

Green Hydrogen Applications in Mongolia

Technology potential and policy options

Authors:

Anna Nilsson, Gustavo de Vivero, Pablo Lopez Legarreta, Thomas Day
(NewClimate Institute)

Martin Pudlik, Bernhard Seyfang (Fraunhofer ISI)

Bayasgalan Dugarjav (National University of Mongolia)



September 2021

Green Hydrogen Applications in Mongolia

Technology potential and policy options

Authors

Anna Nilsson, Gustavo de Vivero, Pablo Lopez Legarreta, Thomas Day, Martin Pudlik, Bernhard Seyfang, Bayasgalan Dugarjav



Capacity Development for climate policy in the countries of South East, Eastern Europe, the South Caucasus and Central Asia, Phase III

On behalf of:



Federal Ministry
for the Environment, Nature Conservation
and Nuclear Safety

of the Federal Republic of Germany

*This project is part of the International Climate Initiative (IKI).
The German Federal Ministry for the Environment, Nature
Conservation and Nuclear Safety (BMU) supports this initiative
on the basis of a decision adopted by the German Bundestag.*

*Credits for cover photo: “[Golden hour in the Mongolian Gobi Desert](#)” by Patrick Schneider /
Unsplash*



Download the report

<http://newclimate.org/publications/>

Table of Contents

Summary of key findings	1
1 Introduction	3
1.1 Country context and introduction to green hydrogen as a decarbonisation option	3
1.2 Policies and targets for the decarbonization of the energy sector and national GHG emission reductions	4
1.3 Aim and objectives	5
2 Setting the scene – Green hydrogen as a decarbonisation option.....	7
2.1 Green hydrogen production methods.....	7
2.2 Barriers to the widespread deployment of green hydrogen	8
3 Role and implications of hydrogen as decarbonisation option in Mongolia.....	13
3.1 Supply side	13
Heat and Power supply.....	14
Energy Security	21
Water supply.....	22
Geographical locations for green hydrogen production.....	26
Hydrogen production costs.....	28
3.2 Demand side	30
Heavy duty transport in mining	31
Public transportation	33
Heating and cooking	36
3.3 Impacts of technology implementation.....	38
GHG emission reduction potential.....	38
Sustainable development agenda	39
4 The role and importance of policies.....	42
4.1 The broad view - Overarching policies	44
4.2 Supply side policies	46
General supply side policy.....	46
Electrolysers	49
Power supply	51
Infrastructure.....	52
Water supply.....	54
4.3 Demand side policies	56
Heavy duty transport – mining trucks in the south Gobi.....	57
Public transportation – fuel cell buses in Ulaanbaatar	58
Space heating.....	60

5	Conclusions	62
6	References.....	65

List of Figures

Figure 1. Green hydrogen production and end-uses.	8
Figure 2. Alternative configurations of hydrogen production with respect to the power grid.	17
Figure 3. Division of four regions to assess their renewable energy potential in Mongolia.	19
Figure 4. Potential full load hours for wind (left) and solar PV (right) generation.....	20
Figure 5. Electricity generation costs for wind power across Mongolia in 2020, divided into four key regions.	20
Figure 6. Projected annual precipitation (mm) in Mongolia in a SSP245 scenario, 2021-2040.....	22
Figure 7. Annual runoff in 2019 (mm) (left) and Climatic water deficit in 2019 (mm) (right).	23
Figure 8. Saline groundwater in the region.	23
Figure 9. Process water price calculation and forecast.....	26
Figure 10. Potential of wind (left) and PV solar (right) energy resources and their overlaps with the five non-interconnected power grids.	27
Figure 11. Approximate share of cost contribution for green hydrogen production in Mongolia.....	29
Figure 12. Methodological flowchart over the steps considered in the modelling exercise.	31
Figure 13. Operation costs of mining vehicles in southern Mongolia.....	33
Figure 14. Cost comparison for public transport buses in Ulaanbaatar in terms of energy delivered to the wheel.	35
Figure 15. Cost comparison for public transport buses in Ulaanbaatar in terms of operating costs, including CAPEX.	35
Figure 16. Cost comparison of decentralised residential heating and cooking fuels in ger districts.....	38
Figure 17. Estimated GHG reduction potential in terms of ktCO ₂ e/year for heavy-duty transport in the Mongolian mining and public transport sectors.....	39
Figure 18. Overview of the process of the introduction and development of a green hydrogen sector.....	45

List of Tables

Table 1. The key characteristics of available electrolyser technologies.	11
Table 2. Estimated water prices for additional water demand in the South Gobi Region.....	25
Table 3. Modelling results for electricity generation and hydrogen production.....	28
Table 4. Impact of hydrogen on Mongolia's sustainable development agenda.	40
Table 5. Overview of policy options to promote green hydrogen.....	42
Table 6. Suggested categorisation system for the use of hydrogen technology in the analysed end-use sectors.	57

Summary of key findings

Green hydrogen could be a feasible option to decarbonise hard-to-abate sectors in Mongolia.

Mongolia faces significant challenges in its decarbonization efforts, particularly in its hard-to-abate sectors. Despite being endowed with rich renewable energy resources, electrification is technically challenging in the heavy-duty transport and building sectors. One of the key alternatives could be the introduction of green hydrogen, produced from renewable electricity and water. This study assesses the technoeconomic potential of green hydrogen production in Mongolia, and its application in the heavy-duty transport, urban public transport and decentralized heating sectors. Based on the results, the greenhouse gas (GHG) emission reduction potential is estimated, followed by an analysis on policy options for the development of a green hydrogen sector.

Green hydrogen could be produced in Mongolia at comparatively low cost. Green hydrogen could be produced in Mongolia at 3.3-4.7 USD/kg-hydrogen in 2020, falling to 2.8-2.9 USD/kg-hydrogen by 2030. This is significantly lower than the global average costs of 4.8 USD/kg-hydrogen in 2020. With such favourable conditions, Mongolia is a promising location for the further development of green hydrogen technologies. However, as its production is reliant on water supply, a growing green hydrogen sector may require water infrastructure development.

Green hydrogen may be particularly promising for heavy duty transport in the mining sector. A shift to fuel cell trucks in the mining sector would cost only 12% more than the continued use of diesel trucks, in terms of energy delivered to the wheel, with vast emission reduction potential. A shift to fuel cell trucks for the entire copper production industry and half of the iron ore production industry could mitigate an estimated 1.2 MtCO_{2e} annually, corresponding to about 3.5% of national GHG emissions in 2014, at an abatement cost of approximately 10 USD/tCO_{2e}.

Due to the current lack of other feasible mitigation options for transport vehicles in the mining sector, a shift to green hydrogen technologies appears not only affordable but also necessary to achieve decarbonisation of the sector. Technology specific policies such as the allocation and distribution of public finance for R&D and piloting are required to move towards this potential. Public-private partnerships could test and demonstrate the technology to build interest among private stakeholders.

Green hydrogen may be one of several technology options for public transport in Ulaanbaatar.

A shift to fuel cell buses for public transport in Ulaanbaatar would be only 15% more expensive than purchasing and operating new diesel buses. Switching the full fleet of public buses in Ulaanbaatar to fuel cell technology could mitigate about 39 ktCO_{2e} annually, at an abatement cost of above 100 USD/tCO_{2e}.

Green hydrogen is not the only promising technology option for the decarbonisation of the public transport sector in Ulaanbaatar. In this case, technology-neutral policies which incentivise various decarbonisation technologies equally can be used to engage the private sector to identify the most suitable technology. In the case of the transport sector, such policies could include tax exemptions, purchase grants and vehicle emission standards. Alternatively, the comparatively small-scale nature of the sector could make for a useful demonstration project to support the further development of green hydrogen technologies for other applications, as well as in neighbouring countries.

Green hydrogen for decentralized heating is not a cost-effective option in the near-term. Using LPG as a benchmark fuel, a shift to green hydrogen for heating and cooking in decentralized heating systems would be 148% more expensive in 2020. As such, green hydrogen is not considered an economically feasible decarbonization option for that purpose, at present.

Nevertheless, the heating sector remains one of Mongolia's most emissions intensive sectors and will require further research efforts weighing various potential decarbonization technologies against each other. In such technology portfolio, green hydrogen should not be immediately ruled out, but should be evaluated along with other novel heating technologies in conjunction with the aim to phase out fossil fuels in the sector.

Ambitious national-level climate and energy targets can support technology development.

Beyond sector specific policies, economy wide policies such as net-zero emission targets and clean fuel targets will be important instruments to send clear signals to the private sector, and to further stimulate interest in the application of novel technologies.

1 Introduction

Mongolia is heavily reliant on fossil fuels and faces challenges in decarbonising its hard-to-abate sectors. While being endowed with vast renewable energy resources, the direct electrification of those sectors is technically challenging. A key option beyond direct electrification could be the production and application of green hydrogen. This section gives an introduction to green hydrogen as a decarbonisation option and an overview of the Mongolian context and its energy and climate related policies.

1.1 Country context and introduction to green hydrogen as a decarbonisation option

Traditionally a largely agriculture dependent country with a significant share of the population living in herder communities, Mongolia is experiencing an economy transition led by a growing industry sector and increased urbanisation. As the impacts of climate change are starting to emerge, natural disasters and livestock losses are forcing more people to move into urban locations. In the meantime, the rich mineral resources in the country are being increasingly exploited for economic benefit, gradually shifting the economy from livestock- to industry-centred (Senshaw, 2020). Such transition comes with challenges as well as opportunities for the country to reduce emissions in accordance to its ratification of the Paris Agreement and its long-term goal to keep global temperature rise well below 2 degrees Celsius above pre-industrial levels, and to pursue efforts to limit it to 1.5 degrees Celsius (United Nations, 2015).

Endowed with vast coal resources, the country is dependent on coal for a major part of its energy supply. In 2018, 97% of the total energy supply was sourced from coal and oil (IEA, 2020c). However, on a positive note, the country has rich renewable energy resources, with high solar potential in large parts of the country, and optimal wind conditions found in regions across the country (Batmunkh *et al.*, 2018). Given the country context, Mongolia faces challenges to find low-carbon solutions to decarbonise its carbon intensive sectors, including heat, power and transport. Such efforts will be dependent on the wide integration of clean energy sources, the phasing out of coal and the adoption of innovative technologies. Based on this, the Government has recognized the unconditional need for the wide integration of renewables in the energy supply sector in order to reduce greenhouse gas (GHG) emissions (Government of Mongolia, 2014, 2016, 2020).

On many occasions, the decarbonisation of the global energy supply will to a large extent be dependent on electrification. However, under some circumstances such as poor access to the national grid, extremely cold climates and due to other technical barriers, direct electrification will not be feasible. These sectors are commonly referred to as “hard-to-abate” sectors, and include industry, buildings, heavy freight transport, aviation and shipping. According to a study from IRENA, direct electrification could satisfy about half of global energy needs by 2050. For widespread decarbonisation to be successful, there is thus a recognized need to find alternative solutions to meet the remaining half (IRENA, 2020c). Under such circumstances, alternatives to store clean energy in order to transport and dispatch it on demand need to be considered.

Based on this, and given the intermittent characteristics of variable renewable energies (VREs), energy storage solutions will be a prerequisite to the wide integration of renewable energy in these sectors. VREs offer high production potential under the right climatic conditions and fluctuate within a day as well as seasons. To fully harness this potential, and to meet a growing energy demand, efficient storage of the generated power can provide dispatchable clean energy. There is thus a need for energy storage

solutions to decarbonize hard-to-abate sectors, and in the long term, the wide integration of VREs needed to electrify other sectors will generate vast amounts of excess power which, if not stored, will be curtailed.

Traditional storage solutions such as batteries, pumped hydro and compressed air come with certain drawbacks or limitations related to scalability, long term storage potential and raw material availability (Widera, 2020). Hydrogen has been used globally as an energy carrier since the 1970s, however traditionally using natural gas or coal as the energy feedstock (Hydrogen Council, 2020). Green hydrogen offers a promising alternative to providing dispatchable green energy. By producing hydrogen from VRE sources, it can offer grid balancing solutions, enabling a more efficient and wider use of VREs by delivering dispatchable green energy which can be applied in hard-to-abate sectors (Widera, 2020).

Green hydrogen production could therefore be particularly favourable in countries with the ability to generate cheap electricity from renewables and several countries have drafted strategies to increase its use as one of the necessary tools towards decarbonisation. However, as for any energy conversion process, green hydrogen production means efficiency losses along the value chain and, importantly, direct electrification will always be the more efficient option. The wider deployment of green hydrogen still faces some main barriers including production costs and infrastructure development. To assess the potential value a transition to green hydrogen could bring, sector specific assessments are needed, analysing the techno-economic potential of hydrogen in a particular sector given the country context. Further, the supply side must be analysed to identify the green hydrogen production potential and its expected costs, given context-specific parameters.

This study aims to conduct such assessment in the context of Mongolia. Given its rich renewable energy resources and faced with significant challenges to decarbonise energy intensive sectors such as space heating and heavy freight transportation, hydrogen could be a feasible option to decarbonisation. To do so, a techno-economic modelling exercise is conducted based on sector-specific case studies. The output of the exercise serves as a basis for the identification of a categorisation system, outlining the end-use applications most suitable for hydrogen application in Mongolia. Such priority system is based on economic viability, emission reduction potential and the feasibility of other decarbonization options.

1.2 Policies and targets for the decarbonization of the energy sector and national GHG emission reductions

At present, the Mongolian energy sector is regulated through six energy related laws and three energy policy documents. These include: the National Laws on Energy, Licensing, Renewable Energy, Foreign Investment, Concessions, Energy Conservation; the State Policy on Energy 2015-2030, the Government Action Plan 2016–2020 and the Medium-term Energy program 2018–2023.

Overall, the main objectives of the policies are focussed around three key aspects:

1. Ensuring energy security
2. Ensuring sustainability of energy sector development and to establish a basis for a more rapid take up of renewables
3. To become an energy exporter in the mid-term

Through the State Policy on Energy 2015-2030, these objectives are further contextualized by the definition of specific goals. The Policy is divided into two phases: The first covering the period 2015 through 2023 and the second phase covering the period 2023 through 2030. Related to the first two key aspects, a reliable and secure energy system include the goal of doubling the existing coal capacity. As for technological achievements, various technologies are listed as expected to be used to reach these

goals. With respect to coal, sub-critical and coal bed methane are expected in the first phase, followed by super and ultra-critical technology in the second phase. As for energy storage technologies, battery and pumped energy storage are mentioned in the first phase, while a transition to hydrogen is noted under the second phase. In order to implement the energy policy documents, a medium-term energy program (2018-2023) was implemented in 2018. The program lists several projects to be implemented to achieve the objectives of the policy. Under the scope of renewable energy expansion, an energy storage project of 100 MW capacity is stated, however, no technology is specified.

To ensure that more renewables are added to the system, hydropower should contribute to at least 10% of installed capacity. Further, renewables should contribute to up to 20% of installed capacity by 2023 and to 30% by 2030 (Oyunchimeg *et al.*, 2020). More specifically, there is an aim to install 675 MW of additional hydropower, 354 MW of wind power and 145 MW of solar power under the State Policy on the Energy Sector (2015) (Dugarjav, 2021). Recent positive trends in renewable energy deployment have partly been an effect of some regulative measures implemented through the Renewable Energy Law. Part of the law was the introduction of a feed-in-tariff (FIT) directed at on-grid solar and wind generation. The regulation was first amended in 2015 and most recently in 2019 to reduce the feed-in-tariff and to adjust a renewable auctions scheme that is specific in terms of location, capacity and technology (Hans *et al.*, 2020; REN21, 2020). Such progress has allowed the installed renewables capacity (solar and wind) to reach 17% in 2019, while the share of total gross electricity production was 8% in the same year (Dugarjav, 2021).

In the mid-term (second phase), Mongolia aims to export electricity generated from efficient and environmentally friendly technologies to neighbouring countries. This includes the establishment of collaboration between Russia and China and includes the expansion of installed coal capacity based on domestic coal reserves. With respect to renewable capacity, abundant solar and wind resources in the Gobi desert are to be exploited through the implementation of the Gobitech project, which is part of the Asian Super Grid Initiative, aiming to export electricity to North-east Asian countries (Oyunchimeg *et al.*, 2020).

In terms of climate change impacts and GHG emissions, Mongolia submitted its first National Determined Contribution (NDC) to the UNFCCC in 2020 in which it commits to a 22.7% reduction of national GHG emissions by 2030 compared to projected emissions under a business-as-usual scenario. Adding to that, additional conditional measures such as carbon capture and storage and waste-to-energy technology, Mongolia could achieve GHG reductions of 27.2% by 2030. The targets presented in the NDC are in line with the national development policy documents and are to be reached through mitigation actions in the energy, agriculture industry and waste sectors.

As such, green hydrogen is not yet explicitly part of the Mongolian energy or climate policy framework but could potentially be one among other tools to achieve its renewable energy and emission reduction targets. This potential is further investigated in this study.

1.3 Aim and objectives

This study aims to identify the potential and feasibility of power to green hydrogen as a decarbonisation option in Mongolia. It further aims to provide a basis for energy planning and policy through the careful analysis of the value chain feasibility of different power to green hydrogen applications in the Mongolian context.

The study aims to do so through answering the following questions:

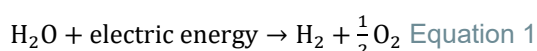
- What is the techno-economic potential of green hydrogen production and end-use applications in Mongolia?
- What are the requirements and opportunities for the development of the energy sector to unlock this potential?
- What are the potential impacts of policy support for technology implementation?
- What policy options can create enabling conditions and foster implementation?

2 Setting the scene – Green hydrogen as a decarbonisation option

Green hydrogen is increasingly seen as a key component of a decarbonised future. Although the extent of its final contribution is still to be determined, efforts to reduce its production costs and its technical integration into sectoral applications are rising. This section gives a brief introduction to hydrogen production methods and the key barriers to the widespread use of green hydrogen.

2.1 Green hydrogen production methods

Hydrogen was first introduced in large scale processes in the 1910s for ammonia synthesis and is thus not a new energy feedstock (Pudlik, Seyfang and Franke, 2021). What is different in the current discourse is the shift toward green hydrogen use. Historically, hydrogen has been produced using fossil fuels (typically natural gas and coal) to be used in certain applications such as in industries reliant on hydrogen as a reduction agent. Today, around 96% of hydrogen is still produced from fossil fuels with various levels of carbon intensity (IRENA, 2020c). Hydrogen is typically classified as grey, blue, turquoise or green, depending on the energy source and production route. Grey hydrogen refers to hydrogen produced from methane or coal through steam methane reforming or gasification, while blue hydrogen is sourced from the same components as grey, but the process is equipped with carbon capture and storage (CCS) technology. Hydrogen is considered turquoise if it is produced from methane through pyrolysis. The only type of hydrogen which can be considered completely fossil free is green hydrogen as it is produced through electrolysis with electricity exclusively generated from renewable energy sources (IRENA, 2020a). Green hydrogen is produced from water through the chemical process of splitting water molecules into hydrogen and oxygen as presented in $\text{H}_2\text{O} + \text{electric energy} \rightarrow \text{H}_2 + \frac{1}{2}\text{O}_2$ Equation 1.



The process is driven by electricity and facilitated by an electrolyser. By using clean electricity as energy input in that process, no greenhouse gases are emitted, and the hydrogen can be classified as carbon neutral. Depending on the end-use application, hydrogen can be used directly, or be transformed into other energy carriers (Figure 1). Using it directly, hydrogen can be dispatched in a fuel cell to generate electricity on demand. Hydrogen is also used directly as a chemical feedstock in industrial processes.

Further, through several different processes, using carbon as an input (typically CO_2), hydrogen can be used to produce synthetic fossil fuels (synfuels), which can substitute conventional fossil fuels - for instance in the mobility sector. This process is generally referred to as Power-to-Liquids (PtL). The CO_2 used in the synthetic fuel production process can come from three main sources, namely direct capture from the atmosphere, flue gas capture from industrial processes, or biomass hydrogenation. Each of these sources face individual challenges related to sustainability, technological potential and costs. As the carbon stored in the synfuel will be recirculated to the atmosphere when it is combusted, the carbon must come from sustainable sources in order to be classified as carbon neutral. As such, recycled carbon from flue gases originating from fossil fuelled plants cannot be considered to be carbon neutral. Moreover, generating uses of such flue gases could create revenue streams from fossil fuel driven processes, resulting in perverse incentives for fossil fuel consumption. Instead, sustainable synfuels will need to be generated using carbon either from direct air capture or from biomass hydrogenation using sustainable biomass. These two processes face barriers in terms of technological development, costs and sustainable biomass supply.

Hydrogen can also be converted to ammonia (NH_3), using Nitrogen (N_2) captured from atmospheric air. This process is generally referred to as Power-to-Ammonia (PtA). Ammonia has several end-uses, including as a chemical feedstock in industrial processes or as a fertilizer (as ammonium nitrate). As hydrogen is somewhat unpractical to transport over long distances, ammonia can also serve as an energy carrier for hydrogen. For final use it can undergo a catalytical re-conversion to N_2 and H_2 , and can also be used directly for energy purposes in solid oxide fuel cells, internal combustion engines (ICEs) or in gas turbines (Giddey *et al.*, 2017).

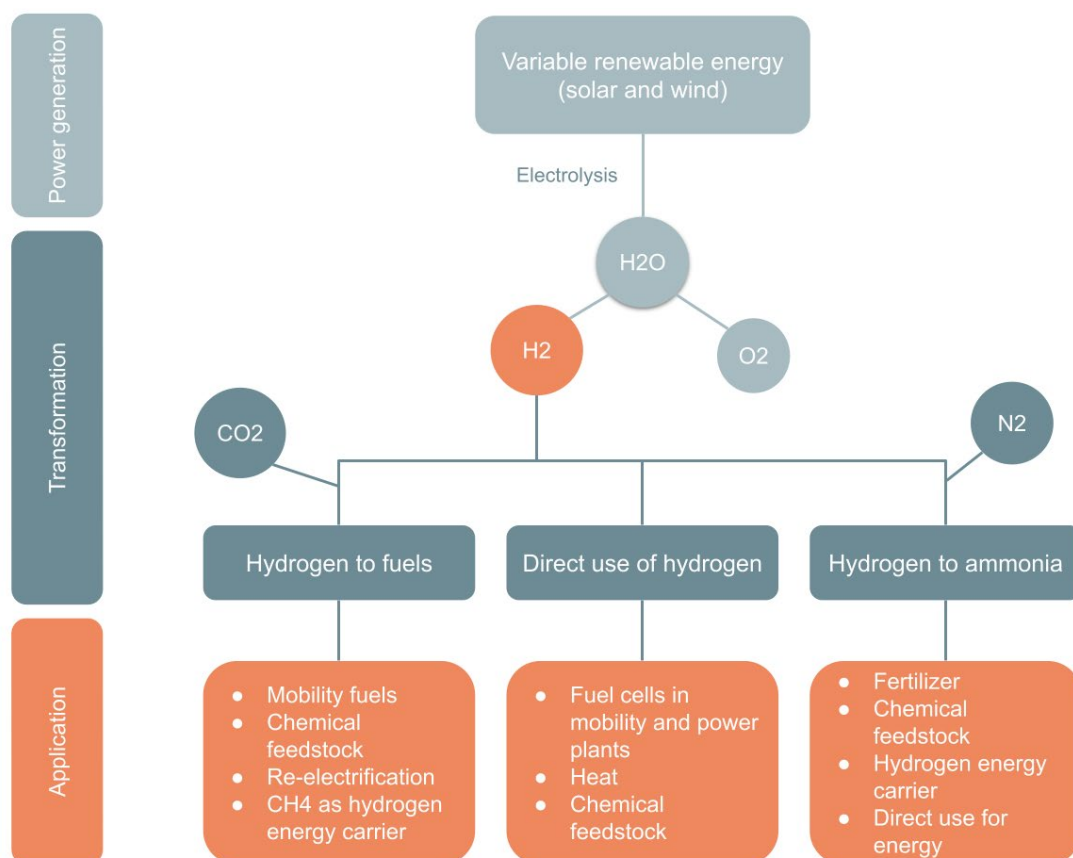


Figure 1. Green hydrogen production and end-uses.

2.2 Barriers to the widespread deployment of green hydrogen

A set of favourable features often comes with a set of drawbacks. Its many end-use applications, conversion possibilities and ability to store energy over long periods of time makes green hydrogen a flexible energy carrier. In addition, its high energy density in some cases makes it favourable to other storage options such as batteries. Nevertheless, several key barriers limits its applicability and efficient use (IRENA, 2020c). This section provides an overview of the main barriers faced by the deployment of green hydrogen.

Economic barriers

The main barrier to the widespread deployment of green hydrogen is its cost competitiveness to fossil fuels and can be tied to four main factors; renewable power generation costs, the capacity factor at which plants run, the cost of electrolyzers and transportation costs (Liebreich, 2020). While the cost of electrolyzers is important, recent studies show that the cost of renewable power generation is the most critical factor with regards to the cost competitiveness of green hydrogen (Liebreich, 2020). Further, the

relevancy of the electricity price on the final hydrogen price per kilogram is directly linked to the capacity factor of the plant.

A low capacity factor means fewer hours of full capacity hydrogen production, which decreases the hydrogen output. That means that there will be fewer hydrogen units to which the investment cost of the electrolyser can be distributed. An increased capacity factor would thus increase the hydrogen output and decrease the impact that investment costs of the electrolyser have on the final hydrogen price. Therefore, with a higher capacity factor, the electricity price will have an increasing impact on the final hydrogen price. Today's rather high electrolyser investment costs¹ therefore require relatively low electricity prices (around USD 20/MWh) for green hydrogen to be able to compete with grey hydrogen (IRENA, 2020a).

The capacity factor at which a plant can be run is dependent on the quality of the renewable energy resource. For this reason, green hydrogen production will be most cost-efficient when it is produced at locations with high quality solar and wind resources, and particularly when you can combine the two. But the type of electrolyser also influences the overall capacity factor. Today, two different types of electrolyzers are most widely used: Alkaline and Proton-Exchange Membrane (PEM) electrolyzers. The alkaline electrolyser technology is more mature and has lower production costs. However, it requires a more stable pace and is difficult to ramp up and down to follow peaks and troughs in electricity supply. The PEM technology is less developed but can more easily follow an intermittent electricity supply. Depending on the load factor and the type of electrolyser used, the overall efficiency of these systems currently ranges between 60% and 81% (IEA, 2019). The technological status and characteristics of electrolyzers is further discussed in the end of this section.

Renewable electricity costs continue to plummet and are increasingly cost-competitive to fossil-based electricity generation. In most parts of the world, not considering external costs, renewable electricity is today cheaper than generating electricity from a new coal power plant, and in many places cheaper than operating existing coal power plants (REN21, 2020). Under optimal conditions, wind and solar plants generate power at about USD 15/MWh with a continuing declining trend. Even at a cost of USD 20/MWh, the cost of solar and wind corresponds to about one third of the cost of power from other sources (Liebreich, 2020).

As has been seen with wind and solar energy in recent years, falling cost trends are also seen for electrolyzers with observed cost reductions of just below 20% per each doubling of capacity. Between 2014 and 2019, the cost of North American and European alkaline electrolyzers fell by 40%. Even more progress is observed in China, where costs are about 80% lower compared to those in the West (Bloomberg New Energy Finance, 2020). With improved process efficiencies and system optimisation, prices are expected to continue to fall in the near- to mid-term. The Hydrogen Council estimates that electrolyser investment costs will fall by 60%-80% by 2030 through large-scale manufacturing and further technology improvements (Hydrogen Council, 2020).

Driven by these improvements, prices for hydrogen production are falling. According to a recent study by Bloomberg New Energy Finance (BNEF), green hydrogen could become a competitive option to current natural gas prices in various regions globally by 2030, in terms of energy units (Bloomberg New Energy Finance, 2020). Further, a study by IRENA suggests that green hydrogen production costs have the potential to reach 1-3 USD per kilogram of hydrogen in the medium to long term, compared to current production costs of 2.6-6.7 USD/kg of hydrogen. Such improvement would make green hydrogen competitive to blue hydrogen (IRENA, 2020c). Another study by the Hydrogen Council suggests that, under optimal renewable power generation conditions, prices could reach 2.5 USD/kg in the early 2020s,

¹ About USD 750-800/kW as of 2020 for alkaline electrolyzers

declining to 1.90 USD/kg by 2025 and possibly to 1.20 by 2030 (Hydrogen Council, 2020). That is, under optimal wind and solar conditions, further deployment of renewable energy and improved hydrogen production efficiency, green hydrogen could become cost competitive to blue hydrogen already by 2025.

Nevertheless, the final price of green hydrogen is not only dependent on optimising the production, but also its storage and transportation, which faces some significant barriers. The additional storage and transportation costs will mainly vary depending on the volume, distance and energy carrier used, which are discussed in detail in the next subsection.

Storage and transportation

Depending on the location and the end-use application of the hydrogen, there are various ways to store and transport hydrogen, of which some are more efficient than others. Under atmospheric conditions, hydrogen is stored as a gas in high pressure tanks in underground storage or as a liquid at low temperatures. However, due to its low density, its storage and transportation is significantly more complex than that of fossil fuels since the compression of the gas requires additional energy. Without converting the hydrogen to alternative energy carriers, hydrogen is compressed and stored in tanks which are transported in trucks. It can also be transported as a gas in pipelines or converted into other energy carriers such as ammonia for more practical transportation.

Because of its low density, the transportation of compressed hydrogen has proven less suitable for longer distances. Under such circumstances, a potentially more attractive option is the possibility to convert hydrogen into more practical energy carriers such as ammonia or synthetic fuels. Although each such conversion step requires additional energy, those efficiency losses can be offset by the gains made from the more efficient transportation for larger distances.

Liquification of hydrogen is possible and requires less storage volume but comes with increased energy needs; Under atmospheric conditions, hydrogen liquefies at temperatures below -253°C. Given the high cooling and compression requirements entailed, liquification of hydrogen is often more costly than its actual production (Bloomberg New Energy Finance, 2020).

The most efficient mode of transporting hydrogen over large distances, however, would be via pipelines. This could particularly be a feasible option in regions with an already existing pipeline infrastructure. Technically, existing gas infrastructure could be used for hydrogen transportation, albeit with some retrofitting of the pipeline system needed (IRENA, 2020c). In regions where gas infrastructure does not already exist, that option could be more of an economic and timely challenge, perhaps more suitable as a long-term objective or for countries aiming for large scale production and hydrogen export (Hydrogen Council, 2020).

Based on this, the optimal distribution type will be dependent on context specific parameters such as the scale of the production and the proximity to the end-use site. Generally, production of hydrogen close to the end-use site will remain the most efficient way to minimise costs and climate impact, as it reduces the overall need for transportation. From a pure cost perspective, a study by the Hydrogen Council found that compressed gaseous hydrogen is the most cost-effective option for short distances, while for longer distances (300 to 400 km), liquification is more economical (Hydrogen Council, 2020). More specifically, a study by BNEF estimates that compressed hydrogen could be transported for local transportation at a cost of 0.65-1.73 USD/kg of hydrogen, depending on the distance. For inter-city transportation, transportation of compressed or liquified organic hydrogen could come at a cost of 0.96-3.87 USD/kg of hydrogen, while inter-continental transportation of liquified organic hydrogen could range from 3.87-6.70 USD/kg hydrogen (Bloomberg New Energy Finance, 2020).

A different option could be to, instead of transporting the hydrogen, transport the electricity used for the production of green hydrogen. By locating the hydrogen production close to the end-use site, transportation needs can be reduced. Yet, such approach would increase power transmission and distribution costs. Further, it would be dependent on the geographical distribution of optimal renewable energy sources.

Technological barriers – electrolyzers

While there at present are four main electrolyser technologies with varying technological characteristics and level of maturity, two of those are currently most widely used; the Alkaline and the PEM electrolyzers are currently most represented on the market, while the solid oxide (SOFC) and the Anion exchange membranes (AEM) electrolyzers are less developed with only a few companies commercializing them. As each technology faces unique challenges, there is yet no clear preferable option (IRENA, 2020b). The main overall challenges with respect to electrolyzers include costs, scalability, and overall efficiency. Table 1 provides an overview of the key characteristics of these technologies, including their level of maturity, its advantages and disadvantages.

Table 1. The key characteristics of available electrolyser technologies.

Electrolyser	Maturity	Advantages	Disadvantages
Alkaline	Commercialised	<ul style="list-style-type: none"> • Relatively easy to manufacture • Long lifetime 	<ul style="list-style-type: none"> • Cannot easily be ramped up and down to follow variations in electricity supply • Lower efficiency compared to other electrolyzers
PEM	Commercialised	<ul style="list-style-type: none"> • High efficiency • Flexible – can operate more reactively to intermittent power supply • Can be designed to be overloaded for some time (160% of its capacity) 	<ul style="list-style-type: none"> • Requires Titanium-based materials, noble metal catalysts and protective coatings, which drives up the cost of the technology • Scalability and lifetime have yet to be validated
SOEC	Lab scale	<ul style="list-style-type: none"> • Requires cheaper materials and less electricity • Waste heat can be recovered to meet part of the energy demand • Can be operated reversely as a fuel cell • Suitable for the production of synfuels 	<ul style="list-style-type: none"> • Shorter lifetime compared to other electrolyzers • Technological barriers still need to be resolved
AEM	Lab scale	<ul style="list-style-type: none"> • Holds the combined advantages of Alkaline and PEM electrolyzers • Simple design with high efficiency • Does not require noble materials 	<ul style="list-style-type: none"> • Still faces some technological barriers

In terms of costs, Alkaline electrolyzers are currently the most cost-efficient technology, although the cost of PEM electrolyzers has gone down in recent years and is likely to continue to do so (IEA, 2019). The higher cost of the PEM electrolyser can partly be explained by its noble material requirements. The SOEC technology uses ceramics as the electrolyte and has therefore relatively low material costs (IEA, 2019). However, in addition to material costs, the electrolyser lifetime impacts the overall cost-efficiency of the electrolyser. In this respect, the Alkaline has the advantage of having a longer lifetime compared to the PEM electrolyser, which is expected to remain the case over the coming decade (IEA, 2019).

To further bring down electrolyser costs and to overcome technical barriers, scaling of electrolyser systems is required. Plant scales have increased by an annual factor of ten since 2015. Typical plants sizes today range from 0.1 MW – 1 MW, while several projects at 10 MW - 20 MW are emerging and plants in the range of 100 MW – 200 MW are being discussed (IRENA, 2020b).

Water quality and availability

As water is an essential feedstock in hydrogen production, an assessment of water availability and quality should be part of any green hydrogen project or strategy, particularly in water-stressed regions. On a stoichiometric basis, 1 kg of hydrogen requires about 9 kg of water (Oesterholt *et al.*, 2016), and produces about 8 kg of oxygen as a by-product (IEA, 2019). However, water is also typically used as a cooling agent in the electrolysis process, which increases the overall water demand. According to an IRENA study, taking into account water requirements for additional aspects such as cooling and water demineralisation, the overall consumption per kg of hydrogen typically ranges between 18 kg and 24 kg (IRENA, 2020b). However, a recent study finds that the water requirements vary substantially under different assumptions, and that it could range between 22 and 126 litres per kg of hydrogen when producing green hydrogen with electricity generated from solar PV as water is also required for cleaning the panels (Shiab, Liao and Li, 2020).

In addition to the aspect of water quantity, the water going into the electrolysis process also requires a certain water quality. The water entering the process needs to be deionized and is typically pre-treated to ensure a high level of purity (Oesterholt *et al.*, 2016). Depending on the type of electrolyser used, the required purity level of the water differs, yet impure water could affect the lifetime of the electrolyser significantly and thus also impact the price of hydrogen (IRENA, 2020b). Nevertheless, the water purification cost has low sensitivity to the price of hydrogen and is typically close to USD 1/m³, corresponding to about USD 0.01/kg of hydrogen (IRENA, 2020b).

Although water requirements for green hydrogen can become significant and pose a limiting factor in water stressed areas, there may be solutions to overcoming those depending on the regional context. Hydrogen consumed in fuel cells, in stationary applications or for transportation purposes, produces pure water as a by-product which could be recollected. In regions where seawater is accessible, desalinated water can be used for hydrogen production (Dresp *et al.*, 2019). In locations where that is not an option, the transportation of water via pipelines could be a viable solution, although careful water availability assessments should be part of any green hydrogen project to ensure the sustainability of the project from a water balance perspective.

3 Role and implications of hydrogen as decarbonisation option in Mongolia

This section investigates the potentials, role and impacts that hydrogen production and consumption could have in the Mongolian energy sector and in a selection of end-use applications. The introduction of a new energy carrier into the energy mix leads to structural changes along the supply chain, not only in how energy is consumed but also on how energy is produced and transported.

On the supply side, we analyse hydrogen production in terms of its direct impact on the functioning of existing power and heat systems, the importance of renewables potentials and water resources and their geographical distribution, as well as the implications for energy security (Section 3.1).

On the demand side, we examine the implications of hydrogen in terms of its use and impacts on a selection of hard-to-abate end-use applications in Mongolia, including heavy-duty transport in the mining sector, public transportation and heating in the building sector (section 3.2). The aim of such analysis is to investigate the potential for a wider expansion of green hydrogen in those sectors, with the main purpose of achieving decarbonisation.

The study looks exclusively at the green hydrogen supply and demand sides. As such, the storage and transportation of hydrogen is not part of the scope. As Mongolia does not have an existing pipeline infrastructure, the development of such is not considered an economically viable option in Mongolia and hydrogen would thus need to be transported by road.

A study by Fraunhofer ISI was commissioned for this report (Pudlik, Seyfang and Franke, 2021) to quantitatively estimate the techno-economic feasibility of hydrogen in the Mongolian context. The exercise applies the Enertile model (Fraunhofer ISI, 2021) to assess the potential and develop cost estimates for renewable energy generation and green hydrogen production accounting for local and regional circumstances, including water cost projections. The results of these calculations for three sector case studies are incorporated in the following sections. As only green hydrogen is considered, a particular type of electrolyser with defined maximum power and part-load operation is defined as the reference. These sector case studies are tailor-made to the potential demand situation for hydrogen in Mongolia and are compared to alternative scenarios where the incumbent or alternative energy carrier is used. The comparison is based on the production cost of energy available to the end-user, without considering intermediary trade margins or hydrogen transport infrastructure needs, unless indicated otherwise.

3.1 Supply side

The energy sector is Mongolia's largest contributor to GHG emissions, accounting for almost 54% of the country's emissions in 2018 (excl. LULUCF) (Gütschow, J.; Günther, A.; Jeffery, L.; Gieseke, 2021). According to its updated Nationally Determined Contribution (NDC), mitigation measures on the energy supply side cover 49% of the total GHG emissions reductions by 2030, mainly through increased use of renewables and reduced utilisation of combined heat and power (CHP) plants (Government of Mongolia, 2020). In addition to those measures, the production and utilisation of green hydrogen could play a role in the decarbonisation of the energy system in Mongolia. Green hydrogen, however, is not mentioned as a potential mitigation measure in the NDC.

Efforts to develop a green hydrogen sector in Mongolia and the analysis of its costs and benefits should not be undertaken in isolation, but as part of a broader system and as a complement to other

decarbonisation solutions. Moreover, in addition to its climatic benefits, green hydrogen production could bring other non-emission benefits to the energy system that should be incorporated into its analysis. Ignoring the implications and interactions of hydrogen in a broader systemic sense may limit or discourage its development and hinder the definition of ambitious strategies for the decarbonisation of the energy system.

This section discusses the impacts and interactions that green hydrogen production could have for the energy supply from three angles: implications for the heat and power supply, effects on the grid depending on its configuration regarding grid connection (i.e. grid connected vs. off-grid), and implications for energy security. This section also investigates the relevance of water supply.

Heat and Power supply

Heat and power supply is the main energy use in Mongolia. The potential impacts the deployment of green hydrogen could have on Mongolia's heat and power sector are investigated in a qualitative and quantitative manner. The analysis finds that the rich renewable resources in Mongolia can generate electricity to affordably power electrolyzers for green hydrogen production, and that these can be configured as part of a hybrid system that is also connected to the electricity grid, or as stand-alone applications for off grid use in remote locations. We also find that priority should be given to scaling up renewable capacity to gradually decouple heat and power production.

Mongolia's electricity system and heat supply are closely coupled. The power generation fleet is dominated by coal-fired combined heat and power (CHP) plants. In 2019, coal-fired CHP plants generated 90.6% of the electricity while the remaining 9.4% came from wind, hydro, PV and diesel, (Energy Regulatory Commission of Mongolia, 2020a). The generally inflexible CHP plants in Mongolia operate mainly to satisfy the heat demand - not power demand – which is particularly high during the winter months. This system is particularly problematic as the heat and power demands are not necessarily aligned. In its latest NDC, the Mongolian government highlighted the reduced internal use of CHP plants as one of the mitigation actions to reduce GHG emissions (Government of Mongolia, 2020).

Mongolia's power supply sector consists of five power systems: Western, Altai-Uliastai, Central, Eastern and Southern power systems. The interconnection between power systems is limited due to long distances and low capacity of the lines and can therefore not be operated as one power system. The central power system, which includes Mongolia's largest city Ulaanbaatar, consists of seven CHP plants for base-load operation. The Central, Western, and Eastern power systems are connected to the Russian power grid, allowing for power imports.

The strong coupling between heat and electricity supply in Mongolia presents a key technical challenge to significantly decarbonise either sector. A gradual decoupling of the sectors could facilitate the adoption of solutions and technologies targeted to decarbonise each sector individually, in which green hydrogen could contribute.

In contrast to CHP plants, which generate heat and power simultaneously, green hydrogen production would allow to decouple electricity production (from renewable resources) from heat consumption. The progressive installation of hydrogen plants could enable to gradually decouple both sectors and untap solutions targeted to decarbonise each sector individually. Moreover, the restoration of heat infrastructure (including heat generation and transmission) is an opportunity to look for alternatives that reduce GHG emissions in the sector. The potential of hydrogen to supply heat should be factored-in among the alternatives to modernise the infrastructure of the sector.

The district heating system in Mongolia, which serves most of the urban buildings, is old and unreliable, having some heating plants operating past their intended lifetime (Carlisle and Pevzner, 2019). Many transmission lines are in urgent need of restoration, resulting in high system losses. The current coal-reliant heating system contributes to substantial GHG emissions, exacerbated by the inefficient transmission network and poorly insulated buildings.

The role of hydrogen in the decarbonisation of the heat supply varies depending on the end-use of heat (e.g., centralised building heating, decentralised heating, industrial heating). The potential use of green hydrogen for heating and cooking in Mongolia are further analysed in section 3.2.

Although green hydrogen could facilitate the decarbonisation of the Mongolian heat and power system, its deployment should not limit the uptake of direct renewable energy integration to the energy sector. Instead, its development needs to be carefully planned, considering the whole energy system to ensure additionality.

While the development of a renewable energy industry is key to the production of green hydrogen, the reverse is not true: the development of an industry around hydrogen is not a pre-requisite to develop and integrate variable renewable energy (VRE) sources in the power system. The development (or lack) of green hydrogen should not hinder the scale and speed of renewable energy deployment in the country.

Mongolia has abundant wind and solar resources that could be exploited to reduce air pollution, bolster energy security and decarbonise its power sector. According to the Mongolian government's targets, renewable electricity capacity should increase to 20% in total installed capacity by 2023 and 30% by 2030 (ESCAP, 2015). Despite the rich resources, renewables only represented 9% of total generation in 2019 of which wind was the main contributor of 6.5%, hydro generated 1.5% and solar PV 1% (Energy Regulatory Commission of Mongolia, 2020a). Mongolia has already experienced curtailments of renewable power due to the technical and economic constraints of coal-fired CHP.

The significant inflexibilities in a power system dominated by CHP plants lead to substantial curtailments of renewable energy, undermining the potential of the resources and impacting its attractiveness for investors (see Box 1). The fact that renewable energy project developers are required to bear the costs and risks of curtailments is one of the key reasons why the renewable energy industry has not developed further and fulfilled its potential in the country.

The Mongolian power system is expected to grow in response to increasing electricity demand, which has seen approximately 5% annual growth in the last five years (Energy Regulatory Commission of Mongolia, 2020a). In addition, the existing power plants are becoming obsolete and inefficient due to ageing. The growth in demand and the decommissioning of old power plants require the installation of new generation capacity which provides and opportunity to accelerate the installation of cost competitive VRE capacity without significant impacts on system operation.

Box 1: The value of flexibility in the Mongolian power system.

Power system flexibility in the Mongolian context and its value to decarbonise its energy system

The lack of flexibility in the Mongolian power system is the main reason why VRE sources have not been developed in the country despite its abundance. Flexibility refers to the capability of a power system to cope with the intermittency that solar and wind energy introduce aiming to avoid, or minimise, curtailment of power from these sources while satisfying customer energy demand in a reliable manner (IRENA, 2019b). Most power systems globally count with inherent flexibility, which have allowed them to integrate the first shares of VRE with minimum impact on the operation and reliability of the systems. That includes, for instance, flexible generation, flexible markets, or interconnections (De Vivero-Serrano *et al.*, 2019). Significant investments in, and structural changes

to the system aiming to boost flexibility are typically only needed to integrate high generation shares of VRE (e.g. more than 20-30% share).

Mongolia, on the contrary, faces flexibility limitations which challenges the incorporation of even modest shares of VRE to the system. The main causes of the high level of inflexibility in the Mongolian energy system can be summarised as follows:

- **Limited interconnection:** The limited interconnection capacities between regions reduces the capability of the system to balance fluctuations in the supply and demand of electricity using resources available in a wider geographical area.
- **Inflexible generation:** The dominance of CHP plants in Mongolian energy system, which operate mainly to follow heat demand, not electricity, reduces the flexibility in the operation of generation plants to respond to changes in electricity demand or fluctuation from other generation resources (e.g., wind or solar). The production of electricity driven by heat demand also lead to low capacity factors of the existing generation fleet. On average the installed capacity in 2018 ran 2560 full load hours, indicating a rather low utilisation.
- The **lack of financial resources** in the sector also poses a problem in the operation and maintenance of equipment in the power system. The reduced efficiency or outdated condition of some parts of the power system also reduces the flexibility in the system.

An inflexible system results in high risks of curtailments even at low shares of VRE, impacting the financial attractiveness of the renewable energy projects that carry the economic burden of the generating less electricity, which makes the technologies more costly.

The inflexibility of the system in Mongolia exacerbates the dependence on expensive imports to meet the demand when it is too high. Similarly, CHP plants must run at full capacity even when the electricity demand is low in order to meet the heat demand. This results in electricity curtailments from renewables or the need to export electricity at very low prices, or even in negative prices if allowed by bilateral trading.

The implications of hydrogen production in the power sector differ depending on the configuration of the electrolyser with respect to the grid, i.e., if it is connected to the main grid, interactions with on-site VRE power generation, or a stand-alone configuration next to the main hydrogen end-use (Figure 2).

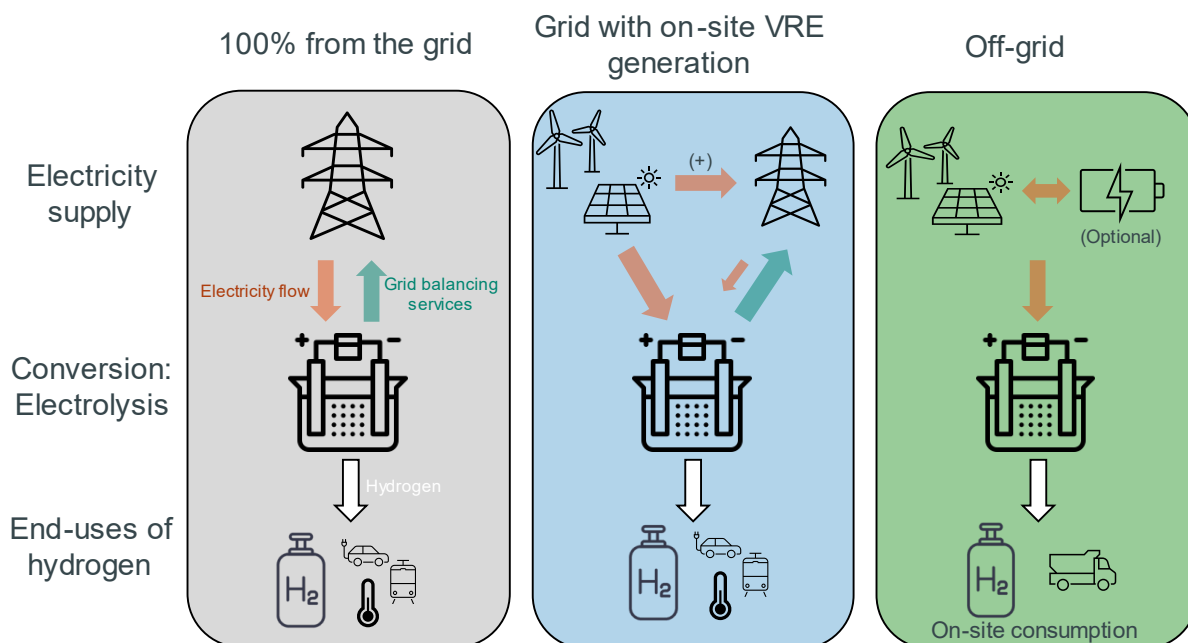


Figure 2. Alternative configurations of hydrogen production with respect to the power grid².

Electrolysers supplied with on-site variable renewable energy but connected to the grid is the most suitable configuration to minimize the carbon intensity in the production of hydrogen in Mongolia while delivering flexibility benefits to the grid.

This configuration is more advantageous when it is close to the major demand centres and it is limited to locations with grid access, rather than locations with rich renewable resources (middle column in Figure 2). Other benefits of this configuration include:

- Absorb excess of electricity from the grid when the system cannot reduce its production due to inflexible CHP or when other sectors cannot consume it, minimising curtailments and cheap exports.
- The grid can be used as a 'battery' to compensate the fluctuation of the on-site VRE power generation of the hydrogen system. This means injecting VRE to the grid when there is an excess of on-site generation and withdrawing electricity from the grid to keep the minimum production of hydrogen. However, excess on-site renewable generation would also be curtailed when it coincides with excess supply to the grid.

However, to produce green hydrogen, the electricity supply needed for the electrolysis must come from on-site VRE generation, not from the main grid. Consequently, the design and sizing of VRE and electrolyser capacities should be tailored to the consumption and profile of end-uses of hydrogen, not to the grid.

This intermediate configuration allows for the deployment of VREs in Mongolia for both grid-connected and off-grid systems, and enables a feasible alternative to produce green hydrogen targeted to decarbonise a specific end-use sector. For these reasons, and given the Mongolian energy sector context, the quantitative assessment of the potential of hydrogen in Mongolia is based on a configuration where the electrolyser is connected to the grid, but the main electricity supply comes from on-site VRE.

² Note that to be considered green hydrogen, the electricity needs to come 100% from renewable resources. Thus, the option in the left cannot be considered as green hydrogen in the Mongolian context

Stand-alone green hydrogen production could be an alternative to decarbonise carbon-intensive applications in remote locations.

Another alternative to green hydrogen production is through the application of off-grid power supply and could particularly be useful in locations with no or poor access to the grid. This configuration comes with various implications. A stand-alone configuration is an alternative when the use of hydrogen is the only alternative to decarbonise carbon-intensive activities in remote locations (e.g., energy uses in the mining sector). Under such circumstances, green hydrogen must be produced on-site because the electricity grid or gas pipeline expansions are not alternatives from both technical and economic perspectives. The high investment costs and electrical losses to bridge long distances do not justify the benefits of connecting the hydrogen production to the grid. Therefore, low-carbon off-grid energy systems will remain important.

The first advantage of a stand-alone configuration is that it allows to build a 100% green hydrogen production system from the start, and it enables the increased participation of renewable energy in the total energy supply without being limited by the inflexibility of the current power system. Off-grid configurations can thus enable reaching higher shares of VRE in the national energy mix than if integrated to the national grid.

However, such system also comes with a set of negative implications that should be taken into consideration before opting for a stand-alone configuration. The cost structure, scale, and design of the hydrogen system (i.e., electrolyser plus VRE generation) should account for the renewable generation profiles and tailor the consumption patterns of the hydrogen end-use. In some cases, batteries might be needed to optimise the utilisation of the resources. Therefore, the costs and benefits of a stand-alone hydrogen system should also be compared with other zero-carbon alternatives in remote areas.

Fully grid-powered green hydrogen production is not an option in Mongolia due to the high shares of coal in the energy mix. However, a grid-connected electrolyser adds flexibility to the system, such as providing grid balancing services.

Producing green hydrogen exclusively using electricity from the national grid (left column in Figure 2) is not feasible in Mongolia as it would need to immediately upscale the installation of renewable energy to the grid and develop ambitious plans to substantially increase their future participation.

From an economic perspective, the real burden is not the technology cost of VREs, but the costs associated to its integration, e.g., grid reinforcement, expansion to reach regions with rich renewable energy resources, retrofitting of existing power generation fleet or the installation of new flexible power plants. As long as the situation of inflexibility in the power system prevails, the generation of green hydrogen supplied with VRE power from the main grid is technically challenging and it would entail high costs, making it an unrealistic alternative.

However, the production of hydrogen using electricity from the grid can deliver flexibility to the system. The value of hydrogen in the Mongolian power system could therefore go beyond the decarbonisation of end-use sectors and facilitate VRE integration. The role of hydrogen in facilitating the integration of VRE is typically discussed in the context of very high shares of VRE penetration. This is mainly due to hydrogen's capacity to store energy during long periods of time which compensates for seasonal differences between power demand and renewable resources availability (e.g. generate hydrogen with abundant VRE in the summer; storing it and produce electricity with it during high demand in winter). This is not the case in Mongolia, which struggles to integrate even modest shares of VRE.

Hydrogen production with electrolysis has other attributes that could support Mongolia to integrate the first shares of VRE and facilitate its growth. Besides reducing curtailments, an electrolyser can provide

grid-balancing services via active demand response. Electrolysers can ramp up and down rapidly as a flexible load in response to grid needs such as to compensate the fluctuation from VREs (IRENA, 2019b). In power system operation this is called frequency regulation, an essential grid service to maintain a reliable system. The lack of frequency regulation in Mongolia has hindered the participation of VRE in the system. An electrolyser connected to the grid can start bringing flexibility into the system and facilitate the integration of the first shares of VRE, leading a semi-simultaneous development of hydrogen and renewables in the power system. The reduction of curtailments and the improvement of frequency regulation make renewables more attractive to private investors. Further, green hydrogen production can benefit from an increased participation of VRE in the generation mix.

But hydrogen is only one among other options to provide flexibility to the energy system and facilitate the integration of renewable energy in Mongolia. Its value assessment should be done in parallel with other clean and flexible options available. For instance, a utility-scale battery storage is planned for Mongolia and it is expected to provide frequency regulation to integrate additional renewable energy capacity into the grid (ADB, 2020b).

Renewable energy modelling shows that Mongolia can produce affordable power to its electrolysers.

The Enertile model, a software used for the computational analysis of electricity systems and their linked energy services (Sensfuß and Pfluger, 2021), is used as the basis for the case studies presented in this report. The country is divided into almost 37,000 tiles with a size of 42.25 km², which in turn are aggregated into four regions, as presented in Figure 3 (Pudlik, Seyfang and Franke, 2021). Full load hours of both wind and solar PV generation are considered to calculate generation potential and costs for each of the four regions. Land use factors are included in the model and account for geographic considerations such as slope and buffer zones around settlements and cities.



Figure 3. Division of four regions to assess their renewable energy potential in Mongolia.

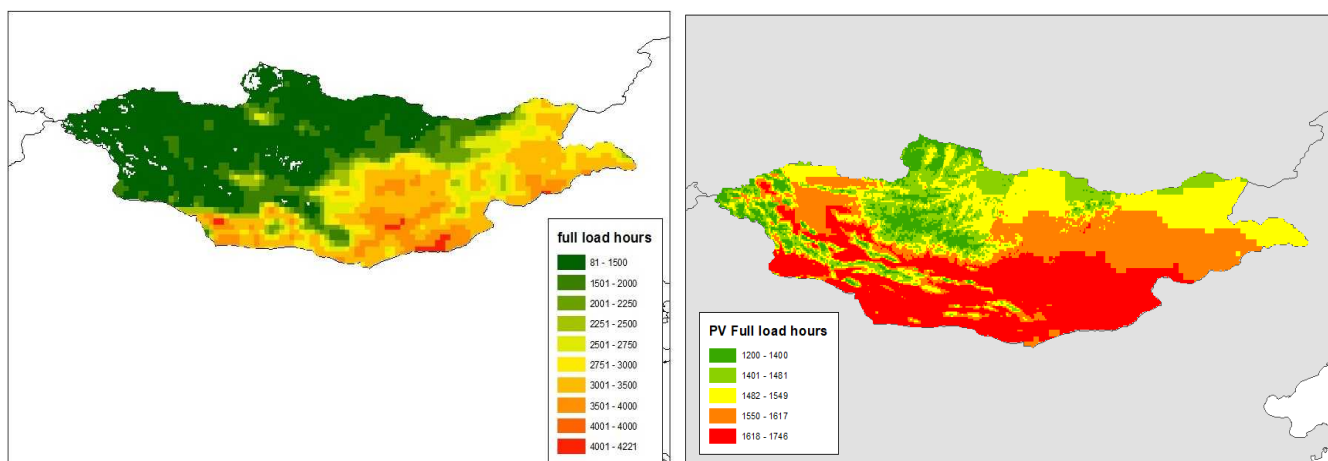


Figure 4. Potential full load hours for wind (left) and solar PV (right) generation.

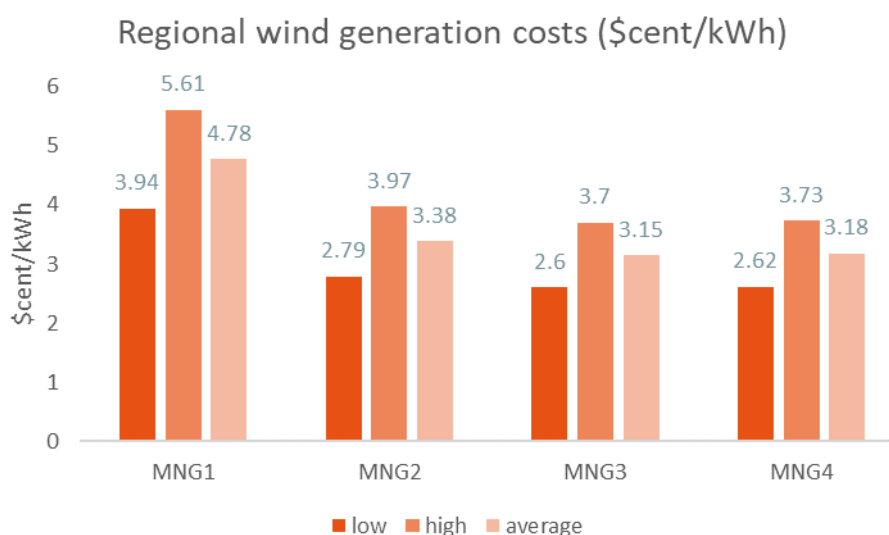


Figure 5. Electricity generation costs for wind power across Mongolia in 2020, divided into four key regions.

The results of this modelling exercise indicate that the potential for wind energy is significantly larger in the south of the country, where electric output can reach as high as 4,200 full load hours, resulting in costs as low as 3.7 \$cent/kWh, as shown in Figure 5. For PV, the picture is more homogeneous, considering the good overall irradiation as well as the efficiency gains from low average temperatures in the country. Generation costs are then set at 4.9\$cent/kWh (considering 1150 \$/kWh and a maintenance effort of 1.5% of the generation costs). It is important to note that these costs do not include necessary grid and road connections, as well as any margins for operators. These modelling results are used in the following sections to derive hydrogen production costs and its eventual use in the three sector case studies.

Energy Security

The development of a green hydrogen sector is likely to have impacts on Mongolia's energy security. Those impacts are qualitatively analysed, suggesting that the introduction of green hydrogen into the national energy mix could improve its energy security, reduce curtailments and the dependence on costly imports by improving the country's system flexibility. Further, the current coupling of the heat and power supply and its heavy reliance on coal make it unfeasible to deploy large scale green production for export purposes in the near- to mid-term.

The development of a green hydrogen sector in Mongolia could improve its energy security by diversifying energy sources, reducing dependence on costly energy imports and increasing reliability during periods of peak demand.

Currently, energy supply in Mongolia depends almost entirely on coal. The introduction of a new energy carrier diversifies the resources and reduces dependency on coal, while providing environmental and health related benefits.

The introduction of a new flexible energy resource, such as green hydrogen, can bring significant benefits to Mongolia's energy security in the power sector. As discussed in the previous section, the introduction of hydrogen production can facilitate the upscale and integration of renewables in the electricity supply, diversifying the energy mix and reducing the dependence on coal to produce electricity.

The contribution from hydrogen to increase the renewables and flexibility in the power system will also reduce curtailments and reduce dependency on costly electricity imports from Russia. Currently, the western, central and eastern systems are connected to the Russian power grid. Electricity imports represented 20% of the country's total electricity supply in 2019 (Energy Regulatory Commission of Mongolia, 2020a). Reduced curtailments and the high costs of imported electricity from Russia would make investments in renewable energy in Mongolia more attractive. Mongolia could benefit from improved international electricity trade through greater flexibility in its power system using electrolyzers (or other flexibility sources).

The increased participation of renewables in the system reduces vulnerability of the system during stress conditions, i.e., during peak demand. The current inflexible system is unable to meet the peak demand and relies on expensive imports from Russia to avoid unserved demand. This undermines the country's energy security by making it dependent on its neighbours to satisfy its peak demand. The expected growth in demand in the future and the need to replace old and inefficient power plants exacerbate this issue. An increased participation and capacity of VRE in the system, facilitated by a more flexible system would significantly diminish this vulnerability.

The substitution to hydrogen as fuel source in some end-use sectors (e.g., transport, heating, mining) not only comes with decarbonisation benefits but also reduce the dependency on oil products. Mongolia is a net importer of oil products, which has increased in the last two decades (IEA, 2020a). The replacement of oil products (e.g., diesel) with hydrogen would minimise the economic and energy security burden on oil imports³.

The current configuration of Mongolia's energy sector makes large-scale green hydrogen production unrealistic in the short to medium term. In the long term, hydrogen is set to play a central role in the decarbonisation of the global economy, and Mongolia's geographical position could be an advantage in diversifying its economy with a green, locally produced product for export to large economies, with great potential for increased demand.

However, the scale and maturity required for Mongolia to become a green hydrogen exporter in the region are not compatible with the current state of its energy sector. As the role that Mongolia can play

³ Mongolia is building its first oil refinery, which is expected to be completed by 2022.

in a future hydrogen economy is unclear, this report focuses on the first steps needed to develop a local hydrogen economy and its potential domestic uses.

It is worth noting that, as hydrogen production increases, so will water requirements as input for the electrolysis process. In a country already facing water scarcity, large scale hydrogen production would need a thorough assessment of water availability as a potential limiting factor.

Water supply

Water supply is a key consideration for hydrogen production as it is - together with electricity - one of the main inputs. A qualitative analysis aiming to assess to which extent there is a sufficient and reliable water supply for green hydrogen production in Mongolia is thus conducted. While scarce, water supply can sustain the start of green hydrogen production in the region where highest renewable energy potential is found. As production could scale up in the future, water transfers from other regions might be necessary, and the cost of this infrastructure should be carefully assessed when considerations for new green hydrogen projects are made, as well as implications for local communities and eco systems.

A mismatch between the spatial and seasonal distribution of water supply and demand leads to local water scarcity and high prices in some regions.

The various climatic conditions and geographies, from glaciated mountains in the north-west to desert in the south, provide Mongolia with a different set of water characteristics. The availability of surface water may range from 2,091 million m³ in a wet year to 1,294 million m³ in a dry year (Fan, 2020). Still, about 70% of the country territory is characterized by its semi-arid to arid conditions.

On a national level, Mongolia has sufficient water to supply the national demand and the projected population and economic growth. However, Mongolia's available water supply varies spatially across the country. The relatively high annual rainfall in the north (reaching about 350 mm per year) and meltwater from the snow and glaciers supplying perennial rivers contrasts with the scarce water sources in the south, its low rainfall (about 80 mm per year) and the absence of perennial rivers, which limits the availability of runoff water (Figure 6). About 75% of freshwater resources in Mongolia is stored in lakes, of which 75% is stored in lake Khuvsgul, situated in the north of the country (Banerjee et al., 2014).

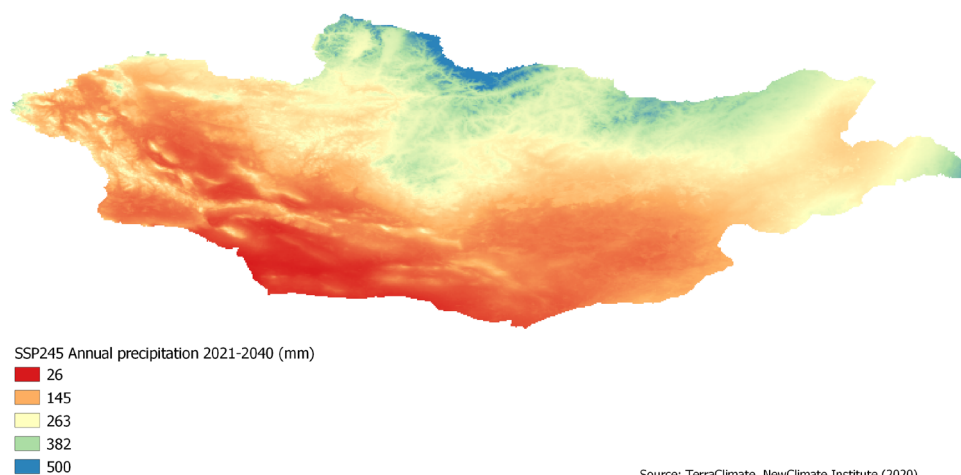


Figure 6. Projected annual precipitation (mm) in Mongolia in a SSP245 scenario, 2021-2040.

Due to the low precipitation and due to the freezing of rivers in wintertime, the availability of surface water in the southern region of the country is scarce. For these reasons, groundwater is the main source for residential and industrial use. However, groundwater reservoirs in the South Gobi Region are classified as fossil as they are not replenished by rainfall or surface water (Fan, 2020). The climatic water deficit and lack of runoff water further reveal the generally dry conditions in that region (Figure 7).

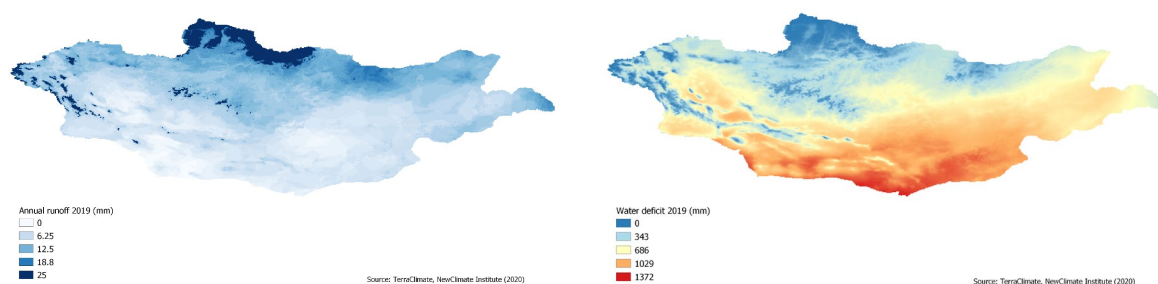


Figure 7. Annual runoff in 2019 (mm) (left) and Climatic water deficit in 2019 (mm) (right).

As with quantity, the groundwater quality also varies geographically. In about one third of the districts of Mongolia, water requires treatment to meet drinking water standards (Fan, 2020). Groundwater in the South Gobi Region is generally saline (Figure 9) and with high levels of arsenic in some areas, requiring a treatment process which drives up the water prices in the region. Further, the desalination of water requires an additional electricity demand of about 3-4 kWh per m³ of water and has a cost range of USD 0.7-2.5 per m³ of water. Such costs translates into an additional USD 0.01-0.02 per kg of hydrogen (IEA, 2019).

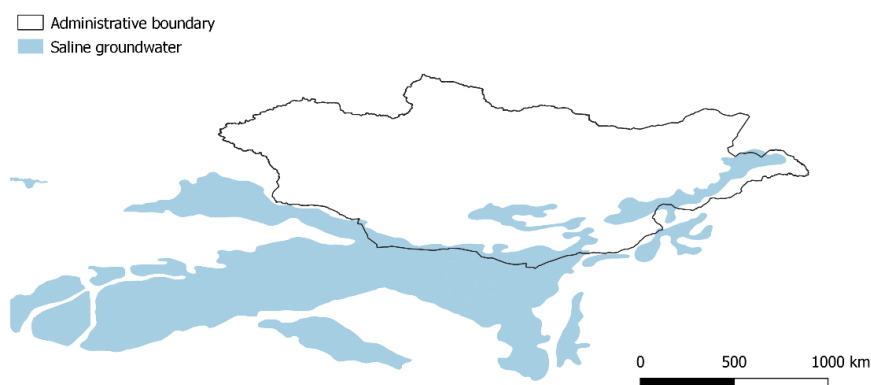


Figure 8. Saline groundwater in the region.

Beyond the current status of water supply, climate change impacts are likely to further exacerbate the situation in the future (Dolgorsuren *et al.*, 2013; ADB, 2020a). As one of the most vulnerable countries to climate change, Mongolia is projected to experience a rise in droughts and *dzuds*⁴, along with extreme temperatures far beyond the world average (Ministry of Environment and Tourism *et al.*, 2018). As a result, water is expected to become scarcer and desertification to expand. Although it is not yet ascertained, climate change is likely to have a negative effect on the water availability driven by increased temperatures, evaporation and seasonal variability (ADB, 2014, 2020a).

⁴ A dzud is a meteorological phenomenon; Followed by a dry summer comes an abnormally harsh winter with low temperatures and high winds. Dzuds severely impacts food supply for livestock and causes livestock losses(ADB, 2020a).

The demand for water is increasing, mainly led by increasing mining activities in the southern region, where water resources are most scarce.

In terms of demand, at present, the agricultural sector accounts for 30% of the water consumption, followed by livestock (24%), residential (18-22%) and mining (13%). Of these, the increasing mining activities are likely to add significant pressure on the water demand in the future. Between 2014-2018, national water withdrawals increased from 534 million m³ in 2014 to 560 million m³ in 2018, and is projected to increase to 884 million m³ by 2030 (ADB, 2020a). As mentioned, the total available water supply would be sufficient to meet such increase in demand at a national level, requiring about 2.5% of total annual renewable water resources. However, regional water shortages are likely to occur as the increasingly water-demanding activities are expected to take place in regions with little or no renewable water resources, such as in the South Gobi Region (ADB, 2020a).

Mining activities are one of the main strategies to stimulate the national economy and is rapidly increasing in the southern region. A growing mining activity comes with rises in population settlements within the proximity of the mining sites, hence also an increased water demand in the residential sector. The limited availability of water supply could become a restraining factor to the growth of the mining industry as water shortages are inducing conflicts in the region and forcing traditional herders in the region to give up their livelihoods (Khaltar, 2020a).

Before 2000, the state-run Tavan Tolgoi coal mine was the only mine in South Gobi. By 2020, twelve large mines were operating in the region, in part due to an increased flow of foreign investments (Khaltar, 2020a). Mining currently accounts for 71% of the annual water demand in the South Gobi Region (Khaltar, 2020a) and estimates suggest some of these -Nyalga Shivee Ovoo and Tavan Tolgoi- will have a water demand-supply gap of 35% and 60% by 2030, respectively. Much of these gaps may be related to the planned expansion of mining infrastructure including power plants, coal-to-briquette plants, coal-to-liquid plants and coal washing (Fan, 2020).

Transfers to supply water for hydrogen production in southern regions are possible, however, their additional implications should be reflected in the feasibility assessment of hydrogen solutions in the region.

Although this paints a grim picture in the light of the expansion of economic activities as well as green hydrogen production potential, some potential solution could be at hand. The low water availability in the south poses a challenge to produce green hydrogen locally for use in the mining sector. Yet, it may not necessarily make it impossible. Options such as efficiency measures and bulk water transfers could be potential solutions but would come with additional costs.

Water demand could be reduced through efficiency improvements to minimise the initial water requirements. Looking at the broader picture, the consumption of hydrogen in fuel cells will return water to the atmosphere in the form of a gas/steam. Technically, it is possible to recollect the exhaust water from the fuel cell to recirculate it as a feedstock for hydrogen production (G. Izenson and C. Rozzi, 2010; E. Tibaquirá *et al.*, 2011). Depending on the overall efficiency of that process, much of the input water for hydrogen production could be recovered and recirculated. By doing so, the additional water demand could be reduced. In addition, the cost for water treatment could be minimised as the water could be recovered with high quality (E. Tibaquirá *et al.*, 2011). However, this technique is not yet commercially available and needs to be further developed.

Another potential solution could be bulk water supply or inter-basin transfers, with systems such as distribution pipelines or water tankers. This could be a long-term option for Mongolia and is already being considered to provide water to the mining industry. Currently, two projects transferring water from the Orkhon-Gobi and Kherlen-Gobi rivers are under review and would both require pipelines of about

700 km at an estimated cost of around USD 550-600 million each (Khaltar, 2020b). Building pipelines comes with many challenges which makes them costly and faces environmental and political issues. Pipelines must be placed deep to keep water in the pipes from freezing during the long and harsh winters. The long winters also leaves a small window for pipeline constructions. In addition, pipelines must be built in a way to be able to withstand the highly seismic activities in Mongolia (Pfister, 2018). Moreover, the sourcing of water may have ecological impacts on the source basin, as well as potential political implications as some of the rivers feed into neighbouring Russia and China (ADB, 2020a) (Khaltar, 2020b).

According to a hydro-economic assessment conducted by ADB, an additional water supply to the mining industry of 20 to 50 million m³ could be sourced from local groundwater or surface water sources at a price range of 0.1-1.2 USD per m³, depending on the groundwater level (Table 2) (ADB, 2020a). For additional water demand, beyond 50 million m³, water would need to be transported from other regions at an estimated price of 2 USD per m³ (ADB, 2020a). Further, from a sustainability perspective, the transportation of the water would need to be done in a climate-neutral manner to ensure that the lifecycle emissions of the hydrogen are carbon-neutral. The option of sourcing groundwater from deep aquifers could thus be less expensive but could nevertheless lead to environmental externalities and the exhaustion of the groundwater resources in the region. in the region.

Table 2. Estimated water prices for additional water demand in the South Gobi Region.

Additional water demand (M m ³)	Water source	Cost (USD/m ³)
20	Low-cost groundwater or surface water	0.1
20 to 30	Medium-cost groundwater or surface water	0.4
30 to 50	High-cost groundwater or surface water	1.2
Beyond 50	Deep groundwater or transported water from other regions	2.0

Considering the options available to source water for green hydrogen production, a combination of those seems to be the most efficient solution, from an environmental as well as economic perspective. The overall water availability in the region will be dependent on the evolution of the mining sector and other water demanding activities. However, based on the available information in the literature from previous water assessments of Mongolia presented in this section, the risk of water shortage in the South Gobi Region seems noteworthy and any efficiency measures aiming to reduce the initial water consumption should be prioritised. Given that water supply is a common issue among industries in the South Gobi Region, hydrogen production could benefit from water conveyance projects to supply water to the mining industry. We therefore recommend that to take hydrogen projects forward at a large scale, this issue is further investigated.

To incorporate water costs into the hydrogen production calculations of this study, process water price is determined and projected based on desk research (Emerton, Luntun and Naldansuren, 2009; World Bank, 2020) and verified by a local partner. Based on this, a price development is calculated as presented in Figure 9. The case studies presented in the following sections suggest an additional water demand of 20,000-25,000 m³ per case study, which is rather insignificant compared to the estimated increase in water demand, expected to reach 884 million m³ by 2030 - mainly from the mining and

industry sectors. Nevertheless, in water scarce areas even a smaller amount of water must be sourced and transported from somewhere. In the case of Mongolia, water supply for green hydrogen production may be included in sourcing projects for the mining industry. Should green hydrogen use be heavily scaled up in the future and water demand increases accordingly, this issue would need to be reassessed.

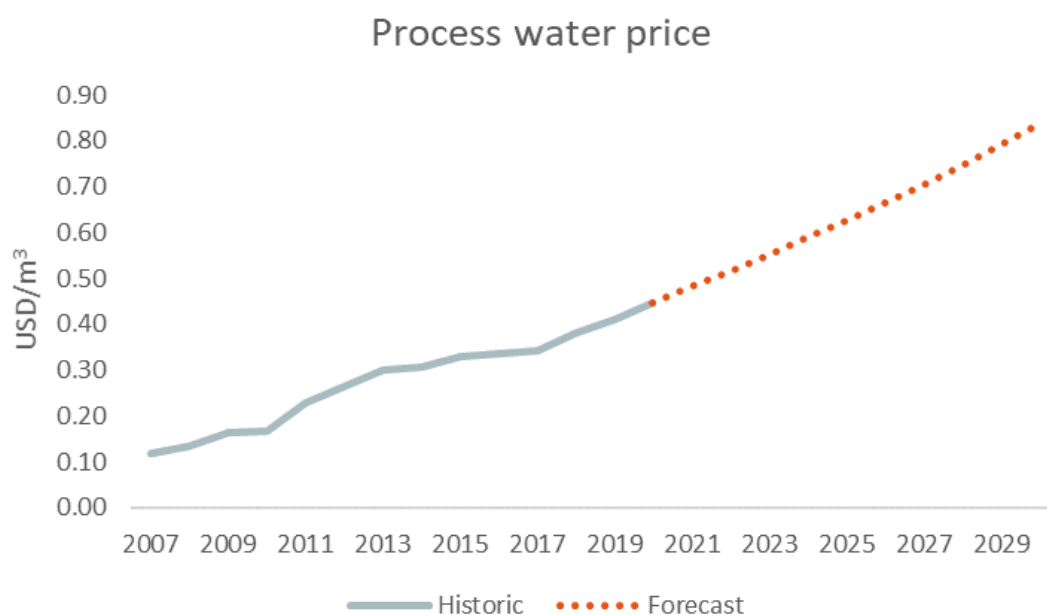


Figure 9. Process water price calculation and forecast.

Geographical locations for green hydrogen production

Being two of the key inputs for green hydrogen production, the geographical locations of renewable energy and water resources are important to identify the most optimal location for its production. In the case of Mongolia, there is a mismatch between the areas where either resource is more widely accessible. Locating hydrogen production sites close to demand centres is preferable in the short term, while in the long term, the decision whether water or electricity would be transported to production sites should be strategically made.

Geographical overlaps between renewable energy potentials, water availability, demand centres, and the existing power grids determine the feasibility and attractiveness of locations for green hydrogen production.

All steps along the value chain in the production of green hydrogen must be considered to define a location that optimises its production, including the renewable electricity supply, water availability, and transportation and uses of hydrogen.

In the matter of renewable electricity supply, the geographical distribution of renewable energy potentials across the country is of relevance because it determines the expected cost estimates of electricity and the utilization factor of the electrolyser.

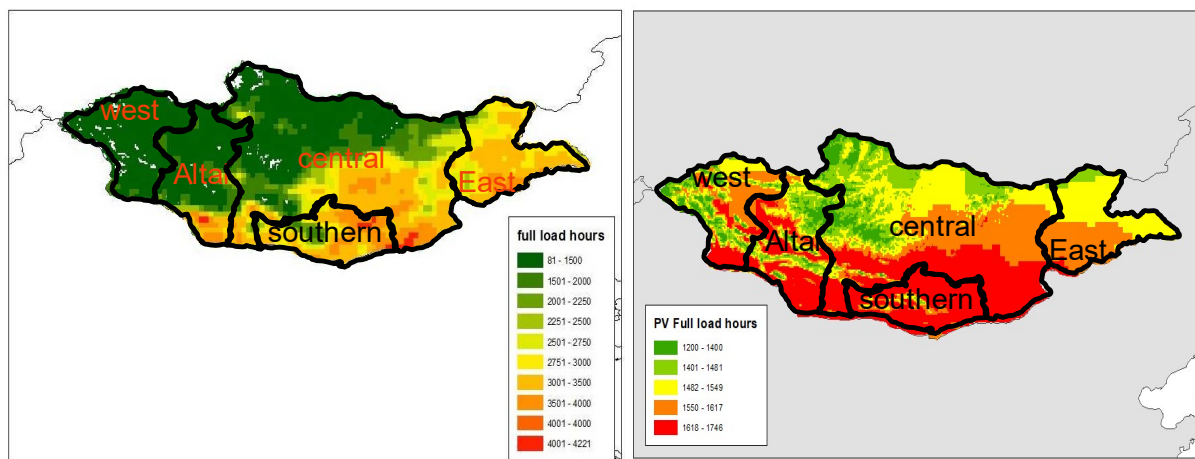


Figure 10. Potential of wind (left) and PV solar (right) energy resources and their overlaps with the five non-interconnected power grids.

In contrast to water availability, the highest potential for wind and solar energy are found in the southern region of the country (Figure 10). But the decision of where best to locate a green hydrogen production site cannot be limited to identifying places with high renewable energy potentials. It is equally important to assess the accessibility to the grid. It is likely that future renewable energy installations will be concentrated in areas with connection points to the existing power grid and where there are favourable renewable energy potentials. The fact that Mongolia has five non-interconnected power grids prevents electricity from being exchanged between regions, which means that abundant renewable resources in a given area (e.g., in the south) cannot supply energy needs in others, especially in locations with the highest demand (e.g., central, north). Hydrogen production cannot benefit from VREs potentials in regions that are not connected to the same grid where the electrolyser is located.

In Mongolia, there is a geographical mismatch with regards to its natural resources, as the greatest potential for VREs is found in the southern region of the country, where water stress is already an existing issue.

It is evident from the analysis made in this section that the locations with rich renewable energy resources does not match those with available water supply. Most mining activities in the country are concentrated to the South Gobi Region which is also the region with the best solar and wind potentials. However, estimates in the existing literature suggest that, with current trends in the mining sector, the South Gobi Region will run dry in the near future (Khaltar, 2020a). The production of green hydrogen in the south would be challenging and costly due to the scarcity of water from local aquifers.

The proximity to potential end-uses of hydrogen reduces the transportation needs for hydrogen. Depending on the required transportation, in terms of distance as well as mode, transportation could have significant impacts of the cost and sustainability of the hydrogen. The lack of a nationwide pipeline grid in Mongolia impedes the transportation of hydrogen over long distances, limiting the possibility to generate green hydrogen in locations with rich renewable resources and transporting it to main centres where it could be consumed.

Potential hydrogen production sites in Mongolia should be located either next to the existing grid or within the proximity of the end-use application.

Substantial investments in power or hydrogen transportation infrastructure would make the development of a hydrogen sector in Mongolia unviable. This is the case of the Northern regions, where renewable energy potentials are not as high as in the south but there is more accessibility to water resources and

to the power grid. The effects related to the need to expand the existing power grid or pipelines are omitted in this study because they are not feasible in the Mongolian context if the sole purpose is to produce green hydrogen⁵.

In the case of the mining sector, the location of most large mining sites geographically overlaps with those of high renewable energy potentials. In these cases, it is more beneficial to locate stand-alone green hydrogen production in this region, with on-site renewable energy power generation and possibly having to transport water, rather than locating the production closer to water resources, having to transport the electricity and green hydrogen.

Besides availability of resources, the identification of locations for green hydrogen production in Mongolia should also consider long-term strategies for hydrogen and its potential with other end-use applications in the future.

Hydrogen production costs

The modelling exercise suggests that Mongolia could produce green hydrogen at relatively competitive costs, particularly in MNG3, and potential future cost reductions in VRE generation and electrolyser technology could further improve them. The cost estimates are subsequently used as input to three case studies in Section 3.2, estimating the economic feasibility to replace fossil fuels with green hydrogen.

Based on the estimated renewable power generation cost, water cost projections and electrolyser costs, the modelling results suggests that green hydrogen could be produced at a cost between \$3.30 and \$4.73 per kg (Table 3). Comparing to a global average cost of \$4.8 per kg of hydrogen, the production cost in Mongolia would therefore be below average (IRENA, 2020b).

For cost considerations and in each of the case studies, an electrolyser unit with electrical power of 18 MW and efficiency of 75% is used as the default in the modelling exercise. Several commercial suppliers offer units on the market within this power range.

The scenarios developed focus on local hydrogen production and utilisation, as a national hydrogen grid is not considered feasible due to Mongolia's large territory, dispersed population and relatively low expected demand.

Table 3. Modelling results for electricity generation and hydrogen production.

Parameter	MNG1	MNG2	MNG3	MNG4
Full load hours	2,800	3,600	5,000	4,200
Electricity cost (\$/kWh)	0.058	0.044	0.041	0.043
Demineralised water cost 2020 (\$/m ³)	30	40	40	25
Expected H ₂ cost (\$/kg)	4.73	3.83	3.30	3.40

By applying the electricity, water and technology costs previously described, green hydrogen production costs were calculated for each of the predefined regions, as shown in Table 3. These values are based on current CAPEX and OPEX for electricity generation and electrolysis. Demineralised water costs are higher than those presented in Table 2 due to conservative estimates that include extraction, purification

⁵ The grid expansion must be assessed in a wider and integrated manner, where hydrogen production is only one of the multiple drivers to be included in the decision-making process. If the idea is to develop the production of hydrogen using electricity from the grid, the hydrogen development plan and the grid expansion should be integrated and consider availability of RES, water, and the feasibility to connect to main load centres.

and transport costs. Predictions dictate that technological learning, larger scale manufacturing and capacity increases will reduce the cost of electrolyzers by 60%-80% by 2030 (Hydrogen Council, 2020). Based on these assumptions, the production costs of green hydrogen in Mongolia would be reduced by \$0.36-0.5 per kg, which could bring the cost down to \$2.8- 2.94 per kg (in the MNG3 region). However, these cost improvements only consider reductions in electrolyser cost and does not reflect further cost savings which could be obtained from a cheaper renewable energy supply. As illustrated in Figure 11, electrolyser costs only contribute to about 25% of the hydrogen production costs, with electricity having a much larger impact in overall costs. The further reduction of the cost of electricity will therefore play a key role in bringing down the cost of green hydrogen in Mongolia.

Hydrogen cost contributors (%)

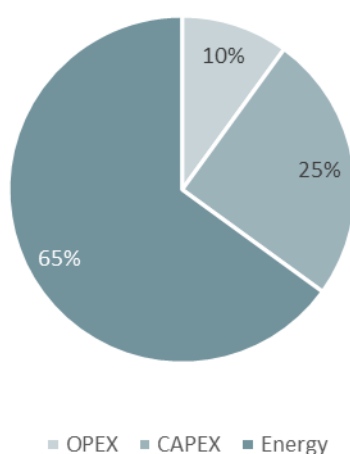


Figure 11. Approximate share of cost contribution for green hydrogen production in Mongolia.

Considering the obstacles that the development of hydrogen-specific infrastructure would face, this study considers the further transformation of hydrogen into other liquid energy carriers, namely methanol and oligo-methyl ethers (OMEs) (Schmitz et al., 2016).

Synfuels can directly substitute widely used fossil fuels such as LPG (in the case of methanol) and diesel (OMEs) and offer additional advantages such as more practical long-term storage than gaseous hydrogen.

The production of synfuels requires CO₂ as an input, which could be sourced in high concentrations from capture in industrial processes such as cement production. These sources could however demerit the carbon footprint of these “green” fuels or create new revenue sources for polluting industries, with a potential extreme consequence of becoming an incentive to their continued operation. Direct air capture of CO₂ is a technology in development that could avoid this issue.

Methanol production requires two steps. First, CO₂ is transformed to CO via water gas shift reaction followed by classical catalytic methanol synthesis. The processes themselves are well established and production cost are in the range of \$1.192 per kg. Two additional steps are needed to transform methanol into OMEs. These additional processing increase production costs to \$1.542 per kg of fuel.

To compare the cost of these fuels by energy content, an evaluation in a use-specific context is made in next section’s case studies where methanol is considered an alternative to LPG for spatial heating, while OMEs could replace diesel in buses for public transportation.

3.2 Demand side

This section investigates some of the potential end-use applications for hydrogen in Mongolia and presents the modelling results for those end-uses in three case studies, namely mining, public transport and residential heating and cooking. We find that a shift to hydrogen-based technologies is close to economically competitive in two of the three applications studied, including the mining and public transport sectors. Although incumbent technologies are still more cost-effective, the margin can potentially be overcome with future cost reductions of green hydrogen production and technologies, or policy measures such as carbon pricing or subsidies.

There are several end-uses for the direct use of hydrogen, including electricity generation in fuel cells, heat in hydrogen boilers or directly as a feedstock for industrial processes. Electricity from fuel cells can be used for mobility in fuel cell electric vehicles, to provide power and heat in buildings, and eventually serve as a balancing operator to the electric grid. Heat produced in hydrogen boilers can serve the residential, commercial, and industrial sectors.

As with any energy conversion process, energy is lost in each conversion step. So is the case for the conversion of electricity to hydrogen, as well as with hydrogen to other energy carriers, such as heat and electricity. As discussed in section 2.2, storage and transportation of hydrogen face several challenges and require energy as an input which drives down the overall efficiency and up the overall costs. By avoiding conversion steps, direct electrification will in most cases be more efficient and therefore the preferred option from both a thermodynamic and economic perspective.

But due to technical barriers, various energy consuming sectors are not fit for electrification. To decarbonise those sectors, clean energy will need to be stored and transported in a way that it can be dispatched on demand, which makes hydrogen an interesting candidate. This section presents and discusses the potential of green hydrogen as an energy supplier to some of those end-use sectors identified as relevant in the Mongolian context, and which are further analysed in case studies in the next section.

The results from the supply side analysis are used as an input to the end-use case studies, where the hydrogen cost is matched with the geographical location of those. Figure 12 gives an overview of the methodological approach, and how the supply side results are fed into the demand side analysis.

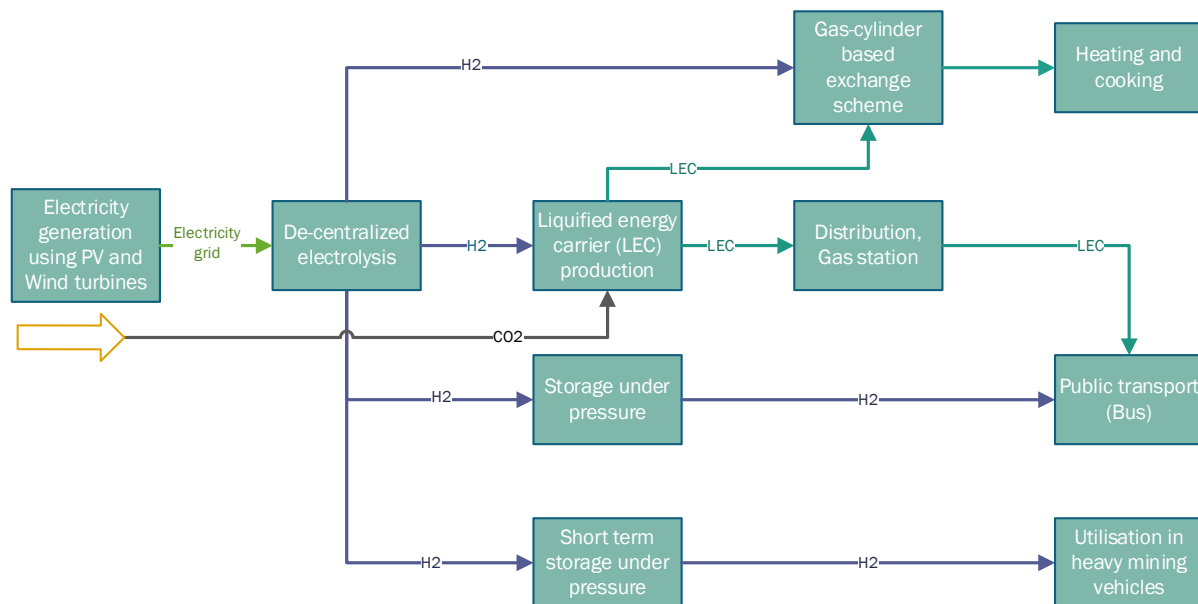


Figure 12. Methodological flowchart over the steps considered in the modelling exercise.

Heavy duty transport in mining

Heavy duty freight transport is one example of a hard-to-abate sector that will require innovative solutions to be decarbonised. The case study of the Oyu Tolgoi copper mine shows that fuel cell trucks are close to being cost-competitive with current diesel technologies, and can offer some additional advantages.

Mining industries are typically found in remote locations and use heavy duty trucks and forklifts for its operations. The trucks are dependent on expensive and polluting diesel which needs to be transported to the mining locations, requiring logistical planning, and causing additional emissions. To reduce diesel dependence and expenses, as well as mitigating GHG emissions, there is an emerging interest for hydrogen in the mining industry.

As medium- and heavy-duty trucks typically transport large amounts of goods over long distances, decarbonisation through heavier battery electric vehicles (BEV) may need further technology development, providing an entry point for fuel cell electric vehicles (FCEV).

The long distances and heavy load require large batteries which are expensive, heavy and require a long time to charge (IRENA, 2020c). Under such circumstances, FCEVs offer favourable characteristics as they are lighter and more suitable for long distances. However, given recent progress in battery development, there is not yet a clear frontrunner technology as both BEVs and FCEV are continuously improving.

Even though fuel cell trucks have not yet been widely deployed, there are several ongoing fuel cell vehicles demonstration projects in the mining industry globally. The global mining company Anglo American plc are planning the construction of a 3.5 MW electrolyser plant driven by renewable power to supply more than 400 mine-haul trucks in South Africa to start in 2021. The project is part of the company's target to reduce its emissions by 30% over the next decade compared to 2016 levels, and a long-term goal to achieve carbon-neutrality by 2040 (Njini, 2020). After demonstration, the trucks would be deployed at other Anglo American mining sites with the expectation of operational costs to decrease (CSIRO, 2020). In terms of cost-competitiveness, FCEVs could overtake fossil driven ICEs in the mid-term, according to a study conducted by the Hydrogen Council (Hydrogen Council, 2020). FCEVs offer

higher fuel-efficiency compared to ICEs, in addition to other energy saving benefits such as energy recovery from braking and driving downhill (Hydrogen Council, 2020). However, such advances will be dependent on the local cost of diesel and the local production cost of hydrogen.

Another alternative to decarbonise heavy duty transport through green hydrogen is to use synthetic fuels produced from hydrogen and carbon dioxide, which can make use of existing vehicle technology and refuelling infrastructure (Shell, 2017).

Although costs are currently relatively high, they are projected to fall considerably and reach about 1 USD/litre in the coming decades (IRENA, 2019a), compared to the current global average price of gasoline of 0.91 USD/litre in 2019 (IEA, 2020b). Assuming a rising price on CO₂ could therefore result in synfuels competing with gasoline. As mentioned, an important aspect of synthetic fuels is its sustainability, which could also affect the price as direct air-capture technology required to produce carbon-neutral fossil fuels currently is more expensive compared to other options.

The Mongolian economy is increasingly becoming more industry centred as a result of a recent rise in mining activities. Between 2015-2018, mining accounted for some 57% of total industry production, contributing to about 23% of national GDP. The mining potential in the country is significant, with up to 80 types of minerals discovered and more than 6,000 mineral deposits. Main active mineral activities include copper, gold, coal and uranium extraction (EITI, 2020a).

Most mining sites are concentrated in remote locations of the Southern Gobi region. The mining activities are fully reliant on fossil-fuelled heavy-duty trucks for the extraction and transportation of minerals, contributing to GHG emissions, oil import dependence and high (fossil) fuel expenditures. Hydrogen-powered fuel cell trucks could therefore be a suitable technology to reduce emissions in the Mongolian mining sector. Further, the optimal conditions for renewable power generation in the Southern Gobi region provide an opportunity for green hydrogen production within the proximity of the mining sites. Current practices use heavy-duty diesel-driven trucks that operate for 8000 hours a year, only interrupted by service and refuelling.

The diesel engine in these trucks can be replaced by a hybrid power train, consisting of a fuel cell system and a battery, as seen in a field test operating in South Africa since February 2020 (Zhou, 2020). The truck used in this study will be used as the basis for this example (800 kW fuel cell system and a 1000 kWh battery).

In the context of this case study, a scenario based on an electrolyser unit with 18 MW maximum power is developed, which is supplied by electricity mainly originating from wind and PV. It is assumed that the electrolyser load can adapt within minutes. As most mining activities, it is assumed to be located in the south-eastern region (MNG3, as per the division showed in Figure 3), where the estimated hydrogen production cost is \$3.3 per kg (see Table 3). All dumper trucks are assumed to pass the service and refuelling station regularly within the loading-unloading cycle, so no further hydrogen distribution infrastructure was deemed necessary. Critical assumptions related to the dumper trucks include:

- CAPEX for a dumper truck with a fuel cell/battery power train is 25% higher than for a diesel driven dumper truck. CAPEX will be amortised over 10 years.
- Power of the fuel cell (800 kW) and capacity of the battery (1000 kWh) in line with the field study running in RSA. Energy recuperation is possible.
- A single dumper truck has 270 t load capacity.
- Every dumper truck operates 24/7 for 8000 h per year.
- Technological risk is not considered in the cost calculation as well as labour cost and maintenance are expected to be comparable to the benchmark scenario.

The scenario is compared to a benchmark scenario in which diesel driven trucks utilisation continues but new trucks are purchased to renew the fleet. The diesel price applied in the benchmark scenario is \$1.20 per litre.

Comparison takes place on the base of the energy carrier cost and the useful energy delivered to the wheel to cover differences in terms of efficiencies correctly. For the diesel driven dumper truck, this evaluation results in an energy cost of \$0.303 per kWh, while the hybrid truck (fuel cell/battery) can be operated at the slightly higher cost of \$0.339 per kWh. However, even if assumptions mentioned above are rather conservative, an error margin of +/- 25 % still needs to be assumed. In total, the electrolyser system produces sufficient hydrogen for more than 6 dumper trucks in this scenario.

Nevertheless, hydrogen can be regarded as a competitive energy carrier in this scenario where the relatively high diesel price and the fact that no distribution infrastructure is required are clear advantages of hydrogen. In addition, additional cost benefits such as the elimination of underground ventilation system costs are not considered in the modelling exercise.

Moreover, should CO₂ emissions be priced in Mongolia, hydrogen could become the most economic option, as a carbon price of \$100/tCO₂ increases the operation costs of diesel trucks to \$0.369 per kWh, as presented in Figure 13.

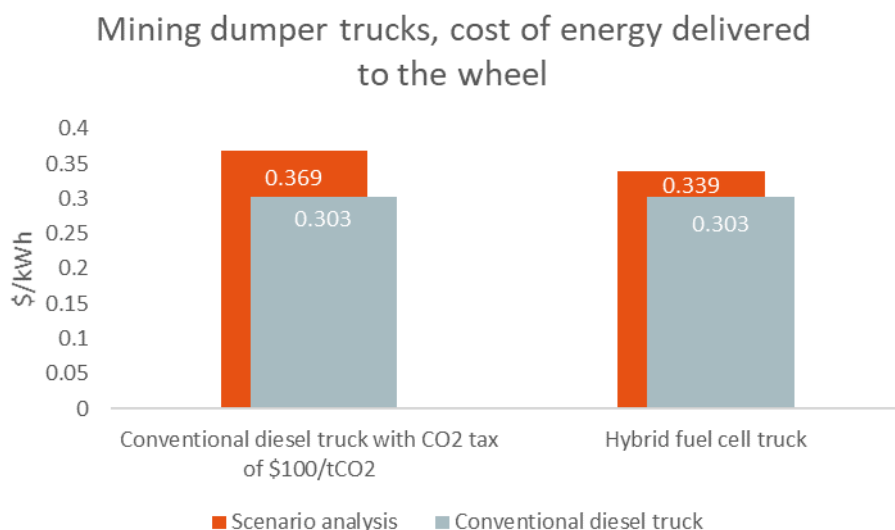


Figure 13. Operation costs of mining vehicles in southern Mongolia.

Public transportation

As for heavy-duty freight, fuel cell vehicles are also an option for decarbonising public transport activities, mainly referring to buses. The case study of the Ulaanbaatar public bus fleet finds that fuel cell buses are still more expensive than current technologies, although the margin is not significant when accounting for the operation of the buses. Fuel cell buses could thus be an interesting decarbonisation option. The use of OMEs in diesel buses, however, is further out of reach.

Buses in public transportation are commonly operated over long stretches of time which yields small windows for charging electric buses. In addition, charging during night-time may make it more difficult to ensure the supply of clean power as solar power is not available, making the power supply highly

dependent on wind. The longer driving ranges and faster charging of FCEVs could therefore be particularly useful for public buses. Nevertheless, as in the case for heavy freight transport, there is no clear frontrunner technology and the most beneficial solution may differ between regions, depending on context-specific aspects.

Fuel cell buses have been successfully demonstrated at various locations globally (Skiker and Dolman, 2017; IEA, 2021). In 2016, hydrogen fuel cell battery buses were introduced in the Chinese city of Yunfu with the main objective to reduce air pollution in the city. As the driving range of battery electric buses could not compete with diesel driven buses, hydrogen fuel cell battery buses were identified as the best option (Liu, Kendall and Yan, 2019).

Ulaanbaatar hosts about 45% of the Mongolian population where the transport sector is responsible for about 11.7% of the city's GHG emissions (Edlev-Ochir, 2019). Out of the city transport demand, about 51% is met by public transportation (Edlev-Ochir, 2019), currently consisting of a fleet of about 900 diesel-driven buses (Pudlik, Seyfang and Franke, 2021). As the current vehicle stock is old and in need of upgrading, there is an opportunity to reduce GHG- and local air-pollution emissions through the introduction of carbon-neutral buses. The substitution of half of Ulaanbaatar's fleet with fuel-cell powered buses is investigated, as is the possibility of using conventional ICE buses powered by synthetic fuels made from green hydrogen, in the same way it can be done for heavy-duty vehicles.

As is the case in the mining scenario, very few pressurising and filling stations would need to be implemented in or close to existing bus depots. This is a significant advantage compared to fuel cell trucks used in general logistics, where nationwide fuelling infrastructure is required.

These considerations make FCEV hybrid buses an attractive, yet slightly more expensive option than current diesel technology when considering a renewal of the fleet. The introduction of prices for carbon emissions would help close that gap. Further, the beneficial impacts on air quality would also be considerable.

The cost calculations are again based on one electrolyser unit with 18 MW maximum power, operated close or in a bus depot in the Ulaanbaatar metropolitan region. The reference bus used in this scenario is set up according to data given for a Solaris Urbino 12 Hydrogen (Solaris, 2020) :

- 70 kW Polymer electrolyte fuel cell
- 100 kwh battery
- 200 kW peak power available for acceleration
- 50 kW recuperation power.
- 350 km range.

Enough fuel for the operation of around 450 buses can be supplied with one electrolyser system investigated in this study, which corresponds to about half of the city's current fleet. Additional parameters considered include \$48,000 additional CAPEX for the fuel cell hybrid system compared to the diesel engine, a depreciation period of 10 years, and 3,000 operation hours per year during the 10-year period.

For this case study, the purchase of conventional buses driven by diesel engines (200 kW) within a regular fleet renovation cycle and equivalent operation and depreciation data as described above is used as the benchmark. In addition to the hydrogen scenario, the alternative of the application of synthetic fuels (OME) used instead of diesel in diesel-run buses is investigated.

From a fuel perspective, the cost of useful energy delivered to the wheel of the bus is the main comparison parameter to include all relevant efficiencies and cost factors. For the hydrogen hybrid bus

(including fuel cell and battery) costs estimates are \$0.345 per kWh while the corresponding results for the diesel driven bus are \$0.270 per kWh, based on a diesel cost of \$0.9 per litre. The results suggest that fuelling a bus with OME would be significantly more costly, resulting in a cost of \$0.570 per kWh.

To also take into consideration the differences in CAPEX, an additional comparison is made in terms of cost per operating hour. The result of such analysis suggests that the fuel cell hybrid bus could operate at a cost of \$22.6 per hour, 14.7% more than diesel driven buses at \$19.7 per hour. OME buses, although with the same CAPEX as diesel buses, run at \$27 per hour. When a price on CO₂ emissions is considered, fuel cell buses are only 5.6% more costly to run, as diesel buses increase their operation costs to \$21.4 per hour (considering a \$100 per tCO₂ price). These comparisons are presented in Figure 14 Figure 15.

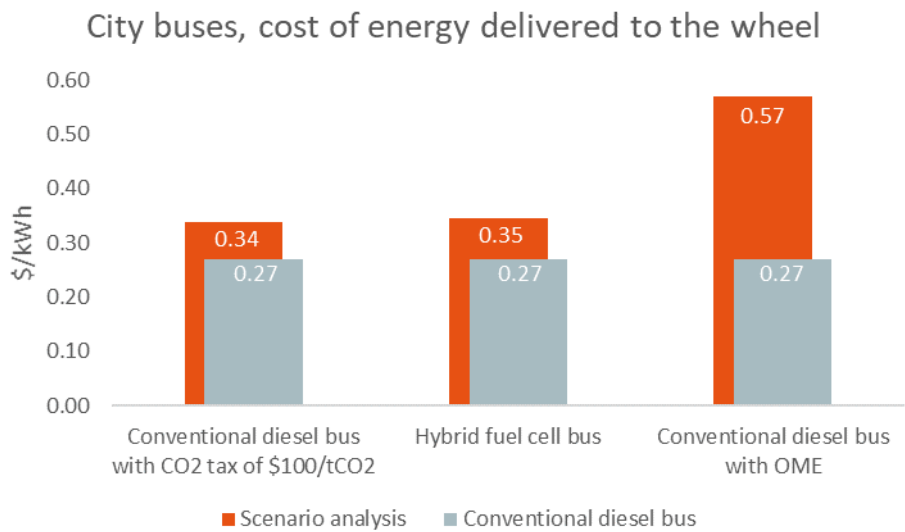


Figure 14. Cost comparison for public transport buses in Ulaanbaatar in terms of energy delivered to the wheel.

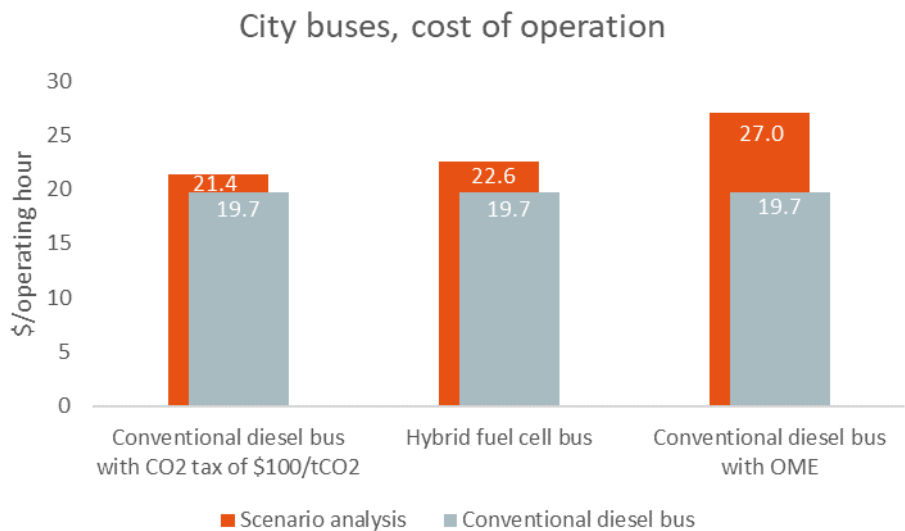


Figure 15. Cost comparison for public transport buses in Ulaanbaatar in terms of operating costs, including CAPEX.

Heating and cooking

Decentralised heating and cooking in Ger districts is currently powered by coal and generates high levels of GHG emissions and poor air quality. Using LPG as a benchmark fuel, the case study shows that green hydrogen for heating is a significantly more expensive option, and thus not suitable as a decarbonisation option in Mongolia in the near-term, from an economic perspective. A key contributor to the high costs is the low energy density of hydrogen which require higher expenditures on storage and transportation.

Heating is yet another example where deep decarbonisation can be challenging. Currently, heat for buildings is typically provided from fossil fuels through a wide range of routes, centralised through district heating systems, or decentralised through the direct combustion of fuels or heat pumps.

Globally, the most commonly used fuel for heating buildings is natural gas (Hydrogen Council, 2020). Among the more climate friendly heating technologies, heat pumps are becoming increasingly popular and is widely used in some regions. Heat pumps consume electric energy to extract heat from the environment, requiring about 1 unit of electricity per 3 units of generated heat (Gerhardt *et al.*, 2020). As previously discussed, from an energy efficiency perspective, the application of hydrogen makes best sense under conditions where direct electrification is not feasible. That is, where heat pumps are technically practical, they will from a technical point of view be preferable to hydrogen as they generally generate more heat per unit of power input. However, in those cases where heat pumps might not be a suitable option, such as in very cold climates or in areas with an already existing gas infrastructure, other solutions may be considered. In addition to heat generated from waste and sustainable biomass distributed in district heating systems, another possible decarbonisation route for heat in buildings is green hydrogen. There are various ways in which hydrogen could do so, each of them facing different challenges.

Under the right circumstances, hydrogen home boilers for space heat generation could provide a promising clean heating solution. The anticipated decrease in hydrogen production costs in conjunction with falling CAPEX for boilers could make hydrogen boilers competitive to biomethane and heat pumps. However, the distribution of hydrogen remains a challenge and would make hydrogen boilers most suitable to regions with an already existing natural gas infrastructure which could be converted into a hydrogen distribution network (Hydrogen Council, 2020). Given such circumstances, hydrogen could become more competitive than heat pumps for old buildings as heat pumps would require substantial refurbishment. According to a study from the Hydrogen Council, a hydrogen price of 5.4 USD/kg would make hydrogen boilers competitive to heat pumps for refurbished dwellings, while the corresponding production price to compete with biomethane would be 3 USD/kg (Hydrogen Council, 2020).

On the other hand, some studies argue that heat pumps offer a more viable solution, in particular from an energy efficiency perspective. The various conversion steps in the hydrogen production process leads to significant losses in energy efficiency.

Another option could be to blend hydrogen into existing natural gas pipelines which can be done with a blending rate up to 20% without significant demands on refurbishment. Beyond the fact that Mongolia does not have a widespread natural gas infrastructure, this option cannot be considered a decarbonisation option as it only brings low- to modest emission reductions (Gerhardt *et al.*, 2020; Hydrogen Council, 2020). In addition, introducing hydrogen blending risks slowing down the transition to advanced decarbonisation technologies.

A second technology for generating hydrogen-based heat in buildings is fuel cells combined heat and power technology (FC-CHP), where waste heat from power generation from fuel cells is recovered and

used for space heating. A clear advantage of this technology is the overall high efficiencies that can be achieved. In a combined electric and thermal mode, the system can achieve up to 95% efficiency (Shell, 2017). However, FC-CHPs typically have a relatively low thermal output, needing a hybrid system in case they are not able to cover the building's heat demand. As for economic feasibility, it is estimated that FC-CHPs could become competitive to hydrogen boilers and heat pumps at a hydrogen cost of 1.9 USD/kg - anticipated around 2030 (Hydrogen Council, 2020). The technology is commercialised and has been demonstrated in several countries and regions including Europe and Japan (Shell, 2017).

Overall, the identification of the most suitable decarbonisation option for space heating of buildings will be dependent on several context-specific factors such as the local energy demand profile, the condition of the local buildings, climatic conditions, hydrogen production costs, distribution costs and equipment costs. Thus, a case-to-case assessment is needed in order to identify the most suitable option for a particular country or region.

In Mongolia, heat for buildings is currently provided from central heating plants, Heat Only Boilers (HOBs) or raw coal burning, the latter commonly used in *ger* districts (Senshaw, 2020). *Ger* districts host more than 60% of the Ulaanbaatar population and typically lack access to public infrastructure. Heat is thus largely generated from coal stoves, resulting in high expenditures on fuels, typically accounting for 25%-40% of family incomes (Carlisle and Pevzner, 2019).

What is more, the current heating system generates large amounts of air pollutants leading to the already recognized issue of air pollution affecting the public health. As an example, Ulaanbaatar, has one of the highest recorded air pollution levels globally, where levels 133 times what is considered safe by the World Health Organization were recorded in 2018 (Ron Cui and Wu, 2019). Air pollution is an even more prominent issue in sub-urban areas where the burning of raw coal and wood for heating is a key driver.

For the heating sector case study, the study focuses on the energy needs in Ger districts for decentralised heating and cooking, comparing hydrogen boilers with LPG technologies.

Centralised hydrogen fuelled district heating is not considered for further analysis due to its lack of competitiveness with heat pumps or combined heat and power (Pudlik, Seyfang and Franke, 2021).

Considering the very low cost of the low-grade coal currently used and the desire to move away from high polluting technologies, LPG gas cylinders are used as the benchmark for this study. As such distribution infrastructure (e.g., a gas cylinder exchange system) would need to be put in place for both the LPG and hydrogen cases. However, due to its fossil origin, LPG cannot be considered a decarbonisation option. The fuel would also need to be imported to Mongolia.

Hydrogen could then be an alternative from both an energy security and health perspective, as no GHGs, soot or other pollutants are formed during its combustion. Another decarbonisation alternative would be to use hydrogen-based methanol, which could also substitute LPG.

As done in the previous case studies, the scope of this scenario includes an 18MW electrolyser unit operating for 4000 full power hours per year and producing 1,360t of hydrogen at a price of \$3.72 per kg H₂. Hydrogen requires to be pressurised at 200 bar and can be stored for several weeks in gas cylinders with 50L volume. In one gas cylinder, 20 kWh of energy can be stored, which is then available for heat generation.

The benchmark scenario, considering the application of LPG gas cylinders, relies on imported LPG available at a price of \$0.06 per kWh. An LPG cylinder containing 11 kg of LPG therefore contains about 141 kWh of energy available for heating or cooking.

The comparison in this case study is made in terms of kWh of useful energy delivered to the stove or furnace. As such, the final cost estimate also includes estimates for filling, storing and the distribution of the gas cylinders. As the energy content in an LPG cylinder is about 7 times higher than in a hydrogen cylinder, this makes a considerable disadvantage to hydrogen. It should also be noted that the high pressure needed to store hydrogen (200bars) presents a challenge.

As presented in Figure 16, the results suggest an LPG cost of \$0.21 per kWh while hydrogen could be available at \$0.52 per kWh. Methanol, once distribution is considered, would end up at a cost of \$0.28 per kWh, according to the results.

Lower energy density, even when pressurised, limits hydrogen potential for this use. Considering this and its higher production costs, direct combustion of hydrogen for heat purposes can be considered a wasteful use of a high-quality energy carrier. Synfuel, while 33% more costly than LPG, has the advantage of being produced locally in Mongolia.

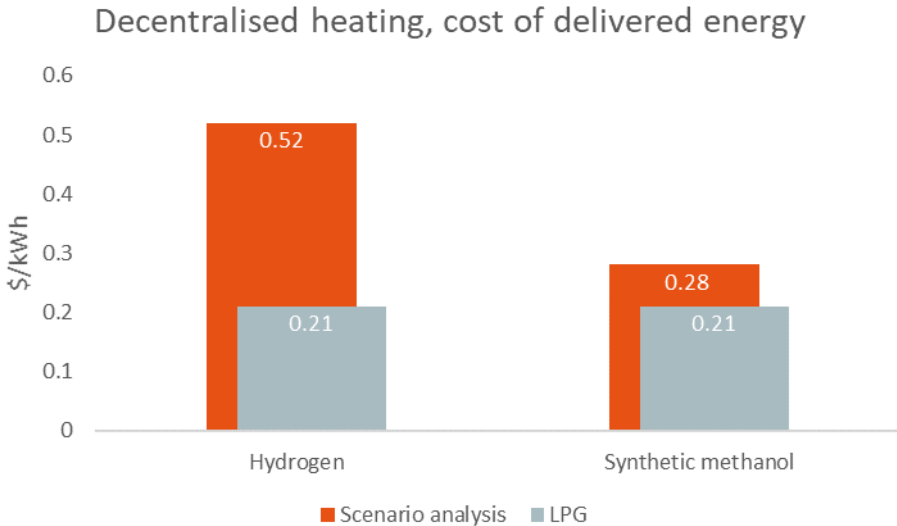


Figure 16. Cost comparison of decentralised residential heating and cooking fuels in ger districts.

3.3 Impacts of technology implementation

Based on the modelling results, this section estimates the impacts on GHG emissions and sustainable development goals a shift to green hydrogen in the analysed end-use sectors could have. The results suggest that a shift to green hydrogen in the mining sector would have the most significant impact on GHG emissions, and that a green hydrogen sector could contribute to achieving 6 out of 10 of Mongolia's Sustainable Development Vision 2030 goals.

GHG emission reduction potential

For heavy duty transport in mining, the potential for replacing parts of the mining vehicle stock with fuel cell trucks powered by green hydrogen could be in the order of 1.2 MtCO₂e per year, or close to 3.5% of the national emissions (excluding LULUCF), at an abatement cost of approximately 9 USD/tCO₂e.

As some of heavy duty mining trucks can consume up to 21,000L of diesel a day, they generate a substantial amount of GHG emissions (Moore, 2020). The six mining trucks considered in the mining

case study could avoid emissions around 32ktCO₂e per year (Figure 17) (Pudlik, Seyfang and Franke, 2021). Considering the full fleet of the Oyu Tolgoi copper mine, consisting of 35 dumper trucks, the impact of switching to an all fuel-cell vehicle fleet could reduce emissions by 160ktCO₂e annually. Coal mining aside, copper and iron are the main minerals produced in the country. Assuming a similar ratio of trucks per mineral output as in Oyu Tolgoi, substituting the dumper trucks in copper production (Oyu Tolgoi and Erdenet mines) and half of the iron ore production, could collectively mitigate about 1.2MtCO₂e per year, or almost 3.5% of the country's national emissions (Economic Research Institute, 2017; Government of Mongolia, 2017; EITI, 2020b). The mitigation potential of switching to fuel cell trucks in the mining sector is thus considerable and could contribute to achieving the national emission reduction targets. Further, such emission reductions could be achieved at an approximate abatement cost as low as 10 USD/tCO₂e.

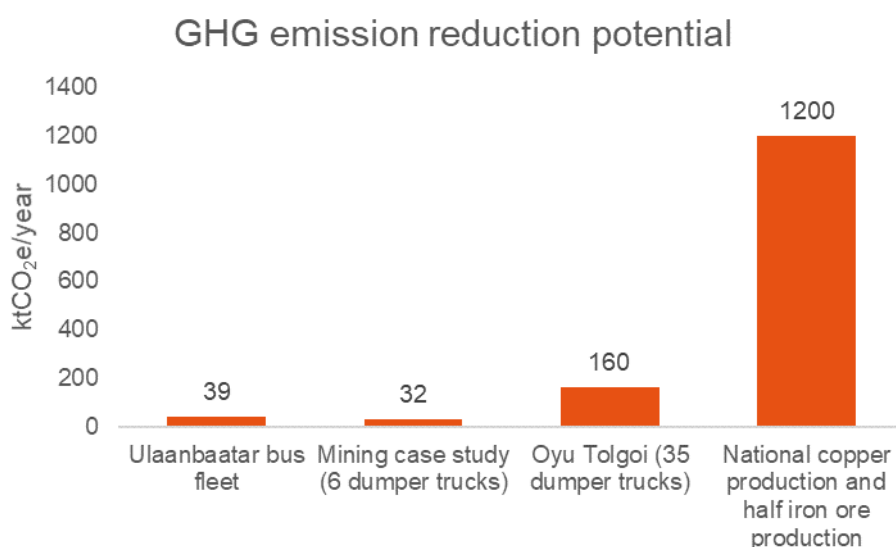


Figure 17. Estimated GHG reduction potential in terms of ktCO₂e/year for heavy-duty transport in the Mongolian mining and public transport sectors⁶.

Due to the limited potential of scaling, the mitigation potential of switching to hydrogen in the public transport fleet is significantly lower compared to in the mining sector. More specifically, replacing the public bus fleet in Ulaanbaatar with fuel cell busses powered by green hydrogen would mitigate 39 ktCO₂e per year, at an estimated abatement cost of above 100 USD/tCO₂e. Ulaanbaatar is the only city in Mongolia with a local public transport fleet with the necessary conditions to be substituted in the short to mid-term, and therefore, this specific application would only be scalable to the fleet operating within the city. However, despite the limited mitigation potential, such a shift could bring other valuable benefits, such as improving the air quality in the city which is further discussed in the next section.











Sustainable development agenda

In addition to the environmental aspect, a shift to green hydrogen in the identified end-uses could bring other benefits. Energy security, trade benefits, air quality and job creation could be positively affected by an increased role of hydrogen in Mongolia's energy system.

⁶ Including a complete switch to fuel cell vehicles in the Ulaanbaatar bus fleet, 6 mining dumper trucks, the complete fleet of the Oyu Tolgoi copper mine, and the complete national copper production and half of the national iron ore production.

Mongolia has made efforts to align its national policies towards sustainable development, particularly through the National Green Development Policy (NGDP), the Sustainable Development Vision 2030 (Vision 2030), and the Sustainable Development Outlook of Mongolia (SOM)(NDC Partnership, 2019). The Sustainable Development Goals (SDGs) are mainly integrated through the Vision 2030 indicators, which are shown in Table 4. Using these indicators, we analyse the impact the introduction of hydrogen technologies could have on their achievement.

Table 4. Impact of hydrogen on Mongolia's sustainable development agenda⁷.

	Sustainable Development Indicator	Impact of hydrogen deployment and decarbonisation	
1	Increase GNI per capita to USD17,500 and become an upper middle-income country based on income per capita		Increased economic activity as a result of improved air quality and health. The implementation of hydrogen technologies can support job creation along the supply chain for construction and operation.
2	Ensure average annual economic growth of not less than 6.6 percent through 2016-2030		Shifting to hydrogen technologies can support job creation along the supply chain for construction and operation.
3	End poverty in all its forms		NA
4	Reduce income inequality and have 80 percent of the population in the middle and upper-middle income classes		NA
5	Increase the enrolment rate in primary and vocational education to 100 percent, and establish lifelong learning systems		NA
6	Improve the living environment of the Mongolian people to lead a healthy and long life; increase the life expectancy at birth to 78 years		The introduction of hydrogen would reduce air pollution which would result in fewer diseases caused by pollution.
7	Rank among the first 70 countries in the human development index		The introduction of hydrogen would reduce air pollution which would result in fewer diseases caused by pollution.
8	Preserve ecological balance and place among the first 30 countries in the ranking of the Global Green Economy Index		Shifting from fossil fuel to green hydrogen would bring ecological benefits
9	Rank among the first 40 countries in the Doing Business Index and among the first 70 countries in the Global Competitive Index in the world		Policy interventions can level the playing field in the energy sector, promoting investments in new technologies
10	Build professional, stable and participative governance, free of corruption that is adept at implementing development policies at all levels		NA

⁷ Analysis by authors. The green colour code signals that the introduction of green hydrogen could positively impact the achievement of the sustainable development indicator. The yellow colour coding indicates that no direct link is identified.

From a public health perspective, the shift to cleaner fuels could improve the air quality by avoiding the generation of particulate matter and other health impacting non-GHG gases. The already recognised issue of bad air quality in Mongolia, particularly in urban areas, could thus be improved from a shift away from fossil fuels and towards renewable energy-based energy carriers.

Even though a shift to low-carbon energy systems requires considerable investments, it also provides returns in terms of job creation. From jobs in the renewable energy generation and hydrogen production to all the potential end-use applications, a more decentralised and labour-intensive economy would provide high skilled job with a potentially multiplier effect when hydrogen is used in conjunction with other resources (e.g. linking production of hydrogen with other resources and promoting trade of these higher value-added commodities) (IRENA, 2019a).

Beyond these indicators, a shift to green hydrogen could promote energy security by reducing the overall reliance on oil imports. Another aspect which could have beneficial economic impacts is the supply of cleaner mining products to the global market. As other major mining nations such as Chile and South Africa are transitioning to hydrogen-based technologies in their heavy industry sectors, the supply of mining products with lower embedded emissions to the global market increases. In a future where countries and regions increasingly consider instruments such as carbon border adjustment mechanisms to put stricter requirements on imported goods, a shift to cleaner technologies in the mining sector could be economically beneficial for Mongolia.

4 The role and importance of policies

Based on the analysis conducted in section 3, this section aims to explore how the results could be used to inform further decision making and policy design. More specifically, enabling conditions for the introduction of green hydrogen are identified alongside an analysis of the global status of hydrogen policy. The Mongolian perspective is considered, seeking to find policy instruments that can create enabling conditions to accelerate a transition to green hydrogen in the sectors where potential added value is identified. A key finding is that, given the early state of the Mongolian hydrogen sector, focus on R&D and piloting should be a priority. Based on the previous results, policies related to the production and the uptake of synfuels in Mongolia are not further analysed.

As with the introduction of most new energy carriers historically, hydrogen will be dependent on policy support to enter the market and achieve market growth. Given hydrogen's complexity as an energy carrier, its policy support needs to be considered and planned carefully. The fact that many hydrogen applications have not yet been demonstrated at scale makes its timely roll-out and potential added value difficult to compare against other decarbonisation options. The variety of decarbonisation options available in some sectors, competing in terms of costs and efficiency over time, makes it challenging for governments to make definite decisions on future technologies.

Table 5 gives an overview of policy options applied globally to support the introduction of green hydrogen to the energy system, some of which are explained in more detail in the following sections. Overarching policies provide cross-sectoral measures, sometimes aiming to promote low-carbon technologies in general, and sometimes setting up a vision for green hydrogen in particular. An overview of policies supporting the supply side is given, focusing on the different key elements of the supply of green hydrogen. The demand side is analysed with a focus on the sectors presented in this study: heavy duty transport in mining and the public transport sector, and the space heating sector through looking at strategic, financial, market and regulatory policy angles.

In the following sections some of these policies are discussed in more detail by explaining the theory behind them, potential advantages and disadvantages from the Mongolian perspective. Global examples are identified. Strategies and policies mentioned are not exhaustive but provide examples of the global status of the considered hydrogen policies. As green hydrogen technologies and their adoption is still in its infancy globally, it is yet difficult to evaluate the implications and effectiveness of most policies that have been put in place.

Table 5. Overview of policy options to promote green hydrogen.

Scope		
Technology neutral		Hydrogen specific
Overarching policies		
Strategic	<ul style="list-style-type: none"> Emission reduction targets Target shares of low carbon-fuels in the energy supply 	<ul style="list-style-type: none"> National strategy MoU Electrolyser capacity target
Financial	<ul style="list-style-type: none"> Funding programmes for low-carbon technologies 	<ul style="list-style-type: none"> R&D support Ensuring access to finance Grants
Market	<ul style="list-style-type: none"> Carbon tax/carbon market Clean energy certificates Fossil fuel subsidies phase out 	

Regulatory		<ul style="list-style-type: none"> Minimum market share requirements
Supply side policies		
General	<ul style="list-style-type: none"> Clean energy R&D support Carbon pricing/emission trading schemes 	<ul style="list-style-type: none"> R&D support and pilot projects Hydrogen production target or quotas Contracts for difference Administratively set pricing instruments Price setting target Introduce hydrogen as energy security International collaborations
Electrolysers	<ul style="list-style-type: none"> Participation of large electricity consumers in power market Encouragement of demand-side response in power system Market design and participation in ancillary market 	<ul style="list-style-type: none"> Capital subsidies and grants Electrolyser capacity targets PPPs Import tax exemptions on equipment
Power supply	<ul style="list-style-type: none"> Policies to decouple heat and power RE support mechanisms Policies targeted to reduce RE curtailments Policies to increase and value flexibility in the system 	<ul style="list-style-type: none"> Tax exemptions on electricity used for H₂ production Cross-subsidies on electricity used for H₂ production Exemption of grid tariff for H₂ production
Infrastructure	<ul style="list-style-type: none"> Third party access to the grid Role and design of grid planning Allocation of the cost of network development 	<ul style="list-style-type: none"> National strategy/needs assessment Funding programmes PPPs Targets for refuelling stations Blending standards and quotas Policies on the main grid's arrival Repurposing infrastructure
Water supply	<ul style="list-style-type: none"> National strategy 	<ul style="list-style-type: none"> International collaborations Water resource management / include hydrogen production as part of water uses
Demand side policies		
Transport		
Strategic	<ul style="list-style-type: none"> Minimum market share targets Zero-emission zones Low-carbon fuel quotas in final energy supply 	<ul style="list-style-type: none"> Minimum market share targets
Financial	<ul style="list-style-type: none"> Purchase subsidies Tax exemptions 	<ul style="list-style-type: none"> PPPs R&D grants
Market	<ul style="list-style-type: none"> Emission trading schemes 	
Regulatory	<ul style="list-style-type: none"> Public procurement programmes Vehicle emission standards 	<ul style="list-style-type: none"> Public procurement programmes

		<ul style="list-style-type: none"> Standards for hydrogen-fuelled vehicles Blending standards and quotas
Space heating		
Strategic	<ul style="list-style-type: none"> Decarbonisation roadmap Renovation/retrofit programmes 	<ul style="list-style-type: none"> Technology applicability assessments
Financial		<ul style="list-style-type: none"> Purchase subsidies R&D funding
Market		
Regulatory	<ul style="list-style-type: none"> Building codes 	<ul style="list-style-type: none"> Blending standards and quotas

4.1 The broad view - Overarching policies

Overarching policies does not specifically target the supply or demand side of green hydrogen but aims to more broadly stimulate the production of, and the demand for, carbon neutral technologies. These policies should be anchored with other national cross-sectoral policies and objectives to ensure consistency. In this section, we discuss the relevance and function of overarching policies in the context of Mongolia.

In addition to policies specifically targeting the supply or demand side, overarching policies aim to more broadly promote the development of a green hydrogen sector, and to anchor its development with other climate policies and strategies. Overarching policies should help set up the vision for the role of hydrogen in the country's decarbonisation. Such policies could be of a top-down character, such as **emission reduction targets**, **target shares** of low-carbon fuels and technologies in specific sectors, or the **phase out of carbon-intensive technologies**.

Mongolia should thus aim to identify potential decarbonisation solutions and design technology-neutral policies to let the market find the most cost-effective option. By doing so, lock-in effects of slowly developing or less efficient decarbonisation technologies can be avoided. In the meantime, Mongolia should consider policies aiming to phase out the use of carbon-intensive technologies. The gap created by the phase-out of these technologies creates a market vacuum for cleaner technologies. Based on that, Mongolia should identify end-use sectors where unique solutions are available and develop policies to specifically promote those technologies.

More specifically, Mongolia should not view green hydrogen as a direct substitute to fossil fuels but should rather consider green hydrogen as one of several potential decarbonisation options. As such, it should be assessed in conjunction with other decarbonisation options such as the direct electrification of end-use sectors. It should be ensured that the deployment of green hydrogen technologies does not interfere with the increase of renewable capacity in the power sector and for direct electrification of end-use applications. Ultimately, it is important to ensure that policy planning to support hydrogen production avoids an expansion of fossil-fired power capacity to meet additional demand from electrolyzers.

Based on this, a first step in its hydrogen policy planning could be the development of a categorisation system which identifies the expected potential, and the added value green hydrogen could bring in specific sectors, given the national and regional context. A first attempt of such analysis in the Mongolian context is provided in this study. The analysis considers supply and demand side barriers to identify the economic feasibility of a transition to green hydrogen in three end-use sectors. However, to identify the most suitable decarbonisation option in each sector, further research and modelling exercises including a comparison with other technologies is suggested. As the

focus of the modelling in this study is on estimating the economic feasibility of green hydrogen on the supply side and in specific end-use sectors, a rational next step would be to conduct an analysis on the comparison with other decarbonisation options that are at hand.

As Mongolia is still at an early stage in terms of considering green hydrogen as a decarbonisation option and has yet no policies related to its development/promotion, a categorisation system could therefore be based on the results of such analysis. The results of this study suggest that green hydrogen is not yet cost competitive in any of the analysed sectors but could become so for some end-uses in the near-to mid-term future. Hydrogen technologies should therefore be included in the development of future decarbonisation strategies. Based on those results, further decisions in terms of most efficient policy design can be made.

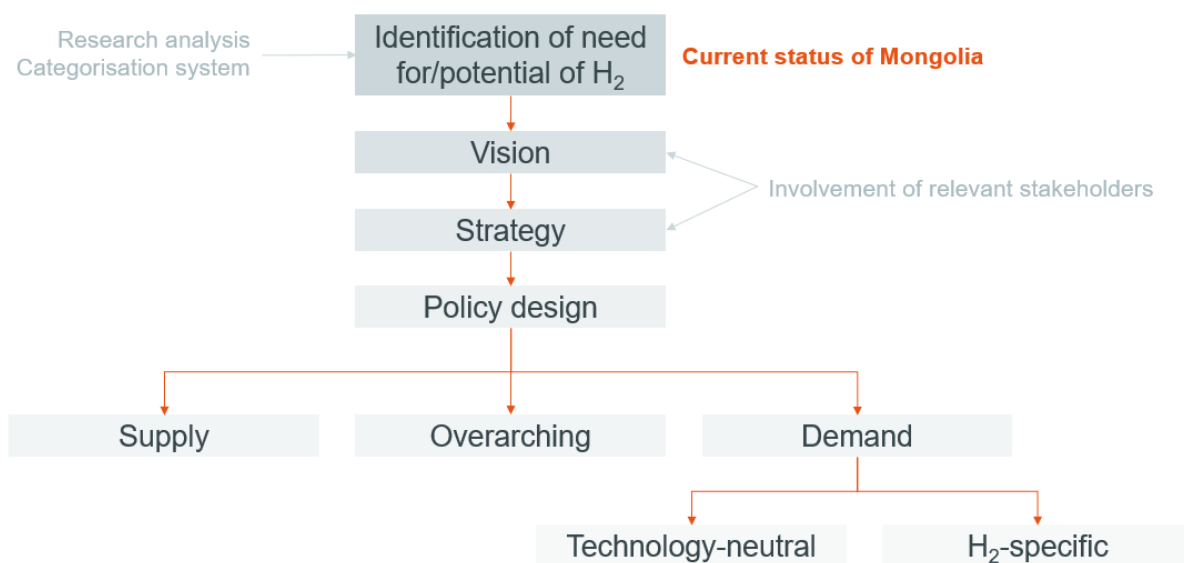


Figure 18. Overview of the process of the introduction and development of a green hydrogen sector.

In the process of categorising end-uses for hydrogen, several factors should be considered. Firstly, it is important to keep in mind the advantages and disadvantages of hydrogen compared to other decarbonisation options. Given the many conversion steps and the resulting efficiency losses, direct electrification will on many occasions be preferable to hydrogen applications. **A general principle should be that renewable electricity should always be directly used for electrification where possible.** However, direct electrification in Mongolia has other complexities - the coupling of the power and heat sectors being a major one - as it limits the participation of renewables and restricts flexibility of the power grid. Further, aspects beyond technology such as need for retrofitting and infrastructure development should be considered.

A categorisation system should therefore be a living document able to dynamically react to system and technology fluctuations. It can then serve as the basis to develop a hydrogen vision, which can eventually be turned in to a national hydrogen strategy (IRENA, 2020a). This process is pictured in (Figure 18). A national hydrogen strategy could serve as a guiding document, clearly stating the objectives of developing a hydrogen economy, and how Mongolia envisages to achieve those objectives. Through target setting for **emission reductions** or **hydrogen production** (further discussed in section 4.2), the strategy can send clear signals to the private sector. Further, the national strategy could identify specific areas for policy development required to support the transition.

Several countries are “piloting” hydrogen as a cornerstone of the energy system through the introduction of hydrogen hubs. Such hubs can be in cities, provinces or ports with a high

concentration of potentially important hydrogen end-users and favourable conditions for green hydrogen production. Through such approach, the complete hydrogen value chain can be trialled at small scale, and barriers, trade-offs and synergies can be identified for consideration for wider deployment. An example of such is the Chinese industrial hub of Hebei which approved a total of 43 hydrogen related projects in the areas of production, equipment manufacturing, filling stations and fuel cells in 2020 (Fuel Cell Works, 2020). Beyond climate aspects, assessments can be made for how a transition to hydrogen could bring additional value such as economic, employment and health benefits.

In the Mongolian context, few cities exist with a reasonable size and a public transportation system in connection with the mining areas which could be used to trial hydrogen in those end-uses. Therefore, a hub approach in Mongolia would more realistically include a cluster of mining or industrial sites that could benefit from green hydrogen production and consumption in trucks on site as well as the long-distance transport of goods. Using such approach, other synergies such as the reuse of wastewater from industries could be explored.

4.2 Supply side policies

Supply side policies aim to stimulate the production of green hydrogen by managing risks and promoting R&D and piloting. A key focal point here is to reduce the costs and to support green hydrogen to reach cost parity with incumbent fuels. In this section, we discuss various policy examples in specific supply side areas, and their relevance in the Mongolian context.

General supply side policy

The choice of policies to support green hydrogen production should be based on the characteristics of the technologies needed (e.g., electrolyser, renewable power, infrastructure) and their state of development. Any policy to support the production of hydrogen is incomplete if it is not accompanied by policies at the demand side to develop its market.

Green hydrogen development needs a steady supply of renewable electricity to be produced, and in this line, the design and implementation of supply-side policies can learn from global experiences of upscaling renewable energy in the last decades. There is not a single policy that successfully leads the development of a technology by itself. The right approach comes from the combination of policies targeting different elements of development such as technology maturity, risk mitigation and access to finance, among others.

On the supply side, there are two types of policies: technology-push and market-pull. In early stages of development, when there typically is substantial potential for technical improvement and cost reductions, the best options are technology-push policies such as **R&D support** or **capacity installation targets**. Moreover, a quantity-based mechanism such as setting a **hydrogen production or electrolyser capacity targets** brings the benefit of knowing the amount of hydrogen to be produced, which has favourable implications for energy system management. Further, as the technology evolves, improvements may only be made if the market for hydrogen grows significantly and allows for economies of scale. This can be achieved by market-pull policies such as **hydrogen production quotas**, **administratively set pricing instruments** for green hydrogen (e.g., feed-in premium) or **contracts for difference**.

The absence of large-scale uses of green hydrogen in Mongolia makes the implementation of quantity-based policies such as hydrogen production quotas unfeasible at present. However, these mechanisms could become adequate when hydrogen eventually moves beyond the R&D phase.

Therefore, these policy instrument could be included in a hydrogen strategy looking at the mid- to long term.

Measures like administratively set pricing instruments and contracts for difference function through the establishment of a fixed price for hydrogen, which reduce risks and provide economic signals to further develop the technologies. However, reducing the risk also requires the producer to be sure of an existing demand for green hydrogen. There could be various ways to do this. For instance, an agreement could be established with the government to purchase the hydrogen at a fixed price. It would then be the governments' responsibility to further distribute the hydrogen. Such could be the case where large parts of the infrastructure network is owned and operated by the state, for example in district heating systems. The state could also sell the hydrogen to private operators. Such policies on the supply side would thus need to be properly matched with demand side policies which aim to ensure the supply and demand are growing at a similar pace.

At present, these types of administratively set pricing signals for hydrogen have not yet been put in practice and there is little real-world experience with regards to their actual impact. There are, however, countries which are planning to introduce them. In its national hydrogen strategy, Portugal proposes a "support mechanism" to cover the cost gap between green hydrogen and natural gas between 2020 and 2030, which can ease the investment risk for green hydrogen producers (Government of Portugal, 2020).

On the one hand, this type of policy instrument might be more suitable to regions where there already is an emerging and confident projected rise on the demand side. However, it might also be what is needed to stimulate the demand side. As such, administratively set pricing instruments could be a good measure where there already is a recognized need for hydrogen specifically. For instance, if the government is willing to bet that green hydrogen will be the most attractive option to decarbonise its heavy-duty transport sector, pricing instruments may be a good way to attract investments and kickstart the supply.

In the Mongolian context, this study shows that - at present - the cost gap between diesel and green hydrogen in terms of energy delivered to the wheel is about 12% in the mining sector (trucks) and 30% in the public transport sector (buses). Along with projected decreasing production prices of green hydrogen as a result of efficiency gains and technology improvements, the price difference support needed from the Mongolian government would also decrease accordingly over time. Based on this, administratively set pricing instruments such as contracts for difference could be a suitable option for the Mongolian government to consider once the technology has been proven and is through the initial pilot phase. Pricing and contract instruments could also be agreed/negotiated with specific actors in the private sector. Moreover, a potential beneficial pathway could be to trial the policy at a smaller scale, for instance jointly with a pilot project in the mining sector. The approach to pilot low-carbon technologies and policies has, for instance, proven successful in China.

Setting a price target could be a complementary policy, particularly for countries aiming to become hydrogen exporters. A price target defines at what price green hydrogen should be produced in a certain year. For instance, Chile aims to produce hydrogen by 2030 at below USD1.5/kg hydrogen (Government of Chile, 2020) compared to Japan's USD3/kg hydrogen by 2030 and USD2/kg by 2050 defined in its national hydrogen strategy (Japan Ministry of Economy Trade and Industry, 2017). As discussed in section 3.1, hydrogen production in Mongolia makes sense when it is targeted at specific uses, rather than being centrally produced to supply a wide range of users or for export purposes. A price setting target is, at present, not relevant in Mongolia if its hydrogen strategy does not target a future role as hydrogen exporter. However, this may change in the future. Considering the favourable conditions for green hydrogen production in Mongolia with regards to renewable energy resources,

exporting green hydrogen could potentially be an ambition for the future. Moreover, considering that several countries in the region, including Japan and Korea, plan to become hydrogen importers, there could be a business case for Mongolia. However, in order to fully investigate that potential, a comprehensive water availability assessment is required.

As with the development of renewable energy, multilateral collaborations, spill-over effects and standardisation are a vital part of a hydrogen transformation, in particular with regards to the development of common standards considering life cycle emissions of hydrogen in order to ensure its sustainability (COAG Energy Council, 2019; Government of Chile, 2020; Norwegian Ministry of Petroleum and Energy and Norwegian Ministry of Climate and Environment, 2020; The German Federal Government, 2020). Molecules of green hydrogen are identical to those of grey hydrogen. For this reason, once hydrogen has been produced, a certification system is needed that allows end users and governments to know the origin and quality of the hydrogen. The schemes used to track origin are usually referred to as **guarantee of origin** (IRENA, 2020a). In any case, the development of a hydrogen supply sector for the domestic as well as international market, Mongolia should initiate a process to develop a certification scheme to ensure the level of sustainability of the produced hydrogen. In such process, it might be beneficial to engage with the international community to develop standards that are in line with a common international certification system. Importantly, given that the main purpose why countries globally are considering the introduction of hydrogen system is to meet and strengthen their emissions reduction targets, the international market for grey hydrogen will be negligible.

Other indirect policies that may support the production of hydrogen include policies which incorporate the costs of negative externalities of pollutant emissions, such as **carbon pricing** or **emission trading schemes**. For instance, in its national hydrogen strategy, Germany emphasised **carbon pricing for fossil fuels** in the transport and heating sectors as one of the instruments to improve the business case for green hydrogen (The German Federal Government, 2020). However, as carbon pricing alone is not expected to achieve the set targets, complementary policies such as tax exemptions, levies and surcharges from the electricity consumed for hydrogen production are also being considered.

Attaching a price to carbon emissions is a pre-condition to trigger the development of green hydrogen production and making it more competitive. By internalising the externalities in the form of either a carbon tax or an emissions trading system (ETS), policy makers can value the benefits of reducing emissions and closing the economic gap with fossil fuel pathways. However, the proper design of a carbon pricing mechanism must understand the economic distortions this can cause and assess whether it brings transformational changes or an additional burden to energy users. For instance, if not well designed, CO₂ prices could end up being as low as zero, or ultimately increase the price of electricity if these costs are passed through to the consumers.

Carbon pricing and ETSs in the Mongolian context, however, is not something that has been discussed to this point. Price-based policies are also not recommended given the current, fossil-fuel heavy energy mix in Mongolia and its difficulties to substitute the energy supply with clean alternatives at a competitive cost. The almost entire reliance on coal-fired CHP plants would mean that a carbon price could significantly increase electricity and heat prices impacting the consumers, including electrolyzers connected to the grid. Nevertheless, some implications for Mongolia could potentially be expected from interactions with ETSs in other countries or regions, as is already the case for some emission reduction activities linked to the Chinese ETS as well as to the Japanese Joint Crediting Mechanism (JCM).

The adequacy of a support mechanism for any technology should depend on its maturity and in understanding its role in the energy supply. Given the current early stages of green hydrogen in Mongolia, policy efforts should be focused on R&D support and pilot projects. Technology-push

policies at early stages of development such as R&D support and pilot projects allow a better understanding of the real potential of hydrogen production, its limitations, and the role it can play in the energy supply. These measures allow to control different key variables such as managing risks, spur implementation, and discover unknown variables. The path to follow after these measures have achieved their purpose is to gradually move to market-based mechanisms (e.g., administrative set pricing, carbon pricing), which are suited to close the gap between the maturity of the technology and the market competitiveness. Mongolia's policy approach should therefore initially be of a high-level character, encouraging green hydrogen production at a small scale through the implementation of pilot projects where technologies and policies can be trialled. If proven successful, the introduction of high-level policies could subsequently be accompanied with additional policies targeting all elements of green hydrogen supply: electrolyzers, power, infrastructure, water. Those policies are discussed below.

Electrolyzers

At the onset of electrolyser development, policy support must address the barrier of high capital costs. On a second level, policies to remove power market barriers are also needed to allow electrolyzers to participate in the market and realise their full potential. With costs being the main barrier to hydrogen deployment, supply side policies should aim at closing the cost gap between hydrogen and incumbent fuels. As shown in this study, Mongolia already has the advantage of being endowed with plentiful renewable energy resources and can produce renewable electricity at relatively low costs (average generation costs between \$40 and \$50 per MWh). However, other costs, such as capital investment for electrolyzers and scaling up production capacity could be brought down with public financial policy support. Such support could be provided in the form of pilot programmes, investment grants and subsidies.

Pilot projects and financial support programmes are a common part of most published national hydrogen strategies to date, albeit varying in scope and sectoral focus. Pilot projects and R&D support help to improve efficiency in electrolyzers, gaining know-how and reduce capital costs. Financial support such as **capital grants, government loans, and subsidies** can improve the business case for the installation of electrolyzers. **Access to finance and fiscal incentives** such as **tax exemptions** can also contribute to make electrolyzers more attractive. The Australian Renewable Energy Agency (ARENA) has recently selected two hydrogen projects under its Renewable Hydrogen Deployment Funding Round which are to demonstrate renewable energy-based electrolysis at large scale. One of the criteria for eligible applicants was that projects must have a minimum of 5 MW capacity, sourced either from renewable energy or through an approved contracting or certificate approach (Minister for Energy and Emissions Reduction, 2020). The United Kingdom has awarded USD 9.8 million for a feasibility study to scale up the size of electrolyzers to 100 MW and is aiming for a 5GW green hydrogen production capacity by 2030 (Element Energy, 2020; Government of the United Kingdom, 2020). The German hydrogen strategy takes a more sector specific approach to direct financial support for electrolyzers. For instance, funding for investments in electrolyzers in the industry sector for the production of green hydrogen in the steel and chemical industries will be prioritized (The German Federal Government, 2020).

Beyond costs, **public-private partnerships (PPPs)** in combination with financing support could be established in pilot projects to gain experience and scale up production to achieve economies of scale. Public-Private Partnerships have been identified as an important instrument to tackle the high capital costs in various countries. In Sweden, the HYBRIT pilot project, a green hydrogen steel plant, is a result from the collaboration between the state and the private sector (SSAB, 2021).

Pilot projects of electrolyzers in Mongolia with different configurations (e.g., connected to the grid, off-grid) can help understanding their potential beyond the production of hydrogen to increase flexibility of the system and gradually decouple heat and power production in the country. Pilot projects of electrolyzers in Mongolia would help understand the importance of flexibility in the system and the role that hydrogen could play in an energy transition and decoupling heat and power supply.

In addition to improving their efficiency and supporting their capital costs reduction, electrolyser pilot projects provide relevant information on their performance, limitations, and interactions in the Mongolian energy system, which can be translated into more effective policies or adjustments in market design in the future. International support from multilateral banks or private investors in the form of PPPs to support pilot projects are needed to reduce the burden of high capital cost at early stages of development.

The interest in and attractiveness of PPPs might be spurred though target setting, which sends clear signals to the private sector in terms of Mongolia's commitment to hydrogen. Current knowledge suggest that the heavy transport mining sector might be a sector with few other decarbonisation alternatives, while the case for buses and space heating looks more diverse. Such information could provide a basis to produce data to inform policies such as **electrolyser capacity or hydrogen production target setting**. However, hydrogen target setting should be based on rather confident projections for a hydrogen sector, as it otherwise risks counteracting other decarbonisation technologies. For instance, should fuel cell vehicles be identified and confirmed as the most suitable decarbonisation option for heavy duty mining operations, estimates on projected green hydrogen demand could be developed and applied as a basis for target setting in Mongolia. Should the conclusion instead be that there is no clear winner in terms of technology, and as a result, it is undecided whether green hydrogen will have an important role in a Mongolian decarbonisation strategy, more technology neutral policies can be the focus to let the market decide on the technology to be adopted.

Various countries have set hydrogen targets as part of their decarbonisation strategies, outlining the envisioned role of hydrogen in the country. As an example, the EU aims to scale up electrolyser capacity to 6 GW by 2024 and 40 GW by 2030 (European Commission, 2020). Chile plans to use its vast renewable energy resources to become one of the major future green hydrogen suppliers globally and aims for an operating capacity of 5 GW by 2025, scaled up to 25 GW by 2030 (Government of Chile, 2020). Portugal aims to break it down further by introducing sector-specific hydrogen targets, in line with the national climate ambition level, availability of technological solutions and current and future investment capacities (Government of Portugal, 2020). Such capacity targets should be developed to be aligned with national climate policies such as GHG emission reduction targets or share of clean fuels in the final energy supply. By doing so, the role of hydrogen in the national climate strategy can be clearly defined and can contribute to a robust decarbonisation pathway.

The current energy market in Mongolia facilitates to gradually adopt more sophisticated market-oriented designs to transition towards a more flexible system (Energy Regulatory Commission of Mongolia, 2020b). However, it lacks the active participation of large electricity consumers in the market as well as a market to provide regulation and ancillary services. This is a barrier already identified regardless of the development of hydrogen in the country. A transition to increasing participation of consumers in the power market and market designs to improve system operation can untap flexibility options in the system and bring other technologies into the system, such as electrolyzers or batteries.

As discussed in section 3.1, electrolyzers can provide flexibility to power systems. Efficient policies and market designs are needed to value this flexibility and allow providers to profit from it, while the system benefits from improved flexibility. For example, allowing large consumers and electrolyzers to

participate in the electricity market, encourage demand side response (e.g., time-of-use tariffs) or the creation of **markets for ancillary services** (reserve regulation, ramping, etc).

Changes in power systems regulation to enable the participation of large consumers can be very challenging. The regulatory and institutional inertia of current frameworks often hinders the implementation of policies that change the structure of the system and the market. The difficulty of these challenges largely depends on the configuration and complexity of each power market and the institutional framework of the power system. Many power markets around the globe have developed to include ancillary services and allow the participation of large consumers in the last decade. These changes have not been related to hydrogen but rather driven by the increasing participation of renewables and more active role of distributed energy resources. For example, the 2019 European Clean Energy Package establishes an energy policy framework to facilitate the transition away from fossil fuels towards cleaner energy and puts consumers at the centre of the energy transition (European Commission, 2019). The evolution in the design of such markets is evolving and becoming more refined as the need for flexibility increases.

Power supply

As from the power supply perspective, any policy or market design that directly or indirectly increases the participation of renewables in the system and reduces electricity price would have a positive impact in the development and competitiveness of green hydrogen. Electricity generation is the major cost component in the production of green hydrogen. The massive deployment and subsequent cost reductions of renewable technologies will be the main driver to achieve further cost reductions in green hydrogen production and make it cost-competitive with fossil-based hydrogen. However, policies are also instrumental in developing the technologies and bringing further down the costs (IRENA, 2020b).

Some policies can reduce the cost of electricity specifically for green hydrogen production. For example, the cost of electricity to produce hydrogen could be **exempt from taxes, grid charges or levies**, reducing its cost per energy unit making it more attractive. Similarly, electricity tariffs for some consumers can be subject to a **surcharge to support hydrogen production**, as it was done in some countries in early stages of renewable development.

Once installed, renewable sources can generate electricity at zero or close to zero marginal costs. In a competitive market, a larger participation of renewables in the energy mix can be reflected in lower wholesale electricity prices. Therefore, a higher share of renewables in the generation mix has two positive effects to produce green hydrogen: on the one hand, it decarbonises the power supply and, on the other hand, it contributes to lower wholesale electricity prices, making hydrogen production more competitive. In this direction, any policy that removes barriers to access to power markets or that aims at increasing renewables in the power sector is positive for green hydrogen, including **renewable support mechanisms** (e.g., feed-in tariffs, renewable auctions, etc.).

Average capital costs of renewable generation reach record lows year after year, and they are expected to continue to decline in the future. As renewable technologies mature, policies to efficiently integrate larger shares of renewable generation in the system evolve, such as policies and market design to **increase flexibility in the system** (e.g., reserves market, ramps remuneration, etc.) or **address renewables curtailments**. Green hydrogen can indirectly benefit from these policies as well.

There is vast experience in policies and market designs created to support deployment of renewables and facilitate its integration to the power systems (IRENA, IEA and REN21, 2018; IRENA, 2019b; IEA, 2020d; REN21, 2020).

Policies and market designs need to be carefully evaluated beyond its impact on hydrogen support, as they can cause market distortions that can lead to inefficiencies in the power system and the economy. Any policy support in power supply targeted to develop green hydrogen production must come after a careful assessment and prioritisation of the uses of electricity in the country. Energy efficiency measures and electrification of end-use sectors should come first in the efforts to decarbonise the economy whenever they are technically feasible. Failing to understand this prioritisation could lead to slow down electrification trends or encourage the installation of more fossil-fired electricity to supply the additional electricity demand for hydrogen production.

There are solid arguments in favour of using a surcharge in electricity price to support hydrogen, impose a carbon pricing or exempting taxes and levies from the cost of electricity used to produce green hydrogen. However, any policy that artificially distorts electricity prices, even if meant to support hydrogen, could also impact vulnerable populations and other sectors, making them less competitive.

Although a tax or cross-subsidies would be a competitive advantage in the production of green hydrogen compared to a fossil-based alternative, it would also impact other economic sectors. The design of a policy affecting electricity prices must understand the linkages between electricity price and other economic sectors.

In the Mongolian context, policies that support the deployment of renewables and the decoupling of heat and power systems would be most beneficial for green hydrogen. Policies that artificially distort electricity prices might place more burdens on the economy than cause a transformational shift towards hydrogen development in Mongolia. In many parts of the world, VRE is becoming the cheapest source of new electricity generation, displacing cheap fossil sources. Mongolia counts with rich renewable resources potential that could be reflected in low-cost renewable energy generation costs. However, the Mongolian power system is not currently able to capture the benefits of cheap renewable technologies and the availability of these resources to reflect it in low electricity prices.

To make green hydrogen a cost-competitive alternative to decarbonise end-use sectors, Mongolia should adopt regulatory instruments or system operation mechanisms that enable to capture renewable energy potentials and reflect them into low electricity costs. Some changes could be easier to address such as increasing flexibility in the system or reducing exposure to curtailments. Other deeper structural changes are the creation of additional revenue streams (e.g., provision and monetisation of regulation reserves) or policies to promote decoupling of heat and power supply.

For instance, allowing negative electricity prices would send economic signals to CHP plants to meet their heating requirements but decouple it from non-valued electricity production. This would also prevent renewable energy from being curtailed (Agora Energiewende, 2014).

Also, efficient ancillary services or regulation reserves in the power market can increase flexibility in the system and reduce the burden of renewables curtailment, which would also allow to capture the low generation costs from renewable power.

Infrastructure

A vital part of the hydrogen value chain is the infrastructure network, providing power for electrolysis and delivering hydrogen to its end-use site. In global terms, existing infrastructure is mainly limited to small-scale systems as most initiatives are yet in the pilot or demonstration phase. Large scale hydrogen distribution network needs will to some extent be dependent on what current infrastructure already exist and what end-uses are to be supplied. Further, the allocation of sufficient

resources to fill current infrastructure gaps needs to be ensured. In this aspect, investments directed at, for instance, the expansion of the power grid could benefit a wider spectrum of objectives such as facilitating a wider integration of renewables to the power sector.

As discussed earlier in this section, green hydrogen production in Mongolia will be dependent on the expansion of renewable energy capacity and policies must therefore promote the integration of renewables to the power grid. The liberalisation of the power sector through granting **third party access** to the power grid could promote competition and allow small players to enter the market which would make it easier for renewable energy actors to enter. As rich renewable energy potential in Mongolia is located in remote locations with poor access to the grid, **energy system planning** and supporting policies for **grid expansion** will be needed. However, the conditions for infrastructure developments such as grid expansion in Mongolia are harsh. Extreme winters and long distances make grid expansion more challenging and costly. Hydrogen projects should therefore initially focus on areas which require no or little infrastructure development, such as the installation of electrolyzers close to the grid or decentralised hydrogen production close to the end-use site. Based on this, and the results of this study, the mining sector could make a suitable option for initial trials.

Policies to support the development of a hydrogen distribution network will vary depending on context-specific parameters and the end-uses of the hydrogen. In terms of international examples, countries take various policy approaches based on their existing infrastructure and visions for hydrogen in the future. Generally, however, a first useful step to get an idea of infrastructure needs is the conduction of an **infrastructure needs assessment**. In Germany, a report assessing the long-term needs developed together with relevant stakeholders aims to give concrete recommendations for action with reference to the development of a hydrogen distribution network. The assessment should take into account aspects such as future demand and possibilities to use existing infrastructure including gas pipelines and railways (The German Federal Government, 2020). By involving relevant stakeholders, concerns and priorities from a wider target group can be considered at an early stage. Similarly, the government of Australia are to put together a national hydrogen infrastructure assessment by the end of 2022, which will consider supply chain needs such as electricity and gas networks, water supply networks and refuelling stations while also accounting for local community aspects. By reviewing and updating the assessment every five years, it will inform government decisions related to future support of hydrogen infrastructure development (CSIRO, 2019). As such, the hydrogen distribution infrastructure may evolve as the demand profile develops.

The need for a hydrogen distribution infrastructure in Mongolia is at present very limited and should not be the primary focus in the development of a hydrogen supply sector. However, once the initial pilot phase is finalised, and there is a better understanding of to which scale hydrogen could play a role in Mongolia, an infrastructure needs assessment should be conducted to inform further policy making supporting the development of a distribution infrastructure.

As discussed in section 2.2, the most efficient way of transporting hydrogen is through pipelines. In countries or regions where a gas infrastructure already exists, **blending quotas** could facilitate the introduction of hydrogen to the system, which could mitigate emissions to a certain extent. As an example, Chile plans to develop hydrogen quotas in their existing gas pipelines (Netherlands Enterprise Agency, 2019a; Government of Chile, 2020; Government of the Netherlands, 2020). However, to fully decarbonise, pipelines must be repurposed for the full integration of hydrogen. Mongolia has no existing gas infrastructure which could be repurposed and developing a distribution pipeline for hydrogen only would be too costly unless hydrogen takes a leading role in decarbonising the economy. Therefore, it might be more beneficial to, at the initial stage, develop infrastructure as demand emerges and develops

In the initial phase of introducing hydrogen to a sector, there might still be a high level of uncertainty with regards to the level of success and projected demand. Distribution projects could therefore initially be an **integrated part of pilot and demonstration** projects to gain better understanding and experience with regards to the most efficient distribution systems. That experience can subsequently be used for more widespread, large-scale development of distribution infrastructure. Therefore, **public-private partnerships** could be particularly useful for such initial trials through risk sharing, capacity building and gaining knowledge. As such, hydrogen in Mongolia might be transported by road in compressed tanks where needed, such as in the case of fuel cell buses in Ulaanbaatar. Through private-public partnerships, that option could be initially trialled at small scale. The mining sector has the advantage of already being situated within the proximity to renewable energy rich areas, which substantially reduces the need for distribution infrastructure development.

Taking refuelling stations as an example, the Norwegian hydrogen strategy emphasizes that the need for refuelling stations is likely to be quite small in the early stage, and thereafter needs to be developed according to how the market develops. Depending on which technologies prove successful, the distribution of hydrogen should adopt thereafter as an integrated part of each individual hydrogen project. It reasons that such step-wise approach is preferable to the development of large-scale, publicly accessible infrastructure, but that companies should consider how their projects could be linked to other projects, sectors and applications as the identification of such connections could bring cost reductions and logistical benefits (Norwegian Ministry of Petroleum and Energy and Norwegian Ministry of Climate and Environment, 2020).

A similar approach could be beneficial for Mongolia. Along with the development of pilot projects, experiences should be collected, and synergies be identified. For example, the potential set-up of a hydrogen hub in the southern Gobi region could provide valuable experiences with regards to distribution networks at small scale. Should Mongolia over time grow more confident in pushing the development of a larger-scale hydrogen sector, an infrastructure needs assessment could be conducted. This could then provide as a basis for policy design to support the development of required infrastructure. Such assessment should also engage with the private sector and other relevant stakeholders to exchange knowledge and priorities.

In sectors where an expected increased demand is quite certain, **public investments** may be required to develop a publicly accessible hydrogen distribution infrastructure. **Investment plans** may be coupled and guided by other measures such as **targets for refuelling station roll-out**. Several countries have set **targets for refuelling station roll-out**, such as Korea and the Netherlands, while In China, the hydrogen charging- and refuelling infrastructure has been identified as one of the main bottlenecks for the development of a Fuel Cell Vehicle infrastructure. For this reason, saved money from its Battery Electric Vehicle subsidy are to be invested in this area (Brasington, 2019). Japan, planning to import a significant share of its future hydrogen demand, are working with international governments and industry stakeholders to develop ways to transport carbon-free hydrogen through the conversion of hydrogen to various energy carriers such as liquified and compressed hydrogen (Nagashima, 2018).

Water supply

The water requirements for green hydrogen production and its impacts on national and regional water availability will be dependent on the scale of hydrogen production as well as the available water supply. Large-scale hydrogen production would generate a water demand comparable to other industrial uses and should thus be an integrated part of a hydrogen strategy – particularly in water-scarce regions. Moreover, the planning of hydrogen production should not only consider water availability and infrastructure, but also its potential local implications for local communities and activities.

The potential restrictions springing from limited water availability will thus vary substantially depending on context-specific aspects including water resources, water-intensive activities, local communities and vulnerability to climate change.

To get a clear picture of potential barriers an initial water assessment considering those aspects could inform further decision making and the identification of potential solutions. For instance, hydrogen planning projects could include **geospatial suitability analyses** considering multiple criteria such as renewable energy resources, access to grid infrastructure, access to water and proximity to hydrogen demand centres. Where criteria do not match, other solutions may be further investigated. Such solutions could include the **desalination of seawater** (although not applicable in the local context), the **reuse of wastewater** or the development of water infrastructure to **transport water** from other regions. **Research** and **piloting** on desalination of seawater and the reuse of wastewater could be useful initial steps to considering those options, while the development of new water infrastructure requires long-term investments and high confidence on the uptake of future green hydrogen production and consumption.

The reuse of wastewater from the energy- and industrial sectors could provide an opportunity to bring economic value to an otherwise unexploited resource. On the downside, creating economic value from a by-product from a fossil fuel-based activity may encourage the continuation of its operation. However, the phase out fossil fuel-based activities would reduce the pressure on the overall water demand, which could give space to green hydrogen production.

As shown in this study, local water availability is likely to be a concern in the Mongolian context. While national water supply is relatively rich, its spatial distribution limits the access to water in renewable energy rich regions, challenging the potential for green hydrogen production. Considering the significant industrial and energy sector activity in those regions, the potential to reuse wastewater could be an interesting path to pursue. In conjunction with small-scale hydrogen production projects, the reuse of wastewater could be piloted to gain more experience on its potential. Portugal is commencing a project on the reuse of wastewater for hydrogen production, which is viewed as an opportunity to enhance synergies between the energy and wastewater sectors, and to gain economic value from a previously unused resource (Government of Portugal, 2020).

The development of water infrastructure is capital intensive and comes with significant challenges in terms of allocation of financial resources and ensuring biodiversity, environmental and local communities' protection. Nevertheless, water infrastructure might benefit various groups already suffering from, or projected to experience water scarcity in the future. These aspects should be taken into consideration when planning water transportation projects from the north to the south in Mongolia. However, considering that the south Gobi region is already experiencing water scarcity, the development of new water infrastructure to transport water from the north could be a well-suited option. Such investment would not be solely dependent on the success of a hydrogen industry as it would serve several other groups including local communities, the agriculture- and the mining sectors.

Another important aspect to be considered is potential international implications from an increased water consumption. As water streams may cross national borders and increased water consumption may affect water streams into bordering countries. On such occasions, **dialogues with neighbouring countries** should be initiated to formulate agreements in water use. The transportation of water in Mongolia could have political implications as some of the rivers feed into neighbouring Russia and China. The potential implications on water flow across national borders therefore should be an incorporated factor in an initial assessment.

In terms of international experience, the water availability aspect has been given little attention in existing hydrogen strategies, although it is not completely ignored. The Australian hydrogen strategy recognizes the potential issue of water availability and states that new jobs and the growth of clean hydrogen should not compromise water availability. As part of its National Hydrogen Infrastructure Assessment (to be completed by the end of 2022), hydrogen supply chain needs, including water supply networks, will be assessed. That will include how to balance the water demand for hydrogen production with other water priorities such as agriculture, industry, mining and households. The strategy includes a geospatial suitability assessment based on important prerequisites for hydrogen production including access to water, ports, pipeline easements and electricity infrastructure. It further concludes that optimal sites for green hydrogen production will have access to renewable electricity and water supplies and that, where available, desalinated seawater or wastewater would be the most feasible option. The use of desalinated sea- and wastewater are to be tested through research and pilot projects (CSIRO, 2019). Desalinating seawater is however not an option for Mongolia as it lacks access costs.

Further, the Chilean hydrogen strategy aims to achieve industrial growth that contributes to an improved living standard while ensuring the responsible use of water resources. Already existing policies related to land uses will be re-assessed to consider the potential of green hydrogen production including potential synergies and challenges in specific regions, such as the use of water resources (Government of Chile, 2020).

As such, Mongolia should include the water availability aspect as an integrated part of its planning of a green hydrogen sector. Geospatial analyses including indicators such as renewable energy potential and water availability could help inform decision making on areas suitable for green hydrogen production, or the planning of water infrastructure.

4.3 Demand side policies

Demand side policies should support the deployment and uptake of hydrogen technologies in specific sectors to incentivise their transition. Depending on the state of technology, policies may focus on R&D and piloting or more market-oriented policies. Moreover, depending on the sector, policy makers may find it more relevant to adopt technology neutral or hydrogen specific policies. The rationale behind this thinking is described and discussed in this section while discussing relevant policy options for Mongolia in the light of the results of this study.

Policies promoting the production of green hydrogen should be matched with policies supporting its consumption. As discussed at the beginning of this section, a first step towards avoiding the promotion of green hydrogen where other decarbonisation options might be more beneficial could be the set-up of a categorisation system where end-use applications are grouped into three key categories. The aim of this would be to explain the potential of, and/or dependence on, green hydrogen to achieve decarbonisation for each end-use sector considered. That potential or dependence is based on technical barriers as well as the country context of Mongolia. Doing so could facilitate the process of policy design. The three main categories could be defined as presented in Table 6. The sectors analysed in this section are further assigned to its corresponding category based on the results and analysis of this study.

Table 6. Suggested categorisation system for the use of hydrogen technology in the analysed end-use sectors.

Category	Description	End-use
1	End-use applications with no or few known and feasible decarbonisation alternatives besides green hydrogen	Heavy duty mining trucks Industry ⁸
2	End-use applications with various known and feasible decarbonisation options, of which green hydrogen could have strategic advantages	Public transport (buses) in Ulaanbaatar Industry ⁶
3	End-use applications with various known and feasible decarbonisation options, of which green hydrogen is currently not the most advantageous option	Space heating Industry ⁶

Demand side policies should be carefully designed to consider where they fit within the categorisation system. In some cases, it could be preferred to implement technology-neutral policies to let market developments define the most feasible option, while in cases with no or few decarbonisation options policy design can be bolder at promoting hydrogen specific solutions.

Policy options are discussed for the three analysed end uses in this section, taking into consideration the results of the case studies and the Mongolian policy context.

Heavy duty transport – mining trucks in the south Gobi

Fuel cell vehicles in the Mongolian transport sector could play a particularly important role in the heavy-duty and mining sector. The current state of technology gives few alternatives for the decarbonization of heavy-duty mining trucks and forklifts. Although battery electric heavy-duty vehicles are still developing, the performance requirements of mining trucks and the long distances in Mongolia suggests that green hydrogen is currently the most feasible option and is thus assigned to the first category in the categorization system. Although implemented policies targeting the deployment of electric vehicles in the light duty sector has brought successful results in many parts globally, the heavy-duty sector faces individual barriers and will likely need a different policy approach. Given the early phase of fuel cell trucks in the light of technology, classic transport policies such as purchase grants and vehicle emission standards might still be too early to implement in Mongolia. Instead, focus should be concentrated at **piloting** and **demonstration** at small scale to ensure the technical suitability and bring down costs. **Public-private partnerships** for pilot and demonstration projects could catalyse the process of technology development and maturity, resulting in a more rapid market penetration.

Other major mining countries are already active in this regard. The Chilean green hydrogen strategy recognises mining haul trucks, heavy duty trucking as one of the end-use sectors with potentially early breakeven points for hydrogen, and thus also plans to provide public support for implementation. Some of the focal regulatory mechanisms discussed include public-private partnerships and pilot projects, aiming to support the kick-start of the hydrogen industry (Government of Chile, 2020). In 2019, two tenders were awarded by the Chilean development bank Corporación de Fomento a la Producción

⁸ The status of technology for some industry sector is yet too immature, and not sufficient data on the Mongolian industry sector was found to conduct a thorough analysis of the Mongolian Industry sector. However, under various circumstances and assumptions, hydrogen could belong to all three categories, based on the industry.

(CORFO) to assess the feasibility of using hydrogen fuelled mining trucks to reduce the carbon emissions from its copper mining industry (Barros, 2020).

Although South Africa have not yet published a national hydrogen strategy, there is already quite some momentum in hydrogen-related activities. In 2020, the South African Department of Science and Innovation invited the private sector to take part in developing the South African Hydrogen Society Roadmap, which aims to contribute to energy security in various sectors including the mining sector (FuelCellsWorks, 2020). Through this initiative, a public-private partnership together with Anglo American is entering a collaboration on the development of a hydrogen valley, trialling the world's largest fuel cell mine haul trucks (Africa Oil and Power, 2021).

Based on this, a similar approach could be taken in Mongolia, particularly in the area surrounding the Oyu Tolgoi mine. Through engaging in dialogues with the private sector, the interest among private actors can be gauged and the set-up of initial partnerships can be formulated. Through financial support from the state, the risks can be shared, and benefits brought to the involved parties. The private actors can subsequently share experiences, valuable to inform further policy making, while gaining benefits as early movers. If proven successful, further policies to promote the uptake of fuel cell vehicles in the mining sector such as purchase grants, tax exemptions and net-zero vehicle targets can be considered. These policies are further discussed below.

Public transportation – fuel cell buses in Ulaanbaatar

Fuel cell buses as a public transportation mode are already active in various locations globally, as well as battery electric buses. As such, there are various technology options to decarbonise the public bus fleet, all subject to individual advantages and drawbacks. Fuel cell buses have the advantages of being able to operate for longer distances and allowing for faster refuelling. However, as already discussed, direct electrification should be the priority where feasible. For these reasons, given the Mongolian context, public transport buses are assigned as second in the categorization system. As such, the adoption of technology-neutral policies could help in providing answers to further policy making aiming to decarbonize the public transport bus fleet.

For the light duty sector, several examples can be drawn from the introduction and expansion of net-zero vehicles globally. Typical policy options in the transport sector include **tax exemptions, purchase grants, target setting** and **vehicle emission standards**. Tax exemptions and purchase grants could stimulate the demand for low-carbon vehicles by providing consumers direct financial incentives, while measures like target setting and vehicle emission standards could send clear signals to consumers and retailers. Targets could be of various types, promoting the uptake of net zero emission vehicles through targets for when all or a certain share of new vehicles sold should be net zero, targets for share of net zero fuels in the transport final energy demand, or targets for a carbon neutral transport sector, among others. Moreover, targets could also take a different approach by **discouraging the continued use of fossil fuelled vehicles** by setting targets for the phase out or the banning of the sales of those.

A combination of policies allows for a more effective transition of the transport sector. Top-down policies such as target setting could encourage consumers to take mid- and long-term targets into account when purchasing new vehicles while bottom-up policies such as tax exemptions and purchase grants give low-carbon vehicles direct advantage on the market, potentially enabling a rapid uptake. This has already been demonstrated in the Norwegian transport sector. Nevertheless, it might prove difficult for policy makers to quantitatively predict the impacts of such policies which could make it difficult to make sure preconditions such as sufficient recharging infrastructure is in place.

In Ulaanbaatar, there are various reasons to consider such policies. In addition to reducing CO₂ emissions, the city is struggling with bad air quality and high pollution rates. In addition, the current bus fleet is old and in need of renewal. Therefore, Mongolia should consider the adoption of technology neutral policies promoting the deployment of net-zero buses, including battery electric and fuel cell buses while providing information on the individual advantages and disadvantages of each option. Such policies could include purchase grants, tax exemptions and vehicle emission standards combined with target shares of net zero energy vehicles, target shares of carbon-neutral fuels in the bus fleet and **setting a timeline for the phase out of diesel buses**. Such policies are already being implemented in various cities globally.

Electric vehicles are exempted from road user charges and from driving restrictions in Ulaanbaatar (Grütter and Kim, 2019), although only 324 are registered in the city as of April 2021 (Dugarjav, 2021). These could be expanded to also cover fuel cell vehicles. Vehicle emission standards are in place and could be further developed to promote net-zero vehicles. There is yet no net-zero emission vehicle subsidy system in place. Nevertheless, subsidies could be a feasible option, yet with regards to hydrogen and fuel cell vehicles, that needs to be combined with supporting policies on the supply side, including infrastructure and charging stations. Should there be an emerging interest for fuel cell buses, refuelling stations might initially be developed at a small scale with support from the government and could be further developed as demand grows.

There are various global examples of countries as well as cities which are adopting technology-neutral policies to encourage the uptake of net zero buses to the public transport system. For instance, Norway aims for all urban buses sold in 2025 to be net zero or use biogas, which is combined with aim to have a net zero emitting transport sector by 2030. Similarly, the Netherlands aims for all new buses that are procured from 2025 to be net zero buses (ElementEnergy, 2017). On the subnational level, several European cities have set targets for their public transport sector, many of them related to the phase out of fossil fuel driven buses. Athens, Paris and Madrid all have committed to phase out all diesel vehicles from their cities by 2025 (ElementEnergy, 2017). Another example is London where all new buses were required to be net-zero emission buses as of 2020, and the complete bus fleet should be of a net-zero type by 2037 (Government of the city of London, 2020).

In China, fuel cell buses are already operational and are helping decarbonise the public bus fleet, as some jurisdictions have differentiated policies for fuel cell and battery electric vehicles. The need for fuel cell vehicles is particularly emphasized for vehicles carrying a heavy load and operating for long periods of time and distances. Through initial four-year pilots in selected cities, fuel cell technologies will be tested, for instance granting financial support to the cities rather than purchase subsidies for consumers (Jin and He, 2020). Moreover, as part of its “Made in China 2025” publication, the country published a hydrogen fuel cell vehicle roadmap in which it sets the specific target of deploying 50,000 fuel cell vehicles by 2035 and one million by 2050. Similarly, Korea also puts particular emphasis on the mobility sector in its hydrogen strategy and expects to direct more funding to hydrogen vehicles than to battery electric vehicles. By 2022, 2000 buses are to be added to the bus fleet, reaching 41,000 by 2040 (Netherlands Enterprise Agency, 2019b). A similar approach could indeed be considered in Mongolia at a stage when its hydrogen sector is more developed and should a clear preference to fuel cell buses be confirmed.

Space heating

The Mongolian heating sector faces various barriers, but its decarbonisation could bring significant benefits. The results of this study suggest that hydrogen does not currently look like a desirable option, but further analysis comparing with other available decarbonisation options should be explored. Based on this, the Mongolian space heating sector is applied to group three in the categorisation system.

The role of hydrogen in the decarbonisation of the space heating sector is yet uncertain and is likely to vary depending on context-specific factors. Further analysis taking such factors into account is needed to provide more information for decision-making and future steps. The outlook for the spatial heating sector is less clear in terms of technology pathways and optimal decarbonisation solutions. As discussed in section 3.2, recent literature suggests that electrification through heat pumps would in many cases be the preferable option. Yet, hydrogen for heating could still be a sensible solution given certain circumstances. For instance, a country with an already existing gas infrastructure for heating could benefit from transforming it to a hydrogen distribution network and, by doing so, avoid costly building refurbishments required for heat pump installations. However, the heating system of Mongolia is complex as it is closely tied to the power sector and needs to satisfy a high heating demand during a large part of the year. The lack of existing gas infrastructure makes the option of a pipeline distribution network very costly and economically undesirable. As shown in this study, neither a decentralized system where hydrogen is distributed in tanks would be an economically viable option. At the same time, a transition to heat pumps would require substantial refurbishment of the building stock to be able to satisfy the heating demand. Assuming a future in which direct electrification plays a dominant role in decarbonising the heating sector, the long and harsh winters in Mongolia might still require some form of seasonal energy storage to meet the full demand (Stryi-Hipp *et al.*, 2018). Green hydrogen could be a potential candidate for that purpose, particularly should a green hydrogen sector be developed in the near to mid-term for other end-uses, which would drive down the costs of green hydrogen.

As discussed in section 3.1, the power sector would benefit from decoupling the power and heating sectors. In addition to that, the significance of the Mongolian heating sector in terms of greenhouse gas emissions and air pollution makes it an important sector to tackle. Future research should therefore look more closely into the complexity of the interlinkages between the Mongolian heating and power sectors to assess the most suitable solution. Under any circumstances, it seems likely that any decarbonisation pathway of the Mongolian heating sector, although costly, would significantly improve some of the country's most pressing issues – from climate change and CO₂ emissions to air pollution and health. Mongolia should therefore **dedicate more research** in this area to analyse and compare the options that are at hand before further considering policy making. In the case that such analysis concludes that there are reasons to trial green hydrogen for heating, the suitability and potential could be further investigated through **R&D** and **piloting**. Although this imposes financial risks on the stakeholders involved, it may give valuable insights for the long-term.

Global examples of policies promoting hydrogen for heating are few, which likely is a result of the level of uncertainty about its efficiency compared to other decarbonisation alternatives. Yet, some countries with a gas infrastructure do consider hydrogen blending through the introduction of quotas. From a global perspective, various countries recognise the potential benefit hydrogen could have in the heating sector, albeit under the right circumstances. There are very few policies explicitly directed towards hydrogen in the heating sector. Nevertheless, hydrogen for heating is mentioned as a possibility in some published hydrogen strategies. In the Netherlands, a set of targeted pilot projects in

the built environment to be realised between 2020-2025 aims to provide more clarity in questions related to applicability, safety, availability, sustainability and affordability.

Germany has since 2016 supported the use of hydrogen for heating in the built environment through its Energy Efficiency Incentive Programme for highly efficient fuel cell heating systems. The programme provides **subsidies** for fuel cell heating systems. In addition to that, the German government is looking into possibilities of providing funding for 'hydrogen readiness' installations (The German Federal Government, 2020).

Other top-down policies can also support the transition to new heating systems. For instance, reducing buildings' heat demand, whether through refurbishing the existing building stock or imposing stricter codes for new buildings can support the transition to carbon-free heating technologies

Overall, the potential for using hydrogen for space heating in Mongolia will be dependent on several context-specific parameters such as the state of the existing building stock, existing energy infrastructure, hydrogen production potential, heat demand and the potential for other decarbonisation solutions.

5 Conclusions

This study provides quantitative estimates on the technical and economic feasibility of producing and adopting green hydrogen in three different end-use sectors in Mongolia. Based on that, the potential emission reduction contributions a transition to green hydrogen could bring in those sectors is estimated. Further, it investigates the policy options required to create an enabling environment for the production and uptake of hydrogen technologies in those sectors. Policy support needs are analysed based on a categorisation system which prioritises end-uses informed by the techno-economic feasibility and the availability of other decarbonisation options.

Although the study provides valuable analysis on the feasibility of green hydrogen in various end-uses in Mongolia, its suitability as a decarbonisation option should be weighed against other decarbonisation technologies. Mongolia has good conditions for producing green hydrogen, which provides a path to decarbonise some of its energy-intensive sectors. However, given the complexities of green hydrogen, its use should be planned in conjunction with the deployment of renewable energy and the decarbonisation of the power sector. As various sectors show different feasibility, policies should be designed to fill the knowledge gap for specific end-uses.

The study finds that the rich renewable energy resources in Mongolia allows for green hydrogen production to be produced at relatively low cost. Depending on the geographic location, hydrogen could at present be produced at a range of USD 3.30 – 4.73 per kg, where the lowest production costs are found in the southeast Gobi region. For reference, the global average cost of green hydrogen in 2020 was around USD 4.8 per kg (IRENA, 2020b). The major share of the production cost is the energy supply, contributing about 65%. A further reduction of the hydrogen cost will therefore be highly dependent on falling energy prices. Moreover, production costs can be further reduced by falling prices of electrolyzers which are expected to decline by 60%-80% by 2030 as a result of efficiency gains and economies of scale.

Another important aspect of the supply side of green hydrogen in Mongolia is the water availability. The current literature suggests that water scarcity is an already existing issue, particularly in the Gobi region, where renewable energy potential is most optimal. On a national scale, however, water availability is sufficient to meet a growing national demand. Based on this, the planning and development of a green hydrogen sector should include a robust water availability assessment, considering potential solutions such as the reuse of wastewater or the potential transportation of water from other regions.

Considering the status of the grid infrastructure in Mongolia, initial focus should be on decentralised production in the context of green hydrogen hubs, alternatively green hydrogen production close to the grid. As such, major infrastructure projects are not recommended in the near term given the uncertainty of the long-term relevance of green hydrogen in Mongolia. Further, initial policies on the supply side should aim to reduce the cost of green hydrogen to reach cost competitiveness to incumbent fuels.

Relative to green hydrogen demand, the analysis finds that out of the three end-uses considered, the most relevant potential for green hydrogen is to power mining trucks in the mining sector. The decarbonisation of this sector has few other technical alternatives, and the study suggests that its economic feasibility is already not far from the incumbent diesel fuelled trucks. At present, a shift to fuel cell trucks would be 12% more expensive than diesel trucks, while the emission reduction potential is rather significant. Due to the long periods of operation and energy intensive activities, replacing diesel with green hydrogen could mitigate an estimated 1.2 MtCO_{2e} per year, corresponding to about 3.5% of national emissions in 2014, if used for most copper and iron ore mining. This corresponds to an estimated abatement cost of only 10 USD/CO_{2e}. As the current state of technology provides few other

decarbonisation options for the mining industry, the adoption of fuel cell trucks is considered relevant in the Mongolian context.

Further, the study finds that the use of fuel cell buses in the public transport system of Ulaanbaatar is not yet economically competitive with diesel buses, although the gap is narrowing. At present, the study finds that the gap in terms of energy delivered to the wheel is 28%, while when comparing the cost per operating hour the cost gap is reduced to 15%. In terms of emission reduction potential, the limited size of the public transport fleet in Mongolia would only bring modest emission reduction. By transitioning the public bus fleet of Ulaanbaatar, a total of 39ktCO₂e could be avoided annually at an estimated abatement cost of above 100 USD/tCO₂e. However, there could be potential for Mongolia to further consider the adoption of fuel cell vehicles for long distance freight which would bring additional emission reductions. Given recent advancements in electric mobility, hydrogen is not the single available decarbonisation option for buses. Nevertheless, it carries valuable advantages. As buses for public transportation in Ulaanbaatar operate over long periods of time, the long drive range of fuel cell busses and their potential to be quickly refilled are clear benefits. However, such benefits must be weighed against benefits of other options.

In addition to the current state, the technoeconomic feasibility of green hydrogen under the circumstances of a carbon price of USD 100/tCO₂e is analysed, indicating that this would make green hydrogen competitive with the incumbent fuels in the mining sector, and almost cost competitive in the public transport sector. However, carbon pricing is considered currently politically unfeasible in Mongolia. Further, the technoeconomic feasibility of synfuels is assessed in both end-uses, suggesting that this option is currently not economically feasible in any of the end-uses.

With regards to the heating sector, the study suggests that hydrogen for heating is not – at present - an economically feasible decarbonisation option in Mongolia. The study assessed the potential of using green hydrogen for decentralised heating in ger areas. Results suggest that, compared to a benchmark fuel of LPG, green hydrogen is not cost competitive with a cost gap of 148%. In contrast to the transportation studies, the heating study suggests that synfuels would be more cost competitive than the direct use of hydrogen, being about 33% more expensive than LPG. What is important to mention here is that the synfuel is produced from CO₂ captured from the flue gases of industrial plants. In order for the synfuel to be considered carbon-neutral, the CO₂ used in the process would need to be captured from the atmospheric air – a technology which is still immature and significantly more expensive.

The Mongolian context presents an opportunity for the country to reduce its emissions along with other benefits and could be promoted through a near-term focus on R&D and piloting. Policies should be further developed along with a national green hydrogen vision, based on sector specific assessments. In general, there is a wide portfolio of available policy instruments which could create an enabling environment for the introduction of a green hydrogen sector in a country. However, what policies are adopted should be carefully considered based on the country context, including the aim and scale of the envisioned functionalities of green hydrogen. In the context of Mongolia, a first step should be to identify the potential added value a shift to green hydrogen could bring in its various sectors. In such assessment, not only the economic feasibility should play a role, but also the availability of other decarbonisation options, mitigation potential and other benefits such as energy security and strategic advantages. A first attempt of such assessment is conducted in this study. Such information can then serve as a basis for the development of a national green hydrogen vision, clearly defining the objectives and target groups of a green hydrogen sector. A vision can subsequently be developed into a national green hydrogen strategy which outlines specific policy measures to be taken in order to reach those objectives.

As shown in this study, Mongolia's rich renewable energy resources provides the country with a clear advantage with regards to green hydrogen production, particularly as the major cost contributor to the production costs of green hydrogen is the electricity required in the electrolysis process. In combination with the comparatively low production costs, and the rather optimistic outlook for the mining sector, the significant mitigation potential provides Mongolia with an opportunity to, through the introduction of green hydrogen, contribute to achieving its GHG emission reduction targets, while further harness additional benefits related to energy security and supplying low-carbon mining products to the global market.

In the near term, Mongolia could thus further investigate this potential in the mining sector through the development of pilot projects through the establishment of public-private partnerships. If proven successful, clear, sector-specific policies, such as purchase grants or tax exemptions, could be adopted – combined with supply side policies to stimulate the production of green hydrogen. Such approach could also be an option in the public transport sector, although given that that is a sector with less clarity in terms of optimal decarbonisation technologies, Mongolia could also consider taking a technology neutral policy approach, incentivising low-carbon vehicles in the public transportation sector through financial and regulatory measures. By doing so, Mongolia could let the market decide on the most favourable decarbonisation technology.

Although the results suggest that green hydrogen for decentralised heating is economically unfeasible at present, it should not be completely ruled out as a potential decarbonisation option in the long term. Responsible for significant GHG and air pollution emissions, the decarbonisation of the Mongolian heating sector would bring valuable benefits. However, current available decarbonisation technologies are costly. Although the green hydrogen production potential in Mongolia is large, Mongolia must consider the optimal use of its renewable energy resources, including direct electrification and the decoupling and decarbonisation of the power sector, as well as the most suitable sectors for green hydrogen application. Aspects beyond the cost of the hydrogen must be considered as other technological, logistical and cost barriers may influence the profitability of the transition.

Under a future scenario in which Mongolia develops a green hydrogen sector for other end-uses, prices are expected to fall and could very well become a feasible option for the heating sector in the long term. Even in a future where much of the heating sector is decarbonised through direct electrification, there may be a need for seasonal energy storage to meet the full heat demand across the year. Under such circumstances, green hydrogen should be considered as a potential option.

6 References

- ADB (2014) *Demand in the Desert - Mongolia's water-energy-mining nexus*. Available at: <https://www.adb.org/publications/mongolia-water-energy-mining-nexus>.
- ADB (2020a) *Overview of Mongolia's Water Resources System - A country water security assessment*. Available at: <https://www.adb.org/documents/mongolia-country-water-security-assessment>.
- ADB (2020b) *Unlocking Mongolia's Rich Renewable Energy Potential*. Available at: <https://www.adb.org/news/features/unlocking-mongolias-rich-renewable-energy-potential> (Accessed: 4 December 2021).
- Africa Oil and Power (2021) 'Anglo American Collaboration On Feasibility Study For South Africa's Hydrogen Valley', 31 March. Available at: <https://www.africaoilandpower.com/2021/03/31/anglo-american-collaboration-on-feasibility-study-for-south-africas-hydrogen-valley/>.
- Agora Energiewende (2014) *Negative Electricity Prices: Causes and Effects*. Available at: https://www.agora-energiewende.de/fileadmin/Projekte/2013/Agora_Negative_Electricity_Prices_Web.pdf (Accessed: 14 April 2021).
- Banerjee, R. *et al.* (2014) 'Mongolia: Targeted Analysis on water resources management issues', *2030 Water Resources Group*, 1(March), pp. 1-60. Available at: http://www.2030wrg.org/wp-content/uploads/2014/07/2030WRG_MONGOLIA.pdf.
- Barros, S. (2020) *CMS Expert Guide to Hydrogen Law and Regulation*. Available at: <https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/chile> (Accessed: 18 February 2021).
- Batmunkh, S. *et al.* (2018) 'Mongolia's potential in international cooperation in the Asian energy space', *E3S Web of Conferences*, 27. doi: 10.1051/e3sconf/20182701006.
- Bloomberg New Energy Finance (2020) *Hydrogen Economy Outlook*. Available at: <https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf>.
- Brasington, L. (2019) *Hydrogen in China*. Available at: <https://www.cleantech.com/hydrogen-in-china/> (Accessed: 4 December 2021).
- Carlisle, S. and Pevzner, N. (2019) *Mongolian Energy Futures: Repowering Ulaanbaatar - Challenges of radical energy sector decarbonization*.
- COAG Energy Council (2019) *Australia's National Hydrogen Strategy*. Available at: <https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy>.
- CSIRO (2019) *National Hydrogen Roadmap - Pathways to an economically sustainable hydrogen industry in Australia*. Available at: <https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-roadmap>.
- CSIRO (2020) *Hydrogen's key role in decarbonising the mining industry*, *Resourceful Magazine*. Available at: <https://www.csiro.au/en/Research/MRF/Areas/Resourceful-magazine/Issue-21/Moving-to-hydrogen> (Accessed: 4 December 2021).
- Dolgorsuren, G. *et al.* (2013) *Integrated Water Management Plan - Mongolia*. Ulaanbaatar. Available at: <http://extwprlegs1.fao.org/docs/pdf/mon169789.pdf>.
- Dresp, S. *et al.* (2019) 'Direct electrolytic splitting of seawater: Opportunities and challenges', *ACS Energy Letters*, 4(4), pp. 933–942. doi: 10.1021/acsenerylett.9b00220.
- Dugarjav, B. (2021) *Consultant Report, Green hydrogen in Mongolia*.
- E. Tibaquirá, J. *et al.* (2011) 'Recovery and quality of water produced by commercial fuel cells'. Available at: <https://www.sciencedirect.com/science/article/abs/pii/S0360319910024146>.
- Economic Research Institute (2017) *Iron Ore Market Study*. Available at: <http://www.eri.mn/download/stitk2r6>.
- Edlev-Ochir, E. (2019) 'Urban Mobility and application of SUTI: Mongolia'.

EITI (2020a) *Mongolia; Overview*. Available at: <https://eiti.org/mongolia> (Accessed: 4 December 2021).

EITI (2020b) *Mongolia Fourteenth Eiti Reconciliation Report 2019*. Available at: https://eiti.org/files/documents/eiti_14_report_en-20201230_mongolia_report_2019.pdf.

Element Energy (2020) *Gigastack: Bulk Supply of Renewable Hydrogen – Public Report*. Available at: <https://www.itm-power.com/news-item/new-factory-update-and-senior-production-appointment> (Accessed: 14 April 2021).

ElementEnergy (2017) *Commercialisation of hydrogen fuel cell buses*. Available at: http://www.element-energy.co.uk/wordpress/wp-content/uploads/2018/01/FC-bus-commercialisation-White-Paper_October-2017.pdf%0Afile:///C:/Users/Zainab/Desktop/Bio ASSIG
AMAFHH/assignment2/references/Commercialisation of hydrogen fuel cell buses.pdf.

Emerton, Luntun and Naldansuren (2009) *The Economic Value of the Upper Tuul Ecosystem, Mongolia*.

Energy Regulatory Commission of Mongolia (2020a) *ENERGY INDICATORS STATISTICS - 2019*. Available at: <https://erc.gov.mn/web/mn/statistic> (Accessed: 14 April 2021).

Energy Regulatory Commission of Mongolia (2020b) *Single buyer model*. Available at: <https://erc.gov.mn/web/en/single-buyer-model> (Accessed: 14 April 2021).

ESCAP (2015) *State Policy on Energy 2015-2030 (Resolution of the Parliament No. 63 of 2015)*. Available at: <https://policy.asiapacificenergy.org/node/3769> (Accessed: 26 July 2021).

European Commission (2019) *Clean energy for all Europeans package*. Available at: https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en (Accessed: 14 April 2021).

European Commission (2020) 'A Hydrogen Strategy for a climate neutral Europe', (July). Available at: <https://ec.europa.eu/commission/presscorner/home/en>.

Fan, M. (2020) 'Making Water in Mongolia Available at the Right Time, at the Right Place, and in the Right Quality', 5(140).

Fraunhofer ISI (2021) *Enertile*. Available at: <https://www.enertile.eu/enertile-en/index.php> (Accessed: 24 June 2021).

Fuel Cell Works (2020) 'China's Hebei Approves \$1.2 bln Hydrogen Production and Consumption Projects'. Available at: <https://fuelcellworks.com/news/chinas-hebei-approves-1-2-bln-hydrogen-production-and-consumption-projects/>.

FuelCellsWorks (2020) 'South Africa's Hydrogen Economy Takes Off, Bambili Energy Invited to Join Government Hydrogen Strategy', 10 August. Available at: <https://fuelcellworks.com/news/south-africas-hydrogen-economy-takes-off-bambili-energy-invited-to-join-government-hydrogen-strategy/>.

G. Izenzon, M. and C. Rozzi, J. (2010) 'Demonstration of Efficient Water Recovery for Fuel Cell Power Systems'.

Gerhardt, N. *et al.* (2020) *Hydrogen in the Energy System of the Future: Focus on heat in buildings*.

Giddey, S. *et al.* (2017) 'Ammonia as a Renewable Energy Transportation Media'. Available at: <https://pubs.acs.org/doi/pdf/10.1021/acssuschemeng.7b02219?src=recsys&#>.

Government of Chile (2020) 'National Green Hydrogen Strategy', 316(5), p. 21. doi: 10.1038/scientificamerican0517-21b.

Government of Mongolia (2014) 'Green Development Policy of Mongolia', pp. 1–11. Available at: http://sdg.1212.mn/en/Content/files/Green_development_decision.pdf.

Government of Mongolia (2016) *Mongolia Sustainable Development Vision 2030*. Available at: http://www.un-page.org/files/public/20160205_mongolia_sdv_2030.pdf.

Government of Mongolia (2017) *Mongolia's Initial Biennial Update Report*. Available at: https://unfccc.int/files/national_reports/non-annex_i_parties/biennial_update_reports/application/pdf/mongolia_bur1_resubmission_and_annexnr.pdf (accessed on 7 March 2018).

Government of Mongolia (2020) *Mongolia's Nationally Determined Contribution to the United Nations Framework Convention on Climate Change*. Available at:

[https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Mongolia First/First Submission of Mongolia%27s NDC.pdf](https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Mongolia%20First/First%20Submission%20of%20Mongolia%27s%20NDC.pdf).

Government of Portugal (2020) 'Portugal National Hydrogen Strategy'. Available at: https://kig.pl/wp-content/uploads/2020/07/EN_H2_ENG.pdf.

Government of the city of London (2020) *Cleaner buses*. Available at: <https://www.london.gov.uk/what-we-do/environment/pollution-and-air-quality/cleaner-buses>.

Government of the Netherlands (2020) 'Government Strategy on Hydrogen', (387), pp. 1–14. Available at: <https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen>.

Government of the United Kingdom (2020) *The Energy White Paper - Powering our Net Zero Future*. Available at: http://www.ret.gov.au/energy/facts/white_paper/Pages/energy_white_paper.aspx.

Grütter, J. M. and Kim, K.-J. (2019) 'E-Mobility options for ADB Developing Member Countries', (60). Available at: www.adb.org.

Gütschow, J.; Günther, A.; Jeffery, L.; Gieseke, R. (2021) 'The PRIMAP-hist national historical emissions time series (1850-2018) (Version 2.2)'. doi: <https://doi.org/10.5281/zenodo.4479172>.

Hans, F. et al. (2020) *The Mongolian electricity sector in the context of international climate mitigation efforts*.

Hydrogen Council (2020) 'Path to hydrogen competitiveness: a cost perspective', (January), p. 88. Available at: www.hydrogencouncil.com.

IEA (2019) 'The Future of Hydrogen for G20. Seizing today's opportunities', *Report prepared by the IEA for the G20, Japan*, 6(June), pp. 246–256. Available at: <https://www.nrel.gov/docs/fy10osti/72740.pdf><https://www.irena.org/publications/2019/Nov/Advanced-biofuels-What-holds-them-back><https://doi.org/10.1016/j.scitotenv.2019.136312>.

IEA (2020a) *Data and Statistics, CO2 emissions by sector, World 1990-2018*.

IEA (2020b) *Energy Prices 2020*. Available at: <https://www.iea.org/reports/energy-prices-2020> (Accessed: 8 December 2021).

IEA (2020c) *Mongolia*. Available at: <https://www.iea.org/countries/Mongolia>.

IEA (2020d) *Policy database – Data & Statistics*. Available at: <https://www.iea.org/policies> (Accessed: 5 November 2020).

IEA (2021) *Fuel cell electric vehicles stock by region and by mode, 2020*. Available at: <https://www.iea.org/data-and-statistics/charts/fuel-cell-electric-vehicles-stock-by-region-and-by-mode-2020>.

IRENA (2019a) *Hydrogen: a Renewable Energy Perspective*, International Renewable Energy Agency. Available at: www.irena.org.

IRENA (2019b) *Innovation landscape for a renewable-powered future: Solutions to integrate variable renewables*. Abu Dhabi, United Arab Emirates. Available at: https://irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovation_Landscape_2019_report.pdf.

IRENA (2020a) *Green Hydrogen: A guide to policy making*. Available at: <https://www.irena.org/publications/2020/Nov/Green-hydrogen>.

IRENA (2020b) *Green Hydrogen Cost Reduction - Scaling up electrolyzers to meet the 1.5°C climate goal*.

IRENA (2020c) 'Reaching zero with renewables: Eliminating CO2 emissions from industry and transport in line with the 1.5°C climate goal', p. 216.

IRENA, IEA and REN21 (2018) *Renewable Energy Policies in a Time of Transition*. Available at: http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Apr/IRENA_IEA_REN21_Policies_2018.pdf [accessed on 23 July 2018].

Japan Ministry of Economy Trade and Industry (2017) 'Basic Hydrogen Strategy (key points)'. Available at: <https://www.meti.go.jp/english/index.html>.

Jin, L. and He, H. (2020) *Ten cities, thousand fuel cell vehicles? China is sketching a roadmap for*

hydrogen vehicles. Available at: <https://theicct.org/blog/staff/china-sketching-roadmap-hydrogen-vehicles-aug2020>.

Khaltar, B. (2020a) *Mongolia plans river diversion as mining boom sucks Gobi dry*. Available at: <https://www.thethirdpole.net/2020/10/14/mongolia-plans-river-diversion-as-mining-boom-runs-gobi-dry/> (Accessed: 21 January 2021).

Khaltar, B. (2020b) *Mongolia plans river diversion as mining boom sucks Gobi dry*. Available at: <https://www.thethirdpole.net/2020/10/14/mongolia-plans-river-diversion-as-mining-boom-runs-gobi-dry/>.

Liebreich, M. (2020) *Liebreich: Separating Hype from Hydrogen – Part One: The Supply Side, Bloomberg New Energy Finance*. Available at: <https://about.bnef.com/blog/liebreich-separating-hype-from-hydrogen-part-one-the-supply-side/> (Accessed: 4 December 2021).

Liu, Z., Kendall, K. and Yan, X. (2019) 'China Progress on Renewable Energy Vehicles : Fuel Cells , Hydrogen and Battery Hybrid Vehicles', pp. 1–10. doi: 10.3390/en12010054.

Minister for Energy and Emissions Reduction (2020) *Strong interest in Hydrogen*. Available at: <https://www.minister.industry.gov.au/ministers/taylor/media-releases/strong-interest-hydrogen> (Accessed: 18 February 2021).

Ministry of Environment and Tourism *et al.* (2018) 'Third National Communication of Mongolia'.

Moore, P. (2020) 'China's Weichai Power and CRRC Yongji complete hydrogen-lithium battery hybrid 200 ton mining truck', *International Mining*, 8 May. Available at: <https://im-mining.com/2020/05/08/chinas-weichai-power-crrc-yongji-complete-hydrogen-lithium-battery-hybrid-200-ton-mining-truck/>.

Nagashima, M. (2018) *Japan's Hydrogen strategy and its economic and geopolitical implications études de l'Ifri monica nagashima Centre for Energy*.

NDC Partnership (2019) *Aligning Mongolia's NDC and SDGs Through its National Green Development Policy*. Available at: <https://ndcpartnership.org/case-study/aligning-mongolias-ndc-and-sdgs-through-its-national-green-development-policy>.

Netherlands Enterprise Agency (2019a) *Hydrogen Economy Plan in Korea*. Available at: <https://www.rvo.nl/sites/default/files/2019/03/Hydrogen-economy-plan-in-Korea.pdf>.

Netherlands Enterprise Agency (2019b) 'Hydrogen Economy Plan in Korea', pp. 1–2.

Njini, F. (2020) *Hydrogen to Fuel Giant Mining Trucks in Green Shift by Anglo, Bloomberg Green*. Available at: <https://www.bloomberg.com/news/articles/2020-07-01/anglo-switching-to-hydrogen-powered-mine-trucks-in-green-shift>.

Norwegian Ministry of Petroleum and Energy and Norwegian Ministry of Climate and Environment (2020) 'The Norwegian Government's hydrogen strategy towards a low emission society'. Available at: <https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf>.

Oesterholt, F. I. H. M. *et al.* (2016) 'The role of water in a future hydrogen economy', (October 2016), p. 9. Available at: <file:///C:/Users/daan/Downloads/OesterholtKoeman-SteinOldenbroekBoerevanWijkTheroleofwaterinafuturehydrogeneconomy-IWABrisbaneAustrali9-14October2016.pdf>.

Oyunchimeg, C. *et al.* (2020) *Energy Sector Current Status, Recent Developments and Energy Policies in Mongolia*. Available at: <https://nautilus.org/napsnet/napsnet-special-reports/energy-sector-current-status-recent-developments-and-energy-policies-in-mongolia/>.

Pfister, P. (2018) *Extreme challenges for 55 km of a cast drinking water pipeline*. Available at: <https://eadips.org/extreme-challenges-for-55-km-of-a-cast-drinking-water-pipeline/?lang=en> (Accessed: 1 March 2020).

Pudlik, M., Seyfang, B. and Franke, K. (2021) *Demand-side analysis of the potential of power-to-hydrogen applications in Mongolia*.

REN21 (2020) *Renewables 2020 - Global Status Report*. Available at: [https://abdn.pure.elsevier.com/en/en/researchoutput/ren21\(5d1212f6-d863-45f7-8979-5f68a61e380e\).html](https://abdn.pure.elsevier.com/en/en/researchoutput/ren21(5d1212f6-d863-45f7-8979-5f68a61e380e).html).

Ron Cui, C. and Wu, Y. (2019) *Paving the way to sustainable heating in Mongolia*. Available at: <https://blogs.worldbank.org/eastasiapacific/paving-way-sustainable-heating-mongolia> (Accessed: 4 December 2021).

Schmitz, N. *et al.* (2016) 'From methanol to the oxygenated diesel fuel poly(oxymethylene) dimethyl ether: An assessment of the production costs', *Fuel*, 185.

Sensfuß, F. and Pflüger, B. (2021) 'Enertile'.

Senshaw, T. N. D. D. (2020) *Development of Green Energy Systems and Energy Efficiency in Mongolia*. doi: 10.1017/CBO9781107415324.004.

Shell (2017) 'The Shell Hydrogen Study: Energy of the Future?', *Shell Deutschland Oil GmbH*, p. 37. Available at: <https://www.shell.com/energy-and-innovation/the-energy-future/future-transport/hydrogen.html>.

Shiab, X., Liao, X. and Li, Y. (2020) 'Quantification of fresh water consumption and scarcity footprints of hydrogen from water electrolysis: A methodology framework', *Renewable Energy*, 154(July 2020), pp. 786–796. Available at: <https://doi.org/10.1016/j.renene.2020.03.026>.

Skiker, S. and Dolman, M. (2017) *Fuel cell buses: A flexible, zero-emission transport solution*, *Eurotransport*. Available at: <https://www.fch.europa.eu/sites/default/files/selection.pdf>.

Solaris (2020) *Urbino 12 Hydrogen*. Available at: <https://www.solarisbus.com/en/vehicles/zero-emissions/hydrogen>.

SSAB (2021) *First in fossil-free steel. Using HYBRIT Technology*. Available at: <https://www.ssab.com/company/sustainability/sustainable-operations/hybrit>.

Stryi-Hipp, G. *et al.* (2018) *Energy Master Plan for Ulaanbaatar*.

The German Federal Government (2020) *The National Hydrogen Strategy*. Available at: <https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html>.

United Nations (2015) 'Paris Agreement'. Paris. Available at: http://unfccc.int/files/essential_background/convention/application/pdf/english_paris_agreement.pdf.

De Vivero-Serrano, G. *et al.* (2019) *Transition towards a decarbonised electricity sector - a framework of analysis for power system transformation*. Available at: https://newclimate.org/wp-content/uploads/2019/10/Report_Transition_Towards_A_Decarbonised_Electricity_Sector_A2A_2019.pdf.

Widera, B. (2020) 'Renewable hydrogen implementations for combined energy storage, transportation and stationary applications', *Thermal Science and Engineering Progress*, 16(December 2019), p. 100460. doi: 10.1016/j.tsep.2019.100460.

World Bank (2020) *2030 Water Research Group*. Available at: <https://www.2030wrg.org/mongolia-stories/>.

Zhou, V. (2020) 'Anglo American to test world's largest hydrogen powered truck', *Australian Mining*, 13 February. Available at: <https://www.australianmining.com.au/news/anglo-american-to-test-worlds-largest-hydrogen-powered-truck/>.



NEXX
CLIMATE
INSTITUTE

 **Fraunhofer**
ISI

giz Deutsche Gesellschaft
für Internationale
Zusammenarbeit (GIZ) GmbH

On behalf of:



Federal Ministry
for the Environment, Nature Conservation
and Nuclear Safety

of the Federal Republic of Germany

Capacity Development for climate policy in the countries of South East, Eastern Europe, the South Caucasus and Central Asia, Phase III.

This project is part of the International Climate Initiative (IKI). The German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) supports this initiative on the basis of a decision adopted by the German Bundestag.