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INTERNATIONAL CLIMATE INITIATIVE

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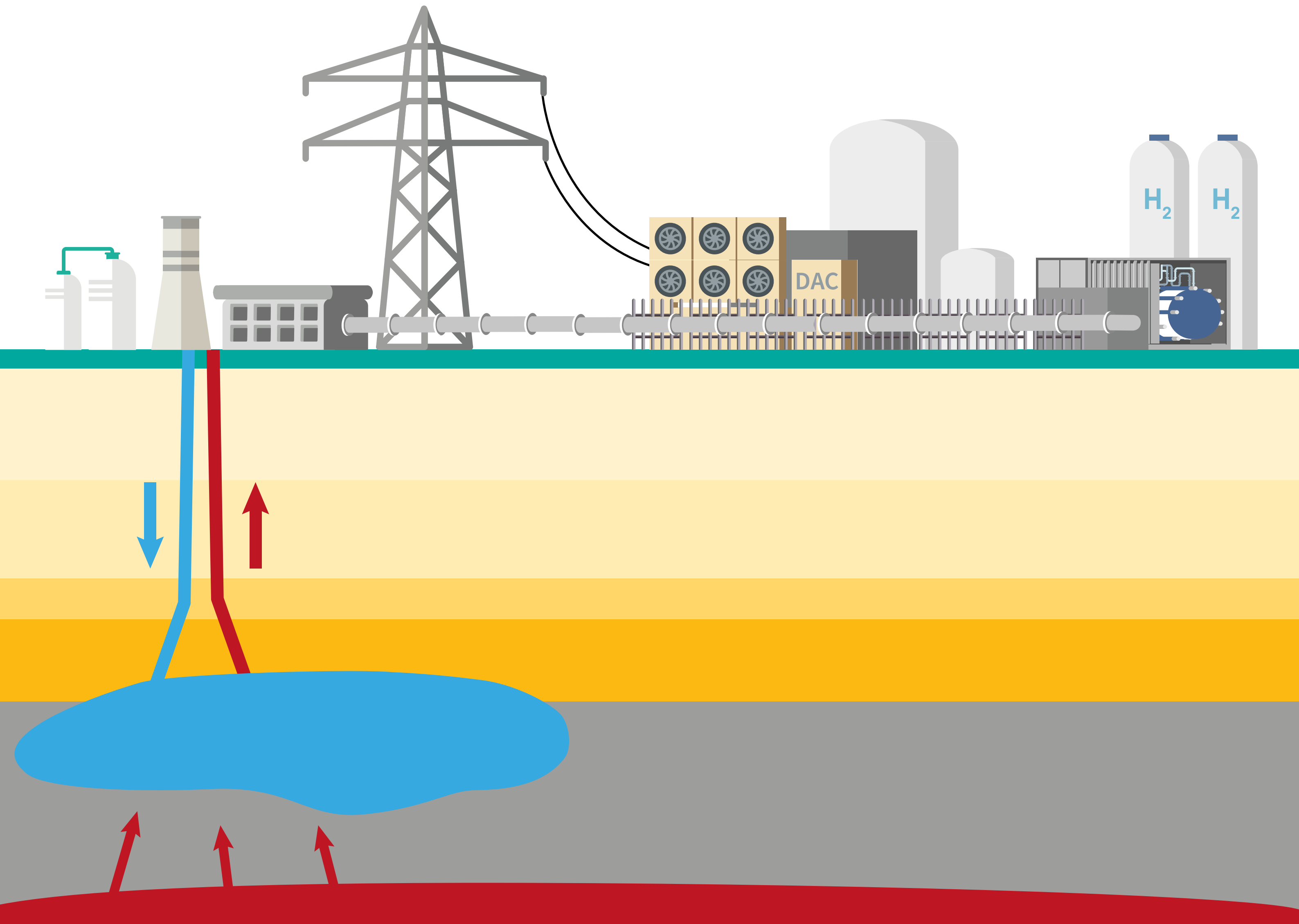
A GEOTHERMAL APPROACH TO POWER-TO-X

in El Salvador, Chile, and Kenya



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Berlin, May 2023

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The study builds on the expertise of the experts of Mannvit Engineering, gefn, Geothermie Neubrandenburg GmbH, the International PtX Hub and GIZ. We would also like to thank our partners for their valuable inputs and comments.

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LIST OF DEFINITIONS AND ABBREVIATIONS

Alkaline electrolysis — Alkaline water electrolysis is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). These electrodes are separated by a diaphragm, separating the product gases, and transporting the hydroxide ions (OH−) from one electrode to the other.

ASU — Air separation unit

Blue ammonia — Ammonia made from natural gas, but with carbon emission capture and storage or utilisation.

Blue hydrogen — Hydrogen produced from fossil fuel, most commonly by reforming of natural gas followed by a water-gas shift reaction, where the carbon dioxide (CO_2) generated is captured and then either stored or utilised.

Blue methanol — Methanol made from residual gases containing hydrogen, carbon monoxide (CO) and/or CO_2, such as from steel manufacturing.

BOP — Balance of plant

CAPEX — Capital expenditures

CSP — Concentrated solar power

e-ammonia — Ammonia made using hydrogen from electrolysis of water in a Haber-Bosch process. Future development might lead to electrochemical processes where nitrogen is reacted directly with water.

e-crude — Liquid, mixed hydrocarbons fuel made using electrical energy for either separated electrolysis of water to hydrogen and CO_2 to CO, respectively, or co-electrolysis of water and CO_2 into hydrogen and CO (syngas), which is converted downstream in a Fischer-Tropsch process. The mixed hydrocarbons can potentially be processes into their fossil fuel equivalents, i.e., gasoline, diesel or kerosine.

e-methane, e-SNG, e-gas — Methane produced by using electrical energy for electrolysis of water to generate hydrogen that is reacted with CO_2 in a Sabatier process. Co-electrolysis of water and CO_2 followed by a water-gas shift can also be applied.

e-methanol	Methanol produced using electrical energy for electrolysis of water. The hydrogen obtained can be reacted directly with CO_2 or CO from electrolysis of CO_2. Co-electrolysis of water and CO_2 can also be applied.
GoK	Government of Kenya
GBP	Great British Pound
Green ammonia	E-ammonia produced using renewable electrical energy or ammonia produced by using green hydrogen obtained by other processes than electrolysis of water.
Green hydrogen	Hydrogen made from renewable sources, such as by electrolysis of water using renewable electricity, reforming of biogas or gasification of biomass.
Green methane, Green SNG	E-methane produced using renewable electrical energy, methane produced by using green hydrogen obtained from other processes than electrolysis of water, or methane produced by anaerobic digestion of biomass (biogas, biomethane).
Green methanol	E-methanol produced using renewable electrical energy and methanol produced by using green hydrogen obtained by other processes than electrolysis of water.
GW	Gigawatt(s)
GWh	Gigawatt hours
IRENA	International Renewable Energy Agency
kW	Kilowatt(s)
Low Temperature Electrolysis (LTE)	Electrolysis of water at temperatures lower than 100 °C. There are mainly two technologies for LTE: Alkaline electrolysis using liquid electrolyte at 80-90 °C and proton exchange membrane electrolysis based on solid electrolyte at 40-80 °C.
High-temperature electrolysis (HTE)	HTE is a technology for producing hydrogen from water at temperatures above 100 °C. High temperature electrolysis is more electricity efficient than traditional electrolysis at lower temperatures because part of the energy required is supplied as heat.
MWth	Megawatts thermal

Methanol-to-gasoline (MtG)	Conversion of methanol to liquid hydrocarbons equivalent to gasoline or kerosine in a process originally developed by Exxon Mobil.
mmoles	Millimole
MT	Megaton(s)
MW	Megawatt(s)
MVR	Mechanical vapour recompression
NGC	Non-condensable geothermal gases
OPEX	Operation expenses
Power-to-X (PtX)	PtX is the process of converting renewable electricity into a wide variety (X) of end products. The X in the terminology can refer to one of the following: power-to-ammonia, power-to-chemicals, power-to-fuel, power-to-gas, power-to-hydrogen, power-to-liquid, power-to-methane etc.
Proton exchange membrane (PEM) electrolysis	Proton exchange membrane (PEM), also known as polymer electrolyte membrane, electrolysis is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes.
RWGS	Reverse water-gas shift
Solid oxide (SOEC) electrolysis	Under applied electrical potential a solid oxide electrolyser cell (SOEC) splits water into hydrogen by transferring oxygen ions (O_2-) through a solid ionic conductive membrane that after are recombining with electrons to form oxygen molecules. Solid oxide electrolyser cells operate at temperatures between 700 and 1000 °C, which enable nonprecious metals as catalysts.
tpy	Metric tonnes per year
tpd	Metric tonnes per day
USD	US-Dollar

1 EXECUTIVE SUMMARY

In recent years, several **Power-to-X (PtX) projects using geothermal energy** have been announced. Some projects are already running or in the planning phase. For example, Reykjavik Energy in Iceland operates hydrogen electrolysers with 750 kW of geothermal power. In Kenya, the Oserian Development Company is conducting a feasibility study for an e-ammonia and fertiliser production facility with 70 MW of geothermal energy. Other countries such as Chile and El Salvador have favourable conditions for geothermal PtX production.

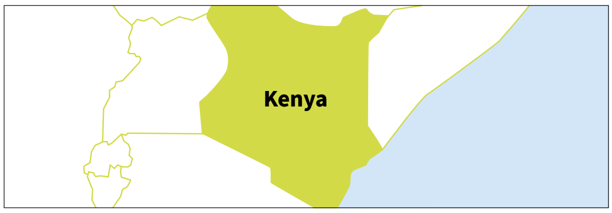
Potential **co-benfits of using geothermal sources for PtX** generation can include the direct use of geothermal heat for the distillation of methanol-water mixture, for regeneration of the rich amine-water mixture in a carbon capture system, or to supply heat to solid oxide electrolysers. Oxygen as a by-product from electrolysers can be used for various purposes, e.g. for fish farming. Non-condensable geothermal gases can contain hydrogen (H_2) and carbon dioxide (CO_2), whereby the hydrogen could reduce the electrolysis required and CO_2 could provide a source of methanol, methane and crude oil synthesis. CO_2 could also be used to promote growth in greenhouses. The high content of hydrogen sulphide (H_2S) is a disadvantage, since Sulphur, as well as some trace components such as chloride and mercury are poison to many catalysts in the PtX processes. However, high hydrogen sulphide content in the gas can make the production of sulphuric acid economical.

Three main electrolysis technologies are in use or being developed to produce hydrogen: alkaline, proton exchange membrane (PEM) and solid oxide electrolyser cell (SOEC). Both alkaline and PEM technologies are well established, whereas SOEC technology is still in development. The SOEC has potential to be the most electrically efficient even though with the toughest operating conditions. At currently reported capital and operating cost for electrolysers, we estimate the lowest production cost of hydrogen in the range of 3-5 USD/kg, depending on CAPEX, electricity price and capacity factor. Further reduction in CAPEX as estimated by electrolyser manufactures might lower that to the range of 1-2 USD/kg.

We consider a reasonable **capital expenditure (CAPEX) for equipment fulfilling European codes**, standards and requirement being approx. USD 600 per kW excluding onsite installation costs. European and US prices for AEL systems are in the range of 900-1,200 USD/kW, and 1,400-1,750 USD/kW for PEM. Prices for SOEC systems are few and inconsistent; NREL states it to be at approximately USD 820/kW whereas peer reviewed articles state it higher than 2,000 USD/kW. We expect prices in the near future to be 1,000 USD/kW for alkaline electrolyser systems and 1,300 USD/kW for PEM electrolyser systems including installation costs and electrolysis power of at least 6-10 MW.

In most PtX processes, hydrogen is used to further synthesise methane, e-crude oil, methanol or ammonia, which can be used as carbon-neutral fuels or processed into other materials (e.g. chemicals). For PtX plants, the economy of scale rule applies. Large-scale projects are needed to make export over long distances competitive. However, for **fulfilling local needs with low transport cost**, smaller PtX projects can be economical using renewable power that ensures high degree of capacity utilisation, geothermal power, or combination of geothermal, solar and wind.

Key findings of the deep-dive assessments:



Opportunities for the use of geothermal and variable renewable technologies for PtX in Kenya are currently being explored. A government working group is developing strategies on how how the government can support PtX projects. Subsequently, Kenya is looking for additional incentives from the western world.

Currently there is an excess energy on the grid during night-time and even sometimes during the day as well, which offers potential for hydrogen production using the available RE resources. One of the greatest opportunities for PtX in Kenya is the production of ammonia for fertiliser production. Geothermal power is considered advantageous for these projects as it **enables the plant to run 24/7**. Kenya could become a refilling point for ships in the Indian ocean. Global issues and policies related to the blue economy and clean energy for ships are expected to affect port operations and it is important to start preparing for that.

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There is **good potential for geothermal in combination with SOEC electrolyser technology**, using heat to reduce electricity requirements. Heat utilisation from geothermal can be used to regenerate the membrane used for direct air capture. The potential CO_2 emissions involved in geothermal power production cannot be dismissed and could negatively impact its use in PtX. It is also important to consider the stress on water availability, reduction of available electricity for general use in Kenya and the short- and medium-term electricity demand when studying the potential of using geothermal energy for PtX projects in Kenya.

An energy plan for El Salvador 2020-2050 is in the works. However, there are still no concrete strategies for geothermal energy and its use for the production of green hydrogen. There is no production of PtX and the local market is small. Exports seem to have the most potential.

In South America, Chile is among the most active countries in terms of PtX and has the goal of expanding its hydrogen production to up to 30-50 GW of electrolyser capacity. In the Antofagasta region in the north, wind and solar energy are used to produce green hydrogen. In the south, near Punta Arenas and Argentine Patagonia, wind and natural gas are used to produce methanol on a large scale. Most hydrogen projects focus on exporting ammonia or methanol. In terms of geothermal energy, Chile has one geothermal power plant with a capacity of 81 MW, which is to be expanded, and two projects under development.

Geothermal can stabilise power supply, increase grid stability, has small space requirements, and can contribute to social development all over Chile through the installation of power plants in the centre of the country, working against a polarised north or south production distribution.

Recommendations for risk management, location and costs of geothermal PtX projects

The construction of a geothermal power plant takes 10-15 years and involves high upfront payments for drilling. Financing a new geothermal power plant requires mitigating this initial risk. Geothermal development is ideally gradual, with the installation of one turbine at a time. However, PtX plants require a lot of electrical energy within a relatively short period of time after commissioning.
Coordinating different renewable energy sources can address this problem, at least in the the beginning.

Many factors contribute to whether a location is suitable for a PtX project, including cost and market, proximity to labour and prospects of renewable energy development. The last aspect should not necessarily be considered as an exclusion criterion, since coordination of different renewable energy supplies is not necessarily effective at the same site, or even same region. Geothermal energy plants provide a baseload capacity which is very important for locating PtX projects.

Investors and project developers should investigate project related energy costs and options based on the actual energy cost structure. The calculations in this study can assist to define the possible costs of hydrogen for PtX projects. This cost analysis should be conducted before making an investment decision. A step-by-step approach and cost calculation for the next project step should be applied.

2 STATUS QUO ANALYSIS

Status of PtX (including hydrogen production) with geothermal energy

2.1 Experience from Iceland and other countries, technologies, and cost

2.1.1 Green hydrogen

- Reykjavik Energy, Iceland, 2018. 750 kW geothermal power. Alkaline electrolysis of water using NEL electrolysers. Used as vehicle fuel. Estimated cost 200 million Icelandic Kronur (IKR) or approximately 2 million USD.
- Linde, UK. Linde announced in January 2021[1] their intention to build, own and operate the world's largest PEM electrolyser plant at the Leuna Chemical Complex in Germany. The new 24-MW electrolyser will produce green hydrogen to supply Linde's industrial customers through the company's existing pipeline network. The electrolyser will be built by ITM Linde Electrolysis GmbH, a joint venture between Linde and ITM Power and be operational in the second half of 2022.
- Yara, Norway. Yara announced in January 2022[2] the construction of a green hydrogen demonstration plant at Yara's ammonia production facility in Heroya, Norway. The project is supported by a NOK 283 million grant from Enova. This is a 24 MW PEM electrolysis plant from Linde, Germany. The electricity will be from renewable energy sources and will provide enough hydrogen to produce 20,500 tonnes of ammonia per year which can be converted to between 60,000 and 80,000 tonnes of green fertilisers.
- National plans or PtX roadmaps have been issued for Denmark, South Africa and India. Usually based on wind and solar power.

2.1.2 Green ammonia

- The Fertilizer Plant Inc., Iceland 1954-2000. 18 MW/240 GWh hydropower. Alkaline electrolysis of water using NEL electrolysers, nitrogen from air separation unit from L'Air Liquide, Haldor Topsoe Haber-Bosch process for ammonia. Used for fertiliser production. The plant used hydropower. The plant was shut down in 2000 due to increased competition from imported fertilisers based on fossil natural gas.
- Norsk Hydro, Rjukan, Norway 1929-1988. 108 MW DC hydropower. Alkaline electrolysis of water using NEL electrolysers, nitrogen from air, IG Farben Haber-Bosch process for ammonia. Used for fertiliser and explosive's production. The plant used hydropower. The plant was shut down in 1988 as Norsk Hydro could sell the electricity at high price and produce the ammonia more economically from natural gas elsewhere.
- Norsk Hydro, Glomfjord, Norway 1949-1993. Hydropower. Electrolysis of water, nitrogen from air, Haber-Bosch process for ammonia. Used for fertiliser production. The plant used hydropower. The plant was shut down in 1993 as Norsk Hydro could sell the electricity at high price and produce ammonia more economically from natural gas elsewhere.
- TEAL Corporation has announced building 800,000 tpy ammonia plant in Sept-Iles, Quebec, Canada. Estimated CAPEX is 1.9 billion CAD. The electrical power is stranded hydroelectrical power. An off-take agreement has been signed with Trammo Inc., international trading, transportation, distribution, and marketing company from New York City.[3]
- Iceland: Greenfuel, a part of the Atome Group, is planning production of green hydrogen and green ammonia in Husavik, using geothermal energy from Theistareykir geothermal power plant. The first stage is a 30 MW unit to start-up in 2023 and the second stage is a 70 MW unit to start-up in 2025. A Haldor Topsoe ammonia technology will be used. The cost has not been disclosed.[4]

2.1.3 Green methanol

- Carbon Recycling International (CRI), Svartsengi, Iceland, commissioned in 2011 and expanded in 2015 to a capacity of 4,000 tpy of e-methanol. Geothermal power for 6 MW in alkaline electrolysis of water. Amine-based carbon capture of approximately 5,600 tpy CO_2 from non-condensable geothermal gases using geothermal heat. Proprietary methanol synthesis loop. Methanol distillation using geothermal heat. Used for biodiesel production and as vehicle fuel. Cost has not been disclosed.[5]
- Iceland: PCC and Landsvirkjun. Changing emissions into green methanol for energy transformation at sea. Landsvirkjun and PCC SE (Germany) will investigate possibility of carbon capture from PCC's silicon plant in Husavik for producing e-methanol to be used as fuel for maritime operations. The estimated energy consumption is 20 MW will be from Theistareykir geothermal power plant. The estimated CAPEX is 9 billion ISK or 72 million USD[6 7] (in Icelandic).
- Iceland: Hydrogen Ventures (H_2V), international energy company, is considering production of green hydrogen and e-methanol in Reykjanes, using geothermal energy from HS Orka. In the first phase 30 MW of electrolysers will be installed as well as a methanol plant. The estimated CAPEX is 100 million EUR.[8 9]

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2.1.4 Other PtX

Nordur Renewables Iceland has announced e-methane production at Hellisheidi Geothermal Power Plant. Hydrogen will be produced using electrolysers, and the CO_2 will be separated from the non-condensable geothermal gases from the power plant. Estimated use of CO_2 is 24,000 tpy and the produced e-methane approximately 6,000 tpy. The produced methane will be liquified and transported to Switzerland to be used as a fuel. The estimated electrical power consumption is 25 MW. No information about cost can be found. The process to be used is a form of the Sabatier process.[10]

2.2 Other countries already using geothermal sources for PtX, hydrogen production or are assessing the potential

2.2.1 El Salvador

El Salvador has signed a partnership with IRENA to boost decarbonisation efforts across the country.
It plans to replace fuel imports with renewable sources of energy such as hydropower, biomass, solar and geothermal. The promotion and production of geothermal energy in El Salvador will be a key area of focus. Despite a long tradition of geothermal energy use, its development has slowed in recent years with a limited number of new projects for power generation or heating applications brought online.[11]

2.2.2 Chile

Several PtX projects have been announced in Chile. Most of them using solar PV and/or wind energy.

- AES Gener Ammonia project[12]. The feasibility of using up to 850 MW renewables to make ammonia for export is being investigated.
- Haru Oni Phase 1, 2, and 3. ENEL, ExxonMobile, HIF, ENAP, Siemens Energy, EmpresesGasco & Porsche. Using wind energy in the Magellans to stagewise make synthetic fuels for export. In the first stage 3.4 MW, 280 MW in the second phase and 2.5 GW in the third phase. Siemens PEM electrolysers will be used for making hydrogen and Direct Air Capture to harvest CO_2 from the air to make carbon neutral methanol. Part of the methanol will be used to make gasoline.
- HNH project[12 13]. Austria energy, Ökowind EE, CIP. Using wind energy in the Magellans to produce ammonia. 1.6 GW wind power plant, 1.4 GW electrolysers and nitrogen from air to make 850,000 MT/year ammonia for export.
- Several other project of various sizes and in various stages have been announced. All based on solar and/or wind.

2.2.3 Kenya

Oserian Development Company Ammonia project in Oserian Two Lakes with project start-up in 2025. Maire Tecnimont S.p.A. announced in 2021 that its subsidiaries MET Development, Stamicarbon and NextChem have started work on a renewable power–to-fertiliser plant in Kenya. MET Development has signed an agreement with Oserian Development Company for the development of the plant at the Oserian Two Lakes Industrial Park located on the southern banks of Lake Naivasha, 100 km North of Nairobi. The project will use 70 MW of geothermal power from the Olkaria area to produce 550 mtpd of Calcium ammonium nitrate and/or NPK fertilisers. The expected start-up date is 2025. The hydrogen will be produced via electrolysis of water, nitrogen from air and ammonia using Haber-Bosch process. Stamicarbon Nitric Acid and AN technology will be used.[14 15]

2.2.4 Other countries

- United Kingdom: CeraPhi Energy will collaborate with Climate Change Ventures (CCV) for the development of green hydrogen using baseload Geothermal as the primary energy source for continual electrolysis from its proprietary Closed Loop CeraPhiWell™ system. The parties will combine CeraPhi's experience in advanced geothermal and proprietary closed loop technology together with CCV's innovative hydrogen technology to develop and roll out baseload geothermal for scalable green hydrogen production anywhere.[16]
- New Zealand: The first green hydrogen plant in New Zealand has officially started production. The 1.5 MW green hydrogen plant, located in Taupo, was established by Halcyon Power and uses electricity generated by the nearby Mokai geothermal power plant. Halcyon Power is a 50/50 joint venture of Tuaropaki Trust and Japan-based Obayashi Corporation. According to Tuaropaki CEO Steve Murray, the plant is expected to begin wholesale of hydrogen domestically by January 2022 and will produce about 180 tonnes in its first year. The long-term goal is for the plant to contribute to a complete hydrogen supply chain that includes transportation, storage, and refuelling.[17]
- Australia: Strike Energy is planning to produce green hydrogen for their urea fertiliser production facility in Western Australia using 10 MW electrolyser powered by geothermal energy from the Perth basin. This will supply 2% of the hydrogen needed for the fertiliser plant.[18 19]
- Canada: Meager Creek Development Corporation looks to turn geothermal energy into hydrogen near Pemberton, B.C. Start-up date is in 2025.[20 21]
- Indonesia: PT Pertamina Geothermal Energy is eying the production of green hydrogen within its geothermal working areas. For production of 100 kg/d the upstream investment needed is estimated USD 3-5 million. Storage and transportation are not included.[22]

The above projects are only samples of many similar worldwide PtX projects to substitute black hydrogen for green hydrogen for various chemical products, fuel and fertilisers.

3 POTENTIAL AND COST ANALYSIS INTERNATIONALLY

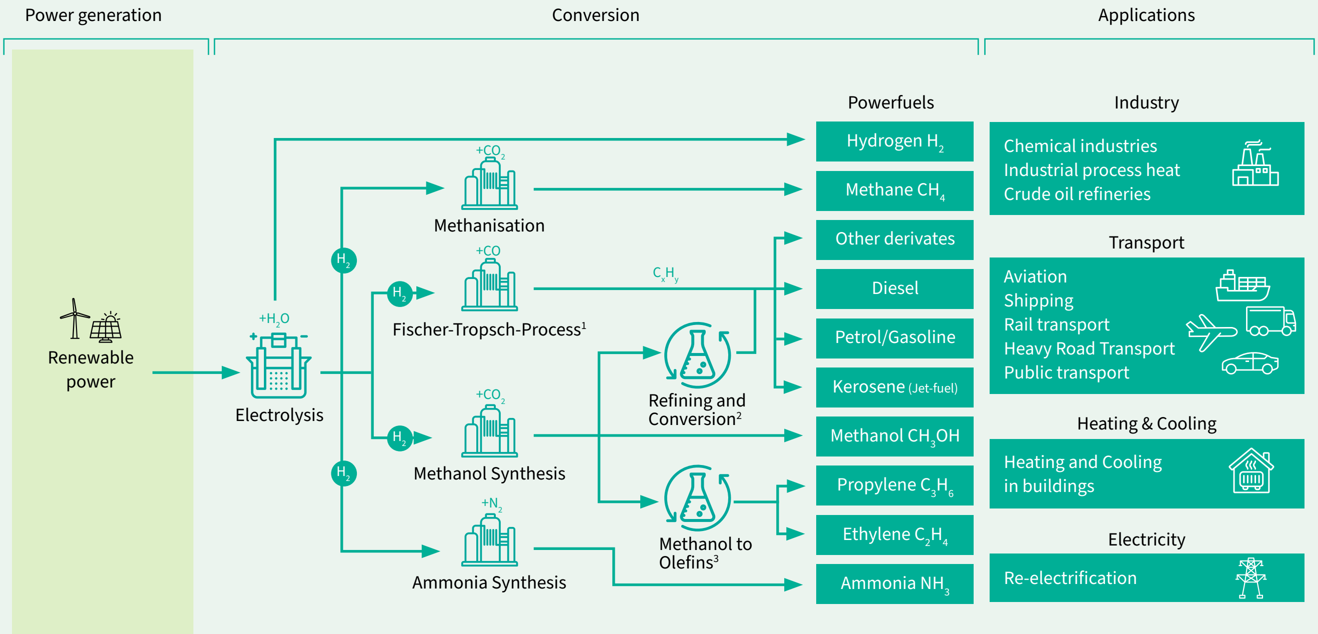
3.1 High level cost assessment for PtX

The PtX's are a range of products, including hydrogen, where the production costs internationally are based on electricity generation using renewable energy sources such as geothermal energy, hydro power, wind, and solar, which costs differs between regions.

3.1.1 PtX processes and products

Main PtX processes can be seen in an overview drawing as described in a report from Deutsche Energie-Agentur (dena) from 2020. Most PtX processes begin with electrolysis of water to make hydrogen but from there are various process routes possible to produce chemicals, fuels, and fertilisers.

Main PtX chemicals that can be produced using renewable electricity



1) Includes: Fischer-Tropsch synthesis, hydrocracking, isomerization and distillation.

2) Includes: DME/OME synthesis, olefin synthesis, oligomerisation and hydrotrading.

3) Methanol-to-olefins process.

Figure 1. Source: Based on dena (2020)[23]

In the following chapters we will describe each group of PtX processes and main products as well as developing a high-level CAPEX estimate for the main products.

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3.1.2 Electrolysis of water

Production of hydrogen by electrolysis of water is either by a low-temperature electrolysis (LTE) or high-temperatures electrolysis (HTE). In LTE, only electricity is used for splitting the water molecules into hydrogen and oxygen at temperature below 100°C. In HTE, heat at temperatures up to over 600°C is used to achieve lower electricity consumption as, potentially, the electrical efficiency of electrolysis can increase by up to 25 % at higher operating temperatures[23].

LTE is a proven technology and consist today of two main processes, i.e., alkaline electrolysis (AEL) generally operated at temperatures between 70 and 90°C and pressures up to 30 bar, and proton-exchange membrane (PEM) electrolysis generally operated at 50-80°C and <70 bar. Currently, typical reported total electricity power consumption of AEL is in the range of 50-54 kWh/kg hydrogen and 3-6 % higher for PEM, both excluding hydrogen compression. NREL has recently reported a typical electricity power consumption of PEM at 54.3 kWh/kg hydrogen with thereof 5.0 kWh/kg hydrogen (9 %) for BOP use[24]. For AEL, similar proportion between the power consumption of the electrolyser stack and the BOP is expected.

HTE is still relatively infant with SOEC as the main technology being in the demonstration phase for large-scale applications. IRENA has reported the total energy consumption of SOEC electrolysers in the range of 45-55 kWh/kg hydrogen, and NREL estimates 30 % of the energy can come from high temperature heat sources[23]. SOEC electrolysers generally operate at atmospheric pressure.

CAPEX for electrolysers is developing as more competition from China is affecting prices worldwide, European manufacturers are fighting back by increased automation in their plants.[25] Sales are expected to increase from several hundred MW pr year now to 9-10 GW/year in 2030. The war in Ukraine might even accelerate investment in electrolysers in the near future even though recent price increase of necessary raw materials makes it more difficult to reach targeted CAPEX prices.[26]

Lowest CAPEX reported for an electrolyser system is 300-500 USD/kW from a Chinese manufacturer of AEL electrolysers[27 28], but we consider a more reasonable price for a Chinese built equipment fulfilling European codes, standards and requirement being approximately USD 600 per kW excluding onsite installation costs. Current European and US prices for complete AEL systems have been reported in the range of 900-1,200 USD per kW[24 27], and 1,400-1,750 USD/kW for PEM[27 28]. Reported prices for SOEC systems are few and inconsistent; NREL states it at approximately USD 820/kW[24] and several peer reviewed articles states it higher than USD 2000/kW[29].

It is not always clear if the prices include the total system cost, such as the BOP (power system, control system, gas and water systems etc.) and onsite installation. We expected prices in the near-future 1,000 USD/kW for alkaline electrolyser systems and 1,300 USD/kW for PEM electrolyser systems including installation costs and an electrolysis power of at least 6-10 MW.

The annual manufacturing capacity of electrolysers is forecasted by analyst Guidehouse Insights to grow from about 1.3 GW at the end of 2022 to 104.6 GW by 2031 — an increase of almost 8,000 %, with a compound annual growth rate (CAGR) of 62.6 %[29]. Many manufactures of electrolysers have announced construction of factories at the Giga-scale, most noticeably:

- Norway's NEL has said its cost has been lowered by 50 % when its new 500 MW fully automated AEL electrolyser plant in Heroya was inaugurated in December 2021 and will be lowered by further 25 % when that plant is fully built to 2 GW before 2025[30].
- UK's ITM Power has built a fully automated 1 GW PEM electrolyser plant in Sheffield, England. It can produce 10 MW electrolysers at 800,000 GBP/MW now and for 500,000 GBP/MW for 100 MW units within three years[31], representing full system turnkey cost, including the electrolyser, power system, control system, gas system and water system. Plant expansion to 2 GW is being prepared.
- Germany's Siemens Energy is building a highly automated 1 GW PEM electrolyser plant in Berlin expected to start-up in 2023[32].
- Belgium's John Cockerill has announced 2 GW AEL electrolyser plant in India with a subsidiary of Greenko Group and is also building 1 GW plant in France[33]. Cockerill already has a plant in China through a joint venture with a local company (Cockerill Jingli Hydrogen).
- USA's Cummins (formerly Hydrogenics) has announced together with Iberdrola in Spain a 500 MW PEM electrolyser plant, expandable to more than 1 GW, that will be completed in 2023[34]. Cummins has formed a 50/50 joint venture with Sinopec in China ("Cummins Enze") on PEM electrolysers plant that will also be completed in 2023. The plant will have an initial capacity of 500 MW, which will be gradually increased over the next five years to 1 GW[35].
- Denmark's Haldor Topsoe has announced 0.5 GW SOEC electrolysers plant in Denmark that will be in operation in 2024. The plant will be scalable to up to 5 GW[36].

Other companies that have announced giga-scale factories are Germany's Thyssenkrupp (AEL – 5 GW), Australia's Fortescue Future Industries (PEM – 2 GW with Plug Power), France's McPhy (AEL – 1 GW), US's Plug Power (PEM – 1 GW in US and 1 GW in South Korea), India's Ohmium (500 MW, expandable to 2 GW) and Germany's Sunfire (500 MW, that will be expanded to 1 GW)[34 37].

Other companies offering electrolyser systems include Germany's H-TEC SYSTEMS (subsidiary of MAN Energy Solutions), Norway's HydrogenPro, Netherlands's Frames Group and China's PERIC and Tianjin Mainland Hydrogen Equipment (also known as THE, 75 % since recently owned by HydrogenPro).

Table 1. Main electrolyser suppliers

Name	Location	Technology	Current annual production capacity	Planned annual production capacity
NEL	Norway	LP AEL	500 MW	2 GW before 2025
ITM Power	UK	PEM	1 GW	2 GW
Siemens Energy	Germany	PEM	1 GM	n.i.
John Cockerill / Jingli	Belgium/China / France/India	AEL	n.i.	2 GW in India 1 GW in France
Thyssenkrupp Nucera	Germany	AEL	n.i.	5 GW
Fortescue FI	Australia	PEM	none	2 GW with Plug Power
McPhy	France	HP AEL	n.i.	1 GW
Plug Power	USA	PEM	n.i.	1 GW in USA 1 GW in S-Korea
Cummins	USA	HP AEL & HP PEM	n.i.	0.5 GW 1st phase in 2023 and >1 GW 2nd phase in Spain 0.5 GW 1st phase in 2023 and 1 GW 2nd phase in 2028 in China
Ohmium	India	HP PEM	n.i.	0.5 GW 1st phase 2 GW 2nd phase
Sunfire	Germany	SOEC	500 MW	1 GW
H-TEC systems	Germany	HP PEM	n.i.	–
Hydrogen Pro	Norway	HP AEL	none	See THE
Haldor Topsoe	Denmark	SOEC	none	0.5 GW 1st phase in 2024 5 GW 2nd phase
Frames Group	Netherlands		none	See Plug Power
PERIC	China	HP AEL & HP PEM	n.i.	–
THE (HydrogenPro)	China	HP AEL	n.i.	300 MW
Advent Technologies	USA	HP PEM	n.i.	–
Bosch	Germany	none	none	–
Convion (Wärtsila)	Finland	SOEC	none	–
Elogen	France	PEM	n.i.	160 MW 400 MW
Enapter	Italy/Germany	HP AEM	n.i.	–
Genvia (Schlumberger)	France	SOEC	none	Start-up 2025
Green Hydrogen Systems	Denmark	HP AEL	75 MW	400 MW

Helbio	Greece	n.i.	none	–
H_2B_2	Spain	PEM	n.i.	–
Hystar	Norway	PEM	n.i.	–
SOLIDpower	Germany	SOEC	none	–

The cost of hydrogen production by water electrolysis is mainly dictated by CAPEX, electricity consumption, electricity price and the capacity factor. The capacity factor represents the time as a proportion of a full year, which the electrolysis process is supplied with electrical power. In the case of a localised utilisation of renewable energy, the capacity factor of the electrolysers is directly related to availability of the power source.

The graph below (Figure 2) illustrates how the above-mentioned factors affect the hydrogen production cost with two scenarios, i.e. a near-future scenario for an electrolyser system having a CAPEX of USD 1,000 pr kW and a total electrical consumption of 54 kWh/kg hydrogen, and a scenario for mass produced electrolyser system having a CAPEX of 500 USD/ kW and a total electrical consumption of 50 kWh/kg hydrogen.

Hydrogen production cost*

*As a function of electricity cost (0, 20, 40, 60, 80 and 100 USD/MWh), CAPEX, energy efficiency, capacity factor for a near-future scenario (above) and a future scenario (below). In both scenarios the operation and maintenance cost are 1.5 % of CAPEX, the depreciation time is 15 years, and the capital cost is 5 %.

Figure 2. Source: Own illustration

As will be discussed in section 3.2, geothermal power plants have in general a considerably higher capacity factor than most other renewable energy sources.

3.1.3 Methanisation

Methanisation is mainly done using the Sabatier process[38]. A small methanation plant is in operation in Japan since 2017, producing 8 Nm³/h from CO_2 and hydrogen. Bigger plant, with capacity of 400 Nm³/h, will start-up in 2024/2025 and plants with capacity of 10,000 Nm³/h and 60,000 Nm³/h are planned for later[39]. A small plant (6.3 MWe & 2,800 tpy CO_2) was operated in Werlte in Germany (EtoGas) from 2013[40], but we cannot confirm it is still in operation[41].

Under pressure (3 MPa), temperature (400°C) and in the presence of nickel catalyst, the following methanation reaction progresses:

$CO_2 + 4\,H_2 \Rightarrow CH4 + 2\,H_2O$ $\quad \Delta H = -165{,}0$ kJ/mol

Other catalyst has been demonstrated to get better results. As mentioned in 2.2.4 a Swiss company is preparing methanation of geothermal CO_2 from Hellisheidi Geothermal Power Plant using this method. Part of that process is a liquification unit to produce LNG for transport. No publicly accessible information is available on the estimated CAPEX or operation expenses (OPEX) for this plant. One source[42] claims that the CAPEX of the CO_2 scrubbing system (using a point source) and the methanation process is 1.5 X the CAPEX of the needed electrolysers, based per MW electrical power usage.

The Nordur plant's capacity is 6,000 tpy of CH_4. Theoretically it will need 3,000 tpy of hydrogen and a total of 25 MW of electrical power. By using the estimate from the CAPEX should be according to the following table.

Table 2. CAPEX for green methane plant; based on (42)

Green methane	budget breakdown
Capacity	6,000 tpy
Electrical consumption	25 MW
Capex (+/- 50%)	47-55 million USD
Of which	
Electrolysers (H_2)	18-22 million USD
Carbon capture (CO_2)	16-18 million USD
Sabatier (CH_4)	13-15 million USD

This cost estimate does not include liquification unit nor tanks for storage of pressurised or liquified gas.

3.1.4 Fischer-Tropsch process

E-crude, or a mixture of hydrocarbons can be produced from green hydrogen and CO_2 by using the Fischer-Tropsch process, developed in the 1920's in German[43] and after that successfully used in South Africa making liquid fuels, first from coal and later from natural gas. For some time, the interest in the Fischer-Tropsch technology has been revived. Interest has been for making liquid fuels from various biomass, plastic waste and recently from green hydrogen and CO_2. The main chemical reactions are:

$CO + 2\,H_2 \Rightarrow -CH_2- + H_2O$ $\quad \Delta H = -152$ kJ/mol

$CO + H_2O \Rightarrow H_2 + CO_2$ $\quad \Delta H = -41$ kJ/mol

The first reaction represents in essence a polymerisation, implying that the product will be a mixture of hydrocarbons with a distribution in molecular weight. Selectivity and control are therefore of key importance in Fischer-Tropsch processes. The second reaction represents a possibility to use hydrogen and CO_2 to generate the essential CO for the Fischer-Tropsch reaction. Originally the catalyst used was fused iron catalyst with potassium promoter, but in recent years a cobalt catalyst on silica, alumina or titania carrier have increasingly been used.

The CAPEX of the Fischer-Tropsch is higher than for other PtX fuels. Therefore, the economy of scale is more important for the Fischer-Tropsch synthesis. The products are hydrocarbon mixtures which need to be separated in a refinery. The selectivity and control of chain length is important for optimal product yields as the chain length can easily be from C1 to C60, whereas usually the optimal products have chain length between C5 to C22. The CAPEX for the Fischer-Tropsch part of the e-crude production is 2.5-3 times higher than for the electrolysers.[42]

From another source[44] the capital cost for a Fischer-Tropsch facility was estimated for plant sizes in the range 10,000-100,000 barrels per day, making fuel mixture for refining from gas, made from gasification of biomass. The smallest unit therefore makes approximately 450,000 m³ per year. The estimated CAPEX is in the range of <100,000 USD/bpd->300,000 USD/bpd or average approximately 200,000 USD/bpd. In yet another source, the CAPEX for the FT part was estimated 400,000 EUR/MW products. This refers to a plant using at least 200 MWe[45].

Based on the above information the following estimate of a 100,000 tpy Fischer-Tropsch plant has been made:

Table 3. CAPEX for a 100.000 tpy FT e-crude plant; based on (42)

FT e-crude	
Capacity	100,000 tpy
Electrical consumption	300 MW
CAPEX (+/- 50%)	990-1,125 million USD
Of which	
Electrolysers (H_2)	280-320 million USD
Carbon capture (CO_2)	325-370 million USD
FT part (CH_4)	382-435 million USD

The cost of the carbon capture varies greatly depending on the source, the range of 15-25 USD/t CO_2 for industrial processes with highly concentrated CO_2 streams to 40-120 USD/t CO_2 for processes with dilute CO_2 streams. The cost range for direct from air capture is in the range of 130-340 USD/t CO_2[46]. We believe that the reported costs are at least in some instances target future cost rather than current cost, which might be considerably higher.

3.1.5 Methanol synthesis

Green methanol or e-methanol is produced using green hydrogen, which in this case is generated by electrolysis of water to obtain e-methanol. There are two main pathways to e methanol, i.e., direct hydrogenation of CO_2, and reaction of hydrogen and carbon monoxide (CO), respectively. For the latter, CO can be sourced from industrial processes, such as steel manufacturing, or generated by co-electrolysis of water and CO_2, and in a reverse water-gas shift (RWGS) reaction where CO_2 is reacted with hydrogen to generate CO and water.

At elevated and controlled temperature (220-270°C) and pressure (5-15 MPa) the following reactions progresses in the presence of a catalyst, which is usually the CZA material (Cu, ZnO, Al_2O_3)[47 48 49]:

$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O$ $\Delta H = -49.5$ kJ/mol

$CO_2 + H_2 \leftrightarrow CO + H_2O$ $\Delta H = 41.2$ kJ/mol

$CO + 2H_2 \leftrightarrow CH_3OH$ $\Delta H = -90.7$ kJ/mol

The following discussion is aimed towards direct hydrogenation of CO_2, which is to date the commercialised process for e-methanol production at scale. However, further development of electrolysis/co-electrolysis of CO_2 and RWGS is expected in the future.

CRI's plant in Svartsengi, Iceland, has been until 2022 the world largest e-methanol plant with a capacity of 4,000 tpy (see section 2.2.3), and the technology is being scaled up to 100,000 tpy in projects underway in Norway and China[50]. Further, several large-scale e methanol projects have been announced by multiple companies world-wide, although mainly in Europe[51].

Simplified overview of the e-methanol process based on direct hydrogenation of CO_2

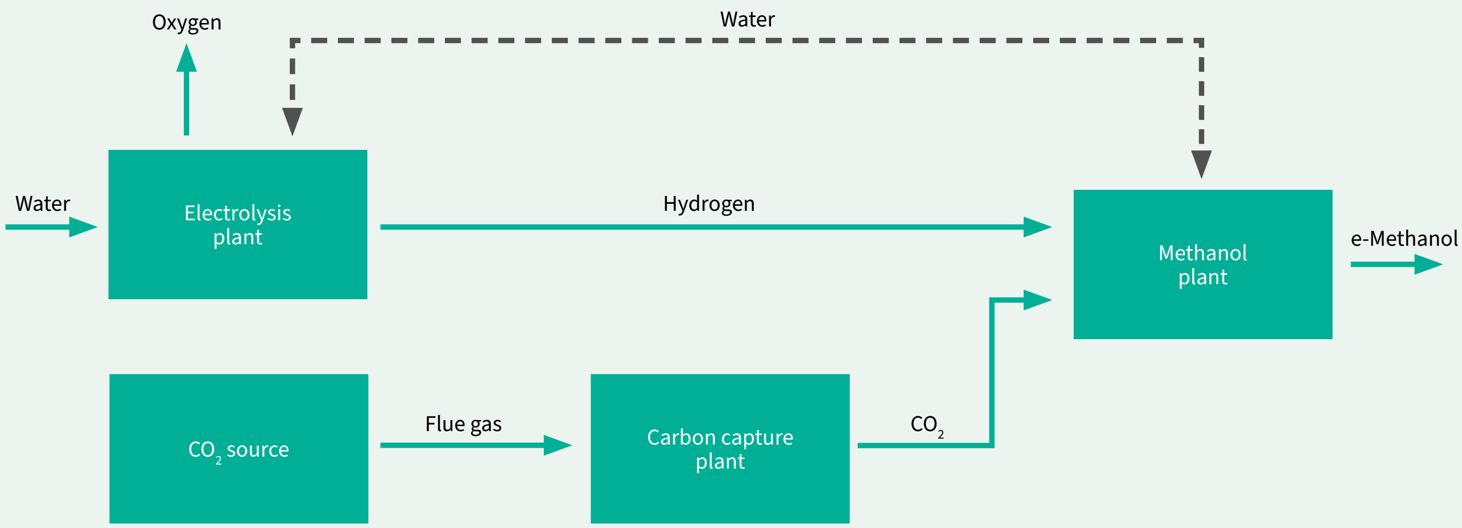


Figure 3. Source: Own illustration

Production of 1 kg of e-methanol requires approx. 0.19 kg of hydrogen and approx. 1.4 kg of CO_2. The exact consumption of hydrogen and CO_2 depends on the composition of the flue gas stream as inert gases, mainly nitrogen, which are usually not removed in the carbon capture process and may negatively affect the both the energy and carbon efficiency of the overall process. With regards to the estimated energy consumption of electrolysers systems put forward in section 3.1.1, the electricity consumption for hydrogen generation is at least 10 kWh/kg e-methanol, depending on the electrolysis technology (AEL or PEM) and its energy efficiency. The e-methanol process also requires electricity for running of compressors, pumps etc. The main supply of energy to the carbon capture plant and the methanol distillation unit (within the methanol plant) is usually done with steam. The energy consumption, the carbon capture and necessary purification of the concentrated CO_2 stream, is typically in the range of 3-8 GJ/tonne CO_2, which is approx.1-3 kWh/kg e-methanol. A considerable part of the steam required for the methanol distillation can be raised by utilising the heat released by the methanol synthesis.

It has been estimated that the cost of hydrogen contributes 52-89 % and the cost of CO_2 contributes 3-27 % to the total production cost of methanol depending on factors such as the electricity cost, the electrolysis technology, the CO_2 source, and the carbon capture technology[52]. Information from various sources indicate the CAPEX for e-methanol plants as listed in Table 4.

Table 4. CAPEX for 300 tpd (100,000 tpy) e-methanol plant

Main systems	Estimated cost in million USD
CAPEX (+/- 50%)	260
Of which	
Electrolysis plant*)	170
Carbon capture plant**)	50
Methanol plant***)	40

*) Depending on electrolysis technology (AEL or PEM) and energy efficiency of the electrolysis system. The estimated CAPEX is an average value based on the energy efficiencies and CAPEX of AEL and PEM electrolyser systems as presented in section 3.1.2

**) The cost is highly dependent on the CO_2 source and the composition of the flue gas.

***) Based on (48) and (53).

3.1.6 Ammonia synthesis

Ammonia is produced using green hydrogen and nitrogen separated from air, in a Haber-Bosch process. The main process units are hydrogen plant, nitrogen plant, hydrogen gas day tank, nitrogen gas day tank, ammonia plant and ammonia storage tank.

In chapter 3.1.2 the CAPEX for hydrogen plants was estimated. For a complete green ammonia plant a CAPEX cost estimate for nitrogen plant and ammonia plants are needed.

Information from international technology provider gives an estimate for the CAPEX for green ammonia plants. Included are electrolysers, nitrogen plant (air separation unit), ammonia plant, utilities, and plant infrastructure. Excluded from the estimate is ammonia storage, as the cost depends on the size of tank which will differ from site to site.

Table 5. CAPEX for green ammonia plant; based on (54)

Green ammonia	budget breakdown
Capacity	200 MT/d
CAPEX (+/- 50%)	172-204 million USD
Of which	
Air separation unit (ASU) (N_2)	9-15 million USD
Electrolysers (H_2)	93-102 million USD
Ammonia (NH_3)	33-41 million USD
OSBL & Utilities	37-46 million USD

A budget offer for ASU from another supplier is within this bracket of estimate.
The main operational cost is the cost of electricity. The annual cost of operation, maintenance, insurance, and administration is estimated 6,0 % of CAPEX cost. These cost items can vary from one site to another and should be evaluated specifically when more accurate cost evaluation is needed. However, depreciation is also a big cost factor for the production. High degree of utilisation is therefore essential for economic operation of the plant.

A total electrical energy consumption is estimated 100-110 MW. Assuming 8,400 hours operation time per year on average it corresponds to 850-920 GWh/year for the above-mentioned plant. Of this approximately 90-91 % is for the hydrogen production, 2 % for the ASU, 5 % for the ammonia plant and 2 % for OSBL and utilities.

Possible off-takers are fertiliser producers and refrigeration plants, coal power plants for mixing into the furnace, shipping companies for mixing into the diesel for the main engines and companies using ammonia fuel cells for electrical energy supply.

The green ammonia process block diagram

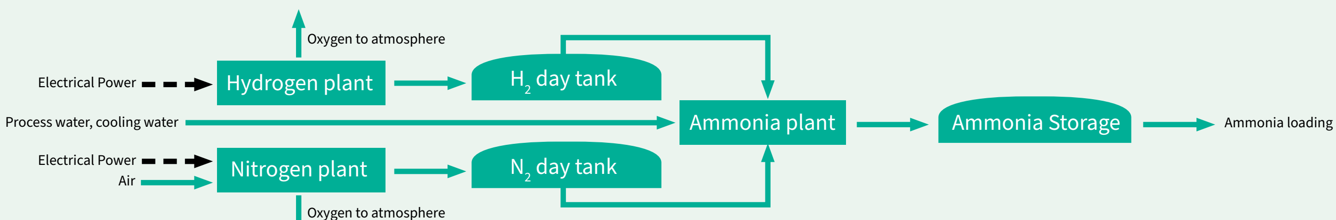


Figure 4. Source: Own illustration

3.2 Comparison with production costs based on electricity generation costs with wind, solar, hydro

3.2.1 Energy Prices and capacity factors

Energy prices as low as 10 USD/MWh of solar PV electrical energy have been reported in news reports for planned PtX projects. Most PtX projects however seem to be based on combination of wind and solar and excessive overcapacity of power production and nameplate capacity of the PtX facilities. This moves part of the cost from OPEX to CAPEX but will not necessarily increase the capacity factor to acceptable levels for economic production.

Table 6. Comparison of electricity generation cost for renewable energy; based on (55)

Renewable energy	Total installed cost 2020 USD/kW	Capacity factor %	Levelised cost 2020 USD/kW
Geothermal	4,468	83	0.071
Solar PV	883	16	0.057
CSP	4,581	42	0.108
Onshore wind	1,355	36	0.039
Offshore wind	3,185	40	0.084

These CAPEX prices are from the IRENA report[55] from 2021. It is not clear from which examples these numbers are taken. According to audited accounts of renewable firms in the UK, the CAPEX for onshore wind completed in 2016-2019 was £1.61 million/MW and for offshore wind it was 4.49 million GBP/MW[56]. According to the same source, the CAPEX of large solar projects is 0.98 million GBP/MW. These numbers are 28 % higher for solar, 38 % higher for on-shore wind and 63 % higher for off-shore wind compared with the numbers from IRENA. Off-shore CAPEX without the expensive Hywind project is 3.99 million GBP/MW or 25 % higher. In this comparison rate of exchange of GBP and USD is set as 1.16.

The actual OPEX for onshore wind in the UK was 77,000 GBP/MW in 2016 in year 1 and is expected to increase to 114,000 GBP/MW in year 15 and 149,000 GBP/MW in year 25 if in operation, which is considered unlikely. For offshore the actual operating cost in 2018 was 184,000 GBP/MW in year 1 and expected to increase to 426,000 GBP/MW in year 15. The actual operating cost for big solar farms in 2017 was 19,000 GBP/MW in year 1 and is expected to increase to 33,000 GBP/MW in year 5.

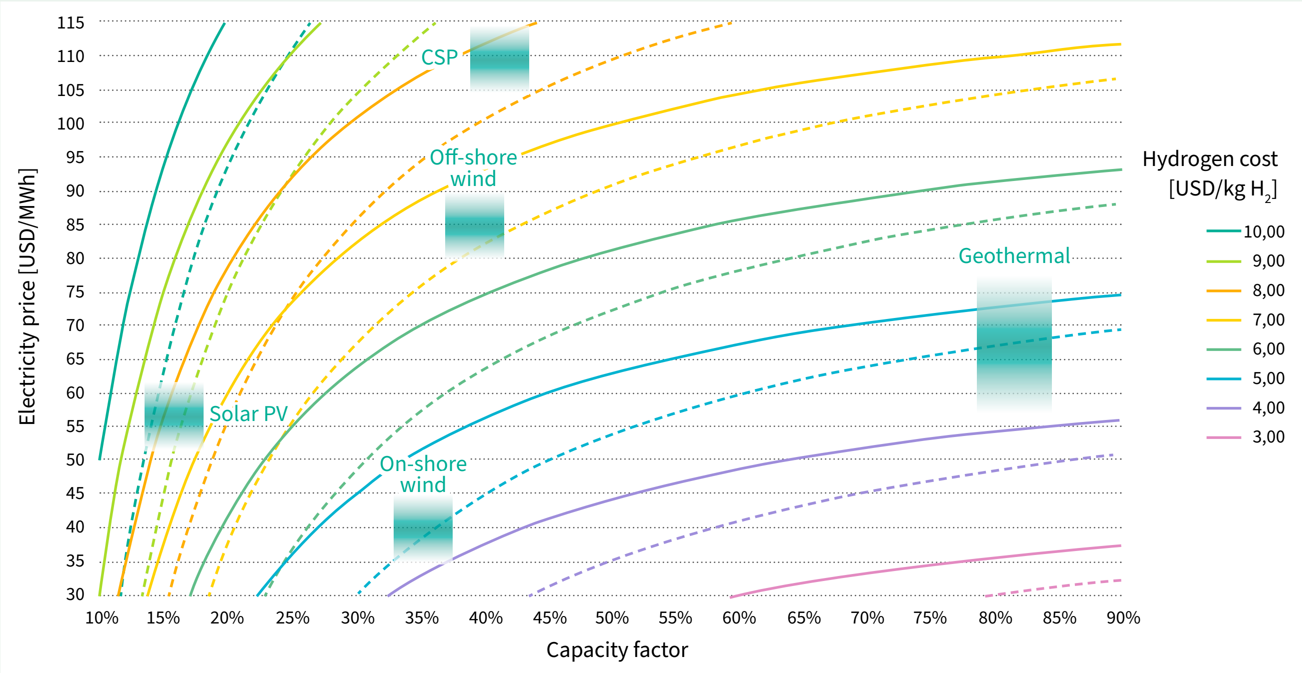
The load factor for onshore wind in the UK has been about 27 % for the last decade, higher load factor for new turbines offset balances the declining load factor of older turbines. On average the load factor for onshore wind declines by 3 % per year. For offshore the average load factor has been 45 % but will also decline steadily over time[56].

The levelised cost of geothermal power in the IRENA report is at least double the current price of sold geothermal power in Iceland. This seems very high according to our experience. Higher capacity factors/full load hours of geothermal generation compared to wind and solar. Worldwide the capacity factor for onshore wind has been gradually increasing and was on average 36 % on 2020 and 44 % for offshore wind[39]. For solar, the capacity factor was 16 % on average (9.9-20.8 %). The capacity factors in 2021 in Europe were 20.2 % for onshore wind, 31.3 % for offshore wind and 11.0 % for solar[40]. This was unusually bad year for wind power. The capacity factor in Icelandic geothermal power plants in 2020 was 90 %[57]. During the interview conducted for this dialog OR Reykjavík Energy gives capacity factor 80-90 % for their geothermal power plants. According to an IRENA report, the capacity factors for geothermal power plants worldwide are in the range of 60 to over 90 %, however most of the plants have capacity factors above 80 %. A PtX plant based on power from geothermal would therefore have the possibility of capacity factor of 80-90 % whereas only in the range of 35-45 % using wind power and 15-20 % if using solar power as the only source.

3.2.2 Hydrogen production costs

Localised production of hydrogen with current electrolyser technology and geothermal energy is potentially the most feasible option together with onshore wind, based on the above discussed electricity costs and capacity factors with an average hydrogen cost of 4-5 USD/kg hydrogen, as shown in the figure below.

Estimated hydrogen production cost intervals for different renewable energy sources related to electricity prices and capacity factors in the short-term*



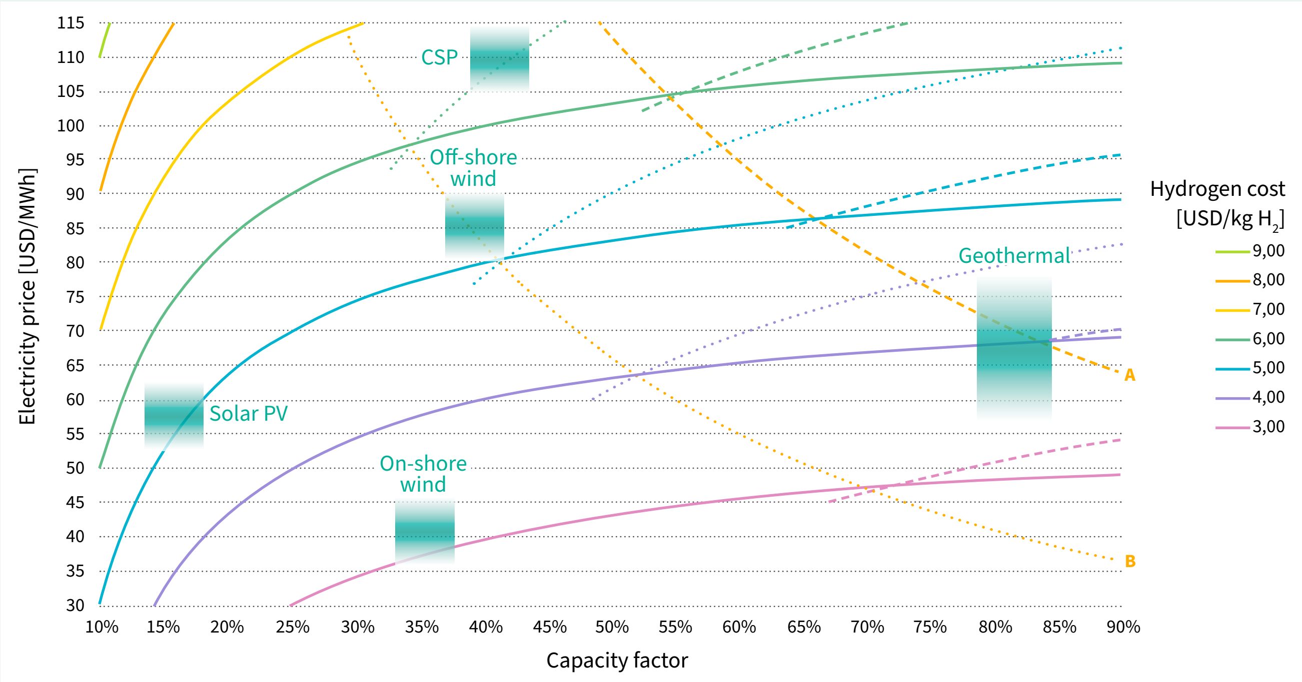
*Unbroken hydrogen cost lines are for AEL electrolysers, and the corresponding broken lines are for PEM electrolysers.

Figure 5. Source: Own illustration

However, it is important to assess the hydrogen cost for different renewable energy sources on a case-by-case basis as their location can highly influence the electricity price and even the capacity factor.

Technology development, increased production volumes and new fabrication methods will lower CAPEX and improve energy efficiency of electrolysers, as discussed in section 3.1.2. Advances in AEL and PEM electrolyser technology might lower the cost of hydrogen production by at least 0.5-1.0 USD/kg hydrogen, which will benefit hydrogen production at lower capacity factors and/or higher electricity prices more than in the case of geothermal power. Potential development of SOEC electrolysers, where a significant share of the energy required for the electrolysis process is provided with thermal energy, might benefit geothermal projects as geothermal steam could account for a considerable share of the thermal energy required. Further, the heat from exothermic downstream processes, such as ammonia production and methanation, could be used to lower the electricity consumption of SOEC electrolysis.

Estimated long-term hydrogen production cost intervals for different renewable energy sources related to electricity prices and capacity factors*



*Unbroken hydrogen cost lines are for AEL and PEM electrolysers, and the corresponding broken lines are for two cases of SOEC electrolysers utilizing geothermal power; case A is for hydrogen production with SOEC electrolysers using geothermal steam (50 %) and electricity to supply heat to maintain high-temperature operation, and case B is when only thermal energy is used, i.e., geothermal steam (50 %) and heat from an exothermic downstream process. The black broken trajectories represent the feasibility region for each case.

Figure 6. Source: Own illustration

3.2.3 Size of PtX plants

The PtX process plants are like any other chemical process plant where the economy of size is generally considerable. This is less important for electrolysis of water since the hydrogen plants consist of electrolysers of some maximum size and thereafter of multiple electrolysers. Methanation, Fischer-Tropsch, methanol and ammonia plant all have considerable economy of size, usually expressed by:

$$\text{CAPEX of plant 2} = \text{CAPEX of plant 1 x} \left(\frac{\text{size of plant 2}}{\text{size of plant 1}}\right)^{\kappa}$$

where κ is usually in the range of 0.6-0.7

From this we can deduct that doubling the size the plant, the CAPEX will increase by approx. 60 %, but per ton of product the CAPEX is reduced to 80 % compared to the smaller plant. The conclusion is therefore that other factors will most likely determine the size the PtX plants, such as the availability of power, potential offtake agreements and financing.

3.2.4 Site locations

There are three types of locations that have been identified for PtX process plants.

- In geothermal power plant sites, where waste heat together with non-condensable gases could be used to benefit the PtX process and the cost for electrical transmission is minimal. These sites have possible a drawback due to longer product transportation routes and possible shortage of qualified staff
- In industrial sites, where there is good transportation infrastructure, possible off-takers for the PtX products and

likely better supply of qualified staff, but higher electrical transmission costs.
- On harbour areas where there is good infrastructure for shipping the PtX products locally or internationally. These locations have the drawback of higher electrical transmission costs

3.2.5 Qualified staff availability

The availability of qualified staff is often seriously overlooked. For the successful operation of any PtX process plant, many qualified engineers and other trained operators are needed. If location of the PtX is remote, supplying enough of qualified staff can become a problem. Not only will higher than average wages be needed but considerable money and effort will be needed for building of infrastructure for recreation and social life outside the workplace. These concerns will favour locations where the PtX plants are closer to industrial hubs or harbour areas as relocation of staff might be easier.

3.2.6 Increased CAPEX due to earthquake risks in geothermal areas

Most geothermal areas do have at least some earthquake risks. The reported CAPEX of geothermal power plants already has all extra CAPEX included. For PtX process plants it will depend on location whether extra CAPEX cost is needed for geothermal area locations or not.

Kenya has a moderate earthquake risk hazard due to the East Africa Rift running through the west of the country[58]. The risk is however moderate, highest near the Tanzania border and lower to the east of the country. Design of any PtX plant must though take this risk into account which will lead to increased CAPEX.

Both Chile and El Salvador have considerable earthquake risk so extra CAPEX is needed at most locations, geothermal or not.

3.2.7 Increased maintenance due to corrosion in geothermal areas

Some extra maintenance is needed in geothermal areas due to corrosive atmosphere compared to “normal” inland conditions. This is mainly due to hydrogen sulphide emissions (natural and from the power plants). Many new geothermal power plants are fitted with hydrogen sulphide abatement units that tackle this specific plant emissions. Any natural emission factors are though to be considered. Extra cost for maintenance can also be expected for marine/harbour locations due to salt induced corrosion.

3.3 Derive high-potential locations

In Kenya, three areas have been identified as high potential for PtX from geothermal power.

- Mombasa and surrounding area (Coast) due to the vicinity to existing infrastructure and the availability of water from desalination. Electricity must be transmitted from the Central and Western parts of the country.
- Wider Olkaria area (Rift Valley) due to vicinity to power generation sources and important power network nodes.
- Wider Nairobi area due to vicinity of generation sources, availability of infrastructure, industrial processes as well as service companies and research and development.

No special locations for PtX projects have been identified in El Salvador, mainly due to lack of geothermal power for such projects. In case of power availability, similar locations as in Kenya would seem feasible: a) Near the geothermal power plants, b) near coastal industrial areas with harbour facilities, c) near industrial areas where potential customers might be located.

Many PtX projects have been announced in Chile, using mainly wind power, but in some instances wind and solar power. There are mainly two locations that have been identified as high potential for PtX projects.

- Magallanes Province in the far south, where unusually high and persistent wind can increase the utilisation factor and therefore the economy of any PtX project. Access to shipping lines makes economic export to Europe possible. This location is unlikely to benefit from future geothermal power harnessing as most of the potential geothermal sites are further north.
- Antofagasta region, where solar and wind power can be combined to increase the capacity factor to much better economy of the PtX projects. Existing port facilities make export much easier than elsewhere on the coast. Future harnessing of geothermal power in the Antofagasta, Tarapacá, and Arica Y Parinacota regions could be used to power PtX projects in the future, either for new PtX projects or to increase capacity factor of the first generation of PtX projects.

4 CO-BENEFITS AND EFFECTS

Potential co-benefits when producing PtX/green hydrogen with geothermal sources could be but are not limited to the following:

- Direct use of geothermal heat sources:
  - Low temperature heat (80-120°C) for distillation of methanol-water mixture from the methanol reactor in a methanol plant.
  - Low pressure steam (2-10 bar, 120-180°C) to regenerate CO_2 rich amine-water mixture in a carbon capture system, and for distillation of methanol and e-crude.
  - High pressure steam (>10 bar, >180°C) to supply solid oxide electrolysers with heat.
  - Low pressure steam can be used for supplying solid oxide electrolyses with vapour and heat if the steam is compressed in a system like mechanical vapour recompression (MVR).
  - Various PtX processes need heat and or vapour for processing, where geothermal heat, or the waste heat from electrolysers, methanol or ammonia reactors can be used for increased benefit.

Direct use of geothermal heat sources

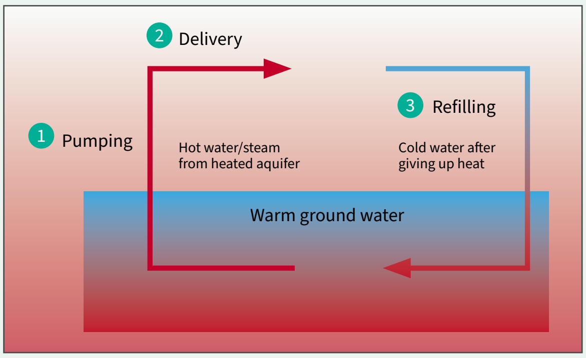


Figure 7. Source: Own illustration

- Oxygen by-product from the electrolysers is saturated with water vapour and is difficult to liquify. It can however be used for various processing nearby, such as for fish farming, where oxygenation of the water can increase productivity of the fish farm.

- Non-condensable geothermal gases (NGC) might contain H_2 and CO_2.
  - Any separated H_2 could reduce the need for water electrolysis (consumption of electricity) and lower the operating cost of subsequent PtX.
  - CO_2 could be a source of carbon for methanol, methane, and e-crude synthesis. If however there is no need for CO_2 source for the PtX, the CO_2 emission from the geothermal power plant can be captured and re-injected into the geothermal field.
    Assuming a 100 MW geothermal power plant, using 1.90 kg/s steam pr. MWe and 1.5 % w/w NCG, where 60 % v/v is CO_2 and 40 % v/v is H_2, then up to 60,000 tons methanol can be produced per year from the available CO_2. The accompanying H_2 would reduce the need for electrolysis by 22 %.
  - CO_2 could be used for enhancing growth at greenhouses if methanol, methane, or e crude is not produced.
  - High content of hydrogen sulphide in the NGC's can make the gas almost worthless due to difficulties in gas separations. Sulphur, Chloride and Mercury are all known poisons for many catalysts in the PtX processes.
  - If hydrogen sulphide, CO_2, and Chloride are not abated, its concentration in the atmosphere may increase corrosion. For instance, copper will be corroded by hydrogen sulphide and gets blanketed by sulphide, leading to operating problems in control systems and power transmission systems. However, these problems are well understood and methods to avoid them are well known and generally applied for geothermal power plants as well as other process plants in geothermal areas. Abatement of hydrogen sulphide have been applied in the Geyser area in California for many decades and new processes have been developed. Amongst them are the SulFix and CarbFix processes used in Hellisheidi power plant in Iceland, where both hydrogen sulphide and CO_2 gases are re-injected into the geothermal field and the gases are re-mineralised, and "fixed" for hundreds of years.
  - Unabated CO_2 emissions from geothermal power plants is usually in the range of 20-100 g/kWhe[57], which is comparable or better than other renewable power production and only a fraction of emissions from fossil fuels use. If waste heat is also used for district heating the emission is in the range of 5-30 g/kWh_{e+th}.

5 DEEP-DIVE ASSESSMENTS

5.1 Kenya

5.1.1 Geology and potential geothermal power production

Kenya's geology can be described by the countries geographical location, range of altitudes and the Eastern Branch of East African Rift System (EARS) that traverses it. The Eastern Branch includes many high temperature resources, for example in the Kenyan rift. Its formation started by up doming and volcanism on the crest of uplift and followed by faulting to form a half graben. The formation of a full graben occurred during the early Pleistocene. It included erupted lava flows of basaltic and trachytic composition and intercalated with tuffs. Subsequently, sheet trachytes were grid faulted with dominant North-South closely spaced faults. The Quaternary times saw the development of many large shield volcanoes of silica composition in the axis of the rift. The entire length of the Kenyan rift has young volcanoes dominantly of silica composition in its axis. The youthfulness of the volcanoes attests to active magmatism under the rift. Similarly, geothermal manifestations are more abundant and stronger within the rift and many cases they are associated with the young Quaternary volcanoes. Geothermal manifestations in the Kenyan rift include fumaroles, hot springs, spouting springs, hot and altered grounds and sulphur deposits. Fumaroles commonly occur on the mountains while hot springs and geysers are common on the lowlands. Sulphur deposits have been observed in several geothermal areas where it is indicative with the presence of a degassing magma body at depth. Extinct manifestations in the form of travertine deposits, silica veins and chloritized zones are also common in other regions, indicating long-lived geothermal activity in the rift.[59]

Kenya's geothermal capacity growth has been one of the fastest in the world for the past years. Taking the year 2015 as a reference, Kenya has increased its installed capacity of geothermal power from 594 MWe to 1,193 MWe in 2020. This is an increase of 599 MWe, or more than doubling in only 5 years. There are only two countries in the world with a larger increase in geothermal power capacity in this time period, Indonesia and Turkey. In 2020, Kenya had the 5th most installed geothermal power in the world.[60]

Geothermal projects in Kenya that have received grants from the Geothermal Risk Mitagation Facility (GRMF) include Barrier, Chepchuk, Arus, Homa Hills and Emuruepoli that have received surface study grants and Longonot, Silali, Akiira One, Korosi, Paka and Menengai West that have received exploration drilling grants.

The Government of Kenya (GoK) plans to have 5,000 MWe on-line by 2030. Since financing through the national treasure is scarce, the GoK has licensed 13 independent power producers to explore 12 greenfield sites and requiring them to drill within 3 years after receipt of these licenses. Although there is significant political will and ambition, it will be a challenge to reach these goals. The European Investment Bank (EIB) has agreed to invest 95 million USD in geothermal power projects across the East African region as a part of its commitment to reduce greenhouse gas emissions.[61]

Geothermal resources in Kenya are located within the East African Rift Valley with an estimated potential between 7,000-10,000 MWth spread over 14 prospective sites.

Location of geothermal prospects in Kenya

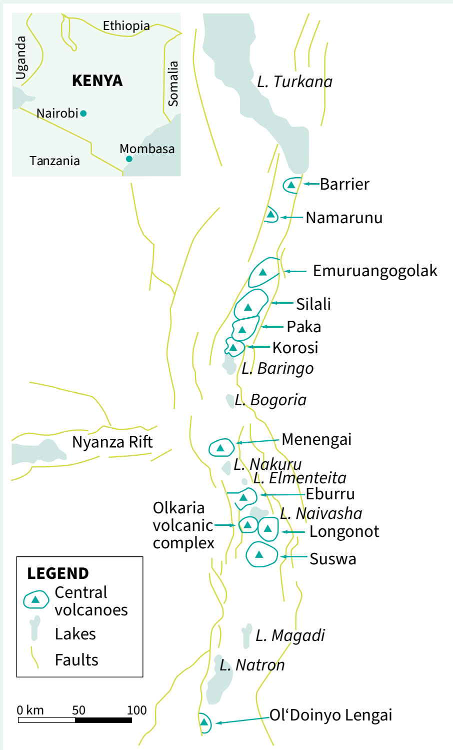


Figure 8. Source: Based on (62)

Table 7. Installed and expected geothermal plants in Kenya

Power plant	Operator	Year commissioned	Installed capacity	Status
Olkaria I	KenGen	Unit 1 – 1981 Unit 2 – 1982 Unit 3 – 1985 Unit 4 – 2014 Unit 5 – 2015 Unit 6 – 2022	3x15 MW 2x70 MW – Total 185 MW – 86 MW	Generation and production drilling
Olkaria II	KenGen	Unit 1 – 2003 Unit 2 – 2003 Unit 3 – 2010	3x35 MW – Total 105 MW	Generation and production drilling
Olkaria III	Orpower4	Unit 1 – 2000 Unit 2 – 2009 Unit 3 – 2014 Unit 4 – 2016	13 MW & 35 MW 36 MW 26 MW 29 MW	Generation and production drilling
Olkaria IV	KenGen	2014	140 MW	Generation and production drilling
Olkaria V	KenGen	2022	172 MW	Generation and production drilling
Olkaria VI	KenGen	2024 (expected)	140 MW	Surface exploration and production drilling
Suswa	CYRQ Energy	2024 (expected)	2x37.5 MW & 6x42.5 MW	Surface exploration and production drilling
Eburru	KenGen	Unit 1 – 2012 Unit 2 – 2024 (expected)	2.5 MW 22.5 MW	Generation and pilot generation
Akiira	AGL	2023 (expected)	70 MW	Exploration and surface studies
Oserian	ODCL	2003	2.5 MW	Production under steam sale
Longonot	AGIL	2024 (expected)	140 MW	Production drilling
Bogoria-Silali	GDC	2024 (expected)	200 MW	Production drilling
Menengai	GDC	2024 (expected)	3x35 MW	Production drilling

5.1.2 Current state of PtX with geothermal energy for energy, transport, chemicals and industry

In a recent study on the potential for power-to-X/green hydrogen in Kenya, the main conclusions are that the opportunities for use of hydrogen can be split into two fields[62]:

- As a commodity for mostly chemical and industrial scale uses, e.g., fertiliser production, which is well established worldwide and until now almost exclusively supplied through carbon intensive production based on natural gas.
- As an energy source. Despite its high energy density and technology availability for more than 150 years, hydrogen utilisation as an energy source has been limited to niche uses. This is because hydrogen is not a primary energy source but an energy carrier. It must be produced with much higher energy input.

In the study the following strategies have been identified for the use of green hydrogen:

- Hydrogen as a commodity for the production of the nitrogen content of fertilisers, via ammonia. The domestic production of fertilisers from local resources would replace imports and by this shift value chains to Kenya and reduce supply risk. By reduced transport cost, expected surplus of RE supply and international energy crises it may already be cost competitive in the near future.
- Hydrogen and its derivatives such as ammonia or methanol as a higher priced commodity for existing and new regional industrial processes, replacing commodity imports and enabling new industrial production processes. This could be combined with the first pathway.

- Hydrogen as an energy carrier for selected transport (mobility) options: (1) converting logistic equipment at defined areas such as Mombasa port to hydrogen as fuel; (2) a Nairobi transport case where – also at defined area with clear routes – new utility or public transport vehicles fuelled with on-site generated hydrogen act as a show case for hydrogen in the sector, though with strong need for subsidies.
- Hydrogen as a commodity and energy carrier for larger scale uses in new technologies with an industrial shift e.g., for green domestic steel production for local and regional demand. It would be new and entail certain risks.
- Hydrogen or methanol/ammonia as an energy carrier for off-grid supply of isolated grids (increasing availability compared to PV battery powered grids) or single consumers such as Stations in the mobile phone network.

Table 8. Key results; based on (62)

Pathway	Time frame	Technical potential	Commercial potential and trend	Comparative advantage	Limits / challenges	Climate change effect
1. Fertiliser. H_2 as a commodity via ammonia	Medium term (start 2025-30 onwards)	300-400/400-500 MW (~1200/1400 MW – region)	(50) – 100 MW Cost decrease expected, but cost shares of RE and non-green H_2 remain main factors	Competitive if external costs factored in (transport and foreign exchange risks)	Established market (risk), suitable size (scale, CAPEX), water availability	Big but abroad
2. H_2 / derivatives higher prices commodity for existing / new processes	Short to medium term (2025 - onwards)	10-20 MW (depends on methanol techn. feasibility) + growth potential	1–10 MW (depends on methanol economic feasibility)	Competitive, kick-start development (combine 1 and 3, potential for clean cooking)	Small market with established supply chain / standards	Small, abroad
3. Transport / mobility a) Logistic Port Mombasa b) Public transportation Nairobi c) Large Scale	Short to medium term (2025 - onwards) c) 2030-2040	a) 5 ->10 MW b) x00 MW (uncertain) c) X000 MW (uncertain)	Initial 5-10 MW, depends on funding, R&D; CAPEX to decrease but not competitive without CO_2 price	(a & b) Confined area, Kick-starts H_2 development / knowhow PR showcase	a) Limited demand b), c) Technical alternatives (potential lower costs)	a) Small b) Medium c) Big
4. H_2 as energy / commodity for large scale use	Medium to long term 2030-40	1500-2000 MW (3000-4000 MW region)	Depends on funding, e.g., 50 – 500 MW, huge potential with ongoing technical development	Market / knowhow, Technological progress	Technology, scale / size, Water, costs	Big, abroad
5. H_2 energy carrier for off-grid supply	Short to medium term	Aggregated 20-40 MW (part of larger base stations)	Depends on funding, uncertain whether niche or mass market	Niche / alternative to diesel and PV-battery	Knowhow / service, costs	Small, Kenya

For the supply of renewable energy for PtX processes, the analysis shows that sufficient renewable energy sources are available in the country for large scale production of green hydrogen and other process parts which need electricity without harming the availability and price for the demand of the current electricity consumers. Considering this as a precondition, the costs for RE based electricity could be in the range of USD 2-5 per kWh depending on what extent excess energy is compensated. This may allow for green hydrogen production costs of USD 2-4 per kg. Depending on the production site the costs have to be escalated by 5-9 % to account for transmission of the electricity.

Kenya offers many suitable areas for PtX production:

- Mombasa and surrounding area (Coast) due to the vicinity to existing infrastructure (port, railway, road, handling / storage areas including sites for chemical processes) and

the availability of water from desalination. Electricity is transmitted from the Central and Western parts of the country.
- Wider Olkaria area (Rift Valley) due to vicinity to power generation sources and important power network nodes (Olkaria/Suswa) with potential for direct supply and availability of infrastructure (transport, industrial parks and vicinity of Nairobi).
- Wider Nairobi area (Central) due to vicinity of generation sources and important power network notes and availability of infrastructure (transport, industry parks, handling and storage areas, industrial processes as well as service companies and research and development).

Other sites do offer some advantages and potential for regional development but have disadvantages in terms of infrastructure. Volumes of necessary water seem manageable in comparison to other technical challenges; special attention should be paid to each project, so the local community and nature is not adversely affected by an additional large water consumer.

For a PtX project using geothermal power exclusively, a location in the Olkaria area seems to be the only option. All other locations require either grid connection, or connection to wind and/or solar PV power supplier.

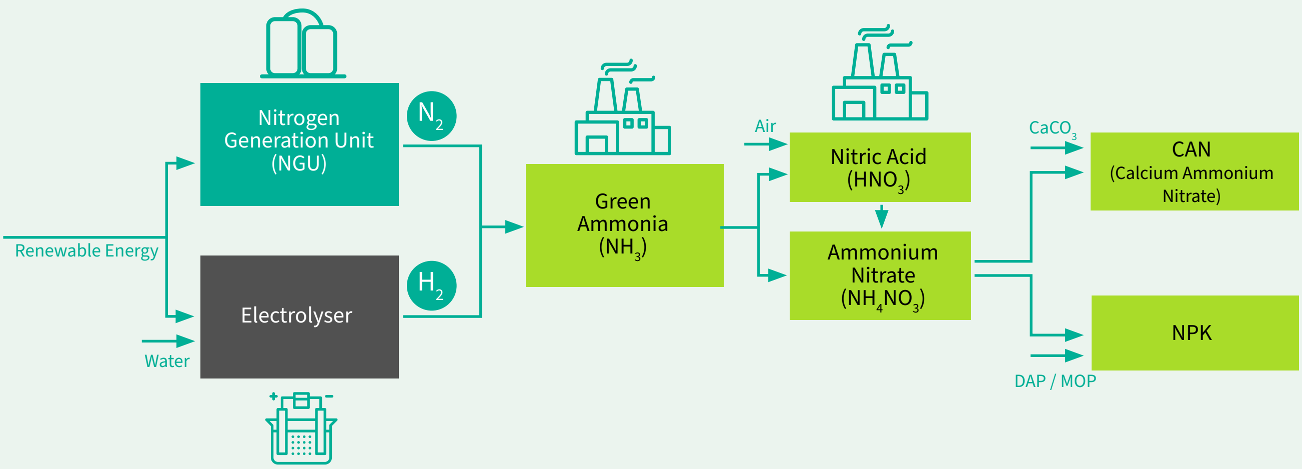
5.1.3 Main conclusions from questionnaire and interviews

As in most countries today there is interest in PtX in Kenya. According to Nickson Bukachi at the Energy and Petroleum Regulatory Authority (EPRA) in Kenya there are currently no policies regarding PtX and the power source, however, opportunities for using geothermal and variable RE technologies (wind and solar) are under consideration. The baseline study for PtX opportunities in Kenya was conducted by the Ministry of Energy in Kenya[62]. There are no direct incentives for PtX from the government at the moment, but the number of studies and interest of the government indicate that they might be aiming at such incentives in the future. A working group has been formed that is supposed to bring together which pathway the government should support to actualise a PtX project. During the interview with Bengisu Yavuz and Ralph Koekkoek at MET Development, it came up that a strong incentive scheme cannot be expected from Kenya and that this must come from the western world.

As pointed out by Nickson Bukachi at EPRA, currently there is an excess on the grid during the night and even sometimes during the day as well, which offers potential for hydrogen production using the available RE resources. According to the interviews, one of the greatest opportunities for PtX in Kenya is the production of ammonia for fertiliser production, as most of the fertiliser used in Kenya is imported. Nickson also mentioned that there are more than 5 private companies considering PtX in Kenya, one aiming to use geothermal energy. EPRA has been in contact with them to consult on power transmission for the production and various other aspects such as transport of PtX products, as their main interest is to produce hydrogen and ammonia for export to Germany. There is also public interest and as an example KenGen is looking into a pilot project to produce fertiliser using geothermal energy with assistance from stakeholders.

MET Development is running a power-to-fertiliser project in Kenya with other partners. The project goes a bit further than most projects in Kenya, as it includes an end product with substantial local demand.

Green fertiliser plant studied by MET Development*



*The idea is to go from renewable power to ammonia to fertiliser, with the final products being calcium ammonium nitrate and NPK fertilisers

Figure 9. Source: Based on MET Development (2022)

Planned location for the Green Fertilizer Plant is in the Oserian Industrial Park (owned and operated by Oserian Development Company). This location has access to water, renewable energy and the benefit of being close to the end users. This is important as the transport of end products can be expensive, especially if the infrastructure is lacking. According to Bengisu Yavuz and Ralph Koekkoek at MET Development, the reason that geothermal power is considered advantageous for this project is because it enables the plant to run 24/7, which allows for an optimal use of the electrolysers. Other sources such as solar or wind or a combination might require either a lower usage of the electrolysers, electricity storage or access to the grid, which could affect the economy of the plant. Solar power is also being considered for the peak hours of operation. In the end it is a CAPEX / OPEX evaluation that will determine the most optimal cost structure.

According to Fredrick Apollo at the Oserian Development Company, several other companies have also shown interest in the Oserian Industrial Park. One organisation is already building up a factory and require 1.4 MW electricity. There are currently 3.2 MW installed at the site, mixture of geothermal and solar energy. Hence, the company is already looking at expanding the power production for use in the industrial park. The challenges are that geothermal power is capital intensive, and they are still looking for funding.

According to Ralph Koekkoek at MET Development, the power-to-fertiliser project aims for a sustainable production while also creating local employment, support smallholder farmers and food security, in a country where this is a real issue. In other projects MET Development might consider a combination of export and fertiliser production, but Ralph stressed the importance of giving back to the local community when setting up a green hydrogen project. The project was set up to use the excess capacity in Kenya with the focus to help local farmers to get affordable fertiliser, in that way supporting the local community.

Regarding special off-takers, Nickson Bukachi at EPRA mentioned there has been talk of Kenya trying to become a refilling point for ships in the Indian ocean. Global issues and policies related to the blue economy and clean energy for ships are expected to affect port operations and it is important to start preparing for that. As previously mentioned, there are active discussions with the ministry of agriculture in Kenya, as fertiliser import is costly, but also active engagement with private sector for green hydrogen production.

During the interview with MET Development, the co-benefits of using geothermal energy with regards to sustainability, available heat or gas streams were also discussed. Ralph Koekkoek mentioned that even though it is still a bit early in the development he believes that there is good potential for geothermal in combination with SOEC electrolyser technology, using heat to reduce electricity requirements. Heat utilisation from geothermal is another aspect that was discussed, and it can be used e.g., to regenerate the membrane used for direct air capture. This is however not relevant for ammonia, as it does not require the CO_2 source. The potential CO_2 emissions involved in geothermal power production cannot be dismissed and could negatively impact its use in PtX, based on the case. Nickson Bukachi also mentioned that it is also important to consider the stress on water availability, reduction of available electricity for general usage in Kenya and the short- and medium-term electricity demand when studying the potential of using geothermal energy for PtX projects in Kenya.

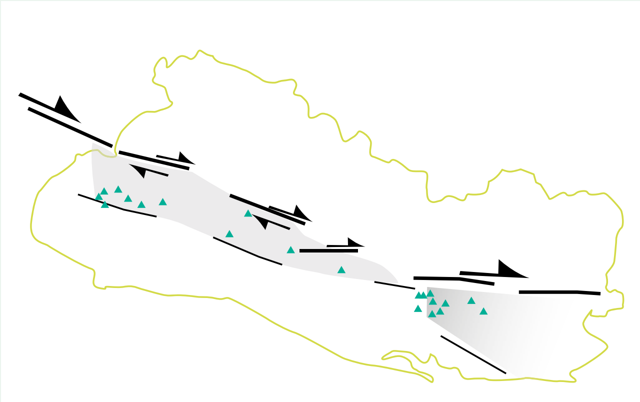
The full minutes of the interviews with EPRA, MET Development and Oserian Development Company can be found in Appendix B and the questionnaire responses in Appendix A.

5.2 El Salvador

5.2.1 Geological overview and state of geothermal development

The main regional geological aspect for the geothermal potential in El Salvador is the subduction of the Cocos Plate under the Caribbean Plate, as part of the "ring of fire" around the Pacific Rim[63]. In the area of El Salvador, a roll back of the subducting slap generated an approximately 150 km long and 20 km wide, segmented fault zone, the El Salvador Fault Zone (ESFZ) (Figure 9). Along the ESFZ a volcano chain developed, which represents the main geothermal potential for El Salvador. Two power plants are already in operation (Berlín and Ahuachapán) in this area and three more sites are under development. The state-owed Comisión Ejecutiva del Río Lempa (CEL) – mother company of LaGeo – is planning to expand the geothermal power generation capacity by 95 MW (from 204 to 300 MW) with three projects in the coming years. They are going to build three new plants: in Chinameca, San Vincente and Volcán de Conchagua. According to LaGeo, the total potential of all fields is about 644 MW.

Main structure of the El Salvador Fault Zone (ESFZ)



Green triangles are Pleistocene volcanoes. Thin black lines are faults. Thick black lines are faults with large escarpments (ticks indicate the downthrown side).

Figure 10. Source: Based on (63)

5.2.2 Developed geothermal fields

Berlín geothermal field

The geothermal field of Berlín is closely located to the pull-apart structure, linking the Berlín and San Vicente segments of the ESFZ. The volcanic succession in the Berlín area is characterised by a local basement corresponding to the Bálsamo Formation (Miocene-Pliocene). Over the basement there are remnants of an old (Pleistocene) stratovolcano, covered by a sequence of ignimbrite layers and pumice fall deposits, which are expected to be related to the formation of the Berlín caldera. The youngest activity is represented by basaltic and basaltic-andesitic lava flows[64 65].

The structural analysis carried out in this area reveals that the E–W strike-slip faults of the ESFZ are associated with minor structures that can be assigned to three different sets according to their fault orientation. The first is WNW–ESE, the second NW–SE and the third set is NNW–SSE to N–S orientated[66].

The actual Berlín geothermal field is located on the northern slope of the Berlín-Tecapa volcanic complex. The NW-SE fault system in the northern part of the Caldera of Berlín is considered the most important geothermally because it permits the ascent of fluids from depth, also the majority of the surface manifestations and the geothermal field itself can be related to this fault system[67]. The heat source to the Berlín hydrothermal system is a recent degassing andesite magma chamber at a depth of around 6 km. The main reservoir of the Berlín geothermal field is characterised by the presence of a resistive deep with resistivity above 40 ohm-m[68 69]. This corresponds with a prophylitic alteration zone in a depth of 1800 m to > 2000 m, which show formation temperature of 250-300 °C. The mineral composition of this zone is documented in Table 8. The general composition of the geothermal fluid is presented by (Table 9). The samples were obtained after the separator, hence a show relatively low total gas content observed.

Table 9. Representative minerals in the production zone of the Berlín geothermal field; based on (64)

	Mineral composition	%
Prophylithic 1800 – > 2000 m	**Chlorite** $(Mg,Fe)_3(Si,Al)_4O_{10}(OH)_2(Mg,Fe)_3(OH)_6$	**5-9**
	Prehnite $Ca_2Al(AlSi_3O_{10})(OH)_2$	**5-7**
	Epidote $Ca_2(Al,Fe)Al_2O(SiO_4)(Si_2O_7)(OH)$	**5-30**
	Actinolite $Ca_2(Mg,Fe)_5Si_8O_{22}(OH)_2$	**1-7**
	Quartz SiO_2	**2-30**

Table 10. Water and gas composition for wells of the Berlín field. Water composition in mg/kg and gas composition in mmoles/mol of water. Tsep is the temperature corresponding to the pressure at the separator; based on (64)

	TR-1	TR-2	TR-3	TR-4	TR-5	TR-9	TR-10
Year	1980	1991	1993	1990	1995	1991	1995
T_{sep} °C	98	154	138	–	138	155	140
pH	7.5	594	7.39	7.38	7.08	7.58	7.33
B	104	11	172	82	123	119	104
SiO_2	357	998	794	428	955	879	397
Na	2766	2900	4942	1650	2695	3201	3104
K	232	622	975	246	711	731	496
Ca	232	37	201	28	5	6	253
Cl	5083	5352	8539	2867	4914	5659	5679
SO_3	88	24	11.4	89.7	8.9	4.5	87.7
Mg	0.15	0.18	0.15	0.43	0.04	0.15	0.27
Al	0.015	0.015	0.015	–	0.015	0.015	0.015
Fe	1.2	1.2	1.2	–	1.2	1.2	1.2
CO_2^d	17	9	28.5	26.4	11.8	27	34.4
H_2S^d	0.05	1.14	0.15	–	0.49	0.73	0.2
NH_2^d	0.095	0.06	0.03	–	0.01	0.07	0.25

H_2	0.305	28.5	15.3	–	11.6	16.3	14.3
N_2	46.2	13.2	-	5.8	18.5	187.3	–
CH_4	0.227	2.9	2.6	–	2.7	2.6	4.9
H_2S	3.25	210.7	137	–	129.6	131.6	50.6
CO_2	28	1426	985	–	638	1079	321
NH_3	0.16	0.6	0.36	–	0.08	0.7	2.67

Estimations of the sub surface conditions, and the origin of the gases was done by (67). Table 10 shows the calculated reservoir temperature and the composition of the fluid at reservoir conditions.

Table 11. Calculated gas concentrations (mmoles/kg) in the aquifer fluid of the Berlín wells

Well	T_{ref} °C[a]	X_{aq}[b]	He	H_2	Ar	N_2	CH_4	CO_2	H_2S	N_2/Ar	mg/kg	CO_2 %
TR-2	280	0.36	$4.79E^{-5}$	0.0264	0.0031	0.21	0.0043	10.63	2.4	66	556	80
TR-4B	288	0.38	$7.58E^{-5}$	0.1252	0.0081	0.48	0.0113	24.24	2.9	59	1180	87
TR-4C	278	0.36	$7.98E^{-5}$	0.1537	0.007	0.39	0.0085	16.75	2.58	56	837	84
TR-5A	291	0.39	$8.48E^{-5}$	0.0332	0.0023	0.31	0.0051	10.13	2.46	135	539	78
TR-5B	287	0.38	$9.34E^{-5}$	0.0405	0.0034	0.28	0.0036	11.59	2.25	83	595	82
TR-5C	278	0.36	$4.45E^{-5}$	0.0229	0.0017	0.17	0.0037	10.72	2.23	99	553	82
TR-5V	293	0.39	$1.07E^{-4}$	0.0364	0.0041	0.32	0.0061	14.21	2.84	78	732	82
TR-9	273	0.35	$2.92E^{-5}$	0.0309	0.0018	0.16	0.003	10.72	1.93	88	542	83

Geothermal exploration of the Berlín field started in the 1960s and the first deep exploratory well (TR-1) was drilled in 1968 to a depth of 1458 m. Between 1968 and 1978 no additional well was drilled. Drilling at Berlin continued during 1978-1981 with the addition of five deep wells (TR-2, 3, 4, 5 and 9). All the wells show good performances, except TR-4[70]. Further development was suspended at the field because of the civil war. During the early 1990 CEL installed two 5 MW wellhead units. It was planned to use wells TR-2 and TR-9 as producers and reinject the spent fluids into well TR-1 and a new well (TR-6) drilled in 1991. During 1993-95 three deep wells were drilled for reinjection purposes (TR-8, TR-10, TR-14), located 1-2 km north of the production wells. At the moment, the Berlín power plant has an Installed capacity of 109 MW and 15 production wells and 20 injection wells in use.

Ahuachapán Geothermal Field

In the Ahuachapán region, four main volcanic stages were identified by geological mapping[71]. The area is characterised by several volcanos (Cerro Laguna Verde volcanic group) and a large caldera event, which is associated with abundant pyroclastic products. The structure is known as Concepción de Ataco Caldera. The Ahuachapán region is located close to the western end of the Motagua and El Salvador fault systems and shows a complex tectonic.

Several faults of different strikes are present that can be assigned to four main groups (Figure 9): (a) N–S, (b) NW–SE, (c) NE–SW, and (d) E–W. The N–S and NW–SE trending structures predominate. Most of these faults are normal with a minor component of oblique motion (either sinistral or dextral). The structures with the most conspicuous morphological evidence are the NE–SW oriented faults that, in the area west of the geothermal power plant, seem to accommodate the active deformation. These structures cut both the N–S and the NW–SE faults. However, the occurrence of very recent tectonic structures (N–S faults) and the analysis of local seismicity suggest an active stress field characterised by E–W extension[72].

The actual Ahuachapán geothermal field is in the northwest sector of the Cerro Laguna Verde volcanic group. The geothermal reservoir of the Ahuachapán geothermal system seems to be genetically related to the regional tectonic evolution of the area. Permeable faults and fractures of this zone form the pathways for deep circulation of the parent meteoric water to the geothermal fluid[67]. Where geothermal fluids reach the surface, acid surface alteration is seen with fumarolic zones, distributed around an area of 50 km^2. The heat source to the geothermal system is a recent andesite-basalt magmatic chamber, less than 0.1 million years old, and located at 9 km depth. This chamber is also supposed to feeds the volcanic complex nearby. The main reservoir is an altered (phyllic prophylithic) andesite. Table 12 shows the representative minerals composition of the reservoir zone. The depth of the main reservoir ranges from 900 m to 1200 m with measured temperatures of 230 °C to 250 °C. In the center of the field, the reservoir is located at 500–800 m depth with temperatures of 210–220 °C[73].

The data for the fluid composition comprise only main elements, a detailed analysis of the reservoir fluid was not available. Table 13 shows the gas content of steam at 1 bar from Ahuachapán by (67).

Table 12. Representative minerals in the production zone of the Ahuachapán geothermal field

	Mineral composition	%
Phyllikc Prophylithic 900 – 1500 m	**Epidote** $Ca_2(Al,Fe)Al_2O(SiO_4)(Si_2O_7)(OH)$	**10-40**
	Calcit $CaCO_3$	**2-32**
	Chlorite $(Mg,Fe)_3(Si,Al)_4O_{10}(OH)_2(Mg,Fe)_3(OH)_6$	**1-15**
	Hematite Fe_2O_3	**1-10**
	Quartz SiO_2	**10-50**
	Anhydrite $CaSO_4$	**3-7**
	Wairakite $CaAl_2Si_4O_{12}.2H_2O$	**1-7**

Table 13. fluid composition from the Ahuachapán wells; based on (67)

Well	Water (ppm)				Steam (mmoles/100 moles H_2O)						
	Na	K	Ca	SiO_2	He	H_2	Ar	N_2	CH_4	CO_2	H_2S
AH-4BIS	3237	419	236	410	0.002	0.2538	0.03	3.6411	0.063	196.76	5.72
AH-4BIS	3508	452	270	428	0.0026	0.2832	0.03	4.2216	0.09	208.97	4.98
AH-4BIS	3393	517	385	397	0.0026	0.2759	0.0331	4.3046	0.0751	227.56	2.43
AH-6	4984	668	450	372	0.0012	0.4541	0.0227	2.6879	0.0567	288.44	10.4
AH-6	$5.2E^3$	848	670	345	0.0018	0.6421	0.0211	3.8397	0.072	291.95	6.67
AH-16A	4954	788	321	537	0.0009	0.216	0.0165	2.2021	0.1669	125.46	5.66
AH-16A	5183	952	499	494	0.0009	0.1784	0.0175	2.0579	0.1249	127.03	3.13

Table 14. The gas content of steam at 1 bar from Ahuachapán wells (concentrations in mmoles/kg steam); based on (67)

Well	He	H_2	Ar	N_2	CH_4	CO_2	H_2S	CO_2 (%)	gases/steam (mg/kg)
AH-4BIS	0	0.1067	0.0128	1.5308	0.0263	82.72	2.41	95	3,766
AH-4BIS	0.0011	0.1211	0.0128	1.806	0.0385	89.4	2.13	96	4,059
AH-4BIS	0.0011	0.1174	0.0141	1.8307	0.032	96.78	1.04	97	4,347
AH-6	0.0006	0.2315	0.0115	1.3704	0.0289	147.05	5.3	95	6,692
AH-6	0.0009	0.3274	0.0108	1.9576	0.0367	148.84	3.4	96	6,723
AH-16A	0.0003	0.0734	0.0056	0.7485	0.0567	42.64	1.93	94	1,965
AH-16A	0.0003	0.0629	0.0062	0.725	0.044	44.75	1.1	96	2,029

The exploration of the Ahuachapán field started in 1968 and the first deep exploratory well (TR-1) was drilled to a depth of 1200 m and proved to be feasible for commercial exploitation. The Ahuachapán Geothermal Project was then launched in 1972 with funding from the World Bank. The first single-flash unit of 30MWe came online in Ahuachapán in 1975 and made Ahuachapán to the first geothermal field in El Salvador to be developed for commercial electricity generation. In 1976, a second 30 MWe single-flash unit was added, thereby doubling the generating capacity. In 1981 a third unit, this time double flash, came online, bringing the total capacity to 95 MWe. At the moment, the Ahuachapán power plant has 19 production wells and 8 injection wells in use.

5.2.3 Geothermal development and exploration sites

Additional to the exploited geothermal fields three sites are under development, Chinameca, San Vincente and Volcán de Conchagua. The main exploration activities in the San Vincente geothermal field started in 2006, until now 6 wells were drilled. The reservoir temperature is about 240 °C. In the Chinameca geothermal field, the main exploration phase started in 2008, until today 5 wells are drilled. The reservoir temperature is about 230 °C. About the geothermal field of Volcán de Conchagua no further information are available.

5.2.4 Current state of PtX with geothermal energy for energy, transport, chemicals and industry

Currently we have found only one PtX project in El Salvador where the use of geothermal energy is to be used for power the project, see section 5.2.5.

5.2.5 Main conclusions from questionnaire and interviews

The following main information could be achieved from the interviews with El Salvador:

- The detailed energy plan of El Salvador ("Política Energética Nacional" (PEN) 2020-2050) is currently under development, in which hydrogen plays an important role. Due to this, it was not yet possible to achieve any concrete strategies or numbers regarding geothermal energy and its potential use for green hydrogen production.
- There is no industrial production of methanol or ammonia in El Salvador.
- Geothermal brings the benefit of constant power supply, which could increase the efficiency of hydrogen electrolysers.
- The local market for potential Off-takers is quite small. Export seems more interesting.
- Since May 2022, there is a pilot project for the production of green hydrogen and ammonia using geothermal energy as an energy source by the CNE in El Salvador.

5.3 Chile

5.3.1 Geological overview and state of geothermal development

Chile is one of the regions with the highest volcanic activity on the planet, given its privileged position in the so-called "Pacific Ring of Fire" the country has about 20% of continental active volcanoes.

Geological studies in the north and south of the country have allowed a preliminary evaluation of the geothermal potential of Chile in approximately 16,000 MW[74]. Geothermal resources of the Andean region of Chile occur in close spatial relationship with active volcanism, which is primarily controlled by the convergence of the Nazca and South America Plates. Two main volcanic zones can be distinguished within the Chilean Andes: The Northern Volcanic Zone (17°S-28°S) and the Central-Southern Volcanic Zone (33°S-46°S) parallel to the coast.

The Northern Volcanic Zone and the Central-Southern Volcanic Zone of Chile

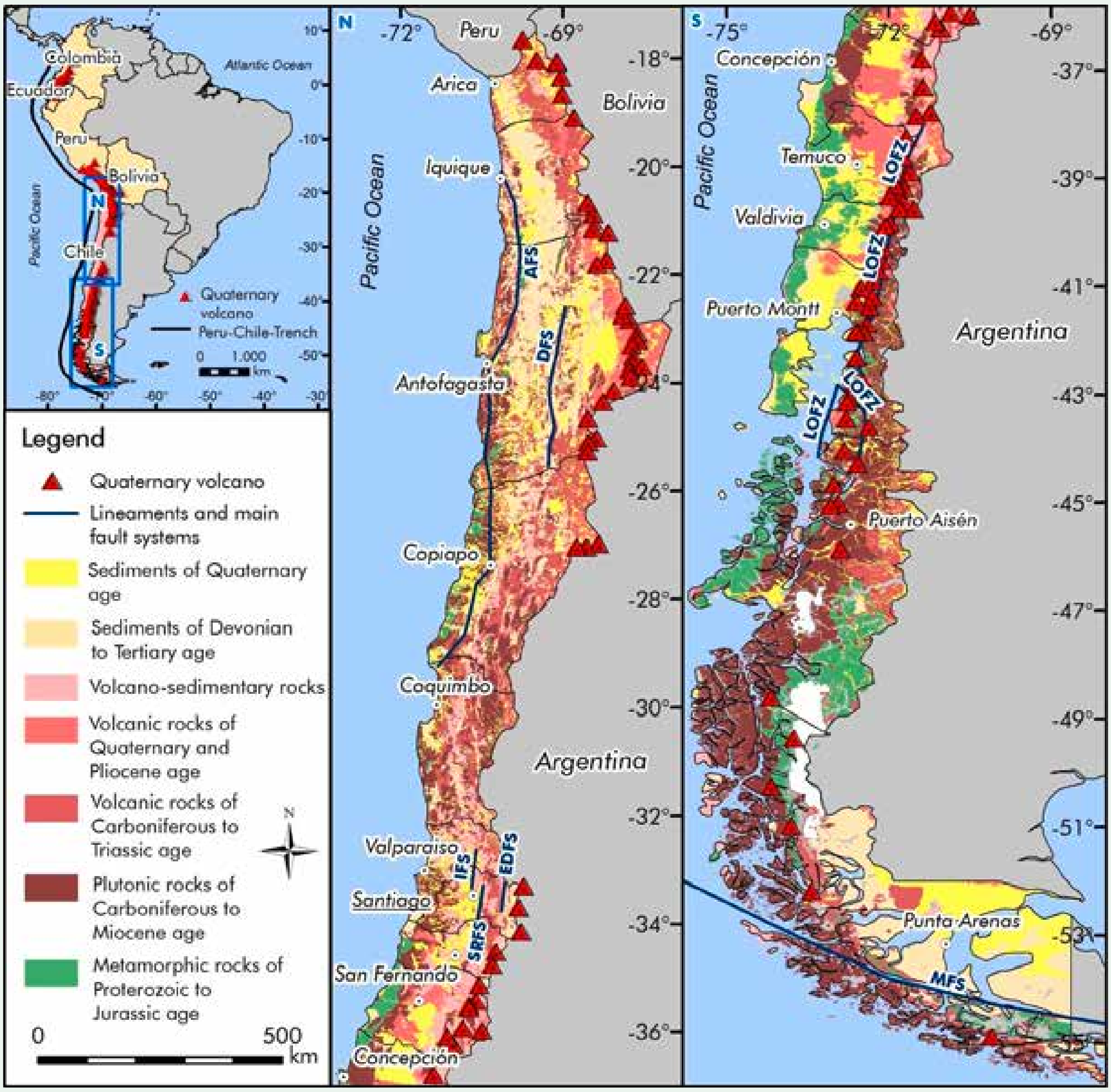
Figure 11. Source: Based on (74)

In northern Chile, the Quaternary volcanism is emplaced along the High Andes and part of the Altiplano. The volcanic rocks of this zone include calc-alkaline ash-flow tuffs and lavas. During the Pliocene and Quaternary times, an extensional tectonic phase caused differential uplifts along nearly N-S, NW-SE and NE-SW trending fault systems. Volcanic vents and hydrothermal manifestations occur within the small grabens associated with these fault systems (e.g., El Tatio and Puchuldiza geothermal fields)[75].

Quaternary volcanism in Central-South Chile is restricted to the Andean Cordillera. This volcanic activity has given rise to stratovolcanoes, pyroclastic cones and calderas, with associated lavas and pyroclastic flows. Lahar type flows from these volcanoes usually cover extensive areas of the Central Depression.

In Central Chile between 32.5° and 34°S, there are three main sets of reverse faults related to a Miocene tectonic inversion[76]: two to the west and verging W, the Infiernillo Fault System (IFS), and the San Ramón-Pocuro Fault System (SRFS), and one to the east of E vergence, the El Diablo-El Fierro Fault System (EDFS) (Figure 14). These reverse faults have an important dextral strike-slip component of motion and play an important role for upwelling of thermal waters[77].

Main lithological units, quaternary volcanoes and major fault systems and lineaments in Chile*



*AFS – Atacama fault system, DFS – Domeyko fault system, IFS - Infiernillo fault system, SRFS - San Ramón-Pocuro fault system, EDFS - El Diablo-El Fierro fault system, LOFZ - Liquiñe-Ofqui fault zone, MFS – Magallanes fault system

Figure 12. Source: Own illustration based on (77), (78), (79) & (80)

The first geothermal explorations in Chile date back to the 1920s. In the city of Antofagasta, a Larderello technical team successfully drilled two wells between 70 and 80 meters deep. Between 1968 and 1976, a series of geological, geophysical, and geochemical studies were carried out in selected areas of the northern part of the country, which culminated in the drilling of exploratory wells in the El Tatio and Puchuldiza area[75 81].

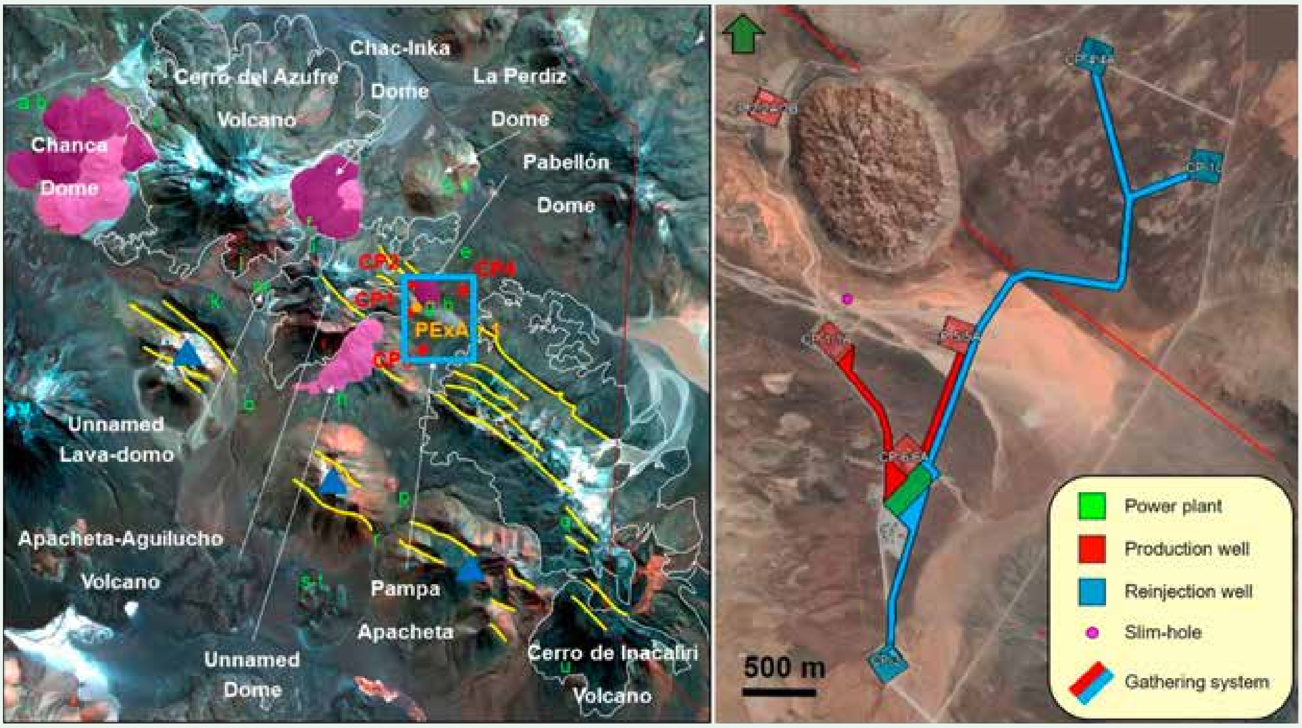
These activities were followed by various studies conducted by the University of Chile, the National Geological Survey and others, in many geothermal areas[76 82 83]. From these studies derives the gross of the current knowledge about the geothermal potential of Chile. Between 1995 and 1999, a joint venture between ENAP and UNOCAL Corp. resumed geothermal exploration in northern Chile. In Southern Chile, geological and geophysical exploration conducted by ENAP, in collaboration with the French Geothermal Company (CFG). In 1995, a 274 m deep slim exploratory well was drilled in the Nevados de Chillán geothermal area. This well encountered wet steam with a temperature of 198°C[81]. In 2000, the geothermal law was created, which promotes the exploration and exploitation of geothermal resources by private companies and establishes the existence of exploration and exploitation concessions that are granted through the Ministry of Energy. In 2017, Cerro Pabellón started operating.

5.3.2 Developed geothermal field: Cerro Pabellón

Cerro Pabellón is the first geothermal system industrially exploited in South America. Located in the “Pampa Apacheta” area at about 4500 m a.s.l. in the Antofagasta region, about 8 km from the Chile-Bolivia border.

The geothermal field is part of the Andean Central Volcanic Zone, a huge magmatic province associated with the subduction of the Nazca Plate under the South American Plate, which gives rise to intense magmatic and hydrothermal activity[84]. The main tectonic element in the area is a NW-SE trending graben, the Apacheta graben that was formed during the Late Pliocene (Figure 15). This graben is flanked by two chains of eroded volcanoes and young lava domes[85].

Map of the Area of Cerro Pabellón*

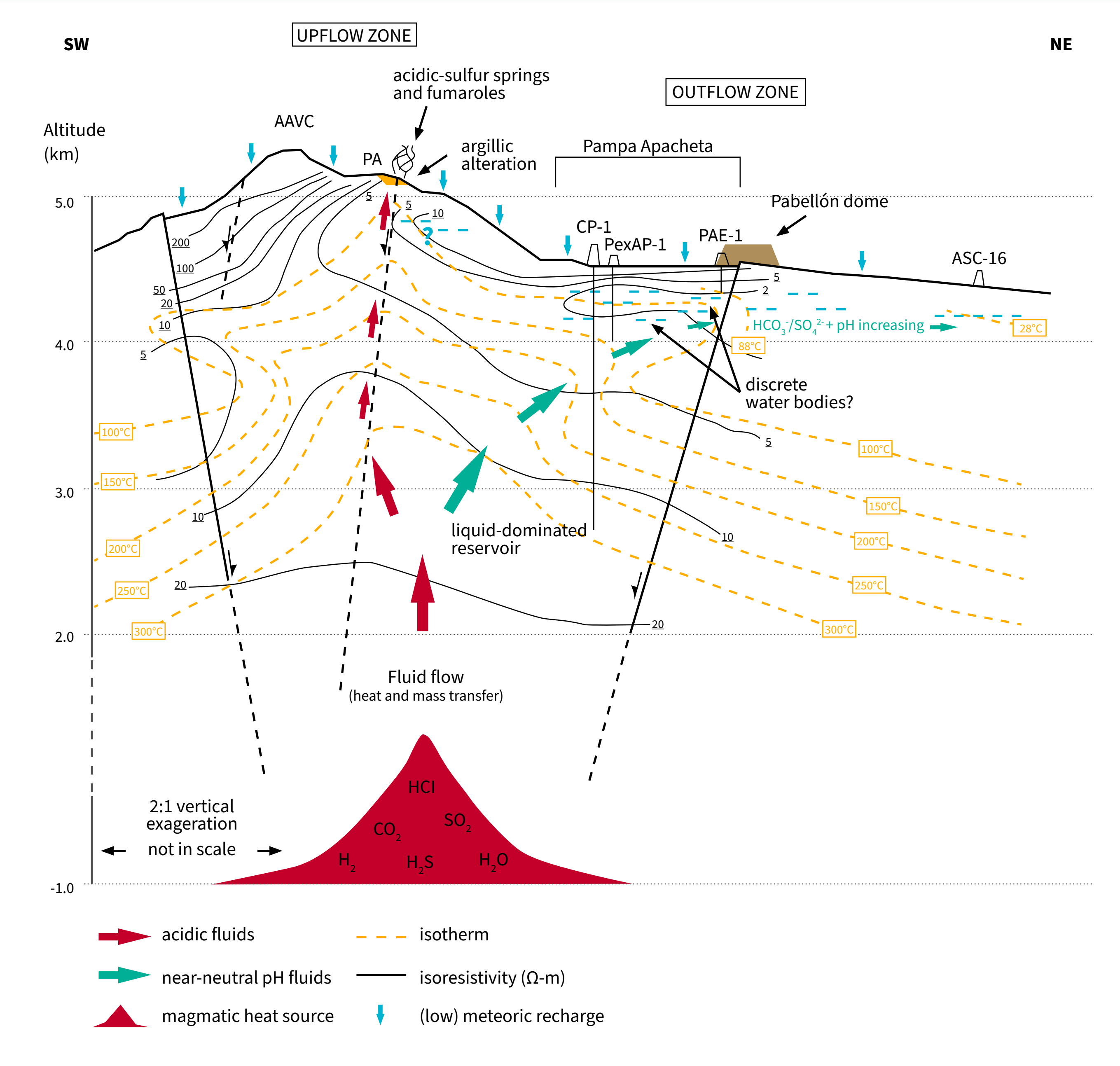


*Main Chain (Pleistocene-Holocene, White Line Polygons), the Secondary Chain (Upper Miocene - Pliocene, Blue Triangles), the Main faults (Yellow Lines), GDN Gradient Well (Orange Circle), Exploration Wells (Red Circles)

Figure 13. Source: Own illustration based on (86) & (89)

The actual geothermal field is located at the northern flank of the Apacheta graben, close to the Cerro Pabellón dome. A propylitic zone represents the beginning of the reservoir domain of the geothermal system (Figure 16). Detailed information about the reservoir is absent, because of total mud loose while drilling. The reservoir is supposed to be highly fractured. The reservoir temperature is about 250°C[86]. The general composition of the geothermal fluid and gas content is presented in[87] Table 11 and Table 12.

Conceptual model for the Cerro Pabellón geothermal field



*SW to NE simplified profile of the area showing temperature isotherms and MT resistivity data.

Figure 14. Source: Based on (85)

Table 15. Brine composition of water samples collected at Cerro Pabellón; chemical composition of the main elements in mg/L, steam fraction and gas-steam ratio in weight %

Well	CP1	CP1A	CP2	CP5	CP5A	CP6
Sampling date	11/06/2010	05/07/2017	10/12/2010	11/06/2016	26/06/2016	04/12/2017
Steam fraction	0.21	0.36	0.32	0.48	0.33	0.21
Gas/Steam	0.54	0.60	0.61	0.87	0.38	0.60
pH	6.89	6.95	7.12	6.74	6.84	6.82
Na	5182	4452	3498	4343	4724	5668
K	871	729	666	638	793	1125
Ca	543	538	597	528	645	541
Mg	0.17	0.36	0.81	0.04	0.13	0.21
Cl	10066	8214	6808	7447	9045	8986
SO_4	22	28	33	29	32	27
F	10.9	0.5	11.5	0.7	0.8	1.5
Br	10.4	7.5	6.5	6.5	7.7	11.7
SiO_2	531	429	362	276	363	574
B	273	293	258	265	312	343
HCO_3	34	51	67	48	46	48
Li	59	50	31	34	50	62
Rb	9.5	6.4	3.0	4.3	6.3	9.5
Cs	32	26	22	20	21	32
Sr	13.4	12.8	10.9	8.3	12.1	13.4
Sb	9.5	1.8	1.6	1.7	2.1	2.9
As	71	79	65	34	44	84
TDS	16769	14146	11778	13095	15385	16569

Table 16. Gas phase analysis of samples from Cerro Pabellón; chemical composition of the main elements in mg/L, steam fraction and gas-steam ratio in weight %, Bdl = below detection limit; nd = not determined.

Well	CP1	CP1A	CP2	CP5	CP5	CP5
Sampling date	10/06/2010	05/07/2017	10/12/2010	09/06/2016	09/06/2016	11/06/2016
Gas/Steam	0.54	0.6	0.61	0.87	0.87	0.87
CO_2	2.18	2.37	2.45	3.51	3.52	3.52
H_2S	$6.01E^{-03}$	$6.09E^{-03}$	$5.57E^{-03}$	$8.14E^{-03}$	$7.38E^{-03}$	$6.43E^{-03}$
CH_4	bdl	$1.22E^{-03}$	bdl	$3.70E^{-03}$	3.69^{-03}	bdl
H_2	bdl	$2.19E^{-03}$	$2.53E^{-03}$	$6.66E^{-03}$	$5.90E^{-03}$	$5.00E^{-03}$

N_2	2.71E^{-02}	1.14E^{-01}	6.00E^{-02}	4.96E^{-02}	3.58E^{-02}	3.28E^{-02}
CO	4.45E^{-06}	1.05E^{-05}	5.06E^{-06}	1.85E^{-05}	1.73E^{-05}	1.79E^{-05}
He	2.89E^{-05}	9.99E^{-05}	4.30E^{-05}	3.70E^{-05}	3.32E^{-05}	5.71E^{-05}
Ar	1.35E^{-03}	nd	nd	nd	nd	nd
Water	996	995	995	993	993	993

The geothermal field has limited surface activity – with only two volcanic fumaroles on the top of Cerro Apacheta. In 1993, a well for industrial water was drilled in Pampa Apacheta (4,511 m a.s.l.). Drilling was stopped at 187 m, since the well, instead of tapping a groundwater resource, started producing steam at 88 °C. After a phase of shallow exploration surveys (geology and geophysics) and a corehole of 560 m depth and four deep commercial diameters exploratory wells were drilled in 2009-2010[88]. The drilling results confirmed the presence of a geothermal reservoir with temperatures of 250-260 °C at depths over 1,500 m. The actual power plant employs 6 production wells and 3 injection wells. The total installed capacity is 48 MW (2x24 MW High Enthalpy Organic Ranking Cycle Units).

Potential geothermal development areas in Chile

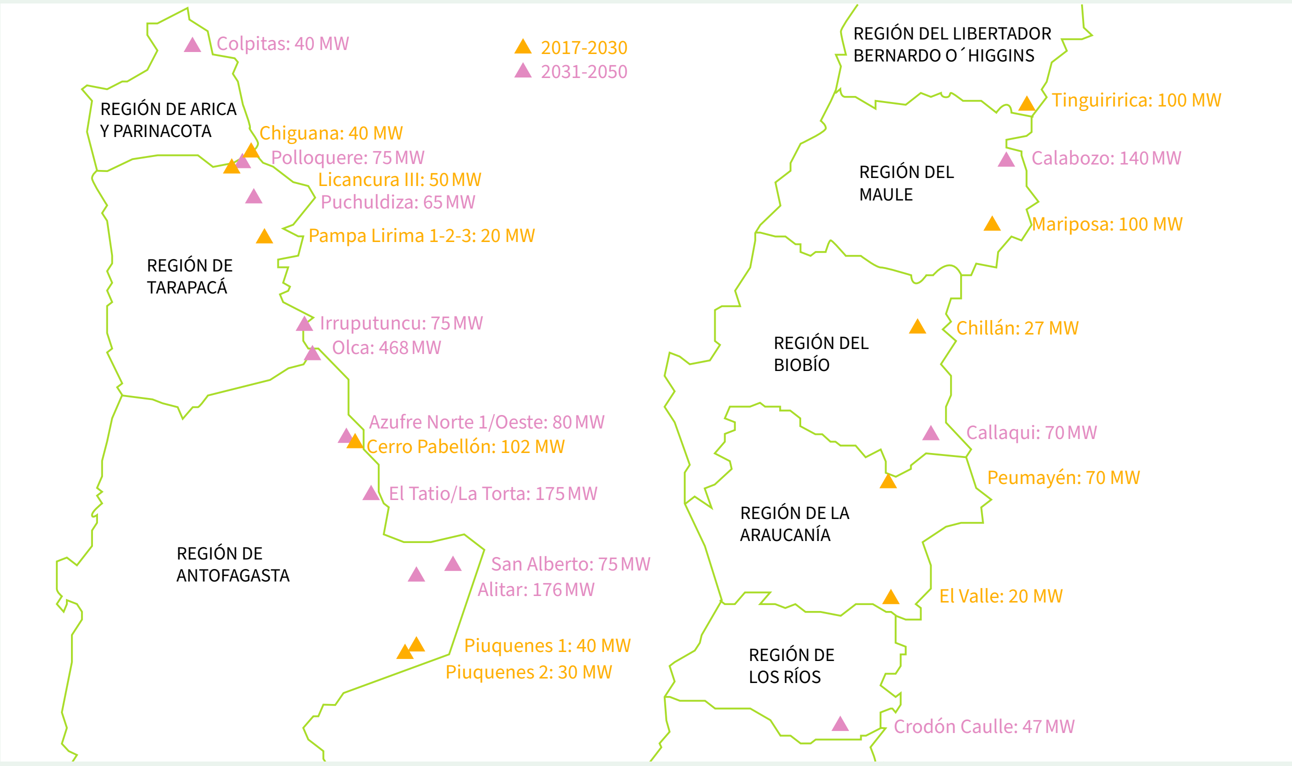


Figure 15. Source: Based on (89)

5.3.3 Geothermal development and exploration sites

Figure 17 shows the potential geothermal development areas in Chile. The figure clearly shows a high untapped potential for the use of geothermal energy. Table 16 and Table 17 show the geothermal concessions, as of March 2022. Notable is the rising number of requests for exploration concessions. In total six exploitation concessions exist and three more are concessions are requested.

Table 17. Geothermal concessions (March 2022)

	Exploration	Exploitation
Existing concessions	0	9
Expired concessions	1	-
Submitted requests	3	3

Table 18. Geothermal exploitation concessions (March 2022)

#	Concession	Holder	Region	Municipality
1	Licancura 3	Transmark	Arica y Parinacota, Tarapacá	Camarones, Colchane
2	Olca	SCM Collahuasi	Tarapacá,Antofagasta	Pica, Ollagüe
3	Apacheta	Geotérmica del Norte	Antofagasta	Ollagüe
4	El Tatio	Geotérmica del Norte	Antofagasta	Calama
5	La Torta	Geotérmica del Norte	Antofagasta	Calama, San Pedro de Atacama
6	Tinguiririca	Energía Andina	de O´Higgins	San Fernando
7	Laguna del Maule	Compañía de Energía Limitada	del Maule	San Clemente, Colbún
8	Pellado	Compañía de Energía Limitada	del Maule	San Clemente, Colbún
9	Peumayén	Transmark	Biobío, Araucanía	Quilaco, Curacautín

During the interview with Carlos Jorquera (Espinos S.A.; President of the Geothermal Council in Chile and regional manager for the Spanish-speaking regions for ThinkGeoEnergy - PiensaGeotermia), he explained that the most advance projects in development are Peumayén-Adobera (border area of La Araucanía and Biobío Regions) and Mariposa (Maule Region). However, he does not expect a realisation within the next five years.

Extensive research on the individual geothermal projects regarding the composition of the brine and associated gases was not successful. Freely available analyses are limited to the sampling of surface manifestations and hence not representative for the reservoir conditions.

5.3.4 Current state of PtX with geothermal energy for energy, transport, chemicals and industry

Currently we have found no information for a PtX project in Chile where the use of geothermal energy is to be used for power the project. However, several PtX projects are being prepared in Chile using wind and solar power.

5.3.5 Main conclusions from questionnaire and interviews

The following main information could be achieved from the interviews with Chile:

- In South America, Chile is the most active country with regards to PtX and has goals to expand their hydrogen production up to 30-50 GW electrolyser capacity.
- The main producers are Methanex and Linde.
- There are two main regions for PtX production. In the Antofagasta region in the north, both wind and solar power is used to produce green hydrogen. In the south, close to Punta Arenas and the Argentinian Patagonia mostly Wind and natural gas is used to power large scale electrolysers to produce methanol (biggest methanol facility in the world).
- Most of the hydrogen projects focus on exporting via ammonia.
- There is currently one geothermal power plant “Cerro Pabellon”, operating at 81 MW and 100 MW in the future. Two projects are currently under development, Mariposa Project and Adobera by Transmark.
- There is no example of geothermal energy used for PtX purposes in Chile yet.
- Mine industry trucks present a use scenario for potential local hydrogen off-takers, which is also supported by the government. Furthermore, hydrogen is locally used in refineries and for production of glass.
- All energy producers are free to participate in the Chilean energy auctions, which pushes the development of solar and wind without storage and dumps the prices.
- The price structure for geothermal electricity in Chile is the power purchase agreement (PPA) plus 10 USD/MWh for capacity payments. Current PPAs lie in the range of 40-60 USD/MWh.
- According to H_2 Chile, by 2025 there supposedly will be 5 GW of electrolyser installed. Until 2030, 25 GW of installed electrolyser capacity is planned. The expected price is 1.5 USD/kg hydrogen. To reach this, an electricity price of 20 USD/MWh is needed. The electricity production in these projects is most likely going to be off grid in order to reach those competitive prices. The actual price for green hydrogen in Chile is currently around 3–5/6 USD/kg.
- The geothermal benefits are stable power supply and therefore adds to the grid stability, and it offers flexibility, is resistant against Ambiental influences, is green, operates 24/7 and occupies little space.
- Important future outtakes:
  - Create a compatible PPA (~6 USD/MWh)
  - The market needs to take more into account the benefits of geothermal. Those are not valued in the PPA yet. The PPA is only awards the best price.
  - A newly structured PPA process that values geothermal’s contribution to the baseload capacity and grid stability could boost the development.
  - The installed capacity of volatile renewable energy sources has reached a critical capacity regarding the grid structure in Chile.
  - Geothermal can furthermore contribute to a healthy social development all over Chile through the installation of power plants in the centre of the country, working against a polarised north or south distribution.

- Currently there exists a very positive business cycle for green hydrogen in Chile. The new administration created a committee only for the development of green hydrogen production projects.

5.4 Readiness analysis

5.4.1 Comparison between Kenya, Chile and El Salvador and other countries

Kenya has currently renewable energy surplus part of the day. Further expansion of geothermal power plants is considered up to 800 MW during the period 2020-2040. Wind power expansion of up to 1,750 MW is considered possible until 2040 and solar PV of 550 MW in the same period[62].

El Salvador depends heavily on fossil fuels to meet its energy needs for industry, transport and for power generation. The country also imports electricity from neighbouring countries to meet domestic demand. The past decade has seen national energy policy recognise the benefits of developing solar, wind and bioenergy, as a wide range of renewable energy technologies can help to diversify the energy mix, expand electricity access and strengthen regional energy integration. Additionally, El Salvador is connected to the Central American Electrical Interconnection System (SIEPAC – Sistema de Interconexión Eléctrica de los Países de América Central), making the country an active participant in the Regional Electricity Market. In 2019 geothermal energy supplied only 3,4% of the total energy supply in El Salvador and 9,6% of the electrical energy[89 90]. The geothermal power plants in El Salvador are the two plants operated by LaGeo, with total capacity of 204.4 MW. The state-owed Comisión Ejecutiva del Río Lempa (CEL) – mother company of LaGeo – is planning to expand the geothermal power generation capacity by 95 MW (from 204 to 300 MW) with three projects in the coming years. They are going to build three new plants: in Chinameca, San Vincente and Volcán de Conchagua. The most obvious use of this electricity is to replace part the current electrical generation from fossil fuels in El Salvador.

Chile has enormous geothermal power potential. Many of the identified sites are remote, making harnessing the power difficult. According to an interview with Carlos Jorquera, President of the Geothermal Council in Chile, conducted during this PtX dialog, it is unlikely that there will be any new geothermal power plants built in the near term (next 5 years). There are also concerns that the erection of geothermal power plants in medium term (5-10 years) might be slow. However as can be seen in 5.3.3 a lot of opportunities exist in most of Chile's regions for future development.

Iceland's electrical energy is almost 100% renewable, hydro and geothermal. Small wind farm is also operating, but no fossil fuel power plant except for short-time local back-up. Big part of the produced power is sold to aluminium- and silicon smelters which use full power 365 days per year. Increased power consumption by the general consumers now fully utilised the power production system. Currently there is no power available for PtX projects. Only few and small new power plants are being planned, so very little possibilities are for PtX projects in the near term. In the long term (5-10/15 years) both hydro power, geothermal and wind power projects are being prepared and several PtX project may be realised. Power price however is rising, partially due to the energy crisis in Europe, which might jeopardise these PtX projects.

5.4.2 Compare geothermal power use to Solar and Wind power for PtX

Geothermal Power

The production of geothermal power is normally stable the whole year unless some unplanned break-down happens. This usually only affects part of a multi-turbine set-up. Every second year, the power plants have short stop in operation for inspection purposes. Every 3-5 years interval, turbines need overhaul, which can last for 1-3 weeks. Using geothermal power for green hydrogen production therefore ensures high-capacity factor, usually up or above 90% (see 3.2). Any type of electrolysers can be used without problems. The economy of the project depends mainly on the energy price.

Wind Power

Energy production using wind power is very variable, even though progress has been made in optimizing the wind turbines for the grid. This makes the operation of electrolyser a challenge. Alkaline electrolysers need a constant power supply and are not as suitable as PEM; while SOEC are more flexible and are normally considered unaffected by variable power supply and are likely the best option when using wind power. Onshore wind capacity factor is approximately 36% worldwide (see 3.2) but can be higher at good locations as well as offshore. Finding the best locations where higher capacity factors can be achieved is of utmost importance for the economy of wind powered PtX project. Most of the current projects are located where high-capacity factors are to be expected.

Solar PV

The low-capacity factor for solar PV (15-20%) is the main disadvantage for PtX, however it fits the need for air conditioning in hot climates, like Kenya, El Salvador, and Chile. The cost of solar PV has been going down for a long time, but the energy crises might delay further cost reductions. The power production is similar from day to day (during solar days), so the electrolysers are started up and ramped to full load in the morning and ramped down and shut off in the evening. This mode of operation is not suitable for most PtX processes, such as ammonia, methanol, and e-crude, which prefer stable continuous operation 24 hour/day. To compensate for this buffering of hydrogen during shutdown is possible but expensive as the buffer either needs large volume and/or high-pressure tanks. The buffer tanks are usually sized for only short electrical disruption to the electrolysers. The low-capacity factor for solar PV can compensated by using a combination of solar PV, concentrated solar power (CSP), wind and/or geothermal power.

Solar CSP

Concentrated solar power is technically more complex than solar PV. Concave mirrors concentrate the sun's radiation towards receivers containing salt solution and heat it up to more than 500°C. This molten salt solution is used in a heat exchanger system to produce high pressure steam for electricity production in a turbine via Rankin cycle. Recent trends are to fit such plants with storage tanks for molten salt solution to enable the plant to produce steam even after sunset. Several CSP plants in Spain have installed storage tanks for 5-8 hours operation after sunset while a new installation in the Atacama Desert in Chile, Cerro Dominator, has 17.5 hours storage, enabling 24/7 operation. This CSP has 110 MW installed turbine capacity plus 100 MW PV to ensure sufficient storage of molten salt[91]. Fitted with storage tanks for molten salt the CSP plants can have higher capacity factor than PV solar plants. However, the installed cost is considerable higher. According to the same source the CAPEX for the Cerro Dominator project was USD 1,400 million or 12.7 million per MW.

Combination of different renewable energy sources

Combining different renewable energy sources should always be considered for PtX, as a complementary setup can achieve high-capacity factors and a reduction in total costs.

As an example, combining the use of surplus geothermal power in Kenya during night-time and solar power during daytime a high-capacity factor could be reached. Similarly combining solar power during daytime and wind power during mornings and evenings in the Antofagasta region in Chile higher capacity factor can be reached.

5.5 Sizing

New geothermal power plants are normally built stepwise while the actual capacity of the geothermal reservoir is developed. These steps are usually by installing one or two turbines during each step. The geothermal turbines are normally 25-50 MW each. For instance, Hellisheidi geothermal power plant is 303 MWe, was built in 4 steps (2x45, 2x45, 33 and 2x45 MW) and is now the second largest geothermal power plant in the world. Some reservoir engineers maintained that these steps were too large and there was a risk for overexploitation of the reservoir. Many geothermal power plants are 50-200 MWe.

Many PtX projects that have been introduced in recent years, based on wind and solar energy, are considerably larger than conventional geothermal power plants, sometimes up to 3 GW of electrolysers[92]. The Murchison Project in Western Australia is meant to produce up to 2 million tonnes of ammonia annually. Other similar projects are also discussed[93]. The reasons for these megaprojects are lower production cost per tonne, making it more economical to export and transport long distances.

PtX projects based on geothermal energy would always be considerable smaller due to the general size of the power plants. The feasibility of such PtX projects might therefore be worse unless it is focused on local needs to avoid high transport costs of exports. Another solution could be combination of geothermal and wind/solar energy to enable larger projects. Larger projects could however be more difficult to finance as usually several finance institutions have to cooperate for the financing.

5.6 Summary of main conclusions

There are no policies regarding PtX in Kenya, however, opportunities for using geothermal and variable RE technologies are under consideration. Government working group has been formed in the purpose to bring together which pathway the government should support to actualise a PtX project. Strong incentive scheme must come from the western world.

Currently there is an excess on the grid during the night and even sometimes during the day as well, which offers potential for hydrogen production using the available RE resources. One of the greatest opportunities for PtX in Kenya is the production of ammonia for fertiliser production, as most of the fertiliser used in Kenya is imported. KenGen is looking into a pilot project to produce fertiliser using geothermal energy. MET Development is running a power-to-fertiliser project with other partners, that includes an end product with substantial local demand. Geothermal power is considered advantageous for this project is because it enables the plant to run 24/7. In the end it is a CAPEX/OPEX evaluation that will determine the most optimal cost structure.

There has been discussion in Kenya about becoming a refilling point for ships in the Indian ocean. Global issues and policies related to the blue economy and clean energy for ships are expected to affect port operations and it is important to start preparing for that.

There is good potential for geothermal in combination with SOEC electrolyser technology, using heat to reduce electricity requirements. Heat utilisation from geothermal is another can be used to regenerate the membrane used for direct air capture. The potential CO_2 emissions involved in geothermal power production cannot be dismissed and could negatively impact its use in PtX. It is also important to consider the stress on water availability, reduction of available electricity for general use in Kenya and the short- and medium-term electricity demand when studying the potential of using geothermal energy for PtX projects in Kenya.

A detailed energy plan for El Salvador 2020-2050 is currently under development, in which hydrogen plays an important role. Due to this, there are not yet any concrete strategies or numbers regarding geothermal energy and its potential use for green hydrogen production. There is currently no industrial production of PtX in El Salvador. The local market for potential off-takers is quite small. Export seems more interesting.

In South America, Chile is the most active country with regards to PtX and has goals to expand their hydrogen production up to 30-50 GW electrolyser capacity. There are two main regions for PtX production. In the Antofagasta region in the north, both wind and solar power is used to produce green hydrogen. In the south, close to Punta Arenas and the Argentinian Patagonia mostly wind and natural gas is used to power large scale electrolysers to produce methanol, in the biggest facility in the world. Most of the hydrogen projects are focusing on exporting ammonia.

H_2 Chile expects 5 GW of electrolysers to be installed by 2025 and 25 GW by 2030. The expected price is 1.5 USD/kg hydrogen. To reach this, an electricity price of 20 USD/MWh is needed. The current price for green hydrogen in Chile is 3 – 6 USD/kg.
There is now only one geothermal power plant "Cerro Pabellon", operating at 81 MW and expanding to 100 MW in the future. Two projects are under development, Mariposa Project and Adobera by Transmark.

The market needs to consider the benefits of geothermal, stable power supply, grid stability and little space requirement. A newly structured PPA process that values geothermal's contribution to the baseload capacity and grid stability could boost the development. The installed capacity of variable renewable energy sources has reached a critical capacity for the grid structure in Chile.

Geothermal can furthermore contribute to a healthy social development all over Chile through the installation of power plants in the center of the country, working against a polarised north or south production distribution.

Currently there is a positive business environment for green hydrogen in Chile. The new administration created a committee only for the development of green hydrogen production projects.

6 OUTLOOK

6.1 The potential of PtX with geothermal energy in Latin America and internationally

6.1.1 Chile

Chile has enormous geothermal power potential. Many of the identified sites are remote, making harnessing the power difficult. According to local sources, it is unlikely that there will be any new geothermal power plants built in the near term. There are also concerns that the erection of geothermal power plants in medium term (5-10 years). Lack of geothermal power would make any PtX project relying on other renewable energy sources.

6.1.2 El Salvador

El Salvador depends heavily on fossil fuels to meet its energy needs for industry, transport and for power generation. LaGeo is planning to expand the geothermal power generation capacity by 95 MW. This power generation will probably be used to reduce dependence on imported fossil fuel.

6.1.3 Costa Rica

The electrical energy in Costa Rica is almost fully renewable. A small production plant for hydrogen is in operation. The plant presents a fully equipped small-scale system of the whole production chain, starting with the renewable energy production (by wind and solar) feeding a compressor and an electrolyser as well as storage tanks with further connection to a transport vehicle using two different distributor types. A lot of interest for PtX is in Costa Rica.

6.1.4 Kenya

Kenya has currently renewable energy surplus part of the day. Further expansion of geothermal power plants is considered up to 800 MW during the period 2020-2040. Wind power expansion of up to 1,750 MW is considered possible until 2040 and solar PV of 550 MW in the same period. Such extensions might open up an opportunity for PtX projects that could be based on a mix of geothermal, wind and sun and therefore able to get high degree of capacity utilisation.

6.1.5 Ethiopia

Ethiopia has an estimated >10,000 MW of geothermal energy potential, more than double its current power generating capacity (4,400 MW). Electricity access stands at 44% of the total population, with 31% in rural areas, so effective development of this low-carbon resource could make a significant impact to equitable delivery of electricity. However, geothermal energy exploitation must be done responsibly to protect valuable water resources under stress from climate-change driven drought conditions and competing uses across agricultural, domestic, and industrial sectors. Ethiopia hosts two major geothermal water types, sodium-alkalinity dominated in the Main Ethiopian Rift and sodium-chloride dominated in the Afar Depression, separated by sodium-mixed waters between Dofan-Fantale and Meteka[94]. The main focus of the Ethiopian government is to supply electricity to the many Ethiopians that do not have access.

6.1.6 Indonesia

Indonesia has the largest latent reserves of geothermal energy in the world and has as such the potential to be a major supplier of power fuel for domestic and international markets from geothermal. High total development potential has been reported based on the Indonesia Government inventories and this has been of the order of 24 to 29 GW while only about 2.5 GW is yet developed for power generation. While, at face value, this indicates abundant "untapped" potential, a large portion of that development potential lies within as yet poorly defined geothermal resources, or resources that may be lower grade and less economic.

Unless some capacity already planned for power generation is redirected to hydrogen production, new capacity for PtX will take some years to be developed.

6.1.7 Iceland

A lot of interest exists in Iceland for PtX for use as alternative fuel and fertiliser. There is currently, and in near future, no electrical power available for such projects. Very little progress has been made for the last 15 years towards new power plants, neither hydro nor geothermal. We do not see a reasonable opportunity for any big scale PtX project in Iceland for at least the next 10 years.

6.1.8 Other countries

Colombia, Panama, and Uruguay are all taking steps towards the development of green hydrogen production. Australia has made plans to produce PtX, mostly in Western Australia, using a mixture of sun and wind, only minor geothermal energy use. The products are mostly to be exported to Japan and South Korea.

6.2 The meaning of the country and site-specific results for other GIZ partner countries with high geothermal potential

6.2.1 Indonesia

4.2 GW have been identified as a potential basis that may be developed for green fuel in Indonesia. With a typical development cycle of 5-15 years, unless some capacity already planned for power generation is redirected to production of green fuel, new capacity from geothermal which could be allocated for green fuel will take some years to develop.

6.2.2 Philippines

The past years are characterised with limited growth in geothermal capacity. Given the typical development cycle of 5-15 years, no significant growth is expected in the next decade at least. Unless some of the already available capacity for power generation will be redirected to production of green fuel, the PtX industry will be led by power sources from non-geothermal renewables.

6.2.3 Costa Rica

The geothermal potential of the country is estimated at 1,000 MW while the current installed capacity is 262 MWe. There is ongoing development of new areas, while the ambitions have slowed due to a stagnating electricity demand.

With the goal to support development of the hydrogen industry, both the public- and the private sector, the geothermal is seen as the ideal power source, delivering stable power through-out the year. With this in mind, production of green fuel powered by geothermal power may very well have a great future in Costa Rica.

6.3 Recommendations and next steps

6.3.1 Risk associated with geothermal development and PtX coordination

Building a geothermal power plant takes a long time, 5-15 years project time is common. High costs in the early stages due to drilling entails high risks for the developer as up-front money is needed before anything is known about the available energy of the resource and therefore the viability of the project. Therefore, the financing of a new geothermal power plant is often difficult. Reducing this initial risk is very important for the future of geothermal development worldwide.

The recommended procedure for geothermal development is a stepwise approach to gradually build up sustainable development, that is install one turbine at the time to test the geothermal field capacity. Further drilling and experience from the first turbine operation may lead to the second turbine installation etc.

PtX projects needs a lot of electrical energy with in relatively short time from start-up. The larger the PtX the unit cost will be lower, making the plant more economical if the product can readily be marketed. Coordination with geothermal development can therefore be complicated. We recommend solving this problem by coordinate different type of renewable energy supply for the PtX project, at least in the beginning.

Another potential is to consider capacity building the PtX project to correlate to the capacity risk of the geothermal development. For green hydrogen this could be feasible in case there is local demand for hydrogen, as gradual increase of modules of electrolysers is simple. This is currently being done at Yara, Netherlands where grey hydrogen is being phased out by green hydrogen in steps. However, this would be more complex for ammonia or methanol production, and not necessarily recommended.

6.3.2 Location

It would also be recommended to study the location of the proposed projects thoroughly. Many factors contribute to whether the location is suitable for a PtX project, among these are the cost and market as mentioned in the report as well as proximity to labour, but the prospect of renewable energy development is also a vital factor. Coordination of different renewable energy supplies is not necessarily effective at the same site, or even same region.

When geothermal development has been established it does provide baseload capacity. This in conjunction with PtX projects is very important and has been highlighted as the result of the interviews and considered for further steps.

6.3.3 Cost of PtX projects

Earlier in this report we have drawn figures (Figure 5, Figure 6) describing the possible cost of hydrogen for a PtX project based on average renewable energy cost according to a recent IRENA report. It would be of interest for investors and project owners to investigate their energy cost and options and redo these figures based on their actual energy cost structure.

We recommend that all PtX projects make cost analysis before any investment decision is made. This analysis should be stepwise and in accordance with how much money is needed for the next step.

7

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