Analysis of alternative electricity supply pathways for a synthetic MENA country in light of the COVID 19-pandemic

Summary of Results

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1. Study Background

Over the course of 2018 and 2019, the project DIAPOL-CE, implemented by Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) on behalf of the German Federal Ministry for the Environment, Nature Conservation, Nuclear Safety and Consumer Protection (BMUV), commissioned Guidehouse Germany GmbH (formerly known as Navigant Energy Germany GmbH) to carry out a study on plans for the expansion of coal-fired power generation in selected countries of the MENA region.[1] In addition, several scenarios – with and without coal and various options for renewable energy (RE) targets – were modelled for a synthetic, i.e. abstract, country in the MENA region.

With the start of the COVID-19 pandemic and its influence on the global economy, long-term investment decisions and energy strategies were put into question. The potential impact of the pandemic on the future energy mix of a synthetic oil- and gas-importing country in the MENA region were analyzed in the context of a first sensitivity analysis in 2020 based on the original study. Now, over two years after the beginning of the COVID-19-pandemic, there is better information available on the consequences of the crisis. Economic recovery has been faster than expected in many regions of the world. In addition, hydrogen as a new technology has come into focus in recent years with particular importance as a flexible energy carrier for the energy transition and for the MENA region with potential exporting countries. This new information and developments led to the commissioning of another set of sensitivity analyses which are presented in this summary.

2. Introduction

Oil and gas producing countries in the MENA region are not only affected by climate change, but also by global mitigation measures. As their economies are heavily dependent on fossil resources, the economic development of MENA countries is particularly exposed to the high volatility of gas and oil prices in the short term and under increasing pressure due to the global efforts to decarbonize the energy sector in the long term. The impact of this dependence was revealed in 2020 when the MENA region was faced with a dual shock from the COVID-19 pandemic and a collapse in oil and gas prices.[2] Despite historically high gas prices at the end of 2021 due to a faster-than-expected economic recovery, long-term forecasts continue to predict that fossil fuel prices will decline through 2050.[3,4] At the same time, the region has excellent wind and solar resources. In combination with decreasing investment costs for solar systems and wind turbines, renewable energies could play a crucial role in the future electricity mix of these MENA countries and help them remain global energy suppliers, albeit of non-conventional energy in the form of hydrogen.

[1] **Navigant (2020):** The role of coal in the energy mix of MENA countries and alternative pathways. Available at: https://www.giz.de/en/downloads/GIZ_2020_Role-of-coal-in-energy-mix-of-MENA-countries.pdf

[2] **Arezki, Nguyen (2020):** Coping with a Dual Shock: COVID-19 and Oil Prices. Available at: https://www.worldbank.org/en/region/mena/brief/coping-with-a-dual-shock-coronavirus-covid-19-and-oil-prices

[3] **IEA (2021):** World Energy Outlook 2021. Available at: https://iea.blob.core.windows.net/assets/4ed140c1-c3f3-4fd9-acae-789a4e14a23c/WorldEnergyOutlook2021.pdf

[4] Gas price spikes in 2022 due to the current political developments are not reflected in the assumptions for this study. It can be assumed that today’s developments will have a decisive impact on long-term energy strategies, especially in Europe, also with implications for demand of energy carriers from the MENA region.

Against the background of these developments, the study aims at answering the following main research questions:

- How competitive are renewable energies and what is their future relevance in the electricity mix of an oil and gas exporting country under the assumption of different gas price paths?

In addition, the following sub-questions should be addressed:

- **Sub-question 1**: What is the impact of assuming higher grid connection costs for renewable energies?

- **Sub-question 2**: What is the impact of assuming an increasing hydrogen production due to a rising domestic demand and new export opportunities?

By answering these questions, the study provides a factual basis for discussions on long-term energy scenarios in the MENA region and formulates recommendations for decision-makers.

Study approach

The study compares system costs and emissions of alternative electricity supply pathways under different scenarios and sensitivities. To identify cost efficient and reliable generation expansion pathways for sustainable electricity supply, Guidehouse's capacity expansion model PowerFys Invest is used. The capacity cost optimization model determines the least-cost expansion plan for a power system required to meet future electricity demand in a reliable manner. Subject of the study is a synthetic, yet very representative, power system of the MENA region and a time frame from 2020 to 2050 is considered. In total, three different scenarios and eight sensitivities are modeled.

The scenarios are based on selected scenarios from the previous study[5]:

Scenario 2: No renewable energies (RE) targets are in place and the addition of coal-fired plants is allowed as an option for meeting increasing electricity demand

- Sensitivity 2.2: Fuel prices are adjusted assuming a "mild gas price recovery" scenario
- Sensitivity 2.2a: Fuel prices are adjusted assuming a "fast gas price recovery" scenario
- Sensitivity 2.2b: Fuel prices are adjusted assuming a "fast gas price recovery" scenario and grid connection costs are taken into account with higher grid connection costs for RE

Scenario 5: As Scenario 2 and a CO_2 price of 45 USD/tCO_2 is introduced in 2035 and remains constant until 2050

- Sensitivity 5.1: Fuel prices are adjusted assuming a "mild gas price recovery" scenario
- Sensitivity 5.1a: Fuel prices are adjusted assuming a "fast gas price recovery" scenario

[5] **Navigant (2020):** The role of coal in the energy mix of MENA countries and alternative pathways. Available at: https://www.giz.de/en/downloads/GIZ_2020_Role-of-coal-in-energy-mix-of-MENA-countries.pdf

Scenario 11: As Scenario 2 but a CO_2 price of 25 USD/tCO_2 is introduced in 2025, increasing linearly to 75 USD/tCO_2 by 2050

- Sensitivity 11.1: Fuel prices are adjusted assuming a "mild gas price recovery" scenario
- Sensitivity 11.1a: Fuel prices are adjusted assuming a "fast gas price recovery" scenario
- Sensitivity 11.1b: Fuel prices are adjusted assuming a "fast gas price recovery" scenario, grid connection costs are taken into account and assumptions on energy demand include the production of hydrogen for export as well as domestic uses

The modeling was built primarily on the data basis used in Navigant (2020). However, the analyses of fossil fuel price developments over the last years, developments in electricity demand in the MENA region and studies on the impact of COVID-19 on the energy transformation led to updated assumptions for electricity demand and fossil fuel prices. The CAPEX of renewable and battery storage has also been adjusted to reflect updated knowledge. In summary the following changes have been made compared to the assumptions in Navigant (2020) reflecting new developments:

- **Electricity demand growth rates**: lower average growth rates in the time frame 2020-2024 for the modelled synthetic oil/gas exporting country

- **Natural gas and coal prices:** slightly lower coal prices over the entire planning time frame 2020-2050, significantly lower gas prices in the "mild gas price recovery" scenario, and still overall lower, but rapidly recovering gas prices in the "fast gas price recovery" scenario

- **CAPEX cost**: significantly lower CAPEX of photovoltaic (PV), slightly lower CAPEX of wind and battery energy storage

In order to incorporate Sensitivity 2.2b and 11.1b, the data basis was extended with assumptions on grid connection costs, hydrogen demand (considering domestic demand and export), cost parameters for electrolyzer cost parameters for hydrogen storage (salt caverns) and cost parameters for hydrogen ready gas turbines. To model the hydrogen demand, a dedicated demand time-series for hydrogen is considered. In the model, produced hydrogen can be stored and re-electrified, thus serving as a bulk storage technology to integrate volatile RE. It is set as constraint that demand for hydrogen outside the power sector needs to be met by additional RE capacity. Investments in hydrogen storage are not restricted in the model.

The detailed data assumptions can be found in the Appendix.

3. Modeling Results

3.1 Future relevance of renewable energies under the assumption of different gas price paths

Gas prices determine the role of renewables and coal in the energy mix

Figure 1 presents the annual electricity generation of the two modelled sensitivities 2.2a (fast gas price recovery path) and 2.2 (mild gas price recovery path). These are the results for the Scenario 2, where no RE deployment targets are set, and the model is allowed to invest in coal-fired power plants (although this does not happen due to coal not being competitive with gas).

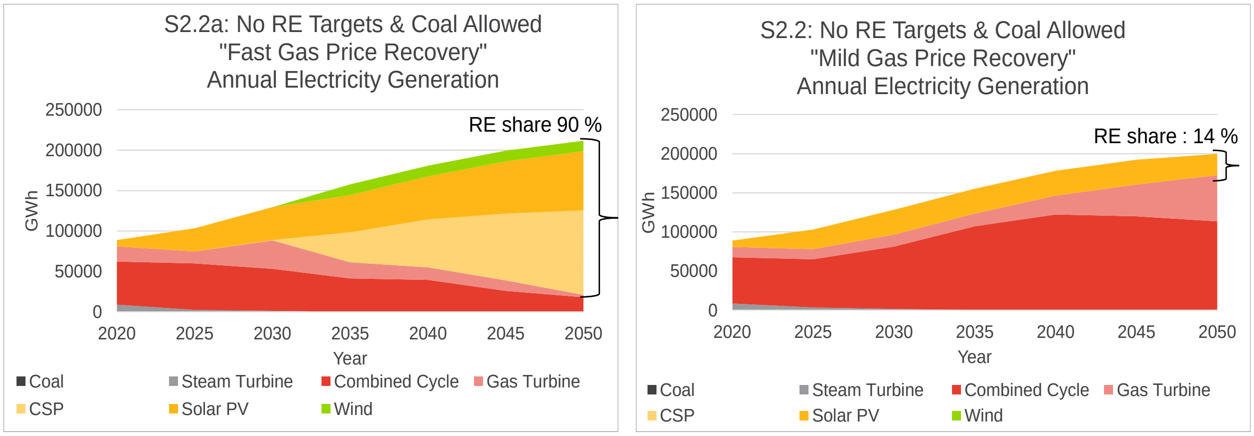


Figure 1: Annual electricity generation by technology over the planning time frame for Sensitivity 2.2a (left) and Sensitivity 2.2 (right).

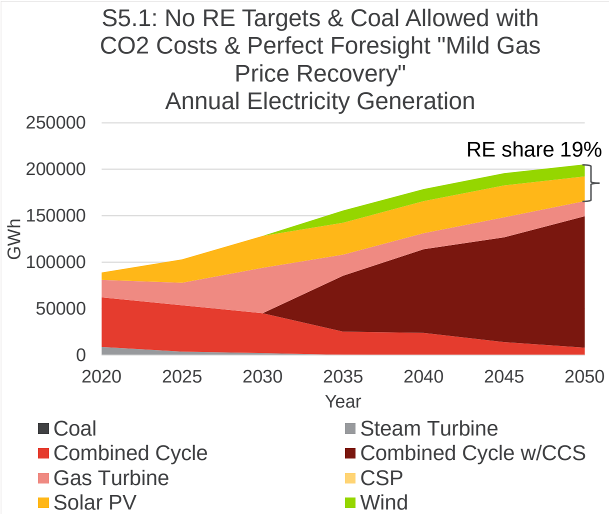
- **No investments in coal-fired plants:** In both gas price development paths, the lower gas price and lower CAPEX, especially of PV plants, lead to the absence of investments in coal plants despite the assumption of lower coal prices. This can also be explained by the cost structure of coal-fired power plants. Since these plants are very CAPEX-intensive, lower fuel prices have less impact than on the investment decision in gas-fired power plants. In addition, the assumed lower electricity demand from 2020-2024 leads to a decrease in demand for base load power plants.

- **Low gas prices lead to large-scale investments in gas-fired power plants:** With low gas prices, gas-fired power plants account for 75% of total net installed capacity in 2050. The demand for electricity is mainly met by combined cycle gas turbines. The share of RE in annual electricity generation in 2050 is only 14% (right side of Figure 1).

- **Higher gas prices lead to a high share of RE by 2050:** With higher and more rapidly rising gas prices, the model invests increasengly in PV systems from 2020. From 2030, concentrated solar power (CSP) plants equipped with 10-hour storage increasingly replace the flexible capacity of gas-fired power plants. The share of RE reaches 90% of annual electricity generation in 2050 (left side of Figure 1). This share is provided by 21 GW of CSP, 30 GW of PV and 5 GW of wind power plants.

With low gas prices, the introduction of CO_2 prices does not induce a shift in investment to renewable energies

In scenario 5, a CO_2 price of 45 USD/tCO_2 is introduced in 2035 and remains constant until 2050. In scenario 11, a CO_2 price of 25 USD/tCO_2 is introduced in 2025, increasing linearly to 75 USD/tCO_2 by 2050. Figure 2 shows the impact of the CO_2 price in both scenarios on the annual electricity generation when a mild gas price recovery path is assumed:



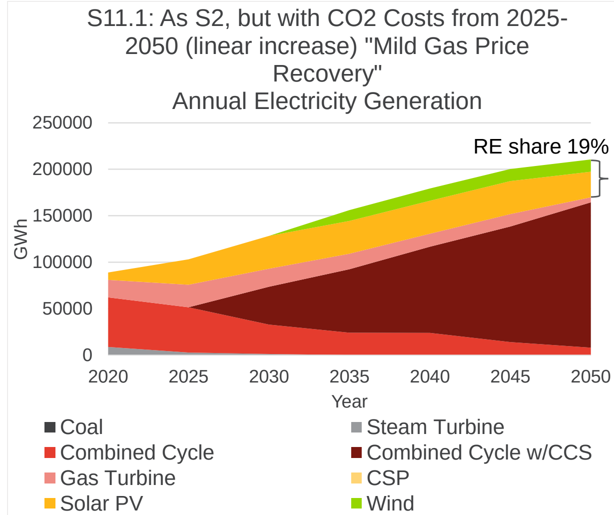


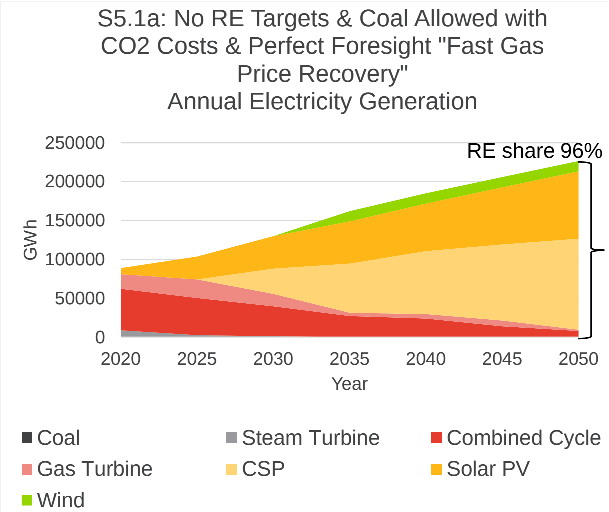
Figure 2: Annual electricity generation by technology over the planning time frame for Sensitivity 5.1 (left) and Sensitivity 11.1 (right) with a mild gas price recovery path.

- **CO_2 price incentivizes investments in carbon capture and storage (CCS):** Once a CO_2 price of 45 USD/tCO_2 is introduced in 2025 in Senstivity 5.1 and the CO_2 price reaches 35 USD/tCO_2 in 2030 in Sensitivity 11.1, the model invests in combined cycle gas turbines with CCS. The introduction of a CO_2 price also results in flexible capacity in the power system not being provided exclusively by gas-fired power plants. In both sensitivities, storage capacity is additionally provided by an increasing share of pumped hydro storage and a limited share of battery energy storage.

- **A CO_2 price is not enough to trigger substantial RE shares by 2050:** The CO_2 price results in more RE plants being installed than in the scenario without a CO_2 price. Nevertheless, the share remains at a low level of 19% of annual electricity demand by 2050. The comparison between the two scenarios in Figure 2 shows that the earlier introduction and increase of the CO_2 price in scenario 11 has almost no impact on the installed capacities of RE. This is because CO_2 prices are not high enough to compensate for low gas prices and provoke a substantial shift in investments towards RE.

As shown in Figure 3, assuming a faster and more consequent gas price recovery changes the picture regarding the impact of introducing a CO_2 price:

- **CO_2 price incentivizes more investments in RE if gas prices are high:** Figure 3 shows that the introduction of a CO_2 price in combination with higher gas prices leads to an increase in investments in RE plants. The share of RE is 96% of the annual electricity generation in 2050 in both sensitivities. However, this also makes it clear that the gas price has the decisive influence on investment decisions in the model. With an earlier introduction of a CO_2 price in Sensitivity 11.1a, the share of RE already reaches 67% in 2030 compared to 57% without a CO_2 price. Battery energy storage plays no role in both sensitivities in 2050.



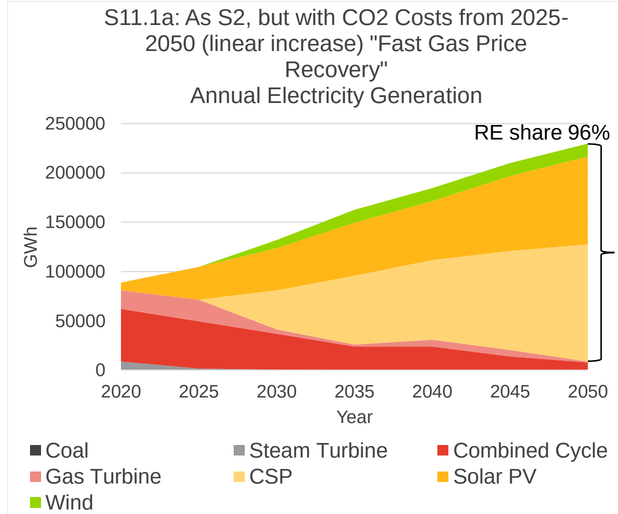


Figure 3: Annual electricity generation by technology over the planning time frame for Sensitivity 5.1a (left) and Sensitivity 11.1a (right) with a fast gas price recovery path.

The incentives set by CO_2 prices reduce CO_2 emissions of the energy mix significantly

Figure 4 illustrates the differences between the CO_2 emissions of each sensitivity from 2020 to 2050.

- **Sensititivities with higher gas prices lead to high share of RE & lower CO_2 emissions:** Without CO_2 prices and the assumption of a mild gas price recovery path, CO_2 emissions are over six times higher by 2050 (Sensitivity 2.2) compared to Sensitivity 2.2a with higher gas prices. With the introduction of CO_2 prices, the investments in combined cycle gas turbines with CCS reduce emissions in Sensitivity 5.1 and 11.1 significantly despite low shares of RE.

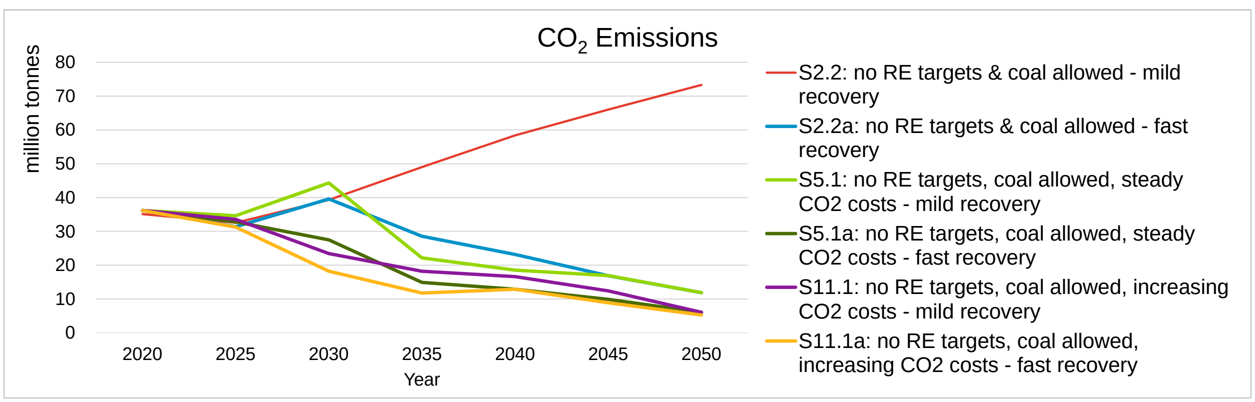


Figure 4: Development of CO_2 emissions for each sensitivity over the planning time frame.

Large-scale investments in RE and the introduction of CO_2 prices lead to higher system costs

Figure 5 shows illustrates the differences between the total costs of each sensitivity over the whole planning time frame from 2020 to 2050:

- **Sensitivities with higher gas prices & high RE share incur higher total costs**: Without CO_2 prices and the assumption of a mild gas price recovery path, total costs are 20% lower by 2050 (Sensitivity 2.2) compared to Sensitivity 2.2a with a fast gas recovery. The introduction of CO_2 prices leads to higher system costs in all sensitivities. Thereby, CO_2 prices have a greater impact on total costs in sensitivities with a high share of fossil fuel generation (Sensitivity 5.1 and 11.1). Sensitivity 2.2 with very low gas prices and a RE share of 14% by 2050 is the scenario with the least overall costs. Sensitivity 11.1a with higher gas prices, a RE share of 96% by 2050 and increasing CO_2 prices is the scenario with the highest overall costs.

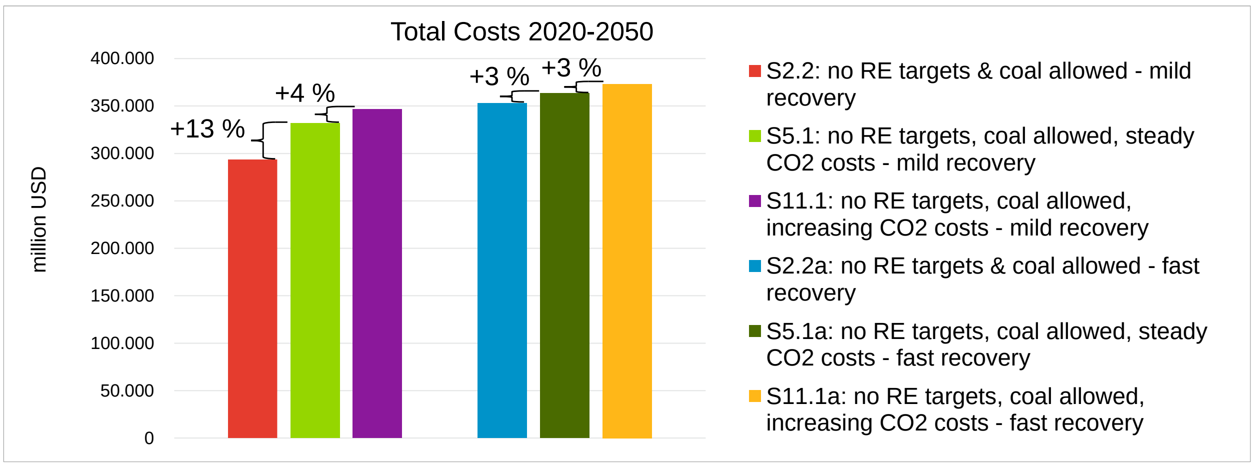


Figure 5: Development of total costs for each sensitivity over study time frame.

Renewables become competitive at a gas price of 25 USD/MWh

The modeled sensitivities show the large impact of the gas price on the composition of the energy mix. In a tipping point analysis, this influence was examined in more detail. For this tipping point analysis, based on sensitivity 2.2, the gas price was kept constant and gradually increased. The procedure is illustrated in Table 1.

- **Renewable energies become the dominant energy source with gas prices above 25 USD/MWh**: The assumption of a gas price of 25 USD/MWh in combination with decreasing investment costs of RE lead to strong RE development especially from 2035 onwards.

Table 1: Assumed gas price paths for the tipping point analysis

Gas price ($/MWh)	2020	2025	2030	2035	2040	2045	2050	Effects on RE Expansion
Mild recovery	11.3	15.6	15.8	16.0	16.2	12.6	11.0	RE share 2050: 13%, only solar PV built
Constant prices	17	17	17	17	17	17	17	RE share 2050: 31%, solar PV + wind
	20	20	20	20	20	20	20	RE share 2050: 56%, solar PV + CSP + wind
	23	23	23	23	23	23	23	RE share 2050: 73%, solar PV + CSP + wind
	25	25	25	25	25	25	25	RE share 2050: 79%, solar PV + CSP + wind
Fast recovery	11.3	24.1	24.8	25.8	26.0	26.6	29.4	RE share 2050: 90%, solar PV + CSP + wind
Current prices & market outlook	11.3	29.0	37.7	42.0	46.2	50.5	54.7	

3.2 Impact of assuming higher grid connection costs for renewable energies

To answer the question on the impact of assuming higher grid connection costs for RE, Sensitivity 2.2b is compared to the Sensitivity 2.2a. Both sensitivities follow the “fast gas price recovery” price path, i.e. higher gas prices. The results are shown in Figure 6.

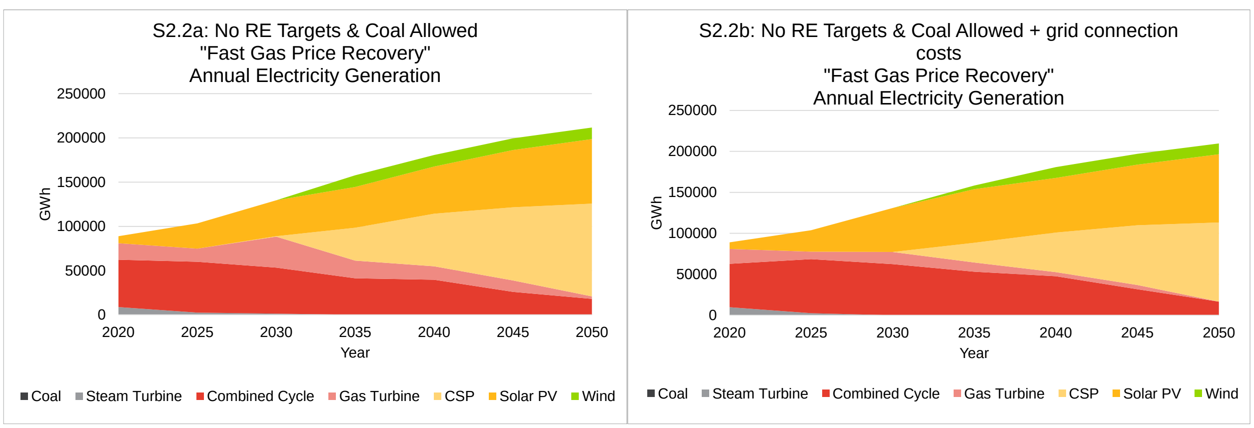


Figure 6: Annual electricity generation by technology over the planning time frame for Sensitivity 2.2a (left) and Sensitivity 2.2b (right) with grid connection costs.

- **RE remain the dominant source of electricity**: The share of renewables remains comparatively high at around 90% in 2050. However, there is a slight difference in the composition of the electricity mix between 2030 and 2050. With the assumption of grid connection costs (in Sensitivity 2.2b) investments in PV systems become more competitive compared to CSP. The flexibility to balance the fluctuating PV generation is provided by battery systems and pumped hydro storages in S2.2b. This combination of flexible capacities leads to a slightly more linear decline in gas-fired power plants.

As expected, the higher share of RE in Sensitivity 2.2b (with grid connection costs) leads to 34% lower CO_2 emissions and 13% higher system costs by 2050. The results are shown in Figure 7.

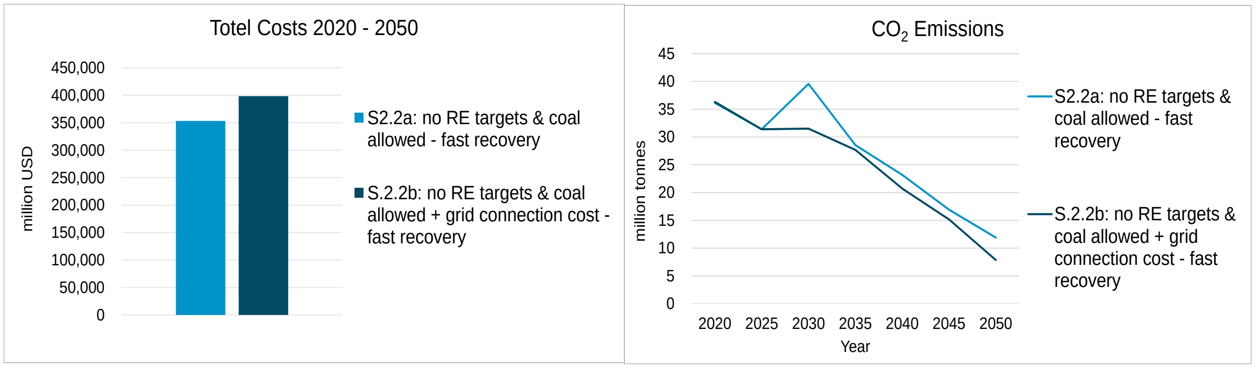


Figure 7: Total costs and CO_2 Emissions S2.2a compared to S2.2b.

3.3 Impact of an increasing hydrogen production on the electricity mix

Hydrogen demand for domestic use and export is assumed to increase linearly from 2030 to 2050 onwards, resulting in increasing demand for electricity. Only the production of green hydrogen is allowed in the model. The sensitivity is modeled in a “fast gas price recovery” scenario (higher gas prices) with CO_2 prices from 25 USD/tCO_2 in 2025 to 75 USD/tCO_2 in 2050, so that insights can be obtained by comparing the Sensitivity 11.1b and 11.1a. The impact of an uptake of hydrogen in the synthetic MENA country on the future electricity mix is shown in Figure 8.

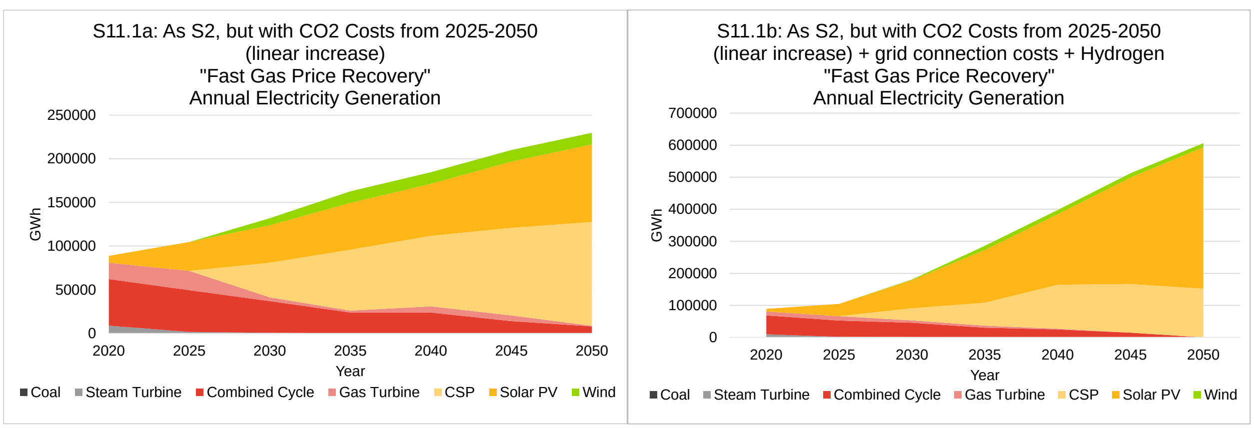


Figure 8: Annual electricity generation by technology over the planning time frame for Sensitivity 11.1a (left) and Sensitivity 11.1b (right) with grid connection costs and hydrogen.

- **Overall installed capacity almost triple by 2050:** The results show that immense growth in renewable electricity is needed to meet the additional electricity demand. This additional electricity demand caused by green hydrogen is mainly met by solar PV. The solar PV capacity is about 5 times the capacity 2050 of the scenario without hydrogen demand. The additional flexibility needed to integrate such large shares of fluctuating solar PV is provided by the hydrogen storages.

With a share of 99% RE by 2050, CO_2 emissions of the electricity mix can be reduced to 27,200 tonnes in Sensitivity 11.1b, which is 99% less compared to Sensitivity 11.1a without the consideration of hydrogen demand. Comparing both scenarios in terms of total costs, Figure 9 shows that the tripled installed net capacity to meet hydrogen demand leads to 2.5 times higher overall costs by 2050.

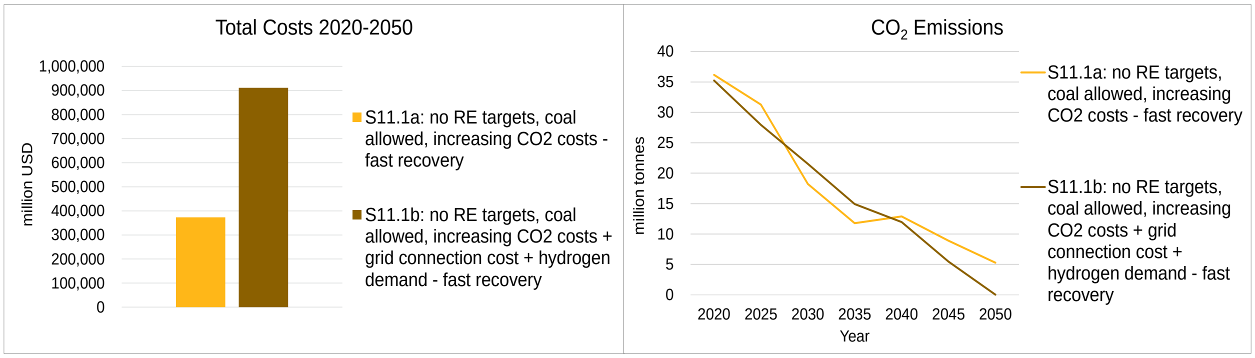


Figure 9: Total costs and CO_2 Emissions S11.1a compared to S11.1b.

4. Summary

In summary, the assumption of different gas price paths leads to the following results in the modelled scenarios.

- **A mild gas price recovery path** leads to extensive investments in gas-fired power plants, no investments in coal power plants, and a low share of RE also in the long-term, with PV being the only competitive RE technology. In this case, the introduction of CO_2 prices (25-75 \$/tCO_2) leads to slightly more investments in PV, incentivizes investments in combined cycle gas turbines with CCS and in pumped hydro storage and battery storage. The overall RE share by 2050 remains low.

- **A fast gas price recovery path** leads to extensive investments in PV and CSP, no investments in coal power plants, and a low and decreasing share of gas-fired power plants as complement to RE. In this case, the introduction of CO_2 prices (25-75 \$/tCO_2) leads to more investments in PV, CSP and wind power, incentivizes investments in pumped hydro storage and leads to a stronger and more linear decrease of investments in gas-fired power plants.

- **The introduction of higher grid connection costs for RE** has only a minor impact on the future electricity mix. RE remain the dominant and most cost-efficient source of electricity. The technology mix to provide the flexibility for a reliable electricity supply changes slightly, with more investments in battery storages and pumped hydro storage when considering grid connection costs.

- **An uptake of green hydrogen** requires a fast and massive deployment of RE capacities from 2030 onwards. With low CAPEX costs and excellent availability of solar resources in the MENA region, hydrogen demand is mainly met by solar PV. Hydrogen storage can play a crucial role to buffer volatile solar PV generation.

5. Conclusion and Recommendations

Based on the new sensitivity analyses, the following **main conclusions** can be drawn:

- **Gas price developments** are the **main influencing factor** for the share of RE in the electricity mix. Their impact on RE is significantly larger than the introduction of a CO_2 price. This points to the strong **investment uncertainty** resulting from volatile fossil fuel prices.

- **Assuming very low gas prices** over a longer period of time bears the risk of limited investments in RE, resulting in **lock-in effects on a gas-dependent path** and **less efficient technologies** (open cycle gas turbines (OCGT) instead of combined cycle gas turbines (CCGT)). As gas prices are influenced by political decisions, any investment decision based on gas price developments bears significant uncertainty. **High RE investments** can be used as a **hedging strategy** against fossil fuel price volatility.

- With **decreasing investment costs of PV, wind power plants**, and **CSP**, RE become more and **more competitive**. Investments in **coal power plants become economically unattractive**, even when the cost of externalities is neglected. These conclusions **do not change even if higher grid connection costs are assumed for RE** because they may be located further away from demand centers.

- The introduction of **CO_2 prices incentivizes investments in technologies**, such as RE or CCS, **that reduce CO_2 emissions** from the energy system. As a result, the energy mix becomes more diverse, which has a positive impact on resilience and energy security.

- **Hydrogen demand can be met by RE** but **fast and massive deployment** of their capacities is needed. A mix of technologies, such as **CSP** or **hydrogen storage**, can **provide the needed flexibility to integrate high shares of RE** and ensure reliability.

Based on these results, the following **recommendations** can be formulated for policymakers in the MENA region:

- **Capture benefits of low RE cost** to implement low-carbon energy pathways and hedge against fossil fuel volatility. Due to the reduction of investment costs, RE are already competitive compared to fossil fuel alternatives in many cases. This trend will increase in future. It will however remain important for the international community to support de-risking renewables investments, i.e. by supporting targeted financial mechanisms.

- **Define long-term energy strategies** with a focus on resilience, decarbonization and investment security by aiming for high shares of RE. The excellent solar resource availability of the MENA region allows the use of CSP instead of gas power plants as flexibility option. Therefore, **investments in renewables** and especially in PV and CSP **represent a no-regret path** for the MENA region.

- **The introduction of CO_2 pricing** – as can be observed globally – has a positive effect on RE investments. This would be amplified with significantly higher CO_2 prices. International exchange on carbon pricing, for example in the framework of "Climate Clubs" can facilitate the implementation of CO_2 pricing.
- **CO_2 prices can also provide incentives for investments in (new) technologies such as CCS**. Uncertainty surrounding the commercial viability and leakage potential of CCS still need to be addressed.
- **Consider the role of green hydrogen in long-term energy strategies**. Green hydrogen can not only enable the integration of RE and thus contribute to decarbonization, but also offers the countries of the MENA region the opportunity to export the energy from RE in the form of molecules. Due to the impacts on the energy system of large-scale hydrogen production in terms of electricity demand, a hydrogen strategy should be developed as part of a long-term strategy with a systemic view. Cooperation between future hydrogen importers and exporters should take place around the development of national strategies.
- **Assess country specific RE and hydrogen storage potential** to better classify the role of individual resources and technologies within a country. Also, the **costs and benefits for sustainable low-emission energy pathways until 2050** should be made transparent. International and regional cooperation for the development of such pathways can offer synergies.

Appendix A. Updated Assumptions

Table 2: Update of coal and natural gas prices (USD/MWh)

	2020	2025	2030	2035	2040	2045	2050	Source
Original study (June 2019)								
Coal	10.0	11.0	11.5	11.6	11.8	11.8	11.8	(IEA, 2016) and own assumptions
Natural gas	21.8	27.0	29.3	31.1	32.8	33.1	33.4	(IEA, 2016) and own assumptions
Update 1 (May 2020)								
Coal – Low for long	6.7	8.7	9.0	9.1	9.2	9.2	9.2	XW1 and TMA coal indexes on 26.05.2020 and own assumptions
Coal – Fast recovery	8.3	10.2	11.2	11.3	11.5	11.5	11.5	XW1 and TMA coal indexes on 26.05.2020, trend extrapolation to 2030
Gas – Lower for longer	3.6	8.1	11.3	11.9	12.6	12.7	12.8	Dutch TTF and UK NBP Future prices on 26.05.2020 and own assumptions
Gas – Mild recovery	5.6	12.6	17.5	18.6	19.6	19.8	20.0	Dutch TTF and UK NBP Future prices on 26.05.2020 and own assumptions
Gas – Fast recovery	7.9	17.9	24.8	26.4	27.8	28.1	28.3	Dutch TTF and UK NBP Future prices on 26.05.2020, trend extrapolation to 2030
Update 2 (July 2021)								
Coal – Fast recovery	7.4	10.0	9.9	9.9	9.9	9.8	9.7	IEA (2020) STEPS averaged prices across regions >2025, trend extrapolation to 2050
Gas – Mild recovery	11.3	15.6	15.8	16.0	16.2	12.6	11.0	IEA (2020) SDS averaged prices across regions > 2025, trend extrapolation to 2050
Gas – Fast recovery	11.3	24.1	24.8	25.8	26.0	26.6	29.4	IEA (2020) STEPS averaged prices across regions > 2025, trend extrapolation to 2050

Note: STEPS = Stated Policies Scenario, SDS = Sustainable Development Scenario

Table 3: Update of coal prices (USD/tonne) and natural gas prices (USD/MMBTU)

	2020	2025	2030	2035	2040	2045	2050	Source
Original study (June 2019)								
Coal	69.8	76.8	80.2	80.9	82.3	82.3	82.3	(IEA, 2016) and own assumptions
Natural gas	6.4	7.9	8.6	9.1	9.6	9.7	9.8	(IEA, 2016) and own assumptions
Update 1 (May 2020)								
Coal – Low for long	46.8	60.7	62.8	63.5	64.2	64.2	64.2	XW1 and TMA coal indexes on 26.05.2020 and own assumptions
Coal – Fast recovery	57.9	71.2	78.2	78.9	80.2	80.2	80.2	XW1 and TMA coal indexes on 26.05.2020, trend extrapolation to 2030
Gas – Lower for longer	1.1	2.4	3.3	3.5	3.7	3.7	3.8	Dutch TTF and UK NBP Future prices on 26.05.2020 and own assumptions
Gas – Mild recovery	1.6	3.7	5.1	5.5	5.7	5.8	5.9	Dutch TTF and UK NBP Future prices on 26.05.2020 and own assumptions
Gas – Fast recovery	2.3	5.2	7.3	7.7	8.1	8.2	8.3	Dutch TTF and UK NBP Future prices on 26.05.2020, trend extrapolation to 2030
Update 2 (July 2021)								
Coal – Fast recovery	52	70	69	69	69	68	68	IEA (2020) STEPS averaged prices across regions >2025, trend extrapolation to 2050
Gas – Mild recovery	3.3	4.6	4.63	5.0	4.8	3.7	3.2	IEA (2020) SDS averaged prices across regions > 2025, trend extrapolation to 2050
Gas – Fast recovery	3.3	7.0	7.1	7.3	7.6	7.6	7.8	IEA (2020) STEPS averaged prices across regions > 2025, trend extrapolation to 2050

Note: STEPS = Stated Policies Scenario, SDS = Sustainable Development Scenario

Table 4: Update of CAPEX cost of PV, Wind (USD/kW) and Battery Energy Storage (USD/kWh)

	2020	2025	2030	2035	2040	2045	2050	Source
Original study (June 2019)								
Wind	1320	1310	1300	1290	1285	1280	1275	(IEA, 2016) and own assumptions
PV	890	725	645	625	600	580	560	(IEA, 2016) and own assumptions
Battery Energy Storage	394	281	198	180	179	178	175	(IEA, 2016) and own assumptions
Update 2 (July 2021)								
Wind	1631	1487	1400	1331	1280	1245	1216	ewi (2020)
PV	602	496	441	396	364	330	306	ewi (2020)
Battery Energy Storage	345	265	225	204.5	184	161	149	WEO (2020) & NREL (2021) - Mid Price for 2020, 2045, 2050

Note: STEPS = Stated Policies Scenario, SDS = Sustainable Development Scenario

Table 5: Assumptions on weighted average cost of capital (WACC)

	Time Frame	WACC
Original Study	2020 – 2050	5 %
Update 1	2020 – 2030	8 %
	2030 – 2050	5 %
Update 2	2020 – 2050	5 %

Note: STEPS = Stated Policies Scenario, SDS = Sustainable Development Scenario

Table 6: Update of average annual electricity demand growth rates

	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2050
Original study (June 2019)						
Synthetic country	5.0 %	4.5 %	3.9 %	2.8 %	1.5 %	0.7 %
Update 1 (May 2020)						
Synthetic oil/gas importer	4.0 %	4.5 %	4.0 %	3.0 %	2.0 %	1.0 %
Synthetic oil/gas exporter	1.0 %	4.5 %	4.0 %	3.0 %	2.0 %	1.0 %
Update 2 (July 2021)						
Synthetic oil/gas importer	5.0 %	4.5 %	3.9 %	2.8 %	1.5 %	0.7 %
Synthetic oil/gas exporter	3.0 %	4.5 %	3.9 %	2.8 %	1.5 %	0.7 %

Note: STEPS = Stated Policies Scenario, SDS = Sustainable Development Scenario

Appendix B. Assumptions on grid connection costs

Table 7: Assumptions on grid connection costs with investment cost (USD/MW/km) and O&M cost (% of inv. cost)

	2020	2025	2030	2035	2040	2045	2050	Source
Investment cost*	895							IEA (2016) and own assumptions
O&M cost	1							Dii (2016)

Note: * Investment costs are originally from NREL (2012) and US specific. Dii (2016) and Alqahtani & Patino-Echeverri (2019) indicate that transmission investment costs are lower in the MENA-region (20-70 % lower than in Europe or the US). We assume 40 % lower costs of the stated minimal value in IEA (2016) for the MENA-region.

Appendix C. Assumptions on hydrogen demand and technologies

Assumption on hydrogen demand

Table 8: Electricity demand (TWh/a) and projected PtX demand (TWh) of Morocco

	2020	2025	2030	2035	2040	2045	2050	Source
Electricity demand	34.02	44.7	56.5	71.4	82.8	95.9	108.6	IEA (2022), World Bank Group (2020), trend extrapolation >2035
PtX demand (domestic & export)			30.1		67.9		153.9	Frontier Economics (2020)

Table 9: Hydrogen and electricity demand (TWh/a), efficiency of AEL (%) and scaling factor (%)

	2030	2035	2040	2045	2050
Electricity demand synthetic MENA-country [TWh/a]	128,342	155,532	178,100	192,292	199,621
Efficiency electrolyzer AEL [%]	69	71	72	74	75
Scaling factor [%]	25	54	82	112	142
Hydrogen demand synthetic MENA-country [TWh/a]	32,085	83,117	146,051	215,096	282,888
Hydrogen defined as add. electricity demand synthetic MENA-country [TWh/a]	46,501	117,066	202,848	290,670	377,185

Note: The relation PtX (of Morocco in Table 8) to electricity demand is used to derive a scaling factor to size the hydrogen demand according to the country size (in terms of electricity demand) of the synthetic MENA country.

Assumptions on electrolyzer

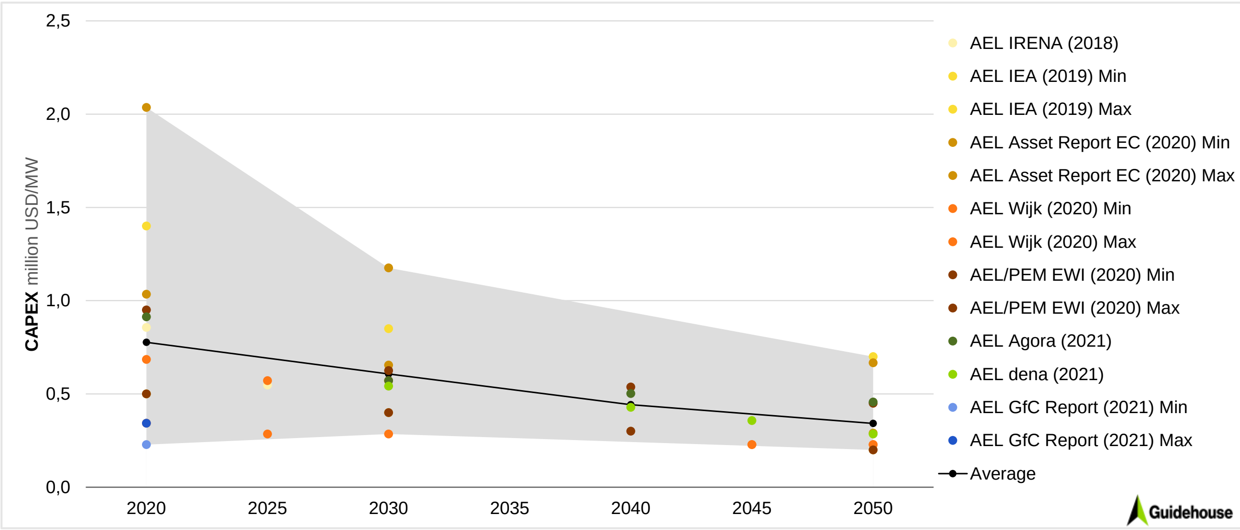


Figure 10: Electrolyzer Alkaline water electrolysis (AEL) – Investment cost in Literature

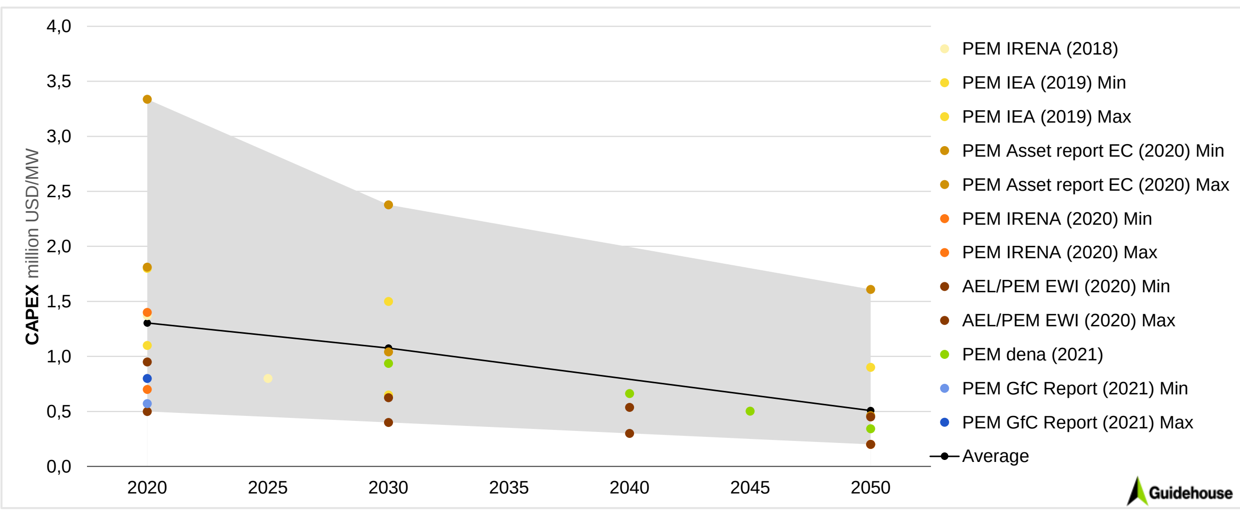


Figure 11: Electrolyzer Polymer electrolyte membrane (PEM) – Investment cost in Literature

Table 10: Electrolyzer: Investment cost (USD/kW), O&M cost (% of CAPEX), Efficiency (%), Lifetime (years)

	2020	2025	2030	2035	2040	2045	2050	Source
AEL								
Investment cost	913 [228-2034]	742	571 [285-1176]	537	502 [300-528]	479	457 [200-700]	Agora (2021), linear interpolation
O&M cost	4 [2-10]							Agora (2021)
Efficiency	64 [51-70]	67	69 [63-72]	71	72	74	75 [69-80]	Asset Report EC (2020), linear interpolation
Lifetime	25 [20-30]							EWI (2020), Agora (2021), IRENA (2018)
PEM								
Investment cost	1812 [500-2034]	1427	1041 [400-2377]	896	800	607	462 [200-1610]	Asset Report EC (2020), linear interpolation
O&M cost	4 [2-9]							dena (2021)
Efficiency	61 [53-61]	64	67 [59-67]	69	70	72	73 [65-73]	Asset Report EC (2020), linear interpolation
Lifetime	20							IRENA (2018)

Note: Numbers in square brackets indicate range in literature.

Assumptions on hydrogen-ready gas turbine

Table 11: Hydrogen-ready OCGT: Investment cost (USD/kW), O&M cost (USD/kWa), Lifetime (years)

	2020	2025	2030	2035	2040	2045	2050	Source
Investment cost	947	947	878	822	788	788	788	Agora (2021), 2020: assumed to be equal to 2025
O&M cost	23	23	22	21	21	21	21	Agora (2021), 2020: assumed to be equal to 2025
Lifetime	40							Agora (2021)

Assumptions on hydrogen storage

Table 12: Hydrogen storage (salt caverns): Investment cost (USD/MWh), O&M cost (% of inv. cost), Efficiency (%), Lifetime (years)

	2020	2025	2030	2035	2040	2045	2050	Source
Investment cost	883 [381-1200]	807	757	689	626	563	500	2020: Average value based on GIE (2021), EC (2020), Hydrogen Europe (2020); > 2020: trend extrapolation based on described trend in Hydrogen Europe (2020)
O&M cost	4							NREL (2019)
Efficiency	98							Elberry et al. (2021)
Lifetime	50							GIE (2021)

Note: Numbers in square brackets indicate range in literature.

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