

Technoeconomic Comparison of Hydrogen Production from Steam Methane Reforming with Carbon Capture and Renewably Powered Electrolysis

**Prepared By** Pete Psarras Exaere Consulting LLC

Prepared For Stark Area Regional Transit Authority

#### **Disclaimer of Liability**

With respect to the information in this report, <u>Exaere Consulting LLC</u> makes no warranty, express or implied, including the warranties of merchantability and fitness for a particular purpose, nor assumes any legal liability for the accuracy, completeness, or usefulness of any such information, or of any apparatus, product, or process disclosed, nor represents that its use would not infringe on privately owned rights.



# Technoeconomic Comparison of Hydrogen Production from Steam Methane Reforming with Carbon Capture and Renewably Powered Electrolysis

**Prepared by** Pete Psarras Exaere Consulting LLC

Prepared For Stark Area Regional Transit Authority

Final Report 1/5/2020

Exaere Consulting LLC 215 E Orangehill Circle Orange, OH 44022 exaere@outlook.com

# **Executive Summary**

While the emergence and increased penetration of electric vehicles has helped reduce carbon emissions in the transportation sector, physical limitations exist that will make these solutions difficult to deploy in certain segments of the sector, e.g., long-haul trucking and aviation. Hydrogen is a promising option as it has a gravimetric energy content of 122kJ/g, nearly 2.5 times higher than gasoline, has no carbon-containing combustion byproducts, and can be employed in high efficiency fuel cell vehicles. However, hydrogen production can be a significant source of carbon dioxide, as over 95% of the hydrogen produced in the United States is made from steam-methane reformation, of which  $CO_2$  is a major byproduct.

In order for hydrogen production at scale to be considered a viable option for transportation emission reductions, the hydrogen system must be configured to a) minimize carbon reductions and b) produce hydrogen at a cost that is competitive with conventional production or that meets Federal targets (i.e., <  $2.00 \text{ /kg H}_2 \text{ produced}$ ). This report compares the technoeconomic assessment of three hydrogen production configurations:

- 1. Steam methane reforming (SMR) of natural gas with solvent-based carbon capture using Selexol<sup>™</sup> (SMR CC)
- 2. Electrolytic hydrogen generation from water using alkaline water electrolysis (AEC)
- 3. Electrolytic hydrogen generation from water proton exchange membrane electrolysis (PEM)

Economic models were developed using input parameters likely encountered along the Midwest region of the Interstate 80 corridor, with a focus on three unique scales of production: refueling station (1500 kgH<sub>2</sub> / day), mid-sized (50000 kgH<sub>2</sub> / day) and centralized (314000 kgH<sub>2</sub> / day). Major findings of this study reveal that steam methane reformation of natural gas coupled to carbon capture is the most cost-effective route to low-carbon hydrogen at every scale, meeting DOE targets for H<sub>2</sub> production in the mid-sized and centralized facilities. Further, markets for carbon dioxide along the I-80 corridor match well with the scale of CO<sub>2</sub> production from refueling stations and could make logical source-sink pairings for carbon dioxide supply to niche, small-scale markets. Reliable storage is possible given the large scale of CO<sub>2</sub> potentially captured at centralized hydrogen production facilities, with suitable reservoirs within proximity to minimize transport cost via pipeline. Finally, while renewably-powered electrolysis cannot match SMR – CC at current input conditions and equipment costs, optimistic mid-decade cost projections for electrolyzers provide a pathway for AEC and PEM to become cost-competitive, particularly when the goal is minimal carbon footprint.

# **Table of Contents**

Executive Summary	iii
Introduction	1
Results and Discussion	4
Conclusions and Recommendations	12
References	14

### Introduction

While the emergence and increased penetration of electric vehicles has helped reduce carbon emissions in the transportation sector, physical limitations exist that will make these solutions difficult to deploy in certain segments of the sector, e.g., long-haul trucking and aviation. Hydrogen is a promising option as it has a gravimetric energy content of 122kJ/g, nearly 2.5 times higher than gasoline, has no carbon-containing combustion byproducts, and can be employed in high efficiency fuel cell vehicles (HFCV).<sup>1-2</sup> It is anticipated that by 2050, HFCVs will drive the hydrogen gas to a market value of \$1 Trillion.<sup>3</sup> However, hydrogen production can be a significant source of carbon dioxide, as roughly 95% of the hydrogen produced in the United States is made from steam-methane reformation,<sup>4</sup> of which  $CO_2$  is a major byproduct, via reactions 1 and 2:

$$CH_4 + H_2 0 \rightleftharpoons CO + 3H_2 \tag{1}$$

$$CO + H_2 O \rightleftharpoons CO_2 + H_2 \tag{2}$$

Generally speaking, for every one tonne of H<sub>2</sub> produced, 9 tonnes of CO<sub>2</sub> is generated. The outlet stream from the low-temperature shift reactor is approximately 86 % H<sub>2</sub>, 12%  $CO_2$ , 0.3 – 1% CO, and 1.6%  $CH_4$ <sup>5</sup> After separation of  $H_2$  via pressure-swing adsorption (PSA), the PSA tail gas is approximately 45.1 mol% CO<sub>2</sub>, making it a prime candidate stream for CO<sub>2</sub> separation given the high CO<sub>2</sub> content, along with the steam reformation flue gas (19.1 mol% CO<sub>2</sub>).<sup>6</sup> Typically, at low acid gas partial pressure (<20%) chemical solvents, e.g. monoethanolamine (MEA) are favored due to higher uptake and fast kinetics. However, streams with a higher CO<sub>2</sub> content are more suitable for physical solvent separation, where physical solvents like methyldiethanolamine (MDEA) typically outperform their chemical counterparts in terms of acid gas loading and have lower regeneration penalties. Rubin et al. show that pre-combustion capture from integrated gasification combined cycle power plants with Selexol<sup>™</sup> has a lower avoided cost of CO<sub>2</sub> capture than amine separation from pulverized coal and natural gas combined cycle using post-combustion capture with amine solvents.<sup>7</sup> Note that the CO<sub>2</sub> content post-shift in the IGCC plant (ca. 37 mol%) is much higher than that typically encountered in the flue gas of natural gas and coal fired power plants (ca. 5 and 12 mol%, respectively), and is on the order of that observed in the PSA tail gas from SMR H<sub>2</sub> production.

Carbon capture at SMR facilities is not a new practice, with the state-of-the-art approach recommendation of MDEA capture from the shifted syngas. Collodi et al. studied five SMR–CC configurations for a plant size of 100,000 Nm<sup>3</sup>/h (ca. 210,000 kg H<sub>2</sub> / day).<sup>8</sup> These configurations included a base case of SMR without carbon capture, SMR with monoethanolamine (MEA) capture from the SR flue gas, SMR with MDEA capture from the shifted syngas, SMR with MDEA capture from the PSA tail gas, and SMR with

membrane capture from the PSA tail gas, where the latter case exploits the higher partial pressure of CO<sub>2</sub> in the PSA tail gas stream to drive diffusion across the membrane. Their findings show that the least-cost option is MDEA capture from shifted syngas (+18% over base levelized cost of hydrogen (LCOH)), and the highest cost is MEA capture from the SR flue gas (+45% over base LCOH). However, while the specific CO<sub>2</sub> captured is comparable for MDEA or membrane technology applied to the post-shift or PSA tail gas (ca. 5 kg CO<sub>2</sub> / kg H<sub>2</sub>, or a capture rate of around 55%), the highest capture rate and thus the greatest CO<sub>2</sub> reductions is achieved via MEA applied to the SR flue gas, at 90%; thus, the hydrogen plant operator will observe a cost premium to maximize CO<sub>2</sub> capture at the facility.

Cormos et al. evaluated the physical solvent Selexol<sup>TM</sup> poly (ethylene glycol) dimethyl ether) against MDEA, capturing from the post-shifted syngas at a 100,000 Nm<sup>3</sup> / hr hydrogen SMR facility. These configurations achieved capture rates of 65 and 70%, respectively, owing to the higher selectivity for CO<sub>2</sub> in chemical solvents.<sup>9</sup> Inclusion of pre-combustion capture resulted in a specific capital investment increase of 37 and 45% for the Selexol<sup>TM</sup> and MDEA configurations, respectively, over the base case SMR facility without carbon capture. More importantly, the increase in hydrogen production cost over the base case was lower for Selexol<sup>TM</sup> (+10%) than in MDEA capture (+14%). Further, the avoided cost of CO<sub>2</sub> – the levelized cost of CO<sub>2</sub> adjusted for CO<sub>2</sub> emitted directly and indirectly – was 36% lower for Selexol<sup>TM</sup> capture compared to MDEA.

Since the cost of fuel dominates SMR H<sub>2</sub> production, the falling cost of natural gas in the US, in particular in regions coinciding with shale exploration, makes SMR economically attractive. Facilities with larger scales of production may be able to take advantage of city gate natural gas pricing (ca. 3.78 / MSCF) or hub pricing (ca. 2.43 / MSCF). Other feedstocks are available but exist currently at a cost premium. For example, hydrogen generation from biogas is shown to be highly dependent on the feedstock cost, with a study yielding a cost of 2.69 and  $4.27 / kg H_2$  for 150000 and 1500 kg H<sub>2</sub> / day production facilities, respectively.<sup>10</sup>

In the goal of low-carbon hydrogen production, electrolysis of water using low-carbon electricity has emerged as a promising option, particularly with the increasing presence of low-cost renewable energy sources. Further, this technologically simple approach obviates the need for carbon capture installation and subsequent treatment and transport of captured CO<sub>2</sub>. However, electrolysis is an energy intensive process, with a thermodynamic energy yield of  $20 - 40 \text{ kg H}_2$  / kWh (compare at 60 kg H<sub>2</sub> / kWh for conventional SMR).<sup>11</sup> Electrolysis is also capital intensive, with costs in the US ranging from \$500 - \$1400/kW for alkaline electrolyzers and \$1100 - \$1800/kW for proton exchange membrane (PEM) electrolyzers. This results in a higher cost range for H<sub>2</sub>

production than observed in SMR production, at  $2.85 - 28.75 / kg H_2$ .<sup>12</sup> A case-study of electrolysis used in a hybrid system in Texas showed the flexibility of electrolysis paired with intermittent sources and yielded a hydrogen breakeven cost of  $3.53 / kg H_2$ .<sup>13</sup>

According to the literature analysis above, three technologies have been selected for technoeconomic analysis:

- 1. Steam methane reforming (SMR) of natural gas with solvent-based carbon capture using Selexol<sup>™</sup> (SMR CC)
- 2. Electrolytic hydrogen generation from water using alkaline water electrolysis (AEC)
- 3. Electrolytic hydrogen generation from water proton exchange membrane electrolysis (PEM)

Selexol<sup>™</sup> was selected as the optimal carbon capture technology due to its observed lower cost of CO<sub>2</sub> avoided and smaller increase to the LCOH when compared to other technologies. Two electrolysis technologies were selected for comparison: AEC is more mature and has a lower capital intensity, while PEM is projected to be the dominant electrolysis technology over the next decade.

# **Results and Discussion**

To assess the economic impact of competing hydrogen generation technologies along the I-80 corridor, a full technoeconomic model was built and adapted to convey 2018 USD costs of hydrogen production in the functional cost of  $H_2$  for three separate pathways:

- 1. Steam methane reforming (SMR) of natural gas with solvent-based carbon capture using Selexol<sup>™</sup> (SMR CC)
- 2. Electrolytic hydrogen generation from water using alkaline water electrolysis (AEC)
- 3. Electrolytic hydrogen generation from water proton exchange membrane electrolysis (PEM)

These technologies were evaluated for three production capacities with unique input parameters and plant properties, characteristic of that anticipated to be encountered along the Midwest region of I-80. These parameters are described below in Table 1.

Type	Canacity	Price of NG	Price of	Plant	Canital
Type	(ka Ha (day)		oloctricity	oconomio	rocovoru
	(Ky 1127 uay)				fectorely
			(\$/IVIVVN)	inetime (yrs)	Tactor
					(%)
<b>Refueling Station</b>	1500	7.66	92.9	20	0.0802
Mid-sized	50000	3.78	60.0	40	0.0583
Centralized	314000	2.43	30.0	40	0.0583

 Table 1. Parameters and input costs for three scales of hydrogen production facilities.

Technoeconomic models were adjusted from the literature for SMR with carbon capture<sup>14</sup>, electrolysis using AEC<sup>15-16</sup>, and electrolysis using PEM<sup>17</sup>, using constant 2018 USD and adjusting inputs to reflect current retail, city-gate and hub pricing. Results from our technoeconomic analysis are conveyed in Table 2. Our findings show that SMR with carbon capture is the least-cost option of those considered at every scale, with a low value of \$0.99 / kg H<sub>2</sub> assuming a natural gas price of \$2.43 / MSCF and electricity price of \$30/MWh. For this technology, the dominant capital expense is the steam methane reformer (47% of total capital) followed by the pressure swing adsorption unit (11%) and the Selexol<sup>TM</sup> capture unit (10% (Figure 1). The total capital investment for a 1500 kg H<sub>2</sub>/day production plant is estimated at \$4.7 M USD(2018), whereas the mid-sized and centralized production facilities will command roughly \$77 M and \$337 M USD(2018), respectively. The dominant operational expense is the cost of natural gas (32%) followed by overhead (22%) and labor and maintenance (17% each). However, these costs only cover production of hydrogen. Transportation of hydrogen off-site from mid-sized and

	Hydrogen p	roduction cost (2018\$	/ kg H <sub>2</sub> )
Туре	SMR – CC	AEC	PEM
Refueling Station	3.24	6.21	6.64
Mid-sized	1.47	4.16	4.60
Centralized	0.99	2.54	2.97

**Table 2.** Cost projections for hydrogen generation from SMR with carbon capture and competitive electrolysis technologies.



**Figure 1.** Capital (top) and operating (bottom) expense breakdown for a steam methane reformation facility equipped with carbon capture (Selexol<sup>™</sup>).

centralized production is dependent on distance to site with longer range hauling (over 150 mi.) commanding closer to  $5/kg H_2$  (at a general transport cost of  $0.03 / kg H_2 / mi$ .)

Included in this analysis is an estimated transportation and storage cost of  $22/tCO_2$ . With capture, the anticipated cost of CO<sub>2</sub> fully delivered is  $43/tCO_2$ .

The amount of CO<sub>2</sub> captured over a single year at a 1500 kg H<sub>2</sub>/day production plant equates to approximately 3050 tonnes. This is on par with the scale of many niche demand opportunities along the I-80 corridor, e.g., beverage carbonation plants or use as a refrigerant in large supermarkets. Additional opportunities may be available regionally if extended delivery (> 100 mi) is considered. Figure 2 depicts the geospatial distribution



**Figure 2.** Geographical dispersion of potential primary and secondary market sinks for carbon dioxide captured along the I-80 corridor. Outside of enhanced oil recovery (white circles), most opportunities are low volume (<  $1 \text{ ktCO}_2 / \text{ yr.}$ ) Extended transport to +/- 100 miles from I-80 increases the potential CO<sub>2</sub> market volume by the order of 3.5x.

of geological storage reservoirs and carbon dioxide sinks surrounding the Midwest (Illinois, Indiana, Michigan, Ohio, and Pennsylvania) stretch of Interstate 80. Together,

532 sites are identified as primary and secondary markets for carbon dioxide. Primary markets currently take CO<sub>2</sub> as an input and (likely) have incumbent suppliers and contracts for supply. Primary markets include beverage carbonation (113 sites, 162.3 ktCO<sub>2</sub> / yr demand), EOR (9 sites, 323.3 ktCO<sub>2</sub> / yr demand), and urea manufacturing (1 site, 112.5 ktCO<sub>2</sub> / yr demand). Primary markets benefit from existing infrastructure to handle CO<sub>2</sub> delivery and storage, as well as mature processes to incorporate the CO<sub>2</sub> into a valuable product. The drawback of primary markets exists in the nature of incumbent providers, where cost competitive  $CO_2$  is delivered in bulk from merchant  $CO_2$ suppliers. Industry analysis shows that the range of delivered CO<sub>2</sub> ranges from \$40-\$50 to \$400-\$600 per short ton,<sup>18</sup> with high purity CO<sub>2</sub> delivery at ISBT specifications (99.9% CO<sub>2</sub>) suitable for food and beverage use commanding higher prices. Secondary markets are defined as those that do not currently take CO<sub>2</sub> as an input but could in the future. These markets include refrigeration systems and various chemicals manufacturing. The obvious disadvantage of secondary markets is uncertainty surrounding process design and deployment. Additional opportunities and the cumulative estimated demand for CO<sub>2</sub> are listed in Table 3. A more conservative estimate for CO<sub>2</sub> sink opportunities limits the delivery region to between – 41.0 and – 42.2 latitude. This spans an approximate 83-mile wide region through which Interstate 80 traverses. This confined region results in a total CO<sub>2</sub> market of approximately 215000 tonnes per year, a factor of 3.5× times lower than the total market listed in Table 3, notably due to the exclusion of high demand EOR opportunities in Northern Michigan. Confinement to this smaller region would be motivated to reduce transportation costs, particularly in trucking delivery. Trucking CO<sub>2</sub> in low volumes is economically inefficient and commands a cost of \$0.15/tonne/mile and greater. High volume CO<sub>2</sub> transport by pipeline on the other hand is shown to be much more economical in the long run, commanding lower than \$0.05/tonne/mile for volumes of 2 million tonnes per year and larger. Generally, trucking is more economical for very low volumes while pipeline is more suitable for bulk transport, with a rough crossover of 500000 tonnes per year transport at which pipeline overtakes trucking as the more economical mode of transport.<sup>19</sup>

At 50000 and 314000 kg H<sub>2</sub> /day capacities, SMR equipped with carbon capture can capture approximately 105000 and 650000 tonnes CO<sub>2</sub>, respectively. Both of these volumes meet the minimum threshold to qualify for Federal tax credits for storage (currently 25 / 1002, escalating to 50 / 1002) or beneficial reuse (currently 15 / 1002, escalating to 35 / 1002). Since *delivered* CO2 from these processes is priced at near 40 / 1002, these tax credits have the potential to offset a substantial amount of the incremental cost of capture. If the CO<sub>2</sub> is sold at market value (40 - 60 / 10002 tonne for bulk and higher for ISBT grade), CO<sub>2</sub> capture could be profitable to the hydrogen production plant. Further, at these larger volumes, both facilities would meet the criteria suitable for injection into underground reservoirs for the purpose of permanent sequestration.

Carbon dioxide market	Facility count	Cumulative CO <sub>2</sub> demand (ktCO <sub>2</sub> / yr)
Chemicals	1	0.005
Enhanced oil recovery	9	323.229
Fireproofing materials	6	0.094
Food Products-Retail	5	2.341
Gas-Industrial & Medical-Cylinder & Bulk	25	0.821
Grocers-Retail	336	127.692
Methanol	1	6.383
Plastics & Plastic Products	10	1.150
Plastics-Foam	1	0.070
Plastics-Manufacturers	1	0.085
Plastics-Raw Materials/Powder/Resin	4	1.839
Polyurethane Products	13	27.640
Resins	1	0.187
Safety Equipment & Clothing	1	0.226
Soft Drink Manufacturing	113	162.348
Sponges	1	0.245
Urea Manufacturing	1	112.480
Urethane & Urethane Products	3	2.224
Total	532	769.062

**Table 3.** Primary and secondary carbon dioxide markets located within the IL/IN/OH/MI/PA stretch of Interstate 80.



Figure 3. Sensitivity analysis to the cost of energy inputs for the SMR – CC centralized plant.

A sensitivity analysis is presented around the energy input costs (natural gas and electricity) for the centralized SMR–CC configuration (Figure 3). The levelized cost of hydrogen is very sensitive to the cost of natural gas, as this represents roughly 60% of the operating cost as indicated in Figure 1. The LCOH is less sensitive to the cost of electricity, with a change in cost of +/- \$10/MWh leading to a change of +/- \$0.01 to the overall LCOH.

Alongside SMR-CC, two electrolysis approaches were evaluated for economic impact. Both electrolysis technologies are considered non-competitive with SMR-CC and are highly dependent on the cost of electricity. Figure 4 shows the sensitivity of both electrolysis as a function of electricity price measured against SMR–CC. The major difference between cost estimates comes down to a difference in the (uninstalled) capital cost (\$1000-1200/kW and \$1800-2000/kW for AEC and PEM, respectively) and the greater stack lifetime (*ca.* 1.5 x) for AEM, leading to lower equipment replacement costs over the lifetime of the plant. However, both systems were modeled at a consistent plant availability of 97%. It is known that PEM technology is more flexible and thus suited for pairing with intermittent sources; thus, a PEM system is likely to operate at a higher capacity factor when compared with an AEC linked to an intermittent power source, leading to a greater cost parity between these two technologies.



**Figure 4.** Levelized cost of hydrogen production as a function of electricity cost. The energyintensive electrolysis process is far more sensitive to electricity cost than SMR with CC, yet costs do not converge even at optimistic electricity cost projections. Analysis conducted at a fixed NG cost of \$3.50/MSCF for a large scale (centralized plant) facility.

A recent expert solicitation study projects PEM to overtake AEC as the dominant technology in 2030 cost projections.<sup>20</sup> Figure 5 shows the sensitivity of the levelized cost of hydrogen production to electrolyzer capital cost. Through learning projections driven by increased RD&D the next decade, it is anticipated that by 2030 PEM will become cost-competitive with AEC, with both technologies projected to have a capital cost between \$600 and \$800 / kW.



**Figure 5.** Sensitivity of hydrogen production cost to electrolyzer capital cost, placed against SMR-CC. Increased RD&D over the next decade is anticipated to converge PEM and AEC capital costs. Neither technology, however, is anticipated to overtake SMR-CC as the most cost-effective route to low-carbon hydrogen.

A note on carbon intensity: electrolysis of water is extremely energy intensive; thus, it is imperative to have a near-zero carbon source of electricity to supply operations. Use of intermittent renewable energy may pair better with a more flexible process like PEM electrolysis than with the more mature AEC process. Nevertheless, using grid electricity is not recommended under any circumstance if low carbon intensity hydrogen is the goal. Figure 6 shows the effect of electricity carbon intensity on the specific carbon emissions during hydrogen production (kg  $CO_2$  / kg  $H_2$ ). These emissions consider both those emitted directly, as in the SR flue gas from SMR-CC hydrogen production, and the indirect emissions associated with electricity consumption. Results indicate that a crossover point occurs around 50 gCO<sub>2</sub> whereby electrolysis becomes less carbon intensive through the addition of an MEA capture unit on the SR flue gas, but at a cost premium of 45% over the base case of SMR without carbon capture; thus, as the hydrogen manufacturer demands a product with minimal carbon footprint, electrolysis coupled to renewable

energy becomes the least cost option. Note that this excludes any potential revenue gained from CO<sub>2</sub> resale to consumers from SMR-CC operations.



**Figure 6.** Carbon intensity of hydrogen production as a function of the carbon intensity of the electricity source. Electrolysis becomes competitive when the electricity source dips below 50  $gCO_2$  / kWh, the range occupied by renewable sources like solar, wind, and geothermal energy (in the US), as well as power from nuclear plants.

# **Conclusions and Recommendations**

This study has examined the economic impact of three approaches to hydrogen production, covering mature SMR with carbon capture and electrolysis options, using market conditions relevant to the Midwest section of Interstate 80 and adjusted to scale: refueling station (1500 kg H<sub>2</sub>/day), mid-sized (50000 kg H<sub>2</sub>/day), and centralized production. The major findings are as follows:

- Steam methane reforming with carbon capture was the least cost option considered at each scale spanning \$1 to \$3.24 / kg H<sub>2</sub>. The physical solvent Selexol<sup>™</sup> proved to be optimal in terms of incremental cost of capture, yielding an avoided cost of around \$21 / tonne CO<sub>2</sub> at a capture rate of near 70%.
- Alkaline electrolysis proved to be more cost effective than proton exchange membrane, though there is not a reasonable configuration of inputs (cost of electricity or cost of natural gas) to make electrolysis economically competitive with steam methane reformation.
- Increased RD&D is expected to drive down the capital cost of electrolyzers, and PEM technology is expected to be the predominant form of electrolysis by 2030, despite an anticipated cost edge to alkaline electrolysis. This is due to the added flexibility of PEM and ability to operate at a higher availability when coupled to renewable energy sources.
- The total market for CO<sub>2</sub> in the Midwest stretch of Interstate 80 is 215,000 tonnes, with a possible 770,000 tonnes within reach if extended transport is considered (at a rate of approximately \$0.15/tonne/mile for trucking, \$0.05/tonne/mile for pipeline). This includes high volume EOR and urea manufacturing facilities, as well as numerous, well-dispersed lower volume facilities (e.g., beverage carbonation) that match well with the scale that could be provided from carbon capture at refueling stations.
- In the goal of minimizing carbon footprint of hydrogen generation, only low-carbon (under 50 g CO<sub>2</sub> / kWH) sources like nuclear and renewable power yield a smaller footprint than SMR-CC based hydrogen generation. As the carbon intensity of hydrogen becomes more stringent, electrolysis (both technologies under study) prove more cost effective than SMR-CC. Note that this excludes the resale of CO<sub>2</sub> to external customers or the inclusion of Federal tax credits for beneficial reuse.
- The scale of carbon capture from mid-sized and centralized hydrogen generation facilities has the potential volume to be considered for pipeline transport to geologic storage sites. The Midwest region of Interstate 80 is well situated to take advantage of proximal CO<sub>2</sub> storage in geological reservoirs.

To properly assess hydrogen generation along the I-80 corridor (Midwest), a full analysis of hydrogen plant spacing needs to be conducted. Additional factors must be assessed including, but not limited to: proximity to carbon dioxide providers, proximity to hydrogen providers, natural gas line infrastructure, spatial considerations for on-site equipment and storage and, if electrolysis is desired, spatial considerations for PV panels and storage. Additionally, the full hydrogen delivery cost should be estimated, including filling station costs, transport costs (hydrogen and carbon dioxide) and any resale value or applicable tax credits.

# References

1. Singh, S.; Jain, S.; Ps, V.; Tiwari, A. K.; Nouni, M. R.; Pandey, J. K.; Goel, S., Hydrogen: A Sustainable Fuel for Future of the Transport Sector. *Renewable and Sustainable Energy Reviews* **2015**, *51*, 623-633.

2. Han, S.-K.; Shin, H.-S., Biohydrogen Production by Anaerobic Fermentation of Food Waste. *Int. J. Hydrogen Energy* **2004**, *29*, 569-577.

3. Dou, Y.; Sun, L.; Ren, J.; Dong, L., Opportunities and Future Challenges in Hydrogen Economy for Sustainable Development. In *Hydrogen Economy*, Elsevier: 2017; pp 277-305.

4. Lattin, W. C.; Utgikar, V. P., Transition to Hydrogen Economy in the United States: A 2006 Status Report. *Int. J. Hydrogen Energy* **2007**, *32*, 3230-3237.

5. Luengnaruemitchai, A.; Osuwan, S.; Gulari, E., Comparative Studies of Low-Temperature Water–Gas Shift Reaction over Pt/Ceo2, Au/Ceo2, and Au/Fe2o3 Catalysts. *Catal. Commun.* **2003**, *4*, 215-221.

6. Collodi, G.; Wheeler, F., Hydrogen Production Via Steam Reforming with CO<sub>2</sub> Capture. *Chemical Engineering Transactions* **2010**, *19*, 37-42.

7. Rubin, E. S.; Davison, J. E.; Herzog, H. J., The Cost of CO<sub>2</sub> Capture and Storage. *Int. J. Greenhouse Gas Control* **2015**, *40*, 378-400.

8. Collodi, G.; Azzaro, G.; Ferrari, N. *Techno-Economic Evaluation of Smr Based Standalone* (*Merchant*) *Hydrogen Plant with Ccs*; IEAGHG: 2017.

9. Cormos, A.-M.; Szima, S.; Fogarasi, S.; Cormos, C.-C., Economic Assessments of Hydrogen Production Processes Based on Natural Gas Reforming with Carbon Capture. *Chemical Engineering Transactions* **2018**, *70*, 1231-1236.

10. Kaiwen, L.; Bin, Y.; Tao, Z., Economic Analysis of Hydrogen Production from Steam Reforming Process: A Literature Review. *Energy Sources, Part B: Economics, Planning, and Policy* **2018**, *13*, 109-115.

11. IEA. *The Future of Hydrogen*; IEA, Paris, 2019.

12. Bartels, J. R.; Pate, M. B.; Olson, N. K., An Economic Survey of Hydrogen Production from Conventional and Alternative Energy Sources. *Int. J. Hydrogen Energy* **2010**, *35*, 8371-8384.

13. Glenk, G.; Reichelstein, S., Economics of Converting Renewable Power to Hydrogen. *Nature Energy* **2019**, *4*, 216.

14. DOE INL *Htgr-Integrated Hydrogen Production Via Steam Methane Reforming (Smr) Economic Analysis*; accessed from:

https://art.inl.gov/NGNP/INL%20Documents/Year%202010/HTGR-

Integrated%20Hydrogen%20Production%20via%20Steam%20Methane%20Reforming%20-SMR-%20Economic%20Analysis.pdf, 2010.

15. Eichman, J.; Townsend, A.; Melaina, M. *Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets*; National Renewable Energy Lab.(NREL), Golden, CO (United States): 2016. 16. Guerra, O.; Eichman, J.; Hodge, B.-M.; Kurtz, J. *Cost-Competitive Electrolysis-Based Hydrogen under Current U.S. Electric Utility Rates*; National Renewable Energy Lab.(NREL), Golden, CO (United States): 2018.

17. James, B.; Colella, W.; Moton, J.; Saur, G.; Ramsden, T. *Pem Electrolysis H2a Production Case Study Documentation*; National Renewable Energy Lab.(NREL), Golden, CO (United States): 2013.

18. IHS Markit, *Chemical Economics Handbook (Ceh)*: Available at: <u>https://ihsmarkit.com/products/chemical-economics-handbooks.html</u>, 2018.

19. Psarras, P. C.; Comello, S.; Bains, P.; Charoensawadpong, P.; Reichelstein, S.; Wilcox, J., Carbon Capture and Utilization in the Industrial Sector. *Environmental Science & Technology* **2017**, *51*, 11440-11449.

20. Schmidt, O.; Gambhir, A.; Staffell, I.; Hawkes, A.; Nelson, J.; Few, S., Future Cost and Performance of Water Electrolysis: An Expert Elicitation Study. *Int. J. Hydrogen Energy* **2017**, *42*, 30470-30492.