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Renewable Fuel Production from Geothermal Resources

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ABSTRACT

Geothermal resources have a large potential to be utilized for more than electricity generation and district heating only. Most geothermal power plants have great unused potential in the form of thermal energy of various grades after the geothermal steam has been harnessed for electricity production. Gas emitted from geothermal power plants includes CO_2, currently treated as a waste stream that is emitted to the atmosphere, but with the potential to be captured and harnessed as a value stream for various processes. As the emphasis on more efficient utilization of earth's resources and on CO_2 emission reductions increases globally, it is becoming increasingly important and commercially viable to harness these geothermal waste streams and turn them into value. This circular economy approach can benefit both the owners of the geothermal resources and society as a whole. One usage case for geothermal waste streams is the production of renewable fuels.

Geothermal areas can be very suitable locations for the production of hydrogen via electrolysis. Such production requires electricity and water, both of which are readily available at most geothermal power plants. In high-temperature electrolysis (solid oxide electrolysis), the water input can be supplied in the form of steam, thereby reducing the need for electrical energy input to the electrolysis process. This is particularly feasible in geothermal areas where excess thermal energy in the form of steam is accessible. The produced hydrogen can be utilized directly, e.g. as a transportation fuel, or used as a raw material for other industrial processes.

Geothermal areas can also be very suitable locations for the production of synthetic, sustainably produced hydrocarbon fuels such as methane or methanol. Such fuels can be produced by reacting hydrogen with CO_2 that has been captured from the gas emissions of the geothermal area and subsequently purified. Fuels produced in this way, often called electrofuels, can be considered carbon-neutral and can replace fossil fuel usage in e.g. the transportation sector. Electrofuels are foreseen to become a vital component in decarbonizing those mobility applications where direct electrification is not feasible, and here geothermal resources can play a role.

Landsvirkjun operates the Krafla geothermal power plant in Iceland, which emits approximately 28 kilotons of CO_2 annually. Landsvirkjun has the goal of becoming CO_2 neutral by the year 2025, and for realizing this target, renewable fuel production from geothermal resource streams, including CO_2, might play a role. This paper provides an overview of the main technological pathways for renewable electrofuel production from geothermal resources and includes a brief case study for potential renewable fuel production at Landsvirkjun's Krafla geothermal power plant in Iceland.

1. INTRODUCTION

A complete transition away from fossil fuels and towards renewable, carbon neutral fuels is necessary as a part of mitigating the ongoing global climate crisis. A large share of mobility applications, such as cars, trains, buses and smaller marine vessels, can and should be directly electrified using batteries. For most remaining mobility applications, such as long-distance heavy transport, some trains and buses, larger marine applications and aviation, battery electrification is not feasible for practical reasons. One reason is the low gravimetric energy density of batteries, which means that heavy vehicles with a comparable driving range to fossil fueled vehicles would require prohibitively heavy battery loads, significantly reducing their payload. Other reasons include the requirements regarding infrastructure and charging times, which are often infeasible for the operation of commercial vehicles. The decarbonization of these mobility applications will therefore require renewable fuels such as hydrogen, synthetic hydrocarbon fuels (such as methane, methanol, diesel, gasoline, kerosene etc.) or ammonia (Siegemund *et al.*, 2017).

The decarbonization of various energy applications in buildings and industry will also require renewable fuels (Bazzanella and Ausfelder, 2017). Energy for space heating and domestic hot water is mainly supplied by fossil natural gas in many areas. Switching to hydrogen or renewable, synthetic methane gas could, in some cases where other renewable options are not feasible, help decarbonizing energy usage in buildings. Many industrial chemical synthesis routes, such as those of methanol, ammonia or steel currently rely on CO_2 from fossil sources that could be replaced with processes involving renewable hydrogen and CO_2 captured from non-fossil sources. Renewable fuels can thus play a key role in decarbonizing the chemical industry.

Renewable fuels can be produced in a variety of ways, e.g. in processes starting with the fermentation or gasification of biomass or by recycling used mineral oils. Renewable fuels can also be produced using electricity, water and (in some cases) a carbon source, in so-called power-to-gas (P2G) and power-to-liquid (P2L) processes. In these processes, electricity is used for producing hydrogen by electrolyzing water. The hydrogen can either be used directly as a fuel, be reacted with carbon to form synthetic hydrocarbon fuels or be reacted with nitrogen (captured from the atmosphere) to form ammonia. Fuels produced via such pathways, that rely on electricity input, are often referred to as *electrofuels* (Ridjan *et al.*, 2015), or as *e-fuels* (Siegemund *et al.*, 2017). If the electricity for the process is of fully renewable origin and the carbon (if needed) is recycled from the atmosphere or from other emission sources, the fuels are carbon neutral and can be called renewable electrofuels.

This paper provides an overview of the main technological pathways for electrofuel production from geothermal resources and examines what the main technological and economic opportunities and barriers exist for electrofuel production at geothermal sites. The paper also includes a brief case study for potential renewable fuel production at Landsvirkjun's Krafla geothermal power plant in Iceland.

2. GEOTHERMAL RESOURCES FOR ELECTROFUEL PRODUCTION

Geothermal sites can be very suitable locations for the production of electrofuels. As shown in Figure 1, all resources required for the production are typically available at geothermal power plants. Surplus heat is almost always available at geothermal power plants, e.g. in the form of hot water from separators or even in the form of steam that is not used for power production. Cold (or lukewarm) water is usually, although not always, available in large quantities, in the form of groundwater and/or condenser water. It should be noted that electrolysis for hydrogen production is not a very water-intensive process, but purification of CO_2 can be rather water-intensive if water scrubbing technology is used.

High voltage electricity is available directly from the geothermal power plant. The electricity from geothermal power plants is often generated as cost-competitive base-load energy. This can help ensuring a higher number of annual operating hours for electrofuel production facilities than if electricity from wind or solar is used for the production, and without the need for electrical energy storage. This results in a better utilization of the investment and can translate to lower specific electrofuel production costs.

Carbon dioxide is often a dominating part of the chemical composition of non-condensable gases (NCG) from geothermal power plants, although the specific CO_2 emissions per unit of energy are, in almost all cases, only a fraction of those from fossil fueled power plants. The CO_2 can be captured and reacted with hydrogen to form electrofuels such as methane, methanol, diesel, gasoline or kerosene. The concentration of CO_2 in the geothermal fluid varies strongly between geothermal areas and can also vary significantly between individual wells in a single geothermal area. The CO_2 concentration in the fluid and the total amount of CO_2 in a geothermal area are important factors in how economical carbon capture and utilization at a geothermal power plant is. The design of the power plant is also an important factor for this, as it dictates how simple it is to extract CO_2 from the geothermal fluid. The gas can usually be extracted downstream from the condenser, where NCG gases are separated from the geothermal steam. The captured CO_2 must be purified prior to utilization, in particular to remove any compounds containing sulfur. The precise purity requirements of the CO_2 stream depend on its application. The production of ammonia requires nitrogen instead of carbon dioxide. The required nitrogen can be extracted from the atmosphere using air separation equipment. When extracting nitrogen from the atmosphere at geothermal power plants, any sulfur containing compounds must be removed prior to ammonia production, e.g. by a coal filter.

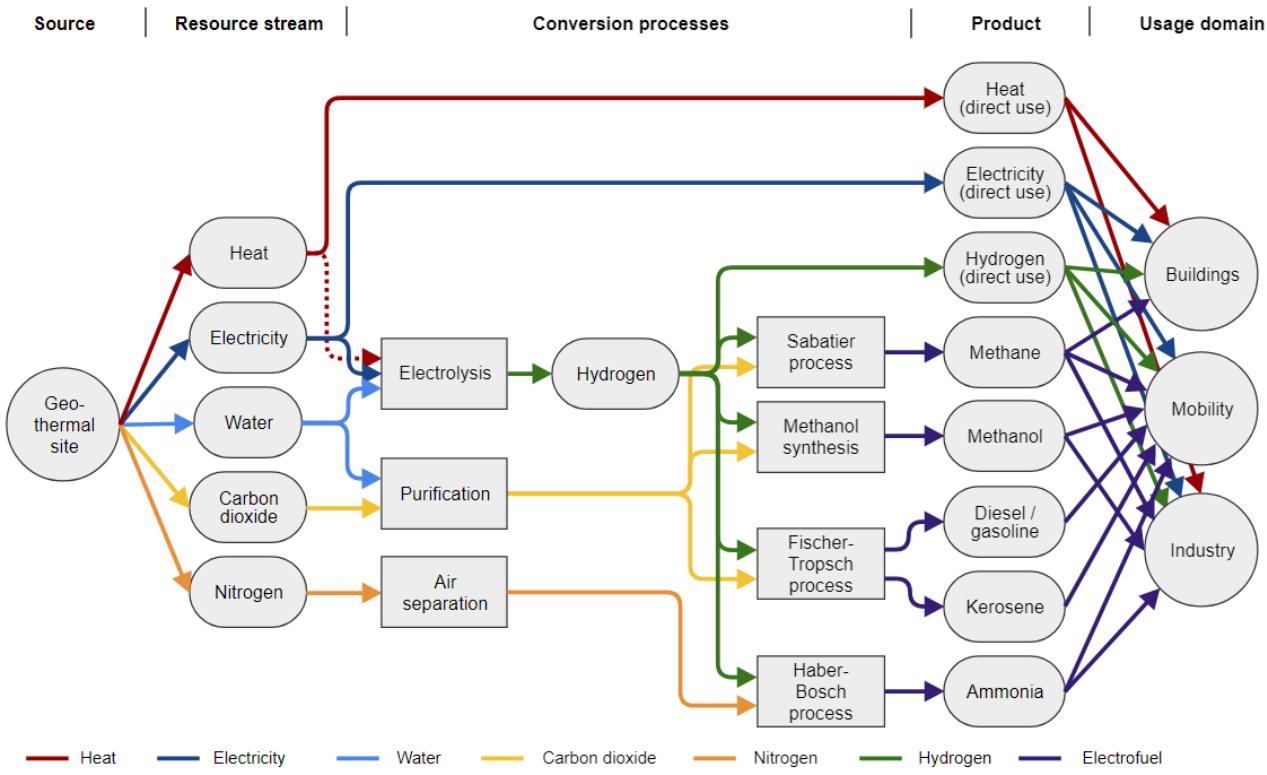

Figure 1: A flow chart illustrating how the resource streams from geothermal sites can be used for the production of electrofuels and in which domains of energy demand they can be used. Not all resource streams may be available at all geothermal sites. Nitrogen is assumed to be captured from the atmosphere.

While the available resource streams at geothermal power plants can make them technologically very feasible as locations for electrofuel production, other aspects must also be taken into consideration when assessing the overall feasibility. Geothermal power plants are often located in environmentally sensitive geothermal areas. Ecological aspects of locating chemical plants in such areas must be thoroughly evaluated. Furthermore, geothermal areas are sometimes aesthetically beautiful areas with tourism activities close to geothermal power plants. Some types of electrofuel production facilities require a large footprint and tall structures, e.g. for

scrubbing columns or distillation towers. The harmony of the structures with the nature of the area must be taken into account, and efforts should be made to minimize the visual impact in the architectural design of the structures. These environmental aspects do not at all exclude geothermal areas as sites for electrofuel production but should be taken seriously into account in any such project.

The sustainability of the resources used for electrofuel production must be assessed, ideally in a life-cycle assessment for each individual case. Since carbon dioxide is usually released from geothermal power plants, the electricity from the plants cannot be considered fully emission free if no carbon sequestration or utilization measures are taken. The specific CO_2 emissions per energy unit from most geothermal power plants are, however, very low compared to the average CO_2 intensity of the electricity generation mix of most countries or areas.

The CO_2 emissions from geothermal power must be considered as emissions caused by human activity, as the drilling and harnessing of geothermal wells accelerates any naturally occurring emissions in geothermal areas. If this CO_2 is captured and used for electrofuel production, the resulting fuels can be considered carbon neutral because the CO_2 from the power production is recycled and the same amount of CO_2 emissions from fossil fuel combustion is avoided. The carbon loop of the CO_2 in electrofuel production is, however, not a closed one, since CO_2 is harnessed from the ground and emissions from the electrofuel combustion are not reused. Because of this, the net amount of CO_2 in the atmosphere will still be somewhat increased, even when the emissions of the geothermal plant are recycled for carbon neutral fuel production, but the same amount of CO_2 emissions from fossil fuels, that would otherwise take place, will be displaced. In order to avoid double-counting of the emission reduction, it must be clear how the CO_2 reduction benefits are split between the CO_2 supplier (the owner of the geothermal plant) and the CO_2 consumer (the electrofuel producer or the end-consumer). A truly closed carbon loop option would be to capture CO_2 for electrofuel production directly from the atmosphere. However, in lieu of economically viable and technically scalable options for direct air CO_2 capture in the near or medium term, electrofuel production by geothermal CO_2 utilization is currently one of the most feasible and sustainable options for the production of carbon neutral fuels. It is also a perfect example of how industrial symbiosis can enhance the sustainability of two different products.

3. ELECTROFUEL PRODUCTION PATHWAYS

3.1 Hydrogen

Hydrogen is an essential energy carrier for decarbonizing various segments of the energy system, in particular selected applications in mobility, industry and buildings (IEA, 2019; IRENA, 2019 and FCH, 2019). Hydrogen can be used as a mobility fuel (e.g. in fuel cell electric vehicles), for injection in existing natural gas grids (e.g. for space heating) and as a replacement for fossil fuels for some industrial processes (e.g. as a reducing agent in steel production). Hydrogen is furthermore a necessary building block for other, more complex electrofuels and chemicals such as methane, methanol and ammonia. Hydrogen can be transported over short and medium distances in pipelines or in pressurized vessels or over long (international and intercontinental) distances in liquified form or chemically stored in other compounds such as ammonia or liquid organic hydrogen carriers (LOHC).

Today hydrogen is mainly used in various chemical industries, such as in ammonia production for fertilizers and in the refinement of petroleum products. 96% of all hydrogen produced worldwide today is of fossil origin, derived mostly from natural gas and oil (IRENA, 2018). Only 4% of hydrogen is produced by electrolysis of water. This will need to change, as considerable amounts of CO_2 are emitted from hydrogen production from fossil fuels (although adding carbon capture and storage to the process could mitigate those emissions to some extent). The only CO_2 emissions from electrolytic hydrogen production come from the CO_2 emissions of the electricity used for the process. Using electricity from renewable sources, such as geothermal energy, enables the production of hydrogen with no or very low CO_2 emissions and replaces fossil fuels that would otherwise have been extracted from the ground.

The chemical reaction of the electrolysis of water is

$$2H_2O + \Delta H_f \rightarrow 2H_2 + O_2 \quad (1)$$

where ΔH_f denotes the enthalpy of formation, which equals the total required energy for the reaction to take place. In electrolysis this energy is supplied as electrical energy. The only byproduct of the process, oxygen, may in some cases be captured and supplied to other industries, such as fish farming. There are currently three technologies for electrolytic hydrogen production: Alkaline electrolyzers, proton exchange membrane (PEM) electrolyzers and solid oxide electrolyzer cells (SOEC).

Investment costs for all three electrolyzer technologies have decreased rapidly in recent years and are expected to decrease further with further scale-up and increased installed capacity for electrolytic hydrogen production in coming years (IRENA, 2018 and Bazzanella *et al.*, 2017). The largest operating expense by far in electrolysis is the cost of electricity. High electrolysis energy efficiency, a high number of annual production hours and a low electricity price are the most important factors for ensuring low production costs of electrolytic hydrogen.

3.1.1 Alkaline Electrolysis

Alkaline electrolysis is the oldest, most established and currently least expensive method for electrolytic production of hydrogen. The process has been employed since the 19th century and is considered mature technology with a technology readiness level (TRL) of 9. The technology development has nonetheless been substantial in the last decade and alkaline electrolyzer costs have decreased. Alkaline electrolyzers typically operate at around 80°C and at a pressure of 1-30 bar. The alkaline electrolysis process yields low-grade excess heat, which keeps the electrolyzer at its operating temperature. The water input temperature should not exceed 30 °C.

State of the art energy efficiencies (electricity to hydrogen) of alkaline electrolyzer systems are around 60-65%, measured for the lower heating value (LHV) of hydrogen. This translates to an electricity consumption of 4,6-5,0 kWh/Nm^3 of hydrogen or 51-56

kWh/kg of hydrogen. Typical capacities of alkaline electrolyzer modules (stacks) are from a few kW up to around 5 MW, measured in electrical input power. For larger systems, multiple stacks are connected in one plant. Typical investment costs for alkaline electrolyzers are currently in the range of 600-1000 USD/MWh, the costs decreasing with scale (IRENA, 2018; IEA, 2019 and DEA, 2017). Alkaline electrolyzers typically take a few minutes for ramping production up and down, which is enough for providing some load flexibility to the power grid, but not sufficient for providing grid services on a time scale of seconds.

3.1.2 Proton Exchange Membrane Electrolysis

PEM electrolysis has been developed in the last few decades. The PEM technology has only become commercial in the last decade and has a TRL of 8-9, with further scaling up and improvement of the technology anticipated in coming years. Individual PEM stacks have capacities from a few kW to a few MW, with the possibility of connecting multiple stacks for a larger plant. PEM stacks have a significantly smaller footprint than alkaline stacks. PEM electrolyzers are operated at temperatures below 100 °C, usually at pressures of 30-80 bar and take cold inlet water as an input.

The energy efficiencies (electricity to hydrogen) for PEM electrolyzer systems are currently around 55-60% (LHV). This equals an electricity consumption of 5,0-5,5 kWh/Nm^3 of hydrogen or 55-61 kWh/kg of hydrogen. Typical investment costs for PEM electrolyzers are currently in the range of 800-1500 USD/MWh, the costs decreasing with scale (IRENA, 2018; IEA, 2019 and DEA, 2017). An advantage of PEM electrolyzers over alkaline electrolyzers is the ability to ramp the production up and down within seconds. This opens up the possibility of serving as fast balancing units in the power grid and possibly obtaining additional revenue in the form of grid service payments from the transmission system operator (TSO).

3.1.3 Solid Oxide Electrolysis

SOEC is a technology that has been developed in the last few decades. A SOEC produces hydrogen and oxygen from water (steam) at elevated temperatures of approximately 650-800°C. SOEC electrolysis currently has TRL 6-7, with further technology improvements and scale-up of the technology yet to be seen before full commercialization (Bazzanella *et al.*, 2017). In the long run, solid oxide electrolyzers have the potential of becoming less expensive than alkaline or PEM (due to inexpensive material components) and to have a higher energy efficiency (due to the high-temperature operation).

A very interesting property of SOEC electrolysis, especially when considering hydrogen production at geothermal sites, is the possibility of supplying part of the required energy input as thermal energy, thereby lowering the need for electrical energy input. Assuming the chemical reaction described in Equation 1 takes place at constant temperature, the enthalpy of formation can be written as

$$\Delta H_f = \Delta G_f + T\Delta S_f \tag{2}$$

where ΔG_f denotes the Gibbs free energy of formation, T denotes the temperature and ΔS_f denotes the entropy of formation. The chemical equation for the electrolysis of water then becomes:

$$2H_2O + \Delta G_f + T\Delta S_f \rightarrow 2H_2 + O_2 \tag{3}$$

The Gibbs free energy input ΔG_f must be provided in the form of electrical energy, but the energy for the $T\Delta S_f$ term can be supplied either in the form of electrical or thermal energy (Ebbesen *et al.*, 2014).

The ratio between ΔG_f and $T\Delta S_f$ for the reaction varies somewhat with temperature. For an operating temperature of 700 °C, 22% of the total energy input may be supplied in the form of thermal energy (steam), thereby reducing the need for electrical energy by the same amount. This is important because the cost of electricity is the largest cost component in the production cost of electrolytic hydrogen. If high-grade thermal energy can be made available to the process at low cost, as is most often the case at geothermal power plants, this can translate to substantial savings in hydrogen production costs.

Typical energy efficiencies (electricity and heat to hydrogen) for SOEC systems today are around 80-82% (LHV). If only electricity and no heat is provided as input, this efficiency equals an electricity consumption of 3,6-3,8 kWh/Nm^3 of hydrogen or 41-42 kWh/kg of hydrogen. If both electricity and heat are provided as inputs, the electricity consumption is around 2,9 kWh/Nm^3 of hydrogen, or 32 kWh/kg of hydrogen, while the thermal energy consumption is around 0,8 kWh/Nm^3 of hydrogen, or 9 kWh/kg of hydrogen. The investment costs for SOEC systems is currently estimated at approximately 2000-2500 USD/MWh (DEA, 2017).

An additional benefit is that utilizing surplus geothermal heat instead of electricity decreases the amount of primary energy consumption from the geothermal system for the electrolysis process, as direct steam utilization is more efficient than first converting the steam to electricity in a turbine. Similar to PEM systems, SOEC systems can ramp production up and down in seconds while kept at operating temperature. Other interesting features of SOEC systems include the ability to electrolyze water and CO_2 simultaneously, thereby producing syngas (a mixture of hydrogen and carbon monoxide), and the ability to operate in fuel cell mode, making the reaction in Equation 1 run in the reverse direction to produce electricity from hydrogen.

3.2 Methane

Methane is the main component in natural gas of fossil origin, which is distributed in gas grids and used for power production, space heating and other applications worldwide. Renewable methane, also called synthetic natural gas (SNG) can be produced by reacting CO_2 and hydrogen in the Sabatier reaction:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O + \Delta H_f \tag{4}$$

The resulting SNG can be used for the same applications as fossil natural gas, or as a carbon neutral fuel for mobility applications. SNG can be transported via the existing natural gas infrastructure or transported in pressurized form (compressed natural gas, CNG) or liquid form (liquified natural gas, LNG) over long distances. Liquefaction of SNG is usually less costly than liquefaction of natural gas of fossil origin, as SNG contains less impurities and therefore needs less purification before the liquefaction stage (Bazzanella *et al.*, 2017). The SNG can be considered carbon neutral as long as the hydrogen is produced using carbon neutral electricity and the CO_2 for the production is captured from a CO_2 stream that would otherwise have been directly emitted to the atmosphere.

Methane production via the reaction in Equation 4 requires 0.5 kg of hydrogen and 2.7 kg of CO_2 per kg of methane. If alkaline electrolysis is used for the hydrogen production, the electricity demand is approximately 27 kWh/kg of methane. This equals 2.16 kWh of electricity consumption per kWh of produced methane.

There are two main methods for producing SNG from CO_2 and hydrogen; methane synthesis using an inorganic catalyst and organic methane synthesis using microbes (Sveinbjörnsson and Münster, 2017). A few pilot plant of each type exist, but full scale commercialization of the technology has not yet been realized. The technology is considered to be at TRL 7.

The production cost of renewable methane can be estimated to be 250-800% of the market price for conventionally produced methanol in Europe (Bazzanella et al., 2017). This is without costs for H_2S purification of CO_2 and depends heavily on the electricity price to the electrolyzer.

3.2.1 Catalytic Methane Production

With this production method an inorganic nickel-based catalyst facilitates the reaction of hydrogen and CO_2 to methane. Such catalysts are very sensitive to compounds containing sulfur, such as hydrogen sulfide (H_2S) that is usually present in gas of geothermal origin. In order to produce methane using an inorganic catalyst, the CO_2 inlet gas must be purified such that the H_2S content is reduced to a level of around 1 ppm. This can be very costly and can seriously affect the business case for methane production.

3.2.2 Organic Methane Production

Certain types of microbes, called archaea, can be used for producing methane. Methanogenic archaea are fed with hydrogen and CO_2, releasing methane that can be captured and used. In this process, the chemical reaction in Equation 4 takes place without the presence of an inorganic catalyst. The archaea utilized for the process were originally discovered in geysers and therefore have a high inherent tolerance for hydrogen sulfide. The purification requirements for CO_2 used in organic methane production are therefore much less stringent as for the case of catalytic methane production, which can substantially decrease the cost of the purification step. The resulting methane, however, needs to be purified such that it meets the sulfur content limits of the equipment to which the methane will be injected, but this is typically less costly than the purification needed for CO_2 before the inorganic methane production step. Because of this, organic methane synthesis is usually expected to be more economical than synthesis using inorganic catalysts when utilizing geothermal CO_2 for the production.

3.3 Methanol

Methanol is one of the most used products in the chemical industry, but also has the potential of being utilized as a fuel for heavy land vehicles and ships. Methanol is conventionally produced in very large-scale plants via steam reforming of natural gas of fossil origin. Renewable methanol can be produced by reacting CO_2 and hydrogen in the following reaction:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O + \Delta H_f \quad (5)$$

This process requires 0.19 kg of hydrogen and 1.37 kg of CO_2 per kg of methanol. If alkaline electrolysis is used for the hydrogen production, the electricity demand is approximately 11 kWh/kg of methanol. This equals 2.23 kWh of electricity consumption per kWh of produced methane. The methanol can be considered carbon neutral as long as the hydrogen is produced using carbon neutral electricity and the CO_2 for the production is captured from a CO_2 stream that would otherwise have been directly emitted to the atmosphere. The technology is considered to be at TRL 7.

A few pilot plants that produce methanol via this reaction are currently in operation. One of these plants is operated by Carbon Recycling International (CRI) and is located adjacent to a geothermal power plant at Svartsengi in Iceland (Olah, 2008; CRI, 2019). The renewable methanol plant is a small pilot plant that receives electricity and CO_2 from the geothermal plant. Hydrogen is produced at the plant using an alkaline electrolyzer with a capacity of 6 MW. The capacity of the plant is 4000 Mt/year of methanol, but a full-scale plant would have at least 10-20 times that capacity. Due to the large scale of a full-scale methanol plant, the CO_2 demand for such a plant would be at least 50-100 Mt/year. Only very large geothermal power plants with high CO_2 emissions would be technically able to deliver this amount of CO_2 for the process, and therefore other sources of CO_2 would likely be needed.

The methanol production reaction in Equation 5 relies on an inorganic catalyst that is very sensitive to compounds containing sulfur, such as hydrogen sulfide (H_2S). In order to produce methanol using an inorganic catalyst, the CO_2 inlet gas must be purified such that the H_2S content is reduced to a similar level as for inorganic methane production, or around 1 ppm. This can be very costly and can affect the business case for methanol production.

The production cost of renewable methanol can be estimated to be 120-200% of the market price for conventionally produced methanol in Europe (Bazzanella *et al.*, 2017). This is without costs for H_2S purification of CO_2 and depends heavily on the electricity price to the electrolyzer.

3.4 Ammonia

Ammonia is the second most produced chemical in the world, with the majority of ammonia being used for the production of fertilizer for agriculture. Ammonia also has the potential of being utilized as a transport fuel, in particular for large ships. Ammonia is conventionally produced in very large-scale plants using the Haber-Bosch process:

$$N_2 + 3H_2 \rightarrow 2NH_3 + \Delta H_f \quad (6)$$

This process requires 0.18 kg of hydrogen per kg of methanol. If alkaline electrolysis is used for the hydrogen production, the electricity demand is approximately 12.5 kWh/kg of methanol. This equals 2.23 kWh of electricity consumption per kWh of produced methanol.

Ammonia contains no carbon, and no carbon is therefore used in the Haber-Bosch process itself. The hydrogen for the process is, however, conventionally produced by steam reforming of natural gas of fossil origin, in which CO_2 from the natural gas is released. Due to this, the average CO_2 emissions in European ammonia production are 1.33 kg CO_2 per kg of ammonia (Bazzanella *et al.*, 2017). This can be avoided by producing the hydrogen via electrolysis using electricity from renewable sources. Here, geothermal power has the advantage of enabling a higher number of annual operating hours for the hydrogen and ammonia production than would be possible using hydrogen from wind or solar power. The design and construction of ammonia plants with hydrogen production from electrolyzers, rather than hydrogen of fossil origin, has not reached commercial scale and is at TRL 7.

Ammonia plants usually operate at pressures of 150-350 bar and temperatures of around 450°C. There are considerable economies of scale and ammonia plants are usually very large, similar to methanol plants. The ammonia production reaction in Equation 6 relies on an inorganic iron-based catalyst that is very sensitive to compounds containing sulfur, such as hydrogen sulfide (H_2S). In order to produce methanol using an inorganic catalyst, the N_2 inlet gas (which is acquired by separation from atmospheric air) must be purified such that the H_2S content is reduced to levels on the scale of 1 ppm. This can be costly, in particular in geothermal areas with a relatively high concentration of atmospheric H_2S, and can affect the business case for methanol production.

The production cost of ammonia from renewably generated hydrogen can be estimated to be 130-230% of the market price for conventionally produced ammonia in Europe (Bazzanella *et al.*, 2017). This is without costs for H_2S purification of N_2 and depends heavily on the electricity price to the electrolyzer.

3.5 Diesel, Gasoline and Kerosene

Diesel and gasoline are currently by far the most widely used transport fuels on land and sea and kerosene is virtually the only fuel used in the aviation sector today. While substituting fossil diesel, gasoline and kerosene demand for renewable fuels such as electricity, hydrogen or carbon neutral methane, methanol or ammonia should be technically possible for most mobility applications on land and sea, some demand for diesel and gasoline fuel will most probably remain. Substituting all fossil kerosene with some of these less energy-dense renewable fuels may furthermore prove difficult for the aviation sector. For these applications, synthetic diesel, gasoline and kerosene production in the form of electrofuels is the way to decarbonization. Renewable diesel, gasoline and kerosene can be produced from CO_2 and hydrogen via the Fischer-Tropsch (FT) process:

$$CO_2 + 3H_2 \rightarrow -CH_2- + 2H_2O + \Delta H_f \quad (7)$$

Here the term $-CH_2-$ denotes hydrocarbon chains of various lengths. This process requires around 0.5 kg of hydrogen and 3.1 kg of CO_2 per kg of FT-fuel (König, 2016). If alkaline electrolysis is used for the hydrogen production, the electricity demand is approximately 26 kWh/kg of FT-fuel. This equals 2.28 kWh of electricity consumption per kWh of produced methane. The methanol can be considered carbon neutral as long as the hydrogen is produced using carbon neutral electricity and the CO_2 for the production is captured from a CO_2 stream that would otherwise have been directly emitted to the atmosphere. Renewable FT fuel production is considered to be at TRL 5-7.

A few pilot projects have demonstrated the production of renewable FT fuel. The company Sunfire operates a small pilot plant in Germany where hydrogen is produced using SOEC and reacted with CO_2 in a Fischer-Tropsch synthesis process to form synthetic diesel. The production cost for the process is estimated to be 200-600% of the price for fossil crude oil (Bazzanella *et al.*, 2017). Similar to methanol and ammonia production, FT synthesis takes place at elevated temperatures and high pressures and therefore has considerable economies of scale. Synthetic diesel, gasoline and kerosene production is therefore likely to be best suited for very large-scale plants.

The FT-fuel production reaction in Equation 7 relies on an inorganic catalyst that is very sensitive to compounds containing sulfur, such as hydrogen sulfide (H_2S). In order to produce FT-fuel using an inorganic catalyst, the CO_2 inlet gas must be purified such that the H_2S content is reduced to a level the catalyst can tolerate. This can be very costly and can affect the business case for the production.

Table 1: A summary of the electricity, hydrogen and CO_2 demand for the fuel types discussed in subsections 3.1-3.5. The estimated production cost for the electrofuels, relative to the fossil fuel variant of the same fuel, is also shown. Here, hydrogen production with alkaline electrolysis is assumed. The value for the production cost of hydrogen stems from (IEA, 2019).

Electrofuel	Electricity demand (kWh/kWh electrofuel)	Hydrogen demand (kg H_2 / kg electrofuel)	CO_2 Demand (kg CO_2 / kg electrofuel)	Production cost (% of fossil fuel market price)	Technology readiness level (1-9)
Hydrogen	1.6	-	-	120-300%	9
Methane	2.16	0.50	2.70	250-800%	7
Methanol	2.23	0.19	1.37	120-200%	7
Ammonia	2.23	0.18	-	130-230%	7
FT-fuel	2.28	0.50	3.1	200-600%	5-7

4. CASE STUDY: KRAFLA GEOTHERMAL POWER PLANT IN ICELAND

The aim of this section is to briefly discuss, which types of renewable fuel production could be suitable at Landsvirkjun's Krafla geothermal power plant in Northeast Iceland and which quantities of fuel production the resource streams from the plant could sustain. Landsvirkjun aims to be CO_2 neutral by the year 2025. Landsvirkjun furthermore aims to reduce the greenhouse gas emissions from its geothermal operations by 60% by 2025 compared to the year 2008.

In the year 2019, 44% of Landsvirkjun's total greenhouse gas emissions (measured in CO_2 equivalents and without counting CO_2 offsetting measures such as tree planting) were due to CO_2 emitted from the Krafla power plant. To reach the goal of carbon neutrality and the goal for 60% geothermal emission reductions by 2025, Landsvirkjun is developing solutions for capturing the CO_2 emissions from Krafla's NCG and sequestering them in the underground or turning them into a value stream for e.g. electrofuel production. In the case of CO_2 capturing and utilization, the splitting of the carbon reduction benefit between Landsvirkjun and the electrofuel producer would need to be cleared to avoid double-counting, as mentioned in Section 2.



Figure 2: A photograph of the Krafla geothermal power plant in Northeast Iceland.

The available resource streams at Krafla power plant are illustrated in Figure 3. Heat is available in the form of steam (35 kg/s at 126-171 °C) and separator water (approx. 100 kg/s at 126 °C). This thermal energy is currently not harnessed. The power plant has a nameplate capacity of 60 MW (two 30 MW turbines) and can produce around 500 GWh of electricity per year. This electricity is currently sold to Landsvirkjun's customers, but for the purpose of this case study, it is assumed here that this demand could be fulfilled by some of Landsvirkjun's other power plants if the electricity generated at Krafla were to be used for electrofuel production (which may not be strictly correct at all times). Cold and luke-warm water is available in the form of water from the cooling tower (100 kg/s, 20-40 °C) and ground water (6-16 °C, approx. 75 kg/s). The carbon dioxide content in the emission stream from the cooling tower in 2019 was approximately 0.94 kg/s, which equals 28 kiloton/year of CO_2 at full power plant operation. This stream could be captured and purified, which is not done today. In the case of ammonia production, nitrogen can be captured from the atmosphere and purified.

Krafla power plant has water-cooled direct contact condensers. In this design, atmospheric oxygen comes in direct contact with the cooling water and the NCG. The CO_2 must thus be captured from a raw gas stream containing, among other species, oxygen and hydrogen sulfide. Oxygen and hydrogen sulfide can react and form elemental sulfur, and any CO_2 capture system at Krafla must thus be designed such that any potential problems due to sulfur scaling are avoided. This should well be possible but adds a level of

complexity to CO_2 capture at Krafla power plant (and other geothermal power plants with direct contact condensers) but is not an issue for CO_2 capture at geothermal power plants with surface condensers (e.g. Landsvirkjun's Þeistareykir power plant), as the NCG does at such plants contains no or very little atmospheric oxygen.

The maximum electrofuel production volumes that can be obtained using the resources available at Krafla (illustrated in Figure 3) are shown in Table 2. Electrical power demand is the limiting resource stream for hydrogen and ammonia production volume, while CO_2 demand is the limiting resource stream for electrofuels containing carbon (methane, methanol, FT-fuel). For electrofuels containing carbon, the electrical power needed to fully utilize the CO_2 resource is 30-38 MW, depending on the fuel type, while hydrogen and ammonia may be produced using the full electrical power of the plant, 60 MW. When utilizing CO_2 from Krafla power plant in electrofuel production involving inorganic catalysts, the CO_2 must be thoroughly purified to remove any H_2S from the gas (the H_2S content in the unpurified gas stream is 0.15 kg/s).

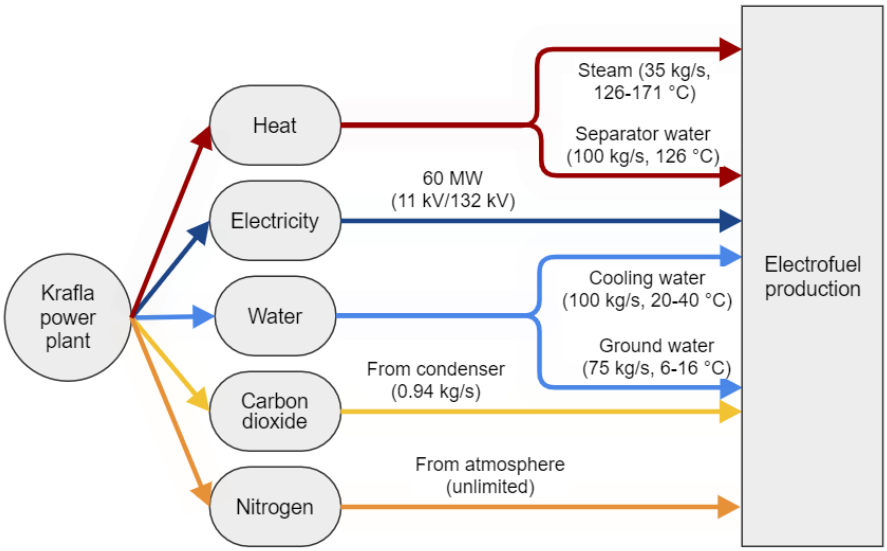

Figure 3: A flow chart of the main resource streams from Krafla geothermal powerplant that could potentially be utilized for electrofuel production. The box titled "electrofuel production" in this flow chart represents the parts of Figure 1 labelled "conversion processes", "products" and "usage domains".

Table 2: A summary of the estimated maximum electrofuel production volumes that can be sustained using the resource streams from Krafla power plant. The value of the limiting factor for each fuel type is shown in bold in the table. The electrical energy demand is calculated assuming 8,300 annual full load production hours. The energy efficiency from electricity to electrofuel is calculated as the annual electrofuel production volume divided by the annual electrical energy demand.

Electrofuel	Electrofuel production volume (kiloton/year)	Electrofuel production volume (GWh/year)	Electrical power demand (MW)	Electrical energy demand (GWh/year)	CO_2 demand (kiloton CO_2/year)	Electricity to electrofuel energy efficiency (%)
Hydrogen	9.33	311	**60**	498	0	63%
Methane	10.4	144	38	311	**28**	46%
Methanol	20.4	113	30	251	**28**	45%
Ammonia	35.7	223	**60**	498	0	45%
FT-fuel	9.1	109	30	248	**28**	44%

The energy efficiency, measured as the energy content of the produced electrofuel divided by the electrical energy input, is highest for hydrogen production (63%) and lower for the other fuel types (44-46%). This is because the production of hydrogen only requires one energy conversion step (electrolysis of water), while the other fuels require two conversion steps (electrolysis and subsequent reaction of CO_2 and H_2 reaction. The energy efficiency of the electrolysis step is assumed to be 63%, but the assumed energy efficiency of the second step varies between 70 and 74%, depending on the fuel type. The total electricity to electrofuel energy efficiency is a product of the efficiencies of the two conversion steps.

Typical scales of electrolytic hydrogen production around the world today range between a few hundred kW to a few MW, with new projects on the scale of tens of MW being planned. An electrolyzer capacity up to 60 MW, as could theoretically be obtained using the electricity output from Krafla power plant, is therefore sufficient for large scale electrolytic hydrogen production.

The production processes of methanol, ammonia (Haber-Bosch process) and diesel, gasoline and kerosene (Fischer-Tropsch process) require high temperatures and high pressures. The production of these fuels therefore benefits greatly from economies of scale, and full-scale plants that produce these chemicals from fossil sources today typically have a production capacity in the order of magnitude of 1,000 tons per day, equivalent to approx. 360,000 tons per year. This is more than 10 times the maximum production capacity for these electrofuels if only the resources at Krafla power plant were to be used. Various research groups are working on identifying smaller-scale, low-temperature and/or low-pressure reaction pathways for methanol, ammonia and FT-fuel production, but these are still on early research and development stages. Until such pathways can be improved, scaled up and commercialized, the production of these fuels will be most economical at very large scales, which would require much larger amounts of CO_2 and/or electricity than available at Krafla. Krafla can, nonetheless, be a suitable location for pilot and demonstration projects for the production of such electrofuels, within the scales indicated in Table 2.

The production of synthetic methane from CO_2 and is currently carried out in a few places on a pilot scale. Production on the order of magnitude of 10 kiloton per year could potentially be a feasible size for a full-scale plant, in particular for biological methane production, where high temperatures and pressures are not required for the production, and economies of scale are consequently not as great. This scale of methane production could be sustained using the resources at Krafla power plant, as shown in Table 2. Biological methane production is, furthermore, more feasible at Krafla than inorganic catalytic production, due to lower H_2S purification requirements for the biological route. For these reasons, methane production is likely the most feasible hydrocarbon electrofuels that could be produced using the resources at Krafla.

In addition to the technical aspects of electrofuel production at Krafla, which is the focus of this analysis, environmental aspects need to be taken seriously into consideration. The potential production and handling of fuels in the Krafla geothermal area would need to be performed with great care and with minimal impacts on the environment, also in case of malfunction or leakage. The plants usually require distillation columns, which are tall structures. They also require water or amine scrubbing columns for CO_2 capture. This makes the overall plant structures rather tall, especially for large-scale plants, and care should be taken to design any potential electrofuel plant in the area such that the visual impact is minimized.

5. CONCLUSION

Most geothermal areas contain all resource streams needed for the production of the electrofuels discussed in this work. This can enable the production of renewable fuels that could displace fossil fuels in mobility, industry and buildings, while in some cases also turning geothermal waste streams into value. The magnitude of the available resource streams varies greatly depending between geothermal areas. A brief case study has been performed for Krafla geothermal power plant in Iceland. The results indicate that from a technical point of view, Krafla would likely be well suited for full-scale hydrogen production, for medium-scale biological methane production or for pilot-scale methanol, ammonia or FT-fuel production. The CO_2 and electricity resources available at Krafla would not sustain full-scale production of methanol, ammonia or FT-fuels, judging by the typical scale of such production from fossil fuels today.

The production cost for electrofuels is in all cases considerably higher than the market price of the corresponding fossil derived fuel, as shown in Table 1. Renewable fuels do, however, usually have a considerably higher market value than fuels from fossil origin, due to some consumers' willingness to pay a premium for a sustainable product. The readiness to pay a premium for sustainability is only expected to increase in the future, due to increased public awareness on the climate crisis and due to regulatory measures. Fossil fuels also often carry emission taxes, which can only be anticipated to increase in the future. For these reasons it's not strictly necessary that electrofuels reach fossil parity before being viable in the market. Stopping all forms of subsidies for fossil fuels, which are still widely practiced despite the ongoing climate crisis, would further improve the competitiveness of electrofuels. Cost reductions in electrofuel production are and will continue to be important in securing their economic viability. If electrolyzers and electrofuel synthesis technology will be employed on a large scale worldwide, this will likely lead to significant decreases in capital cost, similar to what has been observed with e.g. wind and solar power in the last decade. Some fuel types can be produced in an economically viable way in some locations already today. This is in particular true for hydrogen production (IEA, 2019; IRENA, 2018).

The energy efficiencies shown in Table 2 are all lower than those of battery electric vehicles. From an energy conservation perspective, battery electrification should therefore be prioritized in those applications where it is practically feasible, hydrogen fuel should be the second option and electrofuels should be reserved for applications where neither battery electrification or hydrogen fuel are feasible options. Hydrogen and electrofuels are also necessary for decarbonization of industries that cannot be electrified.

The technical aspects of electrofuel production at geothermal areas have been the focus area of this work, but other important factors such as the environmental and societal effects of such operations in geothermal areas must be taken very seriously in any such projects. This would need to be examined further for individual projects and is outside the scope of the current work. The case study in this work has no connection to any existing or planned projects but is simply intended as a rough quantification of how the resources at Krafla power plant would fit for the production of various electrofuels. Geothermal areas can hopefully play a role in the decarbonization of the mobility, building and industry sectors with carefully chosen electrofuel projects that match the available resources of the areas in question and where any environmental impacts of such projects can be kept to a minimum.

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