December 2024

Dunkelflaute: Driving Europe Gas Demand Volatility

1. Introduction: *Dunkelflaute* drives gas demand volatility

Dunkelflaute (literally 'dark wind lull') is a German term that has become popularised in the energy industry to describe weather conditions where reduced sunlight and wind strength mean that little or no energy can be generated from renewable energy sources.[1] As renewable generation grows its share of European power generation, the impact of these episodes has been to drive up the volatility of gas demand[2] and influence prices (particularly at times of tightness in the market) when gas-fired power is despatched to fill that intermittency gap, even though the total gas demand in power continues to fall as the renewables build-out continues.

This Energy Insight examines the impact of two recent *Dunkelflaute* episodes January and November 2024 on gas demand in Europe (EU27 + UK) and the need for growing flexible supply.[3] The second chapter after this introduction provides context on gas demand trends in 2024, with a focus on the power sector. The following sections dive into more detail about wind and gas in the generation mix, and the impacts on gas demand volatility. Supply comes next, highlighting the limited flexibility from pipeline imports and production and the key role played by storage and LNG sendout during these episodes. The final section draws some conclusions.

Key messages:

- Gas-fired generation still acts as the main source of flexibility for the European power system and a drop in wind generation over more than a few hours will invariably lift the call on gas-fired power plants (and vice versa).
- Growing exposure to wind generation in the power sector triggers peaks in gas demand, for which size and duration are hard to predict. *Dunkelflaute* also tends to happen during colder temperatures in Europe, at times of increased space heating requirements, a second simultaneous gas demand driver, magnifying the power sector demand peaks.

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[1] The term literally means 'dark calm' or 'dark lull', reflecting a lack of sunlight for solar and wind for wind power generation.

[2] The impact of these episodes is to drive up the volatility of gas demand at least until other forms of flexibility develop at scale. Indeed, gas-fired plants are not the only form of back-up to intermittent renewables, but it is the main one other forms of flexibility exist providing a wide range of back-up options, such as batteries (back-up for a few hours), demand side response (so far rather limited) or even hydro power (flexibility potentially similar to gas, provided adequate capacity and hydro levels). Additional flexibility is being deployed to support growing renewable capacity, which one day, will limit the use of gas-fired plants to back-up intermittency, although the timeframe and extent of this is uncertain, a matter of debate and still dependant on future policies to support deployment.

[3] We define Europe as the EU-27 plus the United Kingdom, unless otherwise stated.

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- While the power sector used to be a source of short-term gas demand flexibility, this has now changed. Gas use for power has become more volatile, somewhat less predictable and importantly, more resilient to peaking gas prices compared to just a few years ago.
- With deteriorating flexibility on the demand side, the European market requires growing flexibility on the supply side, which came almost exclusively from storage and LNG in 2024.

2. European gas demand trending lower amid falling power sector demand

The context of this greater demand volatility is that in aggregate, gas demand[4] in Europe remains well below pre-crisis level: our estimates (calculated at the end of November) show a drop of roughly 100 Bcm over the past three years.[5]

The region is even on its way for another small decline in total gas demand in 2024, a third consecutive year of contraction, as gas consumption declined by 1 per cent year-on-year in the first eleven months of 2024 (Figure 1).

The steep decline in gas burn in the power sector has been the main driver of this decline (Figure 2), more than counterbalancing year-on-year demand growth in the industrial sector and the residential and commercial sectors (respectively almost 5 per cent and 4 per cent over the first eleven months of 2024).[6]

Gas used in the power sector was down by about 10 per cent year-on-year over the same period, despite an increase in total electricity demand of 4 per cent year-on-year[7] (Figure 3). This came after a decline of about 20 per cent in 2023 (calendar year), as illustrated in Figure 4, raising questions as to whether some of these gas demand for power losses may be permanent.

[4] A word on methodology and definition:
- The analysis presented in this Energy Insight is based on the author's analysis of her own data. Gas demand is driven by a combination of factors and the biggest difficulty to analyse the impact of these drivers comes from the lack of timely, detailed and consistent data that would allow for an accurate analysis of drivers and trends. When data is available, there are also differences in methodologies and definitions, which complicates comparison between national markets and between sectors.
- This author collects data from various publicly available sources. The charts in this Insight are based on this author's assumptions, this author's calculations and sometimes this author's corrections of the raw data to complete and make the data uniform to allow a clear picture of recent European gas demand trends by sector. In other words, **the sectoral data on gas demand is not taken from, nor it is the responsibility of, any of the publicly available sources from where this author takes the raw data. The sectoral demand data presented in this Energy Insight is my own data and my sole responsibility**. Because it is based on non-final raw data, it is also a work in progress and is continuously updated when (or if) raw data is made available from one or various sources.
- Finally, a word on vocabulary: in this Energy Insight, gas "demand" and gas "consumption" are used interchangeably; as well "power" and "electricity".

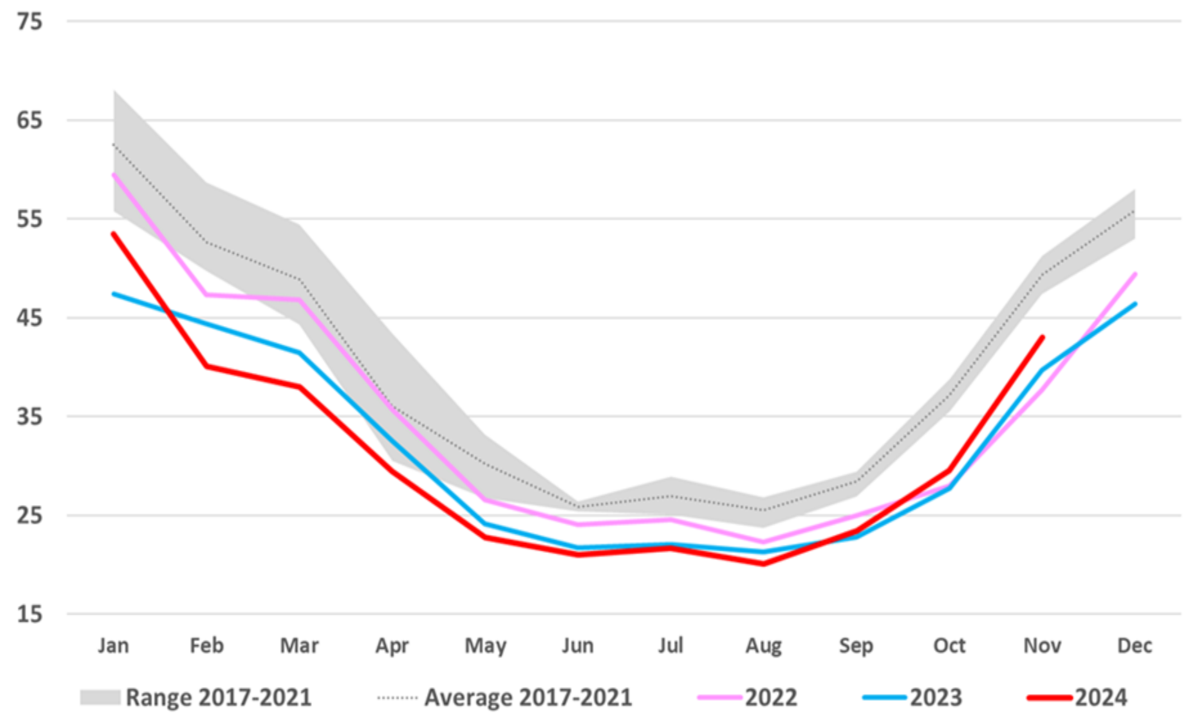
[5] Gas demand was 489 Bcm in 2021. Demand in 2022 was 62 Bcm lower year-on-year, then again, 33 Bcm lower in 2023 year-on-year, based on Eurostat data. Over the first eleven months in 2024, European gas demand was 3 Bcm lower over the same period in 2023 (author's calculations). In other words, if gas demand in December 2024 is equal to gas demand in December 2023, then annual demand in 2024 will be close to 390 Bcm, therefore roughly 100 Bcm lower than in 2021. Any variation between December 2024 and December 2023 will change the estimated annual level for 2024 accordingly.

[6] There are three major sectors of gas demand in Europe: power, industrial and residential and commercial. These three sectors typically account for about 90 per cent of gas demand. This Energy Insight only takes a closer look at the power sector. For a cursory examination of all three sectors in 2024 and outlook for the coming months, see Farren-Price B., Honoré A. and Sharples J., "European Gas Market Supply & Demand: Winter Outlook 2024/25", November 2024, Oxford Institute for Energy Studies: https://www.oxfordenergy.org/publications/european-gas-market-supply-demand-winter-outlook-2024-25/

[7] Higher electricity demand year-on-year in the first eleven months of 2024 were driven by above normal temperatures this summer, a glimpse of cold snaps in January, early winter weather in September, and a rebound in the industrial and commercial sectors.

The share of gas used for power generation typically represents 30-35 per cent of total gas demand in Europe on an annual basis (Figure 5),[8] although monthly variations throughout the year are important, from about 25 per cent in winter (when space heating is the primary use for gas) to 45-50 per cent over the summer.

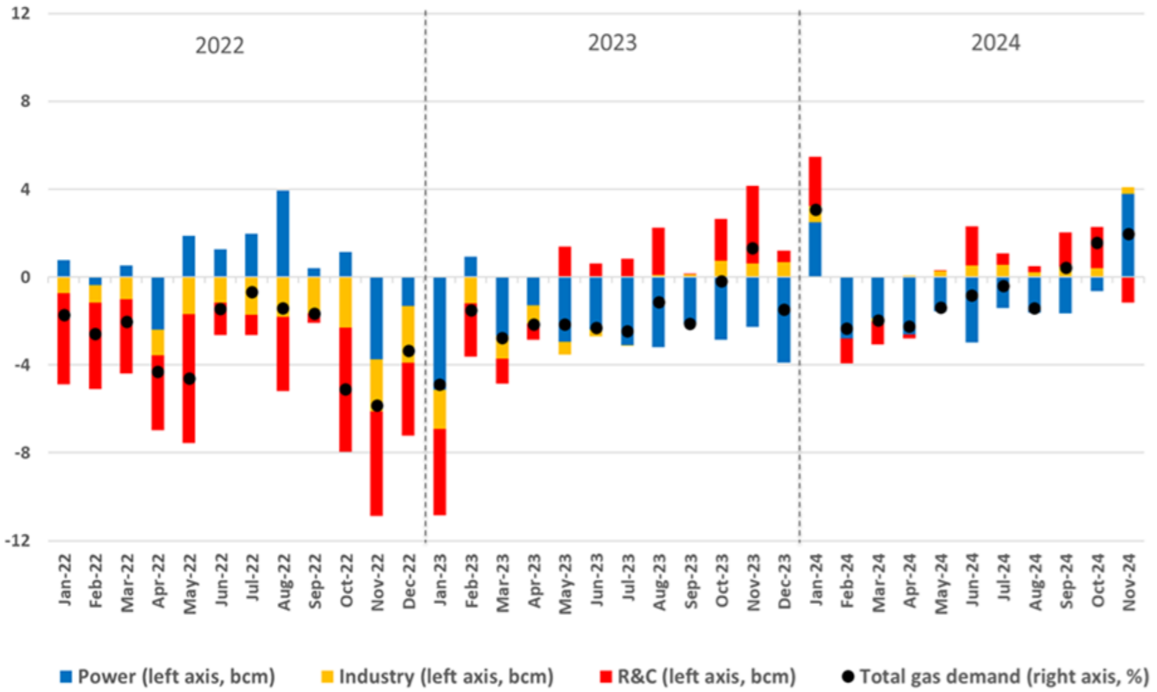
Figure 1: Monthly gas demand in the EU27 + UK (Bcm)



Source: A. Honoré (OIES). Data calculated by this author using raw data from various sources, including data from IEA, Eurostat, ENTSOG Transparency Platform, and TSOs. Graph by the author.

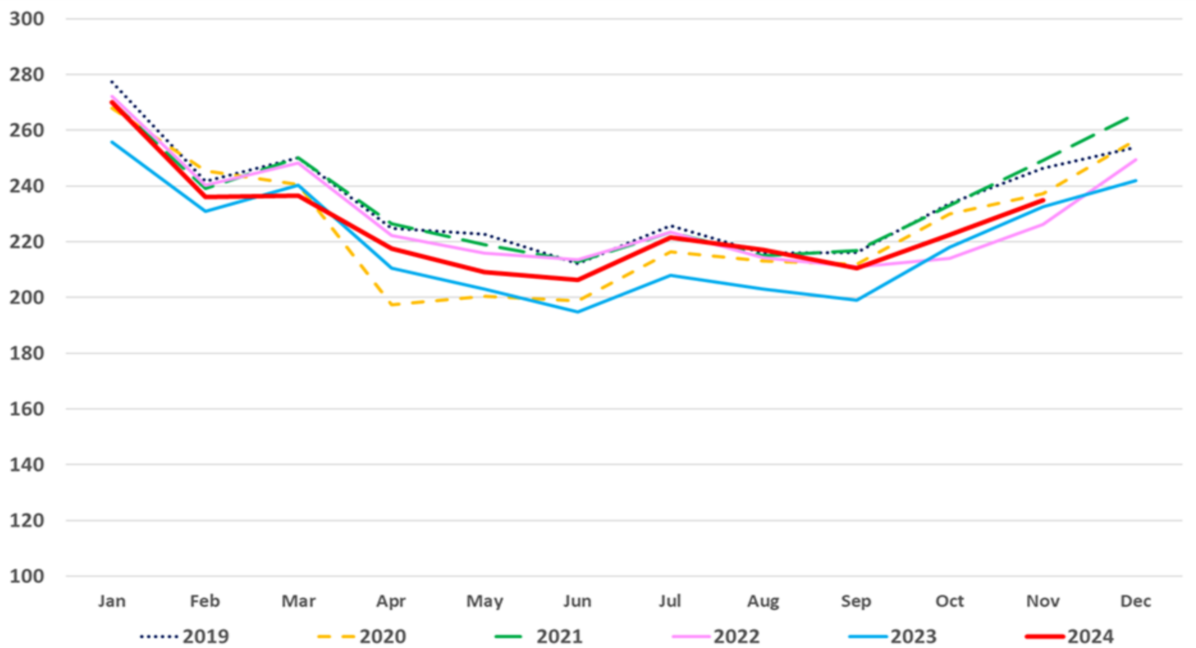
[8] In the first eleven months of 2024, the share of gas for power generation represented on average roughly 30 per cent of total gas demand (Figure 5)

Figure 2: Year-on-year change in sectoral gas demand in the EU27 + UK (Bcm, left axis and per cent, right axis)



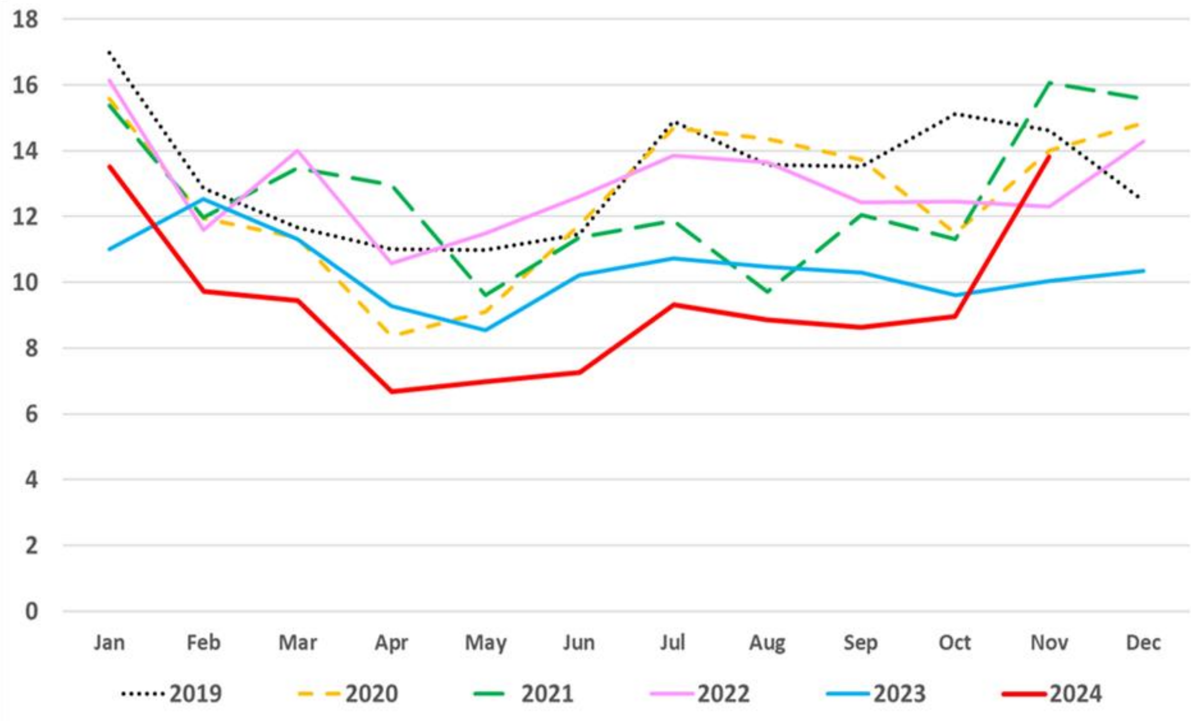
Source: A. Honoré (OIES). Graph by the author.
Note: only the 3 major sectors are shown

Figure 3: Monthly (total) electricity generation in EU27 + UK (TWh)



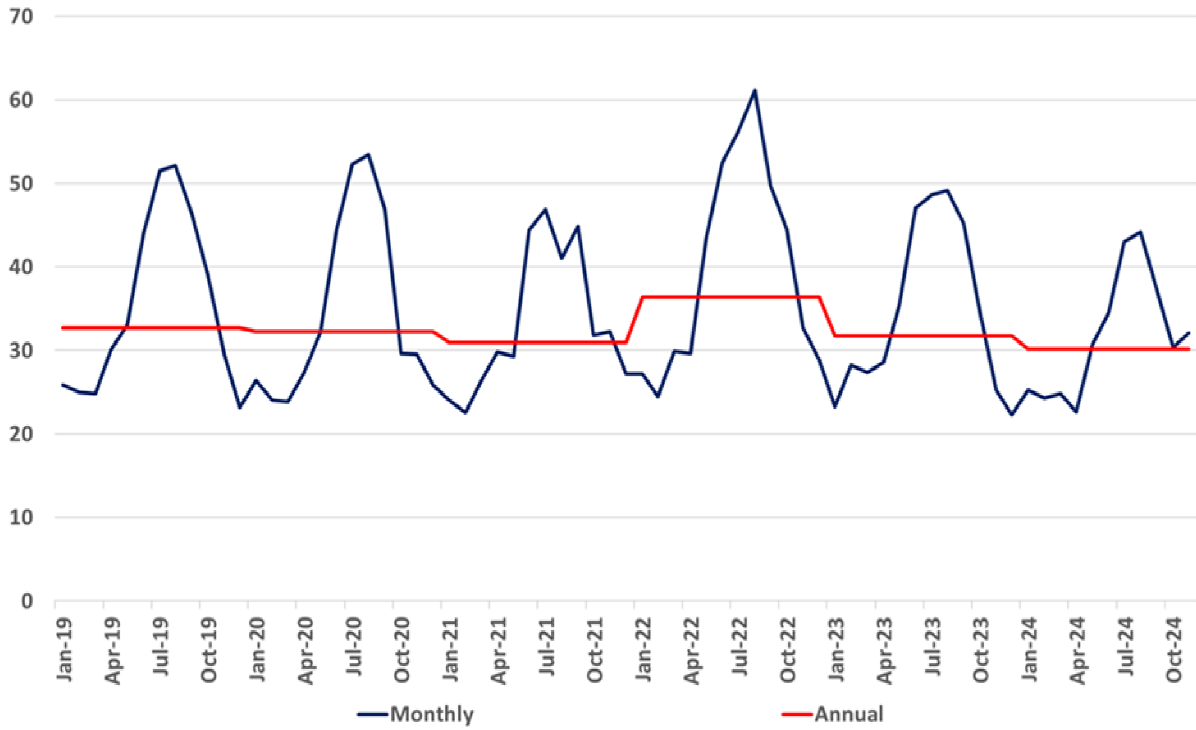
Source: A. Honoré (OIES). Data calculated by this author using raw data from ENTSOE Transparency Platform, Gridwatch and NESO. Graph by the author.

Figure 4: Monthly gas demand in the power sector in EU27 + UK (Bcm)



Source: A. Honoré (OIES). Graph by the author.

Figure 5: Share of gas demand for power in total gas demand in EU27 + UK (per cent)



Source: A. Honoré (OIES). Graph by the author.

3. Rapid transformation of the electricity mix and the use of gas plants

In the electricity generation mix, gas covered less than 15 per cent on average in the first eleven months of 2024 (Figure 6), well below last year's 17 per cent over the same period and 20 per cent at the same time in 2022.

The reasons behind this year's decline have been a mix of factors specific to 2024 and structural changes brought about by the rapid transformation of the electricity mix:

- The continued strong expansion of renewable capacity across Europe, especially wind and solar.[9] In 2024, renewables typically covered 45-50 per cent of monthly electricity generation, roughly 10 percentage point more than just two years ago (Figure 6).
- Higher nuclear availability driven by the progressive return of the French nuclear fleet in line with EDF's target and roughly back to 2021 levels before the stress corrosion issues[10] emerged (generation was even higher in November).
- Good availability of hydro power, at least for the first 10 months of 2024. November was down year-on-year, which limited overall generation but also the extent of the flexibility usually provided by hydro in the power mix.

The combination of improved renewables availability (hydro, wind and solar), as well as much higher nuclear generation have pushed fossil fuels down the merit order most of the time, with gas plants moving further away from providing baseload power and more and more toward a role of back-up, whose utilisation is determined by the availability of other power sources. Two months broke the pattern of continuous decline in 2024: January and November (Figure 7).

- In January, monthly data highlight the high level of total electricity demand triggered by episodes of cold temperatures (+6 per cent year-on-year). The renewables were only able to cover 45 per cent of the mix, with gas stepping up and providing 18 per cent of the mix.[11]
- In November, monthly charts clearly show low wind availability in conjunction with low hydro power, and a share of just about 40 per cent covered by renewables. The share of gas climbed to 21 per cent for the first time since October 2022 to make up for the shortfall.

The most interesting story, however, is illustrated by daily variations in the electricity mix (Figure 8) which show a clear correlation between renewables (wind in particular) and gas generation: days when wind availability is good, the use of gas plants is low, and conversely, when wind is limited, gas plants ramp up to cover the shortage (Figure 9). In other words, dispatchable generation capacity remains essential to integrate such a large share of intermittent renewables and gas plants in particular as the main source of back-up for intermittent renewables, and more generally, the main source of flexibility for balancing the power grid[12] (as seen in 2022 with episodes of low nuclear and hydro[13]).

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[9] This author estimates that wind capacity in Europe rose by 35 GW between 2021 and 2023 to 249 GW; and solar by 94 GW between 2021 and 2023 to 273 GW

[10] The second half of 2022 saw French nuclear generation fall to historic lows as the utility EDF faced a wave of repairs caused by stress corrosion plus delays to its scheduled ten-year maintenance plan due to the COVID pandemic (as well as strikes in France in October 2022), which forced a record number of reactors offline for most of the year. As a result, French nuclear generation was down by 23 per cent in 2022, and it was still 11 per cent 2023 (compared to 2021), lifting thermal power generation in the country and in neighbouring markets. In 2024, generation was only 1 per cent below 2021 in the period cover January to November, with a rapid recovery throughout the year. Source: A. Honoré (OIES), data calculated from Entsoe transparency platform.

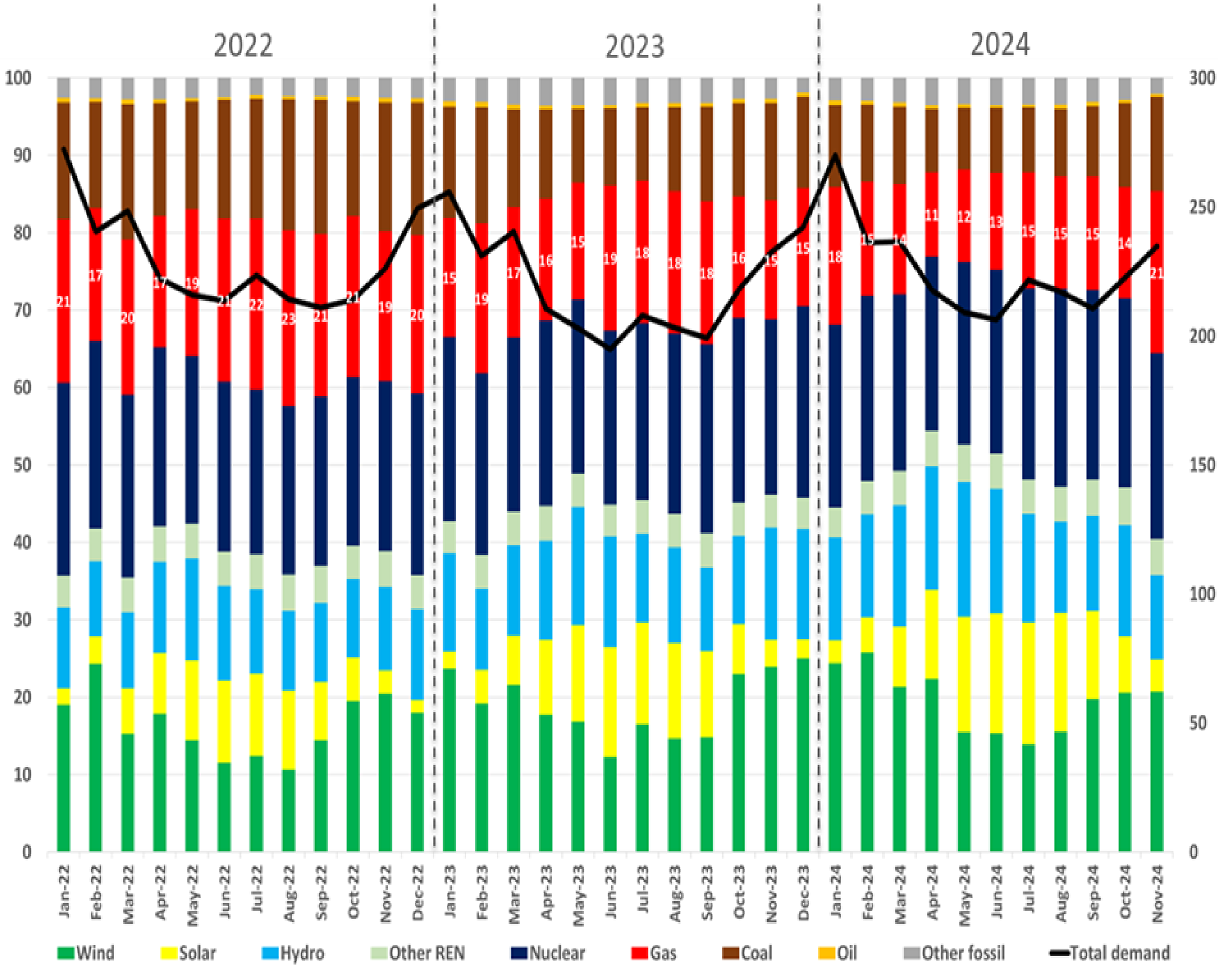
[11] Coal plants also increased their output, but their contribution only covered about half the electricity generated by gas plants, a logical outcome considering that clean spark spreads were at the time well above clean dark spreads around Europe.

[12] These conclusions are only representative of the regional market as a whole. National differences are important and should not be underestimated. They will be covered in a forthcoming paper (2025) by A. Honoré (OIES).

[13] For more details about the power sector in 2022 and the main challenges from nuclear and hydro, see A. Honoré, European gas demand fundamentals, H1 2023 review and short-term outlook, July 2023, Oxford Institute for Energy Studies, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/07/Insight-134-European-gas-demand-fundamentals.pdf

Gas demand in the power sector has therefore become more volatile, somewhat less predictable and importantly, less responsive to higher prices.[14] This trend is also supported by the progressive phase-out of coal plants around Europe, which leaves little room for coal to/from gas switching, which used to be an important characteristic of gas demand flexibility in Europe during winter, as it allowed some degree of short-term gas demand response (driven by coal, gas and carbon prices).

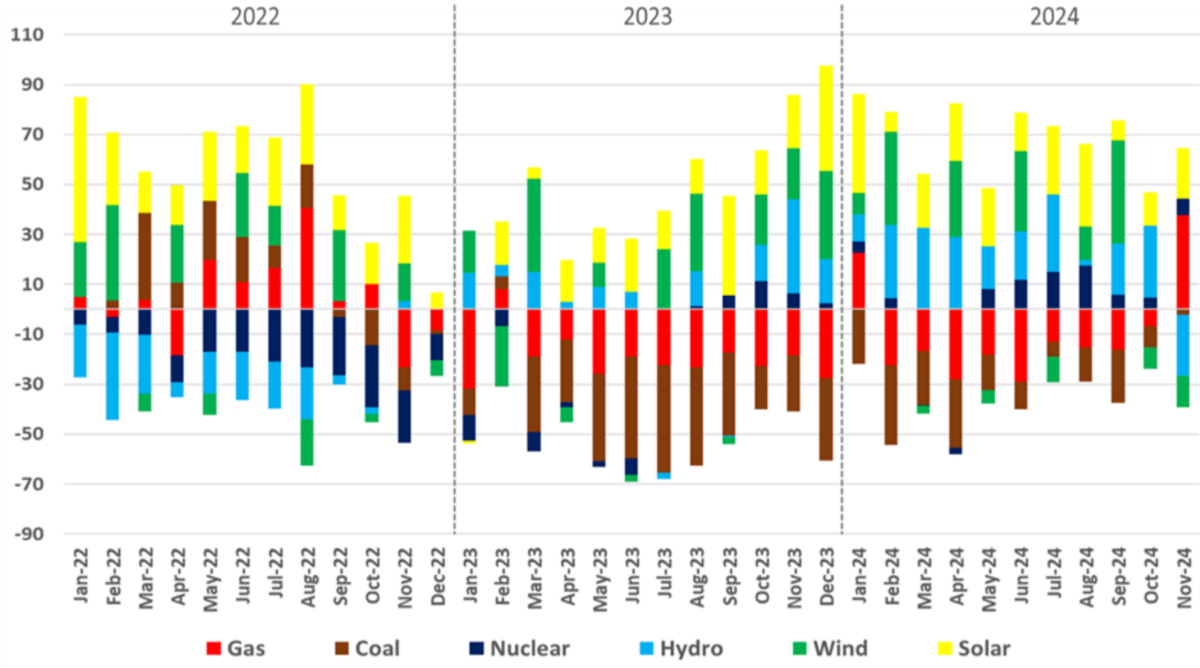
Figure 6: Share of electricity generation by sources (per cent, left axis, bar chart) and electricity demand (TWh, right axis, black line) in EU27 + UK



Source: A. Honoré (OIES). Data calculated by this author using raw data from ENTSOE Transparency Platform, Gridwatch and NESO. Graph by the author.

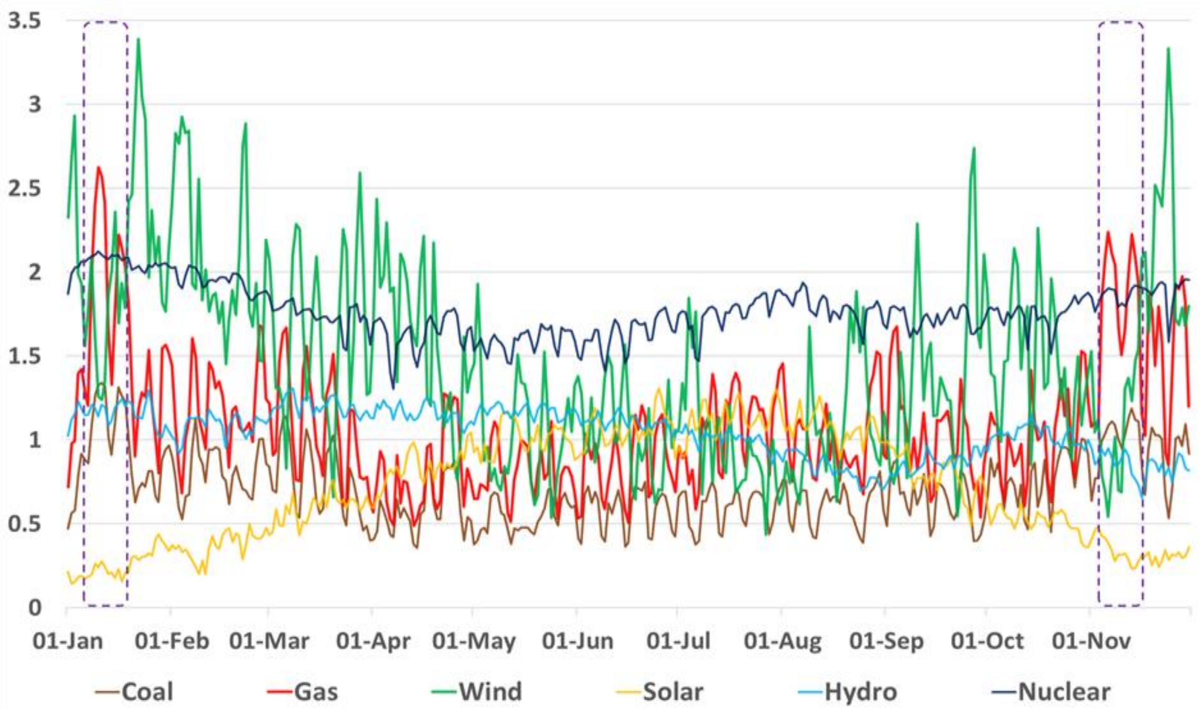
[14] Gas for power demand is less price responsive than just a few years ago. This will be covered in more details in a forthcoming paper (2025) by A. Honoré (OIES).

Figure 7: Monthly changes in electricity generation in EU27 + UK by main sources (per cent year-on-year)



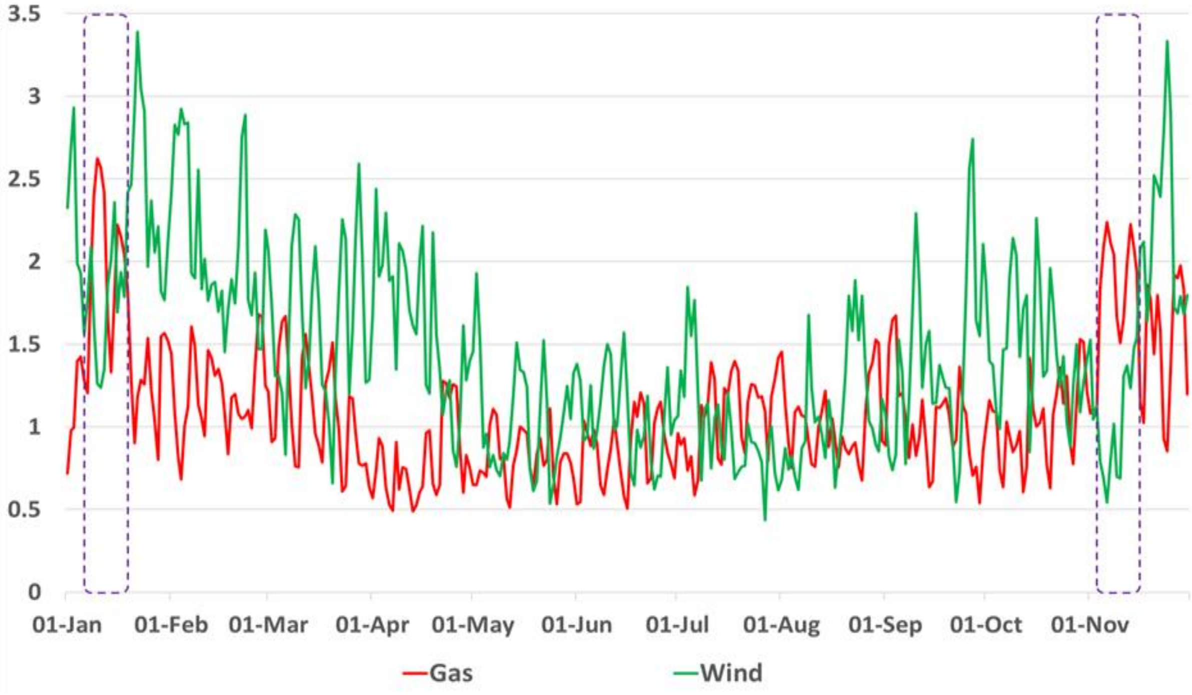
Source: A. Honoré (OIES). Data calculated by this author using raw data from ENTSOE Transparency Platform, Gridwatch and NESO. Graph by the author.

Figure 8: Daily electricity generation by main sources in EU27 + UK (TWh/d)



Source: A. Honoré (OIES). Data calculated by this author using raw data from ENTSOE Transparency Platform, Gridwatch and NESO. Graph by the author.

Figure 9: Daily electricity generation from gas and wind in EU27 + UK (TWh/d)



Source: A. Honoré (OIES). Data calculated by this author using raw data from ENTSOE Transparency Platform, Gridwatch and NESO. Graph by the author.

4. *Dunkelflaute* episodes: new gas demand volatility drivers

Gas demand in Europe displays strong seasonality and sudden and short-term spikes are normal during winter. But the growth of wind generation brings another layer of uncertainty, with additional peaks in gas demand, for which size and duration are harder to predict.

There were several episodes of low availability of renewables, or *Dunkelflaute*, in 2024, most of which went unnoticed and did not make market headlines. These episodes get more attention however when the market is already tight, for instance at times of cold temperatures (which increase both gas and electricity demand for heating).

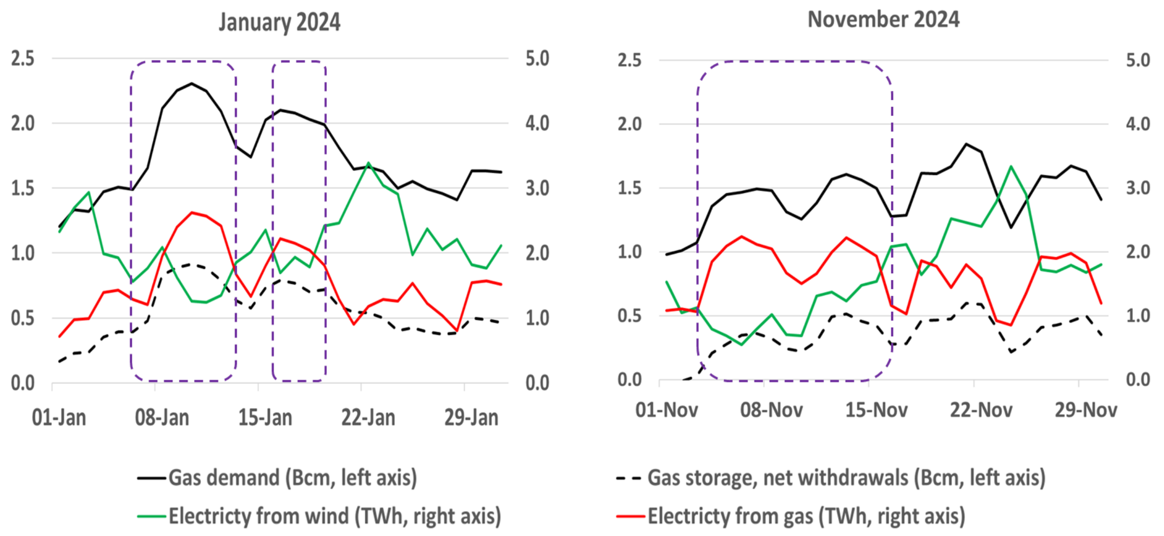
Many people learnt what *Dunkelflaute* meant in November when limited generation from wind (and solar) prevailed for several days in Germany. This phenomenon happened in several countries around Europe at the same time, most of which also experienced relatively cold weather. The spike in gas demand triggered the withdrawal of 4.5 Bcm from 3 to 16 November (Figure 10), a sharp decline this early in the winter season. The rest of the month saw even more gas come out of storage (5.9 Bcm), triggered by heating demand, although the 2.5 Bcm of this gas was also supported by a drop in wind generation which kept gas high in the mix over the period from 25 to 30 November.

In January, cold temperatures and a drop in wind generation which happened twice within a few days, at a time of high gas and electricity demand for heating in the middle of winter, created a gas demand spike. It did not make headlines under the *Dunkelflaute* phenomenon, but it nonetheless bolstered the call on gas storage by about 10 Bcm in just 13 days from 6 to 19 January (Figure 10), representing about 10 per cent of underground storage capacity in the EU27.

The combination of *Dunkelflaute* and cold temperatures can influence gas prices, but there was no clear correlation between total gas demand and prices in January, while it was better in November when the market was generally tighter.[15]

While the overall level of demand remains low by historical standards, short-term spikes in gas demand should be expected in frequency and depth. With limited short-term flexibility on the demand side (for now, this should improve in the future), flexible and rapidly available gas supply will be increasingly crucial to balance the system in Europe.

Figure 10: Daily gas demand and net storage withdrawals (Bcm/d, left axis) vs power generation from wind and gas (TWh/d, right axis) in EU-27 + UK in January & November 2024

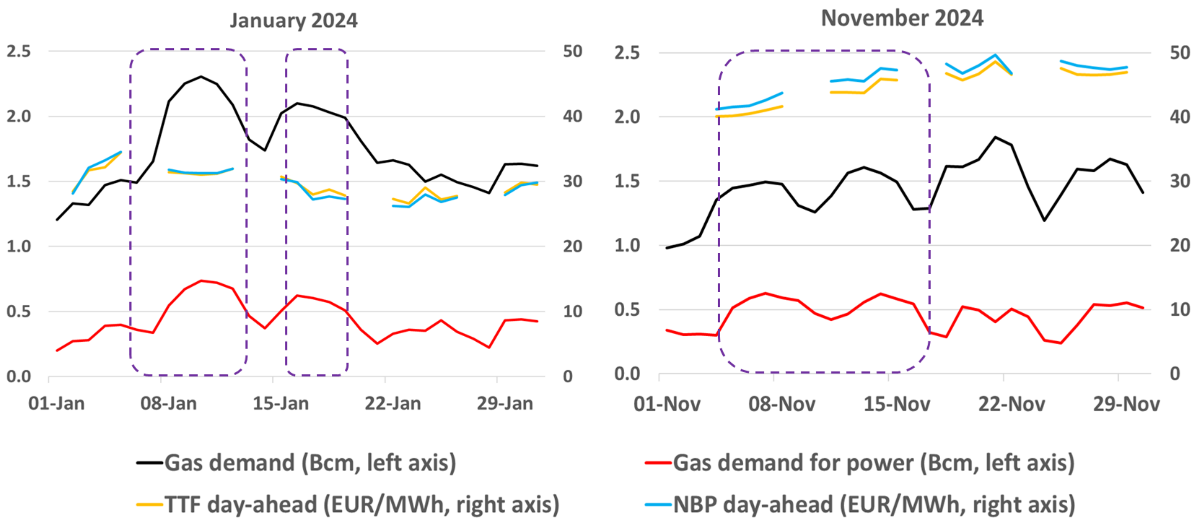


Source: A. Honoré (OIES). Data on gas demand calculated by this author using raw data from various sources, including data from IEA, Eurostat, ENTSOG Transparency Platform, and TSOs; data on power generation from gas and wind calculated by this author using ENTSOE Transparency Platform, Gridwatch and NESO; data on storage from https://agsi.gie.eu/[16]. Graph by the author.

[15] In January 2024, the correlation between daily gas demand and TTF (and NBP) day-ahead prices was pretty much inexistant with negative correlation of -0.38 (and -0.29) over the period 6-19 January. In November 2024, the relationship between demand and prices appears to be better with a positive correlation of 0.53 (and 0.57) when the market was tighter. However, even a high correlation would not mean that a variable was causing the change in the other (correlation is not causation). Source: A. Honoré (OIES). Data on gas demand calculated by this author; data on prices from Argus Direct [subscription required]: TTF and NBP day-ahead daily (mid-point) prices.

[16] The author thanks J. Sharples (OIES) for extracting and providing the data on storage

Figure 11: Daily gas demand (Bcm/d, left axis) in EU27 + UK vs TTF and NBP day-ahead daily (mid-point) prices (EUR/MWh, right axis) in January & November 2024



Source: A. Honoré (OIES). Data on gas demand calculated by this author using raw data from various sources, including data from IEA, Eurostat, ENTSOG Transparency Platform, and TSOs; data on prices from Argus Direct [subscription required]. Graph by the author.

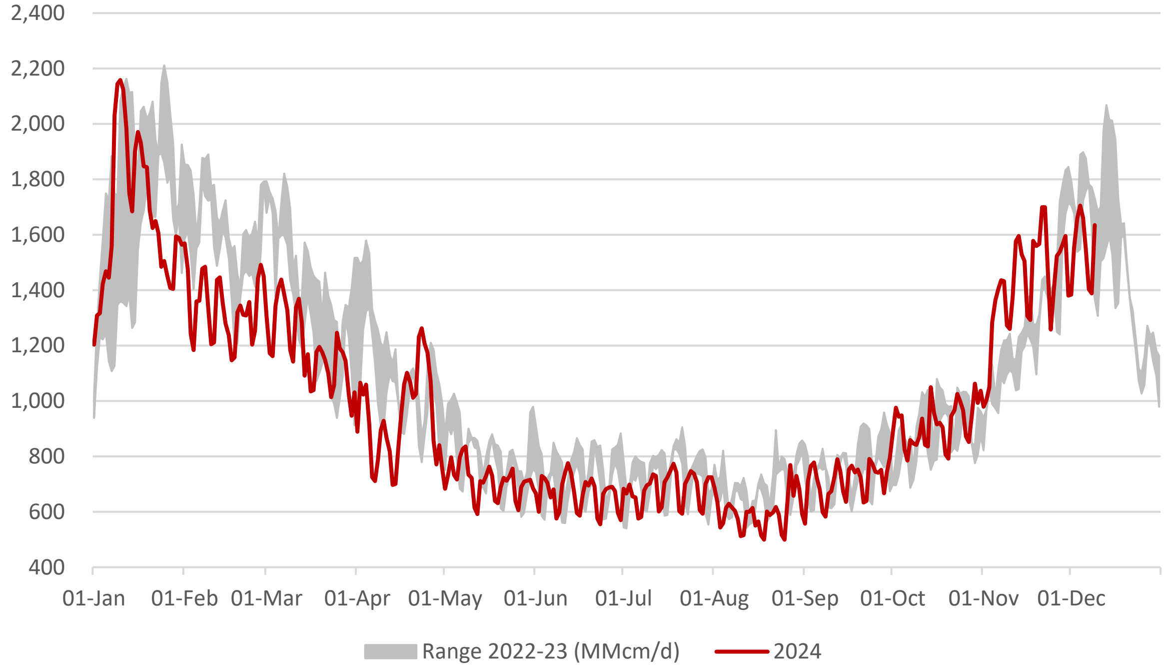
5. European gas supply

The European gas supply system[17] – in terms of both its physical infrastructure and traded market - has been developed over the past several decades to cope with both seasonal and daily variation in demand. But in the context of more volatile and relatively inelastic gas demand as discussed above, there is a need for supply that is flexible on both a seasonal and daily basis. As can be seen in Figure 12, below, in 2024 alone, total European gas supply varied from a seasonal peak of 2,124 MMcm/d on 11 January to a low of 499 MMcm/d on 25 August.[18] Short-run volatility in January 2024 saw supply rise from around 1,200 MMcm/d on 1 January to over 2,100 on 11 January and then back to 1,400 MMcm on 27 January. Similarly, in November, supply rose from 979 MMcm/d on 1 November to a peak of 1,700 MMcm/d on 21 November and then back to 1,258 MMcm/d on 24 November.

A key question for the European supply side is where that flexibility is located. As

Figure 13 and Figure 14 illustrate below for January and November 2024 respectively, the flexibility lies in withdrawals from underground gas storage facilities and in sendout from LNG regasification terminals. By contrast, flexibility from pipeline imports and Europe's own gas production is limited.

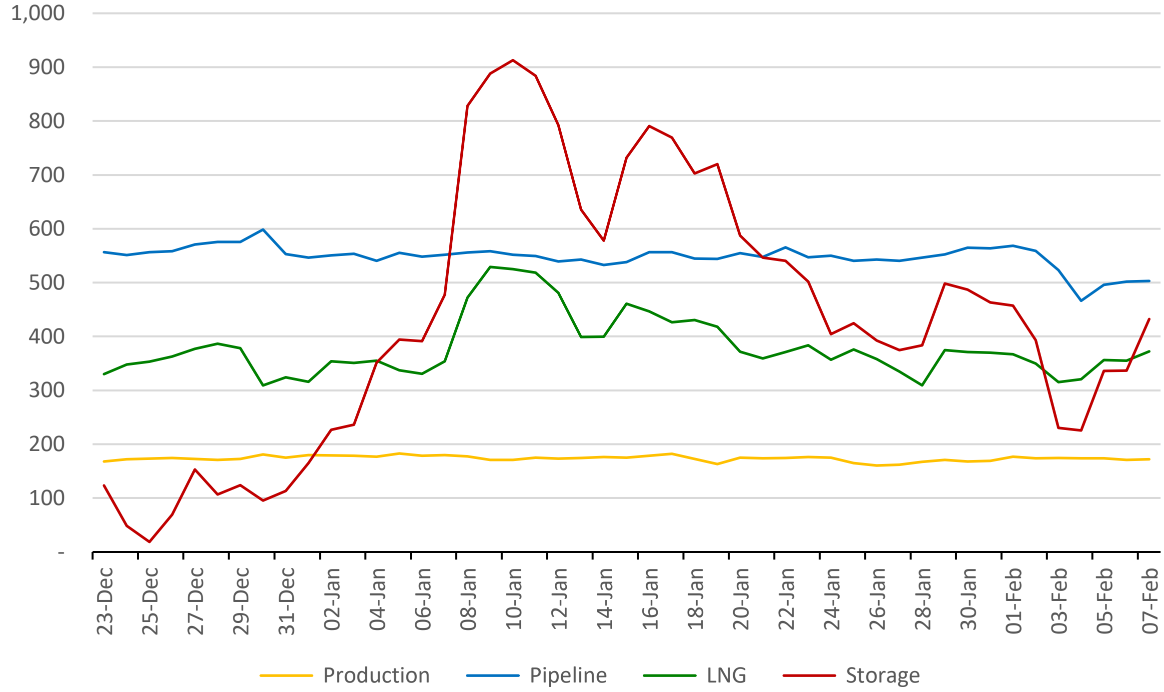
Figure 12: European total daily gas supply (MMcm per day)



Source: J. Sharples (OIES). Data calculated by this author using raw data from: Eurostat,[19] ENTSOG Transparency Platform,[20] Gas Infrastructure Europe Aggregated Gas Storage Inventory (AGSI),[21] Gas Infrastructure Europe Aggregated LNG System Inventory (ALSI),[22] and National Gas Transmission (UK).[23] Graph by the author.

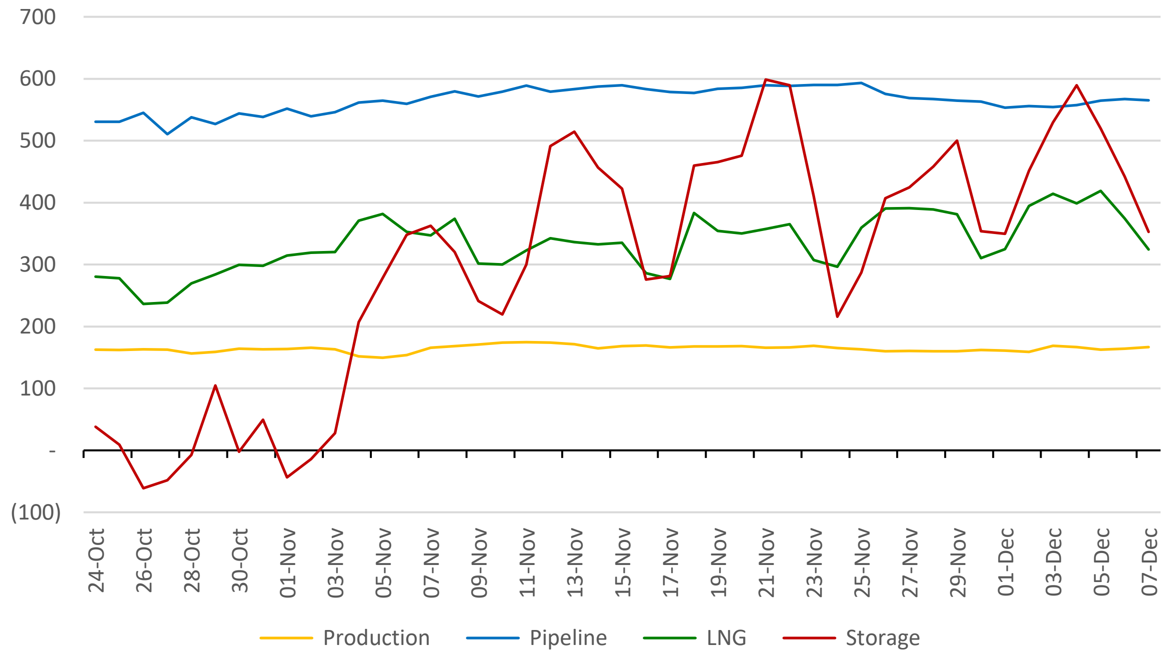
[17] Supply is calculated as a combination of production, pipeline imports, sendout from LNG regasification terminals, and net storage withdrawals, minus physical pipeline re-exports to Ukraine and Morocco. Total supply is implied consumption.
[18] Monthly average European gas supply in 2024 ranged from 1,666 MMcm/d in January to 597 MMcm/d in August.
[19] Eurostat, 2024. Supply, transformation and consumption of gas - monthly data [nrg_cb_gasm]. https://ec.europa.eu/eurostat/web/main/data/database
[20] ENTSOG, 2024. ENTSOG Transparency Platform. https://transparency.entsog.eu/
[21] GIE, 2024. Aggregated Gas Storage Inventory. https://agsi.gie.eu/
[22] GIE, 2024. Aggregated LNG System Inventory. https://alsi.gie.eu/
[23] NGT, 2024. Find Gas Transmission Data. https://data.nationalgas.com/find-gas-data

Figure 13: European total daily gas supply by source in Dec-23 to Feb-24 (MMcm per day)



Source: J. Sharples (OIES). Data calculated by this author using raw data from: Eurostat, ENTSOG Transparency Platform, Gas Infrastructure Europe Aggregated Gas Storage Inventory (AGSI), Gas Infrastructure Europe Aggregated LNG System Inventory (ALSI), and National Gas Transmission (UK). Graph by the author.

Figure 14: European total daily gas supply by source in Oct-Dec 2024 (MMcm per day)



Source: J. Sharples (OIES). Data calculated by this author using raw data from: Eurostat, ENTSOG Transparency Platform, Gas Infrastructure Europe Aggregated Gas Storage Inventory (AGSI), Gas Infrastructure Europe Aggregated LNG System Inventory (ALSI), and National Gas Transmission (UK). Graph by the author.

5.1. Limited supply-side flexibility from pipeline imports, production

The relative lack of response from pipeline imports to higher demand reflects a lack of flexibility in pipeline supply. During the winter, monthly average pipeline supply from **Norway** tends to flow at a high plateau of 345-355 MMcm/d, which is close to the maximum capacity of the Norwegian system to produce, process, and export pipeline gas. Similarly, supply from **Azerbaijan** (as measured at the Kipoi interconnection point on the Turkey-Greece border) is constrained by the 34 MMcm/d capacity of the Trans-Adriatic Pipeline (TAP). Pipeline supply from **North Africa** is mostly sourced from Algeria and delivered to Spain and Italy, while a very small volume (roughly 2-7 MMcm/d) flows from Libya to Italy. The Algerian pipeline supply to Spain is constrained by the capacity of the Medgaz pipeline and generally tracks in a corridor of 21-31 MMcm/d. Algerian pipeline supply to Italy has seen monthly average flows between 42 and 72 MMcm/d over the past two years, although daily flows have occasionally reached the full capacity of the Transmed pipeline (85 MMcm/d). Pipeline supply from Algeria offers some flexibility in line with the range of nominations permitted to Italian buyers under long-term contracts with Sonatrach but is also constrained by Sonatrach's need to meet its domestic and LNG export commitments, which can limit the volume of gas it can offer to the spot market over and above its long-term contracts.

The most significant loss of flexibility in pipeline supply to Europe over the past three years is the decline in supply from **Russia**. Prior to Russia's invasion of Ukraine in February 2022, Gazprom was able to offer substantial flexibility through a) the range of daily supply nominations permitted under its long-term contracts and b) its ability to offer additional volumes to the spot market through downstream trading subsidiaries that operated on European trading hubs (such as Gazprom Germania, and Gazprom Marketing & Trading) and through additional sales on its Electronic Sales Platform. Gazprom had both the supply (from its own gas production) and the pipeline export capacity to offer those additional volumes, as it did in 2019, when Russian pipeline exports reached their annual peak. With the Russia-Ukraine gas transit contract expiring on 31 December 2024, and unlikely to be renewed, Russian supply is set to fall further and be limited to deliveries via the Turkish Stream pipeline to markets in South-Eastern and Central Europe: Greece, Serbia, North Macedonia, Croatia, and Hungary.

European gas **production** does not offer notable flexibility in daily supply and the end of production from the Groningen field in the Netherlands (after several years of ramping down) has removed the only notable source of seasonal swing in production in the EU-27. In the UK, production does not offer seasonal swing but does experience a downturn in late spring/early summer for maintenance.

5.2. Flexibility instead from storage and LNG sendout

As Russian pipeline supply to Europe declined in 2022, net **LNG imports**[24] ramped up to record levels. Having already risen from 50-53 Bcm in 2017-18 to 83-101 Bcm in 2019-21, imports rose dramatically to 143-144 Bcm in 2022-23. Those LNG imports are likely to fall back somewhat in 2024, having reached 102 Bcm in the first eleven months of 2024. The flexibility of that LNG supply depends on multiple factors. At the macro level, Europe benefits from the existence of a large, liquid, global LNG market. In particular, Europe has benefitted from the ramp-up of commercially attractive, destination-flexible LNG supplies from the United States, which grew from near zero in 2015 to being the world's largest LNG exporter in 2023. In the first 11 months of 2024, the United States was the source of 46 per cent of European LNG imports, by far the largest share of any single supplier.[25]

However, there are also constraints to the flexibility of that supply. The first constraint is the time it takes for LNG cargoes to arrive, even when the delivery destination was confirmed at the point of cargo loading. For example, in November-December 2024, the quickest journey made by an LNG carrier from the United States to Europe took 11 days, but most deliveries on that route took 12-16 days. The second constraint is the availability of spot cargoes at the time of a surge in demand, and the time it takes those

[24] Defined as the volume of LNG unloaded from LNG carrier vessels into storage tanks at LNG regasification terminals, minus the volume of LNG withdrawn from storage tanks and loaded back onto LNG carrier vessels for re-export

[25] Data from Kpler LNG Platform [subscription required]

cargoes to arrive. For example, an LNG carrier in the mid-Atlantic or halfway down the West coast of Africa en route from the United States to Asia could still take a week to arrive in Europe if it were re-sold and physically diverted.

Beyond the availability of LNG cargoes (in both physical and trading terms), the capacity to unload cargoes at regasification terminals is defined by the number of jetties and the hourly offloading capacity of the regasification terminal. This is generally not a constraint, but summer 2022 saw LNG regasification terminals in northern France, Belgium, and the Netherlands operating at full capacity amid the decline in Russian pipeline gas supply via Nord Stream. The addition of new regasification capacity in this region (and the rebalancing of the regional market) has eased this constraint. In August 2022, European LNG import capacity stood at 210 Bcma (17.5 Bcm per month), rising to 254 Bcma (21.1 Bcm per month) by January 2024, and set to reach 298 Bcma (roughly 25 Bcm per month) by the end of 2026. While some of that expansion is at onshore terminals (for example, a new 190,000 m3 storage tank at the Isle of Grain in the UK), much of the growth between 2022 and 2024 has been from the addition of ten[26] new Floating Storage and Regasification Units (FSRUs), with another four planned for Germany and Italy in 2025.[27]

Once the cargoes have arrived, the capacity to store LNG in tanks at regasification terminals and then make it available to the market through controlled variation in **LNG sendout** adds flexibility to supply. Large, onshore regasification terminals have storage capacities that often range from 320,000-1,000,000 m3 of LNG, with substantial daily sendout capacity. By contrast, FSRUs are roughly the same size as a single LNG cargo - around 170,000-174,000 m3. Therefore, the FSRUs have less storage and sendout capacity – and, therefore, less flexibility – than large, onshore terminals. As illustrated below, at regasification terminals in the EU-27, onshore terminals can send out roughly two and a half times as much as a single FSRU and can store the equivalent of 8.7 days' maximum sendout, while single-FSRU terminals can store 7.5 days' maximum sendout. The term 'FSRU-2' refers to terminals where two FSRUs are placed side-by-side, at Eemshaven (Netherlands) and Mukran (Germany). Across the whole of the EU-27, regasification terminals can store the equivalent of 8 days' maximum sendout, which serves to highlight the importance of regular cargo arrivals during periods of peak LNG demand.

According to Gas Infrastructure Europe, the EU-27 has the capacity to sendout just under 700 MMcm/d from its 28 LNG regasification terminals,[28] which is more than the combined capacity of Norway, Algeria, Libya, and Russia to deliver pipeline supply to that same market (roughly 600 MMcm/d up to the expiry of the Russia-Ukraine transit contract on 31 December 2024, and around 560 MMcm/d thereafter). That 700 MMcm/d equates to eight days sendout from full stocks at its 5.6 Bcm of natural gas storage capacity at LNG regasification terminals.[29] However, total inventory on any given day over the past 12 months has been in the range of 2.4-3.6 Bcm, which equates to four days' maximum sendout.[30]

In addition, the UK has roughly 1.25 Bcm of natural gas storage capacity at Milford Haven (home to the South Hook and Dragon terminals) and the Isle of Grain, bringing European LNG storage capacity close

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[26] This includes Inkoo in Finland; Le Havre in France; Wilhelmshaven, Brunsbüttel, and Mukran (2) in Germany; Alexandroupolis in Greece; Piombino in Italy; and Eemshaven (2) in the Netherlands. See Gas Infrastructure Europe, 2024. *Aggregated LNG Storage Inventory*. https://alsi.gie.eu/ [accessed 9 December 2024]

[27] Wilhelmshaven and Stade in Germany, and Ravenna in Italy.

[28] This does not include the small-scale LNG regasification terminals in Finland, Sweden, Italy, Malta, and Gibraltar. It also does not include the LNG storage facility at Musel in Spain. See Gas Infrastructure Europe, 2024. *Aggregated LNG Storage Inventory*. https://alsi.gie.eu/ [accessed 9 December 2024]

[29] It is reported as 9 million tonnes of LNG in its liquid form, or 93.4 TWh of energy equivalent. At ratios of 1 m3 of LNG to 600 m3 of natural gas and 10.83 GWh per million m3 of natural gas, this equates to 5.41-5.85 Bcm. See Gas Infrastructure Europe, 2024. *Aggregated LNG Storage Inventory*. https://alsi.gie.eu/ [accessed 6 December 2024]

[30] Daily inventory at EU-27 regasification terminals is reported as 26.0-38.5 TWh from 4 December 2023 to 4 December 2024. See Gas Infrastructure Europe, 2024. *Aggregated LNG Storage Inventory*. https://alsi.gie.eu/ [accessed 6 December 2024]

to 7 Bcm.[31] This is particularly important to the UK, given its limited underground gas storage capacity (roughly 1.5 Bcm at Rough and another 1.5 Bcm at a range of small, fast-cycle facilities) relative to the size of the UK market (64 Bcm in 2023).[32]

Finally, **underground gas storage** plays a hugely significant role in balancing the substantial seasonal variation in European gas demand, allowing imports received in summer to be stored for consumption in winter. The EU-27 plus UK has underground storage capacity of around 108 Bcm[33] and has held stocks close to that level by late October in the period 2022-2024, in a market with annual demand of around 390 Bcm.

However, for the purpose of the present analysis, it is the ability to ramp withdrawals up and down on a daily basis that is so crucial for the maintenance of a balanced European gas market. The total daily withdrawal capacity of storage in the EU-27 is around 20,000 GWh/d (1,846 MMcm/d). Not only is this daily supply around 2.5 times higher than the daily sendout of all EU-27 LNG regasification terminals combined, but it can also be maintained for extended periods, and so complements the 'quick burst' of supply from LNG regasification terminals (where the storage tanks are being continuously replenished) at times of surging demand.

It is also worth noting that LNG regasification capacity and underground storage capacity are unevenly distributed across the European market. For example, of the 7,740 GWh/d of LNG sendout capacity across the EU-27, Spain (27.5 per cent) and France (19.1 per cent) account for 46.6 per cent of the total. Belgium, Germany, Italy, and the Netherlands account for a further 37.5 per cent between them, meaning that 84 per cent of EU-27 LNG sendout capacity is concentrated in six member states. Similarly, of the 20,000 GWh/d of underground gas storage capacity, Germany (34 per cent) and France (12.5 per cent), Italy (14.6 per cent), and the Netherlands (13.8 per cent), meaning that four EU member states account for 75 per cent of EU-27 storage daily withdrawal capacity.

While some European markets have access to substantial LNG sendout and storage withdrawal capacity (Germany, France, Netherlands, and Italy), in some European markets the balance is skewed towards LNG sendout (Belgium, Greece, Lithuania, and the UK) and in others storage is the dominant source of flexibility (Austria, Hungary, Czech Republic, Slovakia, and Latvia). Therefore, storage and LNG sendout are complementary both in terms of operational profile, but also in terms of geographical spread in the European market as a whole.

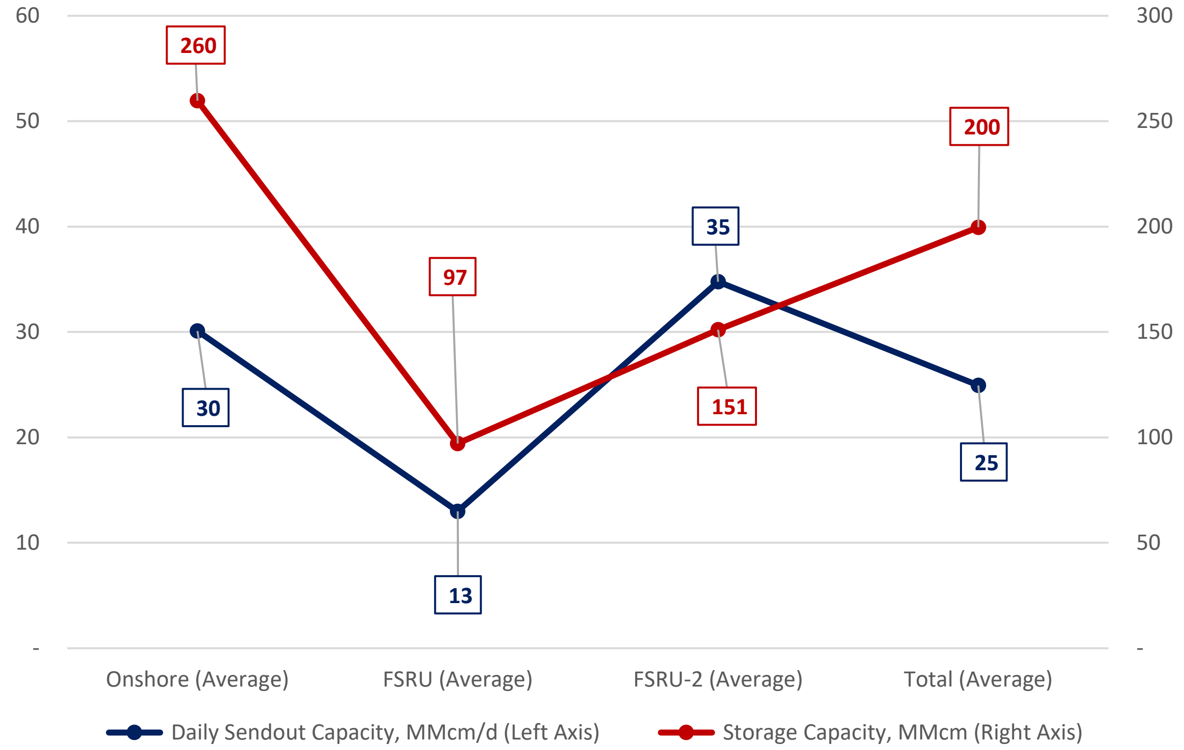
The value of supply-side flexibility from LNG sendout and storage withdrawal was illustrated in January and November 2024, as seen in Figure 13 and Figure 14. In January 2024, daily net storage withdrawals were ramped up from an average of 380 MMcm/d on 4-6 January to an average of 895 MMcm/d on 9-11 January. When LNG sendout is added to the storage withdrawal, three-day supply from those two sources combined rose from 720 MMcm/d on 4-6 January to 1,420 MMcm/d on 9-11 January. In November 2024, LNG sendout was already matching the fluctuation in weekday/weekend demand, while storage withdrawal followed the same weekday/weekend pattern at the same time as ramping up from a net withdrawal of 28 MMcm on 3 November to 590-600 MMcm/d on 21-22 November. It is this ability of storage withdrawals to provide a substantial and sustained ramp-up in supply, especially during winter, that so readily complements the almost instantaneously reactive variation in daily LNG sendout.

[31] The combined capacity of Dragon & South Hook at Milford Haven is 1.095 million m3 of LNG, plus 1.0 million m3 at Isle of Grain, which is set to expand to 1.19 million m3 by mid-2025. Data from Kpler LNG Platform [subscription required]

[32] UK government, 2024. *Energy Trends: Natural gas supply and consumption (ET 4.1 - quarterly).* https://www.gov.uk/government/statistics/gas-section-4-energy-trends [accessed 9 December 2024]

[33] 105 Bcm in the EU-27 and 3 Bcm in the UK

Figure 15: Average storage capacity (MMcm) and daily sendout capacity (MMcm/d) at EU-27 LNG regasification terminals



Source: J. Sharples (OIES). Raw data from Gas Infrastructure Europe Aggregated LNG Storage Inventory (ALSI). Calculations and graph by the author.

Note: This does not include the small-scale LNG regasification terminals in Finland, Sweden, Italy, Malta, and Gibraltar. It also does not include the LNG storage facility at Musel in Spain.

6. Conclusion

Many people learnt what *Dunkelflaute* meant in November 2024 when limited generation from wind (and solar) lasted for several days in Germany. This phenomenon happened in several countries around Europe at the same time, most of which also experienced relatively cold weather.

With gas-fired generation still the main source of flexibility for the European power system, a drop in wind generation over more than a few hours typically lifts the call on gas-fired power plants at the regional level (national pictures may differ). This, in turn, triggers peaks in gas demand, for which size and duration are hard to predict.

While the power sector used to be a source of short-term gas demand flexibility (primarily through coal to/from gas switching), this has now changed. In other words, gas use for power has become more volatile, somewhat less predictable and importantly, more resilient to peaking gas prices compared to just a few years ago.

In addition, *Dunkelflaute* also tends to happen during colder temperatures in Europe, at times of increased space heating requirements, a second simultaneous gas demand driver, magnifying gas demand peaks.

With deteriorating flexibility on the demand side (especially in the power sector), the European market requires growing flexibility on the supply side.

On the supply side, the ongoing decline in European gas production in general, and the loss of seasonal swing at Groningen in particular, has reduced the flexibility of European supply.

That situation has been exacerbated by the curtailment of Russian pipeline supply to Europe since 2022. That loss has been somewhat offset by the reduction in overall European gas demand and the increase in LNG supply, and in particular the flexibility of that LNG supply in terms of variable daily sendout.

As the experience of January and November 2024 have shown, Europe needs flexibility in gas supply that goes beyond seasonal variation in demand and must be able to cope with daily fluctuations in demand. That flexibility is provided by LNG import and regasification capacity and underground gas storage capacity working in tandem, in response to pricing signals that reflect surges in demand. In short, the market works.