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Burning the Bridge to Ostpolitik? Stress-Testing Europe's Shift from Russian Gas to Renewables Using a Global Energy Model

Supplementary Information (SI) 3: Detailed analysis of modelling results

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Results

This section of the paper is structured as follows: the implications of decoupling from Russian gas on European energy security are outlined in §1.1, followed by an assessment of the impact distribution among Member States (MS) in §1.2. The last subsection (1.3) discusses implications for climate change and investments in renewables in Europe.

1.1 Implications of decoupling from Russian gas on European energy security

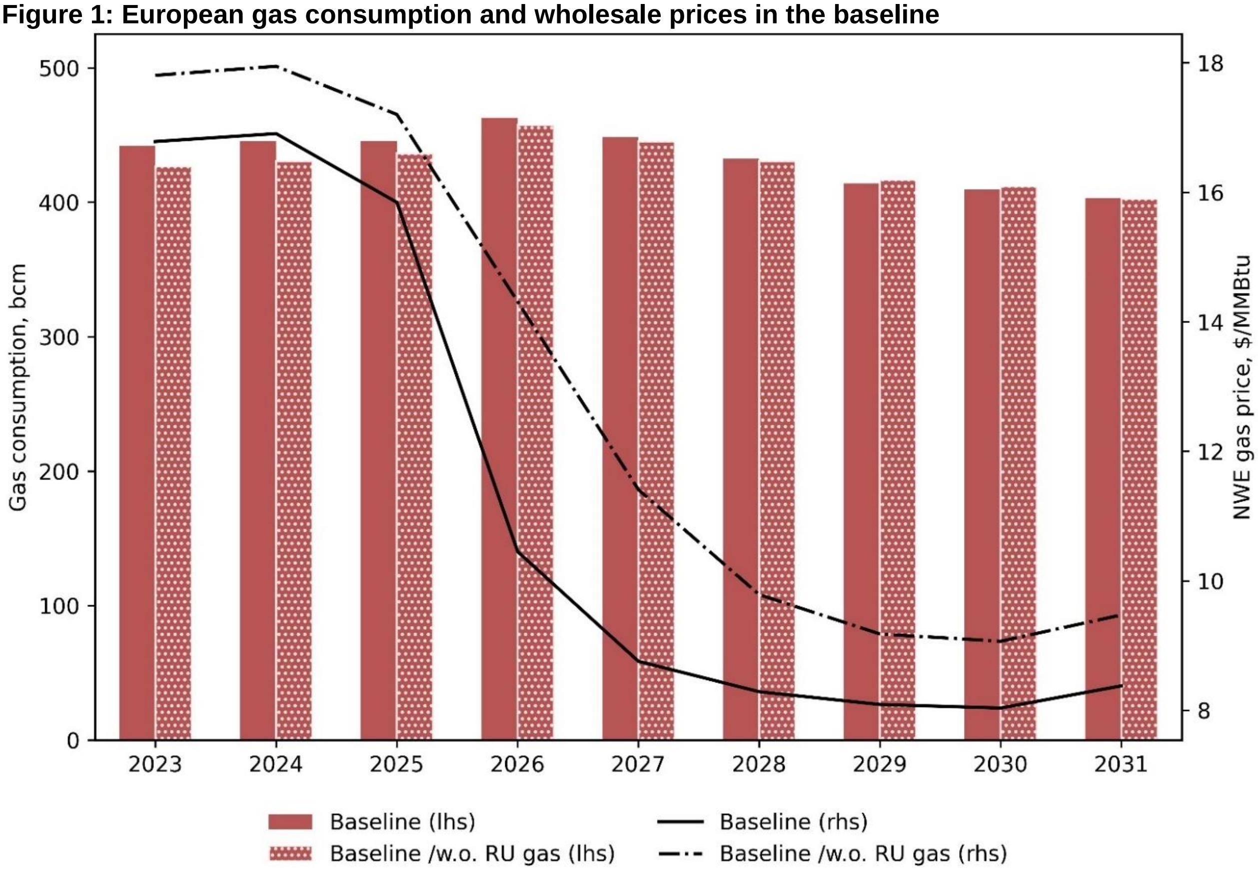
Section 1.1.1 delves into three primary sources of gas flexibility for Europe to replace Russian gas during a *normal* winter year, followed by an analysis in Section 1.1.2 of how Europe addresses extreme weather events.

1.1.1 Sources of flexibility to replace Russian gas

The section briefly describes the gas market's evolution through 2031 based on model results under different scenarios. More specifically, it describes gas markets in Europe in the context of decarbonising its power system as planned by NECPs and the evolution of the global LNG market. It also briefly illustrates the impact of a complete phase-out of Russian gas supplies on market equilibriums.

First, European gas markets are expected to be tight in the short term (before 2026) and loosen as more LNG and renewable electricity supplies are commissioned (see Figure 1 for price and demand evolution).

Figure 1: European gas consumption and wholesale prices in the baseline



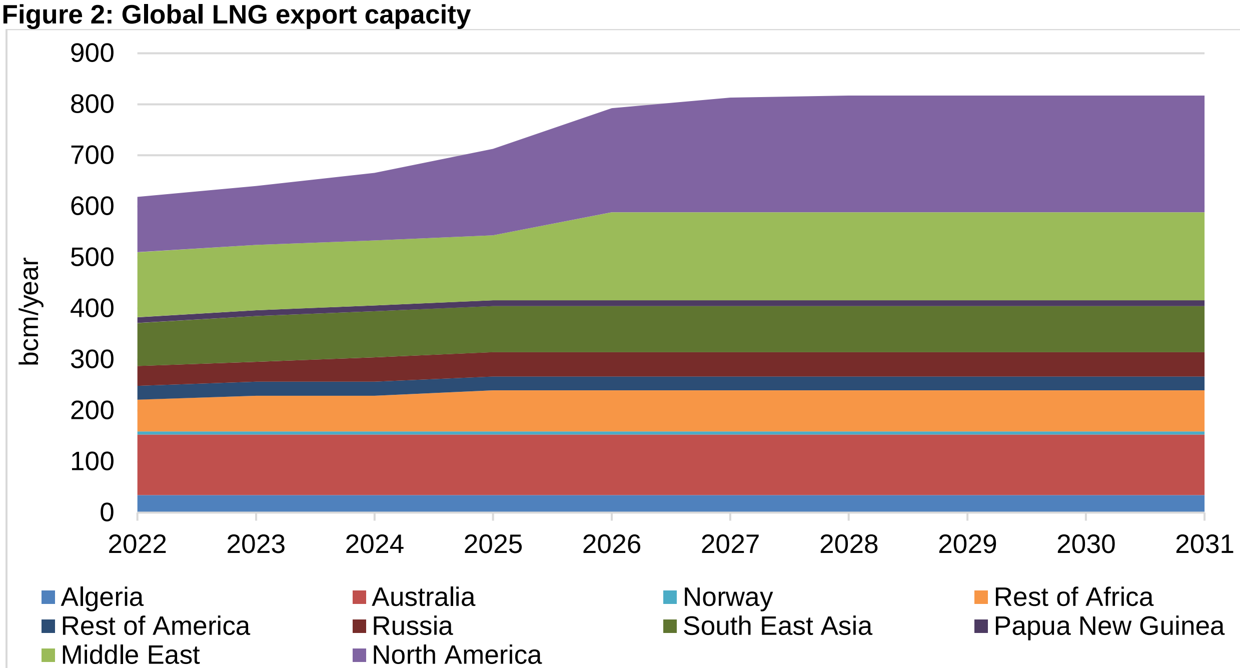
Note: Bars show the total gas demand in Europe (EU27, Norway, Switzerland, the United Kingdom and Ukraine). Full font (resp. full lines) shows the demand (resp. average gas price) with Russian gas flows, while dotted font (resp. dotted lines) shows scenarios without supplies of Russian gas to Europe.

Gas demand is projected to increase by 3.9% from 2024 to 2026 as Europe phases out coal plants, and deployment of renewables is just emerging. Europe will reach an annual demand of 463 bcm in 2026, and gas prices will remain high (around 17$/MMBtu). After 2026, gas prices steeply decrease to an average of 8.7$/MMBtu (from 2026 to 2031) due to a significant increase in global LNG (Figure 2) and domestic renewable supplies, reducing gas demand in power generation.

Without gas supplies from Russia, delivering alternative gas to Europe is more expensive. Northwest-European (NWE) prices increase by 1-4$/MMBtu (+16% on average) between 2024 and 2031 compared to the baseline Russian gas flow scenario, and the structural price decrease is not fully realised, especially between 2026 and 2028, with gas prices reaching an average of $11.8/MMbtu (see Figure 1). Despite Europe's ability to absorb this shock, phasing out Russian gas results in a cumulative (2023-2031) +$139bn increase in wholesale gas costs and a +$308bn increase in electricity costs compared to a scenario with access to Russian imports.

The rest of this section outlines three levers activated by the phase-out of Russian gas: (i) redirection of global gas supplies, (ii) flexibility in the power sector, and (iii) demand side response (DSR) in the industrial and residential sectors. The examination will focus on how each mechanism substitutes import flows from Russia. There is a maximum of 31 bcm/y of Russian pipeline gas and ca. 19 bcm/y of Russian LNG supply to Europe (see Table 1 for more details).

Figure 2: Global LNG export capacity



Source: based on the Refinitiv LNG infrastructure database (accessed July 2023)

Table 1: Baseline Russian gas flows to Europe

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Pipeline	25.7	27.6	28.9	28.9	29.8	29.5	29.3	29.3	30.7
LNG	17.0	17.2	16.1	19.3	17.6	17.5	17.5	17.5	17.4
Total	42.7	44.8	45.0	48.2	47.4	47.0	46.8	46.8	48.1

Notes: Pipeline flows account for pipeline transit through Ukraine (Sudzha) and Bulgaria from Turkey (Turkstream). LNG flows count all LNG ships from the Yamal peninsula to Europe.

Redirection of global gas supplies

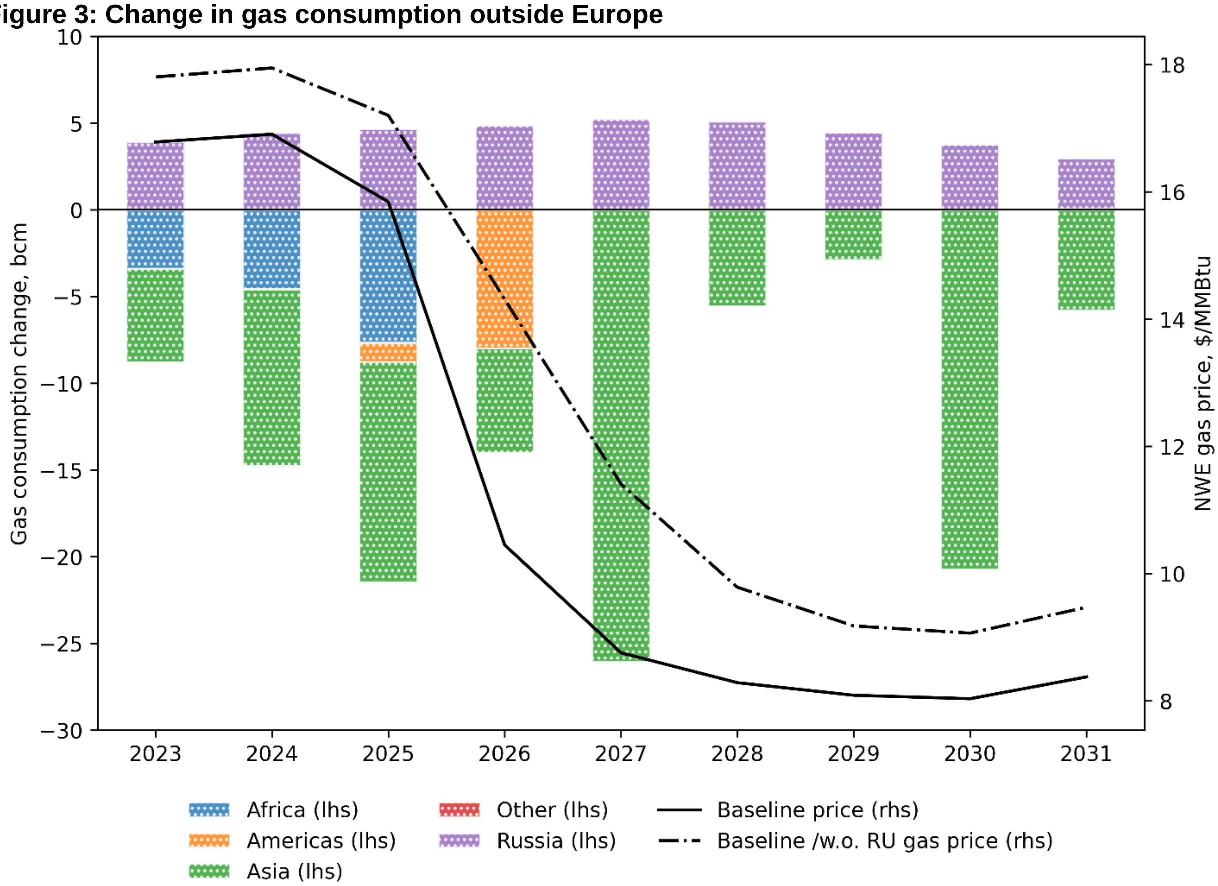
An important effect of phasing out Russian gas supplies is redirecting global gas flows. These flows come to replace Russian gas supplies in sectors with limited alternatives to natural gas due to (i) economic causes (gas boilers have high upfront costs, or because gas is an essential feedstock in industrial processes) or (ii) security and reliability objectives (winter gas consumption secured with mandatory storage filling targets).

As a result, Europe sources this hard-to-replace demand from global markets, redirecting flows initially destined for other regions. A flow redirection from an origin is made possible by a fuel switching in the power sector, replacing gas with another fuel (mostly coal and oil).

Figure 3 shows the magnitude and location of gas demand changes due to Europe replacing Russian imports, causing higher global gas prices. Where gas demand decreases, there is a fuel switch in the power sector: before 2026, 9-21 bcm of gas is redirected from India, South East Asia, and Africa. After 2026, the gas flows will mainly be redirected from Northeast Asia and the Americas.

Due to the modelled embargo of Russian LNG in Europe, the flow from Russia is redirected to Asia while alternative LNG supplies are rerouted to Europe. This reshuffling of global flows has important implications for the EU's energy security. LNG is becoming an essential source of gas flexibility for Europe and stresses the importance of a strategy to reduce dependence on natural gas imports, not only Russian gas. Section 1.1.2 analyses how this affects flexibility during extreme weather conditions.

Figure 3: Change in gas consumption outside Europe



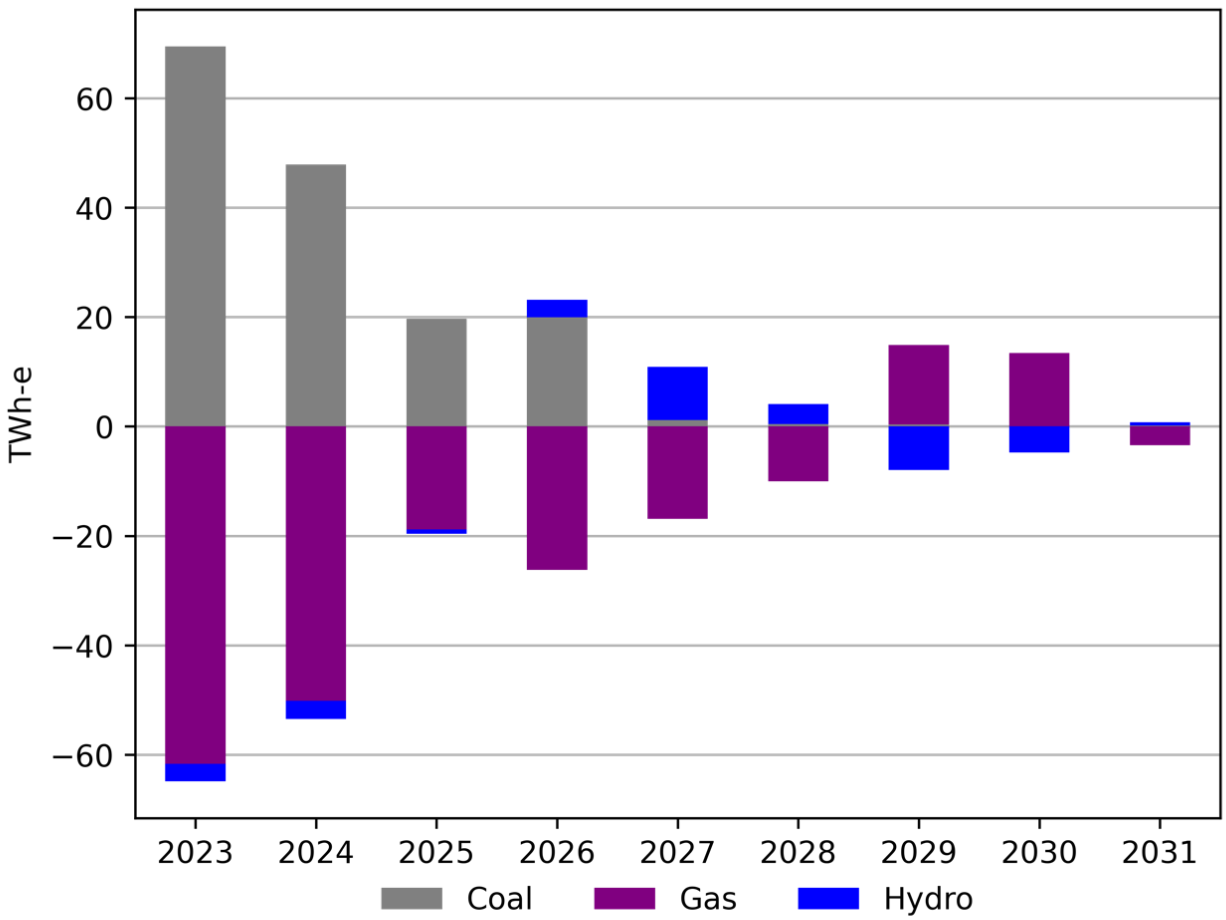
Notes: Stacked bars show the total change in gas demand in the power sector in different regions from the baseline flows to the disrupted gas flows scenario.

Power sector flexibility

In the short to medium term, dispatchable generation (fossil- and hydro-based) will play an increasing role as mid-to-peak load suppliers as the European power system decarbonises with the increased penetration of VRE supply. NECP19 aims to reduce the share of coal in the generation mix, phasing out 25% of Europe's 2023 coal capacity by 2025 and reaching a 44% reduction (88 GW) in 2030. Given this anticipated evolution of the power system and the decreased availability of Russian gas, the flexibility provided by dispatchable generation will likely be under stress throughout 2023-2031.

The removal of Russian gas from the power sector triggers flexibility from two sources: (i) a gas-to-coal switch between 2023 and 2026, with a cumulative 157 TWh of gas generation replaced by coal generation, and (ii) a change in the operation of hydropower generation[1], to arbitrage between scarce and abundant supply periods. Hydropower shifts 33 TWh (21% of gas replaced by coal) of electricity from gas (see Figure 4). Indeed, hydropower substitutes gas in some years (e.g., 2027), while gas replaces hydropower in other years (e.g., 2029), resulting in net zero generation changes[2].

Figure 4: Change in power generation in Europe



Note: Hydro refers to hydropower sources (reservoir and pumped open-loop systems) enabling the control of their output generation, similar to electricity storage sources.

[1] referring to reservoir and open-loop pumped hydropower generation.

[2] summed across all years

The power sector mainly absorbs gas shocks via the gas-to-coal switch. However, this does not provide a definite solution, as coal plants will be decommissioned. Most of the coal capacity (~40 GW) will be located in Ukraine and Poland in 2030, accounting for 60% of the coal capacity in Europe. Meanwhile, a significant portion of weather-driven (mainly hydropower and onshore wind) and outage-prone generation (nuclear[3]) fluctuations will be in Western Europe. Replacing gas with coal as a provider of power flexibility might, therefore, require power grid developments: the mismatch between the power flexibility demand (nuclear plant outage, hydropower reduced availability, and VRE inter-annual variability) and supply (dispatchable power generation) will widen as the EU decommissions coal capacity.

Thus, replacing gas with coal in Europe as the power system is decarbonised is a challenging task as it requires (i) anticipating the location of flexibility needs for tackling IAV of VRE supply, nuclear and hydropower output, (ii) fitting the incumbent power transmission design to leverage coal capacity which is more concentrated than gas capacity (detailed country-level analysis can be found in §1.2).

Demand side response

The gas DSR is another source of flexibility that contributed to Europe's replacement of Russian supplies. In the case of a complete phase-out of Russian gas, the DSR increases in both industrial and residential sectors between 2023 and 2025, peaking at seven bcm until 2024 in the industrial sector and averaging three bcma in the residential sector (see

Figure 5).

Even with Russian gas imports at the baseline flow level, Europe triggers DSR between 2023 and 2025, as global gas markets are expected to be tight due to the war in Ukraine and the 2022/23 energy crisis. The results also highlight a relative inflexibility of gas demand in the residential sector (see discussion in Sperber et al., 2024), implying that DSR capability should be developed further in light of increasing volatility in global energy markets due to geopolitical and weather-related shocks.

The reduced industrial output in the short term relates to the recent situation of some gas-consuming industries (e.g., steelmaking, cement, fertilisers, petrochemicals, etc.) halting their activities and closing plants due to increased energy prices. As the curtailments illustrated in the results, the reduced industrial demand for gas alleviated Europe's gas shortages. Still, it might lead to prolonged deindustrialisation, as energy-intensive manufacturing would likely not resume before prices fall and stabilise. The 2021-2023 period showed evidence that energy-intensive industries tend to substitute domestic production with imports when energy prices are high (Ruhnau et al., 2023; Moll et al., 2023; Chiacchio et al., 2023), hitting the most energy-intensive industries in Europe.

Decoupling from Russian gas only slightly affects the previous conclusions: (i) before 2026, DSR replaces 3-5.6 bcm/y of Russian gas, while (ii) after 2026, the increase in global LNG supply makes DSR unnecessary (

Figure 5) despite the phase-out of Russian gas. Nonetheless, gas prices remain relatively high, and the subsequent sections will explore how this influences the usage of Demand Side Response (DSR) in extreme weather conditions, specifically in §1.1.2.

Figure 6 summarises Europe's response to a phase-out of Russian gas. While fuel switching in the power sector and gas DSR are significant sources of flexibility, their importance erodes after 2026 because of:

1) the increase in global LNG supply,
2) higher renewable electricity supply in Europe, and
3) higher cost of burning coal in the power generation sector due to higher carbon prices.

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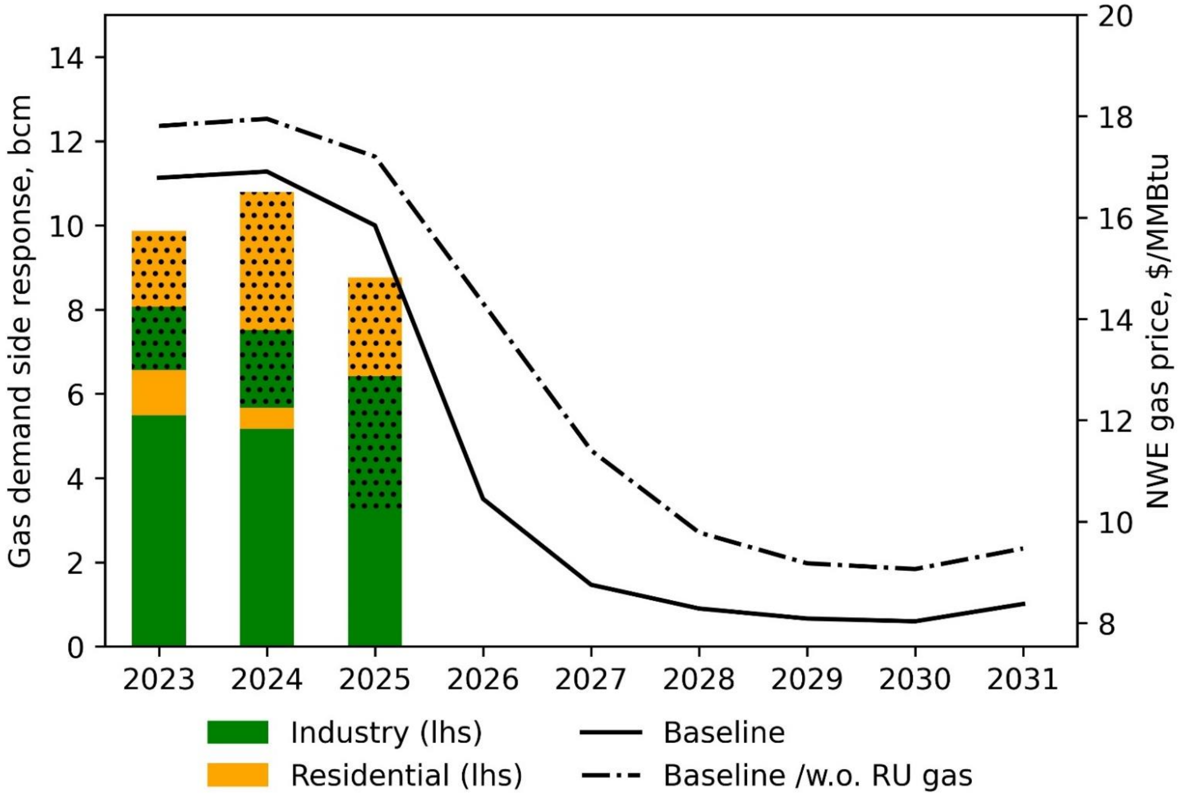
[3] see https://www.catf.us/2023/07/2022-french-nuclear-outages-lessons-nuclear-energy-europe/ for more information on the cause of reduced nuclear output in France.

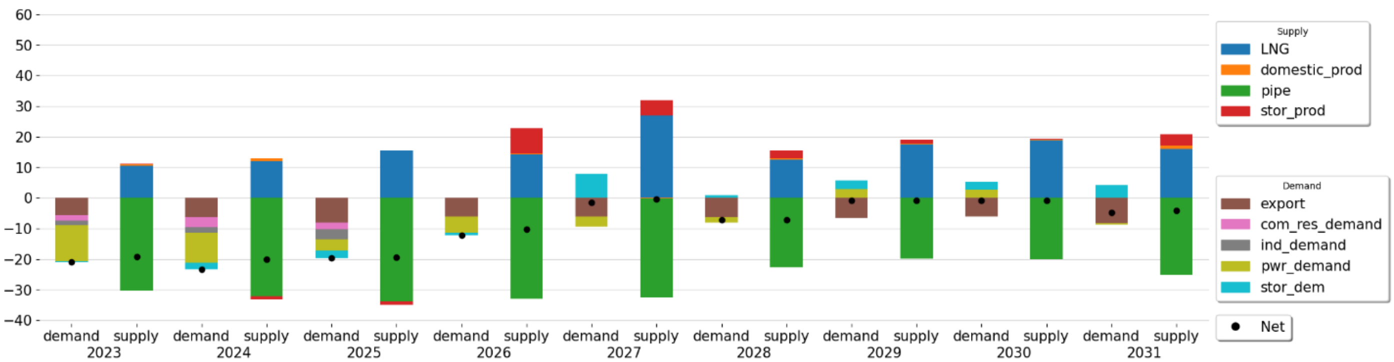
Nonetheless, the reshuffling of global gas flows, especially the rise of LNG supply, will be an essential source of flexibility throughout the decade. In the following subsection, the analysis focuses on how utilising flexibility to replace Russian gas flows affects Europe's ability to cope with extreme weather events.

Figure 5: Gas demand-side response by source in the baseline (with and without Russian gas)



Note: The chart represents the gas demand-side response in Europe with the NECP19 pathway. The solid font represents the gas DSR with baseline Russian gas flows, while the dotted font represents the additional DSR triggered in a scenario without Russian gas imports to Europe.

Figure 6: The impact of the Russian gas phase-out on gas demand-supply balance under the baseline weather scenario (bcm)



Notes: The chart represents changes from baseline Russian gas to a complete phase-out scenario in the NECP technology mix. The supply side accounts for LNG and pipeline imports from non-European regions, European domestic production, and gas storage withdrawal. The demand side describes consumption changes in all gas sectors, including gas DSR mechanisms, exports to non-European regions, and gas storage injection.

1.1.2 Addressing extreme-weather events without Russian gas

This subsection briefly describes the flexibility requirements in the European energy system under various weather scenarios. Then, the analysis explores each described flexibility source's response in different weather scenarios and quantifies the impact of phasing out Russian gas during extreme HILP events.

Impact of weather on European gas and electricity sectors

Extreme weather scenarios show changes in both electricity demand and generation output. The weather-driven variations on the electricity demand side are explained by changes in electric heating and cooling demand due to temperature variations and changes in the cooling and heating system's efficiency, which is affected by temperature and humidity conditions[4]. On the supply side, hydroelectricity is the largest single source of energy supply variation across weather scenarios, followed closely by onshore wind and offshore wind (Ah-Voun et al., 2024).

The potential generation from these sources is a product of different technological, environmental and climate factors impacting their combined energy output (see Figure 7). Europe's wind, solar and hydro generation decreases by four bcm-eq/y in the *cold* scenario and by 14 bcm-eq/y in the *coldest* scenario; meanwhile, the *coldest*+ scenario reflects a further decrease in hydro availability[5] by 18.1 TWh-e and 80.0 TWh-e of nuclear generation, totalling an overall supply deficit of 31.3 bcm-eq/y compared to the *normal* scenario. On the electricity demand side, the demand for space and water heating, lighting, and other electric appliances increases by 14 bcm-eq/y in the *cold* scenario and 21.5 bcm-eq/y in the *coldest* scenario. It reaches a 23.8 bcm-eq increase from the *normal* to the *coldest*+ scenario. Thus, the power sector variability in electricity supply and demand is equivalent to ca. 55 bcm-eq/y of additional gas demand from the *normal* to the *coldest*+ scenario, of which the supply side (changes in wind, solar, hydro and nuclear generation) contributes around two-thirds of this potential need.

Second, colder temperature scenarios impact the gas demand for space and water heating. The results reflect this in the increased demand for gas in the commercial and residential sectors. Gas demand increases by 16.7 bcm/y in the *cold* scenario and up to 26.8 bcm/y in the *coldest* and *coldest*+ scenarios.

Finally, it is interesting that the *mild* scenario reflects a total 16.4 bcm-eq/y decrease in total gas demand compared to the *normal* scenario, primarily due to a reduced need for residential heating (-9.2 bcm/y). The range of variability of gas demand equals 98.4 bcm-eq/y (changes from the *mild* to the *coldest*+ scenarios), a fifth of Europe's total gas demand in 2023 (and a fourth of 2031 demand) and ca. 90% of the entire loss of Russian pipeline gas in 2021-2023[6]. Much of this gap comes from the power sector, which requires higher scrutiny of the interaction between electricity and gas demand and supply sources, especially the performance of those highly dependent on technological and climate factors.

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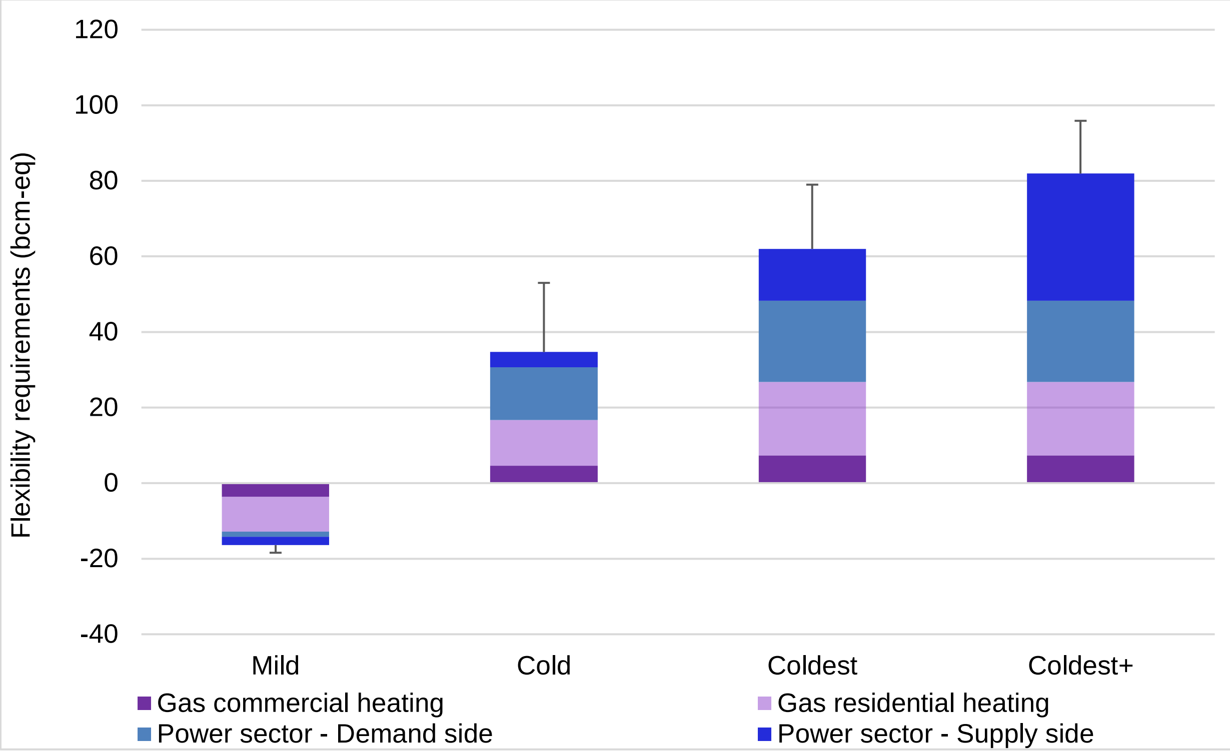
[4] for more details, see ENTSO-e, 2021, https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/Demand%20Forecasting%20Methodology%20and%20Insights%20(ERAA%202021).pdf

[5] historical minimum

[6] In 2021, Russia supplied ca. 132 bcm to the EU by pipelines, in 2022 the supply was reduced to 61.5 bcm, and in 2023 it is estimated at 22 bcm (Chyong and Henderson, 2024)

Figure 7: Average demand and supply flexibility requirements in various weather scenarios



Notes: The bars stack to the median value; each stacked bar represents a weather scenario's impact on gas and power sectors in gas equivalent units (bcm-eq). The values are differences from the baseline scenario: NECP pathway and *normal* weather scenario. The equivalent gas consumption is what a gas CCGT would consume to fill the power supply-demand gap (calculated at the country level). Values represent either an increase in flexibility needs on the demand side (due to higher energy needs) or on the supply side (to replace the reduced output from VRE, nuclear and hydro). See Section 0 for a more granular analysis. The tick bar shows the varying range of the supply side needs from the median to the maximum value, which increases with the penetration of renewables in the power sector over 2023-31.

Impact of Russian gas phase-out on flexibility in Europe

The following section describes sources of flexibility available for phasing out the Russian gas supply under HILP shock scenarios. As described above, these weather scenarios result in higher energy demand: higher gas demand from the commercial and residential sectors, lower VRE and nuclear generation, and higher demand in the power sector.

The response to these shock scenarios is a mix of (i) additional gas imports to Europe, (ii) additional power generation using fossil-powered plants, and (iii) demand-side response (DSR) in the industrial and residential sectors. Similar to §1.1.1, the examination focuses on the capacity of three primary sources of flexibility to meet demand during extreme weather conditions, namely: (i) global gas flow redirection, (ii) power sector fuel switching, and (iii) DSR. In addition, the analysis examines the role of large-scale energy (gas and hydro) storage in shifting gas supply and consumption intra and inter-annually. Each section concludes with an analysis of each source's role before and after halting Russian gas flows to Europe.

Redirection of global gas flows

The model captures the flexibility provided by the power sector in non-European regions. Thus, LNG supply flexibility mainly comes from flow redirection, a product of fuel switching in non-European regions' power sector. In colder scenarios (*cold, coldest, coldest+*), Europe's demand for natural gas increases in the heating and power sectors, shifting the global market's equilibrium to higher prices (see Figure 8, lhs).

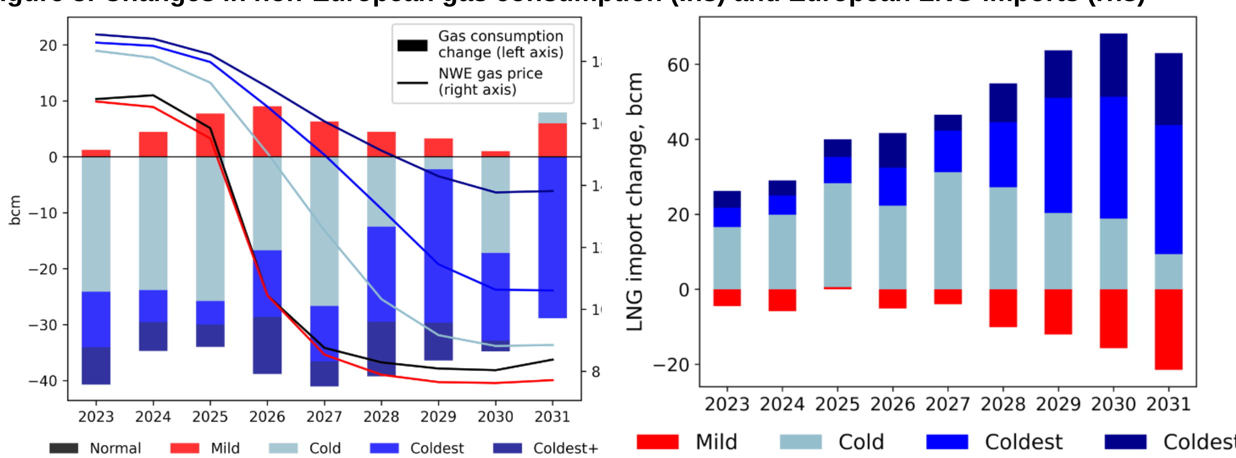
Europe heavily relies on LNG in the *cold* scenario before 2028, with ~24.1[7] bcm-eq/y demand reduction outside of Europe, equivalent to 65% of the flexibility requirement (35 bcm-eq/y[8]). In 2029 and 2031, pipeline gas supplies will be sufficient to cover the shock of the *cold* scenario, limiting the redirection of LNG to Europe. This is because gas demand decreases as Europe decarbonises its power sector, leaving pipeline supplies available for tackling cold weather events.

The *coldest* scenario only slightly increases Europe's dependence on LNG from 2023 to 2026. However, as the share of wind and solar capacity increases, Europe requires significant volumes of LNG in the *coldest* (resp. *coldest*+) scenario, covering 48% (resp. 43%) of total requirements 62 bcm-eq/y in the *coldest* scenario (resp. 81.9 bcm-eq/y in the *coldest*+ scenario), which indicates a more significant dependence on LNG markets later in this decade (2029-2031).

In the *mild* (warm) scenario, heating demand, hence gas demand, drops in Europe, reducing global gas prices and increasing gas demand outside Europe. This indicates that marginal gas volumes to Europe are LNG flows throughout the entire modelling period and that these are diverted to global markets in warmer European winters. In this context, climate uncertainties might challenge LNG markets, as long-term contracts could over-hedge volume risks, and reliance on spot markets exposes them to high price volatility (e.g., the volume needed in the *normal* vs *cold* winters).

Looking at the origin of this flexibility (see Figure 9), there is a decrease in gas consumption in other regional gas markets: 23-35 bcm/y in Asia, 2-13 bcm/y in Africa, and 1-8 bcm/y in the Americas. High EU ETS carbon prices and global gas market developments favour a coal-to-gas switch in Europe after 2026 (see following sections). Nonetheless, this is reversed in other regions, highlighting the carbon leakage issue. Thus, in the *coldest*+ scenario without Russian gas, additional gas flows are redirected to Europe as gas prices increase. Global gas markets are tighter in extreme weather scenarios when Europe cannot access Russian gas vs with access to Russian gas. The economic impact of the phase-out under the *coldest*+ scenario increases after 2026, as Europe's dependence on LNG increases, with a $2-3.5/MMBtu difference in European gas prices between the *coldest*+ and the *normal* scenario, reaching ~+$8/MMBtu difference in 2029-2031. As explained in §1.1.1, the competition in global gas markets is exacerbated by the redirection of Russian LNG to non-European regions.

Figure 8: Changes in non-European gas consumption (lhs) and European LNG imports (rhs)



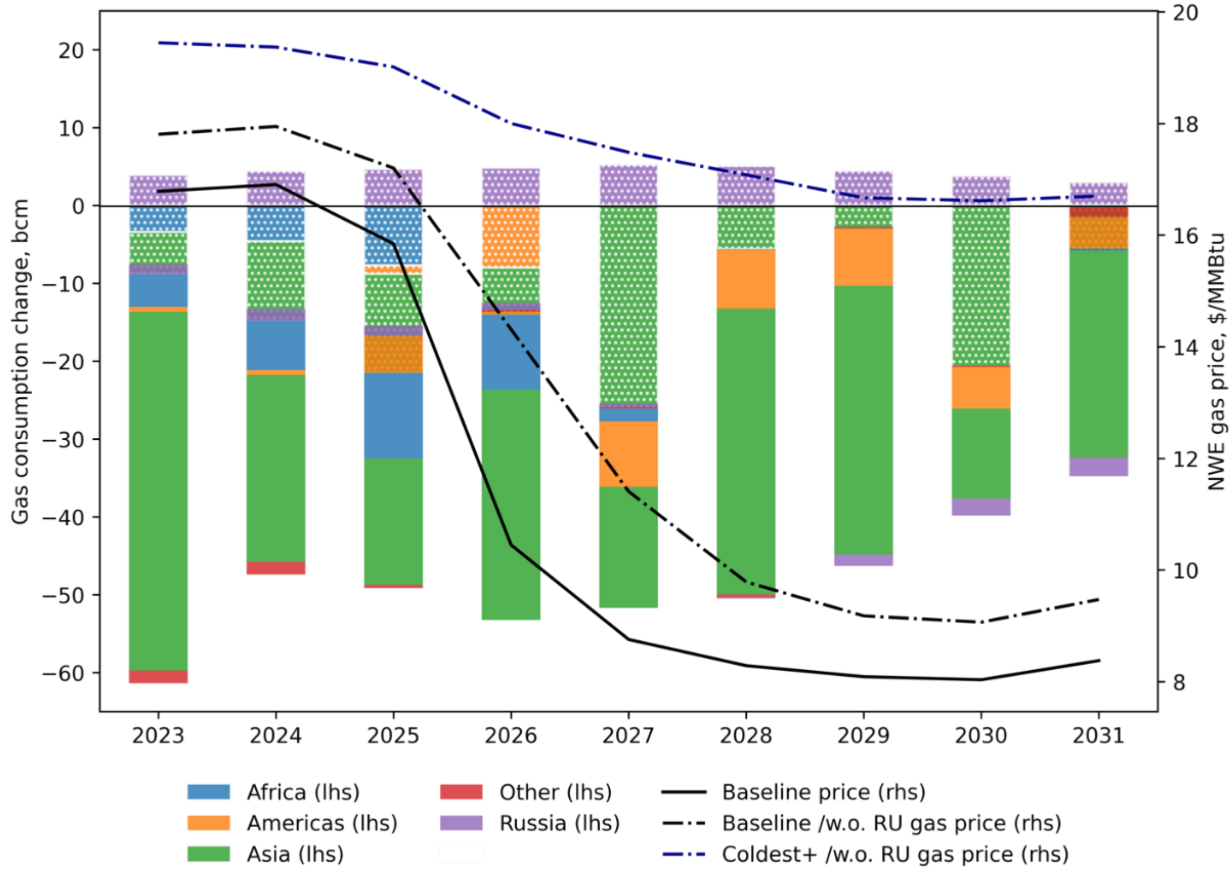
Notes: The chart shows the changes in gas consumption outside of Europe in each modelled weather scenario compared to the baseline scenario.

Notes: The chart shows the changes in LNG imports in Europe

[7] Median decrease in non-European gas consumption in 2023-2027

[8] in the *cold* scenario

Figure 9: Change in gas consumption during extreme weather after Russian gas phase-out



Note: Values represent the change in gas consumption outside Europe from the baseline to the most extreme weather scenario (*coldest*+), summing the impact of Russian gas flow replacement (dotted font) and weather conditions (solid font, *coldest*+ scenario). Lines compare the NWE prices in Europe in different Russian flow scenarios (with vs. without) and weather (*normal* vs. *coldest*+) scenarios.

Power sector flexibility

As discussed above[9], the power sector can experience significant supply and demand variability in different shock scenarios. The following sections first describe generation and price changes in these scenarios, then analyse the stress-test scenarios of the power system under the most extreme conditions (*coldest*+) with and without access to Russian gas supplies.

In colder scenarios, Europe's variable electricity supply decreases significantly compared to the *normal* scenario, leading to exceptional calls on peak generation and heightening European power prices (Figure 10). While volume shock for each scenario remains more or less constant throughout the modelling horizon, its impact on price stability varies greatly. Indeed, power prices are moderately robust to these shocks before 2026: even the most extreme (*coldest*+) scenario only entails a 9% increase in power prices. Conversely, a much more significant price spike occurs during colder years after 2026, showing +12% in the *cold* scenario, +25% in the *coldest* scenario, and +40% in the *coldest*+ scenario. This is because, in most cases, the marginal source of electricity generation—natural gas—sets the power prices. The emerging challenge is for market design to effectively send price signals to power suppliers to lower the costs of extreme-events mitigation, given the uncertainty spread across long periods while developing a power system compatible

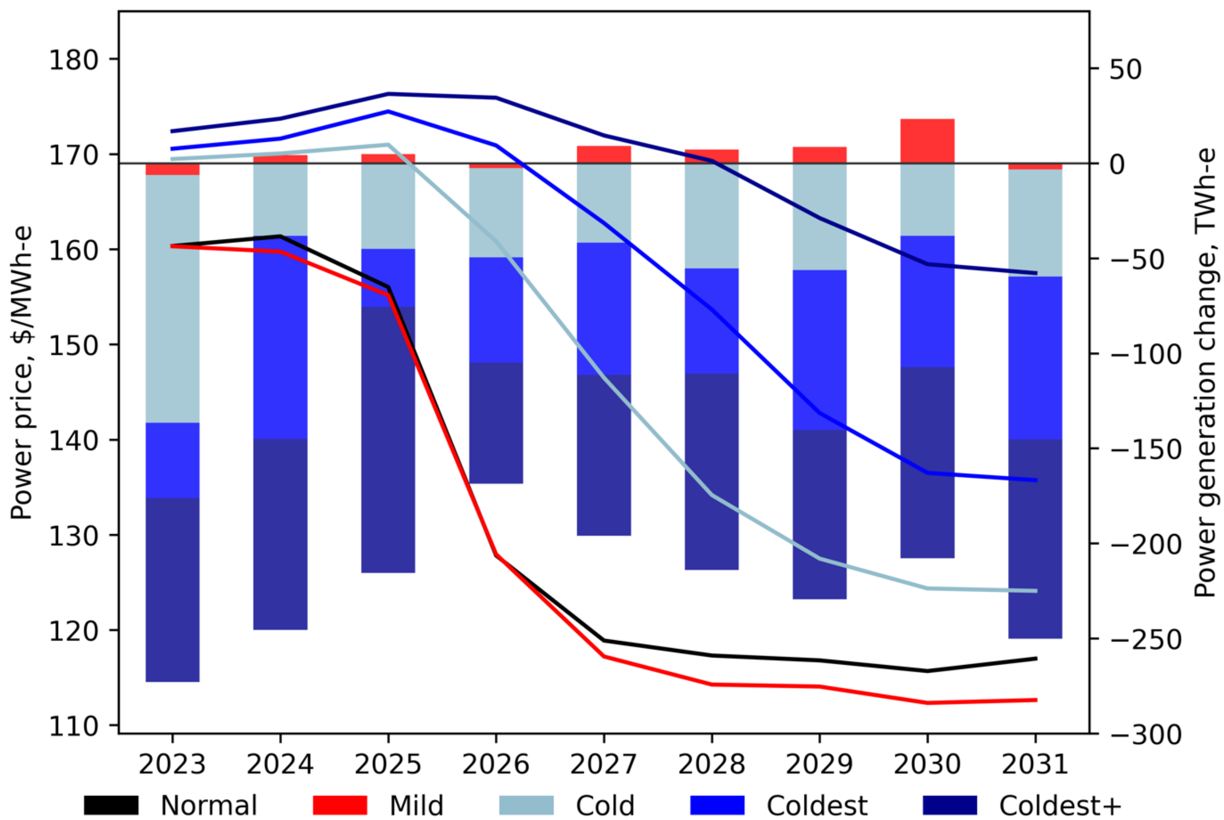
[9] See Section *"Impact of weather on European gas and electricity sectors"*

with climate goals. Another interesting finding is the asymmetrical impact of temperature changes on power prices and generation. In Figure 10, price and volume in milder climate years only marginally differ from the *normal* scenario.

The power sector has to deal with a significantly larger residual load in case of extreme weather events (see §1.2.1). Figure 11 shows how the model arbitrages using different energy sources in different years. Europe (under the NECP19 pathway) mainly relies on coal before 2026, then transitions to using gas to generate electricity in years with lower VRE, nuclear and hydro output after 2027. Hydropower also provides flexibility to the power system, moving energy from years with more significant coal availability to later years, filling gaps left by coal phase-out (2025-2028). The extended extreme weather conditions modelled are HILP scenarios. However, these scenarios describe the power system's directional behaviour due to a supply and demand shock, and hydropower systems' arbitrage pinpoints years with the lowest flexibility availability (2026, 2027, 2030).

It is essential to highlight that the impact of weather on the power sector is relatively constant throughout the modelled years. In 2031, the only significant difference from 2023 is the reduced variable electricity supply of ca. 20 TWh due to increased wind and solar capacity. However, weather changes are not the primary driver of variations observed in the composition and magnitude of flexibility requirements, such as coal-gas switching and hydropower storage, across different years. Instead, there is a combination of the following effects: (i) decreased availability of coal generation as a result of the decommissioning of coal plants (see §1.1.1); (ii) increasing EU ETS carbon prices, from \$119/tCO_{2e} in 2023 to \$146/tCO_{2e} in 2031; and (iii) structural decrease in gas prices after 2026 with the commissioning of additional LNG supply.

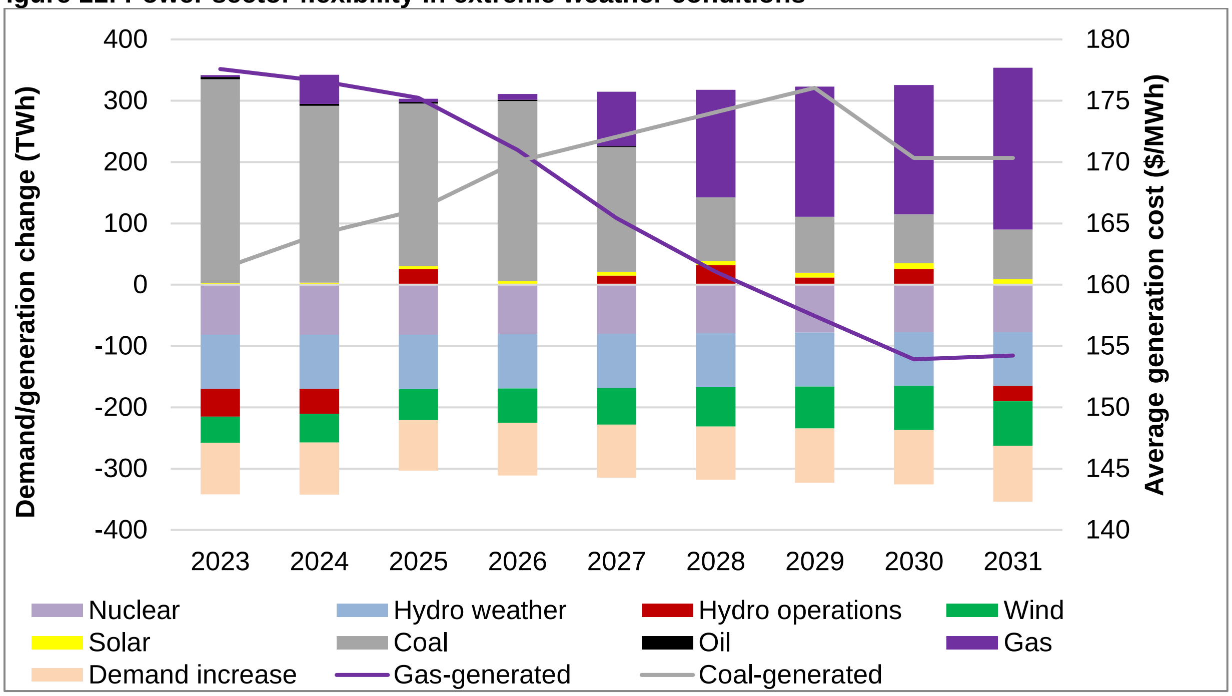
Figure 10: European power prices and generation change from the baseline in different weather scenarios



Notes: The chart shows power prices (left axis) and stacks marginal generation changes (right axis) across different weather scenarios in Europe.

Another finding is coal and gas power generation costs (and therefore power prices) peak in 2026-2027, incentivising hydro systems to hold energy in earlier years, when the average generation cost set by coal is 162.5$/MWh, and release it in 2026-2027 when the generation cost reach 170$/MWh. Another small change is the release of energy by hydropower systems in 2030 instead of 2031. This is explained by the more significant gas availability to Europe in the latter, as its gas consumption decreases from 2030.

Figure 11: Power sector flexibility in extreme weather conditions



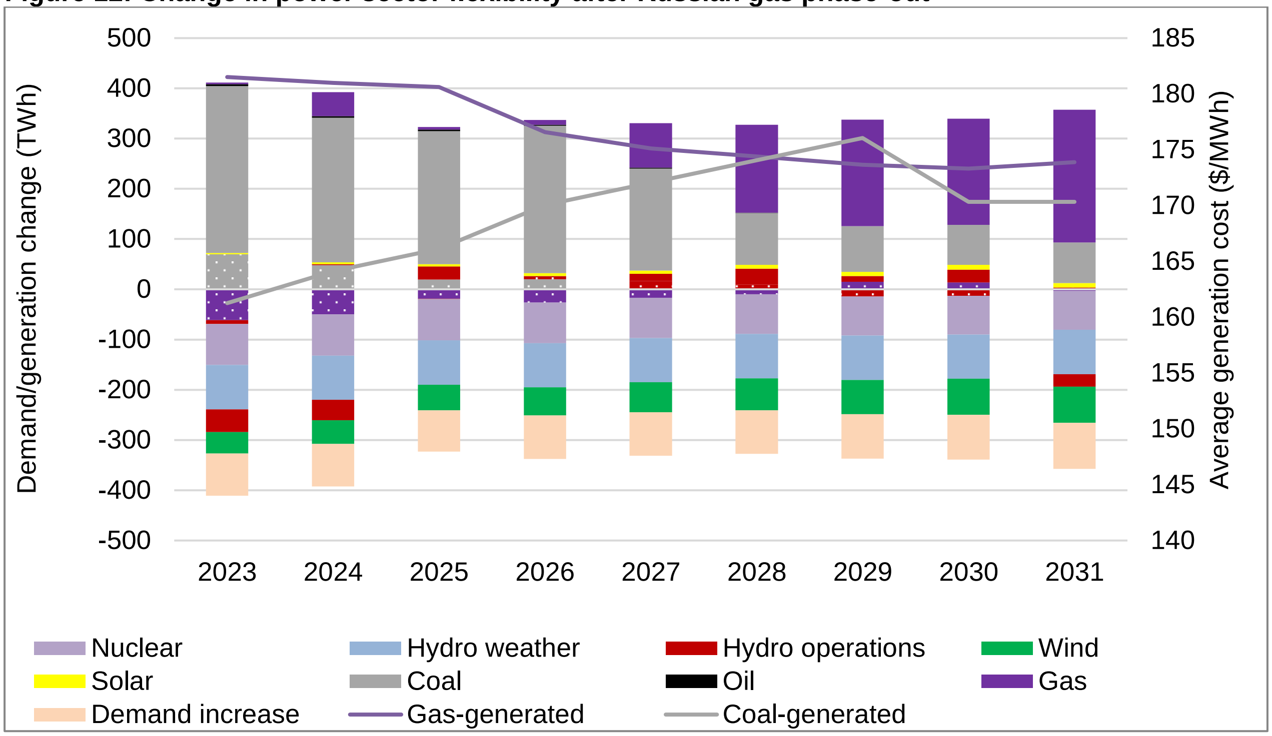
Note: Values represent the change in electricity generation from a normal weather year to the most extreme weather year (*coldest+*) scenario. Lines compare the average cost of generating electricity using coal or gas. Generation costs account for the carbon intensity of power plants (0.971 tCO_2/MWh for coal generation and 0.411 tCO_2/MWh for gas generation), their conversion efficiency (0.5 for gas turbines and 0.35 for coal turbines), and assume a 3.41 MMBtu/MWh-g conversion factor.

The analysis now turns to the power sector's response to the coldest+ scenario without access to Russian gas (see Figure 12). First, gas generation decreases by 77 TWh/year on average (compared to the coldest+ scenario with access to Russian gas). This decrease is evenly spread across all years (61-90 TWh) except for a more significant decrease in 2026. Gas flexibility is less preferred than other options across the timeline and has been replaced with available options such as coal or hydropower generation. The share of gas generation in response to coldest+ events changes from 32%-95% in 2027-2031 to 28%-76% if Europe phases out Russian gas.

Second, coal generates an additional 40-164 TWh of electricity in the coldest+ scenario without access to Russian gas. On average, an additional 77 TWh/year of coal-fired electricity is generated, peaking at 164 TWh in 2026. There is a change in hydropower generation. Though the amount of energy shifted to arbitrage flexibility in different years is stable (+5 TWh), hydro energy is released in different years without Russian gas. There is almost no hydropower generation in 2026 (compared to +56 TWh in the coldest+ scenario with Russian gas) and more in 2025 and 2028 (resp. +25 TWh and +22 TWh compared to the coldest+ scenario with Russian gas). The conclusion drawn from the behaviour of hydropower systems in coldest+ scenarios (with and without Russian gas) indicates that 2025, 2027, and 2028 are years when Europe has limited flexibility options.

The impact of phasing out Russian gas under the *coldest+* scenario is that coal stays longer in the European generation mix: coal generation will be used after 2027, as opposed to no coal generation beyond this date in the baseline. Longer coal generation life increases consumer costs and negatively impacts the environment in extreme conditions (see §1.2.3).

Figure 12: Change in power sector flexibility after Russian gas phase-out



Note: Values represent the change in electricity generation summing the impact of weather conditions (solid font) and the impact of Russian gas flow disruption (dotted font). Lines compare the average cost of generating electricity using coal or gas.

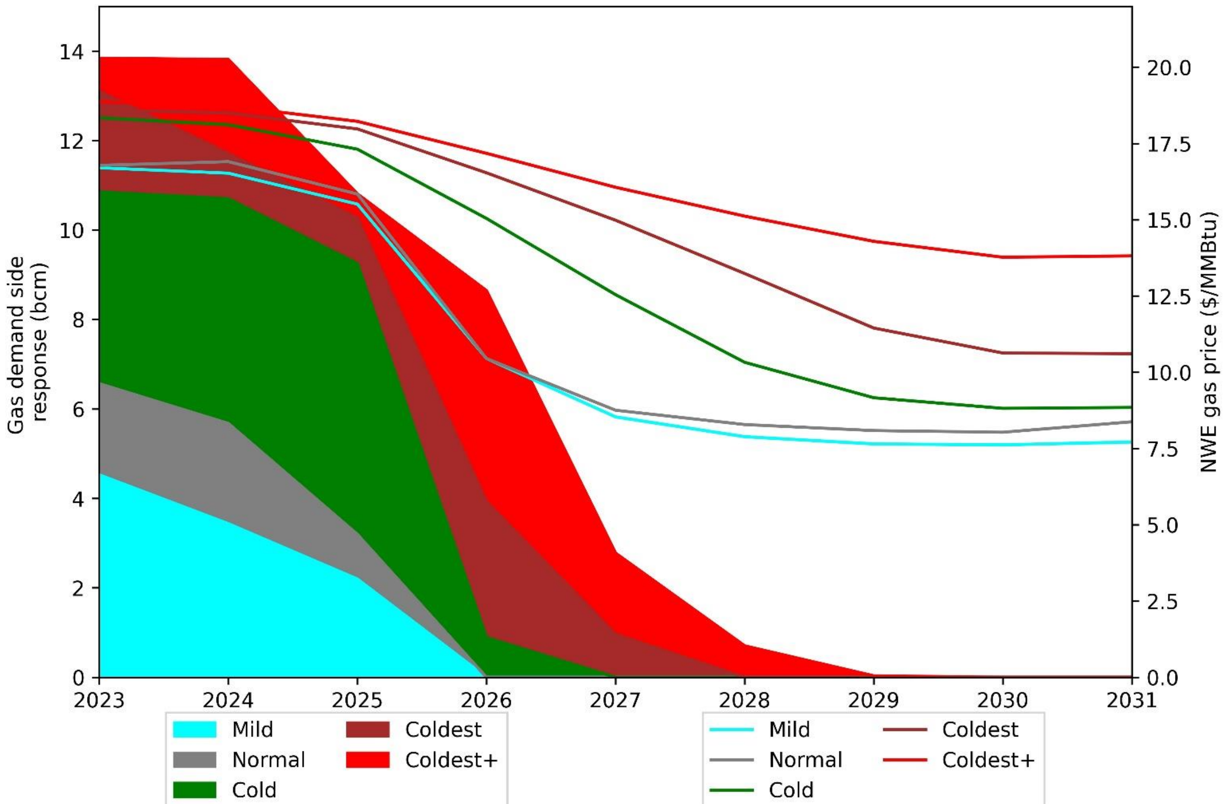
Demand side response

The gas DSR helps European countries alleviate supply and demand shocks by temporarily reducing gas demand. However, the analysis of different shock scenarios shows that their influence erodes after 2026 as the global gas market becomes less constrained, easing global gas prices.

Figure 13 shows the DSR triggered under different European scenarios throughout 2023-2031. DSR is triggered in the *mild* scenario before 2026, hinting that incentives to develop them are high in the short term due to the impact of the 2022/23 energy crisis and gas shortage created by the war in Ukraine. However, after 2026, there is little to no DSR, even under the most extreme shock scenario, as global gas supplies are increasing with new supply sources.

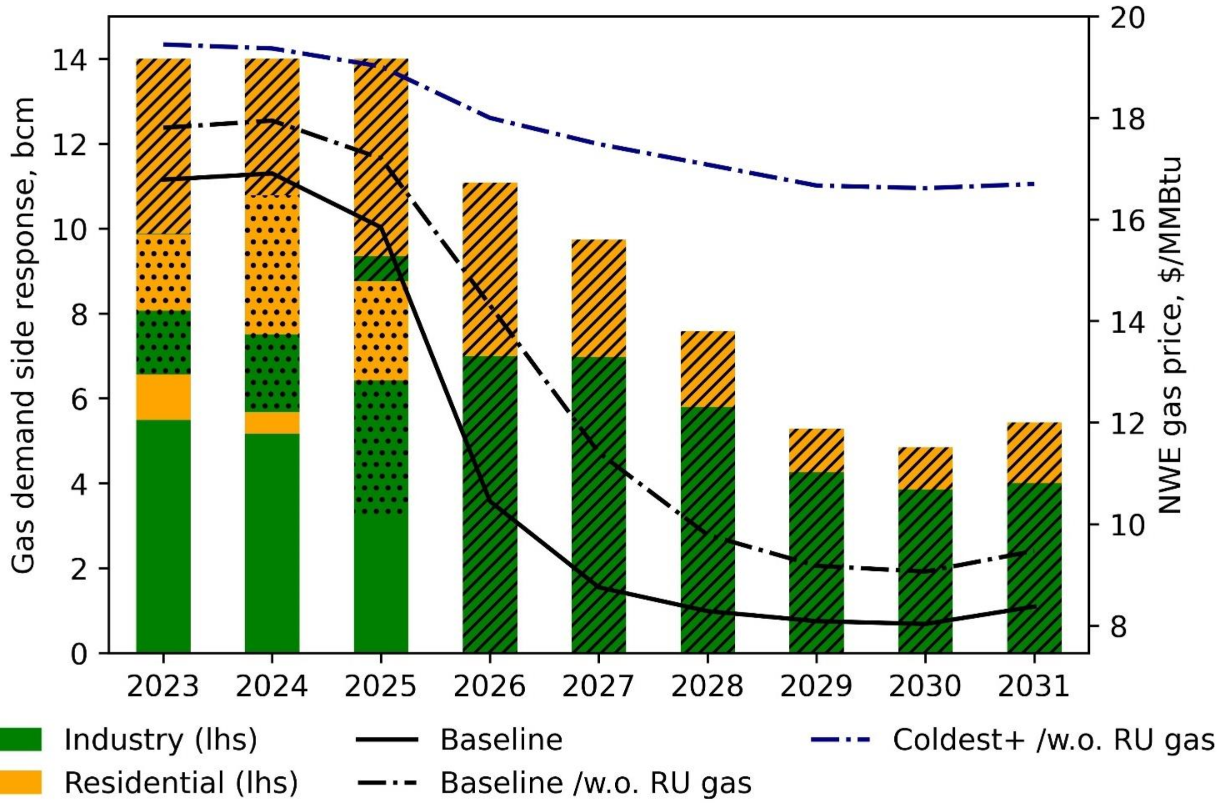
Without Russian supplies, gas prices increase closer to the DSR price trigger (Figure 14). As a result, extreme weather events lead to higher DSR than with Russian gas (primarily industrial DSR) and continue after 2027. In 2023-2025, DSR will already be triggered to replace Russian flows, reducing the available capacity for extreme weather events.

Figure 13: Gas demand side response in different scenarios



Notes: The chart shows the changes in total gas demand side response in Europe in each weather scenario, stacking on top of the demand side response in the *mild* weather scenario.

Figure 14: Gas demand side response in different shock scenarios without Russian gas



Note: Values represent the gas demand side response (DSR) from a normal weather year scenario to the extreme weather year scenario (*coldest+*). Solid fillings represent the DSR in normal weather years, the dotted fillings represent the additional DSR due to the Russian gas supply phase-out, and dashed fillings represent the additional (when no Russian supplies are available) DSR triggered in extreme weather events.

Large-scale gas and hydropower storage

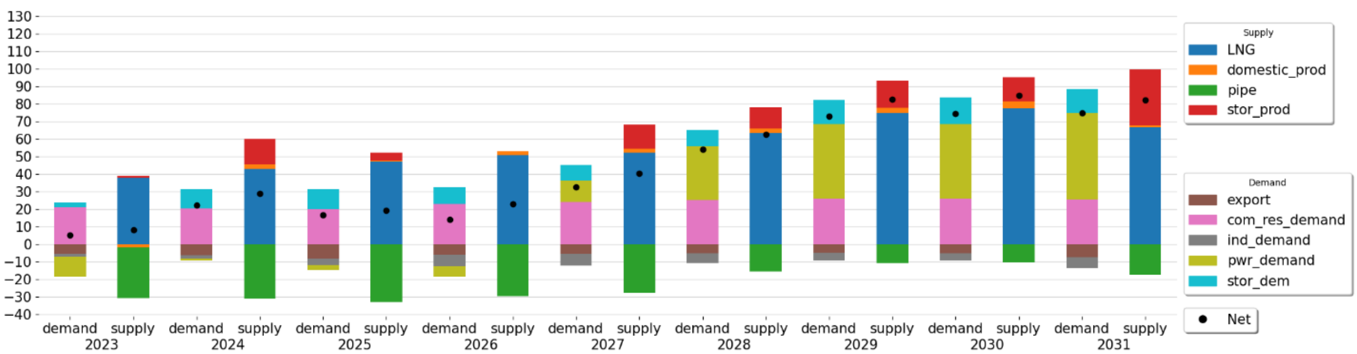
Another interesting finding is that the phase-out of Russian gas supplies entails changing the behaviour of large-scale gas and hydropower storage during the *coldest+* scenario. The figures below describe gas and hydroelectricity storage levels and changes under different scenarios. Figure 16 shows that storage will mostly withdraw in earlier years (2023-2025), with the most significant net year-on-year level changes for electricity storage, illustrating the usage of hydropower as an inter-annual storage resource. Hydropower arbitrages between cheap and expensive years because gas storage has limited flexibility due to the regulation mandating European countries to meet specific fill targets until 2026. Meanwhile, gas storage shows limited utilisation for moving energy across years: after 2025 (end of storage obligations), storage levels are constant throughout the entire period. The conclusion is that after 2026, the development of global gas supplies and Europe's increasing reliance on LNG will lead to limited inter-annual arbitrage opportunities for storing gas across *normal* weather years.

Second, looking at the impact of a phase-out of Russian gas (starting from 2023), there is limited change in the usage of electricity and gas storage in Europe. Electricity storage holds 43 TWh (roughly one-third of the capacity) more energy in earlier years (e.g., 2023-2024) and releases it in 2027-2030. Gas storage releases six bcm in the same period, holding more in earlier years, too.

However, the impact of the *coldest+* scenario would entail a more significant change in utilising inter-annual storage. It is observed that significantly higher volumes of electricity are stored in earlier years for use in later years. This indicates that the economic value of electricity storage increases in later years when the need for flexibility primarily originates from the power sector. Gas storage (see the second row of Figure 16), however, releases significant volumes of gas (12-15 bcm reduction of the average storage level) in 2024-2025 on the advent of a *coldest+* year (see third column). In the leftmost and rightmost charts (Figure 16), 30-40 bcm of gas storage is left unused[10] every year after 2026. The conclusion is that shifting gas inter-annually holds no significant value after 2025, even without access to Russian gas supplies.

In the baseline scenario, extreme weather requires an additional 83.5 bcm-eq of gas supply in Europe. On the supply side, LNG flows are redirected to Europe (Figure 15), benefitting from the gas-to-coal switch in other regions. If Russian gas is phased out, global gas markets will become tighter as Europe needs to replace Russian pipeline flows (see Figure 16). Mitigation costs of the coldest+ events are higher than in the baseline flows scenario. Gas demand inter-annual variability is more significant in later years when VRE penetration is higher, and the *normal* scenario gas demand is projected to be low. On the demand side, coal and hydro alleviate the impact of VRE reduction in the *cold* scenario. Still, their reduced availability and the increased VRE inter-annual variability increase Europe's dependence on gas, making it economically costlier to do without Russian gas after 2026.

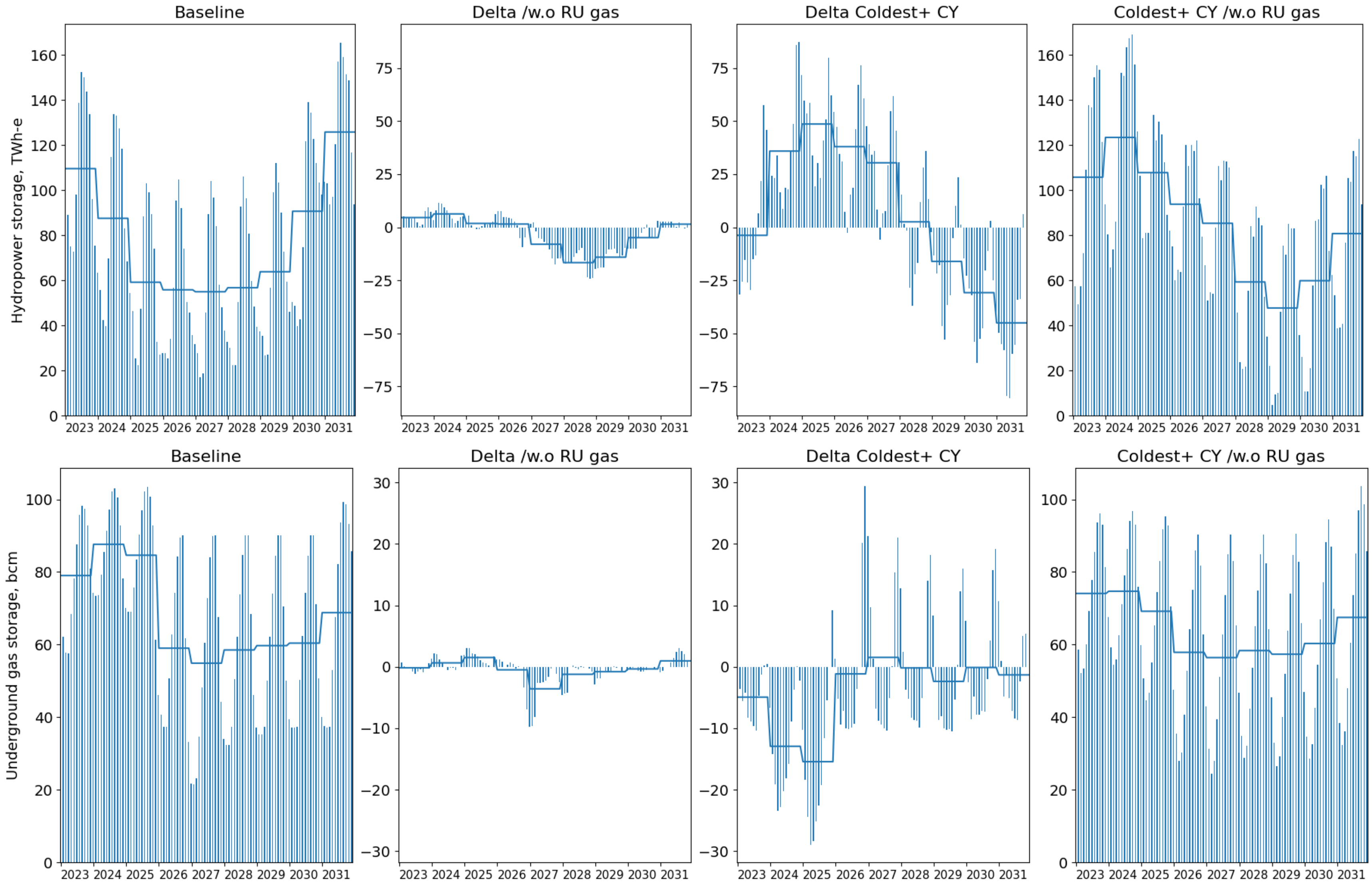
Figure 15: Net changes (bcm) of flexibility sources under coldest+, with and without Russian gas



Notes: The chart represents changes from the baseline scenario to the *coldest+/ w.o. RU gas*

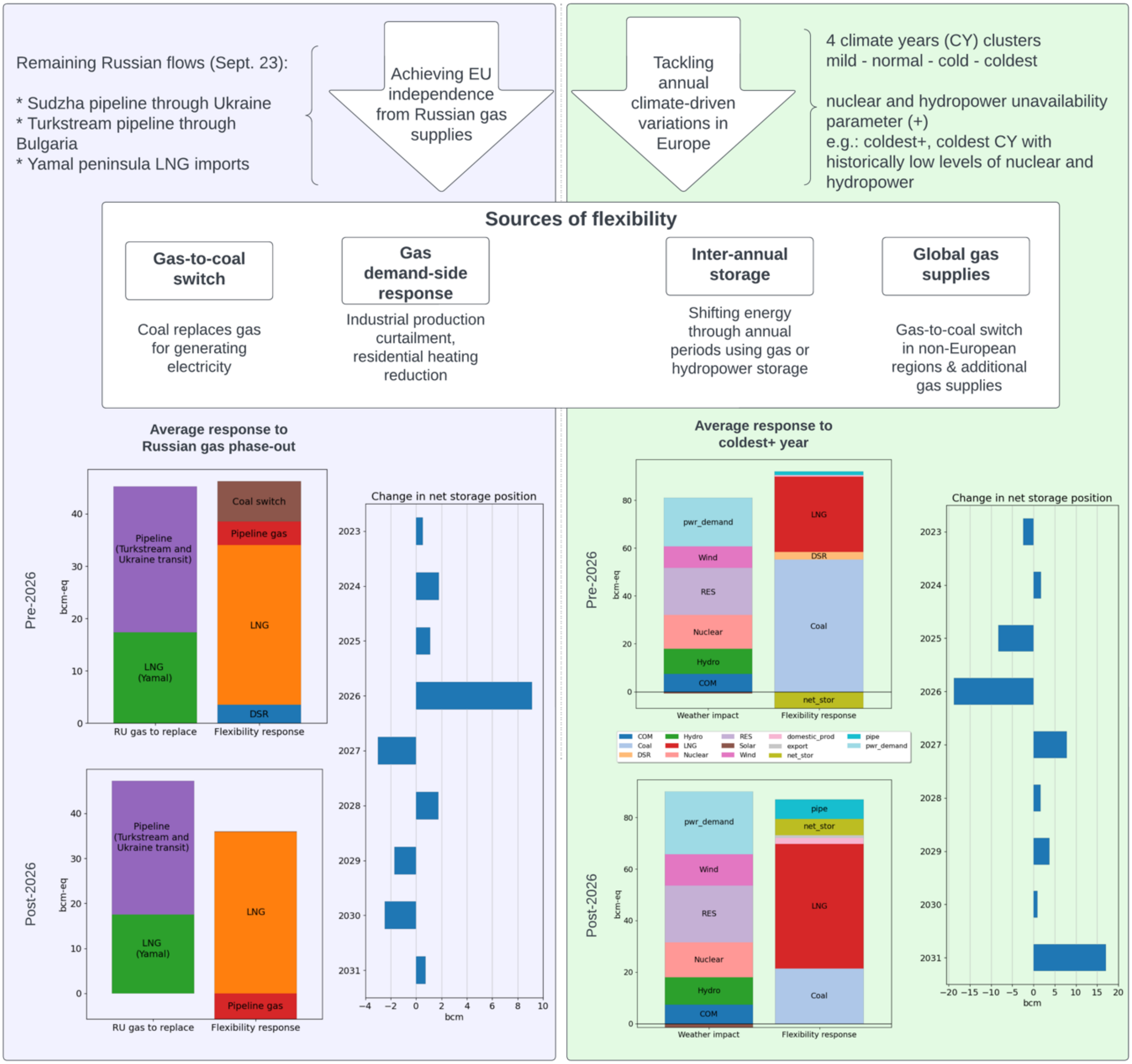
[10] As cushion gas to build up pressure for subsequent storage fill up season.

Figure 16: Gas and electricity storage levels in normal and coldest+ scenarios, with and without Russian gas



Note: The chart shows storage (large-scale gas and electricity storage) levels and changes in 2023-2031 (monthly level) from a baseline scenario to a scenario without access to Russian gas supplies and under a *coldest+* scenario. The bars show monthly values, while the lines show the annual average level.

Figure 16: Summary of the impact of phasing out Russian gas in Europe



1.2 Country-level impact of decoupling from Russian gas

This section analyses results at the national level and describes countries' exposure to energy supply and demand supply shocks. The capacity of each country to respond to gas supply shock includes its access to flexible resources and the needs of its neighbours. Therefore, the scope comprises EU MSs, Norway, the UK, Switzerland, and Ukraine. The analysis begins by outlining the geographical distribution of sensitivity to gas shocks (§1.2.1). Next, it examines the variance in access to flexibility within the power sector, specifically the capability to substitute gas with coal, hydropower, or imports from neighbouring countries (§1.2.2). It concludes by evaluating the relative dependence of European countries on gas and analysing the diverse impacts of phasing out Russian gas and extreme weather events (§1.2.3).

1.2.1 European countries' exposure to gas and electricity shocks

This subsection assumes the currently adopted technological pathway (NECP19). It compares countries' variable energy sources (VES[11]) to characterise countries' sensitivity to weather events, then describes the difference in gas consumption in Europe between 2023 and 2031. Finally, the analysis focuses on countries' relative exposure to gas shocks during extreme weather conditions.

The existing variable sources of energy, as well as their deployment, are unevenly distributed in Europe. France and Germany account for 35% (resp. 33%) of the existing capacity in 2023 (resp. 2031), and the development of new renewable capacity is concentrated in six countries (Germany, Spain, the UK, France, Italy, and the Netherlands). Two implications emerge regarding countries' sensitivity to weather events.

First, MS are not equally exposed to the inter-annual variability of wind, solar, hydropower and nuclear energy output. Some MS are more prone to weather impacts, given the higher share of VES in their electricity production and the higher volume to recover from a decrease in output. More specifically, a distinction is made between reliance on wind and solar versus reliance on nuclear and hydropower. Each experiences a significant reduction in output during colder climate years. However, each case has a different risk profile. Wind and solar have a more frequent though moderate inter-annual variability (on this issue, see Ah-Voun et al., 2024), while nuclear and hydropower unavailability is more episodic but results in a more significant reduction in electricity output.

Germany, France, Spain, Italy, the UK, and Switzerland rely on wind and solar, and these countries account for 65% of the total electricity produced in Europe[12] in 2023 and 2031. Meanwhile, France, Norway, and Sweden produce slightly less than 50% (with France representing ~30%) of the European region's nuclear and hydropower electricity. Given their close geographical location, VES concentration would tend to have a detrimental impact on the power grid. In particular, during unfavourable weather conditions (dryer or colder years), the VES would co-move (at the annual level) in the same direction, resulting in coincidental electricity scarcity in Europe.

When examining all the gas sectors in Europe, it can be concluded that deploying renewables will likely result in a moderate decrease in gas consumption. At the aggregate level, renewables will replace 236 TWh of gas-fired electricity (2031 compared to 2023 level) but also replace decommissioned coal (-228 TWh in 2031 compared to 2023) and nuclear (-75 TWh in 2031 compared to 2023) plants.

New renewables capacity will be deployed in countries to replace coal, nuclear, and gas. Germany and Italy have to respectively replace 17 and 6 GW of coal capacity between 2023 and 2031, while a net 23 GW of nuclear is taken out of the grid in this period (decommissioning in Spain, Belgium, France, and Germany, while the deployment of 3.5 GW in the UK, Hungary, and Finland), creating a gap that renewables will fill. Meanwhile, most wind and solar deployment is anticipated in Germany and Spain, where the role of gas in the power sector is marginal.

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[11] wind, solar, hydropower, nuclear

[12] Referring to EU27, Norway, Switzerland, Ukraine, and the United Kingdom

Despite some progress to switch from gas to electricity for space heating in recent years (Ah-Voun et al., 2023), gas remains a critical heating fuel, with an average (2023-31) of 42% in the total gas consumption, including 30% to the residential sector, and 12% to the commercial sector. Gas consumption is also concentrated in Europe, with eight countries[13] accounting for ca. 80% (average 388 bcm/y) of Europe's demand. These countries are potentially more exposed to price increases and should, therefore, be the focus of risk-hedging measures. Besides the UK, these countries have relative access to large-scale gas storage to tackle gas price volatility. However, it is uncertain how much gas will be needed to tackle inter-annual variations of demand, and hedging against the worst-case scenario is costly given the significant gas IAV range.

By combining previous conclusions about the reliance on VES for electricity generation and the distribution of gas demand in European countries according to the baseline scenario (the NECP19 technology pathway) between 2023 and 2031, it is possible to underline countries' relative exposure to energy supply and demand shocks.

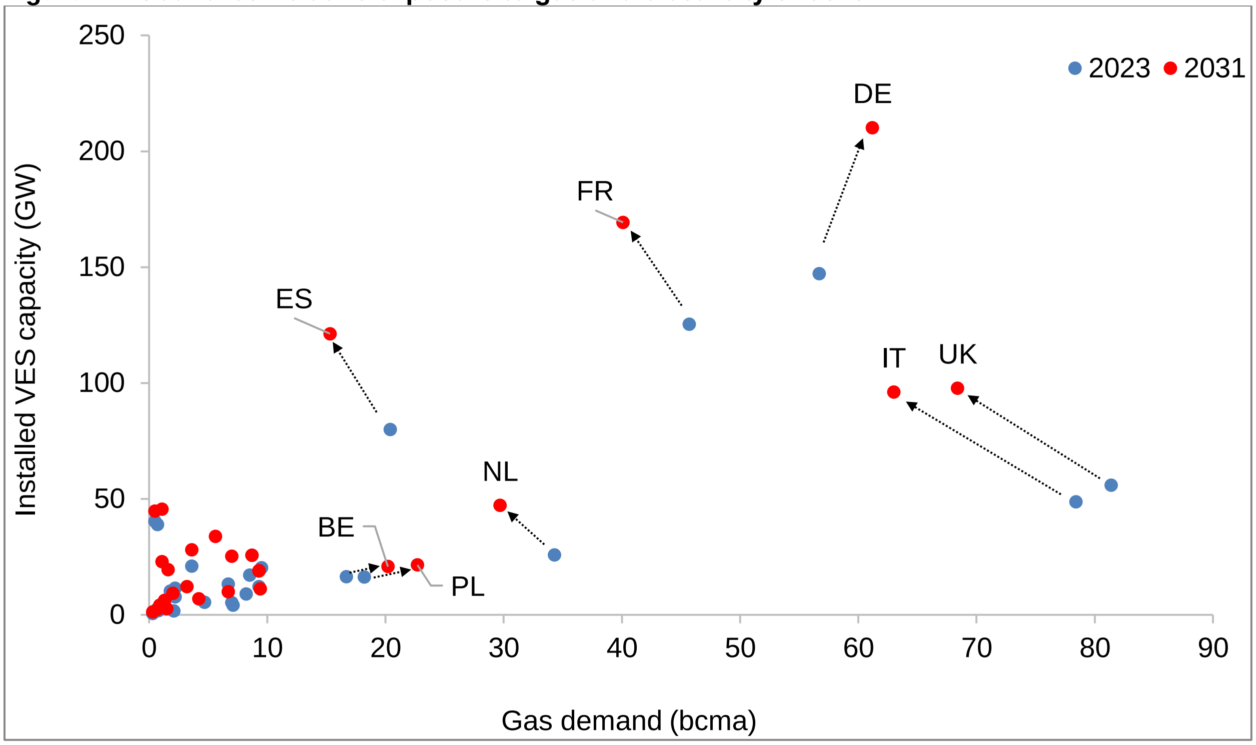
The analysis suggests that colder winters will trigger a synchronised reduction in VES output and higher gas demand for heating. At the same time, geopolitical events can exacerbate consequences, like the phase-out of Russian gas or disruptions in the global LNG supply chain (see Ah-Voun et al., 2024). European countries with a significant reliance on VES for producing electricity or with a high gas demand (especially in the heating sector) face relatively higher risks than others. Although this is contingent on countries' ability to absorb such shocks (see §1.2.2), the goal is to underline a list of countries potentially more exposed to higher risks of combined gas and electricity supply-demand shocks.

Out of 29 countries, Germany, the UK, Italy, France, Netherlands, Spain, Poland, and Belgium are especially prone to gas supply shocks, given their higher gas demand volume and reliance on VES for electricity. Section 1.2.2 will explore whether these countries have access to power sector flexibility, and conclusions on their dependence on gas using stress-testing scenarios will be drawn in section 1.2.3. An interesting finding is that some countries that rely on VES for electricity have the highest gas demand in Europe. These countries are exposed to a double burden in colder winters: a reduced electricity output that potentially triggers higher gas demand in the power sector and higher gas demand for heating. The UK, Italy, Germany and France are especially exposed to energy supply and demand shocks, as they consume over 40 bcm/y of gas[14] and have more than 90 GW of VES capacity installed. Together, they account for ~60% of the gas demand and ~50% of the VES capacity in Europe in 2023-2031.

The impact of the *coldest+* scenario per unit of VES capacity installed in Europe was calculated for comparison purposes. Considering the evolving composition of VES capacity in Europe and how weather affects each technology, a median decrease of -0.21 TWh per GW of VES installed was observed, ranging from -0.28 TWh per GW in 2023 to -0.18 TWh per GW in 2031. This variation reflects the development of solar and wind technologies with less impact than nuclear and hydro technologies. Assuming a Combined Cycle Gas Turbine (CCGT) efficiency of 0.48[15], a gas risk exposure of 0.04 billion cubic meters per year (bcm/y) per GW of VES installed in Europe was calculated.

[13] Germany, the United Kingdom, Italy, France, the Netherlands, Spain, Poland and Belgium.
[14] Across commercial, residential, industrial and power sectors
[15] 0.48 is the median efficiency of a CCGT in Europe.

Figure 17: Countries' relative exposure to gas and electricity shocks



Note: The chart represents countries' VES capacity (nuclear, hydropower, wind, and solar) and total gas demand (across all sectors) as gas risk factors.

Similarly, the impact of the *coldest*+ scenario per unit of heating demand in the commercial and residential sectors was calculated. This impact varies with the temperature sensitivity of heating demand, revealing a median increase of 15.0% from a *normal* to the *coldest*+ scenario. With a median share of heating constituting 40% of the total gas demand (ranging from 39% in 2023 to 44% in 2031), there is a calculated gas exposure of 0.06 bcm/y per bcm/y of gas demand in Europe.

Figure 17 shows potential gas flexibility requirements in *coldest*+ scenarios (assuming no reaction to tackle this shock). For example, Germany's exposure to VES variability results in an 8.3 bcm-eq shock in the *coldest*+ scenario in 2031, while its heating sector would entail a 3.7 bcm increase. Even if the VES shock is larger compared to the heating demand increase, the model shows that in the *cold* scenario (2-in-10 years frequency, see Ah-Voun et al., 2024), the VES gas shock exposure is 0.005 bcm/y per GW of VES installed, while the heating demand increases by 0.036 bcm/y per bcm/y of total gas demand. In the *cold* scenario, Germany's exposure to VES variability would entail a 1.05 bcm-eq shock, while its heating demand would increase by 2.2 bcm in 2031. This highlights the need to weigh shock scenarios considering their likelihood to assess countries' exposure to weather events.

1.2.2 Comparison of gas flexibility in the European power sector

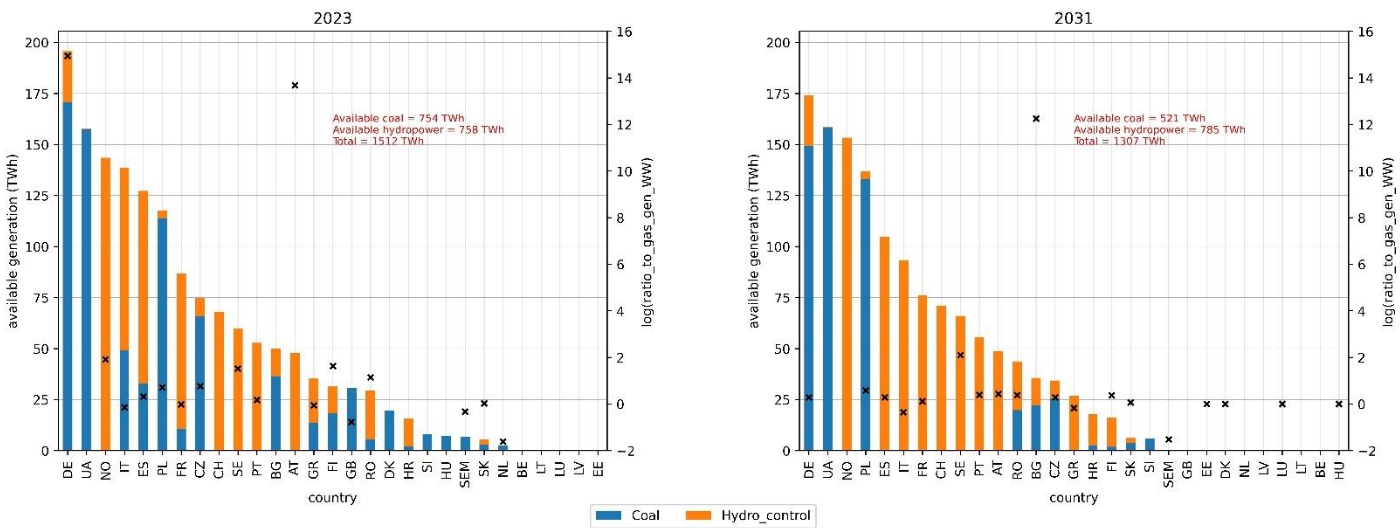
This subsection assesses the ability of countries to reduce their gas consumption in the power sector amid competing usages during a gas shortage. These other usages include (i) domestic usages such as heating with gas or using gas for energy or as a feedstock in the industry but also (ii) releasing (and storing) gas for other countries or other years for which gas is more valuable or more problematic to replace with other energy sources.

Under a *normal* scenario, the analysis proceeds in three parts. First, it scrutinised each country's installed coal generation capacity and utilisation rates. This step determined the potential for fuel switching. Second, it evaluated dispatchable hydropower capacity (pumped open-loop and reservoir systems) for multi-year energy storage. Lastly, it examined the capacities[16] for electricity import and export. Their usage rates were assessed to evaluate the spatial diversity of European electricity generation.

In 2023, coal and dispatchable hydropower capacities are comparable in Europe, with 119 GW and 132 GW, respectively (Figure 20). And the availability of each technology, as defined by the energy that could be produced by unused capacity, is equivalent. The analysis reveals that dispatchable hydropower can produce an additional 758 TWh, and coal can generate an additional 754 TWh in 2023[17]. Nonetheless, the geographical distribution of the technologies differs. While coal is concentrated, with three countries (Germany, Poland and Ukraine) holding 65% of Europe's coal capacity, the distribution of hydropower is sparser, with fourteen countries having direct access to more than 1 GW of capacity.

In the baseline scenario (the *NECP19* technology pathway), coal is decommissioning in Europe (except in Poland), while dispatchable hydropower sees a minor development. The net effect is a decrease in overall available capacity, with 1307 TWh of available power flexibility in 2031 compared to 1512 TWh in 2023. The decommissioning of coal plants also results in a higher concentration of coal-power flexibility, mainly provided by Poland, Germany, and Ukraine in 2031.

Figure 18: Available power flexibility vs gas generation in the coldest+ scenario in European countries



Note: The chart compares the available flexibility from coal and hydropower to the gas generation triggered in the *coldest+* scenario. The marks (right axis) show the log10-ratio of total available generation (coal and hydropower) in the *normal* scenario to the gas generation in the *coldest+* years. Positive values mean the available gas and hydropower capacity is higher than the marginal gas generation triggered during extreme weather events. Countries not displaying marks either do not use gas generation or do not have coal and hydropower available.

Finally, Europe's available import and export capacities enable power flexibility to flow across borders. The focus is on how electricity transmission can facilitate the cross-border utilisation of coal and hydropower flexibility in Europe to address potential energy supply and demand shocks. Therefore, the assessment will cover the capability of the flexibility sources for each selected year.

Across the modelling horizon, 75% of the power flexibility can be provided by the following ten countries: Germany, Ukraine, Norway, Italy, Spain, Poland, France, Czech Republic, Switzerland and Sweden. The results show that Europe cannot leverage flexibility from Ukraine, as a direct interconnection is not developed, and from intermediary countries in Eastern Europe (mainly Poland, Slovakia and Hungary), as

[16] electricity import (resp. export) capacity refers to the cumulative (incoming) transmission capacity from countries to which one is connected. The utilization rate is obtained by dividing the sum of incoming flows by the electricity import (resp. export) capacity.
[17] assuming that both technologies can produce at 100% utilization rate.

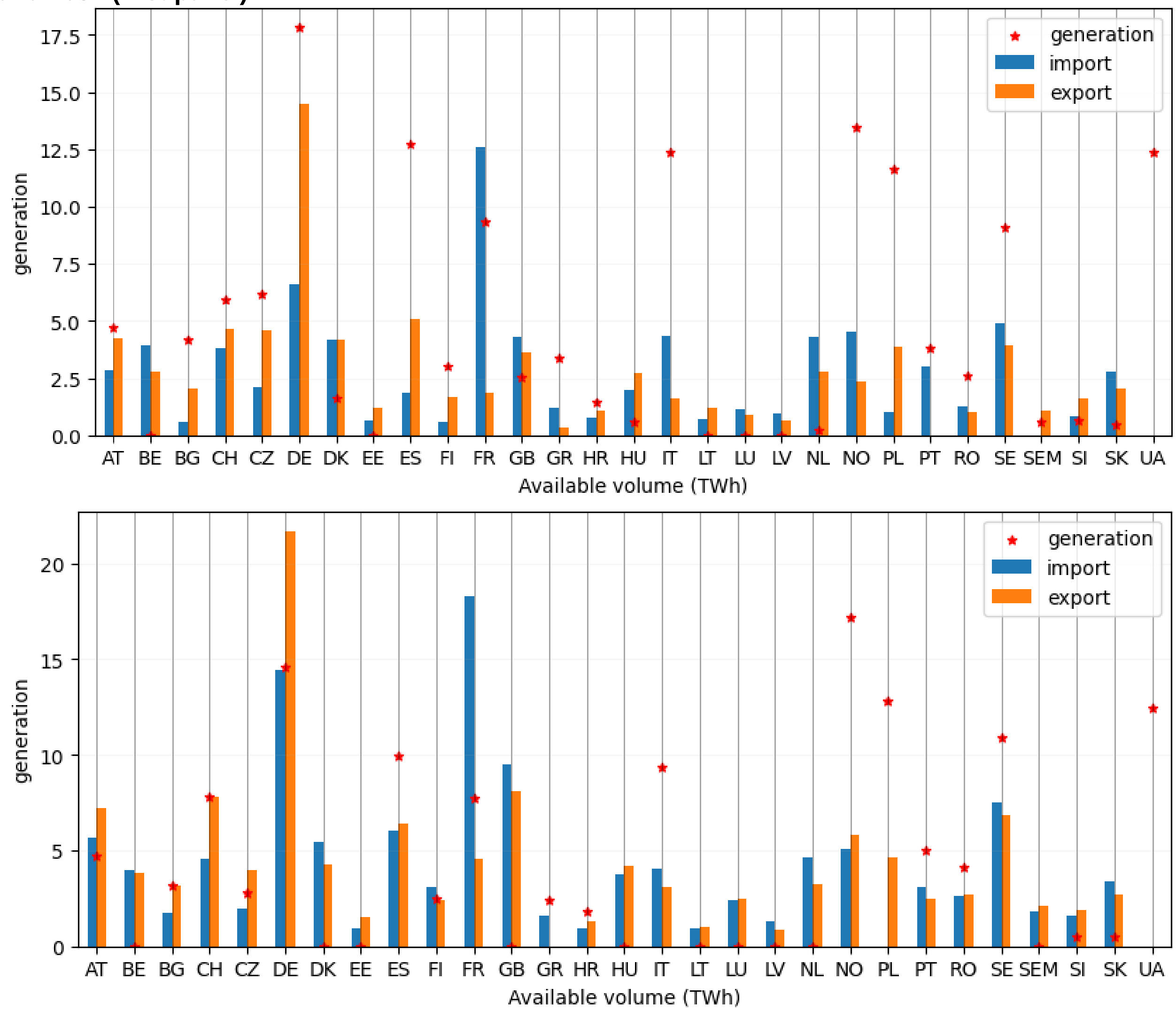
they have relatively low import and export capacities to the rest of Europe. In addition, Italy, Spain, Poland, and Sweden seem to have a relatively low annual export capacity to enable the export of its power flexibility. As a result, if these countries resort to gas-to-coal switching and dispatchable hydropower, it will mainly be for domestic use, not for 'solidarity' purposes.

By examining the changes in capacity and interconnection within Europe, it is observed that Italy, Denmark, and Hungary (along with Spain and France to a lesser extent) experience a relative decrease in available power sector flexibility (respectively -33%, -100%, and -100%, from 2023 to 2031). At the same time, their interconnection availability shows minimal progression (respectively +0.4%, +6.9%, -5.2% for the same periods). These countries require higher scrutiny, as their power flexibility has decreased on the fuel-switch front without developing electricity interconnections.

Upon examining the availability of interconnection and generation from coal and hydropower in January[18] for the selected years (see Figure 20), it becomes clear that countries previously identified as providers of flexibility face limitations in their ability to export electricity. Ukraine, Sweden, Poland, Italy, Spain and Switzerland all show lower export capacities than available generation from coal or hydropower. Bottlenecks are particularly noticeable in France (on the export side) and Poland (on the import side), posing challenges to the transmission of flexibility in gas shock scenarios. Additionally, despite Ukraine's substantial coal capacity, its proximity to Russian borders exposes it to physical/military threats. Combined with limited interconnection capabilities, Ukraine is unlikely to be a secure source of power flexibility for the rest of Europe.

[18] January was selected to illustrate the tensions on the energy system as a winter month while approaching storage refilling target (set on February 1st).

Figure 20: Comparing generation to interconnection availability in Europe in 2023 (second panel) and 2031 (first panel)



Note: The chart superposes the available generation (from coal and hydropower, in marks) to the available interconnection capacity (in TWh) in individual countries in January. The available generation (resp. interconnection) was calculated by multiplying installed capacity by the residual utilisation rate (1-UR), assuming a maximum utilisation rate of 100%. Countries with unaccessible remaining flexibility show a marker above their export capacity (e.g., Ukraine).

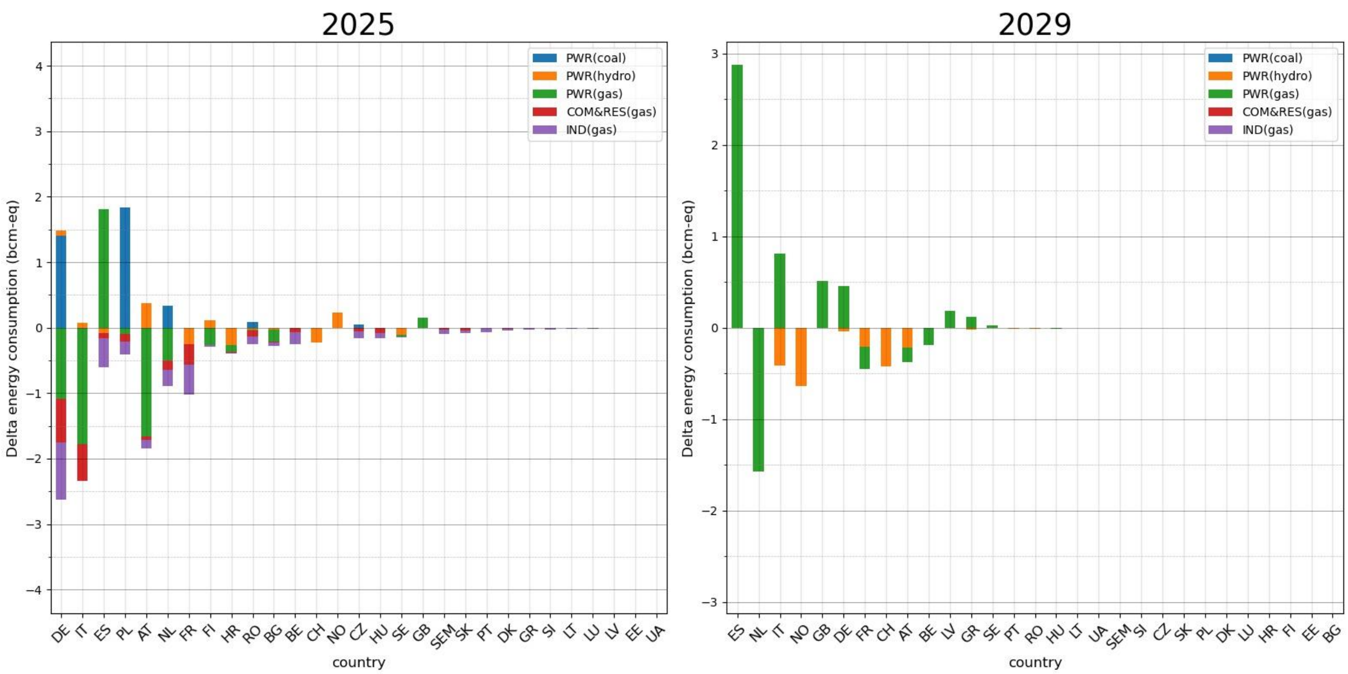
1.2.3 Impact of flexibility resource distribution on Europe's shock mitigation

This subsection analyses the stress test scenarios to assess how countries use power-sector flexibility to deal without Russian gas flows in *normal* and *coldest+* scenarios. Then, the analysis highlights potential bottlenecks in power-sector flexibility when addressing gas shocks and identifies the vulnerabilities of European countries to such shocks through 2031.

The focus will be on two selected years, 2025 and 2029, as they encapsulate both temporal changes in the power system and vulnerabilities to political (Russian gas phase-out) and weather-driven shocks. In 2025, coal capacity is declining, and the carbon price will gradually favour gas generation. Renewables are just developing, and the main impact of the extreme weather scenario is the decrease in nuclear and hydropower output (mainly located in France and Nordic countries). In 2029, the context favours gas-fired generation in the power sector as coal is progressively decommissioned, carbon prices are expected to rise, and the more significant availability of global gas supply makes gas more affordable. The penetration of renewables is high, and its wind variability (-65TWh) is comparable to the decrease in nuclear output (-78 TWh) at the aggregate level[19].

The results illustrate the capacity of the electricity and gas sectors to absorb a complete phase-out of Russian gas, though differentiated by individual countries (Figure 19, the left panel shows the impact of phasing out Russian gas in the 2025 baseline, while the right panel shows the impact in the 2029 baseline).

Figure 19: Impact of Russian gas phase-out on energy consumption



Note: The stacked bar shows the energy consumption difference between a scenario with and without access to Russian gas in equivalent gas consumption. It stacks changes in all gas sectors and the power sector in each country. The equivalent gas consumption for coal and hydropower generation is the gas demand of a gas CCGT in the same country to replace the equivalent power production; "SEM" is the Single Energy Market of the Island of Ireland (the Republic of Ireland and Northern Ireland)

In 2025, gas generation will decrease by a net 3.7 bcm and be replaced by coal generation (100%), mainly from Germany and Poland. Meanwhile, there is a change[20] in the location of (i) gas-fired generation (2 bcm) and (ii) hydroelectricity generation (1 bcm-eq). Interestingly, gas generation is higher in Spain and lower in Italy, Germany, Austria and the Netherlands. This is because Spain uses more gas to generate electricity to export[21] to countries that lack gas supply due to phase out of Russian gas (e.g., Germany, Austria, and Netherlands). These countries replace Russian supplies with coal-fired or hydroelectricity generation, either domestically (Germany, Netherlands) or with imports (Italy and Austria) from countries having access to alternative sources (Poland for coal, Switzerland for hydropower, Spain for gas generation). Gas Demand

[19] In 2025, the decrease in wind generation is -48 TWh, while the decrease in nuclear is -82 TWh

[20] net-zero change in generation

[21] There is lack of gas interconnection between Spain and the rest of Northwest Europe and therefore electricity export is used instead of gas export.

Side Response (DSR) is triggered due to the scarcity of gas supplies (before 2026) in Germany, Italy, and France, indicating that the marginal cost of gas is higher in these countries than in others.

In 2029, there is a change in the location of gas-fired generation, and the total power generation is slightly higher (+0.8 bcm). This is mainly the result of (i) reduced gas exports in the scenario without Russian gas compared to the baseline, as countries use gas for their consumption, and (ii) the replenishment of hydro-based electricity storage that discharged (-2bcm) during earlier years to replace gas when it was more expensive (before 2026). Spain and Italy produce more significant electricity from gas. Meanwhile, the Netherlands produces less electricity from gas as Denmark imports electricity from cheaper sources (Norway, the UK).

On balance, the phase-out of Russian gas results in a higher cost of gas overall, especially for regions that relied most on it (Germany, Netherlands, Austria). The model shows that without Russian supplies, gas is kept for direct usage in the heating and industrial sector and replaced by coal or hydropower if available or through imports of electricity from countries with direct access to the global LNG market (Spain, Italy, the UK) when pipeline gas import is limited.

The study now shifts to examining extreme-weather scenarios, analysing how different European countries respond to increased gas demand for heating and reduced VES output and assessing the impact of a phase-out of Russian gas on that response.

First, Figure 20 (A) shows that countries are affected differently by extreme weather events. The increase in gas demand for heat (COM&RES) is mainly located in the UK, Germany, France, Italy, and Austria, while the increase in electricity demand to meet the shortfall in VES is mainly located in France (nuclear and hydro), Germany, and the UK (renewables).

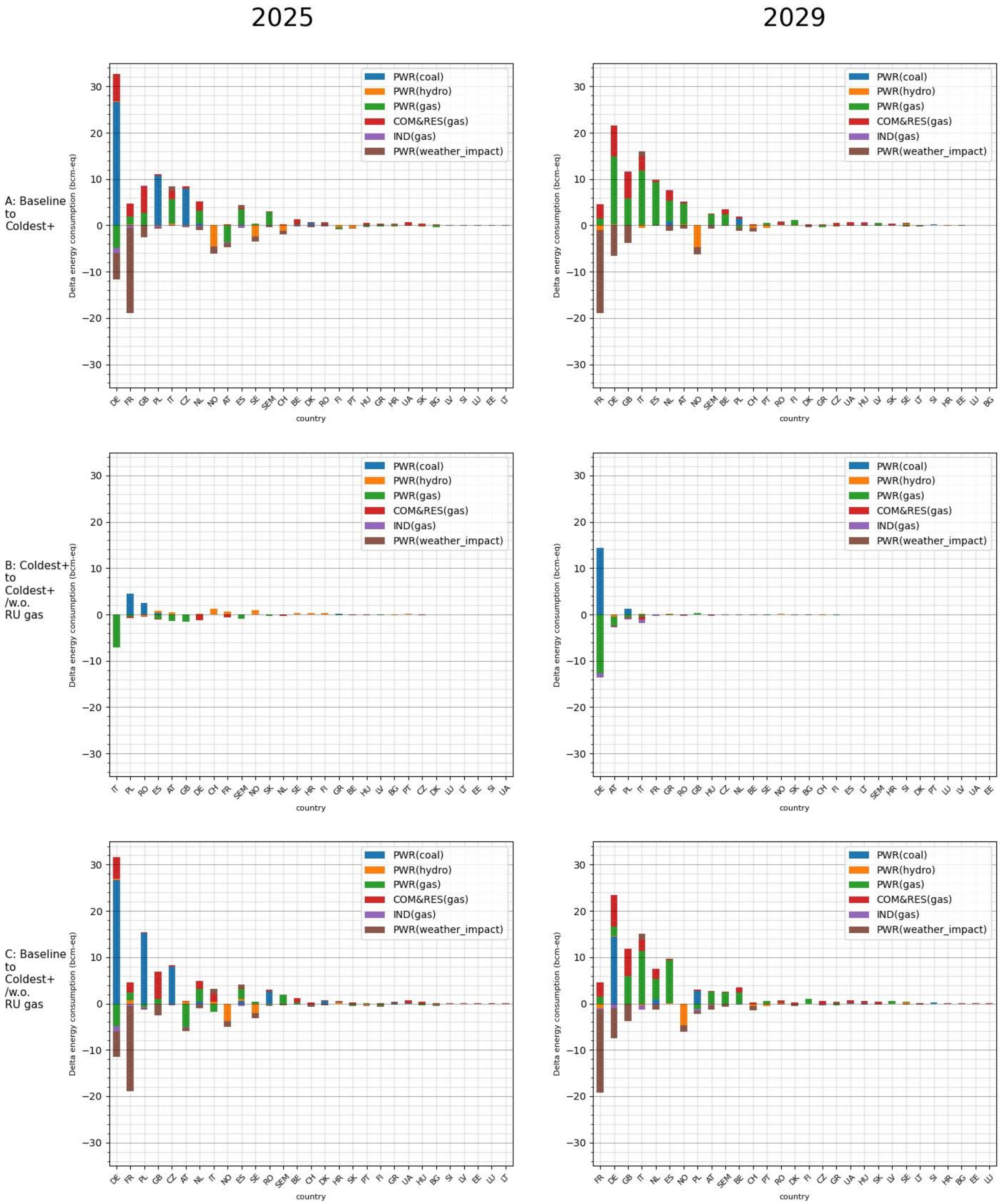
In 2025, Germany will provide most of the flexibility, replacing its gas-fired electricity generation with coal generation and exporting the surplus to other countries. The other sources of flexibility are (i) gas-fired power generation (19.5 bcm) from various countries (Italy, the Netherlands, Spain, Ireland, the UK), (ii) electricity imports generated from coal plants in Poland (10.0 bcm-eq) and Czech Republic (8.0 bcm-eq), and (iii) gas DSR in the industrial sector (3.8 bcm), mainly from Germany, France and Spain.

In 2029, a considerable amount of VES (total of -34.9 bcm-eq, compared to -33.5 bcm-eq in 2025) must be replaced during the *coldest*+ scenario, though it is still mainly located in France, Germany, and the UK. However, gas plants mainly provide flexibility, as they become less expensive than coal in this period. As a result, flexibility is provided by gas-fired generation and electricity transmission to regions in need.

Second, Figure 20 (B) shows the difference in energy consumption (power and gas) under the *coldest*+ scenario with and without access to Russian gas. The results show (i) a gas-to-coal switch in both 2025 (7.4 bcm-eq) and 2029 (15.6 bcm-eq), originating from Germany, Poland and Romania and reducing gas consumption in the power sector in Italy, the UK, Spain, and Austria; (ii) a gas-to-hydropower switch, in 2025, with Spain, Austria generating electricity for their own needs (see row B, left chart), and France, Switzerland and Baltic countries generating for exports; (iii) a trigger of additional DSR (3.8 bcm) in the heating sector (COM&RES), especially in Germany, France, and the Netherlands; and (iv) a decrease in power demand, in 2025, with net -1.1 bcm-eq in the scenario without access to Russian gas flows, due to the postponed and anticipated replenishment of hydropower storage in other years.

Finally, Figure 20 (C) shows combined responses from flexibility sources to the *coldest*+ scenario coupled with phasing out Russian gas. Europe’s response to extreme weather events is different without access to Russian gas. In 2025, coal and hydropower will replace 12.9 bcm gas-fired generation for flexibility, equivalent to 42% of the power flexibility needed to tackle the *coldest*+ scenario with access to Russian gas. There is, thus, a concentration of power generation in coal countries (Germany, Poland, and the Czech Republic), which hints at potential network congestion, analysed in the following paragraphs. In 2029, phasing out Russian gas impacted Germany the most, and it resorted to gas-to-coal switching despite higher carbon taxes and more affordable gas. The change in coal generation amounts to 15.6 bcm-eq, equivalent to 47% of the flexibility needed in 2029.

Figure 20: Extreme weather under the baseline (A), the impact of Russian gas phase-out (B), and total changes in electricity and gas consumption (C)



The analysis focuses on their utilisation rates (UR) to identify bottlenecks that limit power sector flexibility, as shown in Figure 21. The analysis starts with the UR in the baseline scenario, followed by examining the impact of the *coldest*+ scenario and the unavailability of Russian gas on the UR of various flexibility sources. The years 2025 and 2029 are analysed to account for changes influenced by the temporal evolution of the global gas market and the European power sector.

First, in 2025 (Figure 21 A, first column), gas flexibility is saturated with gas plants and pipelines operating at almost full capacity in several countries in the baseline scenario. Additionally, the interconnection capacity is already a bottleneck for the electricity exchange in the January baseline scenario. Indeed, Norway, Portugal, France, Ukraine, and Greece fully utilise their electricity export capacities, even though their coal, gas, and hydropower plants could still generate electricity. In the baseline scenario, gas is at the core of power generation, with many countries relying on it to generate electricity. Given such dependence, it is essential to understand how the power sector reacts to the Russian gas supply phase-out and extreme weather conditions (the *coldest*+ scenario).

The difference in UR of each source of flexibility was calculated to gauge the impact of weather events and phasing out Russian gas. First, examining the impact of the *coldest*+ scenario in 2025 (Figure 21 A, first column) leads to the following conclusions:

- There is much less cross-border electricity trade between European countries. Therefore, the increase in gas demand in the heating and power generation sectors may result in reduced solidarity between MS, as they must meet their domestic demand first. Despite the *coldest*+ scenario, surplus electricity is generated in the Czech Republic, Germany, Italy, and Poland, allowing them to export to other countries;
- A significant switch from gas to coal is observed in the Czech Republic, Denmark, and Germany, often from zero to full capacity, driven by high LNG import costs before 2026. The subsequent analysis will show that the development of global gas supplies shifts the preference from coal back to gas after 2026;
- A redirection of global gas flows in the form of LNG to NL, UK, FR, and ES as the latter are more impacted by *coldest*+ events than other MS (see Figure 22).

Then, to measure the impact of phasing out Russian gas under extreme weather events (the *coldest*+ scenario), the differences in the UR between the *coldest*+ with and without Russian gas in 2025 and 2029 (Figure 21 B, second and fourth columns) were calculated. The following conclusions emerge:

- There is reduced gas generation and exports, as seen in the *coldest*+ scenario; countries like Italy and the UK prioritise their high demand, as they both have high baseline gas demand (in power and heating) and high VES penetration. Meanwhile, as explained above, Poland and Romania see a significant increase in UR of coal-fired generation in the baseline scenario, reaching maximum capacity in Poland (see Figure 21 A, second column).
- There is a substitution of pipeline gas imports with LNG imports. The first reason is a reduction in the Russian gas pipeline flows through Bulgaria, Greece, and Slovakia. Gas initially delivered to the Balkan region is substituted by LNG, as there is an increase in LNG UR in Croatia and Greece. The second reason is the replacement of Russian LNG shipped to Europe (ca. 15.6 bcm) in 2025.
- There are increased electricity imports from regions with high gas exposure (the UK, Italy, and Belgium). A more granular analysis also shows 100% UR of the export connection from Spain to France. This behaviour occurs as countries with significant gas exposure, primarily due to their high VES dependence, seek additional power generation as their domestic gas or coal plants and gas pipeline import capacity are maxed out (see France, Italy, and Germany in Figure 21 A, second column).

From 2025 to 2029, in the *normal* weather scenario (see Figure 21 A, third column), there is a reduction in coal and gas generation as renewables are deployed, coal is decommissioned, and carbon prices are higher. However, the interconnection congestion is untackled despite the anticipated increase in cross-border interconnection capacity under the NECP19. There is still high export and import UR in some countries, which hinders access to flexibility from France, Ukraine, Greece, and Norway.

When examining the impact of the *coldest*+ scenario (Figure 21 B, third column) in 2029, the following differences emerge from the baseline scenario:

- There is relatively important coal generation (in the Netherlands, Poland and Slovenia) despite high carbon prices due to the scarcity of natural gas in the *coldest*+ scenario and interconnection bottlenecks that prevent access to cheaper sources such as hydropower.
- Gas generation is triggered in many countries due to increased LNG import capacity in different countries, enabling access to global LNG supply and responding to sparser flexibility needs as all countries develop more renewables.

In summary, Germany, the UK, Italy, France, Netherlands, Spain, Poland and Belgium are most exposed to gas shocks, given their higher gas consumption and VES capacity (§1.2.1.). In section 1.2.2, it was observed that countries have varying degrees of access to flexibility, particularly notable in that all possess more available power flexibility than they can export. This leads them to self-supply electricity instead of exporting it. Finally, the impact of the Russian gas phase-out and the *coldest*+ scenario at the country level in §1.2.3 was analysed, leading to the following conclusions.

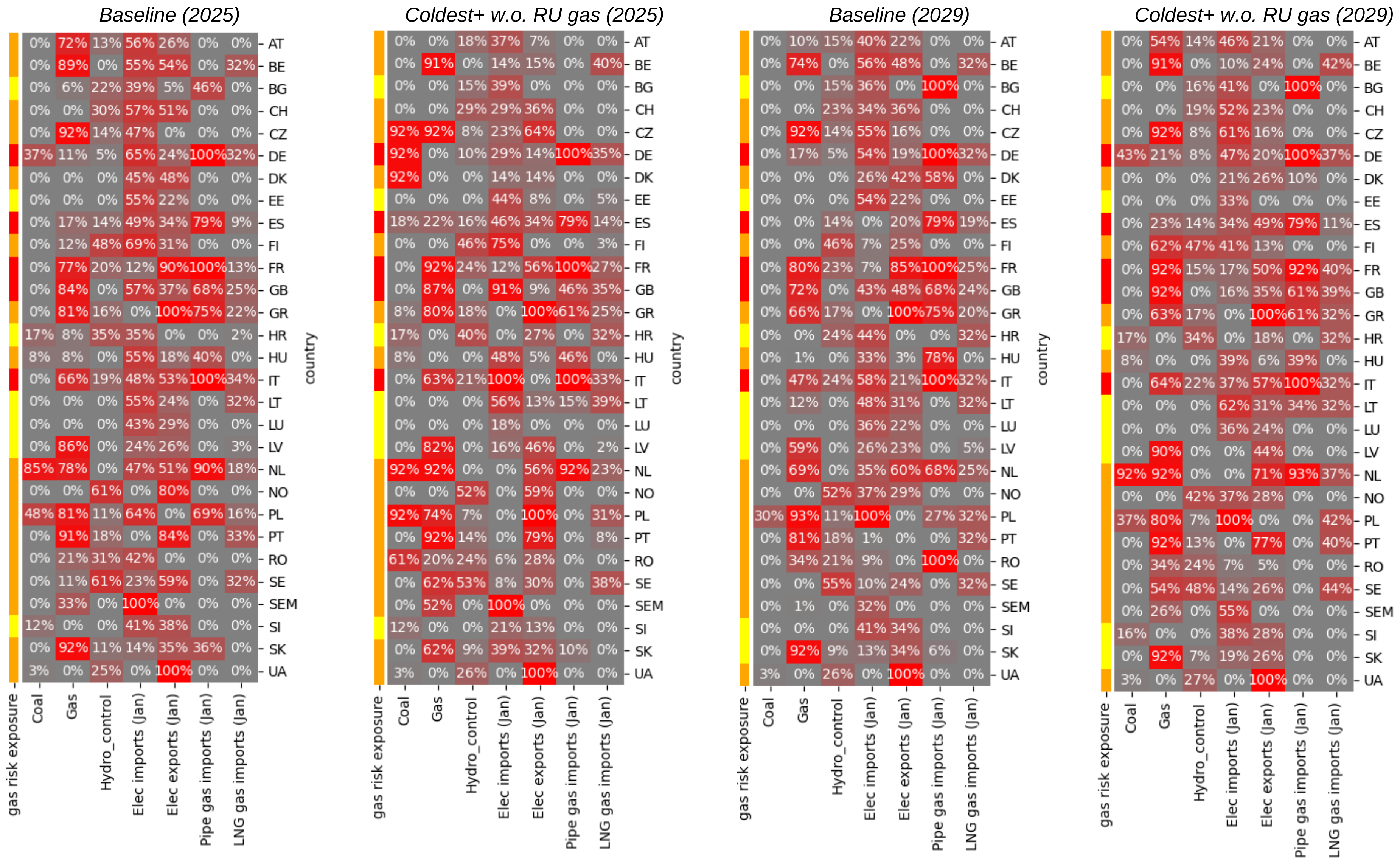
Before 2026, Europe will be mainly exposed to a reduced VES output and increased gas demand in the heating sector from France, Germany and the UK. When comparing countries' response to the extreme-weather scenario under both the baseline and no Russian gas flow conditions, it is evident that the UK and Italy are particularly vulnerable due to their high gas exposure, high import and gas-generation utilisation rates, and lack of direct access to coal generation. Despite moderate gas exposure, Ireland and Finland have a higher risk profile than other European countries.

After 2026, the penetration of VES in Europe will be high, and the heating sector will have to compete with the power sector for gas. At the same time, flexibility options (coal and hydro) that Europe relied upon will become limited – coal is expected to be phased out, and hydropower will see limited development. Interconnection bottlenecks might also lead to LNG-generated electricity bypassing gas transmission congestion in some European countries. European countries depend more on LNG because of higher total flexibility needs and lesser coal availability.

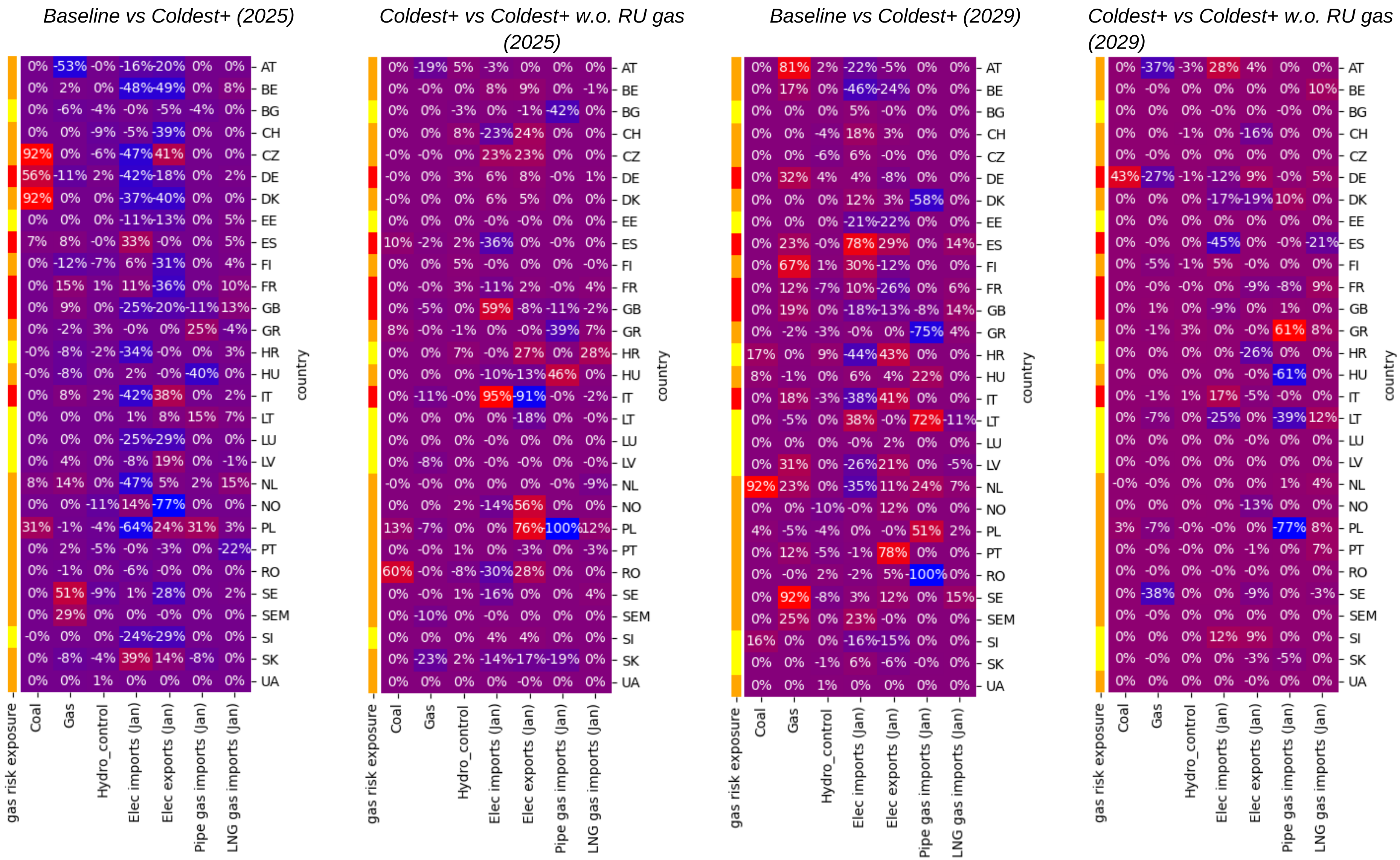
The conclusion is that Poland, Ireland, Hungary, Lithuania, Switzerland, and the Czech Republic are the most vulnerable countries as they are burdened by both (i) limited alternatives to LNG (congested pipeline gas import, coal or hydropower generation, or being landlocked) as evidenced by their high electricity imports and (ii) moderate to high gas exposure.

Figure 21:Uutilisation rates (panel A) of flexibility resources and their changes (panel B) in Europe under modelled scenarios

A

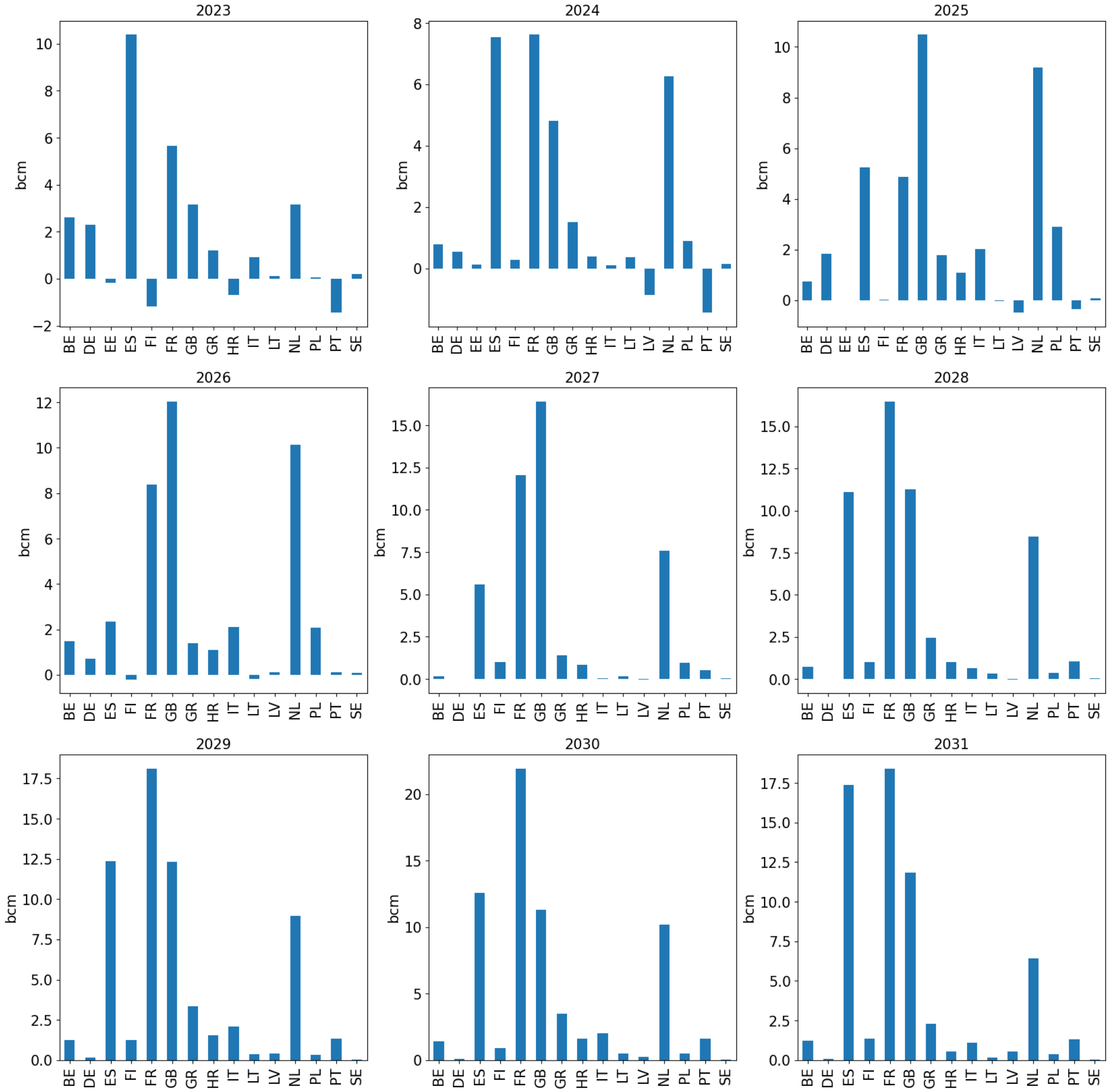


B



Note: Threshold values for gas exposure (bcm-eq) red: >100, orange: 100> & >10, yellow: 10>

Figure 22:Changes in LNG import from normal to coldest+ scenarios



1.3 Implications on global GHG emissions and investments

This last analysis section discusses the implications of the findings on climate and investments in key renewable technologies.

1.3.1 Impact on global GHG emissions

Section 1.1 illustrated pathways for Europe to achieve natural gas independence from Russia. Upon examining the *coldest+* scenario as the most adverse HILP scenario, conclusions were drawn that countries may (i) utilise coal supplies for power generation, thereby freeing up gas for other needs such as residential, industrial, and commercial uses; (ii) decrease gas demand within residential and industrial sectors in the earlier years (2023-2026); or (iii) increase gas imports from other countries, primarily via the global LNG market in the later years (2027-2031).

Whether these sources of flexibility are entirely secure – supply of imported coal or, indeed, LNG – still needs to be investigated. Still, Europe reached a complete phase-out of coal imports from Russia as of August 2022 following the European Commission's embargo decision. Europe's LNG imports are less prone to geopolitical threats than pipeline supplies from Russia because there are numerous LNG suppliers. The LNG infrastructure threats are lower, though not inexistent, as witnessed in December 2023, with LNG vessels rerouting away from the Red Sea transit considering the Israel-Hamas war tensions or the latest decision to delay permitting new LNG supply projects from the US.

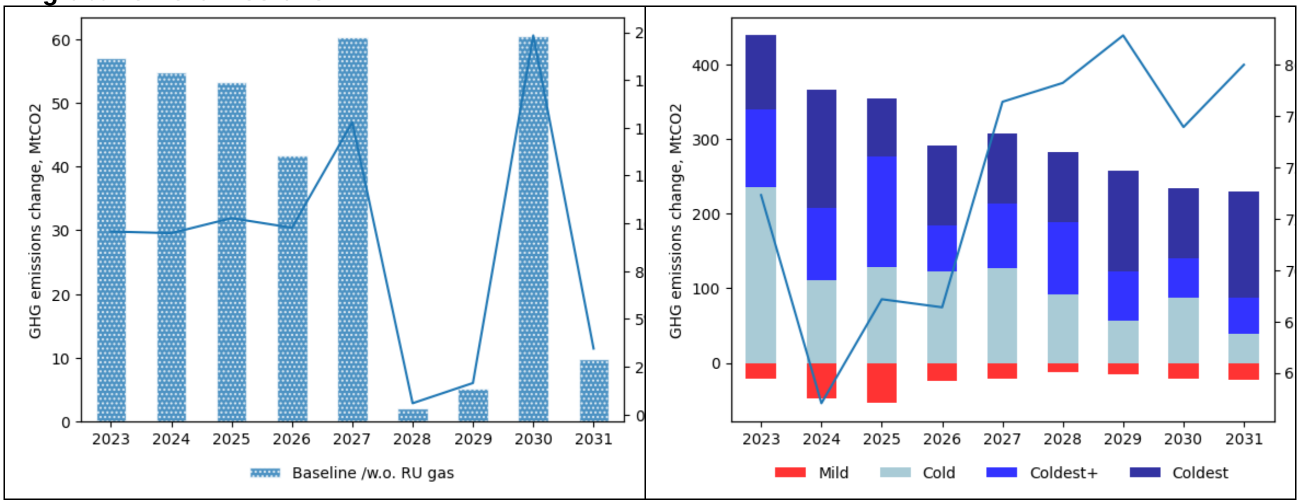
However, such flexibility sources have severe implications for two other pillars of the energy trilemma. First, they are much less affordable. Europe imported about ~60% of its coal in 2023, and political and activist pressure on supply development combined with growing carbon prices entails costlier power prices for consumers. Then, the global LNG market introduced price risks in the gas and power sectors, as seen with spikes in 2022-2023 caused by economic and political events.

Second, the model shows that a European embargo on Russian pipeline gas removes these supplies from global markets, as re-routing gas from these fields will be impossible for at least a few decades. Thus, this gas shortage increases coal consumption globally, pushing global emissions up 0.32% in 2023-2031 (Figure 23, lhs). Then, in the worst European weather scenarios, fossil fuels (LNG and coal) replaced renewable and nuclear supplies and provided heat to buildings. As European countries turn to global gas markets, a fuel switch in the power sector is triggered in non-European countries. Gas prices reach unaffordable levels for the global South[22], reducing gas consumption by more than the volume redirected to Europe (see section 1.1.2). This results in an increase of 2-3.5% (Figure 23, rhs) in global emissions in a single *coldest+* year scenario, highlighting the responsibility of European policies in driving emissions upward outside its territory.

Indeed, the interconnected global markets imply spillovers between different countries' energy markets and, hence, policy responses. Asia and Europe are particularly affected as they look for overseas energy imports. Indeed, in practice, for example, Asian countries like Pakistan and Bangladesh are more affected by higher energy prices as they struggle to compete with Europe to buy gas, suffering from electricity blackouts.

[22] The term 'global South' is a socio-economic and political concept used to describe countries primarily located in the Southern Hemisphere. The term is used to represent regions that have historically been marginalized in the global economic and political suytem, and generally characterized by lower income levels, higher poverty rates, and inequality compared to other countries.

Figure 23: The impact of Russian gas phase-out (lhs) and European weather scenarios (rhs) on global GHG emissions



1.3.2 Impact on wind, solar, and heat pump investment in Europe

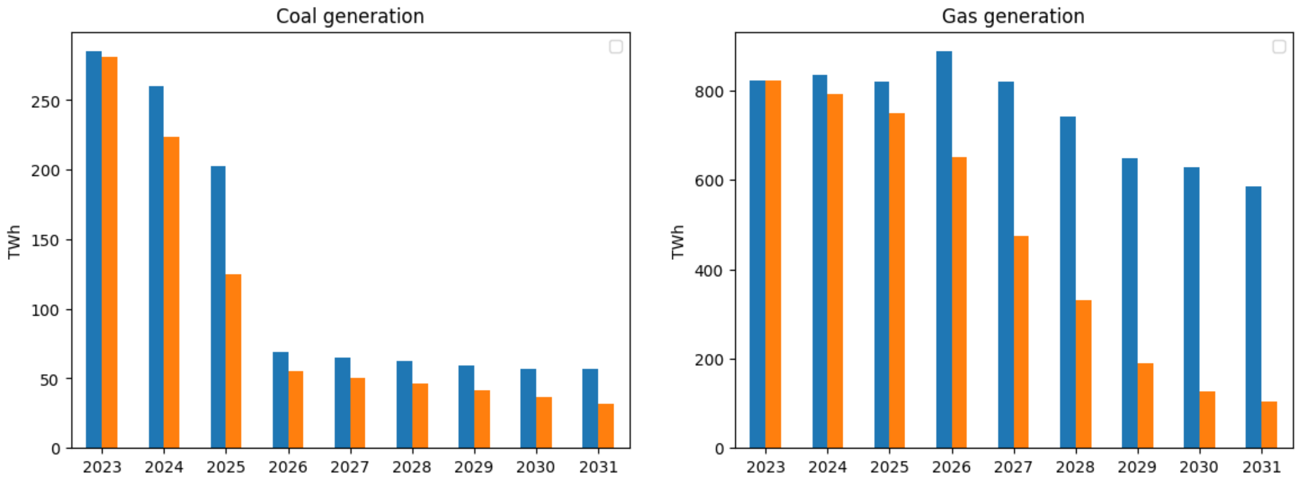
Under the REPowerEU plan, the incremental capacity addition of wind and solar is expected to be 109 GW and 214 GW, respectively (see Ah-Voun et al., 2024). The modelling results for the REPowerEU scenario show that this plan eases the strain on European consumers, vastly decreasing long-term fossil fuel reliance by replacing coal and gas with renewables in the power sector (see Figure 24) in the baseline and weather-related shock scenarios (Figure 25). After 2029, European countries generate less than 200 TWh annually from gas (equivalent to 40 bcm of natural gas, -75% compared to 2023) and less than 50 TWh annually from coal (-85% compared to 2023). Across 2023-2031, the plan saves $1202 billion of wholesale energy costs to European buyers (of which $153 billion is due to the reduction of carbon taxes cashflows), which is about 75% of the investment needed to move from the current technology pathway (NECP19) to the new renewables targets (REPowerEU) at $1609 billion (see Figure 26). From a private investment perspective, wind and solar generation will receive $211 billion in wholesale revenue[23], representing 13% of the investment needed. Thus, total social benefits (private revenue and wholesale energy cost reduction for European consumers) can cover 88% of the investment needed.

Additionally, REPowerEU alleviates the costs of phasing out the remaining Russian gas imports to Europe. Indeed, the tension on flexibility sources due to a total phase-out of Russian gas would significantly burden European countries. In a scenario without Russian gas between 2023 and 2031, wholesale energy costs will increase by $473 billion if Europe follows the NECP technology pathway. If REPowerEU's wind and solar capacity is fully met by 2030, wholesale costs only increase by $190 billion inflicted by phasing out the rest of the flows from Russia. However, the net cost to implement REPowerEU amounts to $560 billion (of which $1609 billion of additional investments in renewables and $1049 billion of savings[24] on energy wholesale markets during the period). This offsets the $283 billion ($ 473-190 billion) savings in the REPowerEU pathway.

[23] Electricity generation from incremental wind and solar capacity addition under the REPowerEU plan times wholesale electricity prices

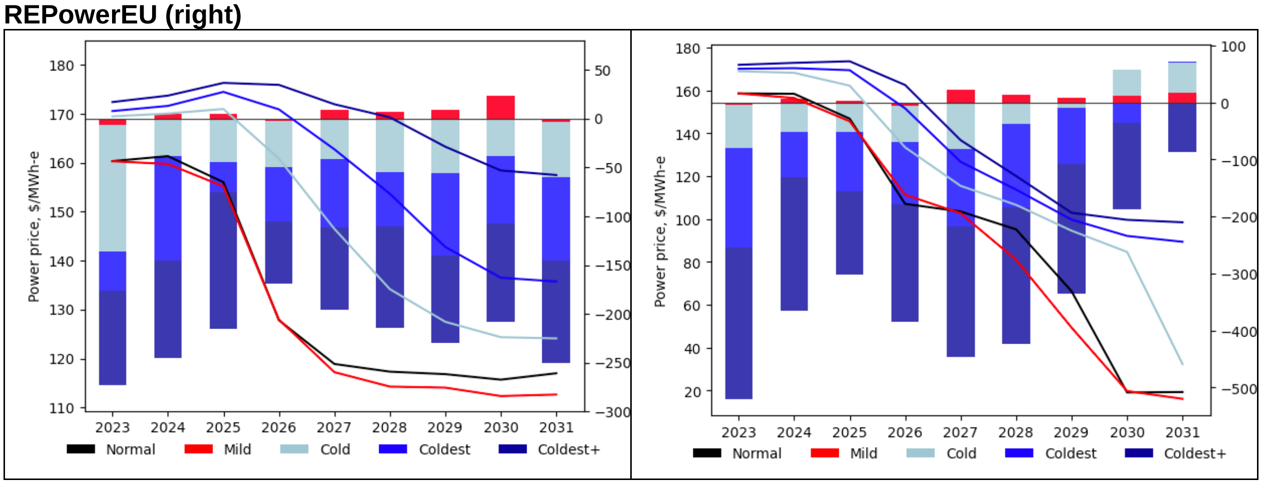
[24] Net of the reduced carbon tax due to the reduction in fossil power generation.

Figure 24: Fossil power generation in Europe in NECP (left) vs REPowerEU (right) pathways



Note: The figure shows the annual generation from coal and gas plants in Europe in two technological scenarios (NECP and REPowerEU). It assumes baseline gas flows from Russia.

Figure 25: Power prices and generation changes under weather scenarios – NECP (left) and REPowerEU (right)



Still, REPowerEU has an essential impact on the global scale over 2023-2031. First, the plan helps to cut significant amounts of greenhouse gas emissions, with -1.6 $GtCO_2$ emissions (of which 1.25 $GtCO_2$ are avoided in Europe) due to a total of 2778 TWh of fossil fuel generation reduced in Europe and a switch of 701 TWh from coal to gas outside Europe. This switching results from the ease of the competition for gas in global markets as Europe reduces its reliance on the commodity with more aggressive renewable targets, freeing more affordable gas to other regions and helping to phase out coal there. Moreover, when considering the reduction in wholesale costs outside of Europe, the global reduction in total wholesale energy costs offsets REPowerEU's implementation cost by $662 billion.

It is worth noting that these calculations are rather simplistic as they neglect other costs associated with deploying renewables in Europe, such as infrastructure (e.g., scaling up electricity and gas infrastructure[25]) and integration (e.g., storage technologies to manage intermittency) costs. However, these calculations show the potential economic, climate and geopolitical benefits of the REPowerEU plan for Europe and the rest of the world. Thus, phasing out Russian gas with renewables aligns with the energy policy trilemma of meeting climate policy, affordability, and energy security objectives. Moreover, it has potentially far-reaching global geopolitical consequences in that there will be a reduction in reliance on energy supplies from unstable regions.

An essential driver of the increase in gas demand is the demand for space and water heating during winter. Europe had more than 90 million residential gas boilers in 2023[26], and they are increasing the demand for gas by up to 27 bcm in the *coldest* scenario compared to a *normal* weather year in both technology pathways (Figure 7). Thus, another target proposed by the REPowerEU plan is to aim for at least 41.5 mn heat pumps by 2030 compared to around 20 mn under the NECP19 pathway (Ah-Voun et al., 2024).

An ex-post analysis, informed by modelling results, was undertaken to determine if (a) the REPowerEU plan gives a stronger price signal to consumers to switch from gas boilers to heat pumps (see

Figure 27) than under the NECP19 pathway and (b) what the effect of phasing out Russian gas will have on incentives to switch. The analysis considered (i) the net gain from switching to a more efficient heating system (heat pumps are, on average, 2.15 times more efficient than gas boilers if electricity comes from CCGT and 4.31 times more efficient if electricity comes from wind and solar generation[27]), and (ii) the cost of avoiding a future carbon tax in the heating sector (assuming an ETS2 price at $40/tCO2 starting from 2027[28]).

[25] For example, Germany's gas grid requires $4.8 bn investments to accommodate additional LNG import faciliities (https://www.bloomberg.com/news/articles/2023-12-21/germany-s-grid-needs-to-spend-4-8-billion-to-connect-lng-terminals); these additional LNG terminals are expected to cost $10.4 bn (see https://www.reuters.com/business/energy/germany-certain-exceed-98-bln-eur-lng-terminal-bill-econmin-2023-03-03/).

[26] 68 mn for the EU (https://joint-research-centre.ec.europa.eu/jrc-news-and-updates/residential-heating-heat-pumps-would-knock-down-energy-consumption-and-emissions-2023-06-21_en), 23 mn for the UK (https://www.uswitch.com/energy/boiler-statistics/#:~:text=23%20million%20homes%20in%20the,unexpected%20expense%20in%20the%20future)

[27] assuming a 0.5 gas turbine efficiency, a 3.75 heatpump efficiency, and a 0.87 gas boiler efficiency

[28] On the timing of ETS2, see: https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/ets-2-buildings-road-transport-and-additional-sectors_en

Figure 26: Impact of the REPowerEU plan with and without Russian gas imports to Europe

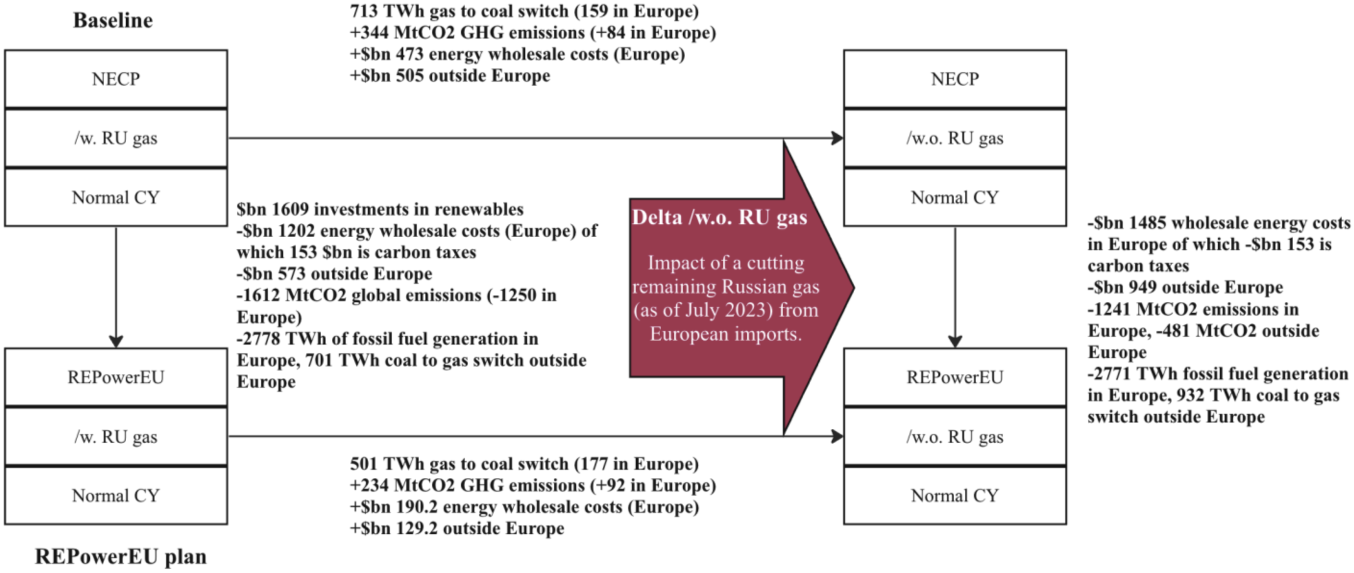
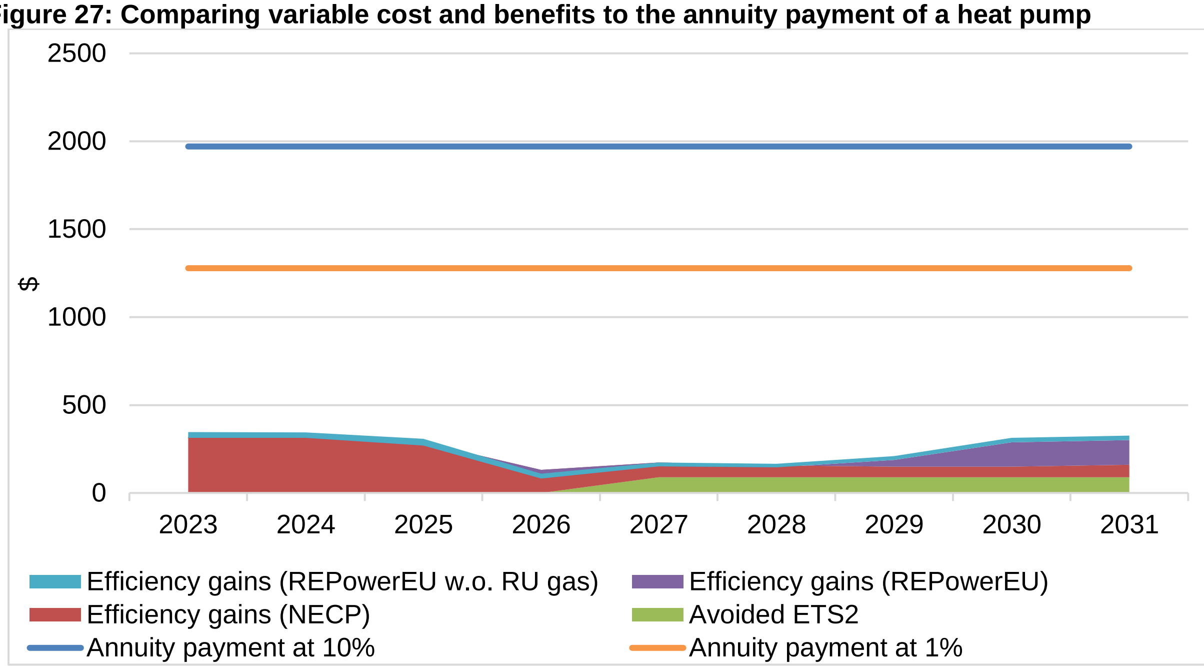


Figure 27: Comparing variable cost and benefits to the annuity payment of a heat pump



Note: Efficiency gain is the difference between the variable cost of a gas boiler and a heat pump. Variable cost is defined as the average heat demand per dwelling (8.32/MWh/dwelling, UK average for 2015[29]) divided by the efficiency of a heat technology (gas boiler average efficiency – 0.69[30]; heat pump – 3.75) times wholesale energy cost (gas boiler – gas cost; heat pump – electricity cost). Avoided ETS2 is defined as total avoided gas consumption for space heating times carbon intensity of natural gas times assumed CO_2 price of $40/tCO2e. Annuity payment is the difference between a heat pump's upfront cost and a gas boiler's upfront cost (Element Energy, 2017). Calculations assume a *normal* weather scenario.

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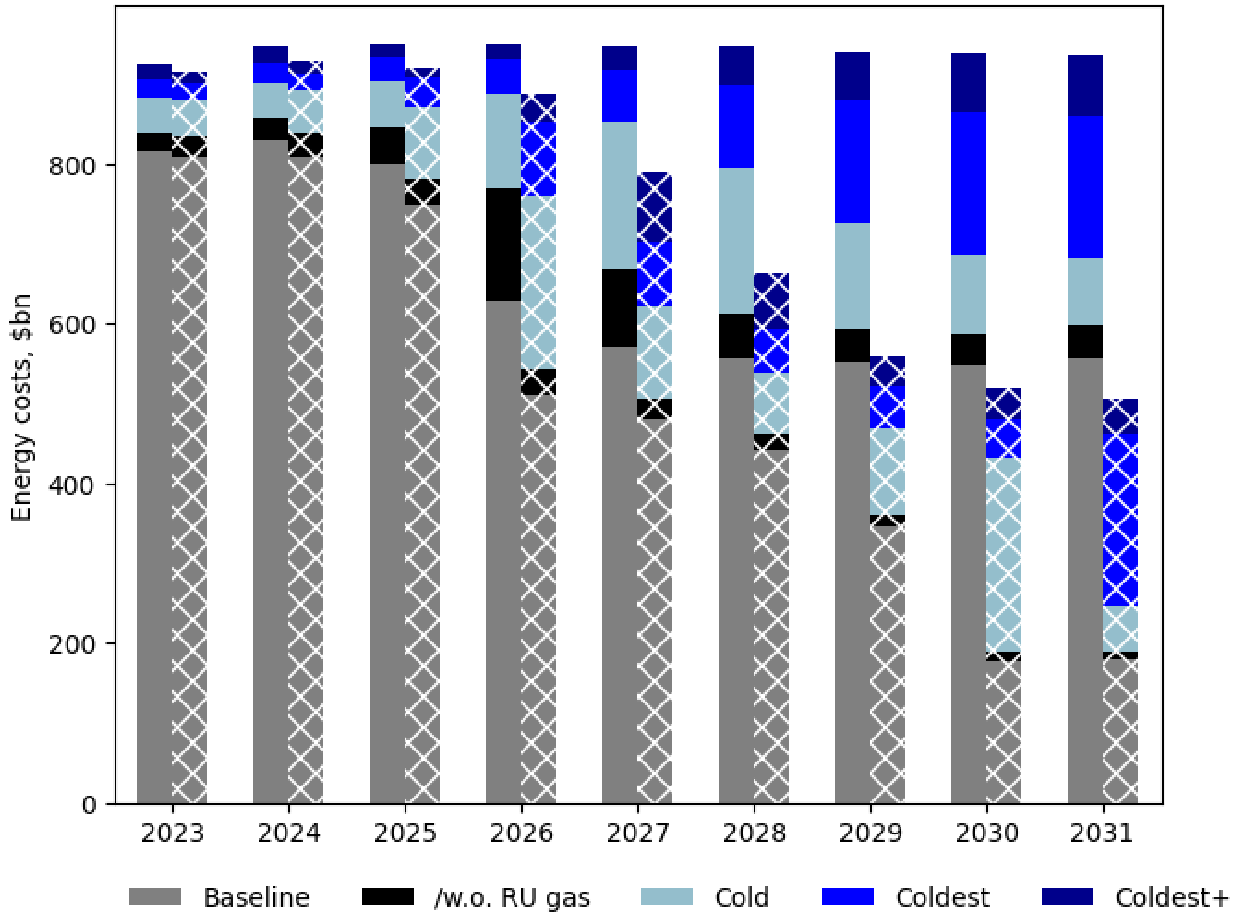
[29] JRC IDEES 2015 dataset
[30] JRC IDEES 2015 dataset

Key insights from this analysis are as follows:

- Under the NECP19 pathway, heat pumps will be more profitable on a variable cost basis than gas boilers, primarily until 2026. This is because, after 2026, wholesale gas prices will be reduced with increased global gas supplies, making heat pumps relatively more expensive (see Figure 1). Thus, after 2026, under the NECP19 pathway, heat pumps will only be marginally attractive compared to conventional gas boilers. The impact of phasing out Russian gas under the REPowerEU plan only marginally increases incentives to switch to heat pumps before 2026.
- However, after 2026, under the REPowerEU pathway, heat pumps become increasingly more attractive than gas boilers (on a variable cost basis only). Switching to heat pumps becomes more attractive with the avoided carbon tax under the expected EU ETS2 (after 2026). By 2030, the total gains (on a variable cost basis) of switching to heat pumps is ca. +$314 (relative to running a gas boiler), which is roughly 15% of the annuity payment for the heat pump (10% case). The benefit of REPowerEU is that it increases economic incentives to switch to heat pumps relative to the NECP19 pathway because wholesale electricity cost is much lower, especially closer to 2030. The efficiency gain in 2030 is three times higher under REPowerEU than under NECP19.
- Phasing out Russian gas under the REPowerEU further increases the heat pump's attractiveness. For example, in 2030, the impact of higher gas prices due to phase out of Russian gas is ca. 8% of the total expected gain from switching to heat pumps. As Europe decarbonises its power sector with wind and solar energy, the impact of gas prices on the power sector will diminish. Therefore, under the REPowerEU, an increase in gas prices does not increase electricity prices by the same magnitude. This trend increases the attractiveness of heat pumps relative to gas boilers.
- Despite these positive trends, based only on variable cost differences, unsubsidised heat pumps are unlikely to be cost-effective compared to gas boilers in the considered scenarios because the upfront purchase and installation cost of a heat pump is substantially higher than the upfront cost of gas boilers (upfront cost difference between a heat pump and gas boiler is ca. $12,000 (Element Energy 2017). To close the gap (between the total short-run gains and annuity payments over 2023-31), $9651 in subsidies (per heat pump installation) would be required to make users indifferent between a heat pump and a gas boiler (this assumes that the government also subsidises financing costs at 1%). REPowerEU reduces this subsidy by 2%, while phasing out Russian gas reduces this subsidy by another 3%.

Electrifying the heating sector would buffer gas shocks due to extreme weather conditions or a sudden disruption of Russian gas supplies. However, this transfers an additional load to the power system and adds to its IAV. However, the change in gas to electricity IAV due to heat electrification is substantially lower due to heat pumps' much higher efficiency than conventional gas boilers. Thus, two problems, however, are untackled by the REPowerEU plan. First is the cost of weather-driven events in Europe. The potential energy supply gap created by the decrease in renewable generation and the increase in demand is comparable in the two technology scenarios (Figure 25). Thus, as Europe turns to global gas markets for LNG supplies, the change in wholesale costs (from a *normal* to a *coldest*+ scenario) ranges from +$84 billion in 2023 to +$337 billion in 2031 under the baseline (NECP) pathway. Under REPowerEU, the delta *coldest*+ amounts to +$80 billion in 2023 and +$315 billion in 2031. Even if REPowerEU eases the tightness of global gas markets, the magnitude of weather-driven shocks (of comparable volumes, REPowerEU only slightly increases IAV) translates to a similar economic cost to European consumers Figure 30).

Figure 30: Europe's wholesale energy cost in various scenarios in NECP (left) vs. REPowerEU (right)



Thus, additional policy measures are needed to tackle the challenges posed by the increasing IAV of energy supply and demand as Europe decarbonises its energy system while relying on the global LNG market to close potential gaps.