrosion and electrolyte control • Low temperatures and rapid start-up • High efficiency; fuel flexibility; • ability to utilise a range of catalysts • appropriate for CHP	• Solid electrolyte, high efficiency, fuel flexibility, ability to utilise a range of catalysts, suitability for CHP and CHHP, hybrid/GT cycle	• Solid electrolyte lessens concerns with corrosion and electrolyte control • Low temperatures and rapid start-up	• Efficient operation at ambient temperature
Disadvantages	• Sensitive to CO2 in fuel and air • Electrolyte management	• Pt catalyst • Long start-up time Low current and power	• High-temperature corrosion and breakdown of cell components • Long start-up time • Low power density	• High-temperature corrosion and breakdown of cell components • High-temperature operation requires a long start-up time and limits	• Expensive catalysts • Sensitive to fuel impurities • Low-temperature waste heat	• Low power densities, as compared to other technologies, put this technology at a slight disadvantage

Source: Arif, M. et al., 2025. Fuel Cell Comparison to Conventional Power Generation Technologies. In: M. R. Rahimpour, M. A. Makarem & P. Kiani, eds. *Hydrogen Utilization in Fuel Cells.* s.l.:CRC Press, pp. 82 – 112.

2.3 Operational Characteristics

Before calculating the range of round-trip efficiency for PtP technology, it is crucial to present the various operational characteristics of each technology for several reasons. Firstly, this presentation facilitates a comprehensive comparison across all technologies, as efficiency is not the sole criterion for technology selection. Furthermore, it aids in identifying the strengths and weaknesses of each technology. Lastly, this evaluation prepares the groundwork for subsequent comparisons with alternative technologies, such as batteries and pumped hydro storage (PHS). Table 3 summarises and contrasts the different operational parameters of the three PtP technologies under discussion.

ICE and fuel cells exhibit superior operational characteristics compared to gas turbines, particularly in terms of ramping rates, startup times, and overall efficiency. Among these options, ICEs demonstrate the most favourable derating characteristics. However, gas turbines are available in larger capacities, whereas ICEs and fuel cells typically require the deployment of multiple units to achieve substantial power output, a consideration that is especially relevant for fuel cells. For example, the largest operational fuel cell power station - Shinincheon Bitdream Fuel Cell Power Plant- has an aggregate capacity of 78.96 MW. The second phase of this facility, launched in 2021, includes 124 fuel cells, each with a capacity of 440 kW, culminating in a total capacity of 58.96 MW (Doosan, 2021).

Round-trip efficiency is subject to variation based on the specific technology employed, as each technology exhibits distinct efficiency characteristics. Nevertheless, the efficiency of PtH remains uniform across all technological platforms. According to Table 1, the efficiency range for Proton PEM and Alkaline electrolysers before considering compression—recognised as the most developed technologies—varies from 48% to 79% (IRENA, 2020). It is crucial to acknowledge that factors such as partial load operation and the degradation of the electrolyser during its lifecycle can lead to actual efficiencies that are lower than the declared values. For the purposes of this analysis, we shall adopt an assumed efficiency of 70%. This value was chosen based on the assumption that the maximum efficiency of the electrolyser is 75%, which is expected to decline over time. The value of 70% is representative of the average efficiency throughout the operational lifespan of the electrolyser.

Hydrogen will be stored before being used in power generation. Several underground geological structures, including salt caverns, depleted oil and gas fields, saline aquifer and lined rock caverns, are being evaluated as primary options for storing significant volumes of hydrogen (ENTSO-E & Frontier Economics, 2022). In addition to underground options, steel tanks are available for short-term and small-scale storage. These tanks demonstrate a higher efficiency rate, approaching 99%, compared to 98% for salt caverns. However, they tend to incur higher costs and, in the case of smaller tanks, require greater compression than underground storage solutions (ENTSO-E & Frontier Economics, 2022). For the purposes of our analysis, we will focus on underground storage and exploit its 98% efficiency rate.

Table 3: H2P technologies characteristics

Parameter	ICE[8]	Gas Turbine	Fuel Cell[9]	Notes & References
Size range	1MW-23MW	2MW to 600MW	From Kilowatts scale up to 3MW	The sizing is based on natural gas equipment that runs partially or entirely on hydrogen. (Wartsila, 2024), (Arif, et al., 2025), (DOE, 2015)
Efficiency (HHV)	40%-48%	35-39%	40%-70%	Fuel cell efficiencies from data sheets were lower than 70%, (IRENA, 2019), (Arif, et al., 2025)
Part load efficiency	40%-48%	27–32%	Decreases considerably	(IRENA, 2019), (Pilarczyk, et al., 2022)
Derating	Works at 100% of the rated load until 40 ^{0}C and 1000 meters above sea level	Derating starts above 15 ^{0}C and above sea level	maximum Operating temp for PEMFC is in the range of 40 to 50 ^{0}C	(Wartsila, 2024), Different Fuel cell manufacturer datasheets
Start time	2-5 min	5-10 min	From 1 min up to 60 min for SOFC	(IRENA, 2019), (Zargary, 2018)
Minimum load [% Pnom]	10%	20%-50%	0 – 5% for PEMFC	(IRENA, 2019), Different Fuel cell manufacturer datasheets
Avg. ramp rate [% Pnom/min]	>100%	8-15%	>100%	(IRENA, 2019), Different Fuel cell manufacturer datasheets
Minimum Uptime	< 1 min	10-30 min	-	(IRENA, 2019)
Minimum Downtime	5min	30-60 min	-	(IRENA, 2019)
Sensitivity to hydrogen impurities	Low	Low	High	(Arif, et al., 2025)

[8] Data is estimated for Natural gas ICE.
[9] Data is collected from different fuel cell manufacturer datasheets.

2.4 Round Trip Efficiency of PtP

When examining H2ICE, the round-trip efficiency can be understood more clearly by considering the engine's operational efficiency, which typically ranges from 40% to 48%, as indicated in the H2ICE section above. Based on this efficiency, and by multiplying by the estimated electrolyser efficiency of 70%, and storage efficiency of 98%, the overall round-trip efficiency is anticipated to fall between 27.4% and 33%. This indicates the proportion of energy that can be effectively utilised in comparison to the total energy consumed during the entire process.

In a manner similar to H2ICE, when we take into account the efficiency range of gas turbines, which typically falls between 35% and 39%, as indicated in the gas turbine section, and using the electrolyser and storage efficiency, we can estimate that the expected PtP efficiency will be between 24% and 26.8%. This suggests a moderate level of energy conversion effectiveness, highlighting the differences in performance between these two types of engines.

Fuel cell technology exhibits the highest conversion efficiency compared to ICE and gas turbine systems. Consequently, the implementation of fuel cells in PtP applications is anticipated to achieve superior efficiency outcomes. Given that fuel cell efficiencies typically range from 40% to 70%, and using a similar approach as ICE and gas turbine calculations, the expected PtP efficiency is projected to fall within the range of 27.4% to 48%.

Table 4: Summary of round-trip efficiency for different technologies

Technology	Lower limit	Upper limit
PtP ICE	27.4%	32.9%
PtP GT	24.0%	26.8%
PtP Fuel Cell	27.4%	48.0%

In short, ICEs and fuel cells offer better ramping rates, startup times, and efficiency than gas turbines, with ICEs exhibiting the best derating characteristics. However, gas turbines can achieve larger capacities, while ICEs and fuel cells typically require multiple units to generate significant power. According to the paper calculations, round-trip efficiency varies by technology: ICEs are expected to have 27.4% to 33% efficiency, gas turbines 24% to 26.8%, and fuel cells 27.4% to 48%.

2.5 Economics of PtP

The production costs associated with renewable electricity exhibit variability across different countries, primarily due to differences in the availability of renewable resources. Furthermore, the technology utilised for hydrogen production—such as solar photovoltaic (PV) systems and wind energy, whether utilised onshore or offshore—significantly influences these costs. While the type of electrolyser employed does influence production expenses, this impact is generally less pronounced than that of electricity pricing. Additionally, the capacity factor of the electrolyser is a critical element; a higher capacity factor can lead to a reduction in the overall costs of hydrogen production. According to DVN, hydrogen production costs are expected to drop significantly by 2030, with solar or wind-based electrolysis estimated to reach around USD 3 per kilogram of hydrogen. This trend is projected to continue, with average production costs potentially falling to approximately USD 2 per kg H2 by 2050 from USD 5 per kilogram of H2, and some projects may even achieve costs below one dollar per kg H2 (DNV, 2024). The cost reduction will be driven by a 40% decrease in solar panel prices and a 27% reduction in turbine costs, alongside technological advancements. These developments are expected to facilitate an increase of 10% to 30% in annual operating hours, depending on the specific technology and region. Furthermore, we anticipate that capital costs for electrolysers will decline by 25% to 30% due to diminished perceptions of financial risk (DNV, 2024).

An intriguing emerging method of hydrogen production is the extraction of natural hydrogen. Recent studies have documented the presence of hydrogen in seeps and vents worldwide, as well as the successful commercial production of natural hydrogen from a well drilled in Mali. While geological hydrogen has the potential to revolutionise the energy sector and play a pivotal role in the pursuit of a net-zero carbon future, this potential has to be proved by real discoveries of significant deposits (Patonia, et al., 2024). The Mali case is still the only one of confirmed hydrogen deposit that is being actively exploited.

The competitiveness of hydrogen technologies in the context of flexible power generation, which includes load balancing and peak load generation, is contingent upon hydrogen pricing and the potential implementation of carbon pricing or analogous policy measures that penalise CO2 emissions (IEA, 2020). These determinants are fundamentally influenced by the electricity prices associated with hydrogen production. Consequently, the availability of cost-effective electricity is of paramount importance. The integration of variable renewable energy sources (VRES) into power systems is expected to significantly affect electricity prices, with an increase in VRES integration leading to a more significant number of hours characterised by very low or even zero electricity costs (DNV, 2024).

The existing literature presents a diverse array of values when assessing the LCOE associated with using hydrogen as a fuel. Notably, while some ranges have been established for gas turbines and fuel cell technologies, there is a paucity of estimations available for internal combustion engines. In the context of fuel cells, the International Energy Agency (IEA) has catalogued the LCOE for four operational fuel cell plants, which vary in size from 3 kW to 15.2 MW. The LCOE figures for these plants are 237.03, 209.39, 158.07, and 178.14 USD/MWh, respectively. Furthermore, the IEA has reported the fuel cost (hydrogen) at a level of 111.11 USD/MWh, which corresponds to 4.377 USD/kg (IEA, 2020).

In the context of gas turbines, cost estimations vary considerably. For example, Bloomberg NEF has reported a range beginning at approximately 154 USD/MWh for load-following gas turbines and extending to as high as 456 USD/MWh for peaking plants. The estimated cost of renewable hydrogen falls between 2.5 and 4.5 USD/kg (BloombergNEF, 2020). IEA provides a similar assessment, indicating that at a hydrogen cost of 3 USD/kg, the LCOE for gas turbines is anticipated to be approximately 260 USD/MWh. Furthermore, the figure demonstrates that fuel cells exhibit an equivalent LCOE of 250 USD/MWh. (IEA, 2020).

Estimations of the LCOE for gas engines are relatively scarce. Nevertheless, a white paper by Jenbacher indicates that hydrogen engines exhibit significantly lower LCOE at reduced full load hours compared to fuel cells, where efficiency's impact is minimal, and capital costs predominate. Consequently, hydrogen engines demonstrate markedly higher economic efficiency in specific applications, such as backup operations. The estimated LCOE is considerably elevated at 660 USD/MWh; however, the cost of hydrogen fuel remains uncertain (INNIO, 2023).

Table 5: LCOE ranges for different technologies

Technology	LCOE range (USD/MWh)	Reference
Fuel cell	111.11 – 250	(BloombergNEF, 2020), (IEA,2020)
Gas turbine	154 - 456	(IEA,2020)
ICE	450 - 600	(INNIO, 2023)

2.6 Modelling power generation using hydrogen

To improve the understanding of the economics involved in power generation utilising hydrogen, a simple model is developed to evaluate the LCOE and enable comparisons across three distinct technologies.

A variety of scenarios can be envisioned when modelling PtP systems. Each scenario will differ based on the location of hydrogen production and the method of transportation to the designated storage facility. The chosen storage type will also significantly influence the overall electricity costs. Furthermore, the proximity of the power production site to the storage location will play a crucial role in determining the associated expenses. This model is based on the premise that hydrogen production, storage, and power generation occur at a single location, thereby eliminating transportation costs. The costs associated with storage are incorporated into the hydrogen cost estimates within the model. Also, the implementation of PtP at these limited locations may only be useful if sufficient grid connections exist to allow the renewable energy needed to produce hydrogen exist, and to allow for supplying power during dunkelflaute periods or for ramping and other services. Large additional investments might be required, affecting the economics of the PtP. Appendix 1 provides a detailed outline of all the assumptions utilised in the model and references for each value.

It is imperative to indicate that the model and the above efficiency analysis also have certain limitations that should be acknowledged from the start. Commencing with the power to hydrogen section, the energy utilised in desalination facilities is disregarded due to its minimality in comparison to the energy demanded by the electrolyzer itself. Nevertheless, the desalination process itself consumes a considerable number of resources and necessitates infrastructure and access to the sea, coupled with the implementation of environmental safeguards to prevent harm to the ecosystem. Round-trip efficiency estimates omit several loss factors. For example, the efficiency attributed to hydrogen compression is the lowest and pertains to large compressors; smaller compressors would significantly increase power consumption. Moreover, potential boil-off/vent losses in long-duration storage are neglected.

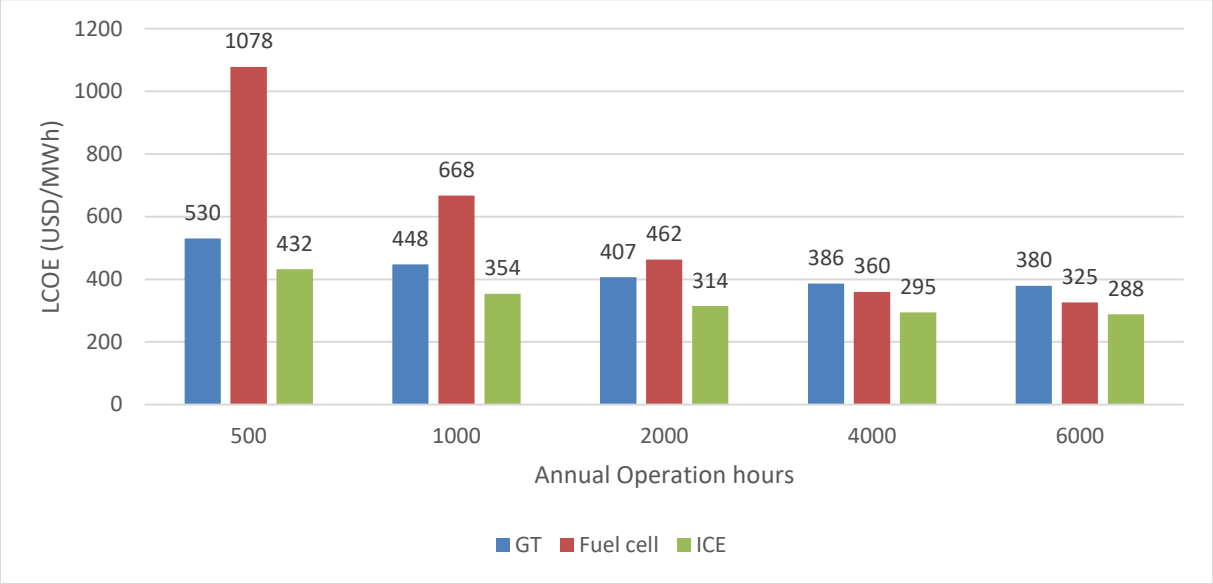
As indicted above, the hydrogen storage facility is co-located with the electrolyser, storage and power producing plants, hence eliminating the necessity for hydrogen transportation and distribution, which could influence hydrogen costs if transported across extensive distances. Also, underground storage is assumed. Many regions lack suitable geology, making the cost and efficiency figures non-transferable. The model contains assumptions that may affect the results if different assumption is applied. Primarily, the model presumes two hydrogen price levels: $5/kg and $1/kg. Real-world quotes vary far more widely, and non-linear cost sensitivities are therefore hidden. Moreover, in certain nations, hydrogen prices may fall outside this range, hence influencing the resulted LCOE. A single weighted-average cost of capital (7 %) is applied to all technologies and countries, masking country-risk and technology-readiness differences.Furthermore, the projected CAPEX for fuel cells is the anticipated CAPEX attained by economies of scale in production. Additionally, many assumptions regarding the internal combustion engine are derived from the present natural gas engine datasheet. This may influence the findings by forcing the LCOE for fuel cells to be higher the computed value. Finally, as the model employs informed assumptions in the modeling and analysis of the PtP. These assumptions are derived from the most recent sources. Nonetheless, various factors could influence and result in alternative conclusions, including the reduction and progression of electrolyzer costs, the development and accessibility of rival technologies, and the condition of hydrogen storage.

With these caveats in mind, the model demonstrates that the fuel cell exhibits a significantly higher LCOE at lower operation hours. This phenomenon can be attributed to the considerably more significant CAPEX associated with the fuel cell than the gas turbine and ICE. As operating hours increase, the effects of the fuel cell's superior efficiency become more pronounced, reducing LCOE. At 3,000 operating hours, the LCOE of the gas turbine and the fuel cell converge. These findings are based on a 5 USD/kg hydrogen cost, as depicted in Figure 1.

The increasing integration of renewable energy sources into the grid is anticipated to substantially impact electricity prices, resulting in a more significant number of hours characterised by notably low or even zero

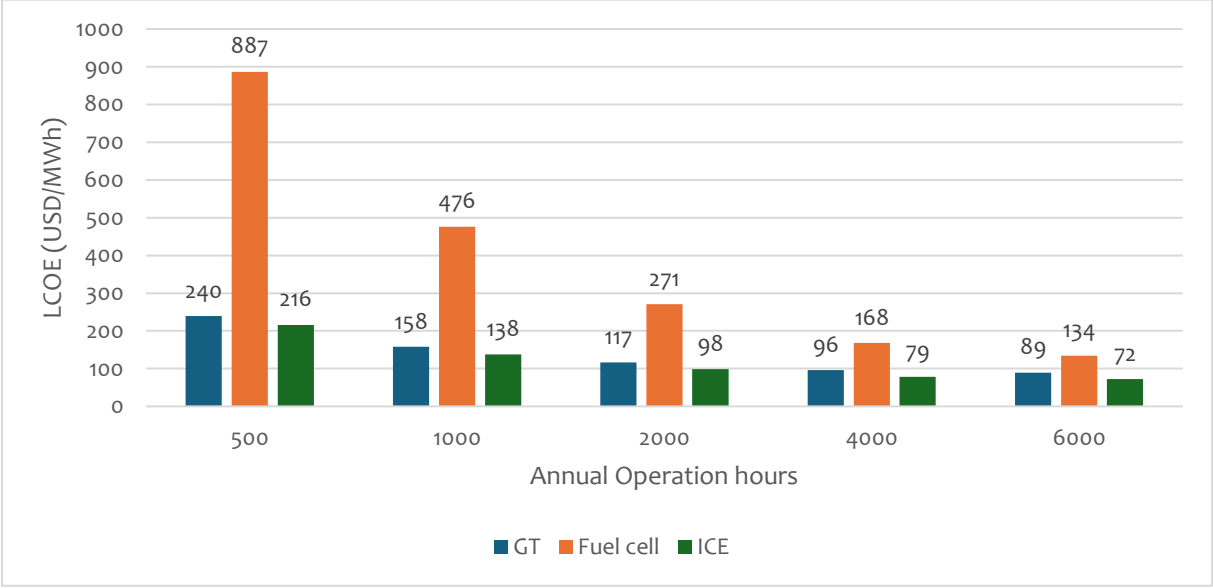
electricity costs. Under the assumption of a hydrogen cost of 1 USD/kg—reflecting a scenario with low or free electricity costs—the model indicates that the LCOE of the fuel cell will remain elevated across all scenarios. This is due to the diminished relevance of the efficiency parameter in light of the reduced fuel costs. Figure 2 illustrates the results based on a 1 USD/kg hydrogen cost. Owing to advancements in the economy of scale for fuel cell production, the CAPEX is expected to decrease to between 1,300 and 900 USD/kW in 2030 (Cigolotti & Genovese, 2021). At the 1,300 USD/kW cost threshold, the fuel cell is projected to compete with the gas turbine at lower operating hours (800 hours) and with ICE starting from 4,000 annual operating hours.

Figure 1: Hydrogen cost 5 USD/kg



Source: Author drawings, results from author's developed model

Figure 2: Hydrogen cost 1 USD/kg



Source: Author drawings, results from author's developed model

Among the three technologies analysed, ICE is noted to have the lowest LCOE. Due to constraints in data availability, the assumptions regarding ICE are based on Liquefied Natural Gas (LNG) ICE specifications. The model results demonstrate that fuel costs constitute the most significant component of total expenses, followed closely by CAPEX. As the number of operational hours increases, fuel costs' share rises significantly while the representations of CAPEX and OPEX diminish. It must be noted that the model does not assume a combined heat and power arrangement that could be applied with the three technologies, which will considerably enhance storage economics.

3. Comparison of efficiencies and costs with other technologies

Energy storage systems, including batteries and pumped-storage hydro plants, facilitate the integration of growing proportions of variable renewable electricity generation and effectively balance escalating electrified demand across various time scales, from milliseconds to seasons (IEA, 2023a). Storage is essential for maximising the utilisation of VRE generation capacity. A study conducted by Robinius in 2018 concluded that by the year 2035, with VRE comprising 80% of the energy mix in Germany, approximately 20% of the installed VRE capacity would remain inoperable without electricity storage, potentially leading to stranded investments. Furthermore, even in the presence of an optimal grid, the potential for curtailed electricity could decrease from 270 TWh to 220 TWh annually. These findings emphasise the critical importance of energy storage, particularly at a large scale measured in terawatt-hours (TWh) (Robinius, et al., 2018).

Pumped hydropower storage (PHS) continues to be the predominant energy storage technology, although grid-scale batteries are rapidly advancing in prominence. As of 2020, the global capacity for PHS was approximately 160GW and capacity of 8,500 GWh, accounting for over 90% of the total electricity storage capacity worldwide. By the conclusion of 2022, the total installed capacity of utility-scale battery storage had approached 28 GW and around 100 GWh. Notably, lithium-ion batteries remain the most widely utilised technology, representing the majority of the newly installed capacity during this timeframe. (IEA, 2023a).

It is essential to recognise that the capacity for PHS and batteries is considerably limited when compared to the storage capacity of natural gas. By the conclusion of 2022, the operational gas capacity of natural gas storage facilities reached 429 billion cubic meters, equivalent to approximately 1,100 terawatt-hours (TWh). Currently, there are 76 storage projects under construction globally, which will enhance capacity by an additional 55 billion cubic meters. Moreover, there are 99 projects in the planning phase, suggesting significant potential for further expansion (CEDIGAZ, 2023). These statistics clearly indicate that the existing capacity for storing energy in molecular forms far exceeds that of other electricity storage methods, with a ratio of more than 100 to 1. This section will briefly provide a comparative analysis of battery storage, pumped hydro storage (PHS), and compressed air energy storage (CAES) for electricity storage, as well as hydrogen storage for PtP electricity generation.

Storage technologies comparison

Table 6 summarises the technical characteristics of the storage technologies under discussion compared to PtP technologies.

Table 6: Characteristics of storage options

	PHS	CAES	Batteries	PtP	Notes/ References
Round Trip Efficiency	70-85%	40-75%	60-98%	24-48%	For batteries, It depends on the chemistry and type of the battery (IRENA, 2017) , (SBC Energy Institute, 2013)
Energy density (Wh/L)	0.2-2	2-6	20-400	600 (200 bars)	Energy density for hydrogen depends on storage medium and pressure (IRENA, 2017) , (SBC Energy Institute, 2013)
Power Density (W/L)	0.1-0.2	0.2-0.6	0.5-10,000	0.2-20	For batteries, it depends on the chemistry and type of the battery (IRENA, 2017) , (SBC Energy Institute, 2013)
Storage duration (hours)	4-12	2-30	few hours	weeks	It is meant here the duration of energy supply from storage. (SBC Energy Institute, 2013)
Cycling/ Lifetime	30-60 years	20-40 years	1000-14,000 cycles	5-30 years	(IRENA, 2017) , (SBC Energy Institute, 2013)
Depth of discharge	80-100%	35-50%	84-100%	N/A	Although batteries could have a depth of discharge of up to 100%, this will considerably reduce their lifetime , (IRENA, 2017),
Response time	Seconds to minutes	Seconds to minutes	<seconds	Seconds to minutes	(SBC Energy Institute, 2013)
Self-discharge (% per day)	0.01 - 0.02 %	0.5 - 1%	0.05 – 1%	0 - 4% (depending on storage technology)	(IRENA, 2017) , (SBC Energy Institute, 2013)

Hydrogen vs PHS

PHS presents numerous noteworthy advantages and operational characteristics. Its operating efficiency, which ranges from 70% to 85%, indicates that most of the energy utilised during the pumping (charging) phase is recoverable when the system operates in turbine mode (discharging). If the turbine is already in motion, PHS can reach the full load within a few minutes from a complete standstill or in less than 60 seconds. Advanced installations, such as the Dinorwig pumped storage station in the United Kingdom, are capable of pre-synchronizing with the grid and can achieve full load from a prepared state in as little as 12 seconds. Furthermore, implementing variable-speed turbine-generator systems enhances the response to frequency deviations and grid faults. Additionally, PHS is distinguished by its high estimated lifespan, allowing for approximately 14,000 storage cycles throughout its operational life (Klaus Krüger, 2021).

PHS presents several limitations. One significant constraint is the requirement for substantial elevation differences between reservoirs, which often makes implementation in countries characterised by lowland topography impractical (Ruiz, et al., 2022). Furthermore, there are locations where the geological and topographical conditions are conducive to the establishment of pumped storage hydropower projects;

however, the absence of a reliable freshwater source can render these projects unfeasible (Slocum, et al., 2021). Nonetheless, a variety of groundbreaking technologies are emerging, designed to address and overcome these challenges effectively (Ruiz, et al., 2022).

The duration of discharge in PSH systems is generally constrained. In many instances, PSH can generate energy for a period of up to 12 hours, provided that the plant undergoes charging and discharging within a 24-hour cycle, referred to as diurnal cycling. Nevertheless, some facilities have been engineered to extend their energy storage capabilities beyond 12 hours, offering in excess of 20 hours of energy storage as in the Snowy 2.0 PSH scheme is currently under construction in Australia (Klaus Krüger, 2021).

There are several distinct differences when comparing PHS to PtP systems. Both PHS and hydrogen storage necessitate specific topographical conditions; however, hydrogen storage presents a variety of options, each requiring particular characteristics for effective implementation. Notably, the availability of hydrogen storage options is more extensive than that of PHS, as demonstrated in (IEA, 2023).

A comprehensive study evaluating the costs and performance of grid energy storage technologies indicates that for large-scale systems ranging from 100 to 1000 megawatts, PSH demonstrates a lower levelized cost at 0.11 USD/kWh. Furthermore, PSH is characterised by a more favourable unit energy capital cost and a higher cycle and calendar life than alternative technologies. Conversely, the levelized cost associated with hydrogen energy storage according to the study is currently 0.35 USD/kWh, primarily attributable to the substantial expenses linked to fuel cells and electrolyser stacks. Nevertheless, the study projects that by the year 2030, the levelized cost of hydrogen is expected to decrease to 0.18 USD/kWh (Viswanathan, et al., 2022).

Hydrogen Vs CAES

Compressed air energy storage (CAES) is a key alternative to pumped hydro storage (PHS) for large-scale, long-duration energy storage. Gaining traction in recent years, CAES is recognised for its high round-trip efficiency and low cost. This technology works by converting electricity into mechanical energy through compressed air storage. When needed, the air drives a turbine to generate electricity. CAES offers several advantages, including long operational lifespans of 20 to 40 years, low losses, scalability, and the use of readily available components (Borri, et al., 2022).

Similar to PHS, CAES faces significant geological constraints. Its low volumetric energy density of about 3–6 kWh/m³ necessitates large storage volumes in underground structures like salt caverns or mine shafts. Above-ground pressurised vessels are mainly used in small-scale systems (under 10 MW) (Borri, et al., 2022).

CAES exhibits lower efficiency compared to PHS (75% compared to 85%); however, it provides a marginally more favourable levelized storage cost. In the context of 100 MW and 1,000 MW systems, CAES technology delivers the lowest LCOS among all available storage alternatives. This advantage stems from its reduced unit energy costs and extended cycle and calendar life. Notably, the minimum LCOS for a 1,000 MW, 10-hour CAES system is 0.10 USD/kWh. Following CAES, PHS presents the second-lowest LCOS at 0.11 USD/kWh for the same power and duration parameters, benefiting from similar cost efficiencies and its superior round-trip efficiency (RTE). Conversely, the current LCOS for hydrogen energy storage is $0.35 per kWh (Viswanathan, et al., 2022).

Hydrogen Vs battery storage

Batteries have been used in various applications for over a century and have become essential in the transportation and power sectors. Between 2010 and 2023, their costs decreased by 90%, while performance improved with higher energy densities and longer cycle lives. As a result, batteries are now vital for transitioning to low-emissions energy systems. In the power sector, battery storage supports grid stability, meets peak load demands, and enhances the integration of variable renewable energy sources (IEA, 2024).

Batteries typically exhibit high-efficiency rates ranging from 60% to 98% and demonstrate considerable responsiveness. Their underlying chemistry significantly influences their performance, including efficiency. Nevertheless, batteries encounter limitations related to their lifecycle, present environmental and safety concerns, and often entail substantial costs. Furthermore, they have limitations concerning power and energy sizing (SBC Energy Institute, 2013).

Lithium-ion batteries dominate the battery storage market. Because storage applications prioritise cost, frequent charging and discharging capacity, safety, and lifespan over energy density, this has led to the increased use of lithium iron phosphate (LFP) type batteries, which accounted for about 80% of the battery storage market in 2023, up from 65% in 2022. While lithium-ion batteries are dominating the market, alternative chemistries such as sodium-ion batteries are being explored to compete or complement their use (IEA, 2024). Lithium-ion and sodium-ion batteries are unlikely to meet the demands of long-duration storage (over days) due to cost and technical challenges related to prolonged high states of charge. Alternative battery chemistries, like redox flow batteries (RFBs), may be more suitable for this purpose.

The storage costs for battery systems with capacities ranging from 100 MW to 1000 MW, designed for a duration of 100 hours, are approximately $0.96 per kWh for Li-ion LFP batteries and $1.13 per kWh for vanadium RFBs. In contrast, for systems of the same capacity intended for a 24-hour duration, the respective costs are $0.28 per kWh for Li-ion LFP batteries and $0.32 per kWh for vanadium RFBs (Viswanathan, et al., 2022).

Table 7 summarises the advantages and disadvantages of discussed storage technologies. In short, each storage technology presents inherent limitations; for instance, PHS is contingent upon specific geographical locations, constraining its availability across various nations and impeding its scalability. In a similar vein, CAES exhibits low energy and power density, thereby diminishing its overall efficacy. BESS are inadequately suited for long-term energy storage, and the practicality of interconnections is heavily dependent on the conditions of the power systems in the exporting nations. Nevertheless, the solutions above are more economical than PtP systems, provided that geographical and technical constraints do not hinder their implementation.

Table 7: Advantages and limitation of storage options

	Advantages	Disadvantages/Limitations	Notes/ References
PHS	• Established technology with high technical maturity and extensive operational experience. • Very low self-discharge rates. • Reasonable round-trip efficiency. • Capability for large volume storage and extended storage periods. • Low installation costs for energy systems. • Good flexibility for starting and stopping operations. • Long lifespan and low costs associated with storage.	• Geographic constraints present challenges, as a suitable site with substantial land use is required • The energy density is low, resulting in a significant footprint. • there are considerable initial investment costs, an extended construction timeline, and a prolonged period necessary to recuperate the investment. • Environmental concerns must be taken into account.	(IRENA, 2017)

CAES	• High energy and power capacity; − • Cost-competitive, with low cost per kWh; − • Adaptable for decentralized plants with artificial reservoirs.	• Constraints on the availability of suitable geological formations: • Current designs depend on gas burners.	(SBC Energy Institute, 2013)
Batteries	• High efficiency; • extensive experience in portable applications; • suitable for small to medium-scale applications.	• Limited lifecycle • Environmental and safety hazards • Restricted flexibility in power and energy sizing	(SBC Energy Institute, 2013)
PtP	• Scalable from distributed systems to large-scale long-term storage; • High specific energy. • Low negative impact on the environment.	• Low round-trip efficiency; • High capital costs; • Safety concerns; • Low volumetric density; • Variable specific energy depending on the storage option (e.g., compressed hydrogen, liquid hydrogen).	(SBC Energy Institute, 2013)

4. The value of PtP to the power system

As the proportion of VRE within power systems increases, the modernisation of energy infrastructure must prioritise enhancing grid flexibility, reliability, and cost-effectiveness. PtP may play a significant role in providing critical services for the power sector. Notably, the value derived from these services can fluctuate greatly depending on various factors. These include specific system requirements, prevailing market conditions, and the overarching policy frameworks that govern energy markets. Hydrogen could play a critical role in enhancing the power system through multiple avenues. For instance, its capacity for long-duration energy storage allows it to store excess renewable energy generated during periods of low demand and release it during peak demand times. Additionally, hydrogen contributes to grid flexibility by enabling more effective integration of intermittent renewable energy sources such as wind and solar.

Other significant benefits include peak load shaving, where hydrogen production can be increased during high-demand periods to alleviate pressure on the power grid. Furthermore, avoiding renewable energy curtailment—where excess renewable energy is wasted instead of utilised—can enhance overall system efficiency and sustainability. Hydrogen also provides ancillary services, which support the reliability of the power system and help maintain the balance between supply and demand. Its versatility in fuel diversification fosters energy security by reducing dependence on a single energy source. It facilitates sector coupling, linking electricity, heating, and transportation sectors for an integrated energy system.

This section will analyse these various services and their value to the overall power system. It will explore critical questions, such as whether the benefits of these services can offset the relatively low efficiency characterising the PtP process. Additionally, it will identify which services are most likely to present a compelling economic justification for adopting PtP technologies. Conversely, the paper will also examine which services may have lower economic value and could thus impact the overall feasibility and attractiveness of PtP implementation. This will be accomplished by enumerating the various services PtP could potentially offer, supplemented by three case studies from countries categorised as having high, medium, and low potential for implementing PtP technology. These case studies (Appendix 2) help provide valuable insights into specific considerations that must be addressed during the implementation of PtP.

Adequacy Capacity

The shift from fossil fuel dependency to weather-dependent renewable energy sources presents a significant challenge known as "Dunkelflaute". This term describes episodes of low energy production from solar and wind sources, particularly during the winter months when sunlight is scarce, and winds are calm. Such conditions can lead to energy droughts lasting anywhere from one to three weeks, creating potential gaps in energy supply (Klaus Krüger, 2021). The effects of Dunkelflaute will not be limited only to the electricity market but will extend to other energy markets. Honoré & Sharples (2024) analysed the impact of dunkelflaute on gas demand. It concluded that, given the current state of gas-fired generation, which remains the primary source of flexibility, a decline in wind generation lasting more than a few hours will inevitably increase the reliance on gas-fired power plants. This observation is supported by two incidents in Europe from 2024, wherein such circumstances triggered peaks in gas demand. Consequently, using gas for power generation has become increasingly more volatile and less predictable (Honoré & Sharples, 2024).

While PHS and CAES can provide bulk GWh of electricity during such interruptions, their supply would only last for hours or, at most, one or two days. Among the various available technologies, PtP offers a solution for delivering the electricity needed during prolonged outages while ensuring environmental sustainability.

Although PtP has its challenges—such as poor economic viability and low efficiency—these drawbacks could be justified in the context of potentially high energy prices. As seen above, when electricity prices exceed 1000 €/MWh, PtP is feasible even when hydrogen costs 5 USD/kgH2 (see Figure 2). Without implementing this technology, consumers, industries, and the economy would bear a significant burden due to escalated energy costs. For instance, it has been reported that a steel manufacturing facility in Saxony procures its electricity from the intraday market and temporarily suspended operations to mitigate superfluous expenses (Wehrmann, 2024).

The renewable draught is expected every few years. The solution is the “adequacy capacity”. Adequacy capacity should not be confused with seasonal storage. Adequacy capacity is allocated explicitly for emergencies and events that occur less frequently than once annually. In contrast, seasonal storage is intended to manage the annual variations in electricity demand. Unlike seasonal storage, adequacy capacity safeguards against rare and unpredictable occurrences.

The expected significantly high prices during renewable drought events and the expected long duration (e.g., two weeks), could make a business case in some contexts. But the unpredictable nature of the demand for this adequacy capacity results in a highly risky commercial scenario, characterised by substantial yet infrequent revenue opportunities (Gerwen, et al., 2020). Given that long-term storage capacity of PtP may only be used rarely (a few times a year or in several years), the risks involved makes PtP rather difficult for commercial players to invest without policy support.

Mitigate Electricity market risks (Negative Electricity Market Prices, energy security, and carbon price)

The phenomenon of negative pricing in energy markets is increasingly prevalent. For instance, in South Australia, where the share of VRE reached 75%, hourly prices registered negative values approximately 25% of the time in 2023, an increase from 19% in 2022. Furthermore, the frequency of negative wholesale electricity prices more than quadrupled in 2023 in countries such as Germany and the Netherlands compared to the prior year. Specifically, in Germany, prices fell below zero for nearly 3% of the hours, while in the Netherlands, this figure was close to 4%. This trend underscores the pressing requirement for enhanced system flexibility by implementing more price-responsive demand and supply mechanisms alongside the development of additional energy storage solutions (IEA, 2024a).

Negative electricity prices have several detrimental effects, notably the exacerbation of balancing risks associated with wind and solar assets and the erosion of profit margins for thermal assets, including gas and nuclear power. Conversely, this situation may also enhance the value of storage and electrolyser assets, which derive advantages from lower electricity prices and price volatility.

One primary reason for this phenomenon is the inadequate flexibility within the current system. Hydrogen production and PtP technologies can enhance grid flexibility, enabling it to mitigate extreme electricity pricing while concurrently yielding economic advantages[10]. A comprehensive study that evaluated the utilisation of hydrogen to bolster flexibility in the European electricity market formulated an integrated energy market model. This model jointly considers the interrelations between hydrogen and electricity markets, as the dynamics of each sector mutually influence one another to achieve an overall welfare optimum[11]. The study concluded that the coupling of electricity and hydrogen markets offers substantial potential for increased flexibility and an overall enhancement in welfare (Loschan, et al., 2023).

Hydrogen has the potential to mitigate energy import dependence by replacing some or all imported resources with domestic alternatives. This shift could facilitate the decoupling of domestic energy consumption from fluctuations in global market conditions and subsequently reduce national energy import expenditures. Following the invasion, the European Union Title Transfer Facility (EU TTF) gas prices surged above 35 $/MMBTU, rendering green hydrogen production cost-competitive in several instances (ETC, 2022). At current price level, PtP could compete with thermal power generation. Even with lower gas prices and a high future carbon tax, PtP could be competitive. A study showed that the hydrogen price level of 1.5 USD/kg, natural gas price of 20 USD/MWh (5.86 USD/MMBTU), and carbon pricing equal or exceeds 90 USD/ton, making PtP the most competitive against natural options using CCGT. At a hydrogen cost level of 3 USD/kg and a natural gas price of 60 USD/MWh (17.58 USD/MMBTU), carbon pricing should be equal to or exceed 120 USD/ton to make PtP competitive (Venizelou & Poullikkas, 2025).

Ramping Reserve/Flexibility

Power system flexibility needs arise from fluctuations in generation, demand, and grid capacity due to their variability and uncertainty. In demand, the electrification of heating, transportation (like electric vehicles), and industries lead to increased variability and unpredictability from larger electric loads influenced by temperature and changing customer preferences. On the generation side, the growing use of VRE makes energy production increasingly dependent on weather conditions, heightening uncertainties. Additionally, the integration of VRE and distributed energy resources (DER) results in less predictable energy flows and reduced inertia, complicating the stability of power systems (ENTSO-E, 2021).

This situation introduces a significant challenge pertaining to flexibility. The diminishing capacity of weather-independent generation may necessitate more rapid adjustments over a broader range of megawatts (MW) than previously required. This is particularly concerning when substantial increases in load align with steep decreases in VRE generation and, conversely, when there are decreases in load alongside increases in VRE generation. For example, demand surges may become more pronounced due to the rising adoption of heat pumps and electric vehicles (EVs), while the scale of VRE generation reductions (e.g., during sunset) is likely to expand with higher levels of VRE integration (ENTSO-E, 2021).

In a study carried out by the European Network of Transmission System Operators for Electricity (ENTSO-E) to assess the future ramping flexibility needs which measure large daily residual load gradients, for example, at sunset in regions with large PV generation capacities became offline and stop production. Residual load is the load left after subtracting VRE generation such as wind, PV and run-of-river hydro from the demand, which will need to be covered by dispatchable generation, imports or exports, and the use of different kinds of storage (ENTSO-E, 2021).

[10] PtP can help stabilize electricity prices if PtP pays a higher price than a zero price for electricity. However, the greater the price paid for the electricity, the less economic the PtP becomes. As such, there is a challenge in finding the right balance.
[11] This methodology allows hydrogen technologies to not act as price takers and the electricity market to not act as price setters; instead, a joint optimum is found. Hydrogen production increases electricity demand, influencing electricity generation and, as a result, the electricity price. The latter influences electricity generation via hydrogen utilisation by fuel cells and thus the price of electricity. Hence, the electricity and hydrogen markets affect each other

In a study to assess the maximum ramps in the residual load in Germany for 2025 and 2030, across 1-hour, 3-hour, and 8-hour time intervals, the findings derived from the 8-hour ramp scenarios demonstrate significant challenges for Germany. Specifically, these results indicate that the values are already 89% of the anticipated dispatchable capacity for 2025 and exceed the dispatchable capacity by 19% by 2030. To effectively address these ramps, it may be necessary use to import dispatchable capacity or other flexible resources from neighbouring countries (ENTSO-E, 2021).

A handful of technologies, including PHS, CAES, and interconnections, have the potential to address ramping needs in energy systems. Although PtP might not be the first option, it may also be significant due to certain limitations inherent in other technologies. PHS is contingent upon specific geographical locations and may not be accessible in various countries, thus limiting its capacity to fulfil all required ramping capabilities. Similarly, CAES possesses low energy and power density, which restricts its effectiveness. The viability of interconnections relies on the power system conditions of exporting countries; when ramping needs coincide across regions, the export of substantial electricity may become unfeasible. Furthermore, batteries often encounter challenges in delivering large quantities of electricity efficiently.

Based on economic principles, PtP technology could serve as a supplementary solution for required ramping capacity once all other alternatives have been exhausted. Alternatively, if other options are not available, PtP technology has the potential to fulfil all necessary ramping requirements. Appendix 2 delineates three case studies: one pertaining to a nation with high potential for the implementation of PtP as a singular option; another concerning a nation with medium potential where PtP exists among alternative possibilities; and a third focused on a nation with low potential for implementing PtP, in which PtP is not considered the optimal choice.

5. Conclusions

Decarbonising the power sector is ambitious and presents challenges, particularly in synchronising energy demand and supply with the integration of VRES. The unpredictable output from solar panels and wind turbines adds to these difficulties. To overcome these challenges, strategies such as energy storage systems, demand pattern optimisation, and improved regional grid connectivity can be implemented. Ultimately, the power system must remain flexible to adapt to these changes.

PHS plants have a global installed capacity of over 160 GW, serving as a key electricity storage resource. Operating at up to 85% efficiency, they can respond to demand within seconds. However, PHS relies on significant elevation differences between reservoirs, making it unsuitable for lowland areas or regions with unreliable freshwater sources. These plants can typically discharge energy for up to 12 hours, with some lasting over 20 hours. Sustainability concerns include land flooding for reservoirs, high land use due to low energy density, and potential disruptions to local ecosystems (Klaus Krüger, 2021). CAES is an effective option for large-scale, long-duration energy storage, known for its high round-trip efficiency and lower costs. However, it has geological limitations and a low volumetric energy density of 3 to 6 kWh/m³, requiring large underground facilities. D-CAES uses natural gas for heating during decompression, resulting in NO_x emissions and significant demand for cooling water (SBC Energy Institute, 2013). While CAES has a lower efficiency of 75% compared to PHS, it offers a more favourable LCOES of $0.10 per kWh, compared to PHS at $0.11 per kWh and hydrogen energy storage at $0.35 per kWh (Viswanathan, et al., 2022). From 2010 to 2023, battery prices dropped by 90%, while their performance improved with higher energy densities and longer cycle lives. Despite this, lithium-ion batteries encounter challenges in long-duration storage, prompting interest in alternatives like redox flow batteries. Li-ion LFP batteries have the lowest installed cost per kWh, about $0.96 for 100-hour systems and $0.28 for shorter durations. Vanadium redox flow batteries are also competitive, costing $1.13 and $0.32 per kWh for 100-hour and 24-hour durations, respectively (Viswanathan, et al., 2022). Batteries outperform PHS and CAES in energy and power density. They are efficient (60%-98%) but face limitations such as lifecycle constraints, environmental issues, and scalability challenges.

The economic viability of PtP is comparatively less advantageous than that of PHS, CAES, and battery technologies, largely due to its lower round-trip efficiency. However, PtP exhibits certain attributes that enable it to outperform all these technologies in specific energy storage applications. It boasts the highest energy density and demonstrates exceptional potential for storing TWh of energy, exceeding the capabilities of any other discussed energy storage solution. These characteristics could position PtP to excel in particular applications where alternative storage methods may fall short. The phenomenon known as the renewable draught, or "Dunkelflaute," is projected to occur every few years. Variations in load and weather conditions can range from 12% to 30%, impacting the residual load. This variability necessitates reserve generation capacity, which may be needed only once annually or every few years (Gerwen, et al., 2020).

An essential aspect of the PtP application lies in its potential contribution to ramping reserves. This is particularly relevant in scenarios where significant demand increases coincide with rapid decreases in VRE generation. Conversely, it is also critical in situations where demand decreases align with increases in VRE generation. For example, demand surges may become more pronounced due to the growing adoption of heat pumps and EVs). At the same time, the magnitude of VRE generation reductions—such as those observed during sunset—is expected to intensify with the increasing deployment of VRE technology.

To determine the feasibility of utilising PtP technology, several critical factors must be considered to discount alternative options. For instance, Germany's mandate for a carbon-neutral power sector precludes fossil fuel options. Furthermore, public acceptance of various alternatives, such as CCS and nuclear energy, remains a pivotal consideration when relying on PtP solutions. PtP technology may offer a supplementary solution under specific conditions, such as in India, where substantial ramping capacity is required alongside long-term storage.

Thus, PtP should be carefully evaluated and implemented with a clear understanding of its limitations and after exploring potential alternative solutions. The sporadic and unpredictable nature of demand poses a significant risk to the commercial viability of the model, which relies on occasional but potentially large revenue events. Since commercial traders typically pay for this capacity only during rare, high-demand periods—sometimes occurring just once every few years—relying solely on such income is risky. To improve the economic feasibility of PtP systems, it is recommended to explore opportunities for participating in additional services that can help offset the substantial investment involved.

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Appendix I: Model Assumptions

Assumption for Gas Turbine

GT Capacity	kW	250000	Estimated
GT Efficiency	%	35%	From different manufacturers data sheet (GE, Mitsubishi, Siemens)
Hydrogen HHV	kWh/kg	39.40	
CAPEX	USD/kW	660	(ETN, 2022), (Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Fixed OPEX	USD/kW	25.3	(ETN, 2022), (Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Var. OPEX	USD/kWh	0.0033	(ETN, 2022), (Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Fuel cost	USD/kgH2	5/1	Estimated
Interest rate	%	7%	Estimated

Assumption for Fuel cell

Capacity	kW	100000	Estimated
Efficiency	%	53%	(Ballard Power Systems, 2023), (Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Hydrogen HHV	kWh/kg	39.40	
CAPEX	USD/kW	1300	(Cigolotti & Genovese, 2021)
Fixed OPEX	USD/kW	33	(Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Var. OPEX	USD/kWh	0.0176	(Kost, Muller, Schweiger, Fluri, & Thomsen, 2024)
Fuel cost	USD/kgH2	5/1	Estimated
Interest rate	%	7%	Estimated

Assumption for ICE

Capacity	kW	100000	Estimated
Efficiency	%	47%	(Vietnam Institute of Energy (IEVN), 2020)
Hydrogen HHV	kWh/kg	39.40	
CAPEX	USD/kW	740	(Vietnam Institute of Energy (IEVN), 2020)
Fixed OPEX	USD/kW	15	(Vietnam Institute of Energy (IEVN), 2020)
Var. OPEX	USD/kWh	0.005	(Vietnam Institute of Energy (IEVN), 2020)
Fuel cost	USD/kgH2	5/1	Estimated
Interest rate	%	7%	Estimated

Appendix II: Case studies

This section delineates three case studies: one pertaining to a nation with high potential for the implementation of PtP as a singular option; another concerning a nation with medium potential where PtP exists among alternative possibilities; and a third focused on a nation with low potential for implementing PtP, in which PtP is not considered the optimal choice. It is crucial to emphasise that the purpose of this section is not to conduct a thorough or exhaustive evaluation but rather to explore the conditions that render the PtP option viable and feasible. A comprehensive modelling approach is essential for assessing the feasibility of PtP in any given context. The practicality of PtP is contingent upon numerous aspects, as delineated in the case study, including but not limited to the renewable energy mix and technology within the electricity grid, geographical location, climatic patterns, interconnections with adjacent nations, and policies implemented.

Germany: A country with high potential to implement PtP

Germany's coalition government has set a target of achieving 80% renewable energy in the power sector by 2030, intending to establish a predominantly decarbonised power sector by 2035. A study conducted by Agora indicates that the "Climate-neutral Electricity System 2035" scenario is feasible. By 2035, renewable electricity generation is projected to increase to 845 TWh, attributed to the sustained expansion of wind energy and photovoltaics. Indeed, wind power and solar energy are poised for substantial growth, becoming the cornerstone of the climate-neutral electricity system envisioned for 2035 (Agora Energiewende, 2022).

To succeed, solar PV expansion must increase from 5 GW in 2021 to an average of 21 GW annually between 2026 and 2035. Onshore wind power must also grow from 1.7 GW to 10 GW annually, a sixfold increase. Offshore wind power will peak at 8 GW and average 6 GW from 2031 to 2035. Onshore wind turbines will lead net renewable electricity generation, contributing 40%, followed by solar PV at one-third and offshore wind at one-quarter (Figure 4) (Agora Energiewende, 2022).

However, with this high share of renewable, Germany will be more vulnerable to the "Dunkelflaute". A study examining occurrences of diminished power generation owing to renewable drought for 14 consecutive days revealed that specific years, notably 1996, 2007, and 2016, experienced exceptionally low power production across both winter and summer seasons. It is important to note that three out of the five instances of the lowest total production during these 14-day periods corresponded to the summer conditions 2016 (Ho-Tran & Fiedler, 2024).

Dunkelflaute does not necessitate a duration of two weeks to disrupt electricity markets. A shorter period, such as several days, can suffice, as evidenced in November 2024. During this time, a sustained absence of sunshine and wind significantly reduced renewable electricity production in Germany, thereby compelling gas power plants to engage in operations. This situation resulted in power prices surging to 800 euros per megawatt-hour for several hours, exceeding ten times the average price observed in preceding months (Wehrmann, 2024).

At this level, PtP is economically and technically feasible to support the grid, reduce electricity prices, and decarbonise it. Other grid options include PHS, CAES, battery storage, and Carbon capture and storage with fossil plants. Upon examining the modelling results in Figure 3, it is observed that the daily average production of solar energy, along with onshore and offshore wind energy, amounts to 2.25 TW. In a 14-day absence of renewable resources, the estimated energy requirement would total 31.6 TWh. The maximum potential of pumped hydro storage (PHS) in Germany is 7 GW, coupled with 100 GWh of energy storage capacity (Klaus Krüger, 2021). This indicates that PHS may not be a feasible solution. CAES is also not feasible, as the current designs for CAES necessitate the use of natural gas (refer to Table 2), and the associated emission intensity is approximately 100 g/kWh (as discussed in the CAES section above), which contradicts the targets for decarbonisation. Given the long duration and the level of TWh required for energy storage, especially since such phenomena occur infrequently, battery storage also proves to be an impractical option.

The amount of energy needed for storage suggests using fossil fuels to bridge existing gaps, and CCS could potentially facilitate the achievement of decarbonisation targets. However, similar to the case of

nuclear energy, public opposition to carbon storage has a storied history in the country, notably with the Green Party being among its most vocal critics over the years. Concerns have been raised regarding the perceived uncontrollable risks associated with carbon storage, resulting in resistance to its adoption as a potential solution for coal-fired power plants (Quecke & Wettenegel, 2024).

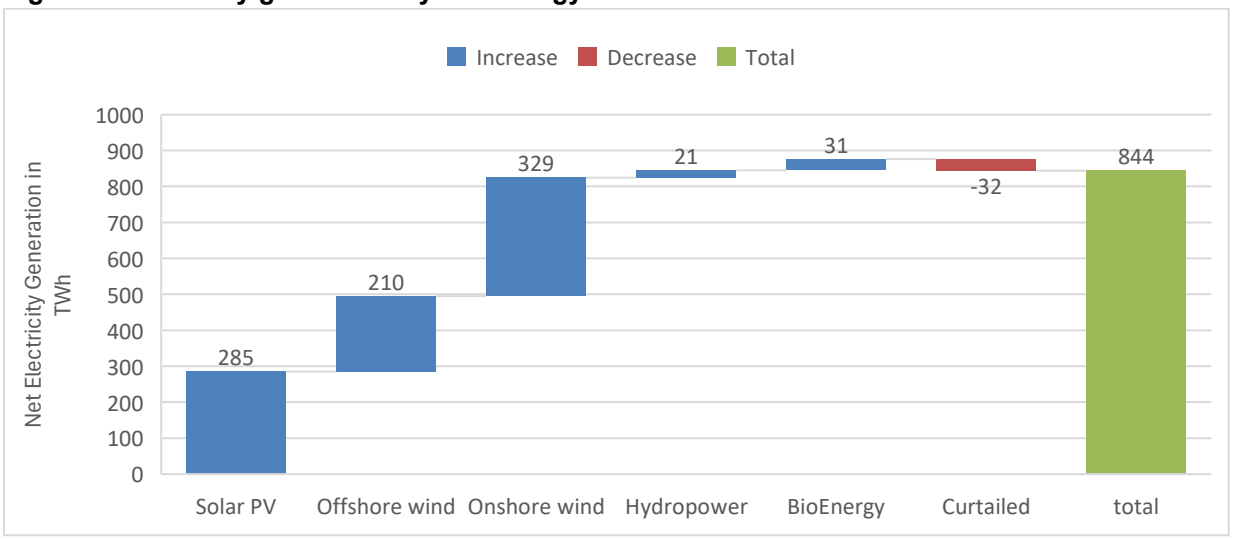
In theory, Germany's CO2 storage legislation permits limited research, testing, and demonstration of CO_2 storage technologies. Nonetheless, individual federal states retain the authority to prohibit carbon storage in designated areas, and several states in Germany have effectively enacted comprehensive bans. Consequently, initiating CO_2 storage projects within the country is currently infeasible. Furthermore, the transportation of CO2 is also regulated under hazardous goods legislation. Establishing a pipeline infrastructure is essential for large-scale CO2 transport; however, the absence of such infrastructure in Germany is attributed to legal uncertainties and outdated regulatory frameworks (Quecke & Wettenegel, 2024).

The interconnection lines will not solve the problem as Europe experiences a homogeneous weather system. Figure 4 illustrates the aggregated output from wind turbines across Germany, Denmark, Ireland, and Spain, recorded in 30-minute intervals during January 2012. This figure indicates that the combined outputs reach their peaks and troughs simultaneously. The underlying reason for this phenomenon is that European weather systems typically span a substantial area of the continent (Klimstra, 2014).

The anticipated curtailed energy is quantified at 32 TWh. Should this energy be allocated for PtP application, with an operational efficiency ranging from 24% to 48%, as delineated in the preceding PtP efficiency section, it could enable the storage of energy sufficient to cover a duration between 3.5 and 7 days of total renewable absence. Consequently, the retention of curtailed energy equivalent to 2 or 3 years may serve as an effective contingency strategy for mitigating 14 days of Dunkelflaute. Presently, approximately 262 TWh of available storage capacity across Germany's underground gas storage facilities can adequately accommodate the necessary volume (Nationler Wasserstoffrat, 2022).

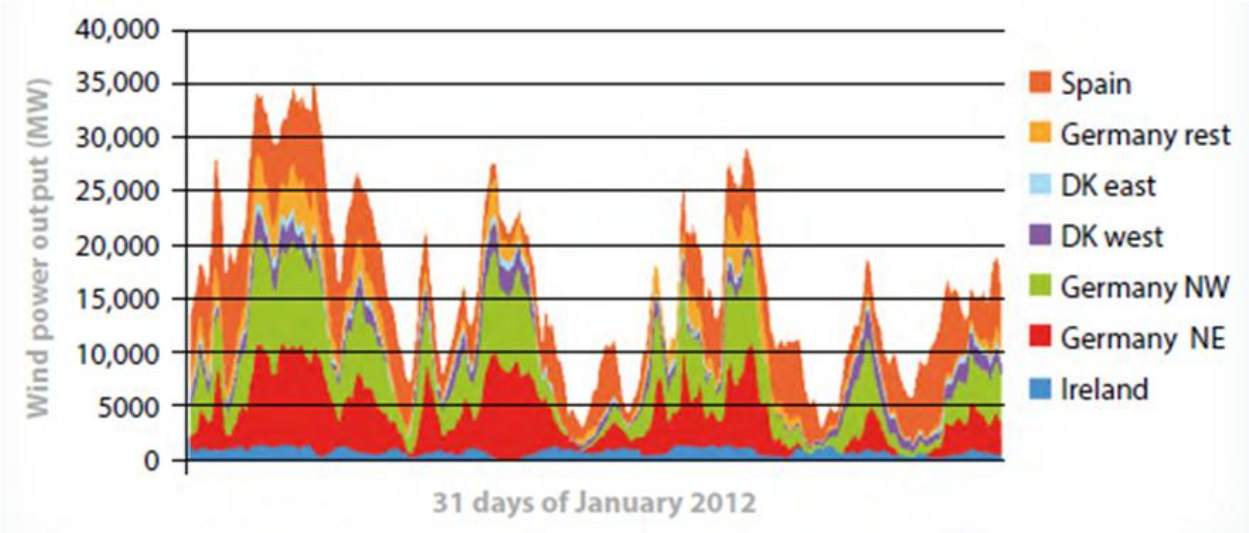
According to Agora, an insurance policy addressing rare extreme events involves utilising power plants that operate for only a few hours each year, specifically designed to ensure load coverage during periods of extreme weather. Within this strategy's framework, these power plants' efficiency is considered less critical. Ammonia is considered an alternative to hydrogen, even though ammonia synthesis may result in more significant energy losses, primarily due to its relative ease of storage and transportation. However, they still need a thorough investigation to make a decision (Agora Energiewende, 2022).

Figure 3: Electricity generation by technology in 2035



Source: Agora Energiewende, 2022. Climate-neutral power system 2035. How the German power sector can become climate-neutral by 2035, s.l.: Agora Energiewende.

Figure 4: Wind power output in selected European countries



Source: Klimstra, J., 2014. Power supply challenges, Solutions for Integrating Renewables. s.l.:Wärtsilä Finland Oy.

India: A country with medium potential to implement PtP

As of March 2023, the installed energy capacity of the country reached 415.4 GW. This total comprises 236.68 GW derived from thermal sources, including 211.8 GW from coal and lignite and 24.8 GW from natural gas. Additionally, the capacity of nuclear energy amounts to 6.78 GW. In terms of renewables, the total installed capacity is 171.8 GW, further divided into several categories: 42.1 GW from hydropower, 66.8 GW from solar energy, 42.6 GW from wind energy, 4.7 GW from small hydro, 4.8 GW from pumped storage, and 10.8 GW from biomass power generation. Notably, coal-based capacity constituted 51% of the overall capacity mix while contributing to approximately 73% of the country's total electricity generation during 2022-2023 (Ministry of Power, 2023).

According to the "Optimal Generation Capacity Mix for 2030" report, where the Indian power system is modelled, the total capacity is projected to increase to 777.1 GW. This will comprise thermal power plants, including coal power plants at 251.7 GW and gas plants at 24.8 GW; nuclear power plants at 15.5 GW; PV systems at 292.6 GW; wind energy at 99.9 GW; and hydroelectric power at 78.17 GW, which includes both small hydro and PHS (Figure 5). Notably, by 2029-30, the installed capacity based on non-fossil fuel sources (including nuclear, solar, wind, biomass, and hydro) is anticipated to account for approximately 64% of the total installed capacity. Furthermore, non-fossil fuels are expected to contribute around 45% of the gross electricity generation (Ministry of Power, 2023).

Solar will have the most significant increase, 333.8%, representing 37.6% of the total capacity, followed by the PHS, which will have a 300% increase (Figure 5). Solar energy will be concentrated in India's northern, southern, and western regions. Eastern and Northeastern areas will have negligible amounts (Figure 6) (Ministry of Power, 2023).

India stretches 3,000km (1,864 miles) from east to west, spanning roughly 30 degrees longitude. This corresponds with a two-hour difference in mean solar times[12] (BBC, 2019). However, India's northern, southern, and western regions span approximately 10 degrees (70 to 80), which means the difference in mean solar times is less than one hour[13]. In other words, a massive capacity of 292 GW, which supplies the Indian electricity grid, will disappear in less than one hour. This capacity has to be replaced with fast ramping power plants that could supply up to the fill capacity of PV 292 GW depending on the demand supplied by the PV.

[12] The passage of time based on the position of the sun in the sky.
[13] Each 15 degrees is one hour.

IEA has projected that India will experience a significant increase in the need for fast and steep ramping reserves by 2030. The substantial rise in VRE will necessitate exponential ramping capacity, with maximum hourly ramp requirements expected to escalate to 68 GW, thereby increasing to 19% of the daily peak net load. Furthermore, the requirements for three-hour ramps are likely to rise to 342 GW, representing 40% of the daily peak net load (Klaus Krüger, 2021). India is strategising the implementation of energy storage technologies, specifically PHS with a capacity of 19 GW and BESS totalling 41.7 GW with 208.25 GWh of energy capacity, to address the significant system ramping requirements (Ministry of Power, 2023).

In order for India to achieve full decarbonisation of its power sector, an increased reliance on solar power is essential, resulting in a heightened requirement for ramping capacity. The ramping capabilities of coal, CCGT, and OCGT power plants are notably limited, with rates of 1-4%/min, 2-4%/min, and 8-12%/min, respectively, rendering them inadequate even when supplemented with CCS. Nuclear power plants, exhibiting a ramping rate of approximately 5%/min, present similar limitations (Shankar, et al., 2023). Consequently, this scenario restricts the available options for future exploration to PHS, BESS, and PtP.

The current potential of 'on-river pumped storage' in India is 103 GW. Of the total installed capacity of 4.76 GW, 3.36 GW is currently in pumping mode. Additionally, approximately 44.5 GW, which includes 34 GW from off-river pumped storage hydro plants, is under various stages of development (Shankar, et al., 2023). While these figures are promising, they are still lower than the PV capacity in 2030 and may prove insufficient to support a fully decarbonised power system with a higher share of PV.

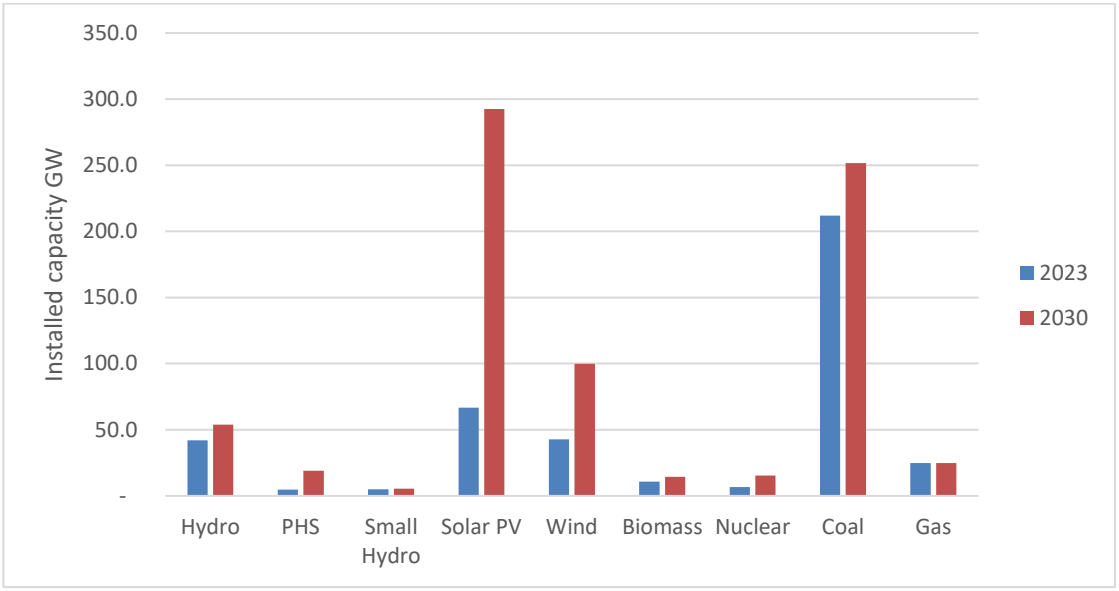
BESS is another available option and could support ramping capacity; however, it will fall short of supporting the long-term storage required in India. The hydro energy availability varies significantly across the years depending on the monsoon rains in a particular year. Moreover, there is seasonal availability of Biomass (Ministry of Power, 2023). The presence of seasonality necessitates the implementation of long-term storage solutions. PtP technology could complement other existing solutions, such as PHS and BESS, by providing ramping capacity and long-term energy storage, thereby contributing to the decarbonisation of the power sector.

Nevertheless, PtP has certain limitations. Given its intended application for ramping services, OCGT utilising hydrogen fuel may not be appropriate due to its operational characteristics comparable to those of conventional systems. This scenario restricts the feasible options to ICE and fuel cells, exhibiting a ramp rate of 100% per minute (refer to Table 3). However, it is noteworthy that these technologies currently do not exist in high-capacity configurations (specifically below 25 MW, as indicated in Table 3). The challenge of developing a power plant with a capacity of 500 MW poses a significant constraint, consequently limiting the utilisation of PtP to distributed power systems aimed at enhancing grid stability.

A joint research study by LUT University and Wärtsilä outlines a pathway for transitioning the Indian power sector to 100% renewable energy by 2050. However, instead of using hydrogen directly, the study assumes using synthetic natural gas (SNG), which requires green hydrogen for its synthesis. Results indicate that ICE will contribute 1.1% to electricity generation by 2050, primarily for peak supply and balancing, supported by over 800 full-load hours. Battery storage plays a crucial role in energy storage, while gas storage provides essential seasonal storage, especially during the monsoon season. Electrolysers not only generate hydrogen but also enhance the flexibility of the power system during the transition (Ram, et al., 2021).

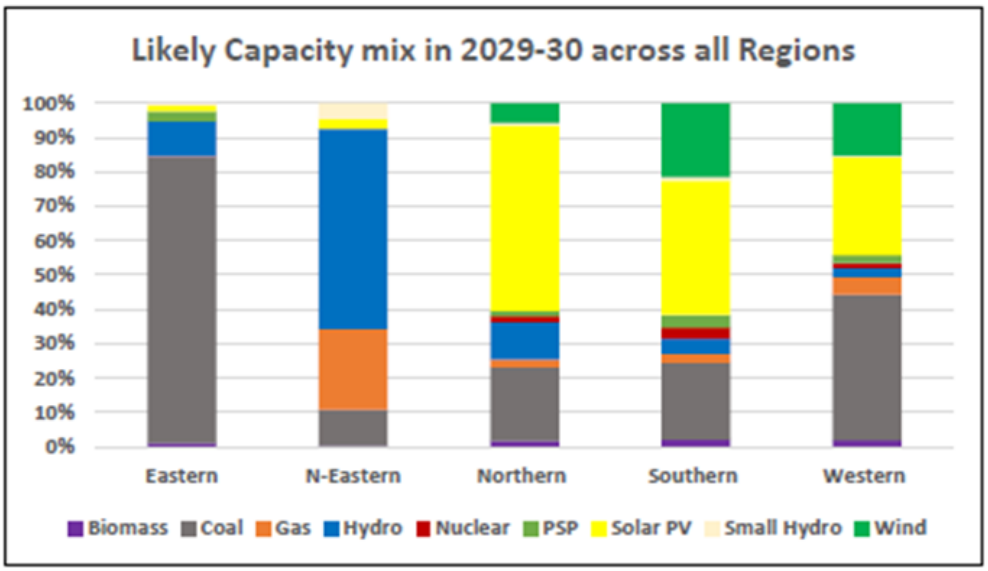
In conclusion, for India to attain full decarbonisation of its power sector, it is imperative to investigate PtP technology as a viable option. Nonetheless, considering their economic viability and technological attributes, PHS and BESS should also be considered first. PtP may effectively complement these alternatives.

Figure 5: Installed capacity by technology in 2035



Source: Ministry of Power, 2023. *Optimal generation capacity mix studies for the year 2029-30,* s.l.: Ministry of Power, Goverment of India.

Figure 6: Renewable energy installation in different regions in India



Source: Ministry of Power, 2023. *Optimal generation capacity mix studies for the year 2029-30,* s.l.: Ministry of Power, Goverment of India.

China: A country with low potential to implement PtP

The electricity sector is poised to play a critical role in advancing China's environmental objectives, which include achieving carbon neutrality and enhancing air quality. The anticipated expansion of non-fossil fuel generation and the electrification of the transportation, industrial, and building sectors are expected to yield substantial reductions in greenhouse gas emissions. Current targets set by China aim for a 60% share of non-fossil fuel electricity generation by 2035, representing a notable increase from the 34% share recorded in 2020 (Nikit Abhyankar, 2022).

To achieve the established targets, all additions to the new generation capacity are anticipated to predominantly consist of non-fossil fuel resources, except for the 150 GW of coal generation currently

under construction. By 2035, the wind and solar energy generation capacity is projected to attain 1,933 GW. Furthermore, battery storage capacity is expected to reach 225 GW by 2030 and 244 GW by 2035 (Nikit Abhyankar, 2022).

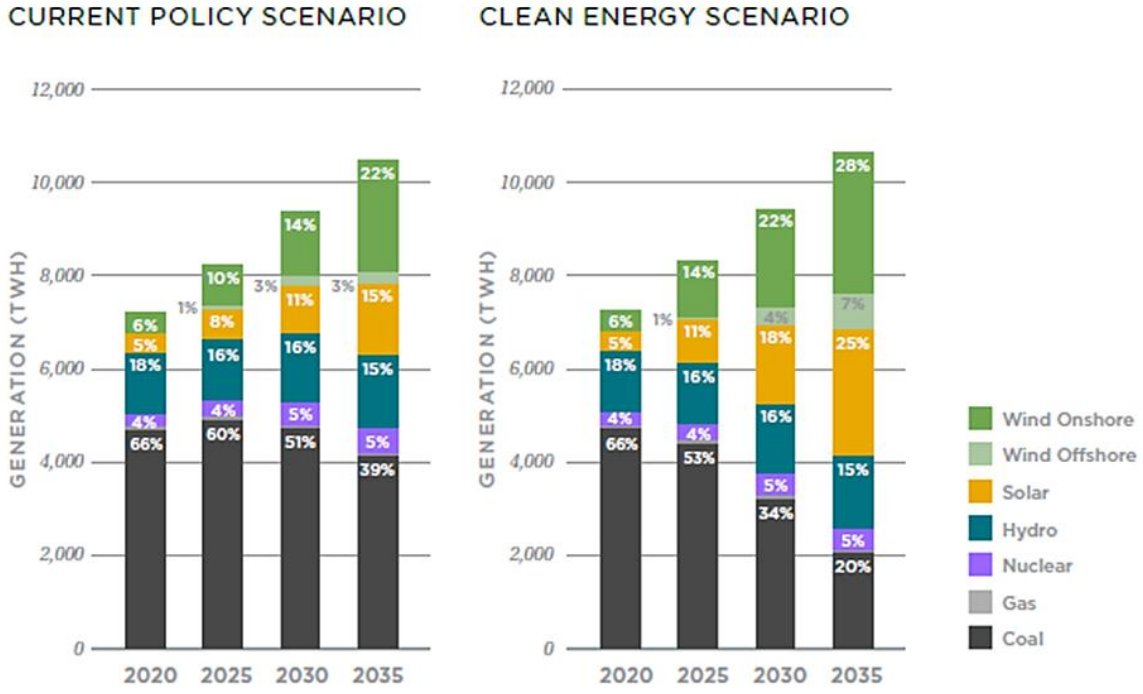
There have been longstanding inquiries within China regarding the feasibility of operating electricity systems characterised by significant penetrations of variable renewable generation. A study conducted by a team of researchers at the Lawrence Berkeley National Laboratory has been undertaken in pursuit of answers. This research considers two primary scenarios: the Current Policy scenario, where the annual deployment of wind and solar generation is confined to existing government objectives, and a more ambitious scenario termed the "Clean Energy scenario," in which the proportion of non-fossil generation in China is projected to increase to 80% (Figure 7) (Nikit Abhyankar, 2022).

The findings indicate that China's electricity system can be operated reliably, even at high levels of non-fossil fuel generation. China is a large country spanning over five time zones. Besides, the renewable generation resources being distributed over the country cause regional and resource diversity. This holds true even during extended periods of diminished wind and solar generation and unpredicted increases in demand. Consequently, China's electricity system can sustain sufficient capacity and energy (Nikit Abhyankar, 2022).

According to the findings of the study, the two primary enabling conditions for ensuring reliability in systems with high levels of renewable energy generation are: (1) the development of a comprehensive approach to optimising the operation of electricity storage facilities, thereby ensuring that individual storage operations contribute to the overall reliability of the electricity system; and (2) the implementation of regionally and nationally coordinated operations, which facilitate the seamless importation of power from neighbouring provinces and regions for both short-term and long-term needs (Nikit Abhyankar, 2022).

Due to its regional and resource diversity, China is not significantly susceptible to the challenges posed by Dunkelflaute and ramping issues. A well-functioning and effectively managed transmission and distribution system could mitigate these challenges. Besides, the well-operated storage facilities of PHS and BESS eliminate the need for PtP technology.

Figure 7: Electricity generation by technology in the modelled scenarios



Source: Nikit Abhyankar, 2022. Achieving an 80% carbon-free electricity system in China by 2035. *iScience,* 25(10).