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MODELLING OF THE ROMANIAN ELECTRICITY SECTOR 2025-2040

REKK with the support of EPG

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Executive summary

To reach climate neutrality by 2050, the European Union has set a 55% emission reduction target for 2030 and the European Commission has proposed a 90% reduction target for greenhouse gas emissions by 2040.

Romania, through its multiple strategies and plans, has set out a vision for gradually decreasing its emissions. While these documents reflect significant strides forward for the energy transition, especially by committing to a coal phaseout calendar by 2032, they are fraught with inconsistencies and partly rely on sizeable investments in fossil capacities. Various projects on nuclear and hydro energy are also constantly announced with limited assessment of their suitability in an increasingly decarbonised power sector.

In this report, we assess Romania's energy transition pathway. The European Gas Market Model and the European Power Market Model developed by REKK were utilised to understand the impact of Romania's plans on emissions and the energy market and to see how Romania could resize its fossil capacity investments and achieve a carbon-neutral power sector in 2040. The models simulate a fully functional and liberalised energy markets to show the impact of different measures on wholesale energy prices.

Based on the modelling results several important conclusions can be drawn:

- Romania can reach a completely decarbonised electricity production mix in 2040 with no security of supply risks by aiming to have no more than 3.5 GW[1] of total installed gas-fired capacities by 2030 and by focusing more on wind power and a higher deployment of storage technologies. In contrast, the investments outlined in Romania's National Energy and Climate Plan (NECP) do not ensure a decarbonised energy sector by 2040. The Romanian power sector would emit 9.2 MtCO2 in 2030 (which can be halved in a lower-gas scenario) and 3.5 MtCO2 in 2040, at slightly higher wholesale electricity prices. Replacing natural gas with hydrogen in 2035 in the all-installed capacities (as outlined in Romania's Long-Term decarbonisation Strategy) would mean that these assets would no longer be utilised. This is because replacing gas with hydrogen would significantly deteriorate the cost-competitiveness of these capacities, immediately reaching a utilisation rate lower than 0.1%, given the high fuel prices of 82 EUR/MWh in 2030, according to renewable hydrogen cost estimations presented in the draft National Hydrogen Strategy. There is therefore a significant risk that even 'hydrogen-ready' investments would continue to operate on fossil fuels for economic reasons, consequently not achieving their promised emissions reductions.
- A higher focus on wind energy (17.7 GW onshore and 7.3 GW offshore in 2040, compared to 13.1 GW altogether in official plans) can contribute to decarbonising the power sector by 2040. Romania appears to have a regional competitive advantage in

[1] Investments in new power plants (CCGTs) will be limited to the completion of Iernut project, to which an additional capacity of 600 MW will be added and divided between Turceni, Ișalnița and Mintia.

wind production. The market value of wind remains higher than that of solar for all modelled years, while lower wind investments are expected in Hungary and Bulgaria.

- Even with higher renewable shares than presented in official documents, Romania's power sector can deliver on security of supply requirements. The higher balancing reserve requirement can be accommodated through investments in storage (reaching 880 MW in 2030 and 3.4 GW in 2040) covered by existing hydro capacities, new storage installations and, until 2035, gas power plants. An annual installation of 800 MW rooftop PV and 120 MW in battery can further decrease balancing pressures and slightly decrease wholesale prices (by about 1.1 EUR/MWh in 2040).
- A high renewables scenario would also have a positive impact on the electricity trade balance. In either scenario, Romania becomes a net exporter of electricity from 2030. 17.5 GW of solar capacities as well as 17.7 GW onshore and 7.3 GW offshore wind is sufficient to achieve a decarbonised power sector by 2040.
- Existing hydro power facilities are key for balancing a renewables-dominated power sector. However, new investments in hydro capacities (including 300 MW in small hydro installations and a 1 GW pumped hydro capacity that would come online in 2032) would only have a limited effect on electricity prices and security of supply – assuming the mentioned battery storage investments are realised.
- Hard coal and lignite phaseout are manageable from a security of supply perspective, even with lower than planned investments in gas capacities. Based on market prices alone, the modelling results show that coal fired production will rarely be economical from 2025 (expected capacity factor of less than 1%).
- New nuclear energy capacities can contribute to achieving a decarbonised power sector, even if the planned investments suffer delays. The modelling results show that slight delays in the construction of new nuclear (two new conventional CANDU reactors and 460 MW of small modular reactors) do not pose security of supply risks, even in a lower-gas scenario of 3.5 GW installed gas capacities. Even with such delays, Romania would continue to be a net electricity exporter after 2030 based on the expansion of its renewable capacities, albeit the prices of electricity and CO2 would be slightly higher, because of the nuclear delay.
- Additionally, the refurbishment of Cernavodă's Unit 1, scheduled for 2027–2029, which will take 700 MW out of the system, will not pose supply security risks, even in a lower-gas scenario. This is because significant new renewable energy sources (RES) will begin operating, with solar energy nearly doubling from 4.3 GW to 8.2 GW and onshore wind increasing by more than 50% from 5 GW to 7.9 GW between 2025 and 2030. Natural gas capacities will increase by 500 MW, and battery storage will see an approximately fourfold growth in the same timeframe.

Accordingly, several recommendations can be derived based on results that are consistent throughout the studied scenarios and sensitivities:

- Investments in new gas-fired capacities should be reassessed and resized according to the actual needs of the power sector. Smaller peaking capacities can balance a renewables-dominated electricity mix before 2040.
- New natural gas capacities cannot switch economically to hydrogen; therefore, these plans should be carefully reconsidered for any new investment.
- Romania should continue supporting the deployment of additional renewable capacities, with an increasing focus on wind and storage. Offshore wind investments should become a priority for the following decade, coupled with an expansion of utility-scale storage technologies.
- Ramping up grids investments is required to accommodate higher shares of renewables and enabling cross-border electricity flows.
- Coal is quickly becoming uneconomical and is not needed for security of supply, therefore authorities should not subsidise coal-fired capacities, but instead reallocate funding to new renewable and storage capacity.
- Rather than focussing on investments in new hydro capacities, which may not have a significant impact, investments in retrofitting existing assets should be prioritised.

1 Introduction

Romania has outlined its strategic vision regarding the EU's climate objectives through its Long-term Strategy (LTS) and draft revised National Energy and Climate Plan (NECP). Given the centrality of the energy sector in the transition process, it is paramount to understand the impact of these plans and their objectives and announced investments on Romania's electricity market, security of supply, and greenhouse gas (GHG) emissions, and to also understand if these outcomes can be improved through a different vision for investment. To this end, REKK, with the support of EPG, developed a modelling exercise. Besides exploring the impact of the existing strategic vision outlined through national plans, another objective of the analysis was to identify the impact of decarbonizing the electricity market by 2040 through reduced use of fossil fuels, including natural gas, at the national level.

According to the LTS and draft NECP, Romania aims to increase natural gas-based power generation up to 5.5 GW by 2030, with a simultaneous increase in renewables capacities (34.6 GW of PV and wind capacities until 2040). EPG proposed an alternative pathway that assumes less natural gas capacity (around 3.5 GW) alongside a more dynamic intermittent RES, especially wind deployment (42.5 GW in PV and wind capacities until 2040).

The main aim of the modelling exercise has been to compare the two pathways and determine the effects of the two scenarios on energy prices and their effectiveness in decarbonising the electricity sector. With additional sensitivities, the modelling also seeks to identify the year in which full decarbonization of the Romanian electricity sector is feasible, and the role of natural gas in the country between 2025 and 2050. A particular focus of the analysis was to understand the extent to which natural gas will contribute to the energy transition at national level and how much of the current investments pipeline is warranted in this regard. Furthermore, other aspects are investigated in line with the Romanian draft updated NECP, such as the transition to hydrogen-based generation in gas power plants from 2035, the deployment of new pumped storage capacities, run-of-river hydro power plants and an accelerated deployment of residential PV.

The modelling has been carried out by REKK's European Power Market Model (EPMM), which is a unit-commitment model simulating the power markets of Europe. The modelling is carried out in five-year intervals, meaning that the report presents results for the years 2025, 2030, 2035, and 2040.

The report is structured into six sections. Section 1 represents the introduction, Section 2 and Section 3 describe the EPMM model, the investigated scenarios and applied inputs, while the results of the two main scenarios are presented in Section 4, being completed by the analysis of the sensitivities in Section 5. The main conclusions and policy recommendations are presented in Section 6.

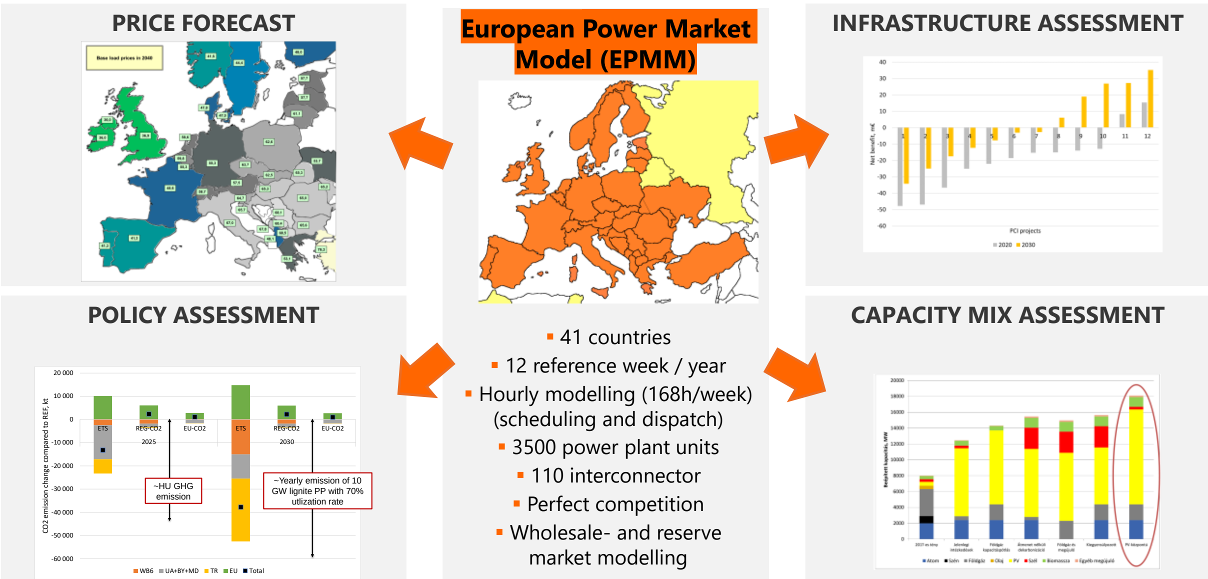
2 Methodology and model description

The modelling was carried out using the in-house European Power Market Model (EPMM) of REKK. The EPMM is a 168-hour unit commitment and economic dispatch model covering the electricity systems of 41 European countries. It simultaneously determines the equilibrium values of the wholesale electricity and reserve markets for each hour and market, taking into account the projected weather-dependent renewable generation, the electricity demand, the reserve requirements for each country, and the technological constraints and costs (minimum operating and off-time, minimum/maximum load level, start-up/shut-down costs, variable costs of generation) for electricity generation and transmission.

Using these inputs, the model predicts the operating status of the power plants every hour of the week (covering almost 3,500 power plants). The calculations estimate the volume of generation at the operating units, the technology mix of capacities set aside for upward-regulation and downward-regulation, the operation of reservoir hydropower plants, the flows on all cross-border interconnectors, and the wholesale market price of electricity and the price of the upward and downward reserve capacities in each country.

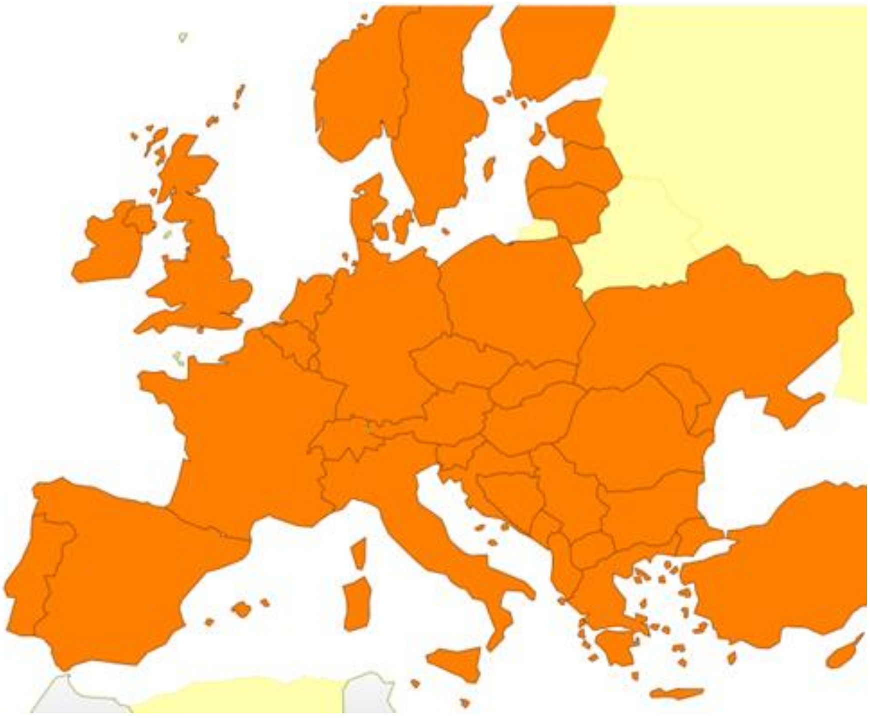
The main appliances of the EPMM, based on the listed outputs are summarised in Figure 1, with illustrative examples.

FIGURE 1: THE MAIN APPLIANCES OF THE EUROPEN POWER MARKET MODELL (EPMM)



There are 41 countries modelled in EPMM: in these countries (indicated with an orange background on Figure 2) prices are derived from the demand-supply balance, while on outside markets (indicated with yellow background) we assume exogenous prices.

FIGURE 2: COUNTRIES MODELLED IN EPMM



There are three types of market participants in the model: producers, consumers, and traders. All of them behave in a price-taking manner: they take the prevailing market price as given and assume that their actions have a negligible effect on this price.

The EPMM models 3,500 power plant units operated with 12 different fuels: natural gas, coal, lignite, heavy fuel oil (HFO), light fuel oil (LFO), nuclear, biomass, geothermal, hydro, wind, solar and tide and wave. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation capacity is constrained at the level of available capacity.

Power flow is ensured by approximately 110 interconnectors between the countries, where each country is treated as a single node, thus no domestic power system constraint is taken into account. Net transfer capacities (NTC) values are used to indicate trading possibilities, seasonal differences are included in the modelling based on historical data from ENTSO-E Transparency Platform. Future investments are assumed based on data from ENTSO-E's latest Ten-Year Network Development Plan (TYNDP), 20222.

Consumers are represented in the model in an aggregated way: by different price-sensitive demand curves for each modelled market. The inverse relationship between prices and the quantity consumed is approximated by a downward sloping linear function. Traders connect the production and consumption sides of a market, through exporting electricity to more expensive countries from cheaper ones.

2 https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission

3 Scenarios & Inputs

3.1 Scenarios

In the modelling, two main scenarios were created: a reference scenario (REF_Scenario), which is mainly based on the draft revised NECP of Romania and the LTS, and Low Gas scenario (Low Gas_Scenario) where lower installation of natural gas power plants but higher installation of solar PV and wind capacities are assumed based on estimations by EPG.[3] For both main scenarios several sensitivity assessments were carried out. The detailed list of the scenarios is summarised in Table 1.

TABLE 1: SUMMARY OF THE ESTIMATED SCENARIOS

Scenarios		
#	REF_Scenario	Low Gas_Scenario
1	New natural gas extraction	Reduced natural gas extraction
2	Extensive natural gas power plant capacity extension (5.5 GW in 2030)	Conservative natural gas power plant capacity extension (3.5 GW in 2030)
3	Solar & wind energy deployment (21.5 GW solar and 13.1 GW wind capacities in 2040)	Dynamic solar & wind energy deployment (17.5 GW solar and 25 GW wind capacities in 2040)[1]
4	Battery storage installation (2.2 GW in 2040)	Dynamic battery storage installation (3.4 GW in 2040)
Sensitivities		
1	Late_nuclear: Refurbishment of Cernavoda's U1 is delayed to 2031 (instead of 2030). Delay in new capacity installations: U3 to 2033 (instead of 2030), U4 to 2034 (instead of 2031), Doicești SMR to 2031 (instead of 2029)	
2	Pumped_storage: A new pumped storage power plant is added to the system in 2032 – 1 GW capacity	
3	High_PV & storage: An additional 800 MW of rooftop PV together with 120 MW of storage are installed in all years until 2040	
4	Low_hydro: Relative to the main scenarios, 300 MW run-of-river hydro is not completed between 2024 and 2030	

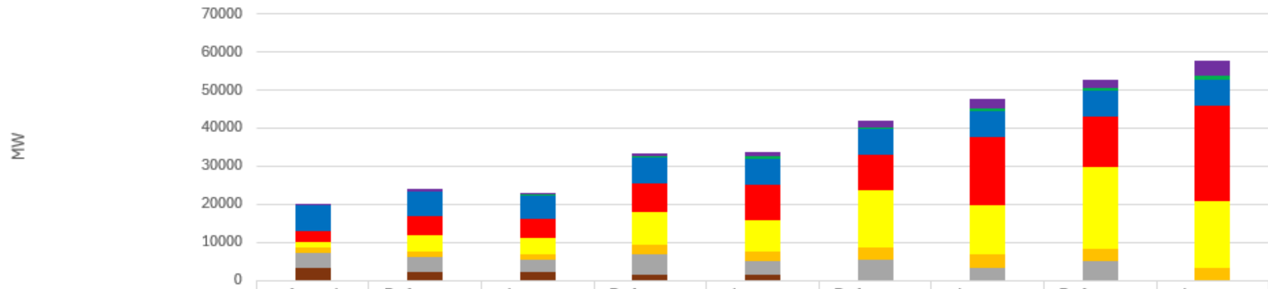
[3] The estimations are based on the recommended scenario for reaching net-zero GHG emissions in Romania by 2050 created by EPG with Climact's Pathways Explorer modelling tool. More information on the scenario and modelling results can be found here: https://www.enpg.ro/wp-content/uploads/2022/12/Romanian_LTS_EPG_Report.pdf

5 High_CO2 Price: EU Commission WAM CO2 price is assumed, reaching 250 EUR/t in 2040[4]

6 Hydrogen_2035: In reference scenario after 2035, natural gas-based power plants are fully fueled with hydrogen, with a fuel price of 82 EUR/MWh[5]

7 Extreme_gas: In the reference scenario 300 EUR/MWh gas price is assumed for Romania, meaning that gas is basically unavailable for the country[6]

FIGURE 3: INSTALLED GENERATION CAPACITIES BY SCENARIOS



	Actual	Reference	Lowgas	Reference	Lowgas	Reference	Lowgas	Reference	Lowgas
	2022	2025		2030		2035		2040	
Battery & Pumped storage	92	498	498	658	1 138	1 503	2 418	2 422	3 698
Other RES	221	221	221	321	621	421	921	521	1 221
Hydro	6600	6 369	6 369	6 796	6 796	6 796	6 796	6 796	6 796
Wind	3000	5 000	5 000	7 600	9 450	9 400	17 825	13 100	25 000
PV	1400	4 300	4 300	8 300	8 240	14 900	12 870	21 500	17 500
Nuclear	1413	1 413	1 413	2 595	2 595	3 315	3 315	3 315	3 315
Gas	3810	3 810	2 950	5 469	3 454	5 409	3 394	5 063	0
Coal/lignite	3300	2 325	2 325	1 420	1 420	0	0	0	0

Coal/lignite Gas Nuclear PV Wind Hydro Other RES Battery & Pumped storage

[4] Compared to the carbon price scenario in the Reference Scenario and Low gas Scenario, the WAM scenario of the European Commission takes into consideration all changes brought by the Fit-for-55 package, including the revision of the Emissions Trading Scheme Directive. Therefore, it represents a more up-to-date assumption regarding the development of the EU EUA prices based on current rules.
[5] Based on levelized cost of hydrogen (LCOH) estimations for renewable hydrogen in 2030 from the Draft Romanian Hydrogen Strategy.
[6] Extreme gas is a theoretical scenario where gas price is extremely high only for Romania, modelling a situation where natural gas is basically unavailable for Romania. Thus, this scenario model how the Romanian electricity market operates without natural gas capacities.

3.2 Inputs

The most important determinants of the modelling are coal prices, ETS price, gas prices, electricity demand and available interconnectors[7]. This subsection presents the key input values and their sources used in the modelling.

3.2.1 Coal and lignite price

For hard coal, several sources are considered:

- European Commission proposal for the NECP Planning[8] (beginning of 2023): 92$/t (2030), 98$/t (2040);
- International Energy Agency, World Energy Outlook (2023)[9] forecast: 57-68$/t (2030), 43-69$/t (2050);
- World Bank[10] forecast (October 2023): 130$/t (2024); 130$/t (2025); 110$/t (2026).

Based on these price projections, the following values for hard coal and lignite prices are used in the modelling, aggregated from various sources.

TABLE 2: COAL AND LIGNITE PRICE FORECASTS, $/T AND €/GJ

		2025	2030	2035	2040	2045	2050
Coal price	$/t	104	53	48	48	48	48
	€/GJ	3.50	1.79	1.63	1.63	1.63	1.63
Lignite price in RO	€/GJ	2.77	2.77	2.77	2.77	2.77	2.77

3.2.2 ETS price

Like the coal price, in the case of CO2 price, several forecasts are considered:

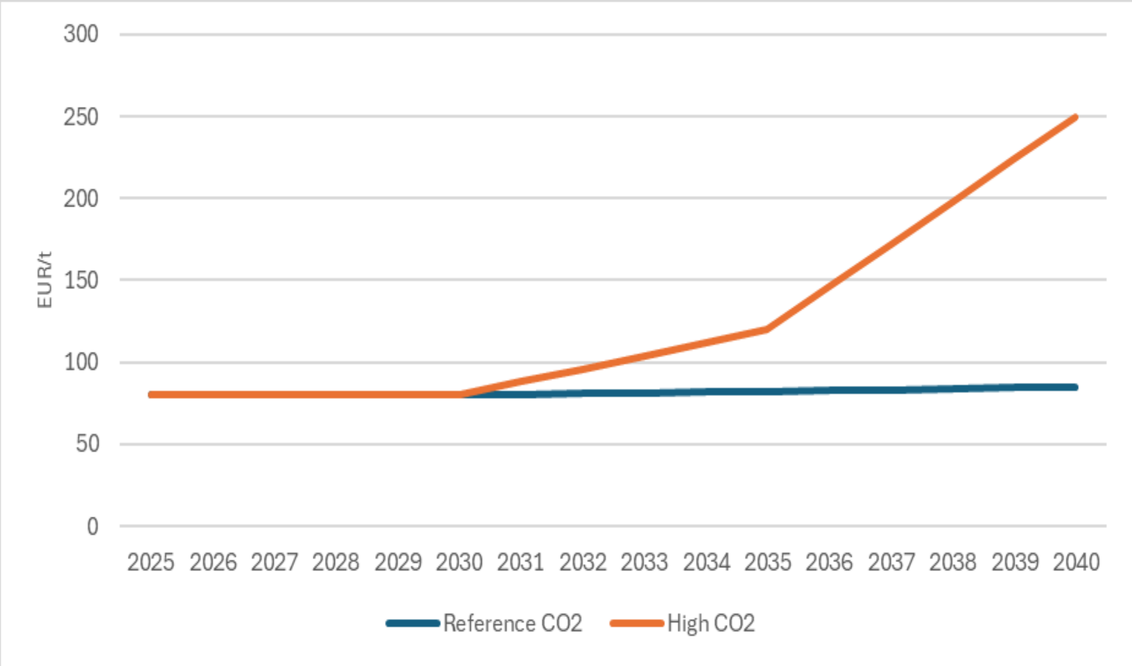
- International Energy Agency: World Energy Outlook (2023)[11]: For 2030, 110-121€/t depending on the scenarios, while in 2050 the range is between 121-225€/t.
- European Commission proposal for the NECP Planning[12]: (beginning of 2023) 80€/t for 2025 and 2030 in both the With Existing Measure (WEM) and With Additional Measure (WAM) scenarios. For 2040, in the WEM scenario, the CO2 price reaches 85€/t, while in the WAM it is much higher, reaching 250€/t.
- ICIS forecast (December 2022)[13]:

The price forecast by 2030 ranges between 80-141€/t and depends on various assumptions.

[7] Assumed capacity mix is also an important determinant but that is presented under the different scenarios.
[8] Not publicly available.
[9] https://www.iea.org/reports/world-energy-outlook-2023
[10] https://www.worldbank.org/en/research/commodity-markets
[11] https://www.iea.org/reports/world-energy-outlook-2023
[12] Not publicly available.
[13] Not publicly available.

Based on these information, two CO2 price scenarios are estimated. In the Reference scenario, the EC WEM scenario is used until 2040, with a price of 80€/t, while in the high CO2 price sensitivity the WAM scenario values are used.

FIGURE 4: CO2 PRICE ASSUMPTION IN THE REFERENCE (REF) AND HIGH CO2 PRICE SCENARIO, €/T



3.2.3 Gas price

The natural gas price forecast is based on the European Gas Market Model, developed by REKK. This model simulates the operation of an international wholesale natural gas market in Europe, covering the EU27 and the EnC Contracting Parties. It incorporates both the demand and supply side of the gas market, including pipeline, LNG and storage infrastructure at the country level. Major external markets, such as Russia, Norway, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices. All long-term supply contracts and physical connections to Europe are integrated in the model.

The gas market modelling considers the following parameters:

- Moderate gas consumption decreases in EU (gas demand and production data are based on EU Primes reference scenario)[14]
- A 90% storage target for EU storages
- 30 bcm Russian imports to Europe
- A 35 €/MWh Japan price.

Two natural gas scenarios are modelled, differing in the assumptions of future natural gas production/extraction in Romania, particularly in the new deep natural gas fields (Caragele and

[14] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en

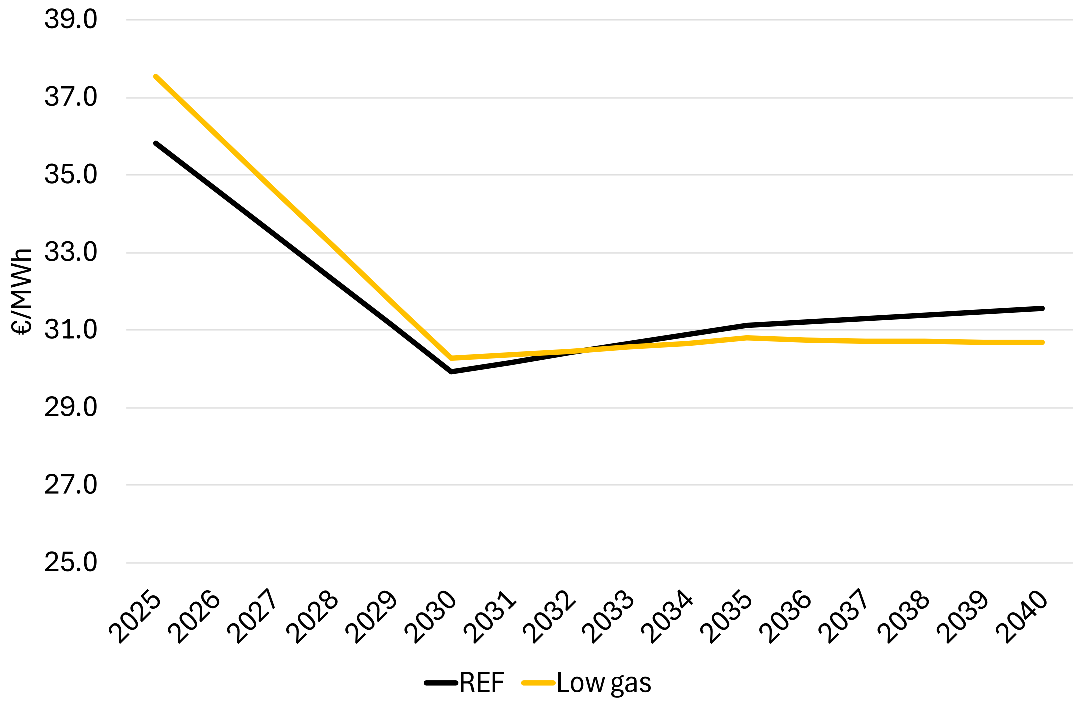
Neptun Deep) and also considering the different amounts of natural gas consumption of new gas-fired capacities. Table 3 summarizes the yearly production in the modelled years of the two scenarios.

TABLE 3: GAS PRODUCTION IN ROMANIA IN THE TWO SCENARIOS (BCM)

	Reference					Low gas				
bcm	Existing fields	Midia	Neptun deep	Caragele deep	Total	Existing fields	Midia	Neptun deep	Caragele deep	Total
2025	8,04	1	0	2	**11,0**	8,04	1	0	0,08	**9,1**
2030	5,64	1	10	2	**18,6**	5,64	1	6	2	**14,6**
2035	3,17	0	10	2	**15,2**	3,17	0	10	2	**15,2**
2040	1,47	0	0	0	**1,5**	1,47	0	6	2	**9,5**

According to the modelling results, the average wholesale gas price drops significantly to around 30 €/MWh by 2030 in both scenarios and remains around this level thereafter. There are only minor differences between the scenarios: until 2030 the natural gas price is lower in the Reference scenario due to the higher production, but after 2033 this changes because, despite the same gas production capacity being considered, the lower gas demand in the Low Gas scenario results in a lower price.

FIGURE 5: WHOLESALE NATURAL GAS PRICE ASSUMPTIONS



3.2.4 Electricity demand

The Romanian electricity consumption data is derived from the draft updated NECP and Long-term Strategy of Romania. For other Member States, the yearly demand growth rate is based on the European Commission's FIT55 Mix (until 2030) and REF scenario (after 2030)[15], adjusted by the starting values to reflect actual data. The following table summarizes the consumption data for Romania and the EU25. According to these figures, the Romanian yearly consumption growth rate is much higher, especially after 2030, compared to what is assumed for the EU2516.

TABLE 4: YEARLY ELECTRICITY CONSUMPTION AND YEAR-OVER-YEAR GROWTH RATE IN ROMANIA AND EU25, TWh

		2025	2030	2035	2040
EU25	Consumption, TWh	2,696.5	2,997.8	3,115.0	3,233.1
	Yearly growth		2.1%	0.8%	0.7%
Romania	Consumption, TWh	56.1	64.3	74.8	82.9
	Yearly growth		2.8%	3.1%	2.1%

3.2.5 Interconnectors

The following two tables summarize the existing capacities of cross-border trade at the Romanian border, based on the ENTOS-E grid map[17]. The new capacities are updated according to the latest available information in the TYNDP 2022[18] and REKK's data gathering.

TABLE 5: EXISTING (UPPER), AND NEW CAPACITIES AT THE ROMANIAN BORDER, MW

Existing capacities			
Origin and destination country		NTC, MW	
From	**To**	**O->D**	**D->O**
RO	UA	500	500
RO	MD	150	150
BG	RO	600	500
HU	RO	1000	1100
RS	RO	800	1000

New capacities				
Origin and destination country		Year of commissioning	NTC, MW	
RO	MD	2024	500	500
BG	RO	2025	600	600
RO	RS	2027	844	600
RO	HU	2027	617	335
RO	MD	2029	500	500
UA	RO	2029	1000	1000
RS	RO	2030	680	720
GE	RO	2030	1000	1000
RO	HU	2031	1117	685

15 https://energy.ec.europa.eu/data-and-analysis/energy-modelling/policy-scenarios-delivering-european-green-deal_en

16 Malta and Cyprus are excluded, as those countries are not modelled by the EPMM.

17 https://www.entsoe.eu/data/map/

18 https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission

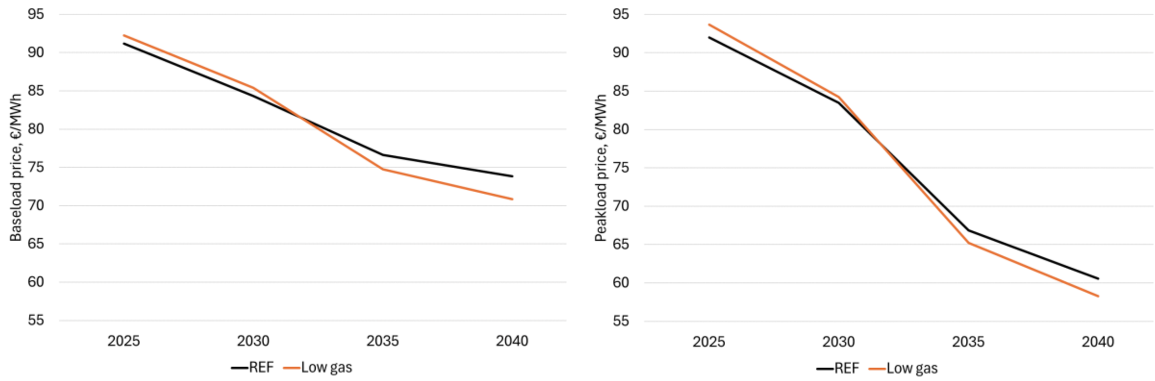
4 Comparison of results for the two main scenarios

In this section the results of the two main scenarios are presented and compared for a better understanding of the implications brought by each scenario for power prices, security of supply, emissions and utilisation of interconnectors.

4.1.1 Market price and RES market value

Figure 6 illustrates the modelled baseload and peakload prices in the Reference and Low Gas scenarios.

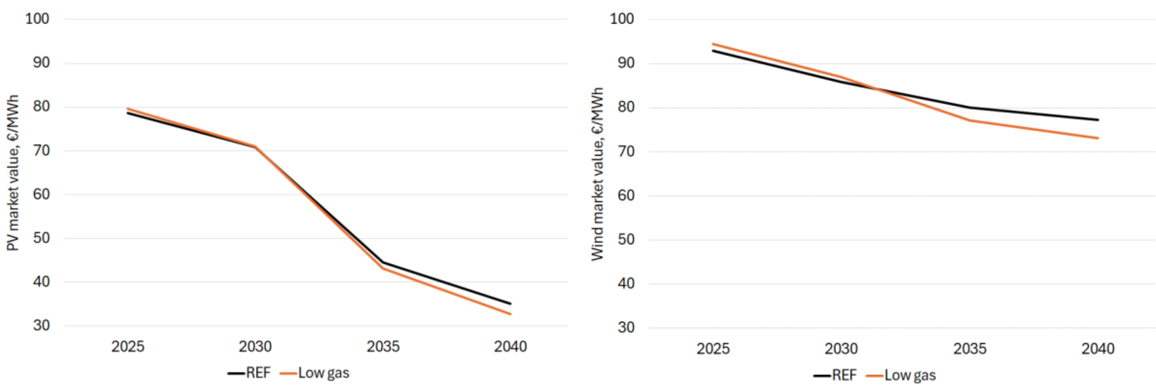
FIGURE 6. BASELOAD (LEFT) AND PEAKLOAD (RIGHT) PRICES IN THE TWO MAIN SCENARIOS (€/MWh)



In both scenarios, baseload and peakload prices follow a decreasing trend. In the Low Gas scenario prices are lower over time due to the higher share of renewables. While prices are almost identical at the beginning of the period, by 2040 there is a price difference of almost 3 EUR/MWh for baseload prices and 2 EUR/MWh for peakload prices between the two scenarios. In both scenarios, baseload prices become higher than peakload from 2030 onwards. The main reason for this is that during the day, PV capacities generally produce a large amount of electricity simultaneously, increasing the frequency of significantly lower prices. Additionally, the share of these low-price hours is higher during the peakload period, which puts additional downwards pressures on peakload prices.

Figure 7 illustrates PV and wind market values calculated as the average market price when these power plants are generating.

FIGURE 7. PV (LEFT) AND WIND (RIGHT) MARKET VALUE IN THE TWO MAIN SCENARIOS (€/MWh)



Similar to the baseload price, the market values of the two scenarios are very close in all modelled years. The market value of PV decreases dramatically in both scenarios, resulting in a market value factor[19] of 46-47% in 2040, while the market value of wind remains higher than that of solar.

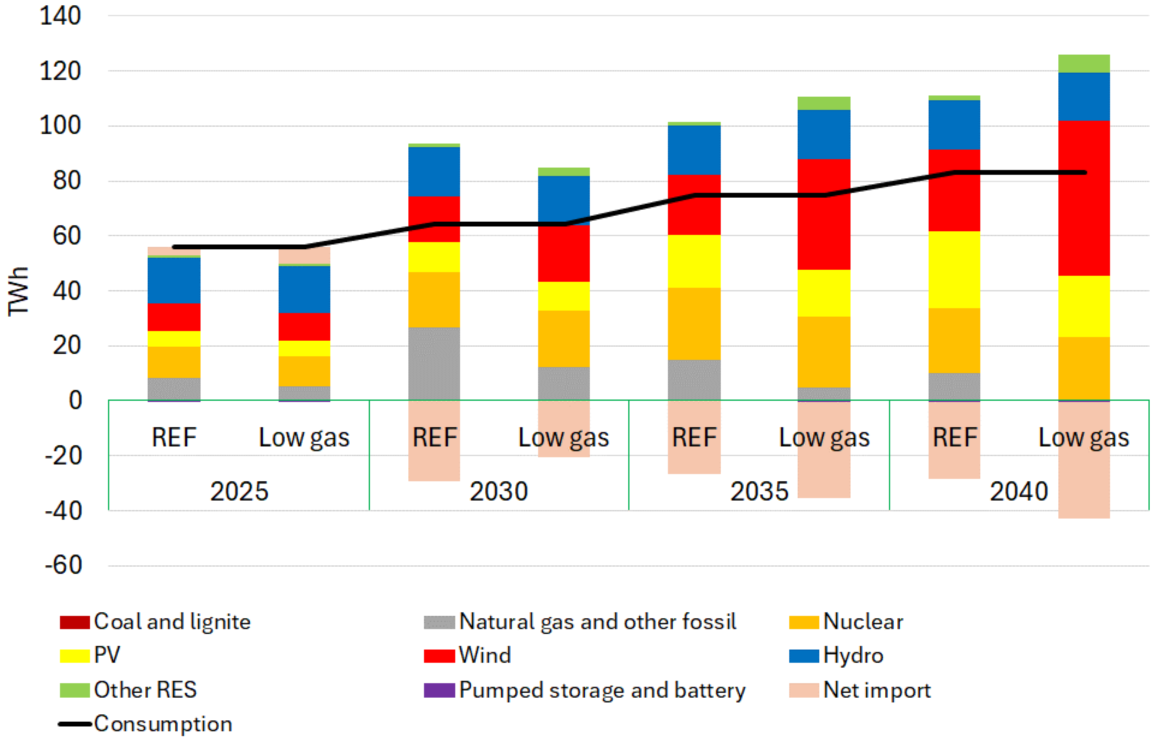
The market value factor for wind is slightly above 100% in both scenarios, meaning that the own price for wind is higher than the baseload price in all modelled years. The difference in market value is mainly explained by the cannibalisation of PV capacities at times of maximum capacity during the day, suggesting potentially higher returns for investments in wind power. Given the regulatory framework limitations in Hungary and to some extent Bulgaria, Romania may therefore have a competitive advantage compared to its neighbours for developing wind capacities.

[19] Ratio between the market value and the baseload price.

4.1.2 Electricity mix

Figure 8 illustrates the Romanian electricity mix for the two scenarios in all modelled years.

FIGURE 8. ELECTRICITY MIX IN THE TWO MAIN SCENARIOS



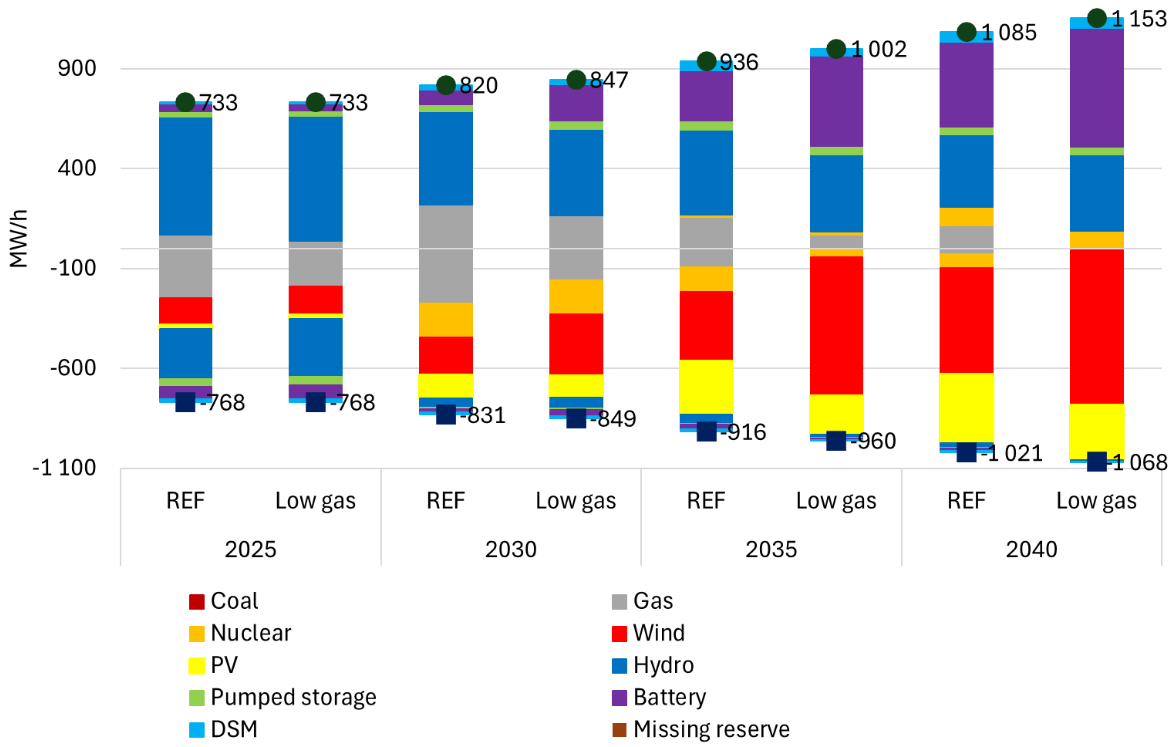
A key difference emerges from the higher gas-fired power generation in the Reference Scenario, while the Low Gas Scenario would see a comparatively higher production of wind power, resulting in higher exports after 2035. Domestic production levels are relatively similar in the Reference and the Low Gas scenario in 2025; production in 2030 is lower in the latter, but becomes significantly higher thereafter due to accelerated RES deployment. The contribution of coal to the electricity mix is insignificant even in 2025. This indicates that under normal market conditions, coal-fired capacities would become uneconomical well before the official complete coal phaseout date in 2032. Hydro and nuclear power remain integral parts of the electricity mix throughout the two scenarios. Based on investments in new capacities, Romania would be a net exporter of electricity in all scenarios and years, except for 2025. Hence, Romania can be a net exporter even with lower gas capacities if investment in renewables and storage is prioritised.

4.1.3 Reserve capacity mix

When estimating the reserve requirement, we assume a moderate increase in line with higher load and variable RES capacities. The relationship is based on a regression analysis carried out on the data of 7 years and 16 countries. Therefore, the reserve requirement is higher in the Low Gas scenario due to a higher renewable rate.

Figure 9 shows how the estimated reserve requirements can be fulfilled in the different scenarios.

FIGURE 9. BALANCING RESERVE MIX IN THE TWO MAIN SCENARIOS



The modelling results show that the reserve requirements can be safely met in both scenarios and in all modelled years, without jeopardising security of supply. This also implies that natural gas can be successfully replaced by 2040 even in the reserve market by a higher share of RES and more dynamic storage capacity, as assumed in the Low Gas Scenario.

Upward balancing capacity is mainly provided by hydro, natural gas, pumped storage and a growing share of batteries over time, while new nuclear capacity also participates to some extent in this market. In the downward direction, natural gas is mainly replaced by renewables and partly by nuclear over time. Nuclear power plants are commonly operated in baseload mode, but they are technically capable to provide frequency regulation. It is a usual assumption in the modelling literature that as flexibility is becoming more valuable, nuclear units will be used for downward regulation as well.

4.1.4 Utilisation of interconnectors

The average utilization of the Romanian export and import interconnectors is summarized in Figure 10.

FIGURE 10. UTILIZATION OF THE ROMANIAN INTERCONNECTORS

		2025		2030		2035		2040	
		REF	Lowgas	REF	Lowgas	REF	Lowgas	REF	Lowgas
Import	UA	94%	94%	37%	56%	51%	38%	25%	19%
	MD	97%	97%	3%	9%	14%	9%	6%	4%
	BG	33%	48%	6%	9%	22%	18%	26%	16%
	HU	4%	5%	1%	2%	0%	0%	6%	3%
	RS	15%	20%	0%	0%	0%	0%	1%	0%
	GE	N/A	N/A	97%	97%	85%	84%	55%	46%
Export	UA	3%	3%	17%	12%	22%	31%	45%	56%
	MD	1%	1%	22%	14%	19%	28%	39%	49%
	BG	13%	7%	67%	54%	37%	46%	36%	52%
	HU	76%	74%	78%	65%	70%	78%	45%	60%
	RS	29%	23%	93%	90%	81%	85%	65%	76%
	GE	N/A	N/A	2%	2%	7%	8%	17%	24%

The import direction from Moldova and Ukraine is fully congested in 2025, but capacity expansions on both borders and the introduction of CBAM reduce the utilisation from 2030 onwards.

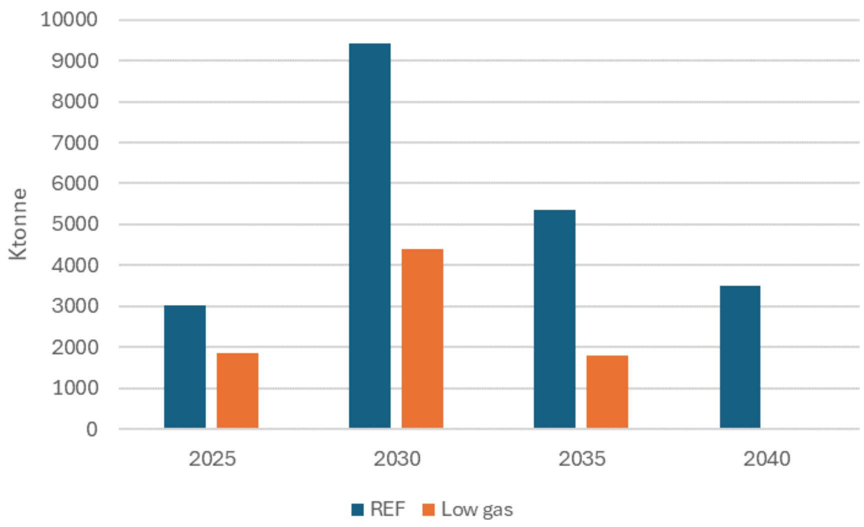
The new GE-RO line is fully congested in 2030 in both scenarios, but its utilisation (sum of directions) drops to around 70% by 2040, with an average export utilisation of 17-24%. In both scenarios, the export lines are highly utilised in 2030 and 2035 (especially to Hungary and Serbia). Except for 2030, bi-directional line utilisation is higher in the Low Gas scenario.

4.1.5 CO2 emissions

The figure below summarizes the CO_2 emissions in the two main scenarios. The Reference Scenario results in higher CO_2 emissions than the Low Gas Scenario in all modelled years due to the power generation from fossil-fired capacities. In both scenarios, emissions reach their maximum in 2030, albeit at a significantly different value with 5 million fewer tonnes of CO_2e in the Low Gas Scenario.

Crucially, in the Low Gas Scenario, the electricity system of Romania becomes decarbonised in 2040, while the Reference Scenario makes decarbonization by 2040 unfeasible. A key finding is that due to a comparatively lower RES penetration, emissions in the Reference Scenario would be slightly higher in 2040 compared to 2025, meaning that based on current plans, Romania risks failing to meet its long-term decarbonisation objectives.

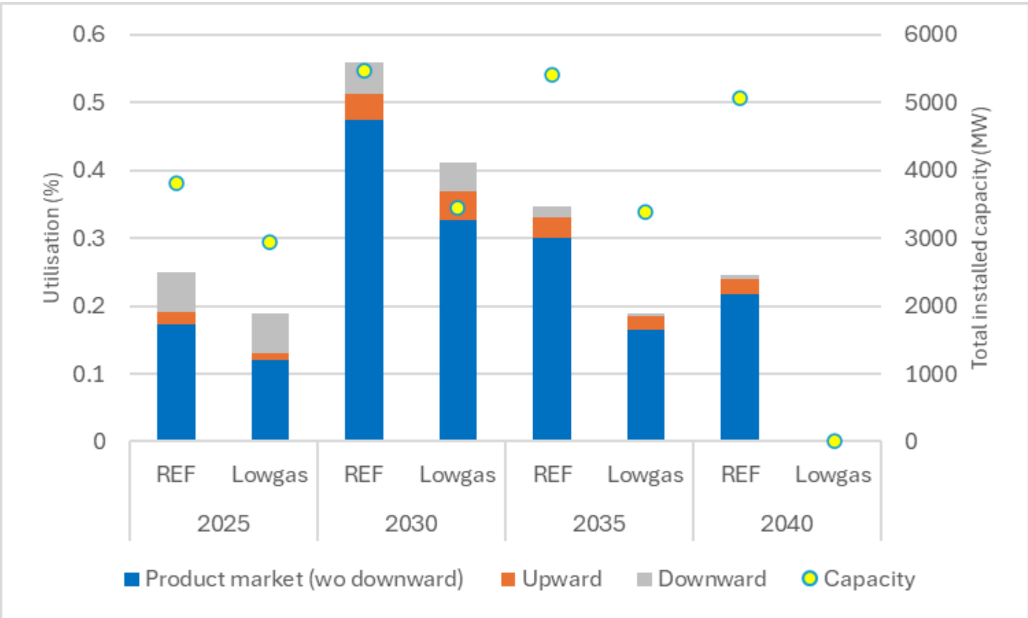
FIGURE 11. CO2 EMISSIONS IN THE TWO MAIN SCENARIOS, kT CO2



4.1.6 Utilization of fossil capacities

Figure 12 compares the utilization of the natural gas capacities in the two main scenarios and in different years.

FIGURE 12. UTILIZATION OF GAS CAPACITIES



Due to the high coal and lignite prices and the old power plant fleet in Romania, the utilisation of coal/lignite power plants reaches almost 0% as soon as 2025, despite those capacities still being available. Due to more newly built efficient gas production capacity, the utilisation of gas PPs is higher in the Reference Scenario than in the Low Gas Scenario in all years. Utilisation is highest in 2030, but decreases significantly in later years, even in the Reference Scenario. In 2040 natural gas would be phased out in the Low Gas scenario as utilisation plummets to 0%.

5 Sensitivities

Several sensitivity analyses have been carried out, listed in Tabel 6. In these sensitivities a single parameter was changed, while all the others remained constant, allowing the effect of the change to be isolated and thus investigated relative to the Reference or the Low Gas scenarios. The results of the sensitivities are summarised along key market measures such as price, electricity and reserve mix, utilisation of power plants and emissions.

TABLE 6: SENSITIVITY SCENARIOS

	Sensitivities
1	Late_nuclear: Refurbishment of Cernavoda's U1 is delayed to 2031 (instead of 2030). Delay in new capacity installations: U3 to 2033 (instead of 2030), U4 to 2034 (instead of 2031), Doicești SMR to 2031 (instead of 2029)
2	Pumped_storage: A new 1 GW pumped storage power plant is installed within the system in 2032
3	High_PV & storage: 800 MW of rooftop PV with 120 MW of storage installed in all years until 2040
4	Low_hydro: Relative to the main scenarios, 300 MW run of river hydro capacity is not completed between 2024 and 2030
5	High_CO2 Price: EU Commission WAM CO2 price is assumed, reaching 250 EUR/t in 2040
6	Hydrogen_2035: In reference scenario after 2035, natural gas-based power plants are fully fueled with hydrogen, with a fuel price of 82 EUR/MWh
7	Extreme_gas: In the reference scenario 300 EUR/MWh gas price is assumed for Romania, meaning that gas is basically unavailable for the country

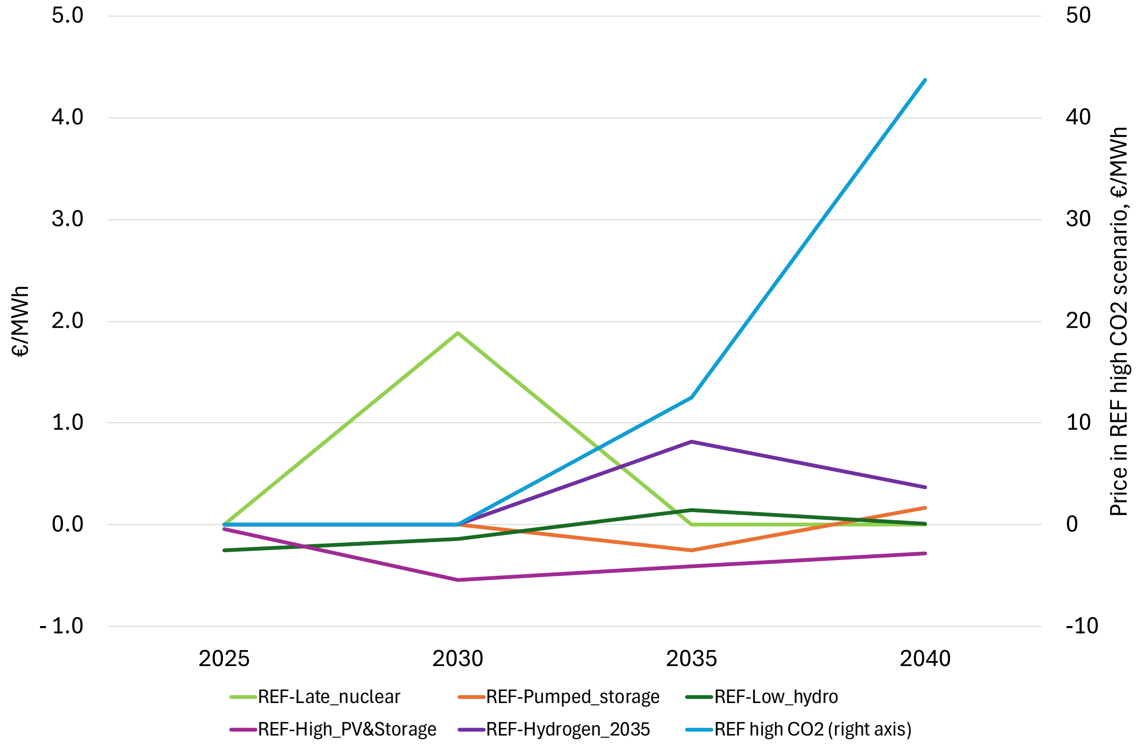
5.1.1 Wholesale price

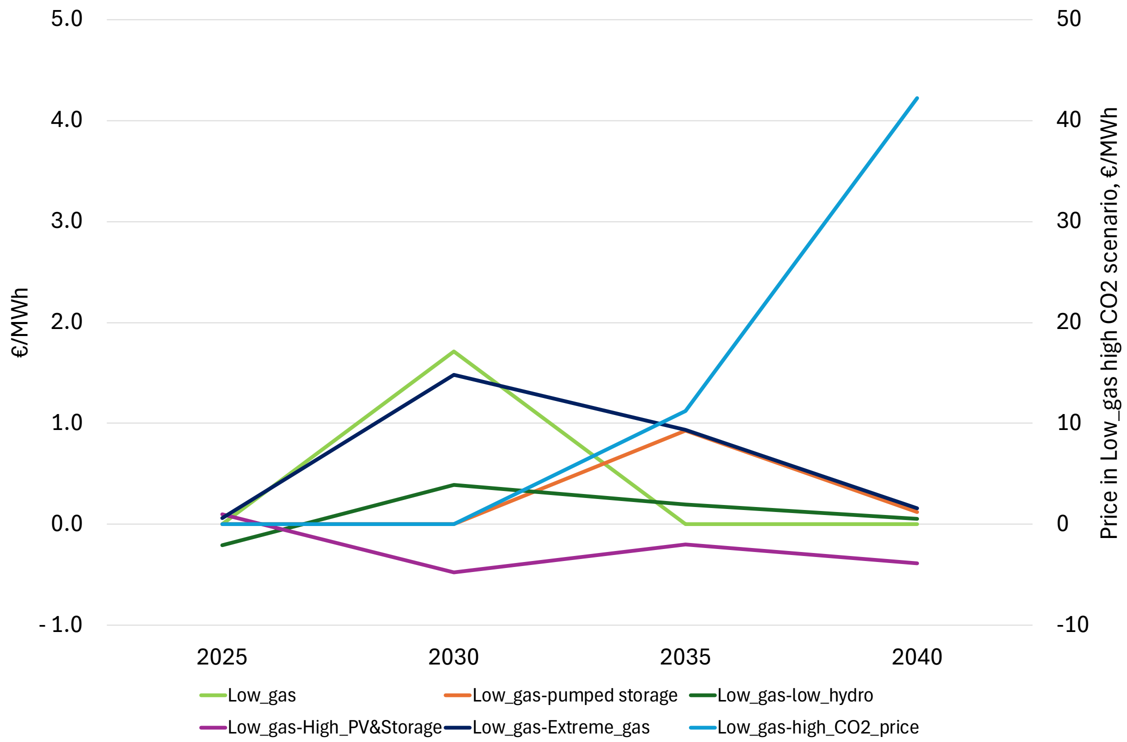
With the exception of the High CO2 price, all other sensitivities have minor or moderate effects on prices:

- Delayed completion of nuclear capacities increases the baseload price by 1.7 €/MWh in 2030 in the Reference scenario and has a bit higher effect in the Low Gas scenario (1.9 €/MWh). The impact on prices of this sensitivity vanishes from 2035 as those nuclear capacities come online.
- Higher PV and storage decrease the wholesale price between 0.2-0.5 €/MWh in both scenarios, with the highest effect in 2030. While the impact is not large, this sensitivity which foresees higher shares of household PVs and storage reduces overall electricity demand from the grid and therefore has a downwards impact on wholesale prices.
- Both sensitives on hydro capacities (the completion of new pumped storage capacities and, respectively, less run-of-river capacities) similarly has no significant impact on prices (less than 0.5 EUR/MWh).

- Replacing natural gas with hydrogen in the CCGTs leads to price increases by 0.5-1 €/MWh, the second largest wholesale price in 2035 and 2040 among all sensitivities.
- The extreme gas sensitivity, which prices out gas-fired capacities, has the highest price effect in 2030 (1.5 EUR/MWh), decreasing to almost 0 in 2040, highlighting that in the long-term those assets have no influence on prices.
- The CO2 price has the largest wholesale price effect. While until 2030 we assume that the CO2 price remains unchanged, in 2035 in the High CO2 price scenario CO2 would be by almost 40€/t more expensive (120 vs. 82 €/t), while by 2040 it would increase by 165 €/t (250 vs. 85 €/t), resulting in a wholesale price increase of 10-11 €/MWh in 2035 and 41-43 €/MWh in 2040 in the two scenarios (Reference and Low Gas). Importantly, the CO2 price not only increases through direct effect in Romania, but also through increasing prices in the whole region and the EU, yet without assumming similarly ambitious RES deployment in other countries. Through market coupling and interconnections, the Romanian power price would thus face upwards pressures.

FIGURE 13. BASELOAD ELECTRICITRY PRICE CHANGE COMPARED TO THE REF (LEFT) AND LOW GAS SCENARIO (RIGHT) IN DIFFERENT SENISITIVITY SCENARIOS, €/MWH





5.1.2 Electricity mix

The Late nuclear and Hydrogen_2035 sensitivities show the largest effect on the electricity mix. The delayed deployment of nuclear facilities would reduce nuclear-based power generation by around 9 TWh in 2030 compared to the Reference scenario. This reduction is mainly compensated by imports and a higher utilisation of natural gas plants by around 2-2.5 TWh in both scenarios. Importantly, even under this scenario, Romania remains a net electricity exporter from 2030 onwards.

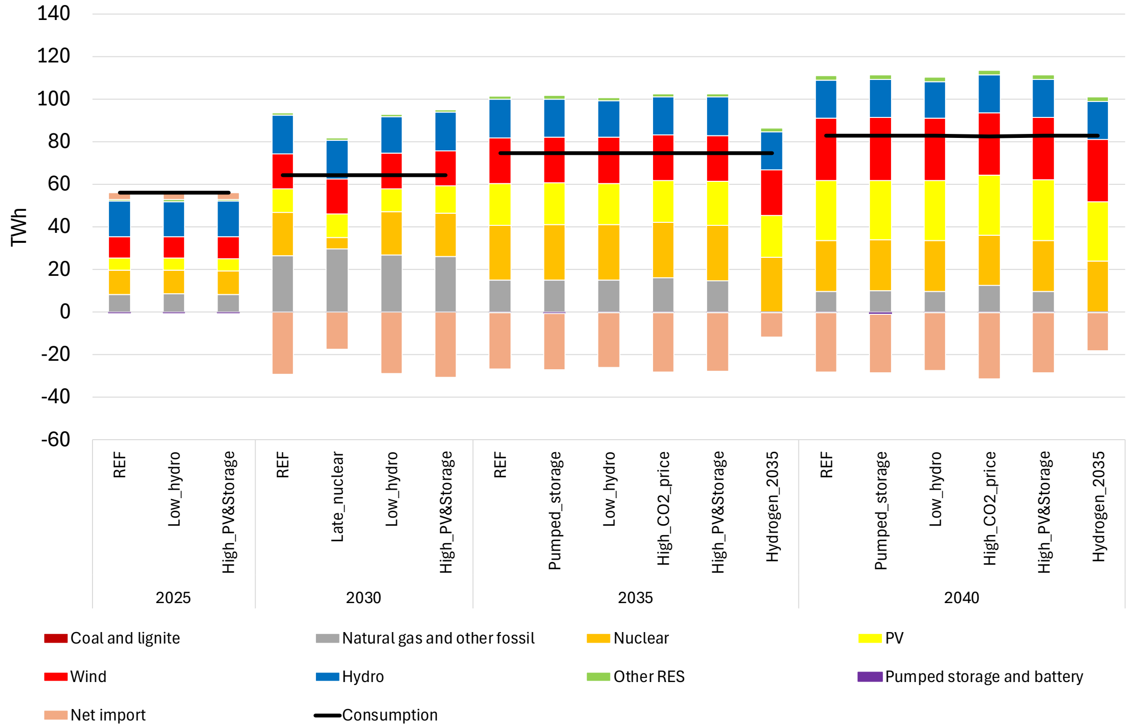
In the Hydrogen_2035 sensitivity, overall production is significantly lower, as gas-based capacities switching to H2 have almost no contribution in the energy mix (less than 0.1%), being priced out of the market because of the higher fuel costs, despite lower costs with the CO2 emissions. This raises the risk that the H2 switch would simply not happen, and natural gas capacities would continue to operate on gas. The costs reduction due to the avoidance of emissions is not sufficient to compensate for the higher fuel cost. Romania would still continue to be a net exporter in 2035 under this scenario, mainly given the expansion in RES capacities in both main scenarios.

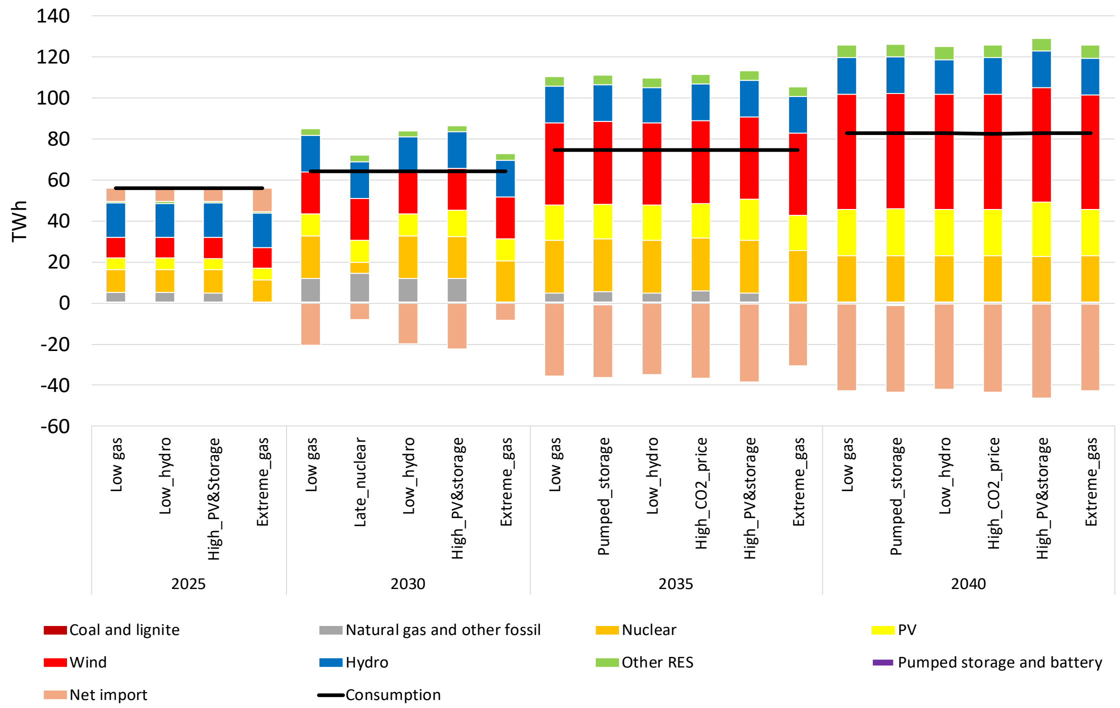
The other sensitivities have only minor effects on the electricity mix:

- Less hydro production (lesser installed run-of-river) primarily decreases exports while new pumped storage slightly increases them, but the overall effect is minimal.
- High CO2 prices provide a similar fossil-based power generation structure (slightly even higher production given Romania's comparative advantage in the region when it comes to production). The reason for the slight increase is that new gas plants are quite efficient and some lost coal production in other countries is substituted by them.

A key finding is that in all sensitivities to the Low gas scenario, fossil-based capacities are not needed in the electricity mix, which becomes fully decarbonised.

FIGURE 14. ELECTRICITY MIX OF THE DIFFERENT SENSITIVITY SCENARIOS BASED ON THE REFERENCE (UPPER FIGURE) AND LOW GAS SCENARIO (LOWER FIGURE), TWh





5.1.3 Utilisation of interconnectors

The highest effect on the utilisation of the Romanian interconnectors in 2030 is in the Extreme gas scenario and Late nuclear, with only minor effects visible in the other two scenarios. In the Extreme gas scenario, the natural gas-based electricity production is negligible, which results in a higher import share, and increases the utilization of import capacities, especially from Ukraine. In the case of late nuclear commissioning, a similar effect occurs in both scenarios.

For 2040, the Extreme gas sensitivity is almost the same as the Low Gas Scenario, due to the lack of natural gas-based generation. If the natural gas-fired power plants switch to hydrogen, then their utilization rate is almost zero, which results a higher share of import and also a higher utilization of import capacities, compared to the Reference scenario.

FIGURE 15. UTILIZATION OF THE ROMANIAN INTERCONNECTORS IN DIFFERENT SCENARIOS, 2030 (UPPER), AND 2040 (BOTTOM)

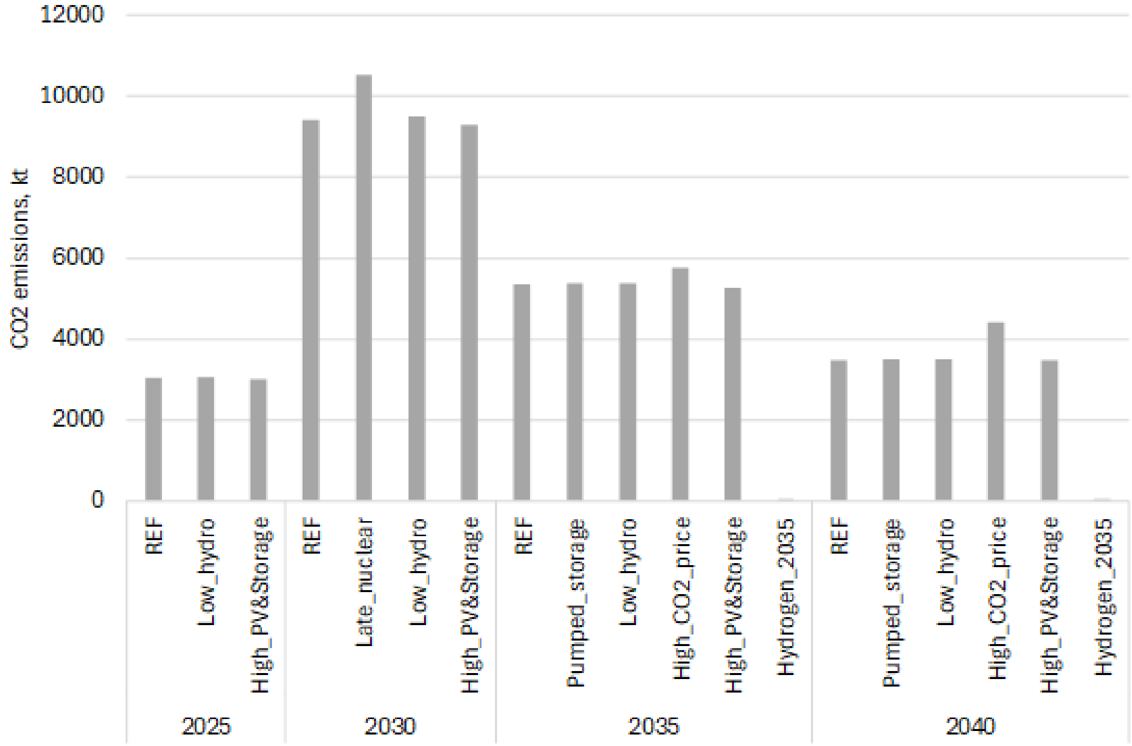
		2030								
		REF	Lowgas	Late_nuclear		High_PV&Storage		Low_hydro		Extreme gas
				REF	Lowgas	REF	Lowgas	REF	Lowgas	
Import	UA	37%	56%	59%	66%	37%	55%	39%	57%	67%
	MD	3%	9%	9%	15%	3%	9%	3%	9%	15%
	BG	6%	9%	12%	20%	5%	7%	7%	10%	19%
	HU	1%	2%	3%	7%	0%	1%	1%	2%	8%
	RS	0%	0%	0%	0%	0%	0%	0%	0%	0%
	GE	97%	97%	98%	98%	97%	97%	97%	97%	97%
Export	UA	17%	12%	9%	6%	19%	13%	17%	12%	7%
	MD	22%	14%	13%	10%	23%	15%	21%	14%	10%
	BG	67%	54%	51%	31%	70%	58%	67%	53%	32%
	HU	78%	65%	60%	41%	80%	68%	77%	63%	40%
	RS	93%	90%	88%	82%	94%	91%	93%	90%	83%
	GE	2%	2%	1%	1%	2%	2%	2%	2%	1%

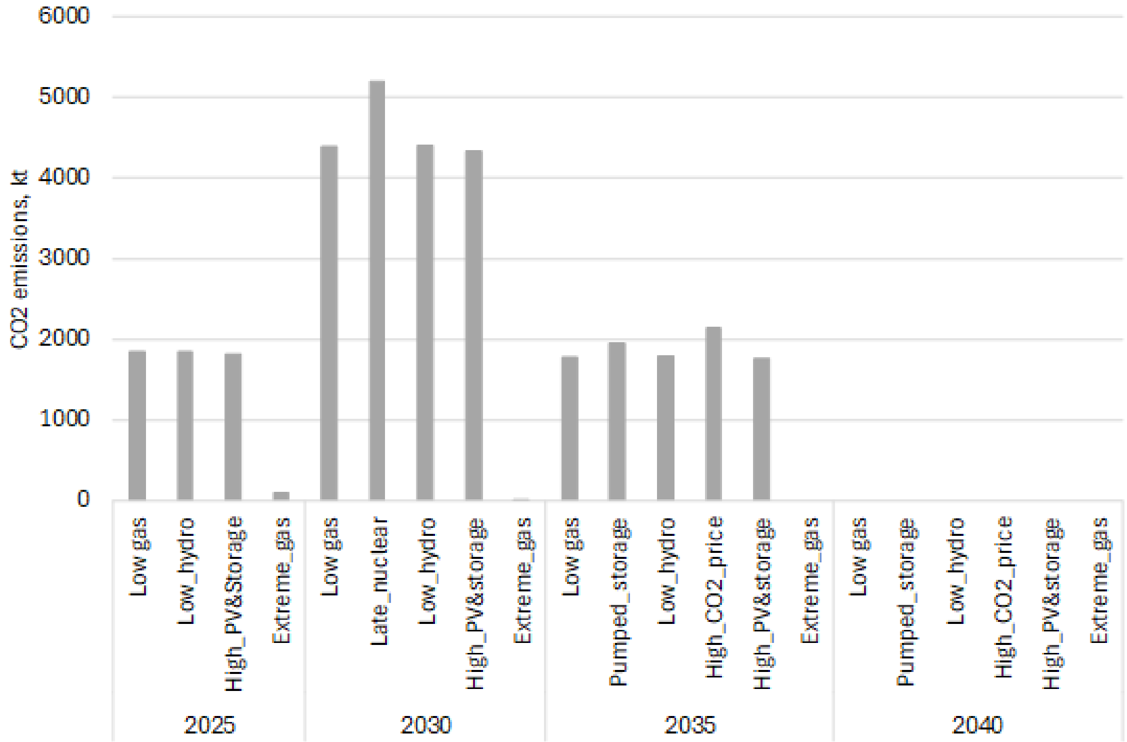
		2040										
		REF	Lowgas	CO2	Pumped storage		High_PV&Storage		Low_hydro		Hydrogen _2035	Extreme gas
				REF	REF	Lowgas	REF	Lowgas	REF	Lowgas		
Import	UA	25%	19%	25%	25%	19%	25%	18%	25%	20%	30%	19%
	MD	6%	4%	5%	6%	4%	6%	4%	6%	4%	8%	4%
	BG	26%	16%	11%	26%	14%	26%	15%	27%	16%	33%	15%
	HU	6%	3%	9%	7%	4%	6%	2%	6%	3%	9%	3%
	RS	1%	0%	2%	1%	0%	1%	0%	2%	0%	2%	0%
	GE	55%	46%	34%	54%	44%	54%	44%	54%	45%	59%	46%
Export	UA	45%	56%	43%	46%	56%	46%	59%	45%	56%	40%	57%
	MD	39%	49%	37%	39%	49%	39%	51%	38%	48%	34%	49%
	BG	36%	52%	56%	35%	53%	37%	55%	36%	51%	26%	52%
	HU	45%	60%	35%	44%	59%	45%	65%	44%	59%	35%	60%
	RS	65%	76%	63%	65%	77%	65%	79%	64%	76%	55%	76%
	GE	17%	24%	33%	18%	24%	17%	24%	17%	24%	14%	23%

5.1.4 CO2 emission

As coal-fired capacities already become uneconomical in 2025, the levels of CO2 emissions in the power sector become fully dependent on the utilisation rate of Romanian natural gas-based electricity capacities. Therefore, the highest CO2 emissions are seen in the late nuclear scenarios (both in the REF and Low Gas scenario). The emissions are negligible in the Extreme gas and Hydrogen_2035 scenarios.

FIGURE 16. CO2 EMISSIONS OF THE DIFFERENT SENSITIVITY SCENARIOS BASED ON THE REFERENCE (UPPER FIGURE) AND LOW GAS SCENARIO (LOWER FIGURE), kT CO2

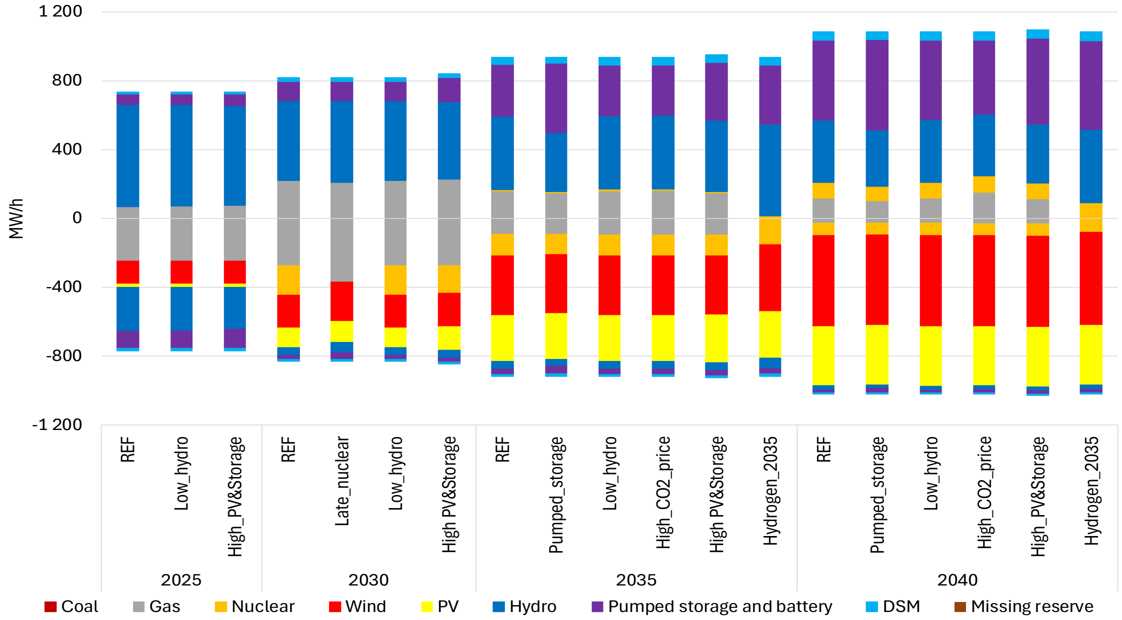


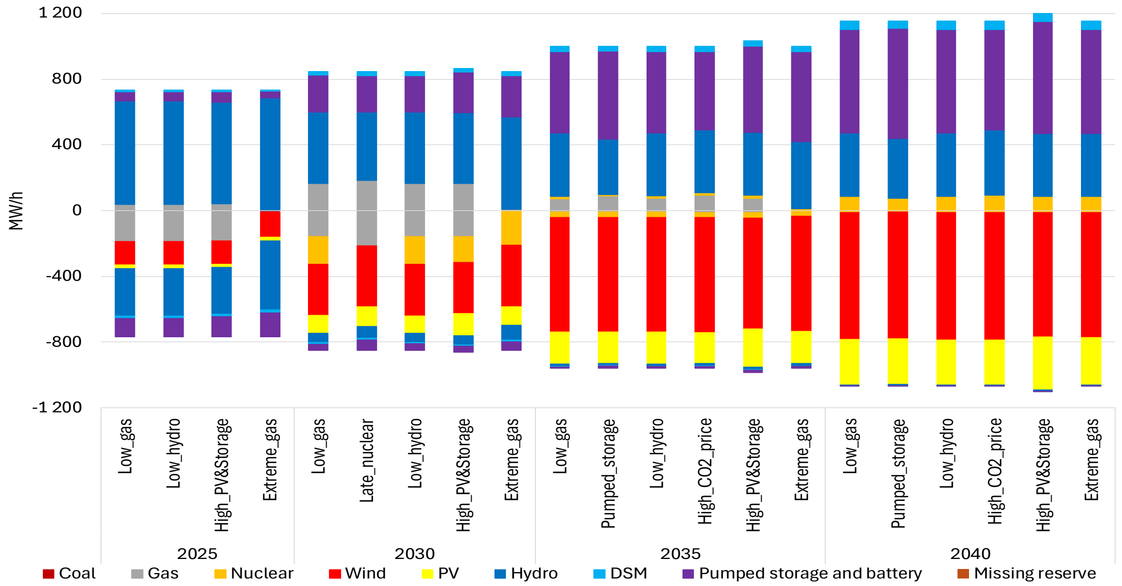


5.1.5 Reserve capacity mix

Most sensitivities do not indicate a significant impact on the reserve capacity mix. In Late nuclear, nuclear capacities in the downward direction are mostly substituted with natural gas and wind capacities in both scenarios. In Hydrogen_2035 or Extreme gas the hydrogen or gas-fuelled power plants does not participate in the reserve market, and these capacities are substituted with RES and nuclear. This shows that the system could be balanced even without gas capacities. Higher pumped storage capacities would contribute to the upward reserve market, which in turn decreases the reserve of hydro storages.

FIGURE 17. RESERVE MIX OF THE DIFFERENT SENSITIVITY SCENARIOS BASED ON THE REFERENCE (UPPER FIGURE) AND LOW GAS SCENARIO (LOWER FIGURE), MW/h

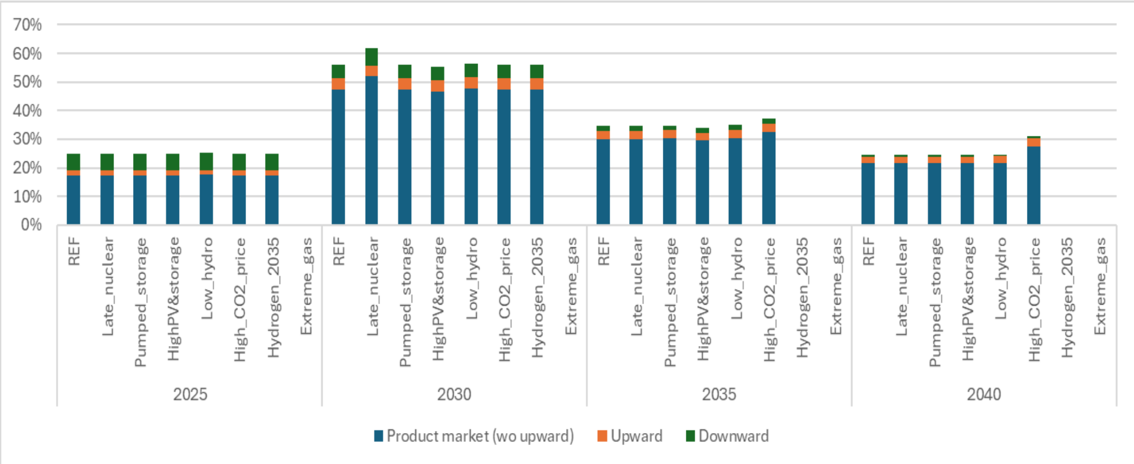


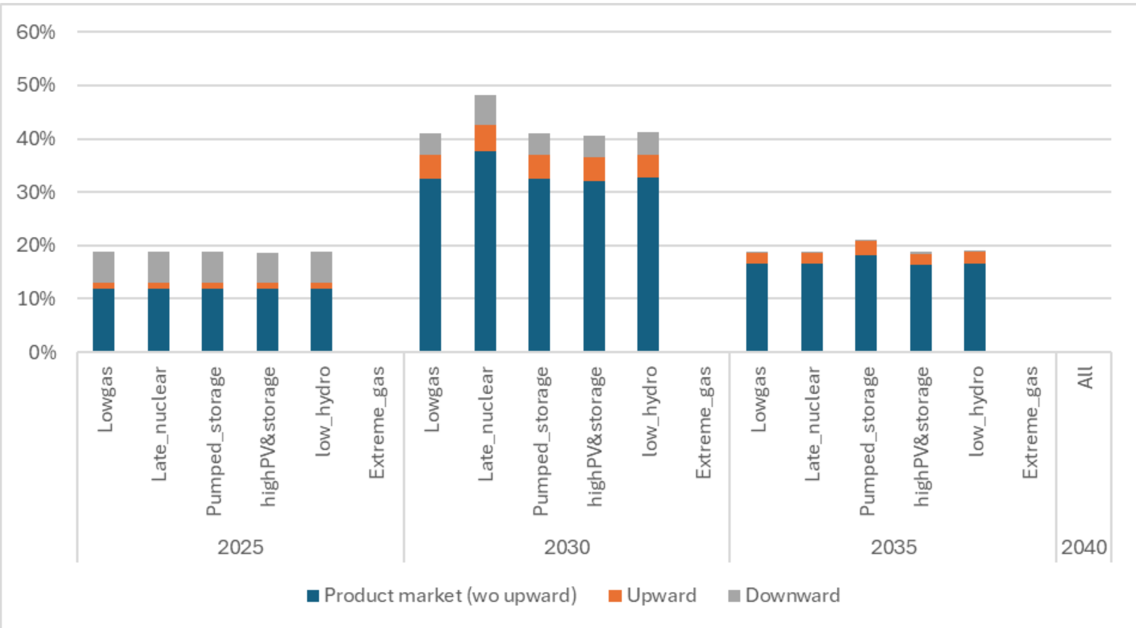


5.1.6 Utilisation of fossil capacities

The utilisation rates are almost the same in all sensitivities, with few exceptions. In the Extreme gas scenario, it is shown that the utilisation of gas power plants is zero, meaning that Romania could operate without gas-based generation. However, there could be some difficulties in the reserve market in 2025 as the mix basically only involves hydro storage, whose availability could be hindered in unfavourable weather conditions. Nonetheless, the utilisation significantly decreases from 2035. If the gas-based capacities are fuelled by hydrogen (Hydrogen_2035 scenario), they will not participate in either the product or reserve market. The utilisation rate of these power plants is around 0.1%. Finally, if the commissioning of new nuclear units is delayed, the utilisation rates of the gas-based generation will increase, especially in the product market.

FIGURE 18. UTILIZATION OF GAS- AND HYDROGEN-BASED CAPACITIES OF THE DIFFERENT SENSITIVITIES BASED ON THE REFERENCE (UPPER FIGURE) AND LOW GAS SCENARIO (BOTTOM FIGURE), %





6 Conclusions for policymakers

This modelling exercise has shown that Romania can reach a completely decarbonised electricity production mix in 2040 with no security of supply risks by aiming to have no more than 3.5 GW[20] of total installed gas-fired capacities by 2030 and by focusing more on wind power and a higher deployment of storage technologies. In contrast, the investments outlined in Romania's LTS and draft revised NECP do not ensure a decarbonised energy sector by 2040. The Romanian power sector would emit 9.2 $MtCO_2$ in 2030 (which can be halved in a lower-gas scenario) and 3.5 $MtCO_2$ in 2040, at slightly higher wholesale electricity prices. This analysis shows that neither scenario would pose security of supply risks for the country. However, even if both scenarios are viable (i.e., no security of supply concerns) future pathway for the country, there are significant differences in terms of cost efficiency and emissions.

6.1 The diminishing role of fossil fuel capacities

The Reference Scenario presents a future for Romania that is heavily reliant on gas[21] for electricity generation even in 2040. In this scenario, several new gas power plants will be constructed, supplemented with new nuclear and renewable capacities. In the Low Gas Scenario significantly less natural gas projects will be completed, but the capacity expansion of renewables will be larger. This contrasts with the gas investments outlined in both the LTS and the draft revised NECP. The modelling results show that, in the early years, the Reference Scenario leads to slightly lower prices, but from 2035 because of large RES capacity expansion, the Low Gas Scenario leads to comparatively lower prices by 3 EUR/MWh.

On top of the lower prices, the Low Gas Scenario leads to significantly lower CO_2 emissions, because of the lower natural gas-based generation. Crucially, the Reference Scenario would result in higher emissions in 2040 compared to 2025, seriously endangering the country's decarbonisation goals, especially considering the upcoming 2040 targets discussions. Given also the results of the Extreme gas sensitivity, that models a scenario in which gas-fired capacities do not contribute to the electricity mix, it is clear that the post-2030 contribution of Romania's planned capacities is not essential. In fact, the results of this modelling exercise show that Romania's official plans probably see the installation of too many new capacities of natural gas, more than necessary for ensuring a secure, low-price and increasingly decarbonised electricity system.

Data released by the Romanian Transport System Operator (TSO, Transelectrica) on April 1st 2024[22] indicate an installed power capacity of 2,275 MW (net power) on natural gas connected to the National Energy System. Nonetheless, a minimum of 2,615 MW of new CCGT and 947 MW of CHP are to be installed as part of the proposed NECP and LTS. This new capacity seems to be underestimated, as one of the main plants (Mintia) plans to install at least double the

[20] Investments in new power plants (CCGTs) will be limited to the completion of Iernut project, to which an additional capacity of 600 MW will be added and divided between (Turceni, Ișalnița and Mintia).

[21] According to Romania's draft revised NECP, natural gas is substituted with hydrogen in 2035, which we estimated as a sensitivity scenario.

[22] Producție - Transelectrica

initially planned capacity, according to public statements. Additionally, other CHP capacities, not included in the two strategic documents have already secured financing support for new projects. Moreover, the Ministry of Energy[23] confirms that it will issue a new call for projects in the second half of the year. These significant investments in gas plants make achieving climate neutrality more challenging.

The results of the Extreme gas sensitivity show that without any gas-fired power plants, Romania would not meet its reserve capacity requirements in 2025. However, from 2030 onwards the country can safely operate without gas if all other modelled capacity expansions are in place (i.e., new interconnectors, renewable and nuclear investments). While in 2030 no gas operation would lead to higher electricity prices (by 1.5 EUR/MWh), from 2035 it would not even have significant price effect. This shows that such investments must be carefully considered and potential short- and medium-term benefits should be balanced against long-term utility (or lack thereof). Such investments in new gas-fired capacities should be reassessed and resized according to the actual needs of the power sector. Smaller peaking capacities could balance a renewables-dominated electricity mix until 2040.

An apparent solution to the lack of a long-term business case and the impact on emissions of the planned gas-fired capacities that has been included in official plans is the switch to hydrogen utilization from 2035. However, the conclusions of this modelling exercise are clear: replacing natural gas with hydrogen in 2035 in all gas power plants would mean that these assets would no longer be utilised. This is because replacing gas with hydrogen would significantly deteriorate the cost-competitiveness of these capacities, immediately reaching a utilisation rate lower than 0.1%, given the high fuel prices of 82 EUR/MWh in 2030, according to renewable hydrogen cost estimations presented in the draft National Hydrogen Strategy (in the process of obtaining environmental assessment). There is therefore a significant risk that even 'hydrogen-ready' investments would continue to operate on fossil fuels for economic reasons, thus not achieving their promised emissions reductions.

The potential use of hydrogen in the energy sector requires detailed technical and economic analysis, as the high cost of hydrogen can make it unattractive for energy production. Also, a comprehensive strategy for hydrogen production, transport and storage is necessary, as the current draft National Hydrogen Strategy primarily focuses on the use of hydrogen in industry and transport sectors. Without this holistic approach, the potential use of hydrogen to replace natural gas in power plants remains highly uncertain.

Important conclusions can also be drawn regarding the existing coal capacities. Hard coal and lignite phaseout are manageable from a security of supply perspective, even with lower than planned investments in gas capacities. Based on market prices alone, the modelling results show that coal-fired power generation will rarely be economical from 2025 on (expected utilisation of less than 1%). This means that coal-fired capacities can be phased out even earlier than the 2032 deadline set in national legislation.

As coal is quickly becoming uneconomical and is not necessary for security of supply, authorities should therefore phase out subsidies for coal-fired capacities. Due to the high cost of production, coal will find it increasingly difficult to enter the merit order in the market. Energy

[23] Romanian Ministry of Energy

production from coal has steadily declined over time, even throughout the energy crisis caused by the natural gas crunch. In a market dominated by renewable energy, balancing the system to ensure energy security relies on highly flexible capacities. Romania does not need a capacity mechanism for coal capacities and should rather focus on creating the right regulatory framework for integrating other sources of flexibilities, such as batteries and other forms of storage, as well as demand-side management.

6.2 The increasing role of renewable energy

A higher focus on wind energy (17.7 GW onshore and 7.3 GW offshore in 2040, compared to 13.1 GW altogether in official plans) can contribute to complete decarbonisation of the power sector by 2040. Romania appears to have a regional competitive advantage in wind production. The market value of wind remains higher than that of solar for all modelled years, while lower wind investments are expected in Hungary and Bulgaria. Hungary only targets around 1GW of onshore wind capacities by 2030, following strong legislative barriers for these type of projects in the last decade, and has no offshore wind potential, while in Bulgaria strong opposition from fisherman organisations and environmental NGOs postponed the approval of the offshore wind law.

A high renewables scenario would also have a positive impact on the electricity trade balance.[24] Achieving the capacity mix from the Low Gas Scenario would require both overcoming current barriers to the deployment of renewables (especially wind) – mainly structural aspects such as grid capacity, limited national objectives and labour shortages – and mobilising funding at a faster rate. Apart from CAPEX-based support through the Modernisation Fund (766 MW so far) and the National Recovery and Resilience Fund (950 MW, €595 million), Romania should quickly mobilise the Contracts for Difference (CfD) Scheme. The recently approved CfD mechanism accounts for €3 billion to incentivise renewable energy development and foresees support for 2 GW in 2024 and 3 GW in 2025 of onshore wind and PVs.

Importantly, Romania also needs to unlock the offshore wind potential in the Black Sea. Offshore wind investments should become a priority for the following decade, as Romania's offshore wind potential is estimated at 76-94 GW, with 22 GW of bottom-fixed turbines and the rest, of floating turbines. Based on a different modelling,[25] Romania needs to develop 15GW of offshore wind capacities by 2050 to achieve climate neutrality.

A framework offshore wind law was adopted in April 2024, being one of the most significant legislative projects in the energy sector in recent years and paving the way for the development of offshore wind project in Romania Black Sea waters. According to the draft Offshore Wind Roadmap for Romania[26] published for consultation by the World Bank in February 2024, two scenarios are envisaged for offshore wind installed capacities, respectively the *Low growth scenario*, accounting for 3 GW, and the *High growth scenario* for 7 GW by 2036. However, based on the accelerated timeline of the recent adopted law, the first installed capacities are expected in 2032 at the earliest.

[24] Though in either scenario, Romania becomes a net exporter of electricity from 2030.

[25] Romanian_LTS_EPG_Report.pdf (enpg.ro)

[26] Romania Offshore Wind Roadmap - Consultation session, February 2024. BVG Associates

Even with higher renewable shares than presented in official documents, Romania's power sector can deliver on security of supply requirements. The higher balancing reserve requirement can be accommodated through investments in storage (reaching 880 MW in 2030 and 3.4 GW in 2040) covered by existing hydro capacities, new storage installations and, until 2035, gas power plants.

At the beginning of 2023, the Romanian Energy Regulatory Authority (ANRE) issued the Order No. 3/2023 approving the technical norms on connecting storage facilities to the electricity grid. Following this overdue clarification, the first storage capacities in Romania started being installed in 2023, with current batteries capacity reaching 16.2 MW (14 MWh) in Q1 2024.[20] The ongoing state-supported investments in battery storage capacities need to be further expanded. So far, funding has been made available for the installation of 240 MW (480 MWh) by the end of 2025 through the National Recovery and Resilience Plan. Additionally, according to public statements by representatives of the Ministry of Energy, a new financing scheme for storage capacities through the Modernisation Fund is expected, without specific information on the timeline or budget at this point.

An annual installation of 800 MW rooftop PV and 120 MW in battery can further decrease balancing pressures and slightly lower wholesale prices (by about 1.1 EUR/MWh in 2040). Following the energy crisis, Romanian households have started installing rooftop PVs installations at an accelerated rate. At the start of 2021 there were only approximately 2,100 prosumers with an installed capacity of 19 MW; in April 2024 their number reached approximately 114,000, with a total installed capacity of 1,500 MW. Ramping up grid investments is critical to accommodate higher shares of renewables and enable cross-border electricity flows. In an evolving landscape of ambitious decarbonization targets, with growing electricity demand and rising installation of renewable energy sources, the expansion, reinforcement and digitalisation of both transmission and distribution networks becomes essential.

Another important finding of this modelling exercise is that existing hydro power facilities are key for balancing a renewables-dominated power sector. However, new investments in hydro capacities (including 300 MW in small hydro installations and a 1 GW pumped hydro capacity that would come online in 2032) would only have a limited effect on electricity prices and security of supply – assuming the mentioned battery storage investments are realised. If a new pumped hydro station is completed in 2032, it will mostly participate in the reserve market, according to the modelling, leading to a higher share of storage technologies in the upward reserve mix. The pumped storage project at Tarnița-Lăpuștești has a history spanning at least four decades and has recently received a lot of media attention. However, by the time this installation would come online, its impact on the power system will be limited, while the environmental footprint of this project in the local area would be significant. Similarly, recurring discussions on finishing previously started small hydro projects of approximately 300 MW in total has been mentioned in both the LTS and the draft revised NECP. The impact of these projects would likewise only bring limited positive contributions to the Romanian power sector.

Rather than focusing on investments in new hydro capacities, which may not have a timely impact, retrofitting existing assets should be prioritised. A dedicated programme may be needed, as the state company, Hidroelectrica, has been struggling in recent years to refurbish turbines that are towards the end of their life cycle, and to invest in the unclogging of lakes.

6.3 The impact of upcoming investments in nuclear energy

New nuclear energy capacities can contribute to achieving a decarbonised power sector, even if the planned investments suffer delays. The modelling results show that slight delays in the construction of new nuclear (two new conventional CANDU reactors and 460 MW of small modular reactors, as well as the refurbishment of Cernavodă's Unit 1) do not pose security of supply risks, even in a lower-gas scenario of 3.5 GW. If the planned nuclear capacities are not completed in time, it will not pose security of supply challenges for the country, but will increase the wholesale price with 2 EUR/MWh in 2030, and will lead to slightly higher CO2 emission in the same year as a result of higher utilisation of gas. Even with such delays, Romania would continue to be a net electricity exporter after 2030 based on the expansion of its renewable capacities, albeit the prices of electricity and CO2 emissions would be slightly higher.

ANNEX

		Reference				Low gas			
	Year	2025	2030	2035	2040	2025	2030	2035	2040
Prices, €/MWh	Baseload price, €/MWh	91.2	84.3	76.6	73.8	92.3	85.4	74.7	70.9
	Peakload price, €/MWh	92.0	83.5	66.8	60.6	93.7	84.3	65.2	58.3
	PV market value, €/MWh	78.7	70.9	44.5	35.1	79.6	71.0	43.1	32.8
	Wind market value, €/MWh	92.9	85.9	80.0	77.3	94.4	87.0	77.1	73.1
Capacity mix, MW	Coal and lignite	1 995	1 090	0	0	1 995	1 090	0	0
	Natural gas	3 810	5 469	5 409	5 063	2 950	3 454	3 394	0
	Other fossil	330	330	0	0	330	330	0	0
	Nuclear	1 413	2 595	3 315	3 315	1 413	2 595	3 315	3 315
	PV	4 300	8 300	14 900	21 500	4 300	8 240	12 870	17 500
	Wind - onshore	5 000	6 100	6 400	9 100	5 000	7 950	12 825	17 700
	Wind - offshore	0	1 500	3 000	4 000	0	1 500	5 000	7 300
	Run-of river	2 902	3 129	3 129	3 129	2 902	3 129	3 129	3 129
	Hydro Storage	3 467	3 667	3 667	3 667	3 467	3 667	3 667	3 667
	Other RES	221	321	421	521	221	621	921	1 221
	Battery	240	400	1 246	2 164	240	880	2 160	3 440
	Pumped storage	258	258	258	258	258	258	258	258
	DSM	239	584	1 040	1 554	239	584	1 040	1 554
Electricity mix, GWh	Coal and lignite	0	0	0	0	4	0	0	0
	Natural gas	8 462	26 494	15 076	9 850	5 082	12 162	4 985	0
	Other fossil	2	10	0	0	3	14	0	0
	Nuclear	11 140	20 459	25 819	23 919	11 140	20 459	25 727	23 075
	PV	5 663	10 931	19 623	27 940	5 663	10 852	16 913	22 565
	Wind - onshore	10 111	12 336	12 943	18 258	10 111	16 077	25 925	35 504
	Wind - offshore	0	4 282	8 565	11 300	0	4 282	14 250	20 551
	Run-of river	7 656	8 254	8 254	8 197	7 656	8 254	8 248	8 179
	Hydro Storage	9 159	9 682	9 683	9 685	9 159	9 682	9 689	9 686
	Other RES	838	1 217	1 596	1 975	838	3 056	4 662	6 267
	Pumped storage	-22	-28	-67	-80	-22	-34	-67	-81
	Battery	-19	-39	-136	-246	-21	-89	-230	-399
	Missing production	0	0	0	0	0	0	0	0
	Net import	3 081	-29 283	-26 572	-27 882	6 448	-20 411	-35 302	-42 399
	Consumption	56 071	64 316	74 783	82 916	56 062	64 307	74 801	82 948
	Net import ratio	5%	-46%	-36%	-34%	12%	-32%	-47%	-51%
	CO2 emission, kt	3 031	9 416	5 343	3 488	1 842	4 393	1 781	0

		Reference				Low gas			
	Year	2025	2030	2035	2040	2025	2030	2035	2040
Reserve market - up, average MW	Coal and lignite	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0
	Natural gas and other fossil	70.6	221.8	158.3	117.3	36.9	165.0	70.7	0.0
	Nuclear	0.0	0.0	10.1	91.8	0.0	0.0	14.9	87.6
	Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Battery	35.9	73.9	254.2	426.3	33.7	183.5	453.9	591.2
	Pumped storage	27.4	36.6	43.1	37.4	25.8	39.2	40.7	39.8
	Hydro storage	590.7	464.7	427.4	362.2	628.2	435.1	386.8	384.0
	DSM	8.7	23.0	43.2	50.2	8.1	23.7	34.6	50.8
	Missing reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	733.3	820.0	936.4	1085.2	733.3	846.5	1001.5	1153.5
Reserve market - down, average MW	Coal and lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural gas and other fossil	249.1	273.0	93.1	27.4	188.6	157.4	9.0	0.0
	Nuclear	0.0	170.6	122.7	70.5	0.0	169.5	32.9	9.4
	Wind	132.9	191.6	346.6	531.0	142.0	311.4	695.7	774.1
	PV	18.9	113.4	268.2	343.6	20.1	108.1	195.1	276.2
	Battery	61.8	16.7	22.4	14.5	68.9	31.7	8.6	2.1
	Pumped storage	39.0	5.7	6.2	3.3	43.1	6.4	1.6	0.4
	Hydro storage	253.0	48.0	45.2	23.1	291.1	54.3	14.7	4.6
	DSM	13.3	12.3	11.4	7.7	14.4	10.6	2.5	0.9
	Missing reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	768.1	831.3	915.8	1021.2	768.1	849.3	960.2	1067.7
RES curtailment, GWh		0.0	0.0	0.0	374.8	0.0	0.0	36.0	482.0