Techno-Economic Assessment Of Production And Transport Of Synthetic Methane From PV And Wind Energy

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ABSTRACT

This study investigates the methanation of green electricity from a combined wind and PV power plant with a peak capacity of 250 MW in three different countries (Chile, UAE, Tunisia) and the transport of the produced methane to Austria. The production costs were calculated through a simulation on an hourly basis over a span of 20 years. The economically ideal size of the conversion components were determined in a parameter study. The specific transport costs were calculated on an annual basis. An optimistic and a pessimistic scenario were defined to represent the uncertainty of costs and technical parameters as well as two years of initial investment (2030, 2040) to reflect the possible technical and economical improvement of elements along the chain. Transport from Chile and the UAE was assumed by ship in a liquefied state and from Tunisia by pipeline in a gaseous state. The resulting import costs from Tunisia were 140 - 271 €/MWh, from Chile 150 - 356 €/MWh and from the UAE 183 - 420 €/MWh.

Keywords: *synthetic methane, SNG, PV, wind power, levelized costs of SNG*

1. INTRODUCTION

1.1. Relevance of the topic

The EU has set itself the ambitious goal to reach net zero CO_2 emissions by 2050. In order to limit the long-term increase in the global average temperature to 1.5 °C, reducing global CO2 emissions is crucial. Therefore, it is estimated that the production of hydrogen-based fuels has to increase from 87 Mt in 2020 to 212 Mt in 2030 and further more to 528 Mt in 2050. Also PV and wind capacity should quadruple until 2030 to reach net zero by 2050. [1]
Another incentive to import renewable methane is to decrease dependency on Russian natural gas import by increasing the diversity of import routes.

1.2. Production chain of SNG

In this study, methane is produced by methanising hydrogen from renewable energy. For this purpose, electrical energy generated by a combined wind and PV power plant is converted into hydrogen using electrolysis. The CO_2 input required for methanation comes from a direct air capture system (DAC), which separates CO_2 from ambient air. For this study the sub systems necessary for converting electrical energy to methane were optimally sized to ensure minimal levelized costs of energy based on given generation profiles of the combined wind and PV power plant. The methane or synthetic natural gas (SNG) produced in this way is then transported to Austria. Depending on the location of the production site, two different modes of transport were chosen. From Chile and the UAE, the SNG is exported in a liquefied state by ship to Europe and regasified again at the import terminal. There it is fed into the European gas grid and forwarded to Austria. From Tunisia, the compressed gaseous methane is transported via the already existing Trans-Mediterranean Pipeline to the Italian mainland and further on via the European gas grid to Austria.

1.3. State of technology

Today there are already many projects in the area of power to methane (PtM) that produce SNG using hydrogen [2], [3], [4], but none of them have the scale of this study. Moreover, these PtM projects do not use DAC, but instead CO_2 from biological fermentation and amine scrubbing. Today there are 18 active DACs with a total capture capacity of 0.01 Mt CO_2 per year, with Climeworks' DAC having the highest capture capacity at 4 000 t/a [5], [6]. In the Net Zero Emissions by 2050 scenario from IEA, direct air capture is increased to almost

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60 Mt CO_2 per year by 2030 [5]. Downstream liquefied natural gas (LNG) technology is well established. In 2021, global LNG trade reached an all-time high of 372.3 Mt. As of April 2022, a total of 641 LNG vessels, a global liquefaction capacity of 459.9 MTPA and a regasification capacity of 909.9 MTPA were available [7].

1.4. Challenges

As mentioned in the IEA report on net-zero emissions by 2050, it is a major challenge to produce electrolysers at the required rate based on today's production capacities [1]. Furthermore, there are currently no direct air capture plants near the scope of this study, resulting in a wide range of economic and technical parameters. The production of renewable hydrogen is not yet a widely tested and utilised technology, particularly for large-scale production units (technology risk and cost risk). Accordingly, production costs are still high and renewable hydrogen not competitive. [10]

2. METHODOLOGY

2.1. Scenario definition

For this study, three different countries were considered as export countries for SNG from renewable energy sources. Tunisia has high solar radiation [8] and therefore is ideally suited for PV power. Additionally, it has an already existing natural gas pipeline that is connected to the mainland of Italy. The UAE also have a high solar radiation [8]. Chile on the other hand side is a country with good wind conditions [9] which makes it highly suitable for wind power plants.
2030 and 2040 were chosen as two different years of first investment as the costs and efficiencies of some of the components in the production and transport chain might improve due to further development and scaling effects. Additionally, an optimistic and pessimistic scenario for each year of the first investment was chosen. While the optimistic scenario represents the lowest costs and best efficiencies, the pessimistic scenario displays the other side of the price range and low performance.

2.2. Components

2.2.1 Renewable energy sources

Renewable energy sources were modeled following the recent study "Importmöglichkeiten für erneuerbaren Wasserstoff" commissioned by the Austrian Federal Ministry for Climate Policy, Environment, Energy, Mobility, Innovation and Technology [10]. New renewable energy sources (RES) with high expansion potential, such as wind and PV power plants, were taken into account. Fig. 1 shows the resulting full load hours per RES and country. A total of 250 MWp of new RES was installed, with various combinations of wind and PV capacity considered in 10 percent increments, starting with only wind or only PV.

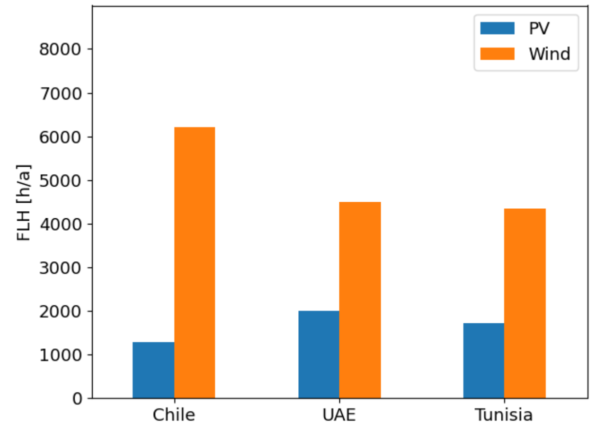

Figure 1 Full load hours of the PV and Wind power plants

The techno-economic parameters are shown in Tab. 1.

2.2.2 H_2 system

The electric energy is first converted to direct current using an AC/DC converter with a varying efficiency depending on the input power. The average efficiency is 98 %. Like the converter, the used proton exchange membrane (PEM) electrolyzer also has a varying efficiency depending on the input power. Maximum efficiency of 62 % is reached at 30 % of nominal power and 54 % at nominal power. For the needed water input seawater is desalinated using osmosis.
The economic and technical specifications of the water system and the electrolyzer are shown in Tab. 1. Markup and installation costs have to be paid every time an electrolyzer is installed and the balance of plant costs only for the first installation. The CAPEX and OPEX of the converter are included in those of the electrolyzer.

2.2.3 Methanation

Hydrogen is methanised using the catalytic Sabatier reaction [11] with CO_2 as shown below:

$$CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O + Q \qquad (1)$$

The highly exothermic reaction results in thermal losses of 17 % of input energy leading to maximum energetic efficiency of 83 % (LHV). The minimum input of CO_2 is 2.743 kg_{CO2} per kg_{CH4}.
The economic and technical specifications for the different scenarios are shown in Tab. 1.

2.2.4 CO_2 system

There are different ways for capturing CO_2 like from CO_2 rich flue gas using amine scrubbing, carbon capture and utilization at biomass power plants [12] or from ambient air using direct air capture (DAC). For this study, the DAC is chosen, because it can be used independently from the chosen location. The DACs

Table 1. Techno-economic specifications of SNG production

	Optimistic		Pessimistic		Sources
	2030	**2040**	**2030**	**2040**	
PV power plant					
CAPEX [€$/MW$]	550 000	440 000	550 000	440 000	[31], [32]
OPEX [€$/(MW \cdot a)$]	4 800	4 800	4 800	4 800	[31], [32]
Lifetime [a]	20	20	20	20	[31], [32]
Wind power plant					
CAPEX [€$/MW$]	1 226 000	868 000	1 226 000	868 000	[33]
OPEX [€$/(MW \cdot a)$]	42 500	42 500	42 500	42 500	[33]
Lifetime [a]	20	20	20	20	[33]
Electrolyzer					
CAPEX [€$/MW$]	158 450	155 550	158 450	155 550	[a]
OPEX [€$/(MW \cdot a)$]	9 000	8 000	9 000	8 000	[a]
Markup and installation [€$/MW$]	455 670	419 280.5	455 670	419 280.5	[a]
Balance of plant [€$/(MW \cdot a)$]	302 865	262 190	302 865	262 190	[a]
Lifetime [h]	60 000	60 000	60 000	60 000	[a]
Water consumption [l/kg_{H_2}]	9	9	9	9	[a]
Water system					
CAPEX [€$/(m^3 \cdot d)$]	725	415	725	415	[34]
OPEX [€$/(m^3 \cdot d)$]	33	17	33	17	[34]
Auxiliary power [MWh/m^3]	0.0036	0.0026	0.0036	0.0026	[34]
Lifetime [a]	30	30	30	30	[34]
Methanation					
CAPEX [€$/MW_{SNG}$]	175 000	145 000	870 000	655 000	[35], [36]
OPEX [% of CAPEX p.a.]	3	3	4	4	[37], [11]
El. energy [MWh/MWh_{SNG}]	0.013	0.013	0.013	0.013	[35]
CO_2 demand [kg/kg_{SNG}]	2.75	2.75	2.949	2.949	[11], [38]
Efficiency (LHV) [%][b]	83	83	78	78	[11], [38]
Lifetime [a]	30	30	20	20	[11], [37]
Direct air capture					
CAPEX [€$/kg_{CO2}/h$]	3 329	2 321	6 701	5 606	[39], [40]
OPEX [% of CAPEX p.a.]	4	4	5	5	[39], [40]
El. energy [MWh/t_{CO2}]	0.23	0.2	0.78	0.66	[5], [39], [29]
Lifetime [a]	30	30	20	20	[39], [40]
CO_2 liquefaction					
CAPEX [€$/kg_{CO2}/h$]	34.2	34.2	86.4	86.4	[41], [42]
OPEX [% of CAPEX p.a.]	5	5	6	6	[41], [42]
Lifetime [a]	25	25	25	25	[11]
Efficiency [%]	100	100	100	100	[11]
El. energy [MWh/t_{CO2}]	0.123	0.123	0.123	0.123	[42]
CO_2 storage					
CAPEX [€$/kg_{CO2}$]	1.35	1.35	2.528	2.528	[42], [11]
OPEX [% of CAPEX p.a.]	1	1	5	5	[42], [11]
Lifetime [a]	25	25	25	25	[11]
Losses [$\%/d$]	0	0	0	0	[11]

[a]Data from different sources was averaged ([34], [43], [44], [45], [46], [47], [48], [49]), [b]It is assumed that the efficiency is constant for varying load

thermal energy demand is fully covered by the thermal output streams of the electrolyzer and methanation [12]. It is further assumed that the DAC is using its full capturing capacity and stores residual CO_2 in a liquefied state. If the CO_2 demand of methanation exceeds the captured amount, CO_2 gets regasified from storage to meet the needs. When the storage is close to full or the generated electric energy is lower than the needed auxiliary power of the DAC, the DAC is shut off.
The economic and technical specifications of the CO_2 system are shown in Tab. 1.

2.2.5 *Gaseous transport via pipeline*

The SNG produced in Tunisia is transported to Austria in its gaseous state. Therefore, it is compressed and sent to a connection hub via a dedicated pipeline with a length of 100 km. It is assumed that the pipeline is connected to the Trans Mediterranean Pipeline which connects Algeria and the mainland of Italy in Mazara del Vallo over Tunisia and Sicily. From there it is transported over the gas grid of Snam Rete Gas to Austria, Arnoldstein.
The economic and technical specifications of the compressor and newly built pipeline are shown in Tab. 2. The transportation costs over the Trans Mediterranean Pipeline are 4.292 $€/month/m^3/h$ for the section operated by TTPC [13] and 2.2275 $€/month/m^3/h$ for the section operated by TPMC [14]. Snam Rete Gas takes an entry charge of 3.208491 $€/a/m^3/d$, an exit charge of 3.265130 $€/a/m^3/d$ and a commodity charge of 0.006992 $€/m^3$ [15]. For the entry to Austria, Arnoldstein Trans Austrian Gasleitung (TAG) charges a capacity-based entry fee of 0.97 $€/kWh/h/a$ and a quantity-based entry fee of 0.08552 $€/MWh$ [16].

2.2.6 *Liquid transport via ship*

Due to the higher distance to Austria, the produced methane from Chile and the UAE is imported to Europe by ship in its liquefied state. Therefore, it is first transported to an export terminal in its gaseous state over a newly built methane pipeline. Like in Tunisia the length is again assumed to be 100 km.
At the export terminal, the incoming methane is liquefied and stored in tanks. In these tanks, the liquefied SNG (LSNG) evaporates continuously due to solar irradiation and the ambient temperature at the outer hull (boil-off). This would lead to an increasing pressure in the tanks and therefore the gaseous SNG has to be extracted from storage and processed. The boil-off gas could be re-liquefied and stored again [17], but in this study, it is taken into account as losses. The capacity of the storage tanks of the export terminal is assumed to be the same size as that of the ships.
LNG tankers which take the SNG as fuel for propulsion [18] are used for transport at sea. Additionally to the boil-off gas extracted from the ship's storage tanks, SNG has to be regasified to cover the needs for propulsion. For 2030 a tanker with a capacity of 40 000 m^3 and for 2040 with 90 000 m^3 was assumed which is rather small compared to the most delivered vessel capacity of 170 000 to 180 000 m^3 in 2021 [7]. For the shipping route from Chile a LNG export terminal in Punto Arenas, Chile is assumed from where the LNG tanker travels to an import terminal in Rotterdam, Netherlands. Therefore, the one-way shipping distance is 13 800 km. For export from the UAE a LNG export terminal in Abu Dhabi, UAE and an import terminal in Ravenna, Italy were assumed which resulted in a one-way shipping distance of 7 800 km.
At the import terminal, the LSNG is unloaded and stored again. The capacity of the storage tanks of the import terminal is the same as the unloaded capacity from the ships. The LSNG is then regasified and fed into the European gas grid. Then the gaseous SNG is transported to Austria using the European gas grid. The breakdown of the costs for the gas grid for both import routes using ships is listed below while the rest of the economic and technical specifications are listed in Tab. 2.

Import from Chile. As the import terminal for the route deriving from Chile is located in Rotterdam a nearby LNG terminal is taken as a reference. The exit fee of Fluxys LNG Terminal Zeebrugge is 0.623 $€/(kWh/h)/a$ [19]. The entry fee for Gasuine TS is 2.69912298 $€/(kWh/h)/a$ and for exiting 2.73606763 $€/(kWh/h)/a$ [20]. Open Grid Europe entry and exit fee are 4.82 $€/(kWh/h)/a$ [21] while the entry fee for Gas Connect Austria is 0.1963 $€/MWh$ [22].

Import from the UAE. The import terminal for transport from the UAE is located in Ravenna, Italy. Therefore, export costs of the nearby LNG terminal Porto Levante Cavarzere, Adriatic LNG are taken as representative with 0.965054 $€/a/m^3/d$ [23]. From there the import costs to Snam Rete Gas are 0.965054 $€/a/m^3/d$ [15]. The rest of the costs are the same as in section Gaseous transport via pipeline, beginning with export costs to Snam Rete Gas.

2.3. *Cost calculation*

The cost calculation was divided into two different parts. First, the project-related costs for producing SNG were calculated in a simulation using hourly resolution over a total period of 20 years. The components for producing SNG are the RES, electrolyzer, water system, methanation and the CO_2 system components. Auxiliary power of these components is covered by the RES. AITs TESCA framework was used and adapted for this specific use case.
As it was assumed that transportation is used by more than just one project, the costs were calculated for a combined transport of SNG of 250 MW in 2030 and 500 MW in 2040.
The components along the transportation route can not be fed with electric energy from the RES. Therefore, an

Table 2. Techno-economic specifications of SNG transport

	Optimistic		Pessimistic		Sources
	2030	**2040**	**2030**	**2040**	
Pipeline compressor					
CAPEX [€$/MW$]	1 499	1 499	1 499	1 499	[11]
OPEX [% of CAPEX p.a.]	2	2	2	2	[11]
Lifetime [a]	20	20	20	20	[11]
Losses [%]	0	0	0	0	[11]
Energy demand [% of input energy]	3	3	3	3	[11]
Pipeline					
CAPEX [€$/MW/km$]	79	79	79	79	[11]
OPEX [% of CAPEX p.a.]	1.5	1.5	1.5	1.5	[11]
Lifetime [a]	50	50	50	50	[11]
Energy demand [% of input energy/1000km]	3	3	3	3	[11]
Liquefaction					
CAPEX [€$/MW_{LSNG}$]	470 000	440 000	975 000	920 000	[18], [50], [51],
OPEX [% of CAPEX p.a.]	3.5	3.5	3.5	3.5	[52]
El. energy [MWh/t_{LSNG}]	0.25	0.25	0.5	0.5	[28], [11]
Efficiency [%]	92	95	90	92	[52], [28], [18]
Utilisation [%]	90	90	90	90	a
Lifetime [a]	25	25	25	25	[52]
Regasification					
CAPEX [€$/MW_{LSNG}$]	55 000	35 000	105 000	75 000	[53], [54], [55]
OPEX [% of CAPEX p.a.]	2.5	2.5	3.5	3.5	[52], [54]
El. energy [MWh/t_{LSNG}]	0.00456	0.00456	0.01053	0.01053	[56], [57]
Efficiency [%]	98.5	98.5	97.5	97.5	[52], [54]
Utilisation [%]	90	90	90	90	a
Lifetime [a]	30	30	30	30	[40], [58]
LSNG storage					
CAPEX [€$/t_{LSNG}$]	620	620	2 080	2 080	[11], [59]
OPEX [% of CAPEX p.a.]	2	2	2	2	[11]
El. energy [MWh/t_{LSNG}]	0.61	0.61	0.61	0.61	[60]
Losses [$\%/d$]	0.08	0.08	0.15	0.15	[28]
Lifetime [a]	20	20	20	20	[11]
Jetty and pipes					
CAPEX [Mio. €][b]	114.1	114.1	114.1	114.1	[61]
OPEX [% of CAPEX p.a.]	4	4	4	4	[35]
Lifetime [a]	30	30	30	30	[35]
LSNG carrier					
CAPEX [€$/m^3$]	1 332.5	1 065.6	1 628.7	1 302.4	c
OPEX [% of CAPEX p.a.]	3.5	3.5	5	5	[52], [62]
loading/unloading time [d]	1	1	1	1	a
Fuel consumption [MJ/km]	2 218.3	2 052.0	2 400.2	2 814.4	d
Speed [km/h]	30	30	30	30	a
Losses [$\%/d$]	0.08	0.08	0.15	0.15	[28]
Lifetime [a]	25	25	25	25	[52]

[a] Own assumption, [b] For a LNG terminal with a capacity of 3Mtpa, [c] Based on different sources [52], [63], [64], [7], [65] $\pm$10% for optimistic/pessimistic, [d] Based on [62] $\pm$10% for optimistic/pessimistic

electricity price independent of the location of consumption was assumed to be 80 $€/MWh$ in the optimistic scenario and 120 $€/MWh$ in the pessimistic [24], [25], [26], [27].
The weighted average costs of capital (WACC) represent the risk of a project as well as the profit expectation of investors. For the optimistic scenarios, it was assumed with 6 % p.a. and 12 % p.a. for the pessimistic scenario.

2.3.1 SNG production

In the first step of the simulation the ideal values for nominal power and capacity of the RES, hydrogen system, CO_2 system and methanation were determined. Therefore, the wind and PV profiles were taken as input in hourly resolution and their maximum power was scaled by 25 MW steps while the sum of both was fixed to 250 MW. For each of these steps, the nominal power of the electrolyser was also varied from 25 to 250 MW in 25 MW steps. Output power of the RES exceeding the sum of the nominal power of the electrolyser and the needed auxiliary power is curtailed, meaning that the surplus power is not stored for further use or fed into the local grid. The ideal parameters were defined by the minimal levelized costs of hydrogen (LCOH) which are calculated by the general equation of levelized costs of energy (LCOE) which can be seen in (2).

$$LCOE = \frac{I_0 + \sum_{t=1}^{N} \frac{CAPEX_t + OPEX_t - v_{res,t}}{(1+WACC)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+WACC)^t}} \tag{2}$$

With this equation, the values of the capital expenditures (CAPEX) and operational expenditures (OPEX) are discounted with the $WACC$ levelized over the total discounted amount of energy E produced in the observation period. I_0 is the initial investment and $v_{res,t}$ stands for the residual value of the components at the end of the observation period N which was set to 20 years in this study.
After the ideal parameters of the RES and hydrogen system were found and fixed, the same strategy was used for the parameters of the CO_2 system and methanation. Therefore, the nominal input power of methanation was increased to a maximum power of 150 MW in 10 % steps and for each of these steps the output capacity of the DAC was also varied up to 20 000 kg/h. The liquefaction capacity was fixed to the one of the DAC. CO_2 storage's capacity was increased in 25 000 kg steps. If the maximum input power of methanation is exceeded, the RES output is curtailed. This is also the case if there is not enough CO_2 available from the DAC and CO_2 storage for methanation. Again the ideal parameters of the components above were determined by the minimal levelized costs of SNG ($LCOE_{SNG}$) with Equation (2).

2.3.2 Transport

For the specific direct costs of each component in transport the CAPEX and the net present values (NPV) for all recurrent expenditures are summed up and divided by the NPV of the input energy. The general formula for the NPV is shown in (3) where X_t could be a cost component or input energy and T is the lifetime of the component.

$$NPV = \sum_{t=0}^{T} \frac{X_t}{(1+WACC)^t} \tag{3}$$

For the representation of the costs due to efficiency η_n of a component n the indirect costs are calculated with (4) where $c_{cum,n}$ are the cumulative costs of the value chain up to the component n.

$$c_{ind,n} = c_{cum,n-1} \cdot \left(\frac{1}{\eta_n} - 1\right) \tag{4}$$

3. RESULTS

3.1. $LCOE_{SNG}$ in Austria

For the overseas transportation of SNG the components liquefaction, storage and carrier have high uncertainties in their economical and technical assumptions while there are none for the gaseous transport. Therefore, the spread of the $LCOE_{SNG}$ of the imported SNG is bigger for production in Chile and UAE. The final $LCOE_{SNG}$ in Austria are lowest for imported SNG from Tunisia with 140 - 271 €/MWh, followed by the one from Chile with 150 - 356 €/MWh and is most expensive from the UAE with 183 - 420€/MWh. The overview of the costs for all scenarios is displayed in Fig. 2 next to the $LCOE_{SNG}$ at the production site.

3.2. Imported SNG over lifetime

As the nominal power of the converters in methanation and also the FLH of the conversion components are the highest in Chile also the imported energy to Austria over a time of 20 years is the highest with 8 to 10.7 TWh. Even though the produced amount of SNG in the UAE is higher, the total imported energy is in the same range as the one from Tunisia. Both are between 4.9 - 5.8 TWh and therefore are roughly half of the amount from Chile.

3.3. SNG production

As the SNG production was simulated in time steps of one hour for 20 years the conversion steps have not been fully utilized. The optimal nominal input power of the converter was below the maximum power generated by the combined wind and PV power plant. The nominal input power of the converter in Chile is higher than for the UAE and Tunisia. This is because of the higher share of wind power in Chile which is less volatile than the profile of PV generation.

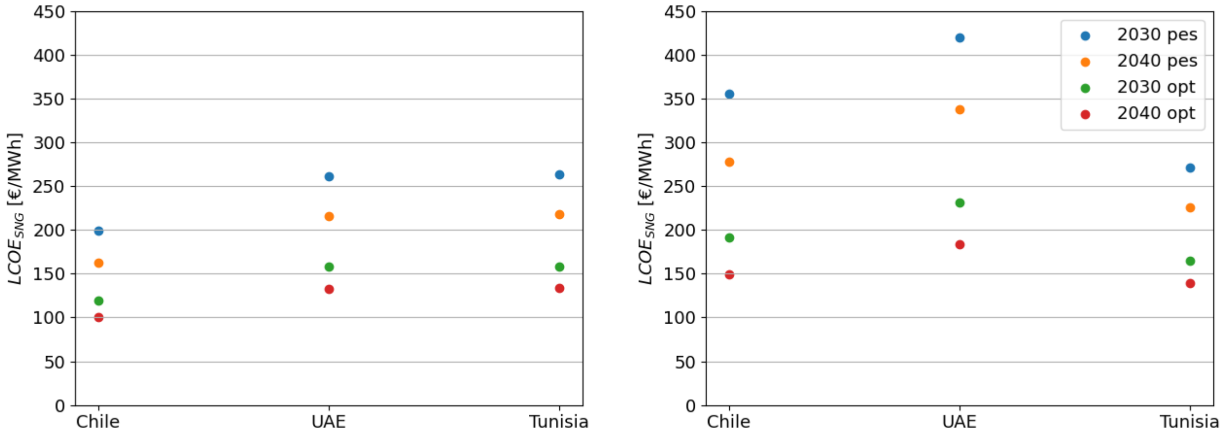

Figure 2 Comparison of the $LCOE_{SNG}$ before (left) and after transportation (right)

Also due to the higher volatility of the PV plants generation, the FLH of the converter, electrolyzer, methanation, and DAC are higher in Chile. While the FLH of the electrolyzer and methanation are 5 900 - 6 700 h/a in Chile they are between 4 500 and 5 300 h/a in the UAE and Tunisia. In Chile, the operating time per year of the DAC is 8 000 - 8 650 h/a, in the UAE 6 500 - 6 700 h/a, and Tunisia 7 000 - 7 350 h/a.

As the lifetime of the electrolyzer was given in FLH, the replacement in Chile has to take place earlier than for the UAE or Tunisia. In Chile, it has to be exchanged every 6 years according to the simulation. In the UAE it has to be renewed every 6 to 7 years and in Tunisia every 7 to 8 years.

Because of the highest nominal power of the electrolyzer and the overall highest FLH in Chile also the nominal power of the DAC is the biggest which results in an average captured mass of CO_2 by the DAC of 113 - 121 kt/a depending on the year of first invest and the scenario. For the UAE it is lower at around 66 kt/a and in Tunisia between 56 and 59 kt/a.

The wide range of the optimistic and pessimistic parameters for methanation and the components of the CO_2 system leads to an increase of the levelized costs of the SNG system by a factor between 2.1 and 2.4, while the levelized costs of the RES and the H2 system only increase by a factor of about 1.3. The decrease of the costs from 2030 to 2040 is between 20 - 25 % for the RES, 12 - 15 % for the H2 system, and 15 - 20 % for the SNG system.

As can be seen in Fig. 2 the lowest $LCOE_{SNG}$ prior transportation are reached in Chile due to the lower volatility in generation by the RES and therefore the highest FLH of the components. For the optimistic scenario with the first investment in 2040, they are the lowest with approximately 100 €/MWh and highest in the pessimistic scenario 2030 with around 200 €/MWh. In the UAE and Tunisia the production costs for SNG range between 130 €/MWh (opt. 2040) and 265 €/MWh (pes. 2030).

These $LCOE_{SNG}$ at the production site can be broken down in relative share of CAPEX and OPEX. The share of the CAPEX for all three countries is rather constant with 78 - 83 % for all years of first investment and the optimistic and pessimistic cost assumptions.

3.4. SNG transportation

Even though the production costs are minimal for Chile, the overall $LCOE_{SNG}$ exceed the ones of the imported SNG from Tunisia. On the one hand side, transportation via pipeline requires less technology along the route which results in less costs. On the other hand side, transportation via ship results in higher losses due to boil-off from the storage tanks, forced boil-off for propulsion, and efficiency losses in liquefaction and regasification.

The increase of the costs for the pipelines in the export countries between the optimistic and pessimistic scenarios is rather small with a factor of 1.2 to 1.3, followed by shipping with 1.7 - 1.9, regasification between 2.2 - 2.3, storage between 2.7 - 2.8 and finally liquefaction with an increase of 2.5 - 2.9. The reason for the relatively high cost increase of regasification and liquefaction is the higher CAPEX, while the storage additionally has to deal with a greater boil-off rate.

Compared to the first investment in 2030 the costs for the storage for 2040 are more or less constant. Costs for regasification decrease roughly by 17 - 18 % and for liquefaction by 20 - 33 %. The highest reduction can be seen for shipping, where for the first investment in 2040 the costs are about 43 - 48 % of the ones for 2030. In this comparison, shipping combines the costs of the LSNG carrier and berthing (Jetty + pipes) while pipeline combines all pipelines and pipeline compressors along the route. The higher reduction in costs for shipping is due to bigger vessel sizes in 2040 and therefore lower specific costs.

Like for the production site the costs can again be broken down into different components, but in the case of transportation additionally to CAPEX and OPEX, electricity costs and the costs for the preexisting natural gas (NG) pipeline grid in Europe have to be taken into account. This is because the electricity produced by the RES can not be used along the transportation route and the characteristic of the NG pipeline costs can not be classified as CAPEX or OPEX. For import from Chile and the UAE, the CAPEX make approximately 30 % of the overall transportation costs in the optimistic scenarios and increase to a share of 48 % in the pessimistic scenarios. The OPEX is rather constant for both the optimistic and pessimistic scenarios with 11 to 13 %. Electricity costs have the biggest share with 37 - 38 % in the pessimistic and 48 - 50 % in the optimistic scenarios. Therefore, the NG pipeline costs are approximately only 3 % in the pessimistic and 7 to 8 % in the optimistic scenarios. In case of import from Tunisia, the share of CAPEX and OPEX is more or less negligible at around 2 % and even less than 1 % for the latter. Electricity costs are 43 % in the optimistic scenarios and 52 % in the pessimistic scenarios. This high share of electricity costs is due to the also small costs for transportation over the natural gas grid.

3.5. *Total efficiency and cumulative costs*

In Fig. 3 the total efficiency along the production chain for the cheapest (2040 opt.) and most expensive (2030 pes.) scenarios are shown. Here it can be seen that the highest losses are at the electrolysis step with an overall efficiency of 55 - 57 %. The boil-off losses of the storage at the import and export terminal are between 2 % in the optimistic scenarios and 4 % in the pessimistic scenarios. For propulsion of the carriers from Punto Arenas, Chile to Rotterdam, Netherlands 3 - 7.2 % of the transported LSNG are regasified and from Abu Dhabi, UAE to Ravenna, Italy 1.7 - 4.1 %. For SNG imported from Tunisia losses only occur due to production. The total efficiency of the whole route from Tunisia is 41 - 42 % and 33 - 39 % for Chile and the UAE.
In Fig. 4 the cumulative costs after each element down the whole production and transportation chain are displayed. As already mentioned above, the generation of electricity and therefore SNG is most expensive in Tunisia and the UAE. But in the case of import from Tunisia, transportation costs are so small, that its overall $LCOE_{SNG}$ in Austria are the lowest in every scenario.

4. DISCUSSION

4.1. *Potentials for lowering $LCOE_{SNG}$*

As the nominal power of the electrolyzer is lower than the peak power of the RES there are different possibilities to use the excess energy of peak generation which was not used for direct electrolysis. One way is to directly inject the surplus energy into the grid and therefore monetize it, but for this strategy, a connection to the local grid is needed. Another solution would be to store the energy by using a battery and electrolyze it in times of less generation.
While liquefying SNG, thermal energy is generated as a byproduct, which could be used or monetized. In the case of regasification of LSNG cold energy is released and could be used for cryogenic air separation, seawater desalination, and refrigeration and cooling in the food industry and commercial sector [28].
In this study, the boil-off gas of the LSNG storage was considered as losses. Usual import and export terminals use boil-off gas re-liquefaction which reduces the losses of the highly potent greenhouse gas. Therefore, the indirect costs of storage would be minimized.

4.2. *Barriers*

As already mentioned in the introduction, one key problem in the methanation of electric energy on a big scale is that there are no active projects comparable. Also, the total installed capture capacity of DACs in the world exceeds the average capture capacities of this study, but in the Net Zero Emissions by 2050 scenario it is assumed that 350 Mt/a of air captured CO_2 is used to produce synthetic fuels in 2050 [29].

4.3. *Import price of SNG*

In this study, the minimal price for imported SNG was approximately 140 €/MWh, when the methanation takes place in Tunisia and it is further transported to Austria via pipeline. For comparison, the import price of natural gas was 108.47 €/MWh in December 2022 according to E-Control [30], which makes the SNG from RES only 30 €/MWh more expensive. Compared to the import price of January 2022 (before the Russian-Ukrainian war) the lowest $LCOE_{SNG}$ are approximately 50 €/MWh higher. But in difference to natural gas, the overall CO_2 emissions are low which could make it more profitable in the future due to increasing CO_2 taxes. Therefore, the import of SNG from green electricity is technically and economically feasible.

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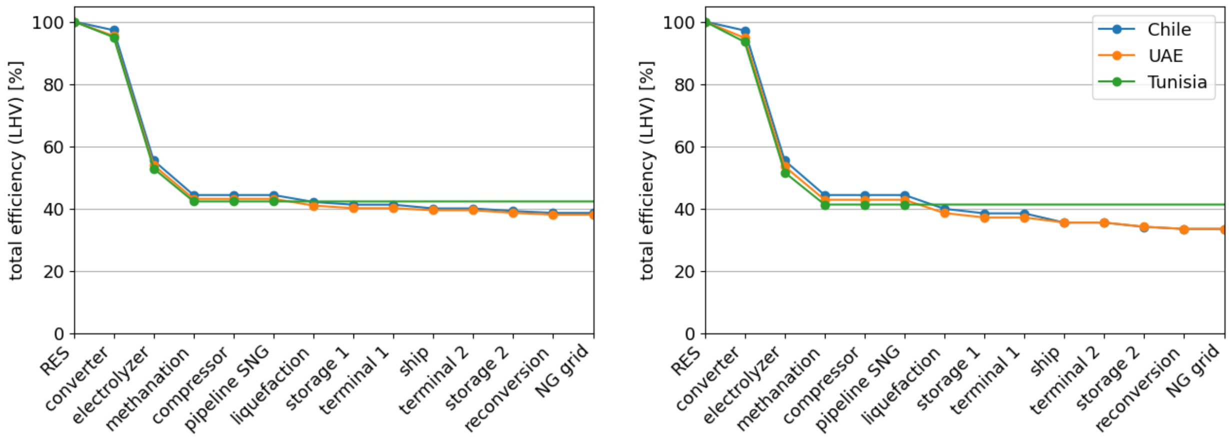

Figure 3 Total efficiency (LHV) down the total production and import route for the least (left) and most (right) expensive scenario

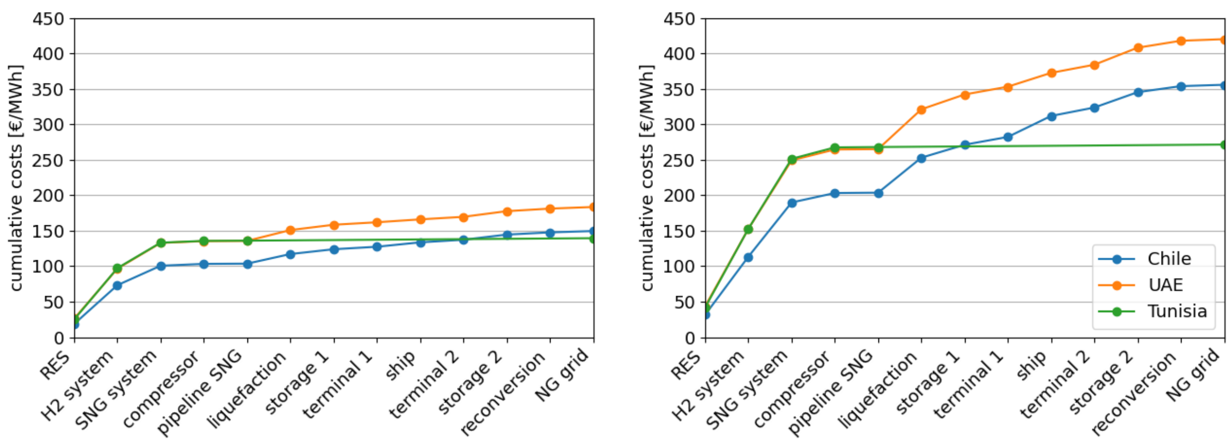

Figure 4 Cumulative costs down the total production and import route for the least (left) and most (right) expensive scenario

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