July 2023



Quarterly Gas Review: Gas Markets in 2023 Tracking Key Metrics

## Introduction

In this third edition of the Gas Quarterly for 2023 we once again review the series of signposts that we outlined as key indicators of the global gas market during the year and also draw some conclusions about the outlook for prices and the supply-demand balance. In summary, our key conclusions are:

- Gas prices in Europe and Asia continue to reflect the benign state of the market thanks to the
  continuing impact of warm weather, a modest recovery in Asian LNG demand and continued
  availability of Russian pipeline gas and LNG, albeit at low levels. However, the situation remains
  tight and an upward price correction later in the year remains eminently possible if there is a shift in
  any of these three indicators or if there is an unforeseen supply outage elsewhere.
- Russian pipeline flows remain stable at around 70MMcm/d, implying an annual 22 Bcm (40 Bcm lower than 2022). We see no immediate threat to these flows, although the question of transit across Ukraine remains a concern, in particular because the current transit agreement expires at the end of 2024.
- Norwegian pipeline supply to Europe has played a major role in balancing the European market over the past 18 months, but maintenance that had been delayed is now taking place. The upward price movements that this has caused have been notable and underline the fact that the market remains fundamentally tight.
- Global LNG supply is only slightly higher than 2022 and the expected increase that we estimated at the start of year has not materialised due to some unexpected issues at various plants. However, this may be rebalanced over the second half of the year, especially if cargoes that are currently at sea get delivered more promptly.
- Asian LNG demand has only increased by 0.4 per cent year-on-year in the first six months of the year, although the significant uptick in Chinese imports in June may point to more aggressive growth in the second half of the year. However, the fact that Asian demand for H1 2023 was 5.5 Bcm lower than we had expected has clearly helped to ensure that Europe has been adequately supplied at relatively low prices.
- This plentiful supply of LNG has allowed European gas storage levels to remain high. Injection levels
  have not been as high as in a number of previous years, but the very high levels of gas in storage
  at the start of the injection season means that around 81 Bcm of gas is now in storage, well ahead
  of EU targets and at the top of the 2017-2021 range for this time of year. Indeed, it is possible that
  storage could be full well before the end of summer.



- If this happens, then use of Ukrainian storage may become an option again, as it was in 2020. Clearly, there are new risks that need to be borne in mind, but Ukraine has announced that it could make 10 Bcm of capacity available to Europe if required.
- European consumption remains consistently lower than 2022, with an average reduction of 14-16
  per cent year-on-year in each of the last several months. This would seem to suggest that the
  increased efficiency and behavioural changes that were encouraged by the EU and member states
  during 2022 are having an enduring impact and could signal a new lower base level for European
  gas demand.

Overall, then, the key signposts continue to point to a period of relatively low prices, although we should remember that the current price of around \$10/MMBtu is still very much at the top end of the range for the five years before the war in Ukraine began. Equally, we should also be mindful that this benign situation could be undermined by relatively small shifts in market dynamics, as was evidenced by the sharp increase in prices in mid-June that was caused by an unexpected extension of maintenance at one of Norway's three main gas processing plants. Looking at the months ahead, it is not difficult to paint a picture of a further dip in prices should European storage by full by early September followed by a sharp upward spike if the winter starts with cold weather. As such, volatility is likely to remain the main feature of the market during the rest of 2023.

In the second half of the Quarterly we include an essay on another interesting dynamic in the global LNG market, namely imports to South America. Ieda Gomes, a Senior Visiting Research Fellow at OIES, reviews the supply and demand balances in Brazil, Argentina and Chile over the past few years and highlights the dramatic swings in LNG imports that have been mainly caused by hydro availability but which have also resulted from the changing fortunes of gas production from the Vaca Muerta field in Argentina and from the gradual decline in gas supply from Bolivia. This latter trend could lead to more LNG imports in the short term, but increased indigenous supply in Argentina and Brazil, plus the completion of key pipeline infrastructure, could ease pressure in the medium term.

If you would like to discuss any of these issues further then please contact Mike Fulwood (mike.fulwood@oxfordenergy.org), Jack Sharples (jack.sharples@oxfordenergy.org), or leda Gomes (ieda.gomes@oxfordenergy.org).

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## 1. Revisiting our signposts for 2023

In this first section of the quarterly review, we include our regular review of some key drivers for the global LNG market as well as for the European and Asian gas markets.

#### **Gas prices**

The previous quarterly review (April 2023) noted the ending of the wide differentials between TTF and the LNG NWE price, as well as NBP and the JKM price, as congestion in the Northwest European regasification terminals and in the UK pipelines with the Netherlands and Belgium ended. The first half of 2023 saw a continuous decline in prices until at least early June, as the combination of weakening European demand, a lack of any meaningful recovery in Asian LNG demand, together with rising LNG supply, exerted downward pressure – see below for more discussion. The front-month contract at TTF dipped below \$7.50/MMBtu on several days in early June before rallying to \$11-13/MMBtu in the middle of the month, and then settling at around \$10-11/MMBtu for the remainder of June and early July, as illustrated in the graph below. As a result, May, June, and the first ten days of July saw TTF front-month prices average \$10.10-10.40/MMBtu.

## Figure 1.1: Benchmark gas prices (TTF, Argus LNG North-West Europe, and S&P Global JKM for North-East Asia), Front-Month, US\$/MMBtu



Source: Argus Media (LNG North-West Europe)<sup>1</sup> and Refinitiv/S&P Global (TTF and JKM)<sup>2</sup>

<sup>1</sup> Argus Direct (subscription required). <u>https://direct.argusmedia.com/</u>

<sup>2</sup> S&P Global/Refinitiv (subscription required).





Figure 1.2: TTF actual front-month prices (to 30 June 2023) and forward prices as at 20 January and 10 July 2023

Source: Data from Refinitiv (S&P Global). Graph by the author

Figure 1.3: S&P Global Japan-Korea Marker (JKM) actual front-month prices (to 30 June 2023) and forward prices as at 20 January and 10 July 2023



Source: Data from Refinitiv (S&P Global). Graph by the author



In order to highlight the shift in market outlook since the beginning of the year, it is instructive to compare the year-to-date average and rest of year forward curve average prices on 20 January 2023 and the current time of writing (10 July 2023).

On 20 January (the date of the first Quarterly Review of the year), the front-month TTF price was \$21.28/MMBtu and the year-to-date average was \$21.19/MMBtu. The average of the forward prices for the rest of 2023 was \$21.77/MMBtu, implying a full-year average price of \$21.65/MMBtu. As the graph above illustrates, this average was influenced by the forward curve rising gradually to around \$22/MMBtu for delivery in September 2023 and then more steeply to just under \$25/MMBtu for delivery in December 2023.

As noted above, the front-month price in the first ten days of July averaged some \$10.40/MMBtu and the year-to-date average (from 1 January to 10 July) was \$14.19/MMBtu. The average of the forward prices for the rest of 2023 is some \$13.55/MMBtu, implying a full-year average price of \$13.69/MMBtu. Compared to the forward curve as it stood on 20 January, the rise in Q4 is steeper, but the winter peak is lower, with the forward curve as of 11 July showing a December 2023 delivered price of \$16.90/MMBtu, up from \$10.00-12.00/MMBtu for much of summer 2023.

In Asia, the JKM front-month price on 20 January was \$22.82/MMBtu and the year-to-date average was \$27.25/MMBtu. The average of the forward prices for the rest of 2023 was \$21.36/MMBtu, implying a full-year average price of \$24.31/MMBtu. The forward curve held at around \$19-20/MMBtu throughout summer, before rising to around \$25/MMBtu by the end of the year.

The JKM front-month price on 10 July was \$12.06/MMBtu and the year-to-date average (from 1 January to 10 July) was \$14.77/MMBtu. The average of the forward prices for the rest of 2023 is \$14.22/MMBtu, implying a full-year average price of \$14.49/MMBtu. Unlike the forward curve on 20 January, the more recent forward curve rises from September 2023 onwards, having already jumped from under \$9.60/MMBtu in the first 20 days of June to around \$12/MMBtu in late June and early July.

The outlook at the beginning of the year was described by OIES as being benign, with the market seemingly pricing in all the good news on the supply and demand balance, with subdued European gas demand, Russia continuing to send pipeline gas via Ukraine, and only a modest recovery in Asian LNG demand, especially in China. It was also noted, however, that any one or more factors such as a sudden cold snap, industrial gas demand recovering in Europe, an interruption or cessation of gas flows through Ukraine, and/or a much stronger than expected recovery in gas demand in Asia, could easily lead to a sharp upward correction in wholesale gas prices, wiping out much of the decline since December 2022.

As of July, the forward curves suggest an even more benign outlook, with the implied full-year average TTF front-month price dropping by around one-third, from just under \$22/MMBtu (20 January 2023) to just under \$14/MMBtu (10 July 2023). The implied full year average JKM front-month price has also dropped by 40 per cent (almost \$10/MMBtu) from around \$24.30/MMBtu to just \$14.50/MMBtu. The reasons for this even more benign outlook are discussed in more detail below but reflect a combination of substantial volumes in European storage, European gas consumption remaining lower year-on-year, continued growth in global LNG supply, and a year-on-year decline in quarterly LNG imports in other markets.



## Russian pipeline supply to Europe

The second benchmark that we continue to follow is the physical flow of Russian pipeline gas to Europe (excluding Turkey). In Q2-2023, this flow continued the dynamic established since 1 September 2022: gas continues to flow via Ukraine and via the Turkish Stream pipeline to South-East Europe, while Nord Stream remains closed and flows via Belarus to Poland and Germany also remain at zero.



Figure 1.4: Russian pipeline supply to Europe (MMcm/d)





Figure 1.5: Daily flows of Russian pipeline gas to Europe in Q2, 2021-2023 (MMcm/d)

Source: Data from ENTSOG.<sup>4</sup> Graph by the author

<sup>3</sup> ENTSOG (2023). *Transparency Platform*. <u>https://transparency.entsog.eu/#/map</u> <sup>4</sup> ENTSOG (2023). *Transparency Platform*. <u>https://transparency.entsog.eu/#/map</u>



As the two graphs above illustrate, the daily flows of Russian pipeline gas to Europe in Q2-2023 were substantially lower than in the previous two years – just as they were in Q1-2023. In Q2-2023, the daily flows ranged between 18 and 79 MMcm/d, averaging 62 MMcm/d. A year earlier, daily flows ranged between 104 and 334 MMcm/d, at an average of 234 MMcm/d. The daily flows in Q2-2023 represent a slight increase on a quarter-by-quarter basis. In Q1-2023, the daily flows averaged 58 MMcm/d, within a range of 42 to 71 MMcm/d. It should be noted that in the period 5-11 June 2023, Russian flows were impacted by the closure of the Turkish Stream pipeline for planned maintenance. Outside that maintenance period, the minimum daily flow was 42 MMcm/d, at an average of 61 MMcm/d.

The previous edition of the OIES Quarterly Gas Review analysed the situation regarding Gazprom's contracts with European counterparties and concluded that the estimated 24.5 Bcma (equivalent to 67 MMcm/d) of annual contractual quantities (ACQ) still operational<sup>5</sup>, with a take-or-pay range of 60-105 per cent of that ACQ, would entail annual offtake between 14.7 Bcm and 25.725 Bcm. Hypothetically, if that annual offtake was evenly distributed across the 365 days of the calendar year, the daily offtake would range between 40 and 70 MMcm/d.

In reality, there is likely flexibility within the ACQs stated in the contracts to exceed the take-or-pay boundaries on a daily basis, as long as the volumes are made up over the course of the calendar year. However, that calculation does provide a reasonable expectation of Russian pipeline gas supply to Europe, given that (outside the maintenance period for Turkish Stream), total Russian pipeline flows to Europe have remained (just about) within that 40-70 MMcm/d range in the first half of 2023, as illustrated by dashed lines on the graph above.

The deliveries of Russian gas to Europe via Ukraine are exclusively delivered via Velké Kapušany on the Ukraine-Slovakia border. Russian gas deliveries via Ukraine to Hungary effectively halted on 31 January 2022, while Russian gas deliveries via Ukraine to Romania halted on 31 March 2022, and Russian gas deliveries via Ukraine to Poland halted on 26 April 2022. Slovakia also receives imports of non-Russian gas from the Czech Republic. The largest onward flow from Slovakia is to Austria, although small volumes are also delivered onwards to Hungary. From Austria, gas is delivered onwards to long-term contract holders in Croatia (PPD) via Slovenia in small volumes and to Italy (Eni) in larger volumes.

Given that the volume of physical flow from Austria to Italy has declined substantially, and that in May 2023, Eni announced that it had begun arbitration proceedings against Gazprom due to shortfalls in delivery volumes,<sup>6</sup> it appears that the majority of the Russian gas crossing the border from Ukraine to Slovakia is destined for long-term contract counterparties in Slovakia (SPP) and Austria (OMV).

The flow of Russian gas into South-Eastern Europe via Turkish Stream crosses the border into the EU at Strandzha-2 on the Turkey-Bulgaria border. Given that Gazprom supplies to Bulgaria were suspended at the end of April 2022 (due to Bulgargaz refusing to pay in rubles), Bulgaria now serves only as a transit state for Russian gas, as it is delivered onwards to long-term contract counterparties in Greece (DEPA, Mytilineos, and PPC), North Macedonia (MakPetrol), Serbia (Srbijagas), Bosnia & Herzegovina (Energoinvest), and Hungary (MVM).

The flow of Russian gas from Ukraine to Slovakia has remained relatively consistent since 21 February 2023, with flows of 32-38 MMcm/d on 126 out of 130 days up to 30 June. The Turkish Stream flows have been more variable, in the range of 18-43 MMcm/d, outside the maintenance on 5-11 June, which brought flows at Strandzha-2 down to zero. Since that maintenance, flows have rebounded to just around 35 MMcm/d on both routes, bringing total Russian pipeline supply to around 70 MMcm/d.

<sup>6</sup> Afansiev, V., 2023. Eni takes Gazprom to arbitration over gas supply cuts. *Upstream Online*, 9 May. <u>https://www.upstreamonline.com/production/eni-takes-gazprom-to-arbitration-over-gas-supply-cuts/2-1-1448127</u>

<sup>&</sup>lt;sup>5</sup> We calculate that the contracts that have neither expired, nor been suspended by the demand for payments in rubles, nor halted by the closure of the Nord Stream and Yamal-Europe pipelines are with the following European counterparties: OMV (Austria), PPD (Croatia), SPP (Slovakia), MVM (Hungary), DEPA, Mytilineos and PPC (Greece), MakPetrol (North Macedonia), Srbijagas (Serbia), and Energoinvest (Bosnia & Herzegovina).



Looking ahead, if this flow of around 70 MMcm/d is sustained in Q3-2023, that implies total deliveries of around 6.4 Bcm in Q3. For comparison, Russian pipeline supply in Q3-2022 was 9.3 Bcm. Given that total Russian supply in H1-2023 was 36.6 Bcm lower year-on-year (having declined from 47.4 Bcm in H1-2022 to 10.8 Bcm in H1-2023), an additional 2.9 Bcm year-on-year decline in Q3 would bring the total decline to 39.5 Bcm in the first nine months of 2023. Given that Nord Stream flows halted on 31 August 2022, and that since then gas has only flowed via Ukraine to Slovakia and via Turkish Stream to Bulgaria, a significant year-on-year decline is not expected in Q4-2023. Therefore, the total year-onyear decline in Russian pipeline flow to Europe in 2023 versus 2022 is expected to be around 40 Bcm.





Source: Data from ENTSOG.7 Graph by the author

One issue that remains on the horizon with regard to Russian pipeline gas supply to Europe is the expiry of the transit contract for the transportation of Russian gas across the territory of Ukraine. That contract expires on 31 December 2024. The contract is between Gazprom (as shipper) and Naftogaz, and Naftogaz then books capacity with the Ukrainian TSO, TSOUA.

On paper, the contract stipulates 109.6 MMcm/d (40 Bcma) of transit under a 'ship or pay' agreement, whereby Gazprom pays for daily capacity. In addition, the Interconnection Agreement between Gazprom (as Russian TSO) and TSOUA (as Ukrainian TSO) states that both sides must make 124.6 MMcm/d of capacity available on their shared border. In the past, TSOUA has auctioned this capacity, but Gazprom has not booked any since August 2021.

Until May 2022, gas flowed across the border from Russia to Ukraine at two interconnection points: Sudzha and Sokhranivka. In May 2022, TSOUA declared force majeure at Sokhranivka, stated that it had lost access to the cross-border metering station and nearby compressor station in the context of military conflict in the local area. Gazprom rejected that force majeure. Naftogaz subsequently reported that Gazprom was no longer paying the full amount for transit capacity and launched commercial arbitration. That issue is likely to complicate transit contract negotiations in 2024, along with the fact

<sup>&</sup>lt;sup>7</sup> ENTSOG (2023). Transparency Platform. <u>https://transparency.entsog.eu/#/map</u>





that Gazprom is currently flowing around 42 MMcm/d via Ukraine (volumes destined for both Europe and Moldova), and so may try to negotiate a smaller ship-or-pay volume. Naftogaz may counter with a demand for a higher tariff, and so the negotiations could unravel. The extent to which both parties need the transit flows to continue, and the willingness of both to make concessions to bring the negotiations to a successful conclusion, could also be influenced by the broader geopolitical context under which those negotiations could take place in summer 2024, which cannot be predicted at the time of writing.

#### Norwegian pipeline supply to Europe

Although not one of the benchmarks noted at the beginning of 2023 for regular review in the OIES Quarterly Gas Review, Norwegian pipeline supply to Europe (or more precisely, its curtailment due to maintenance) has played a significant role in the market balance of North-Western Europe in Q2 2023.

In the second half of 2021, Norwegian pipeline supply to Europe responded strongly to rising prices, being both higher than the 2017-2020 average from July onwards and higher than the 2017-2020 range from September onwards. This trend continued into 2022, where the volume delivered in summer (May to August) was significantly higher than the seasonal norm. However, by Q4 2022, flows were failing to keep up with the standards set in Q4 2021, and in February-March 2023, those flows were back to the levels of February-March 2021. That is, below the levels seen in both February-March 2022 and the 2017-2020 average for those months.





Source: Data from ENTSOG Transparency Platform & UK Government



It was in Q2 2023, however, that the flow of Norwegian gas to Europe showed its most significant yearon-year decline, especially in May and June. That decline may be attributed to a significant extent to maintenance work that curtailed three key elements of Norwegian supply: field production capacity; processing plant capacity; and receiving terminal capacity.

According to Gassco, curtailments related to maintenance brought production capacity down from an average of 334-338 MMcm/d in January-March 2023 to 314 MMcm/d (April), 271 MMcm/d (May), and 232 MMcm/d (June). That capacity is set to recover to around 300-310 MMcm/d in July and August, then dipping again to 264 MMcm/d in September, before finally regaining its full potential of around 345-355 MMcm/d in October-December 2023.

Norwegian gas processing capacity at its three main plants (Nyhamna, Kollsnes, and Kårstø) is around 330 MMcm/d. But maintenance reduced this capacity in Q2 2023 to monthly averages of 310 MMcm/d (April), 245 MMcm/d (May), and 228 MMcm/d (June). That capacity is expected to remain at 270-300 MMcm/d in Q3 2023, 320 MMcm/d in October, and not return to its full 330 MMcm/d until November. In addition to gas processed at Nyhamna, Kollsnes, and Kårstø, some volumes are delivered directly to the UK at St Fergus for processing there, which is why the capacity at Nyhamna, Kollsnes, and Kårstø combined is less than total Norwegian production capacity.

The terminals that receive Norwegian pipeline gas in the UK (at St Fergus & Easington), France (Dunkerque), Belgium (Zeebrugge), Germany/Netherlands (Emden & Dornum), and Denmark/Poland (Nybro) have a combined capacity of 380 MMcm/d. According to Gassco, from late May to late August, and again from 11 September to 1 October, this capacity is planned to be reduced to 330-355 MMcm/d, with a deeper curtailment down to 300 MMcm/d from late August to 10 September, including two days down to 260 MMcm/d (due to annual Emergency Shut Down [ESD] tests at Emden on 29-30 August and Easington on 4-5 September). The impact of the maintenance that has already taken place this year on the daily flows of Norwegian pipeline gas to Europe are illustrated in the graph below.



Figure 1.8: Daily Norwegian pipeline gas exports to Europe since 1 January 2023 (MMcm/d)

Source: Data from ENTSOG Transparency Platform & UK Government



For example, the closure of the Nyhamna processing plant from 20 May to 15 July for maintenance, and the curtailment of the St Fergus receiving terminal from 31 MMcm/d to 4.5 MMcm/d from 24 May to 14 August (with capacity set to fall to virtually zero thereafter, until 30 September) are weighing heavily on Norwegian exports to the UK. Nyhamna was expected back online on 21 June, but on 13 June, Shell announced that it would remain offline for an additional 24 days, with that news contributing to a roughly 25 per cent jump in front-month TTF prices from €30.58/MWh to €37.90/MWh (from \$9.65/MMBtu to \$12.07/MMBtu) between 12 and 14 June.

Elsewhere, pipeline exports to Dunkerque and Zeebrugge fell from 15 May onwards, while the flows to Germany (Emden & Dornum) experienced a gentler decline and flows to Denmark and Poland via the Baltic Pipe remained broadly stable.

Looking ahead to Q3 2023, it appears that Norwegian gas production and processing capacity for exports to the EU (from the Kollsnes and Kårstø processing plants and the gas fields connected to those processing plants) will be higher in the period 8 July to 26 August than they were in much of Q2, before experiencing another dip for most of September, as illustrated in the graph below. Later in Q3, having full access to the Langeled pipeline from the Nyhamna processing plant in late August and early September, at a time Norwegian supply to the EU from Kollsnes and Kårstø is curtailed, could see TTF rise to a premium over NBP and a consequent uptick in re-exports from the UK to the EU.



Figure 1.9: Daily combined production and processing capacity at Kollsnes & Kårstø (MMcm/d)

Source: Gassco, graph by the author<sup>8</sup>

<sup>8</sup> Gassco, 2023. Urgent Market Messages (UMM). *Gassco*, 3 July. <u>https://umm.gassco.no/</u>



## **Global LNG supply**

According to data from Kpler, global gross<sup>9</sup> LNG supply grew from 486 Bcm in 2020 to 504 Bcm in 2021 and 530 Bcm in 2022, meaning that year-on-year growth rates of approximately 4-5 per cent were seen in 2021 and 2022. In the first half of 2023, gross global LNG supply grew by 5.5 Bcm, which was notably lower than the year-on-year growth seen in H1 2020 (10 Bcm), H1 2021 (9 Bcm), and H1 2022 (13 Bcm). Indeed, it was the lowest H1 year-on-year growth in global LNG supply since H1 2016 (6 Bcm).

Figure 1.10: Year-on-year change in global gross LNG supply by source in H1 2022 and H1 2023 (MMcm)



Source: Data from Kpler.<sup>10</sup> Graph by the author

In geographical terms, the strong growth in supply from the United States seen in H1 2022 vanished in H1 2023, and for good reason. While US LNG exports benefitted from supply from Freeport LNG for most of H1 2022, operations were subsequently suspended from 6 June 2022 to 10 February 2023. Freeport had seen loadings in excess of 1.63 Bcm (1.2 million tonnes) per month in 7 of the 11 months prior to June 2022, but did not return to that level until May 2023, having ramped up steadily from 0.816 Bcm (0.6 mt) in March and 1.55 Bcm (1.14 mt) in April. The comparative year-on-year decline in supply from Freeport was offset by the ramp-up of supply from Calcasieu Pass, which launched in March 2022, and supplied 2.45 Bcm (1.8 mt) in H1 2022 and 6.28 Bcm (4.62 mt) in H1 2023. Therefore, the return of Freeport in mid-2023 will provide year-on-year growth in H2 2023 over H2 2022.

Elsewhere, the other notable year-on-year addition to supply in H1 2023 was from Europe, and specifically from the Snøhvit LNG liquefaction plant in Hammerfest. Having been shut down by a fire in September 2020, the plant returned to operation in June 2022. Therefore, having contributed zero

<sup>&</sup>lt;sup>9</sup> Some countries are simultaneously exporters and importers of LNG, such as Indonesia. While a gross figure accounts for all exports, a net figure would subtract imports from the export figure for all exporting countries. Note also that this figure includes only supply from export plants and does not include re-exports from import terminals.

<sup>&</sup>lt;sup>10</sup> Kpler LNG Platform (subscription required). <u>https://lng.kpler.com/</u>



supply in H1 2022, it returned to full capacity for much of H1 2023, although it was taken offline again by compressor failure for several weeks in May and process problems for two weeks in June.<sup>11</sup>

In the January Quarterly Review, it was noted that there weren't many brand-new projects coming on this year, but despite that, another robust year for supply growth was expected. The only new start-ups were thought to be in Congo, Senegal/Mauritania (Tortue) and in Indonesia (Tangguh Train 3) and these seemed likely to be towards the end of the year. Overall, LNG export capacity was projected to rise by around 29 Bcm in 2023, with some 13 Bcm coming from the ramping up of plants which came on in 2022 – Sabine Pass Train 6, Calcasieu Pass, Coral FLNG (Mozambique) and Portovaya (Russia). An additional 6 Bcm could also come from Freeport resuming production and reaching full output in Q2. A full year of production can also be expected from Norway and fewer feedgas issues in Trinidad (where output is already ramping higher) and Nigeria.

On this basis, in the January Quarterly Review we forecast that global LNG supply could be 1.4 Bcm per month higher year-on-year in Q1, 2.2 Bcm per month higher in Q2, 2.8 Bcm per month higher in Q3, and 3.8 Bcm per month higher in Q4. Fulfilling that forecast would result in global LNG supply of 47.4 Bcm per month in Q1 2023, 45.2 Bcm per month in Q2 and Q3, and 49.1 Bcm per month in Q4.

As we have progressed through 2023, there have been some changes to the supply outlook, with extended maintenance planned for the Sakhalin project in Russia, continuing issues with a train in Malaysia, a lack of recovery in feedgas in Nigeria and a further shutdown for Prelude. This has reduced the likely growth in LNG export capacity to some 20 Bcm for 2023. In the figures below we compare the monthly actual growth in LNG supply against our initial forecast for 2023 and also against 2022 supply. Here it is notable that actual supply in February, March, and June was well below our start-of-year forecast, but higher year-on-year in every month except January and March.





Source: NexantECA World Gas Model, OIES Estimates, Kpler

<sup>&</sup>lt;sup>11</sup> Gassco, 2023. Urgent Market Messages (UMM). Gassco, 3 July. <u>https://umm.gassco.no/</u>





Figure 1.12: Cumulative monthly LNG supply (Bcm per month)

Source: NexantECA World Gas Model, OIES Estimates, Kpler

The cumulative monthly global LNG supply in H1 2023 was some 5.5 Bcm (2 per cent) higher than in 2022 but below our start-of-year forecast by 5.6 Bcm (2 per cent). Output from Sub-Saharan Africa (mainly Nigeria), the United States, and the UAE have been somewhat lower than anticipated and Russia has also been lower.

However, it should be noted that LNG supply is measured as the cargoes arrive at the importing terminals – the imports basis from Kpler. If supply was measured as the volumes leaving the exporting terminals – the exports basis – then the measured growth in supply would be much bigger. The increase in cumulative monthly supply (exports basis) in H1 2023 was some 8.4 Bcm per month, compared to a measured rise of 5.5 Bcm (imports basis). Depending on the destination of the LNG exports, the voyage time can be anything from a few days or a week to between 4 and 6 weeks. LNG leaving an exporting terminal, therefore, could easily take a month to arrive at the importing terminal, which is what we are measuring here. Eventually the growth in the export-basis measure of supply and the import-basis measure of supply should match. This will either be achieved by the import-basis measure increasing to meet the export-basis measure or a much slower growth in exports over the next few months.



## Asian LNG demand

The January Quarterly Review noted that what happens to Asian LNG demand is key in the development of the global LNG market. 2022 was the first year that total Asian LNG imports declined. Chinese LNG imports were only just above 2019 levels, losing almost two years of growth. India's imports were back to 2017 levels and Pakistan's LNG imports fell back to 2018 levels. In China, flat domestic demand combined with rising production and pipeline imports to curb LNG demand. India, Pakistan, and Bangladesh also saw declines as demand was hit by rising prices and, in some cases, sellers opting not to deliver under contracts. Japanese LNG demand continued its downward trend of the last 5 years or so – LNG imports are now lower than before the 2011 Fukushima incident. There were some growth areas though, especially the Southeast Asian countries, which were less exposed to the very high spot prices thanks to the prevalence of oil-indexed long-term contract supply.

In 2023, China finally returned to modest growth in May and June, but India has been weak, and Japan especially has seen much lower demand with a weak economy and higher nuclear output. With Pakistan and Bangladesh also remaining weak the only strong growth areas have been in Southeast Asia.





Source: Data from Kpler. <sup>12</sup> Graph by the author

<sup>12</sup> Kpler LNG Platform (subscription required). <u>https://lng.kpler.com/</u>





Figure 1.14: Year-on-year change in Asian LNG demand (smaller importers) in year-to-date (H1) 2022 and 2023

Source: Data from Kpler. <sup>13</sup> Graph by the author<sup>14</sup>

In terms of the year-on-year comparison, monthly Asian LNG imports were lower year-on-year in January, March, and May, but higher year-on-year in February, April, and June. Only in January and June were Asian LNG imports higher than our start-of-year forecast. In cumulative terms, Asian LNG demand in the first six months of 2023 was just 0.7 Bcm (0.4 per cent) higher than in the first six months of 2022, having been 1.5 Bcm lower year-on-year in the period January-May.

Chinese LNG imports were lower year-on-year from December 2021 to February 2023, and were 0.8-0.9 Bcm per month (12-15 per cent) higher year-on-year in March, April, and May. More substantial year-on-year growth of 2.1 Bcm (34 per cent) was recorded in June. This uptick in Chinese LNG imports in June ensured that Asian LNG imports were higher year-on-year in H1 2023.

Overall, the fact that global LNG supply in the first half of 2023 grew by 2 per cent (5.5 Bcm) year-onyear while Asian LNG demand grew by just 0.4 per cent (0.7 Bcm) year-on-year, combined with yearon-year declines in LNG imports elsewhere, provided the additional supply that enabled European<sup>15</sup> LNG imports in H1 2023 to grow by 5.8 Bcm (8 per cent) year-on-year.

In the context of pipeline supply from North Africa and Azerbaijan that was flat year-on-year, Norwegian pipeline supply that was 9 Bcm (15 per cent) lower, and Russian pipeline supply that was 36.6 Bcm (77 per cent) lower year-on-year, the combination of lower overall gas demand (-34 Bcm) and higher LNG imports (+5.8 Bcm) provided the fundamentals that underpinned the substantial decline in European prices between January and June. At the same time, the combination of growing supply and weak Asian LNG demand underpinned the parallel decline in JKM prices in the same period.

<sup>&</sup>lt;sup>13</sup> Kpler LNG Platform (subscription required). <u>https://lng.kpler.com/</u>

<sup>&</sup>lt;sup>14</sup> Note that Indonesia and Malaysia are net LNG exporters, but still import LNG

 $<sup>^{\</sup>rm 15}$  EU-27 plus the UK





Figure 1.15: Average monthly Asian LNG demand (Bcm per month)

Source: NexantECA World Gas Model, OIES Estimates, Kpler

Figure 1.16: Cumulative monthly Asian LNG demand (Bcm per month)



Source: NexantECA World Gas Model, OIES Estimates, Kpler



#### European gas storage

Europe began Q2 2023 with stocks of 58.7 Bcm, 31.2 Bcm higher year-on-year, slightly above the previous record for that date (57.2 Bcm on 1 April 2020), and far higher than on 1 April in 2018, 2019, 2021, and 2022, as illustrated in the graph below.

Europe shifted to consistent net injections on 7 April, with stocks climbing to 63 Bcm (+29 Bcm yearon-year) by the end of the month. Stockbuild in April 2023 (4.7 Bcm) was notably slower than in April 2018-2022, when stocks grew between 7.3 Bcm and 9.2 Bcm, with the marked exception of April 2021, when stocks fell by 0.3 Bcm due to colder than usual weather and higher heating demand in Europe.

In May, the stockbuild (9.4 Bcm) was 4.5 Bcm less than in May 2022 and 0.8 Bcm less than in May 2020, but 1.6 Bcm more than in May 2021. The relatively rapid storage injections in May 2022 may be attributed to the fact that Europe had acquired the political drive to accumulate storage stocks in the aftermath of the Russian invasion of Ukraine, in the context of fears that Europe would lose access to Russian pipeline gas and must be prepared for winter 2022/23.



Figure 1.17: European gas storage stocks (Bcm)

Source: Data from Gas Infrastructure Europe (GIE) Aggregated Gas Storage Inventory. <sup>16</sup> Graph by the author

Between 1 June and 1 July, European stocks grew by 8.8 Bcm, from 73.0 Bcm to 81.8 Bcm. For comparison, June stockbuild in 2018-2022 ranged from 10.2 Bcm to 13.2 Bcm, with the exception of 2020 (8.1 Bcm). As a result, June 2023 may also be characterised as a relatively slow month for stockbuild, in comparison with recent years.

Overall, in Q2 2023, Europe managed to raise stocks from 58.7 Bcm on 1 April to 81.8 Bcm on 1 July, implying a net storage injection of 23.1 Bcm. For comparison, net injections of between 34.7 Bcm and 36.3 Bcm were made in Q2 in 2018, 2019, and 2022. Q2 net injections were slower in 2020 (28.2 Bcm) and 2021 (20.9 Bcm). That places Q2 2023 stockbuild roughly 11-13 Bcm lower than in 2018, 2019, and 2022, and 5 Bcm lower than in 2020, but 2 Bcm higher than in Q2 2021 (which was afflicted by a lack of net injections in April 2021).

The stockbuild in Q2 2023 was achieved despite significantly lower year-on-year Russian pipeline supply (especially given that Nord Stream was still fully operational in April and May 2022), and

<sup>&</sup>lt;sup>16</sup> GIE (2023). Aggregated Gas Storage Inventory. <u>https://agsi.gie.eu/data-overview/eu</u>



Norwegian supply curtailed by maintenance. This lower pipeline supply was expected, while LNG imports had already risen substantially by Q2 2022, leaving only limited scope for further increases.

The previous edition of the OIES Quarterly Gas Review noted that net injections of 41.4 Bcm between 1 April and 30 September would be sufficient to bring stocks back to 100 Bcm (close to the full capacity of 104.7 Bcm) and offered the reminder that net injections in the period 1 April to 1 October in the years 2017-2022 ranged from 42.8 Bcm to 66.7 Bcm. This means that even record low summer injections in 2023 will be sufficient to bring stocks back to close to full capacity.

Europe has a favourable base from which to begin its efforts to reach the European Commission target of filling storage to 90 per cent of capacity (94.2 Bcm) by 1 November 2023.<sup>17</sup> In terms of the intermediate storage filling targets set by the European Commission, stocks on 1 July 2023 (81.8 Bcm) already surpassed the Commission target for 1 July by 33.4 Bcm and have already surpassed the 76.6 Bcm target for 1 September 2023.<sup>18</sup> Based on the June average daily net injection rate of 293 MMcm/d, the 90 per cent target could be reached by mid-August, and stocks of 100 Bcm by early September.



Figure 1.18: European storage capacity, historic stocks, and EU storage targets (Bcm)

Source: Data from Gas Infrastructure Europe (GIE) Aggregated Gas Storage Inventory. <sup>19</sup> Targets published by European Commission on 24 November 2022. Graph by the author

As storage moves towards full capacity, the prospect of short-term oversupply could put downward pressure on front-month hub prices in Europe. However, injection rates could be slowed considerably by the maintenance-led curtailment of Norwegian pipeline supply in late August and early September, and by a reduction in send-out from LNG regasification plants as suppliers await the seasonal pickup in gas demand, especially in northern Europe.

<sup>&</sup>lt;sup>17</sup> European Commission (2022). Commission sets trajectories for filling gas storage in 2023. *Press Release*, 24 November. <u>https://commission.europa.eu/news/commission-sets-trajectories-filling-gas-storage-2023-2022-11-24-0\_en</u>

<sup>&</sup>lt;sup>18</sup> Commission Implementing Regulation (EU) 2022/2301 of 23 November 2022 setting the filling trajectory with intermediary targets for 2023 for each Member State with underground gas storage facilities on its territory and directly interconnected to its market area, <u>https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32022R2301&qid=1669911511115</u>

<sup>&</sup>lt;sup>19</sup> GIE (2023). Aggregated Gas Storage Inventory. <u>https://agsi.gie.eu/data-overview/eu</u>



#### Ukrainian gas storage: an option for Europe?

A final issue regarding European gas storage is the potential use of gas storage facilities in western Ukraine to overcome the potential shortfall in EU storage capacity in summer 2023. At present, Ukraine has 322 TWh (31 Bcm) of gas storage capacity,<sup>20</sup> of which 17 Bcm is at the Bilche-Volytsko-Uherske facility in western Ukraine, close to the city of Lviv and Ukraine's border with Slovakia.<sup>21</sup> On 7 April 2023, Ukraine's gas storage operator, UkrTransGaz (a subsidiary of state-owned Naftogaz), announced that it had 'successfully completed its certification under new EU gas storage regulations'.<sup>22</sup> Also in early April, the Naftogaz CEO, Oleksiy Chernyshov, visited the European Commission in Brussels, where he announced that Ukraine would make 10 Bcm of storage capacity available to Europeans that wished to use Ukraine's gas storage facilities.<sup>23</sup> In early June, the Financial Times reported that EU officials were in talks with both national governments and financial institutions regarding the provision of 'adequate insurance coverage' for the storage of gas in Ukraine.<sup>24</sup>

Ukraine already has a scheme in place for European companies to store gas in Ukraine. Since April 2019, under the 'Customs Warehouse' scheme, European companies may import gas into Ukraine without paying customs duties, and store it for up to three years. At any point up to that three-year limit, they may either withdraw the gas from storage and re-export it without paying any customs duties, or they may pay the customs duty and sell the gas into the Ukrainian market. Since January 2020, TSOUA (the Ukrainian TSO) has offered discounted entry-exit tariffs for gas being transported between the Ukrainian border and Ukrainian gas storage facilities.

This issue was analysed by OIES in May 2020, in the context of a supply-long European market that was also on track to fill its gas storage facilities by the end of summer, albeit under very different market conditions.<sup>25</sup> We returned to the issue in March 2021, to examine how the gas stored in Ukraine had been used, and concluded that the majority of the volume stored in Ukraine had been eventually sold into the Ukrainian market and only a limited volume re-exported. We concluded that the key factors were the differentials between prompt prices in Ukraine and neighbouring EU member states, the discounted entry-exit tariffs offered by TSOUA, and the entry-exit tariffs levied by neighbouring TSOs. To make gas withdrawn from storage in Ukraine competitive against gas withdrawn from storage in Central European EU member states (for sale in those EU member states), the spread between prompt prices in Ukraine and its neighbours needed to be significant.<sup>26</sup>

In the current market context, wide seasonal spreads between near-term and forward prices make storage an attractive proposition. Based on the current forward curve, if a trader is able to purchase gas at currently prevailing prices and lock in the hedge for sale in Q1 2023, this is likely to be enough to overcome the additional costs of storing gas in Ukraine. However, until the question of insurance coverage is resolved, market participants are likely to prioritise utilization of gas storage facilities in neighbouring Slovakia and Hungary, and nearby Austria and the Czech Republic. As storage facilities

 <sup>&</sup>lt;sup>20</sup> AGSI, 2023. Gas Infrastructure Europe Aggregated Gas Storage Inventory – Ukraine. https://agsi.gie.eu/data-overview/UA
 <sup>21</sup> UkrTransGaz, 2023. We Store Energy for Your Safety. February 2023.

https://utg.ua/en/img/menu/company/docs/2023/eng\_16-02.pdf (see pages 12-13)

<sup>&</sup>lt;sup>22</sup> Naftogaz, 2023. UkrTransGaz becomes the second gas storage operator in Europe to successfully pass certification under new EU rules – Oleksiy Chernyshov. *Press Release*, 7 April. https://www.naftogaz.com/en/news/ukrtransgaz-became-thesecond-gas-storage-operator-in-europe

<sup>&</sup>lt;sup>23</sup> Simon, F., 2023. Ukraine offers 10 Bcm of gas storage to Europe for next winter. *Euractiv*, 5 April.

https://www.euractiv.com/section/energy-environment/news/ukraine-offers-10-bcm-of-gas-storage-to-europe-for-next-winter/ <sup>24</sup> Hancock & Tani, 2023. Brussels woos banks to provide guarantees for gas stored in Ukraine. *Financial Times*, 2 June. https://www.ft.com/content/31a314d5-5c4f-47c1-920a-73ecc4f2c0f1

<sup>&</sup>lt;sup>25</sup> Pirani, S., & Sharples, J., 2020. European gas storage: backhaul helps open the Ukrainian safety valve. *Oxford Energy Comment*, 18 May. European gas storage: backhaul helps open the Ukrainian safety valve

<sup>&</sup>lt;sup>26</sup> Pirani, S., & Sharples, J., 2021. Ukraine-EU Gas Market Integration: Short-Term Progress, Long-Term Challenges. Oxford Energy Insight, 25 March. https://www.oxfordenergy.org/publications/ukraine-eu-gas-market-integration-short-term-progresslong-term-challenges/



in those countries are filled, we could see greater use of Ukrainian storage facilities later in the summer and into autumn. The potential for this would be increased if EU gas storage facilities are effectively filled by early September, and Europe also experiences a repeat of the very mild autumn weather conditions that prevailed in September, October, and the first half of November 2022, when net injections into EU gas storage facilities continued to 15 November. Ukraine as a whole has injection capacity of 2,755 GWh/d (265 MMcm/d).<sup>27</sup> If roughly half of this is made available, approximately 7 Bcm could be injected in sixty days in September and October.<sup>28</sup>

In the present geopolitical context, any interruption in gas transit via Ukraine would prevent Ukrainian gas buyers from purchasing gas from European counterparties on the basis of backhaul ('virtual reverse'), meaning that prices in the Ukrainian market would likely surge above those in neighbouring EU countries (even Slovakia, which relies on Russian gas delivered via Ukraine). Holding additional physical stocks in Ukrainian gas storage facilities would improve Ukraine's security of supply, and even in such a negative scenario, withdrawing the gas from storage would likely prove profitable for those European companies storing gas in Ukraine while simultaneously curbing a pricing spike in Ukraine.

According to a Naftogaz press release issued on 10 July, foreign companies are already using Ukraine's gas storage facilities.<sup>29</sup> As of 10 July, Ukraine's total gas storage stocks<sup>30</sup> amounted to 70.94 TWh (6.83 Bcm), up from 48.3 TWh (4.65 Bcm) at the start of the injection season on 17 April.<sup>31</sup> The question of whether insurance guarantees materialize, and whether European companies make use of Ukrainian gas storage in Q3 (and possibly Q4) is an issue to which we will return in the next Quarterly Gas Review.

## Total supply to Europe (implied consumption)

By gathering together data for European production, pipeline imports, LNG imports, and net storage withdrawals, it is possible to calculate Europe's 'implied gas consumption'. This overall total supply (implied consumption) is presented in Figure 1.19 below.

Since the publication of the previous edition of the Quarterly Gas Review (on 17 April 2023), Europe has decidedly moved into the summer period, with net storage injections every day since 15 April. The daily average total supply in June (643 MMcm/d) was just 70 MMcm/d lower than in May (713 MMcm/d). By contrast, between April and May, total supply fell by 296 MMcm/d, as illustrated in the graph above.

The consistency of the year-on-year decline in implied gas consumption in recent months is particularly notable. The year-on-year decline in March (-14 per cent) was followed by similar declines in April (-13 per cent), May (-14 per cent), and June (-16 per cent). In the year to date (1 January to 30 June), the year-on-year decline in implied consumption was -15 per cent, and -25 per cent versus H1 2021.

<sup>&</sup>lt;sup>27</sup> Gas Infrastructure Europe, 2021. Gas Storage Map. https://www.gie.eu/wp-

content/uploads/filr/3997/GIE\_STOR\_2021\_A0\_1189x841\_FULL\_TOPO\_B\_111.pdf

<sup>&</sup>lt;sup>28</sup> In 2018, the daily injection capacity at Bilche-Volytsko-Uherske alone was reported by Gas Infrastructure Europe as 1,265 GWh/d – or 122 MMcm/d. See Gas Infrastructure Europe, 2018. *Gas Storage Map*.

https://www.gie.eu/download/maps/2018/GIE\_STOR\_2018\_A0\_1189x841\_FULL\_FINAL.pdf

<sup>&</sup>lt;sup>29</sup> Naftogaz, 2023. International customers actively storing gas at Ukraine's UGS facilities. *Press Release*, 10 July.

https://www.naftogaz.com/en/news/foreign-customers-place-gas

<sup>&</sup>lt;sup>30</sup> This figure refers to working gas, and excludes cushion gas that must remain in the storage facilities

<sup>&</sup>lt;sup>31</sup> AGSI, 2023. Gas Infrastructure Europe Aggregated Gas Storage Inventory – Ukraine. https://agsi.gie.eu/data-overview/UA





Figure 1.19: Total supply to Europe<sup>32</sup> (MMcm/d)

Source: Data from ENTSOG<sup>33</sup>, Eurostat<sup>34</sup>, Kpler<sup>35</sup>, and Gas Infrastructure Europe<sup>36</sup>. Graph by the author

Setting aside injections into and withdrawals from storage, the combined supply from production, pipeline imports, and LNG imports in H1 was relatively consistent for several years: 234 Bcm in 2020, 237 Bcm in 2021, and 239 Bcm in 2022, before falling markedly to 194.5 Bcm in 2023.

Therefore, the year-on-year decline in total supply in H1 2022 relative to H1 2021 (that is, implied consumption, which includes Q1 storage withdrawals and Q2 storage injections) was primarily due to a combination of lower withdrawals in Q1 and higher injections in Q2, while supply from production and imports remained relatively stable. In H1 2022, supply from production and imports grew by 2 Bcm, but the net withdrawal from storage of 28 Bcm in H1 2021 was replaced by a net injection of 4 Bcm – a swing of 32 Bcm year-on-year.

By contrast, in H1 2023, the year-on-year decline in total supply (including Q1 storage withdrawals and Q2 storage injections) was driven by lower supply from production and imports, which fell by around 45 Bcm. This was only partially offset by Q2 storage injections that were lower year-on-year, as the net injection of 4 Bcm in H1 2022 was replaced by a net withdrawal of 6 Bcm in H1 2023 – a storage swing of 10 Bcm. This is illustrated in Figure 1.20 below.

<sup>&</sup>lt;sup>32</sup> Europe is defined as the EU, UK, Switzerland, and non-EU Balkan states. It excludes Turkey and treats Norway as an external supplier to that European market. Note that 'Total Supply' refers to production plus pipeline imports plus LNG sendout plus net storage withdrawals

<sup>&</sup>lt;sup>33</sup> ENTSOG (2023). Transparency Platform. <u>https://transparency.entsog.eu/#/map</u>

<sup>&</sup>lt;sup>34</sup> Eurostat (2023). Supply, transformation, and consumption of gas - monthly data. <u>https://ec.europa.eu/eurostat/databrowser/view/nrg\_cb\_gasm/default/table?lang=en</u>

<sup>&</sup>lt;sup>35</sup> Kpler LNG Platform (subscription required). <u>https://lng.kpler.com/</u>

<sup>&</sup>lt;sup>36</sup> GIE (2023). Aggregated Gas Storage Inventory. <u>https://agsi.gie.eu/data-overview/eu</u>





Figure 1.20: Supply to Europe (EU+UK) from production + imports vs net supply from storage in H1 (Bcm)

Source: Data from ENTSOG<sup>37</sup>, Eurostat<sup>38</sup>, Kpler<sup>39</sup>, and Gas Infrastructure Europe<sup>40</sup>. Graph by the author

In the previous edition of the OIES Quarterly Gas Review, it was noted that the decline in European demand appeared to be structural, rather than a temporary phenomenon that was wholly attributable to mild weather during the winter heating season. The data for Q2 2023 would appear to support that conclusion. Looking ahead to Q3, price uncertainty could play a role in keeping industrial gas demand at its present lower levels, in particular due to a possible reticence of industrial consumers to restart operations at plants that are currently suspended or operating at partial capacity. Although prevailing prices in June fell back to 'the expensive side of normal', in contrast to the dramatic price rally of summer 2022, concerns that the market could tighten significantly in the coming winter offers the prospect of prices potentially rising rather rapidly in a tight winter market, as a result of any surge in demand or curtailment of supply.

On the supply side, Q3 has already seen the launch of new regasification capacity at Piombino (Italy)<sup>41</sup> and a further addition is expected at Le Havre (France) in September, while the quarter will end with a momentous event: the closure of the Groningen gas field. On 23 June, the Dutch government announced that production at the field would cease on 1 October, although the production capacity would be held 'in reserve' for a further 12 months. The Dutch government plans for the Zuidbroek quality conversion unit to be fully commissioned on 1 October, which will increase the capacity of the Netherlands to convert imported high-calorie gas into low-calorie gas comparable to that previously produced at Groningen.<sup>42</sup>

<sup>&</sup>lt;sup>37</sup> ENTSOG (2023). Transparency Platform. <u>https://transparency.entsog.eu/#/map</u>

<sup>&</sup>lt;sup>38</sup> Eurostat (2023). Supply, transformation, and consumption of gas - monthly data.

https://ec.europa.eu/eurostat/databrowser/view/nrg\_cb\_gasm/default/table?lang=en

<sup>&</sup>lt;sup>39</sup> Kpler LNG Platform (subscription required). <u>https://lng.kpler.com/</u>

<sup>&</sup>lt;sup>40</sup> GIE (2023). Aggregated Gas Storage Inventory. <u>https://agsi.gie.eu/data-overview/eu</u>

<sup>&</sup>lt;sup>41</sup> The first full-sized commercial cargo offloaded on 7 July

<sup>&</sup>lt;sup>42</sup> Fielding, N., 2023. Dutch Groningen gas production to end on 1 October. *Argus Direct*, 23 June.



## Conclusions

The global gas market in Q1 2023 was characterised by falling prices, underpinned by lower year-onyear demand in major importing markets (Europe, China, India, and Japan). That dynamic shifted in Q2 2023, with curtailment in Norwegian pipeline supply to Europe contributing to a price rally in mid-June as storage injection rates slowed, while China's return to year-on-year growth in LNG imports in Q2 was sufficient to lift Chinese LNG imports for H1 2023 into year-on-year growth as well.

Having said that, European gas consumption remains structurally lower year-on-year and while Chinese LNG imports in the first six months of 2023 (44.9 Bcm) were higher than in the same period in 2022 (41.9 Bcm), they are still not yet back at the 2021 level (53.1 Bcm).

In our previous Quarterly Review, we noted that despite the apparently benign outlook for the immediate short-term, as expressed in declining prices, the market remains finely balanced. This was exemplified by the TTF price rally in June, when the market reacted strongly to the news that Norwegian maintenance and supply curtailment would last somewhat longer than originally anticipated.

Looking further ahead, it is quite possible that while the latter part of Q3 could be characterised by oversupply and downward pressure on prices in Europe, the limitation of 105 Bcm of storage capacity – and that capacity being fully utilized – does mean that the advantage of being supply-long in Q3 can only be carried forward through the winter to a limited extent, while highlighting the potential utility of storing gas in western Ukraine. Europe was fortunate to experience a mild winter in 2022/23, which allowed storage injections to continue to mid-November and limited the rate of withdrawal in Q1 2023. If the winter of 2023/24 were to prove to be somewhat colder – perhaps akin to the conditions experienced in Q1 2021, when cold weather in North-East Asia pulled LNG cargoes away from Europe and the heavy European drawdown of storage stocks effectively 'balanced the global LNG market', we could see prices rise rather rapidly. Indeed, even absent such a dramatic scenario, the prevailing forward prices and the promise of a significant seasonal spread continue to encourage European storage injections.

In the wider global LNG market supply is growing, albeit more slowly than expected. However, Asian LNG demand is also showing limited growth, only just rising above 2022 levels in the first half of 2023, and well below the forecast increase in 2023. The consequence of this, together with the weaker European demand, has meant that extra LNG was available for Europe to absorb, allowing storage to fill and putting downward pressure on prices. Prices have now stabilized somewhat as the market remains tight, but if storage does fill fully by mid-September, we could see further weakness in prices until winter demand picks up in the northern hemisphere.

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## 2. The fluctuating pattern of LNG imports in South America

#### Introduction

This article provides an overview of the key markets in the region, their supply/demand fundamentals and the short-term outlook for their gas markets, while also highlighting the extremely volatile nature of the demand for LNG imports.

There are four LNG importing countries in South America: Argentina, Brazil, Chile and Colombia, with 10 LNG importing terminals: one in Colombia, two in Chile, two in Argentina and five in Brazil (with another three under construction). However, Colombia's LNG imports are kept to a minimum, with the Cartagena FSRU utilized minimally to complement hydro power shortages. There is also gas pipeline trade in the Southern region, through 12 pipelines connecting Argentina to Chile, Brazil and Uruguay, and two pipelines connecting Bolivia to Argentina and Brazil.

Chile, Argentina and Brazil are the most significant LNG importers. Chile has long term LNG contracts with Shell and Total, while Argentina issues annual tenders via state-controlled ENARSA. In Brazil, Petrobras purchases LNG on spot/annual contracts to complement its power plant commitments, whereas the flexible integrated LNG-power plants in Porto do Açu and Porto do Sergipe have long term contracts, respectively with BP and Ocean Energy (Exxon/QP).

In 2021 there was a record import of LNG in South America of around 17.8 Bcma, although this was then followed by a sharp decrease in 2022, to 8.7 Bcma (Figure 1). This reflects the fact that LNG imports are heavily seasonal, depending on hydro power availability in Chile and Brazil, and residential and power winter peak demand in Argentina (Figure 2.1).



#### Figure 2.1: Annual LNG imports in South America

Source: IEA database





Figure 2.2: Seasonal demand patterns South America

Source: IEA database

LNG imports increased in 2021 due to a number of key factors:

- Economic recovery after the COVID pandemic which led to increased electricity consumption
- Prolonged drought in Brazil, the worst in 90 years, and to a lesser extent in Chile and Argentina, forcing the dispatch of gas-fired thermal power plants
- Reduced domestic gas supply in Brazil due to maintenance of a gas platform
- Slow recovery of domestic production in Argentina, as a consequence of supply chain issues during COVID

Conversely, LNG demand went down in 2022, due to the following factors:

- Very high and unaffordable LNG prices, in the wake of the Ukraine-Russia conflict, with LNG supplies directed to Europe
- High level of hydro reservoirs in Brazil, with above average rain, with lower dispatch of gas-fired thermal power plants
- Slight recovery of domestic gas production in Argentina coupled with additional imports from Bolivia at lower prices than LNG imports



## Argentina

Argentina has some of the largest shale gas reserves in the world, approximately 308 Tcf, according to the US Energy Administration (EIA).<sup>43</sup> Nevertheless, the country is both an exporter and importer of natural gas. LNG is imported in the winter season (May-August) to cover big swings in residential and power demand. There are two LNG terminals in Argentina which facilitate these imports, both being FSRUs operated by Excelerate: Bahia Blanca (6.2 Bcm regas capacity), located 640 km south of Buenos Aires, and Escobar (6 Bcm regas capacity), located on the Paraná River, 77 km from Buenos Aires.

Meanwhile natural gas is exported mostly in the summer months to Chile, Uruguay and occasionally to a Brazilian power plant on the Brazil-Argentina border. As Vaca Muerta (VC) shale gas supplies have started to ramp-up due to more efficient operations, the country has increased its exports to Chile in the west, but a lack of capacity in the domestic pipeline system has meant that it could not replace LNG imports in the east.

In 2019, there had been a considerable increase in domestic supply, and as a result the country shut down the Bahia Blanca LNG terminal and kept the Escobar terminal as supply insurance. However, the COVID pandemic slowed-down upstream activity, with a considerable decrease in output in 2020. Production is recovering now, albeit not yet to the same level of 2019 (Figure 2.3), with the main problems being the poor state of the economy and the lack of pipeline capacity to transport gas to Buenos Aires. However, in 2022, facing a potential LNG bill of \$4 billion, Argentina took the following bold steps to reduce further pressure in the depletion of foreign currency:

- 1. ENARSA<sup>44</sup> agreed with Bolivia to increase winter supplies, albeit at a much higher price than before, \$20/MMBtu (compared to \$29-40/MMBtu of LNG)
- 2. ENARSA decided to build the first phase of Nestor Kirchner pipeline (NKPL), with government funding

As a result, the commissioning of the 583-km NKPL, connecting the province of Neuquén Neuquén (where VC is located) to Salliqueló, south of Buenos Aires, will allow for 11-20 MMcm/d<sup>45</sup> of gas to reach the largest demand region in Argentina in the second half of 2023, allowing LNG imports to be reduced. Furthermore, Phase 2 of this project, consisting of a 562 km pipeline and the reversion of the pipeline connecting Bolivia to Argentina, will add a total of 40 MMcm/d and will potentially allow Argentina to export to Brazil via the existing Bolivia pipeline infrastructure and also to the northern part of Chile.

<sup>&</sup>lt;sup>43</sup> <u>https://www.eia.gov/todayinenergy/detail.php?id=40093</u>

<sup>&</sup>lt;sup>44</sup> ENARSA: Energia Argentina, a state-owned company in charge of international supply and infrastructure

<sup>&</sup>lt;sup>45</sup> The installation of two compression stations will increase gas flows from 11 to 20 MMcm/d





#### Figure 2.3: Argentina natural gas supply mix

Source: Author's calculation based on Brazil's Ministry of Mines and Energy

Figure 2.4 displays the highly seasonal pattern of natural gas imports by Argentina, driven by the reasons noted above, and shows the role of Escobar LNG and Bolivian pipeline imports in providing stability during peak winter months.



Figure 2.4: Argentina seasonal import patterns

<sup>46</sup> https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp-consulta.php?tipo=importaciones



However, Bolivian production has been declining over recent years, so exports to Argentina have fallen to an average of 5.9 MMcm/d in the period January to April 2023 compared with 9.3 MMcm/d for the same period in 2022. In April 2022 imports from Bolivia were 11.4 MMcm/d falling to 5.2 MMcm/d in April 2023. Therefore, the completion of the NKPL pipeline in 2023 is a key factor in allowing Argentina to reduce LNG imports and cope with reducing availability of supply from Bolivia.

Figure 2.5 summarises the overall picture and shows the supply and demand balance in 2022. There was an increase in domestic production vs 2021 but total supplies were down due to high LNG prices.





Source: Brazil Ministry of Mines and Energy and ENARGAS

These high prices were a particularly critical issue because Argentina's foreign reserves are under great pressure, falling from \$44.6 billion at year-end 2022 to \$37.6 billion on 31 March 2023,<sup>47</sup> with the country's LNG import bill in 2022 causing a big dent in its finances. In 2023, ENARSA still needs to tender for 44 LNG cargoes to guarantee winter supplies, even though it expects to inaugurate the first phase of NPKL in July, and this could become a crucial issue ahead of the presidential elections in October 2023.

<sup>47</sup> https://economic-research.bnpparibas.com/html/en-US/Argentina-again-4/14/2023,48479



	LNG cargoes	Average price (USD/MMBtu)	Total imports (USD million)
2023 (tendered)	44	15.3	1310
2022	41	29.2	2885
2021	56	8.33	1095
2020	24	2.96	140
2019	27	5.92	330
2018	56	7.92	1086
2017	68	5.73	968
2016	79	5.46	1023

#### Table 1: LNG imports and value

Source: https://www.energia-argentina.com.ar/index.php/gas/gnl/

In order to counter this cash outflow Argentina is ramping up exports to Chile, primarily in summer, because producers need to generate hard currency payments, although a lack of storage facilities in Argentina and insufficient transportation capacity to the Buenos Aires region are also drivers of export sales. Figure 2.6 provides an overview of Argentina's regional pipeline exports whilst Figure 2.7 displays the import/export balance in Argentina.





<sup>48</sup> https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp-consulta.php?tipo=exp\_dentro

The contents of this paper are the author's sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its Members. 30





Figure 2.7: Argentina natural gas import and export balance

Source: Author calculation based on ENARGAS<sup>49</sup>

However, the situation should improve over the next 12 months as the commissioning of the first phase of the NKPL pipeline in 2023 will have a substantial impact on Argentina's LNG imports in 2024, which may fall to as low as 1.54 Bcm (compared to 3.31 Bcm in 2021). Phase 2 of NKPL (which has not yet been tendered) could then significantly reduce the imports of gas from Bolivia from 2025 onwards. However, if a lack of supply means that Bolivia has to halve its supply to Argentina in 2024 (which is eminently possible), then it may be necessary to import LNG at similar levels to those imported in 2023, at least for one more year.

The impact of the NKPL pipeline on Argentina's LNG imports in 2023 will be minimal because most of the cargoes that have been purchased are due to be delivered in the May-July period before the pipeline comes online. As a result, only three cargoes due for delivery in August may be impacted, totalling around 193,000 m3 of LNG. However, if Phase 2 of NKPL is completed by 2024-2025, then if this is coupled with a reversion of the Bolivia to Argentina North pipeline, exports from Argentina to Brazil via the existing Bolivia-Brazil pipeline could become a possibility and could transform Argentina's energy trade balance.

LNG	Bolivia	Total
3.37	4.63	8.0
-1.83	0	-1.83
1.54	4.63	6.17
3.55	2.32	6.17
-0.45	-4.63	-5.08
1.09	0	1.09
	LNG 3.37 -1.83 1.54 3.55 -0.45 1.09	LNGBolivia3.374.63-1.8301.544.633.552.32-0.45-4.631.090

Table 2. Algentina, inibact of $M(t) \in O(t) \in O(t)$ and Dollvia inibolity
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Source: Enarsa presentation at MEGSA webinar<sup>51</sup>

<sup>49</sup> https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp.php

<sup>50</sup> Finance not yet agreed

<sup>51</sup> https://www.youtube.com/watch?v=Ef22Jf0X4Yc&feature=youtu.be



## Brazil

Brazil's domestic production has overtaken Argentina's but unfortunately most of the gas is associated with oil that is produced in deep water (more than 2000 meters in depth) up to 300 km from the coast. In 2022, operators reinjected more than 50 per cent of total gas production, citing various reasons: the need to optimize oil production, the high CO2 content in some fields, the high cost of offshore pipelines, and uncertainties about the growth of firm gas demand.

There are currently five LNG terminals in operation, and three under construction:

Three Petrobras-owned terminals, primarily built to supply power plants: Guanabara, State of Rio de Janeiro (11 Bcm); Pecem, State of Ceara (8.2 Bcm), and Bahia, State of Bahia (5.2 Bcm), the latter has been leased to Excelerate for a period of three years;

- Two private-owned terminals, both LNG-power integrated projects: GNA, owned by BP/Prumo, State of Rio de Janeiro (7.7 Bcm) and Porto Sergipe, State of Sergipe, owned by New Fortress Energy/EBrasil (7.7 Bcm);
- Terminals under construction, aiming to supply large industrial consumers and gas distribution utilities: TRSP, owned by Compass Energy, Sao Paulo state (5.2 Bcm), with commissioning planned for H2 2023; State of Santa Catarina and Barcarena, State of Para, both owned by New Fortress Energy with 5.5 Bcm capacity.

Figure 2.8 shows the supply and demand balance in 2022 and the role of imported gas.



#### Figure 2.8: Brazil: gas supply balance 2022

#### Source: Brazil Ministry of Mines and Energy

As shown in Figure 2.9, in 2021 Brazil imported 9.54 Bcm of LNG, and it is interesting to note that Brazil was also a large importer (7.27 Bcm) in 2014 when there was also a combination of a dry season (meaning lack of hydro for power generation, which typically covers 70% of the mix) and a presidential election. Clearly, LNG imports were used in these years as part of an election strategy to ensure continued electricity supply.





Figure 2.9: Brazil: evolution of natural gas supply mix

Source: Brazil Ministry of Mines and Energy

As mentioned previously, the drought in 2021 required the dispatch of gas and oil power plants and because most of these plants do not have long term supply agreements this resulted in the import of increased amounts of LNG. Two integrated LNG and power plants (GNA and Porto Sergipe) were also dispatched in 2021 by the National Operator of the System, further increasing demand for LNG imports. It is also worth noting the increasing role of intermittent wind and solar in the generation mix, and the decreasing share of thermal plants (gas, oil, nuclear and coal). This further complicates the picture for gas imports, but going forward is likely to mean that if the dry season phenomenon starts to be repeated on a more regular basis, then gas will continue to play a balancing role both for hydro but also to back up other renewable energy sources.

The volatility of the situation was clearly visible in 2022, when renewable energy accounted for 92 per cent of the generation mix (see Figure 2.10) and demand for LNG imports fell dramatically as a result.





Figure 2.10: Brazil: power generation by source

Source: Adapted from https://www.ccee.org.br/o/ccee/documentos/CCEE\_1068101

Figure 2.11 helps to explain the overall trends in natural gas demand in Brazil, with firm demand (industrial, NGV and residential/commercial) progressing very slowly, whereas power demand fluctuates around the availability of hydro and more recently the intermittency of wind and solar.

The slow growth of firm demand is a result of the stagnation of the industrial sector in Brazil, high enduser prices (dictated by Petrobras's pricing policy, high taxes and distribution margins), and low penetration of gas into the transportation and distribution grids. In Brazil, for example, there is very little heating demand in the residential sectors, in sharp contrast to the situation in Argentina.





Figure 2.11: Brazil: evolution of natural gas demand

Source: Brazil Ministry of Mines and Energy

From an upstream perspective there are three new projects which are expected to increase the availability of domestic offshore gas by 52 MMcm/d, and therefore potentially to reduce the need for LNG imports. These are:

- Rota 3, south of Rio de Janeiro: 18 MMcm/d of production was expected in early 2023, but commissioning has been delayed by at least one year
- SEAP, northeast Brazil: 18 MMcm/d of supply expected by 2028-2029
- BMC-33, north of Rio de Janeiro: 16 MMcm/d of supply expected by 2027-2028

The above projects are likely to be used to compensate for the expected decline in Bolivian gas and other domestic supplies, and to a certain extent will reduce LNG imports for power plants.

By 2030, domestic supplies are expected to reach 77 MMcm/d<sup>52</sup>, whereas firm demand is projected to reach 85 MMcm/d, of which 10 MMcm/d is expected to be firm power demand with the rest from other sectors. The demand from non-firm power plants is estimated at 37 MMcm/d. Therefore, under those assumptions, LNG demand by 2030 is estimated as follows based on two different import scenarios from Bolivia:

- Zero supply from Bolivia
  - LNG demand of 8 MMcm/d (2.9 Bcma) to meet baseload firm demand, if there is a wet season, such as in 2022/2023
  - LNG demand of 43 MMcm/d (15.7 Bcma) in case of a very dry season such as in 2021
- Bolivia supply at 10 MMcm/d
  - LNG demand is 0-3 MMcm/d (up to 1.1 Bcma), if there is a wet season, such as in 2022/2023
  - o LNG demand of 33 MMcm/d (12 Bcma) in case of a very dry season such as in 2021

<sup>&</sup>lt;sup>52</sup> Brazil, Empresa de Pesquisa Energetica, PDE 2032



## Chile

Chile has negligible domestic gas production in the South and most of its gas supply is imported LNG and pipeline gas. The country extends 4270 km south to north and there are no gas transportation pipelines connecting the regions. There are two onshore LNG terminals, Mejillones (2 Bcm) in the North, and Quintero (5.5 Bcm) in the Central Region. Chile is connected to Argentina via nine pipelines; five of them serve the methanol complex (Methanex) in Punta Arenas, southern Chile, whereas the other four are located in the Central and North regions. Overall, the pipelines have a maximum import capacity of 13.2 Bcma, but gas flows fluctuate depending on demand, and supply availability from Argentina.<sup>53</sup> Total gas demand was 5.95 Bcm in 2021, with power generation accounting for 51 per cent,<sup>54</sup> as seen on Figure 2.12.



#### Figure 2.12: Chile: Natural gas consumption by sector

Source: IEA database

Natural gas installed power capacity totalled 5016 MW in 2021, which contributed 18 per cent of electricity generation;<sup>55</sup> coal installed capacity is around 5000 MW but accounted for 34 per cent of the total generation. Chile is investing heavily in renewable energy and phasing out coal, as a result the existing gas power plants will support the transition by displacing coal and providing back-up to renewables. By 2024, Chile's power generators are expected to decommission 1730 MW of coal fired power plants, requiring additional dispatch of gas power plants; this is an opportunity to import additional gas/LNG volumes of 1-2 Bcma depending on the dispatch factors.

In 2022, the consequences of the Ukraine-Russia conflict on European gas supply led to LNG cargoes destined for Chile being diverted to Europe.<sup>56</sup> Therefore, in the short-term, Chile has had to import larger volumes of pipeline gas from Argentina, as seen in Figure 2.13.

<sup>&</sup>lt;sup>53</sup> https://www.oxfordenergy.org/publications/will-argentina-become-a-relevant-gas-exporter/

<sup>&</sup>lt;sup>54</sup> IEA database

<sup>&</sup>lt;sup>55</sup>https://obtienearchivo.bcn.cl/obtienearchivo?id=repositorio/10221/32492/1/BCN\_Matriz\_energetica\_electrica\_en\_Chile.pdf

<sup>&</sup>lt;sup>56</sup> According to information provided by Chile's Natural Gas Association





Figure 2.13: Chile: LNG and pipeline imports

Source: Author calculation based upon IEA database and ENARGAS statistics

Furthermore, as Argentina ramps up its shale gas production in the Vaca Muerta field, it is exporting additional volumes to Chile. In (South American, southern hemisphere) summer 2022, Argentinian exports reached record volumes of 12 MMcm/d, although winter supplies are still limited to 2-3 MMcm/d. Summer pipeline imports are continuing to progress in 2023 (Figure 2.14), because Argentinian producers are keen to diversify export sales towards international markets, including Chile, in order to be paid in USD as Argentina continues to impose stringent limitations on the export of foreign currency. However, when Phase 1 of the NKPL pipeline is completed, it will be possible to increase Vaca Muerta supplies to Argentina's domestic market, so it is unclear whether any winter exports to Chile will continue. This could mean that Chile is forced to rely on the LNG market more than it might have hoped in years to come.





<sup>&</sup>lt;sup>57</sup> https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp.php



# Conclusions - Key factors impacting LNG to South America imports in the next 3-5 years

The most likely outcome from the analysis above is that Brazil, Argentina and Chile will need less LNG imports in the years to come, but there are a number of key uncertainties linked to domestic production in Argentina and Brazil and to supply from Bolivia.

#### Argentina: Successful completion of NKPL phase 2

Although it is certain that NKPL Phase 1 will be commissioned in H2 2023, Phase 2 is still uncertain because Argentina has not yet secured funding for the project, which requires investment in excess of \$2 billion, of which \$560 million will be financed by CAF.<sup>58</sup>

There is also a risk of declining production at Vaca Muerta due to uncompleted drilling as a result of a lack of currency available to pay service companies, despite the field seeing its second highest number of fracking phases ever in May 2023.<sup>59</sup> According to Rystad,<sup>60</sup> two wells recently stopped due to lack of parts for directional drilling, which has been an ongoing problem since 2022.

If Phase 2 of NKPL is completed in 2024, Argentina is expected to continue importing 1.09 Bcm of LNG for peak winter demand. If Phase 2 is not completed in 2024, LNG imports might reach 1.54-3.55 Bcm, with the higher end of the range occurring if Bolivia halves its pipeline supplies to Argentina post 2025.

#### Brazil: Further delays of Rota 3 commissioning in 2024

The offshore pipeline and gas processing plant was due to be commissioned in 2022 but was then postponed to early 2024. There is no expected impact on LNG imports because Rota 3 supplies would replace Bolivian gas and some LNG in specific power plants. Therefore, if Rota 3 is delayed, Brazil will depend on Bolivia delivering its committed supply of 20 MMcm/d in 2024. If Rota 3 is further delayed to 2025, when Bolivian total supply is expected to fall by 10 per cent, then a shortage of 1.8-2 Bcm might be met by Brazil importing more LNG or by Bolivia reducing its supply commitments to Argentina.

#### Brazil: Availability of hydro power at levels similar to 2022

The risk of drought has been minimized in 2023, with the result that there is no need for dispatch of the LNG integrated plants, and minimal dispatch from non-integrated plants, according to information provided by industry players in Brazil and the electricity regulator, ANEEL. This scenario is likely to be repeated in 2024, as the reservoirs are at a comfortable level and rains are expected in late 2023.<sup>61</sup> However, if these forecasts fail to materialize fully, LNG demand might reach around 3 Bcm, which was the level of imports pre-Covid.

#### **Bolivia: Further decline in production**

Gas production in Bolivia has been declining steadily since 2015 due to a lack of investment in exploration and an unattractive fiscal regime (Figure 2.15). According to S&P Global, by 2030 gas production might drop to 23 MMcm/d<sup>62</sup>, whereas Wood Mackenzie expects production to decline to 21 MMcm/d by 2025, with exports potentially halting totally by 2030 if there is no significant push in exploration and new discoveries<sup>63</sup> and if domestic demand is kept at around 13MMcm/d. According to Wood Mackenzie, in 2021, the Bolivian government released an exploration plan, yet only three of the twenty wells announced were drilled and they have been dry.<sup>11</sup>

<sup>58</sup> Corporación Andina de Fomento

<sup>59</sup> https://www.megsa.ar/App/home

<sup>&</sup>lt;sup>60</sup> https://www.aspen901.com/2023-05-19/paralizan-pozos-en-vaca-muerta-por-las-trabas-a-las-importaciones-20508/

<sup>&</sup>lt;sup>61</sup> https://www.novacana.com/noticias/brasil-bandeira-verde-energia-2024-diretor-aneel-310323

<sup>&</sup>lt;sup>62</sup> Presentation at the Sao Paulo Federation of Industries on 17/04/2023

<sup>&</sup>lt;sup>63</sup> https://www.woodmac.com/press-releases/bolivian-gas-production-to-decline-faster-than-expected-exports-to-brazil-and-argentina-to-cease-by-20303/





Figure 2.15: Bolivia: natural gas gross production and export profile

Source: Brazil Ministry of Mines and Energy.

The decline and potential halt in Bolivia's production will impact Brazil and Argentina, but if the two countries commission the proposed domestic gas pipelines in the next 2-6 years, it is likely that the region will rely less on LNG. This is also compounded by sluggish growth in firm demand, as a consequence of economic constraints. If the domestic pipelines are commissioned by the expected timelines, LNG imports post 2027-2028 might fall to around 6-8 Bcm/y,<sup>64</sup> to supply seasonal power demand, except in cases of severe droughts such as in 2021. In this situation, Brazil would suffer most, requiring LNG supplies as high as 12 Bcm/year by 2030.

Ieda Gomes, Senior Visiting Research Fellow, OIES

<sup>&</sup>lt;sup>64</sup> These figures do not include supply to the integrated LNG to power projects in Rio de Janeiro and Sergipe, which are not integrated to the gas transportation system and are underpinned by 25-years LNG SPAs