Powering the Future of the Western Balkans with Renewables

STUDY

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Preface

Dear reader,

The power systems of the Western Balkans are the most polluting in Europe. Their transformation towards renewables has begun to take shape. Yet, the pandemic, together with Russia's war on Ukraine, have made this endeavour more complex. The conviction that domestic lignite is vital for security of supply has resurged given higher commodity prices and inflation.

The six countries of the Western Balkans have committed to fully decarbonising their economies by 2050, enshrined in the 2020 Sofia Declaration on the Green Agenda and the recent Decarbonisation Roadmap for the Contracting Parties of the Energy Community. By June 2023, Contracting Parties must submit draft National Energy and Climate Plans.

By showcasing options for fully decarbonising the Western Balkan power system by 2045, this study contributes to the public dialogue on this issue. The pathways presented here show how the countries can minimise costs and maximise security of supply while limiting the role of fossil gas and achieving zero-emission power systems. The study's goal is to engage policymakers in the region and in the EU by providing robust economic modelling and insights.

To develop the study's evidence-based scenarios for a net-zero power system by 2045, Agora Energiewende teamed up with enervis energy advisors, RESET from Bosnia and Herzegovina, INDEP from Kosovo and ASOR from Serbia. The takeaway is clear: Coal belongs to the past while fossil gas is not the bridge that will take us towards a decarbonised future. Furthermore, storage technologies are sure to play a vital role in the transition process.

I hope you find this study both engaging and inspiring.

Matthias Buck,
Director EU Energy Policy, Agora Energiewende

Key findings at a glance:

1. **Making Western Balkans' power systems CO_2 free by 2045 is possible and would save money.** Producing electricity from renewable energy sources and green hydrogen will cost 15 percent less up to 2045 than relying on lignite or gas. A full decarbonisation of the region's power system will require a total investment of 43 billion euros over 30 years, 12 billion euros more than the fossil baseline. Even if investments are higher, renewables deployment can largely be financed from market revenues.

2. **A decarbonised power system ensures security of supply.** A reliable yet carbon-free power system can be achieved with a combination of renewables, storage (hydro, batteries, thermal storage) and 5 GW of green hydrogen fuelled power plants. Deeper regional integration can further reinforce security of supply.

3. **Fossil gas is not a bridge fuel.** The need for more ambitious climate action together with high and volatile fossil gas prices and ever cheaper renewables undermine the business case for new fossil gas infrastructure: any new fossil gas plant risks becoming a "stranded asset". If the Western Balkan countries invest in hydrogen-ready infrastructure and storage technologies instead, they can reduce cumulative fossil gas demand by 50 percent up to 2045 while cutting overall costs by 12 percent compared to a strategy that bets on fossil gas to replace aging lignite.

4. **Storage technologies provide flexibility and enable renewables expansion throughout the region.** Greater energy storage capacity enables rapid growth in PV, the most easily scalable renewables technology. Storage also lowers the need for hydrogen power plants that will replace gas plants. It is important not to overestimate hydrogen needs when planning for corresponding infrastructure. 5 GW of green hydrogen plants, covering 7 percent of demand in 2045, are needed for power system security of supply.

Content

1 Executive summary

Climate change and the associated need to reduce CO_2 emissions are driving a global transition from fossil fuels to renewables. Scenarios in line with limiting global warming to 1.5 degrees Celsius require countries to implement quick and deep decarbonisation in all carbon emitting sectors, including in particular the power sector. Strategies to reduce emissions typically foresee phasing out coal and lignite while accelerating renewables expansion. In this connection, natural gas often plays a role as a transitional fuel, depending on the country and sector. However, the war in Ukraine has led to a readjustment of energy policy priorities at the European level. Now, a key objective is to phase out dependency on Russian energy, especially natural gas imports, in order to re-establish Europe's energy sovereignty (European Commission, 2022). The natural gas supply crunch, which originally arose during the post-COVID recovery, but intensified with the outbreak of the war, has demonstrated the vulnerability of natural gas as an energy source. Successful strategies therefore will have to navigate decarbonisation objectives while limiting the role of natural gas.

The goal of this study is to develop scenarios for a fully decarbonised power system in the Western Balkans while minimising costs, maximising security of supply and limiting the role of natural gas. Specifically, we aim to elaborate technological and economic scenarios that can inform the energy policy debate. Three questions are central to the analysis:

→ What are the characteristics of an efficient lignite exit, and how should renewables be ramped up to substitute lignite generation?
→ What technology mix can cost efficiently ensure security of supply and flexibility in a decarbonised power system?
→ What is the role of fossil gas as a transitional fuel in such scenarios, and how can its role be limited in the light of the current gas crisis?

The geographical scope of the project is limited to the Western Balkans, namely the following six countries: Albania, Bosnia & Herzegovina, Montenegro, North Macedonia, Serbia and Kosovo (AKA the "WB-6"). While each of these countries has been analysed in detail (the results of which are available on request), in this paper our findings are shown in aggregate for the WB-6 region.

This study presents three core scenarios. They illustrate two different decarbonisation pathways as well as a baseline scenario without a net-zero target for the power sector. The derived scenario architecture therefore allows us assess the general merits of alternative energy strategies, including the benefits of divergent technological pathways, particularly as they relate to the interplay between natural gas, hydrogen and storage.

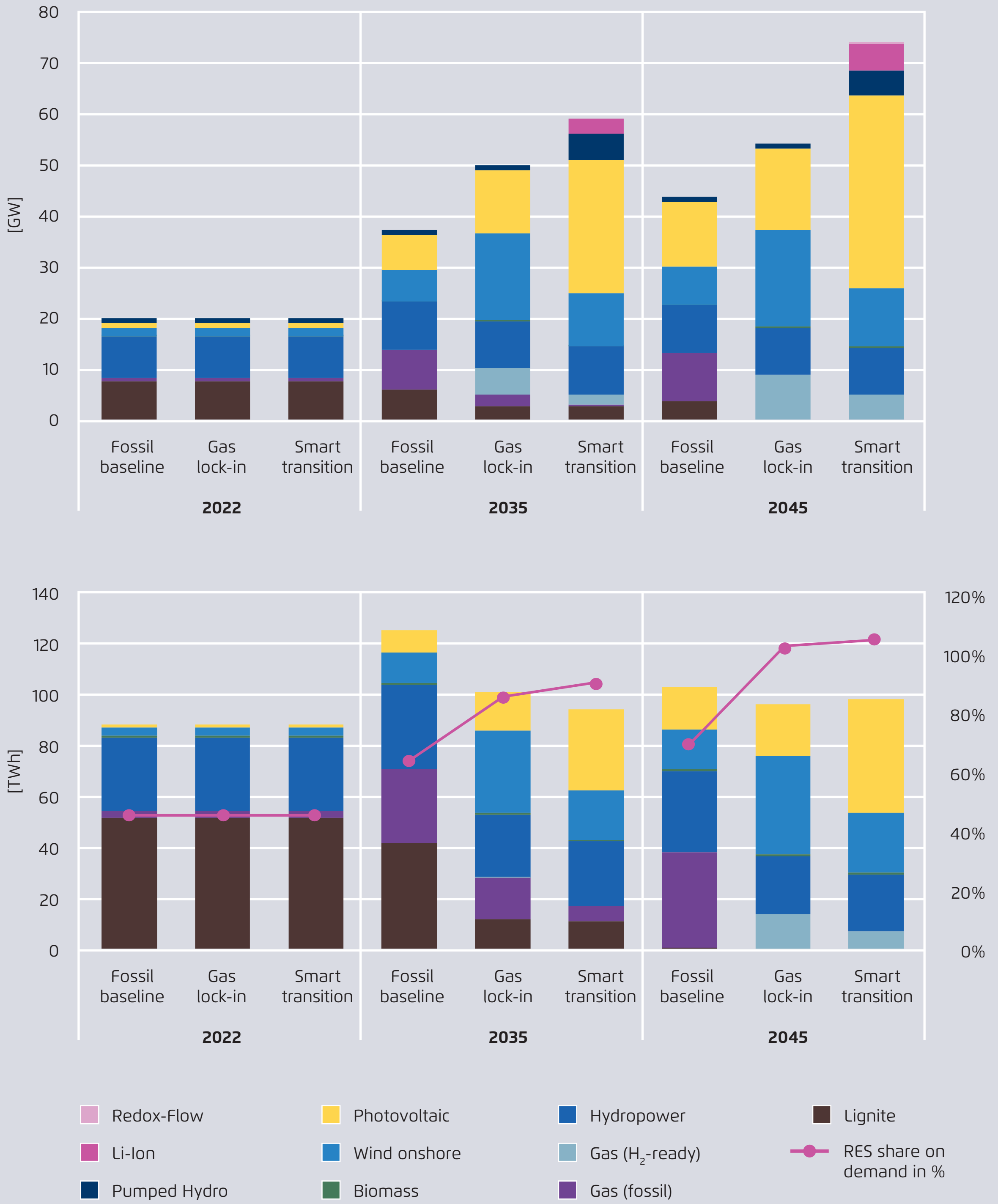
→ The "baseline" scenario represents a continuation of current national plans and policies.
→ The "gas lock-in" scenario illustrates the decarbonisation of the power sector up to 2045 while relying on natural gas for the transition.
→ The "smart transition" scenario showcases the decarbonisation of the power sector up to 2045 while substituting natural gas with energy storage to the greatest possible extent.
→ Additional sensitivity analysis was conducted to further investigate the role of storage technologies.

For each of those scenarios, we conducted a model-based assessment of various indicators, including costs, CO_2 emissions and necessary investments up to 2050.

Our results show that a coal phase-out in the Western Balkans by 2040 is technically feasible at no additional costs if embedded in a transitional strategy that aims at full decarbonisation.

Installed capacities (top) and power generation (bottom) in 2022, 2035 and 2045 in the Western Balkans

Figure 1



enervis modeling results (2022)

Our results also demonstrate that full decarbonisation of the power sector by 2045 is possible while saving costs in relation to the fossil baseline scenario. The energy transition scenarios cut cumulative CO_2 emissions by half (46–51 percent) while reducing overall generation costs by 3–15 percent (compared to baseline). Security of supply is ensured in both scenarios that fully decarbonise the power sector.

The baseline scenario and to some extent the gas lock-in scenario foresee heavy investment in natural gas-fired generation capacity (see Figure 1), which proves to be a dead end over the long term, leading to higher overall costs. If investments in gas plants consider future hydrogen-readiness and efficient storage technologies are deployed, cumulative fossil gas demand can be cut reduced by more than 50 percent (662 TWh down to 294 TWh cumulated) over the modelling time frame, while also reducing overall costs by 12 percent (smart transition vs. gas lock-in).

Li-ion batteries and additional pumped storage are deployed in the smart transition scenario, helping to increase cost efficiency. Storage also helps to switch the RES mix from wind to more easily scalable PV, thus accelerating renewables expansion. Further sensitivity analyses demonstrate that thermal storage at lignite sites as well as redox flow batteries can reach an economic breakthrough if cost reductions are higher relative to the assumptions of the fossil baseline scenario.

Additionally, it should be noted that a strategy which relies heavily on fossil gas at first with the aim of switching to hydrogen later increases exposure to potentially higher than anticipated hydrogen prices.

Long-term, seasonal storage is a necessary enabler of deep decarbonisation while also ensuring security of supply. Based on the current technological outlook, green hydrogen, i.e. hydrogen produced via electrolysis run only on renewables, is of key importance for a complete decarbonisation of the power sector.

Combined H_2-based power plant capacities in the region range at ~5–9 GW in 2050 in the energy transition scenarios. Hence, any gas power plant units that are built must be hydrogen ready.

Hydrogen's role in future power generation remains sharply circumscribed: as a share of demand, hydrogen generation is limited to ~7–10 percent (2045–2050), implying relatively low hydrogen demand overall.

Other storage technologies such as batteries can reduce the need for H_2 capacity and generation, specifically for the short-term balancing of hourly RES fluctuations. Deploying batteries in this manner reduces demand for H_2 capacities by 20 percent in 2050.

2 Introduction and objective

The intensifying threat of climate change is driving a global transition from fossil fuels to renewables. Scenarios in line with limiting global warming to 1.5 degrees C require countries to implement quick and deep decarbonisation in all carbon emitting sectors. The EU aims to achieve net zero by 2050, which requires a complete decarbonisation of the power sector by 2035 (IEA, 2021).

The war in Ukraine has led to a shifting energy policy priorities within Member States and at the European level. A key objective now is to phase out the EU's dependency on Russian energy imports and re-establish Europe's energy sovereignty (European Commission, 2022). Historically, natural gas was mainly imported by pipelines from Russia, accounting for 40 percent of fossil gas consumed in Europe (BP Statistical Review). The Western Balkan countries rely entirely on Russian gas. Bosnia and Herzegovina, North Macedonia and Serbia have historically (status quo in 2019) imported all of their gas from Russia (Eurostat, 2022). This makes the reduction of natural gas imports from Russia one of the most challenging but also important challenges in energy policy (Agora Energiewende, 2022). The European Union's REPowerEU has set forth various measures to reduce energy consumption; diversify supplies; quickly substitute fossil fuels by accelerating Europe's clean energy transition; and intelligently combine investment with and reform. Most of the measures aim to ensure and expedite existing strategies. The underlying proposals have the potential to phase out most Russian gas imports by 2027 (Eurpean Commission, 2022). The Western Balkan countries represent an integral part of REPowerEU's external energy strategy.

The natural gas supply crunch, which originally arose during the post-COVID recovery, but intensified with Russia's invasion of Ukraine, has demonstrated the vulnerability of natural gas as an energy source. Against the backdrop of current threats to European energy sovereignty, it is important to note the inherent – if not perfect – alignment between long-term decarbonisation targets and the goal of phasing out dependency on Russian gas.

In light of decarbonisation targets, coal and especially lignite phase-outs are necessary, and many European countries have therefore taken steps to accelerate their exit from coal. Indeed, some countries aim to exit coal in less than 10 years. The power plant fleet in the Western Balkans consists mostly of hydropower and lignite facilities. Among the latter, 90 percent of capacity is older than 30 years, and 40 percent is older than 40 years (Europe Beyond Coal, 2020). These plants are major emitters of air pollution, breaching effective limits on pollutants by several multiples in many cases (CEE Bankwatch Network, 2019). Accordingly, they are directly impacting people in the region, inducing significant negative health effects. It has been estimated that Western Balkan coal plants are responsible for up to 3 000 premature deaths every year and annual economic damages in the range of Euro 6.1–11.5 billion (Health and Environment Alliance, 2019). In addition to health impacts, these plants produce harmful CO_2-emissions and consume significant public subsidies; in 2018–2019 alone, coal electricity producers received some Euro 150 million in direct subsidies (Miljevic, 2020).

In this way, the power sector in the region is facing major challenges, and a prolongation of the status quo is no longer a viable long-term option. Earlier studies have demonstrated effective trajectories for phasing out lignite in the WB-6 (enervis, 2021) while highlighting expectable benefits. Yet moving beyond the coal exit and to the broader decarbonisation of the power sector, many questions remain. For example: What implications does a transition from lignite to renewables have for fossil gas and hydrogen, especially given non-reliance on fossil gas as a bridge fuel? Can the Western Balkans, as comparatively small gas consumers, instead bridge toward clean technologies, without relying on gas? What role can storage technologies such as batteries play?

Accordingly, this study focuses on answering three core questions:

→ What are the characteristics of an efficient lignite exit, and how can renewables be ramped up to replace lignite?
→ What technology-mix can cost efficiently assure security of supply and flexibility in a decarbonised power system?
→ What is the role of natural gas as a transitional fuel in such scenarios?

Companies and policymakers are seeking to navigate this turbulent moment in energy markets while ensuring domestic energy systems remain affordable, reliable and socially equitable. But what is the best strategy for achieving decarbonisation? The adoption of a decarbonisation strategy implies embracing a technological and economic scenario for achieving carbon neutrality in an effective and cost-efficient manner. In this way, economic modelling scenarios play a crucial role in the energy policy debate, for they highlight viable development pathways for the energy system while also aiding the management of distributional effects.

The goal of this study is to derive least-cost scenarios for power market decarbonisation in the WB-6 region while taking national circumstances into account. In this connection, the study seeks to determine (1) the amount of gas and hydrogen capacity that may be needed – if any – to fill the gap left by lignite, (2) the electricity storage required to supplement the deployment of variable renewables, and (3) the least-cost technology options to meet these storage needs.

The geographical scope of the project is limited to the Western Balkans, namely the following six countries (WB-6): Albania, Bosnia & Herzegovina, Montenegro, North Macedonia, Serbia and Kosovo.

3 Methodology

This section introduces the methodology used to analyse the various energy policy approaches.

3.1 Overview of approach

In order to analyse the long-term decarbonisation of the Western Balkan power sector, we developed a comprehensive model of the power market, as outlined in the following paragraphs.

First, we explore three scenarios for the development of the power market, each of which represents a divergent set of energy policies. The baseline ("fossil baseline") represents a continuation of the "status quo", status quo, which entails completion of currently planned lignite projects. Two possible decarbonisation scenarios are then considered and compared to the baseline. The "gas lock-in scenario" is a decarbonisation scenario relying on natural gas and RES to substitute dependency on lignite, with no early measures for ensuring medium to long term gas-plant fuel switching to H_2. An alternative "smart transition scenario" explores decarbonisation that prioritises flexibility through storage and is mindful of early H_2-readiness. In addition to these three core scenarios, sensitivity analyses are used to explore specific alternative routes under different technology cost developments while focusing on the role of storage technologies. The scenarios and sensitivity analyses are elaborated in greater detail in section 4.

The modelling and optimisation of the scenarios are undertaken using a power market model (see section 3.2 for details). Using this marginal-cost optimisation model of European power markets, one can derive relative generation technology shares and associated capacity investment needs.

The optimisation results are then analysed with regards to the following energy-economic indicators in order to derive conclusions for the development of the power market in the WB-6 region:

→ **Power market capacities and generation:** The evolution of overall capacities and the generation mix serves as one of the key metrics for evaluating decarbonisation strategies. Specifically, additional RES, natural gas, H_2 and storage capacities in the system are quantified, enabling medium and long term comparisons. The model also quantifies synergies between technologies (e.g. PV, batteries) and substitution effects (e.g. from lignite to gas or gas to RES and storages).
→ **CO_2 emissions:** The model allows quantification of annual and cumulative CO_2 emissions from the power sector. This metric enables one to assess the rate of decarbonisation associated with each policy scenario.
→ **Investment volumes per technology:** This refers to the necessary annual and cumulative investment amounts that are channelled into different power sector technologies (lignite, gas, RES, storage). This metric provides insight into the distribution of investment in the region, and into the savings or additional costs of long-term decarbonisation. However, it is not sufficient for assessing total cost implications.
→ **Incremental generation costs** (IGC) represent the core indicator for the general economic efficiency of the scenarios. IGC consist of all costs associated with the power generation mix (e.g. fuel, CO_2, capital, imports etc.). When comparing scenarios, lower cumulative IGC in a target year would therefore indicate relative advantages in economic efficiency. A detailed definition of incremental generation costs is provided in section 3.2.

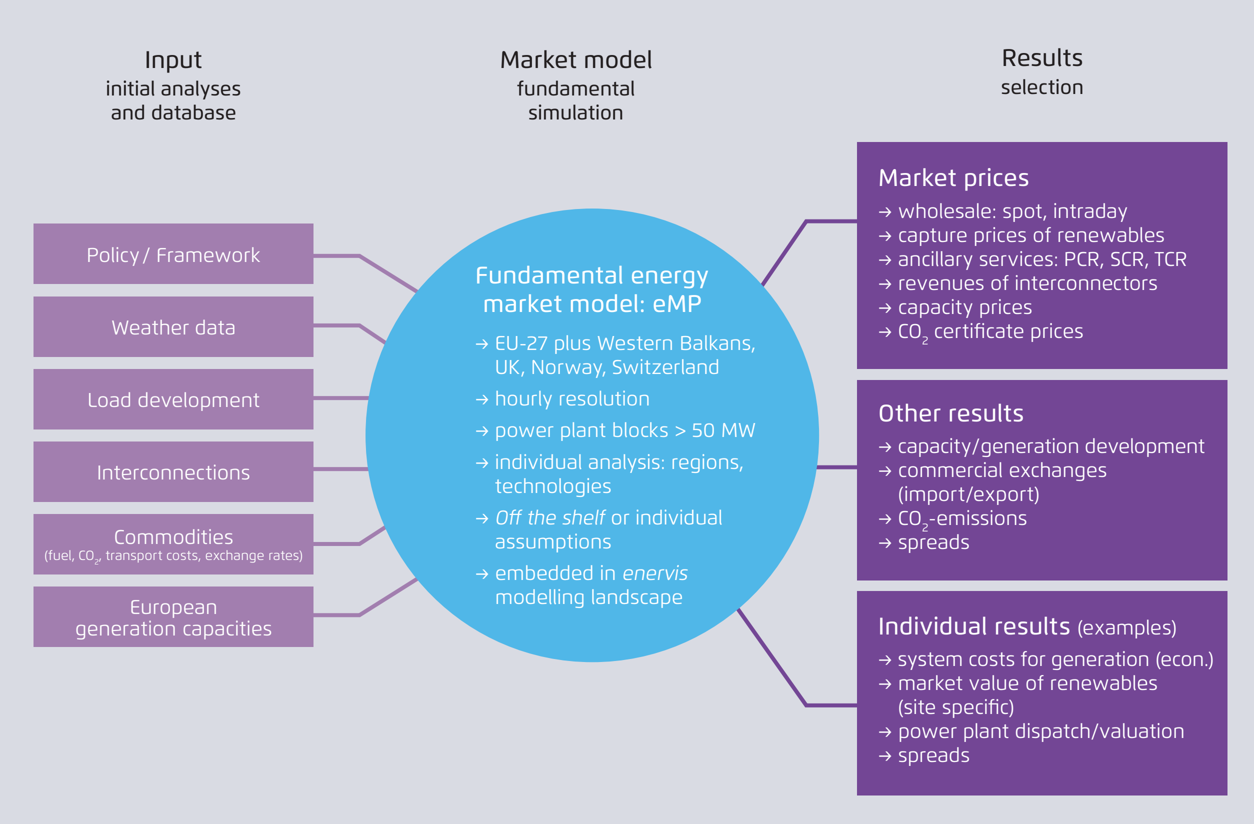
These metrics allow for a comparative assessment of the scenarios and the identification of their comparative merits as a foundation for energy policy.

3.2 Power market model and cost analysis

All modelling in this study is conducted with Enervis Market Power, a comprehensive and proprietary model for the analysis of power markets (see Figure 2). The model draws on a wide range of fundamental energy market data from across Europe, considering the interactions of most ENTSO-E markets/regions via interconnectors. Each market region is modelled with high granularity; the model considers each unit in the power plant fleet, renewable installations, hourly demand, weather data and country-specific assumptions (e.g. market design, policy framework, commodity transport costs, renewable expansion targets and support mechanisms). Accordingly, the model incorporates all relevant drivers of market dynamics, providing a comprehensive forecast of future developments within market prices zones and regions.

Based on a large set of parameters and input data in high temporal and spatial resolution, our marginal-cost optimisation model enables quantification of generation capacity growth and associated investment outlays. For an economic comparison of different power market scenarios, the differences in generation costs, or incremental generation costs (IGC), are a key indicator. We consider costs arising generally within the energy system, independently of who bears them (i.e. suppliers, households, industry, public sector).

Power market model | Figure 2



enervis (2022)

Incremental generation costs are costs that arise when generating (or importing) power in a country or system.

IGC include all variable and fixed costs (including cost of capital) for building and operating power generation facilities as well as demand side flexibilities.

Incremental generation costs include costs that change between scenarios (such as CO_2 and fuel costs). All costs that are the same between the scenarios do not influence the scenario comparison and are thus not necessarily included (e.g. the cost of existing hydro units). If generation costs are comparatively lower in one scenario versus another, this means that power is generated with greater cost efficiency, which can either reduce end-consumer costs or increase the rents (i.e. profits) that accrue to power producers by the same amount (or some division between the two). Since both producer rents and consumer prices are, from an economic point of view, distributional in nature, economic efficiency is best assessed based on generation costs.

We compare the cost of different scenarios, considering the following generation cost components:

- → **Net import costs:** Net power imports from neighbouring markets are assessed based on the wholesale import prices.
- → **CO_2:** This includes all costs arising from the procurement of CO_2 certificates. Please note that these costs also create additional income, e.g. for the public sector.
- → **OPEX:** This component covers the operational costs of conventional power generation. This encompasses fuel costs (including short-run marginal lignite costs) and fixed operational costs, but excludes carbon costs, which are addressed separately.
- → **CAPEX:** This refers to capital expenditures for conventional power generation, including investment outlays and cost of capital.
- → **RES:** All costs relevant for investing in and operating renewable energy sources (OPEX and CAPEX of RES).
- → Power grid investment costs are not included in our calculations because they are assumed to be relatively small in relation to other power system investments.

4 Definition of power market scenarios

In this study, we define three core scenarios for the Western Balkan power markets along two main dimensions: (1) the general level of ambition in the area of power market decarbonisation; and (2) the technological mix available to reach this goal. These scenarios illustrate the implications of two different decarbonisation pathways compared to a baseline without a net-zero target for the power sector.

4.1 Overview of scenarios

This section provides an overview of the scenarios and our calibration of model sensitivity.

As mentioned, our study includes three core scenarios: one baseline scenario and two policy scenarios for achieving power market decarbonisation by 2045. The available technologies for decarbonisation are RES, short-term storage (see section 5) and gas generation units run on green hydrogen (see section 4.2).

We calibrate model sensitivity to account for uncertainty with a view to scenario drivers and to highlight the risks and opportunities inherent to individual pathways.

For a proper interpretation of the results, it is important to understand the scenario assumptions, which were defined based on discussions with different stakeholders in the region. Figure 3 provides an overview of our key assumptions, which are briefly summarised in the following paragraphs.

4.2 Core scenarios and key assumptions

The **fossil baseline ("FB")** scenario reflects current decarbonisation ambition levels in the region as well as available information on national strategies. Most additional CO_2 reductions are thus based on anticipated increases in carbon pricing; renewables take an increasing role due to national policies and general economic factors in energy markets.

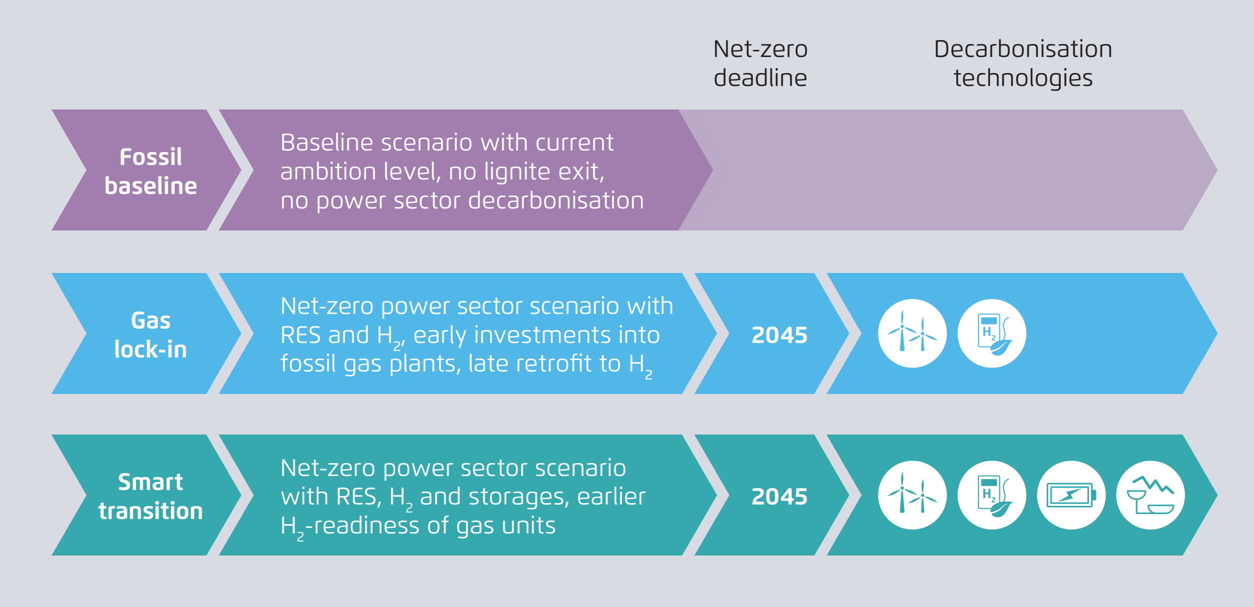
The **gas lock-in ("GL")** scenario represents an increase in decarbonisation ambition, with full decarbonisation of the power sector achieved by 2045. This includes a phase-out of the countries' coal fleet by 2030 alongside a continuously strong increase in renewable energy generation (+22 percentage points in RES demand share compared to 2035 baseline). This scenario relies quite heavily on natural gas in the early phase of power market development. To reach deep decarbonisation by 2045, power plants are later retrofitted to run on hydrogen. Accordingly, the GL scenario implies strategic reliance on natural gas as a transition fuel, with a stronger role for hydrogen over the long term.

The **smart transition ("ST")** scenario almost aims for full decarbonisation by 2045. In contrast to the gas lock-in scenario, the smart transition scenario considers the early establishment of H_2-readiness in new gas power plants and battery and thermal storage technologies in addition to pumped hydro. The technological mix to reach this target is therefore different from the gas lock-in scenario. This represents a strategy less reliant on natural gas as a transition fuel, and includes a stronger role for storage in the capacity mix.

All investments in natural gas power plants are made with a view to future hydrogen readiness from the beginning (for further explanations on costs and scenario variations are provided below). Also, a cost optimised mix of other storage technologies, including in particular battery storage, is leveraged to reduce the need for hydrogen-based power generation. Accordingly, this scenario further minimises the role of natural gas and hydrogen.

Scenario overview

Figure 3



enervis (2022)

Key assumptions underlying the respective scenarios are depicted in Figure 3. The country-level assumptions are based on desk research, including a synthesis of national energy strategies and institutional planning documents (e.g. by national TSOs). They are also informed by discussions with local stakeholders.[1] The data derived from our analysis of official planning forms the basis for the fossil scenario pathway, which aims to reflect currently applicable regional energy policies. Key assumptions underlying the scenarios are explicated in the following paragraphs:

→ **CO_2 targets in the power sector:** While no emissions reduction targets exist in the fossil baseline scenario, both the gas lock-in and smart transition scenarios achieve complete decarbonisation of the power sector by 2045.

→ **Carbon pricing:** Across all scenarios, including the fossil baseline, a phase-in of an emissions trading system (ETS) starting 2030 and gradually aligning with the EU ETS price level by 2050 is assumed. The remaining difference in specific costs for CO_2 emissions is offset via the implementation of a carbon border adjustment mechanism on power imports to the EU (**CBAM**), as set forth in legislative proposals from the European Parliament and Council for establishing a carbon border adjustment mechanism (EUCOM, 2021).

→ **Lignite capacity:** The fossil baseline scenario follows current national plans and foresees continued investment in new lignite plants (if currently planned). In this scenario, lignite plays a central role in future energy supply; existing plants are eventually refurbished for compliance with pollution regulations. After an extended technical lifetime, the plants are shut down. In the decarbonisation scenarios, no investments into additional lignite plants are carried out, and only newer units are refurbished to ensure security of supply over

1 RESET Center for Sustainable Energy Transition (BA), Institute for Development Policy (INDEP) (XK), Association for sustainable development (ASOR) (RS)

the medium-term. The decommissioning of lignite is driven by policy efforts, resulting in a complete phase-out by 2040.

- **RES capacity:** RES expansion targets are realised according to current national strategies in the fossil baseline scenario. In the gas lock-in and smart transition scenarios, the planned expansion is supplemented with additional onshore wind and PV as variables endogenous to the model.
- **Storage:** Given insufficient information on storage expansion targets in the region, a best guess approach is used for the baseline and gas lock-in scenarios. Only the smart transition scenario foresees investment in storage as a variable endogenous to the model (the same applies to RES). Considered technologies include li-ion batteries, redox-flow batteries, thermal storage and pumped hydro storage (see section 5).
- **H_2-ready gas capacity:** For the purpose of this study we define two levels of H_2 readiness: "level 1 H_2-readiness" describes a gas power plant designed from the outset to accommodate future retrofit for running on H_2. Such plants cost the same as power plants run on natural gas. Future retrofitting then upgrades the plant to "level 2 H_2-ready". H_2-ready retrofits can be assumed to cost between 5 percent and 30 percent of new gas plant development (EUTurbines, 2021). We assume that the first level of H_2-readiness can be established at investment costs equal to the cost of a new gas power plant. A retrofit to upgrade the plant to H_2-ready (level 2) costs 5 percent of the total investment cost, thanks to the initial H_2-compatible design. In the event future H_2 retrofit is not considered during initial construction, future retrofitting costs ~30 percent of plant investment. It is assumed in both scenarios that gas plants will be constructed for H_2-readiness from 2030 onward. In the gas lock-in scenario, we assume that new gas plants built in the years up to 2030 in the Western Balkans will not be built under special consideration of future H_2-readiness and will thus require higher retrofit costs 2030 onward. By contrast, under the smart transition scenario, plants are constructed at the outset with H_2-readiness in mind. This leads to overall lower retrofit costs in the 2030s; furthermore, new plants in the 2030s are built directly to be H_2-ready (Level 2) at overall lower investment costs. In the baseline scenario, gas-based power plants do not switch to hydrogen. In the gas lock-in and smart transition scenarios, the H_2 fuel share gradually increases up to 2045.
- **Fossil gas capacity:** The baseline scenario foresees expansion of fossil gas capacities according to planned projects, national targets and economic viability. In the gas lock-in scenario, expansion based on national targets or plans takes place with age-based decommissioning and H_2 retrofitting up to 2040. In the smart transition, no further expansion of natural gas capacities takes place. Existing old units that reach the end of their technical lifetime are decommissioned; the other new units are built H_2-ready.
- **Fuel and CO_2 prices:** These factors determine the marginal generation costs of conventional generation, and in turn strongly impact wholesale power prices and the OPEX of power generation. In terms of CO_2 prices, it is assumed that an ETS-based carbon pricing system is phased-in in the Western Balkans (WB-6 ETS) from 2030 to 2050, and that differences to the carbon price level applicable within the EU are offset by a carbon border adjustment mechanism on electricity exports (Agora Energiewende, 2022).

Short-term price projections for all commodities and CO_2 prices are based on current futures market expectations for underlying commodities. Long-term projections are derived from international energy scenario frameworks reflecting carbon mitigation ambitions in line with the present scenario set. In this study, long-term **fuel and CO_2 price assumptions** are based on the "Announced Pledges" scenario published in the World Energy Outlook 2021 (WEO) by the IEA (International Energy Agency, 2021) and can be referred to in Table 1.

An exception is made for anticipated natural gas prices, which have been adjusted to reflect the war in Ukraine and prevailing high uncertainty regarding the supply situation. In this connection, the short-term futures trajectory from 21 to 27 February 2022[2] already reflects tighter supplies and increased uncertainty regarding short term supply from Russia. It assumed that the mid- and long-term price level does not fall below Euro 40/MWh after 2025.

Gas and CO_2 price assumptions — Table 1

Year	Gas [€/MWh]	CO_2 – EU ETS [€/tCO_2]	CO_2 – WB-6 [€/tCO_2]
2022	93	73	0
2025	41	77	0
2035	41	131	45
2045	41	167	135

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4.3 Sensitivity analysis

This section presents our sensitivity analysis, which modulates key input parameters to identify how alternate assumptions impact scenario trends. Specifically, we focus on uncertainty with regard to storage technologies and future hydrogen prices.

In each sensitivity simulation, we only adjust one parameter, in order to see how alternate assumptions for that parameter change the modelling outcomes for the remaining variables.

We conduct three sensitivity simulations to explore higher green H_2 costs; a breakthrough of redox-flow batteries; and a breakthrough of thermal storage, respectively.

The simulations are defined as follows:

→ **H_2 costs:** This sensitivity analysis explores a scenario in which green H_2 costs are higher than anticipated, e.g. due to underdevelopment of the global market.
→ **Redox-flow breakthrough:** In this variant of the smart transition scenario, a breakthrough in redox-flow batteries takes place, making them cheaper and viable for long-term storage applications.
→ **Thermal storage breakthrough:** In this variant of the smart transition scenario, a breakthrough in thermal storage takes place, reducing associated costs.

2 Which was the latest possible cut-off date for finalising the model calculations of the present study.

5 Storage technologies

5.1 Considered technologies

Energy storage is a key enabler of the transition to a sustainable, carbon-neutral economy of the future. Storage technologies are required to capture energy at times of excess or cheap generation and dispatch energy when needed to help meet demand peaks, fill supply gaps and provide various ancillary services to help balance and stabilise the grid. Various technologies are limited by technical and economic factors, and several are still in the early stages of development. In this project, we considered those technologies deemed most likely to succeed as significant contributors to the future development of energy storage in South East Europe, based on their technical and commercial characteristics. We combined literature reviews with expert interviews to estimate a range of techno-economic parameters for each of these technologies. These ranges were used as initial input assumptions for the power market modelling.

Energy storage technologies can be based on different mechanisms of energy transfer, e.g. mechanical, electrochemical, chemical, thermal and electrical.

By far the largest proportion (>90 percent) of energy storage capacity in Europe today belongs to pumped hydro, where water is pumped up to an elevated reservoir to charge or store energy, and released down to mechanically turn a turbine generator and discharge energy when it is needed. However, this requires suitable geographic topology and has significant ecological impacts, so there is limited scope for the expansion or construction of additional facilities.

The next largest category is electrochemical, or battery storage technologies. There are numerous different chemistries at various stages of commercialisation, but lithium-ion is the fastest growing, driven by massive global investment in automotive, consumer product and power grid applications. Other chemistries such as lead acid have been deployed at scale but are unlikely to be expanded further because of the competitiveness of lithium-ion.

Along with lithium-ion, we also consider redox flow batteries, which are still relatively immature and have various possible chemistries, but which show significant potential for higher duration applications. These batteries use a liquid electrolyte which is stored in tanks and pumped across a membrane to transfer charge.

For chemical storage we include power-to-hydrogen, via the electrolysis of water, which is expected to be deployed at scale in Europe, with 40 GW of capacity targeted by 2030. Known as renewable or "green" hydrogen, this is expected to form a major part of the decarbonisation of certain "hard-to-abate" industrial sectors. Once formed, hydrogen can be used to generate electricity via a turbine or fuel cell.

Lastly, we have also included some estimates for thermal storage technology. Electrical mechanisms such as supercapacitors are typically only for very short duration applications and therefore less relevant to this study.

5.2 Key technical parameters

Energy storage assets are defined by two physical capacities: Power (measured in kW or MW) and Energy (measured in kWh or MWh). These can be combined to describe an asset's duration, a key technical parameter which is defined as how long an asset can charge/discharge at its rated power capacity (often measured in hours). This is an important consideration when designing storage for a grid application, as duration requirements will vary depending on the use case. For example, if daytime solar energy supply needs to be stored for use during evening peak demand, then a few hours of duration may be needed.

Round-trip efficiency is another key technical parameter. This measures how much of the energy initially used for charging the system is returned after it has been stored and discharged. This can vary from below 40 percent for power-to-hydrogen, to above 90 percent for some lithium-ion batteries. The higher the round-trip efficiency, the less energy is wasted.

The technical lifetime of an energy storage system is typically measured in number of charge/discharge cycles, which can then be converted into years depending on the applicable use case. In general, for grid applications, multi-decade lifetimes are desired to enable long term planning.

5.3 Key economic parameters

Economic considerations are the main factor driving the deployment of energy storage technologies. If a technology is technically perfect but prohibitively expensive, then it will not be used.

Cost can be split into capital expenditure, or CAPEX, which is usually the up-front cost of installation (measured in Euro / MWh or Euro / MW of installed capacity); and operational expenditure, OPEX, which is typically a recurring annual cost that can have both fixed (measured in Euro / MW / annum) and variable (Euro / MWh) components.

In addition to CAPEX and OPEX, we also consider the economic lifetime of a project, which describes the financing term of the project, i.e. by which time financial investors will have expected to receive their required return on investment. In some cases, this may also describe from an accounting perspective how long it will take for the asset to be fully depreciated.

In this study all the above-mentioned technologies (pumped hydro storage, lithium-ion batteries, redox-flow batteries and thermal storages) are considered as options for the power mix. The deployment figures for each technology result from the optimizations of the model, with no preference given for one or the other technology.

6 Power system scenarios: results at the regional level

This section presents the results of scenario modelling and analyses at an aggregated regional level for the six Western Balkan countries (WB-6). First, we analyse the model's output for the structure of the power market (in terms of capacity and generation). Second, we compare the scenarios' cumulative CO_2 emissions. Finally, we assess overall economic efficiency and the main cost drivers by comparing the scenarios' incremental generation costs.

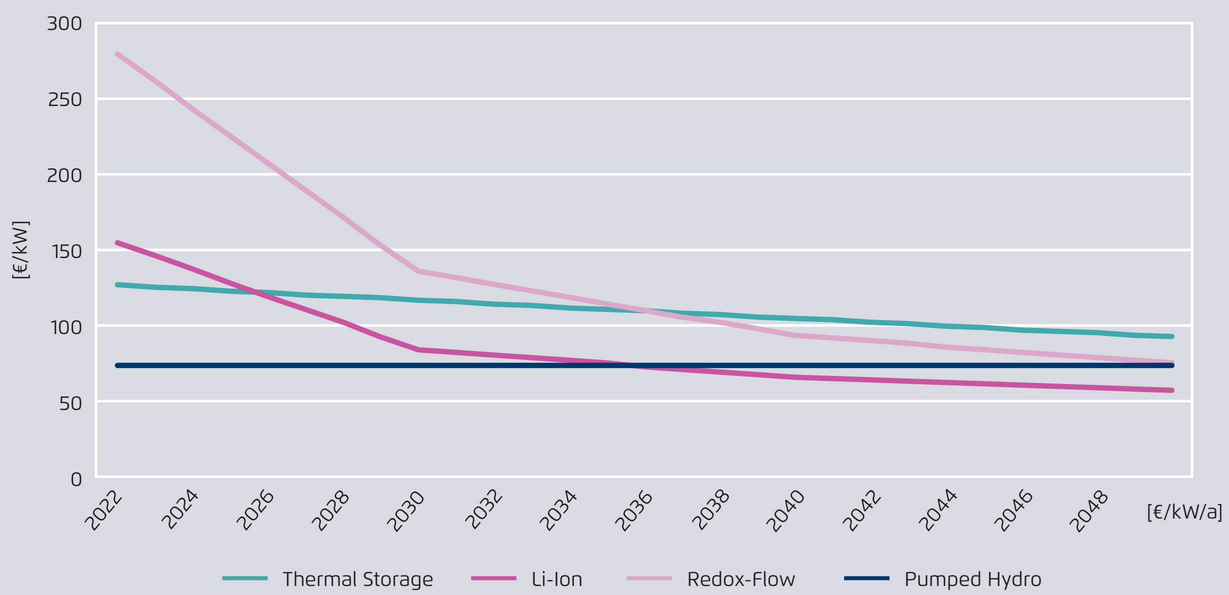
6.1 Capacity and generation structures

Capacity and generation growth trends differ between all of the scenarios. Figure 5 depicts the evolution of these two parameters for selected target years.

Overall, the decarbonisation scenarios (gas lock-in, smart transition) see an accelerated reduction of lignite capacities, substituted by RES (and storage in the smart transition). Gas-fired generation is reduced significantly in the medium term compared to the fossil baseline (down 45 percent by 2035 in the gas lock-in scenario, and even more so, by 80 percent, in the smart transition scenario). Natural gas use is also subsequently replaced by hydrogen. Long-term, investment in energy storage can reduce H_2 demand by 50 percent. In the following paragraphs we highlight differences between the evolution of the selected technologies.

In both decarbonisation scenarios, lignite capacity is replaced by increasing RES capacity. Compared to the

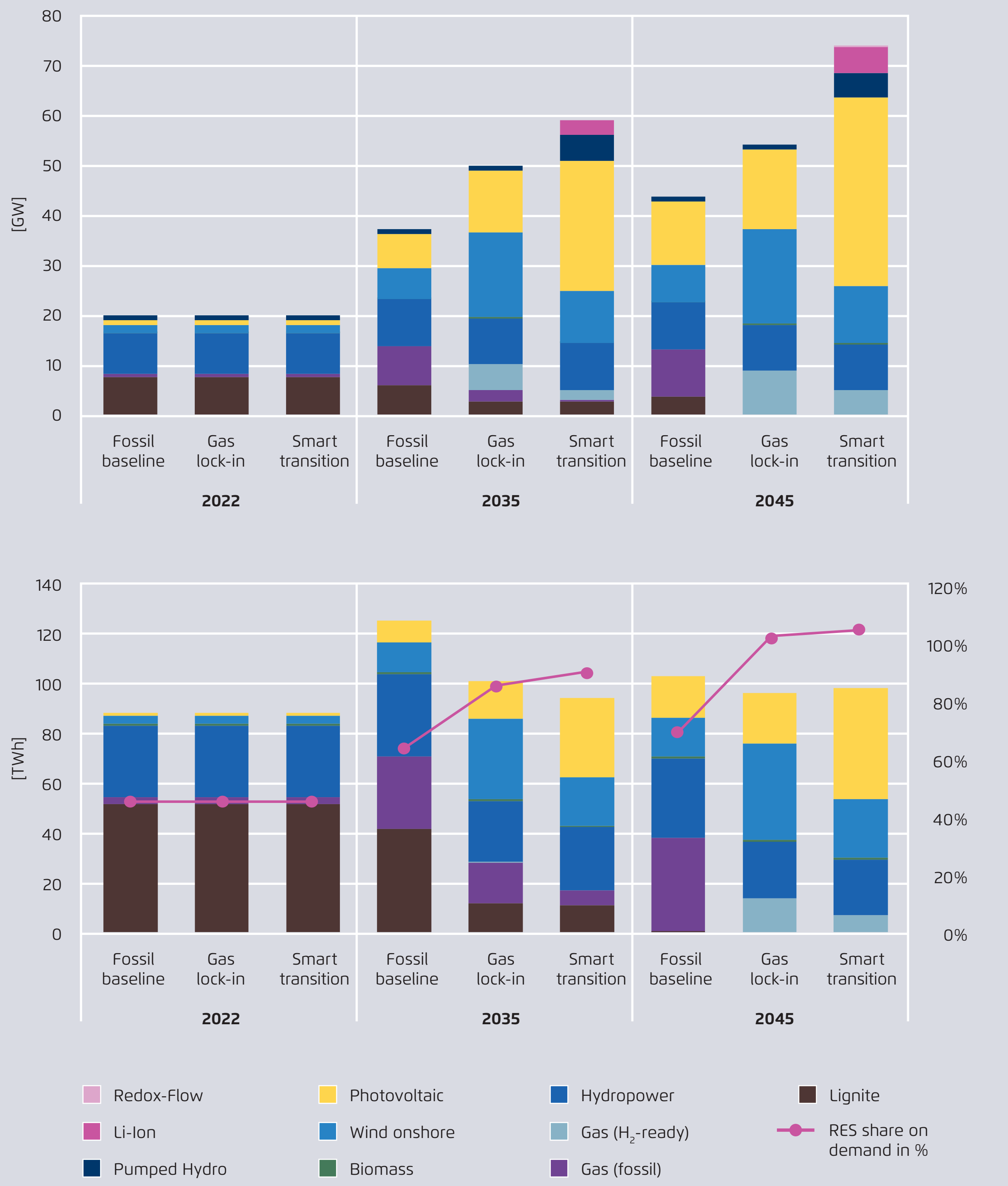
Storage technology investment costs (2022–2050) Figure 4



IEEFA (2022) based on Matt MacDonald (2018), Bauer (2021), European Association for Storage of Energy (2021)

Installed capacities (top) and power generation (bottom) in 2022, 2035 and 2045 in the Western Balkans

Figure 5



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gas lock-in scenario, the smart transition scenario foresees more than a doubling of PV capacity over the long term, including complementary storage expansion. Pumped hydro potential is fully utilised, while an additional 6.7 GW of li-ion batteries are deployed by 2050.

Lignite capacity currently (2022) makes up ~38 percent (or 7.7 GW) of the capacity mix. If current national strategies are continued with no effort to accelerate the phase-out of lignite (as in the fossil baseline scenario), lignite will continue to be a major source of power supply well into the 2030s. In 2035 over 6 GW of lignite-based generation capacity remains in service, since new projects are realised and older plants are refurbished. A market-driven exit only takes place in the long run, although some capacity remains to ensure security of supply until 2050. At this point, however, lignite's contribution to the generation mix is negligible. In the decarbonisation scenarios (gas lock-in and smart transition) 4.8 GW of lignite units are decommissioned up to 2035, reducing total capacity in comparison to the baseline to less than half. This is achieved through a policy-driven lignite exit that prevents new lignite units from being commissioned and phases out all lignite by 2040.

The role of natural gas diverges significantly between scenarios. The baseline scenario foresees heavy investment in gas-fired capacity as a substitute for lignite. Western Balkans natural gas capacity thus stands at 7.8 GW in 2035 and 9.3 GW in 2045. This constitutes a major shift in the structure of the power system, as natural gas currently accounts for a negligible share of generation. In the decarbonisation scenarios, natural gas takes on two different roles. In the medium term (2035), the gas lock-in scenario achieves no significant reduction in gas capacity (down to 7.2 GW), since the phase-out of lignite increases demand for flexible capacity. However, annual consumption of gas (including some H_2) falls significantly, by ~45 percent compared to the baseline scenario.

The need for natural gas capacity (both H_2-ready and non-H_2-ready) can be decreased considerably through the increased deployment of RES and storage, as illustrated by the capacity and generation mix of the smart transition scenario. While the gas lock-in scenario only achieves a minor decrease in natural gas capacity over the medium term, the smart transition reduces the need for gas-based capacity to as little as ~25 percent (~6 GW) of baseline capacity in 2035. This is achieved mainly by investing in storage and RES expansion. This indicates the need for caution when planning H_2 capacity, since storage technology can partially offset H_2 capacity requirements.

Long-term storage is a necessary enabler of deep decarbonisation without jeopardising grid reliability. Based on the current technological outlook, hydrogen is of key importance. Aggregate H_2 capacity in the region stands at ~5–9 GW in 2050 in the energy transition scenarios. The scenarios also indicate that all new gas units should be built hydrogen ready.

RES and energy storage: At present, power infrastructure in the Western Balkans is characterised by a rather high share of hydropower. Hydropower makes up around 9.3 GW or ~40 percent of the installed generation capacity in 2022. Since the potential for expanding hydropower is limited, deep decarbonisation must rely on increasing shares of PV and onshore wind to generate electricity.

In both decarbonisation scenarios, lignite capacity is replaced by increasing RES capacity. By 2035, 12 GW of PV and 17 GW of onshore wind contribute to the regional capacity mix in the gas lock-in scenario. The lignite phase-out therefore leads to a near doubling of PV and wind capacity (slightly less for PV, and slightly more for wind). A strategy that is mindful of the need for storage technology for the supply of flexibility invests heavily in PV (26 GW compared to 12 GW in gas lock-in scenario and 7 GW in the baseline scenario) as a complement to the expansion of li-ion batteries (2.9 GW). This leads to a shift in RES expansion, reducing onshore wind to ~10 GW (down from 17 GW in the gas lock-in scenario). Overall, this shifts the technological focus to a more scalable technology, which should make the implementation of this trajectory more straightforward. This trend carries on to 2045, in which 37.5 GW of PV are installed in the smart transition, compared to 16.1 GW (gas lock-in) and 12.7 GW (baseline). In the smart transition, pumped hydro potential is fully utilised (~5.1 GW), while an additional 6.7 GW of li-ion batteries are deployed in the long term. Other storage technologies are not deployed in the model, indicating that they are not competitive given the underlying costs assumptions.

In all scenarios, security of supply (SoS) is assured. This shows that a coal phase-out in the Western Balkans by 2040 is technically feasible when embedded in a transition strategy aimed at full decarbonisation.

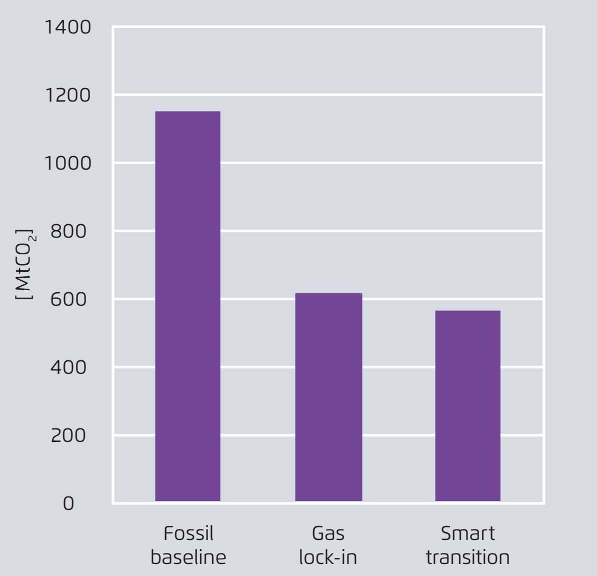
The above-described effects on capacity development have implications for the **generation mix**, which are described in further detail in the following paragraphs.

Lignite: We first consider the share of lignite-based power in the generation mix. In 2022 it accounts for over two thirds of total demand (~67 percent) at an average of ~76 percent utilisation, with annual electricity production of 51 TWh. The decarbonisation scenarios reduce lignite demand to less than a third compared to baseline by 2035.

Fossil gas and green hydrogen: Earlier decommissioning and lower utilisation of lignite plants decreases power exports. This decline in lignite is offset by renewables expansion and higher gas utilisation, especially in the medium term. If new plants are built to be hydrogen ready and efficient storage technologies are employed, cumulative **natural gas demand can be reduced by 50 percent up to 2050** (smart transition versus gas lock-in). Hydrogen's role should not be overstated, however: as a share of demand, generation is limited to ~7–10 percent (2045–2050).

RES generation: The gas lock-in and smart transition scenarios can achieve a RES demand share of over 85 percent by 2035 (compared to 63 percent in the baseline) and 100 percent in 2045 (compared to 69 percent in the baseline).

Cumulated CO_2 emissions (2022–2050) Figure 6



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6.2 CO_2 emissions

Figure 6 shows the cumulative CO_2 emissions in the Western Balkan power systems up to 2050 in the three core scenarios. Both net-zero scenarios show a significant reduction in CO_2 emissions in the power sector. Specifically, long-term cumulative emissions up to 2050 are reduced by 46 percent in the gas lock-in scenario, or 563 Mt CO_2 and an additional 5 percent (i.e. 588 Mt CO_2 compared to baseline) in the smart transition.

CO_2 emissions and cumulated CO_2 emissions in fossil baseline (top), gas lock-in (center) and smart transition (bottom) between 2022 and 2050 — Figure 7

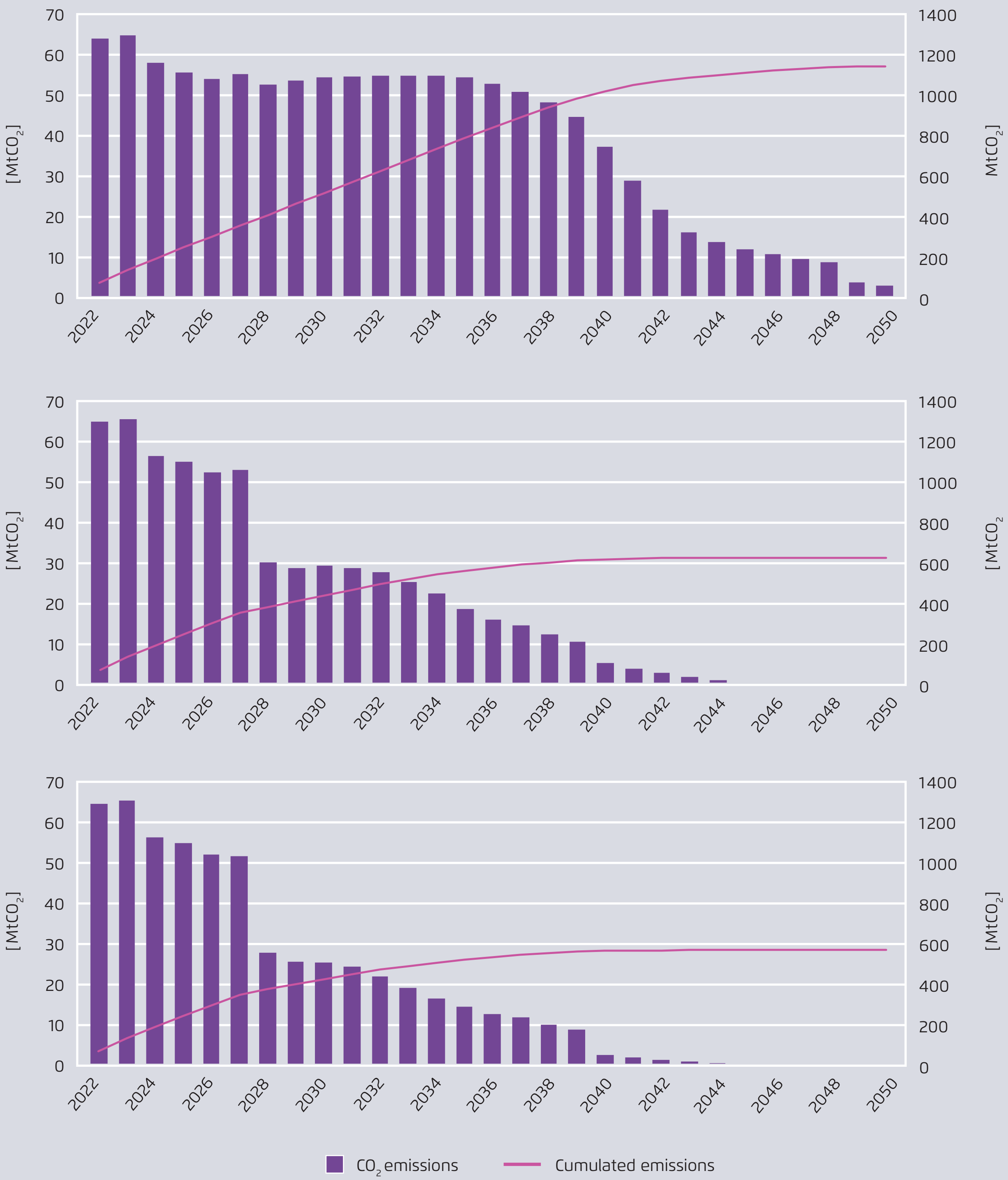

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Figure 7 shows the evolution of emissions over time. In the transition scenarios, the steep decrease in the late 2020s in mainly driven by the decommissioning of ~50 percent of lignite capacity in that decade. Complete decarbonisation of the power sector is achieved by 2045. The findings also indicate (see Figure 7) that the introduction of a CO_2 price is insufficient to reduce emissions over the short to medium term (2030s). Temporarily, annual emissions increase in the baseline scenario in the 2030s, since new gas plants and existing lignite are deployed to meet increasing demand. A lignite phase-out policy that encourages growth in RES and storage can mitigate emissions in the short and medium term more effectively and at an overall lower cost. The following section discusses this issue in greater detail.

6.3 Cost implications

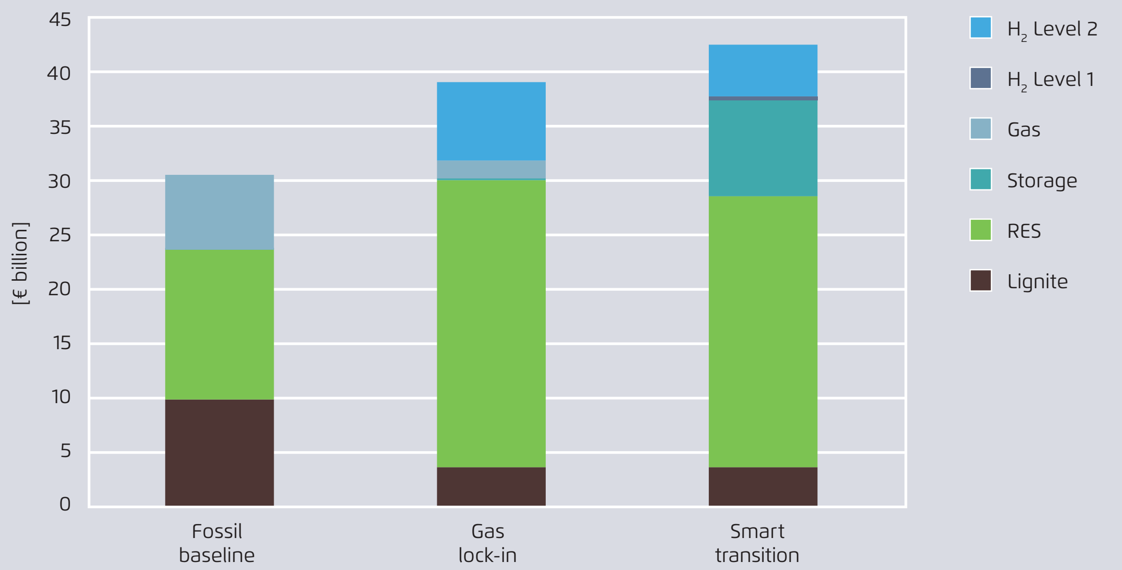
This section assesses and compares the cost implications of each scenario. To this end, we consider annual and cumulative **investment** in different technologies, as well as **incremental generation costs,** as described in section 3, up until 2050.

Figure 8 and Figure 9 display cumulative investment up to 2050 and annual investment volumes per technology.

The fossil baseline scenario is characterised by early investment in new and retrofitted lignite plants and natural gas capacity, while the net-zero scenarios channel investment mainly into onshore wind and PV in the early transition period. A smart transition mitigates the cost of H_2-readiness retrofits, but increases investment needs for storage, resulting in an overall higher total investment.

Required additional investment adds up to Euro 8.6 billion or ~28 percent (gas lock-in) and Euro 7.28 billion or ~39 percent (smart transition) up to 2050 compared to baseline. Figure 7 breaks down and compares cumulative investment amounts.

Cumulated investment volumes by technology (2022–2050) | Figure 8



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Investment volumes and cumulated investment volumes in fossil baseline (top), gas lock-in (center) and smart transition (bottom) between 2022 and 2050

Figure 9

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The benefits of the additional investment required for decarbonisation become apparent when comparing overall generation costs across the three scenarios. Figure 10 presents an overview of cumulative incremental generation costs in each scenario.

Cumulative incremental generation costs up to 2050 are lower in the decarbonisation scenarios compared to baseline – namely, 3 percent lower in the gas lock-in scenario, and 15 percent lower in the smart transition scenario.

These net cost differences at the system level are attributable to the relative development of individual cost components within each scenario. The decarbonisation scenarios do lead to lower costs in each component area compared to the baseline scenario. However, savings realised within some cost components more than offset higher expenses elsewhere (e.g. savings in fuel and CO_2 costs; lower revenues from exports).

This is particularly true for investment costs, which contribute to incremental generation costs. Natural gas and H_2 capacity investment falls under "capital costs", RES capacity investment under "RES costs" and storage capacity investment under "storage costs".

Consequently, the decarbonisation scenarios display higher figures for RES (and storage), while the baseline scenario has higher capital costs.

The baseline scenario has a cost-component advantage over the other scenarios in just one additional area – namely, "net import costs"[3]. This is predominantly attributable to slower lignite capacity reductions. The assumed 2040 lignite phase-out trajectory leads to lower lignite generation potential starting in the mid-2020s and thus lower export

3 The negative figure for "net import costs" in the graph can be read as "net export revenues". Hence, the decarbonisation scenarios see lower net revenues from trade than the fossil baseline.

Incremental generation costs

Figure 10

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potential to neighbouring EU countries, partially during a time frame where carbon pricing is still absent in the WB-6 (see section 4.2).

On the other hand, there are significant cost savings in the decarbonisation scenarios when looking at the components "OPEX var" and "CO_2 costs". Those savings can be quantified as follows: 39 percent cost savings (gas lock-in) and 73 percent (smart transition), respectively, in variable OPEX (fuel costs). Cumulative CO_2 cost reduction in both decarbonisation scenarios are ~80 percent compared to baseline.

These costs are induced by burning fossil fuels, and consequently are highest in the baseline scenario, which strongly relies on lignite and later on fossil gas-based generation (see section 6.1). A shift to fuel-independent generation based on onshore wind and PV, as presented especially in the smart transition scenario, can significantly reduce these costs in the long run.

It is important to note that the variable cost components can be subject to high volatility (see section 4.2)[4]. This source of risk to overall cost trends is particularly acute in the baseline and (to a lesser extent) gas lock-in scenarios, which are OPEX and CO_2 cost-heavy. Both of these scenarios are exposed to greater price volatility risks. By contrast, such risk is significantly mitigated in the smart transition scenario, which has a generation mix much less dependent on potentially volatile commodity prices.

The higher total investment required to realise the smart transition scenario proves to be efficient, reducing costs in the long term and overall. The scenarios with lower CO_2 emissions also achieve lower overall generation costs, thus leading to alignment between goals of cost efficiency and emissions reductions.

4 As illustrated by recent natural gas price spikes.

7 Insights from sensitivity analyses

In this section, we offer further insights into the developed scenario pathways by exploring modelling outcomes for sensitivities introduced in section 4.3:

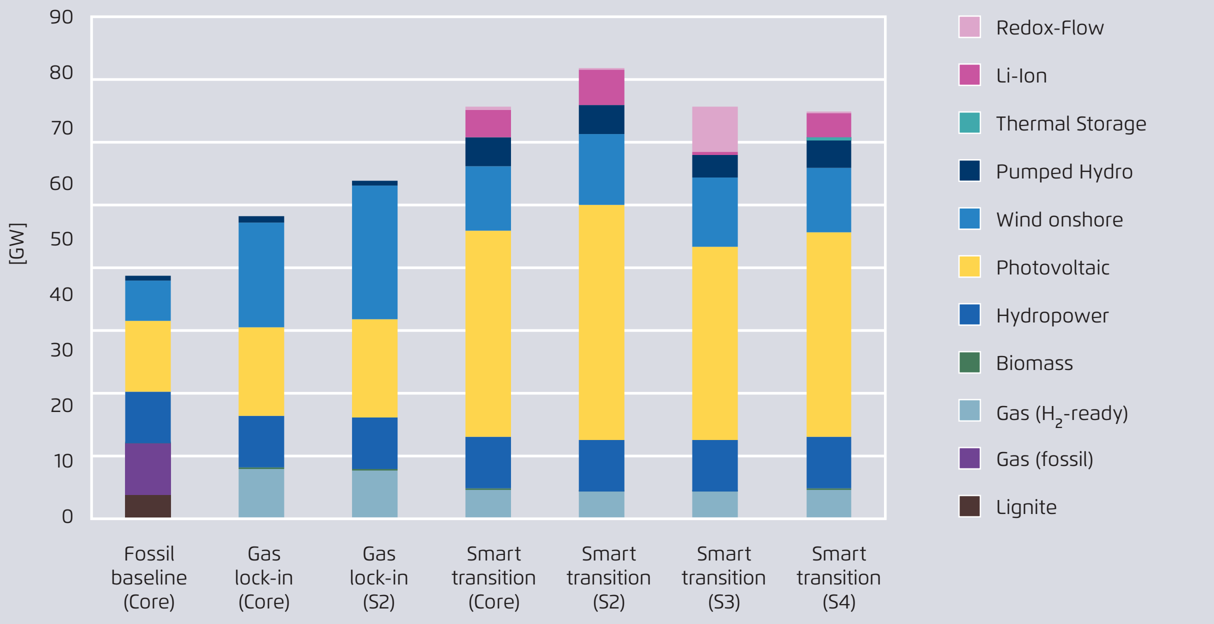
- → Firstly, we analyse the effects of **higher long-term fuel costs for alternative green gases**, assuming a long-term price level double that of the core scenarios (Euro 120 / MWh compared to ~Euro 60 /MWh).
- → Secondly, we consider the potential for a **breakthrough in redox-flow battery technology** such that costs are reduced 50 percent and storage duration is increased 20 hours, potentially making redox batteries competitive in the storage mix.
- → Thirdly, we consider a **breakthrough in thermal storage technology**, with costs falling 75 percent, making thermal storage competitive in the storage mix.

Note that the H_2 fuel cost sensitivity (S2) impacts both net-zero scenarios (gas lock-in and smart transition), while the baseline does not employ any hydrogen as a fuel for power generation and is thus not affected by altering H_2 cost assumptions.

Likewise, the two storage cost breakthrough sensitivities (S3 for redox storage and S4 for thermal storage) only impact the smart transition scenario, since it is the only scenario employing these storage technologies among the available mix of decarbonisation technologies.

In total, this results in a set of four sensitivity scenarios on top of the three core scenarios: gas lock-in (S2) , smart transition (S2) , smart transition (S3) , and smart transition (S4) .

Capacity mix in all scenarios & sensitivities in the year 2045 Figure 11



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The following sections discuss the capacity structures (Figure 11) and cost impacts (Figure 12) that result from these alternate assumptions.

7.1 Green hydrogen costs

In the sensitivity modelling that assumes higher green hydrogen costs, significantly more RES capacity is deployed in both the gas lock-in (S2) and smart transition policy (S2) scenarios. These capacities are deployed to make up for lower hydrogen-based generation, which has become less cost-efficient and is thus reduced by 60 percent (gas lock-in) and 63 percent (smart transition) compared to the respective core scenario.

Notably, the mix of additional RES capacity differs between the gas lock-in and smart transition strategies. The gas lock-in lacks capacity to integrate additional PV with complementary storage, and thus relies on more onshore wind. In the smart transition (S2) , on the other hand, additional RES generation is provided by an increase in PV capacity, which can efficiently be integrated into the power mix based on additional li-ion storage capacity compared to the core scenario.

At the same time, modelled gas capacity is not significantly reduced despite higher fuel costs, indicating it still represents a cost-efficient option for ensuring coverage of peak demand. For example, in the gas lock-in (S2) scenario, gas capacity is only 6 percent lower compared to the core scenario. In the smart transition pathway (S2), the availability of other storage technologies allows the model to decrease gas capacity by 12 percent compared to the core scenario by deploying a mix of additional renewables and batteries in reaction to higher hydrogen prices. This demonstrates that hydrogen-based power generation is still a dominant technology to cover peak demand, but can be substituted to some extent with battery storage.

These findings are reflected in the cost analysis of the sensitivity scenarios: the hydrogen cost sensitivity of each net-zero scenario (the S2 variants in the graph) results in higher total incremental generation costs (represented by the figure "net cumulative costs" in the graph) compared to the respective core scenario for gas lock-in and the smart transition.

However, the cost impact is significantly higher for the gas lock-in strategy, with costs increasing 11 percent in gas lock-in (S2) compared to gas lock-in. This is driven by the substitution of H_2 generation with relatively expensive onshore wind capacity instead of PV, inducing higher RES costs, and reduced income from power exports.

In the smart transition (S2), more expensive green hydrogen causes just a 1 percent increase in net cumulative costs. This is because lower dependency on hydrogen fuel is accommodated with a more cost-efficient mix of PV and additional storage.

7.2 Redox storage cost breakthrough

In the sensitivity modelling for the first storage breakthrough, lower costs for redox flow batteries can reduce overall capacity demand and lead to a shift from li-ion storage to redox flow batteries. Our modelling foresees 8.8 GW of redox flow battery capacity deployed in the long term, smart transition (S3). The RES capacity mix is shifted slightly from PV to onshore wind.

Increased flexibility through storage also reduces gas and, later on, H_2 demand (minus -30 percent for gas in 2035 and minus -20 percent for H_2 in 2050). Thus, the availability of mid-term battery storage can integrate more RES generation and shift fuel costs and associated risk to CAPEX.

Against this backdrop, please note that hydrogen in the power sector is often associated with two different roles:

- → Electrolysers provide "negative flexibility" or the ability to provide additional power demand and thus absorb renewable power generation while producing hydrogen. Electrolysers in this function are not explicitly modelled in this scenario exercise for the Western Balkans.
- → Hydrogen can fuel hydrogen-based power plants to provide generation in times of scarcity.

Together, electrolysers and hydrogen plants provide a functional storage unit, e.g. additional demand in times of low power prices and additional generation in times of high power prices. It is important to note that the second function is independent of the first if hydrogen is provided by other sources, notably imports. The second function is examined in this study, given its key importance for the deep decarbonisation of the power sector. This is mostly because reducing emissions to zero requires technologies that are able to reliably produce carbon-neutral power over extended periods of time, most importantly during times of peak load.

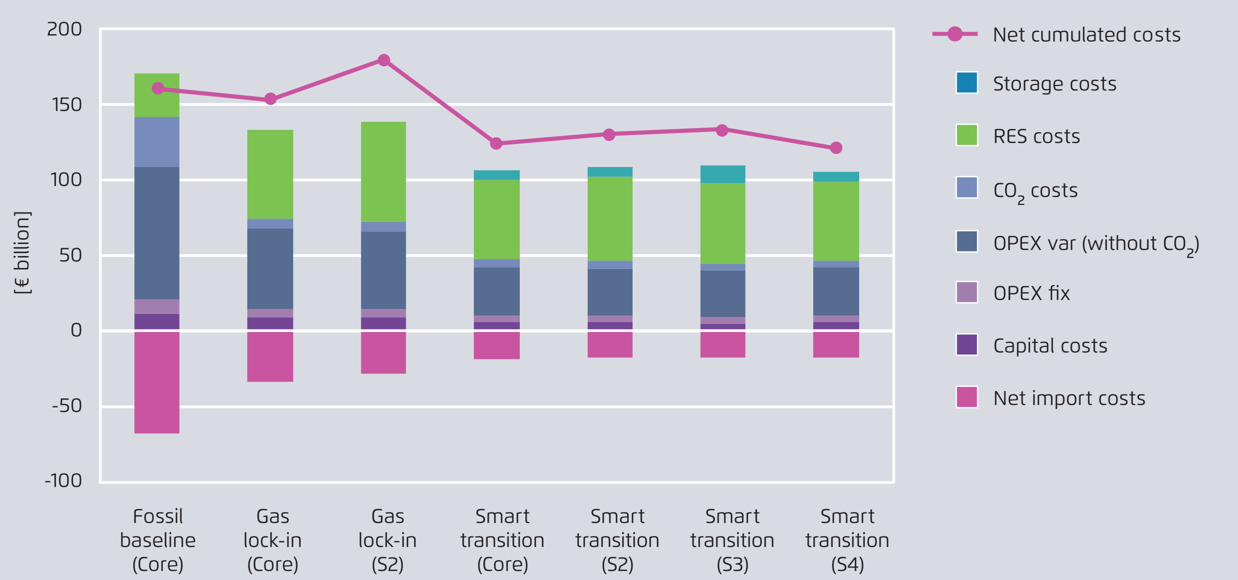
The redox-flow breakthrough scenario has no significant impact on the total CO_2 emissions mitigation, though the reduction of gas-based production in the 2030s decreases annual emissions by about 10 percent in that decade.

Total cumulative investment increases by about 5 percent in this sensitivity variant. This is mainly driven by an increase in total storage cost investment and, to a lesser extent, by additional wind capacity. These additional expenditures are offset by savings in CO_2 costs and fuel costs, such that incremental generation costs remain largely unchanged.

7.3 Thermal storage cost breakthrough

In the thermal storage cost breakthrough scenario, as detailed in the smart transition (S4), 0.7 GW of thermal storage replaces 1.4 GW of li-ion batteries. There is no significant impact on the rest of the capacity mix. A thermal storage breakthrough therefore has no

Incremental generation costs (2022–2050) of all scenarios & sensitivities in comparison | Figure 12



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significant impact on total CO_2 emissions mitigation. Cumulated investment is reduced by ~5 percent. Total incremental generation costs are slightly reduced while the overall cost level and composition of generation remains similar (Figure 12).

7.4 Conclusions from sensitivity analysis

The results of the sensitivity analysis outlined in the previous subsections allow several conclusions to be drawn.

First, hydrogen-fuelled flexible capacity of at least 4.5 GW is required and cost-efficient regardless of hydrogen fuel cost trends. This "capacity floor" covers peak demand during periods of low renewables feed-in, and annual operating hours are low. The capacity floor is capable ensuring system reliability. However, hydrogen should not be used generally for decarbonisation. Furthermore, a failure to consider the need for future H_2 retrofits when making natural gas capacity investments will lead to higher net long-term costs. At the same time, a smart transition with early consideration of H_2 retrofitting and investment in storage can mitigate more significant overall cost increases. The results of the hydrogen cost sensitivity analysis clearly highlight the inherent risks in a net-zero pathway relying on natural gas as a transitional fuel insofar as this implies the use of hydrogen scale. Future reliance on hydrogen can be mitigated based on an intelligent strategy that leverages diverse technologies, including various storage options.

Second, a breakthrough in mid-term storage technologies (redox-flow batteries and thermal storages) would not have a significant impact on CO_2 mitigation and overall net power system costs. However, in both cases these breakthroughs shift investment toward the respective technology (redox-flow or thermal storage) with some substitution effects in the capacity mix and a reduction of overall natural gas and H_2 usage. The results of this sensitivity analysis indicate that breakthroughs in storage technology could aid diversification away from lithium-ion batteries. This would be beneficial given potential future raw material scarcities. Furthermore, strategically incorporating storage technologies in the power sector can provide valuable opportunities for the conversion of existing generation sites to thermal storage facilities.

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Agora Energiewende develops scientifically sound, politically feasible ways to ensure the success of the energy transition – in Germany, Europe and the rest of the world. The organization works independently of economic and partisan interests. Its only commitment is to climate action.

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