Low-cost, low-carbon hydrogen production

Oxygen for in-situ underground gasification of wet crude reserves

By **Stephen B. Harrison**, Managing Director, **sbh4 consulting**

Hydrogen will play an important role in a decarbonised, climate -neutral energy system. Emerging technologies, such as thermolysis of wastes, the use of plasma for methane splitting and in-situ underground gasification of fossil fuel reserves are likely to play increasingly important roles as low-carbon hydrogen production pathways.

To achieve carbon neutrality, it will be essential to produce hydrogen at scale with minimal CO_2 emissions. When traditional steam methane reforming (SMR) technology is combined with carbon capture and storage (CCS), blue hydrogen is produced. Another clean energy source is green hydrogen, which can be produced through electrolysis using renewable electrical power or from biomass. However, there is a constant drive to find technologies that reduce the cost of low-carbon hydrogen production.

Hydrocarbons contain hydrogen in their molecular structure and it is possible to use underground fossil hydrocarbon resources to produce low-carbon hydrogen through in-situ gasification. Instead of bringing oil and gas from the underground fossil fuel reserves to the surface, oxygen and electromagnetic radiation are used underground in the reservoir to stimulate gasification and reforming reactions, thereby creating hydrogen which can be brought to the surface as a clean energy vector.

Demonstration of in-situ underground gasification of wet crude in Canada by Proton Technologies indicates that the cost of hydrogen from this pathway, when scaled up, could be less than 0.3 \$/kg, without carbon dioxide (CO_2) emissions to the atmosphere. Presently, green hydrogen and blue hydrogen can typically be produced in the cost ranges of 1-2 \$/kg and 4-6 \$/kg, respectively.

In-situ hydrogen purification using a proprietary membrane

In the in-situ gasification process, the crude oil reservoir is heated through the application of oxygen, leading to chemical reactions that oxidise hydrocarbons and release heat. When the temperature in the underground reservoir reaches 350°C, water and heavier hydrocarbons will split. Hydrogen and carbon oxides will be produced.

To bring pure hydrogen to the surface, gas separation occurs by installing a downhole membrane separation mechanism. Hydrogen is extracted from the production well and carbon monoxide, carbon dioxide and other hydrocarbons remain underground.

This gas separation membrane is a physical barrier allowing selective mass species transport and based on diffusion velocity differences of the gases that need to be separated. The lower diffusion rate gases, carbon monoxide and CO_2, remain at the feed side and hydrogen, which is a very small and highly mobile molecule, passes through the membrane.

The membrane must be resistant to hydrogen embrittlement and must be able to withstand high pressure and temperature conditions over the long-term. Proton Technologies is conducting their demonstration project using a patented palladium-alloy membrane, which has suitable materials compatibility and creates the appropriate mass transfer conditions.

Polymeric membranes, such as the SEPURAN® technology supplied by Evonik, are used in to separate nitrogen from air and are employed on small-scale onsite industrial gases supply equipment. A cryogenic membrane is also being used by Air Liquide on its proprietary Cryocap™ process for CO_2 capture from SMRs with increased hydrogen yield.

Membranes are also in development for CO_2 separation from flue gas streams to enable carbon capture from power plant emissions. Operating in the liquid phase, reverse osmosis membranes are used to purify water prior to electrolysis for hydrogen generation.

Proving the potential with a pilot project

The Proton Technologies demonstration project is taking place in the Athabasca tar sands region of Saskatchewan, Canada. Saskatchewan has been selected for the pilot because of its suitable geology and infrastructure. Oil production from these highly viscous, heavy bituminous hydrocarbon reserves is difficult, and the recovery factor is low, resulting in high unit costs for conventional extraction processes.

One of the areas under close investigation during the demonstration project is the long-term security of underground CO_2 storage. Although this is not classical CCS, where captured CO_2 gas is injected into underground reservoirs, the process does rely on permanent underground storage of the carbon monoxide and CO_2 gases that are formed as by-products of the gasification. A release of carbon monoxide would be highly toxic and CO_2 emissions would contribute to global warming.

The membrane gas purification efficiency for hydrogen separation is also under scrutiny. It would be

ideal for the hydrogen product to be sufficiently pure to be used in a wide range of applications, from ammonia production, to fuel cells for hydrogen mobility. However, for some high purity applications it might be necessary to install an additional purification unit at the surface.

Transformational potential for heavy oil and gas reserves

The Athabasca deposit is the largest known reservoir of crude bitumen in the world and the largest of three major oil sands deposits in Alberta, alongside the nearby Peace River and Cold Lake deposits. There are around 741 glaciers in Alberta, making it an area of pristine nature and beauty. A shift towards low-carbon energy is therefore essential to maintain its magnificent frozen landscape, which is ever more threatened by global warming.

In the long-term, Proton Technologies intends to use in-situ underground gasification to monetise these wet bituminous hydrocarbon reserves by producing low cost, sustainable hydrogen at scale. Since water (H_2O) is a hydrogen carrier and contributes to enhanced hydrogen production during the underground gasification, crude reserves with high water saturation are the best candidates for in-situ gasification for hydrogen production.

Wet crude or bitumen reserves are ideal, and in the Middle East, there are many stranded reserves in Kuwait which have been disregarded for conventional ▸

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extraction processes due to their heavy, wet nature. The Burgan field, Kuwait's largest reserve, is situated in the south-eastern desert of the country, and has a moisture content up to 26%. With this new hydrogen production technology, these reserves may be seen in a new light as economically viable clean energy resources.

Venezuela currently holds the largest crude oil reserves in the world, amounting to more than 300 billion barrels. However, its crude oil is considered very heavy by international standards, meaning that it must be processed by specialised refineries, of which there are few worldwide and the crude therefore has a low value. The potential of these heavy Venzuelan crude reserves could be unlocked using underground in-situ gasification.

Emissions reduction and oxygen requirements

One significant advantage of underground in-situ gasification, is that it uses the sub-surface reserves as a huge and controllable chemical reactor, thus avoiding the capital cost of building a major process plant above the surface. Furthermore, existing oil and gas infrastructure such as wells, pipelines, roads, and surface facilities could be reused to minimise the cost of the transition to the emerging hydrogen-based economy.

It also leaves carbon monoxide and CO_2 gases in the reservoir without the need for investment in additional CCS infrastructure. These attributes mean that it is a high potential candidate for low-cost, low-carbon hydrogen production.

Another advantage of this method is its capability to produce hydrogen at very large-scale. A heavy oil reservoir with 32 million tonnes of remaining oil could yield 576 tonnes of hydrogen per day through the in-situ underground gasification of 1,740 tonnes per day of heavy crude. The reservoir could operate for a 50-year period at that capacity.

Hydrogen production at that rate would require 6,000 tonnes per day of oxygen. That amount of oxygen could readily be supplied from two 3,000 tonne per days air separation units (ASUs). Such ASUs have been installed by Air Products on large-scale coal gasification projects in Lu'an and Jazan and Air Liquide, Air Products and Linde and have installed on Gas-to-Liquids projects at Bintulu, Escravos, and Ras Lafan, respectively.

This scale of hydrogen production is similar to the hydrogen generation capacity of a very large SMR. The CO_2 produced from an SMR producing 576 tonnes per day of hydrogen would be approximately 5,760 tonnes per day. These CO_2 emissions are avoided through the in-situ undergound gasification because the CO_2 produced during the reactions remains under the ground in the reservoir.

Previously, a barrier to the mass adoption of green or blue hydrogen, has been their high cost when compared to traditional fossil fuels. If the costs from the pilot scale deployment of in-situ underground gasification in Canada are validated through scale up and can be replicated in other schemes, this technology will have the potential to break through the cost barrier for low-carbon hydrogen and accelerate the path towards carbon neutral energy systems. gw