



A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

**GAS TO 2030  
TRANSITION, SUPPLY RISK AND MARKET UNCERTAINTY**

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## INTRODUCTION

### **Bill Farren-Price**

Divergent paths for global gas demand raise critical questions about the medium-long term (10-25 year outlook) demand trajectory for a fuel that retains a critical role in power, industry and residential and commercial use. For policy-makers in industrialized economies, the future of the gas industry will be closely linked to the effort to decarbonize energy systems while maintaining affordability and trying to ensure security of supply. In Europe, gas demand has contracted in 2024 for the third year running since the 2022 Ukraine crisis erupted, with a strategic renewables build-out crimping demand for gas in the power sector and industrial demand eroded by the lingering impact of the 2022 price spike, which devastated many gas-intensive industries. China and other Asian consumers on the other hand have seen a healthy advance in gas consumption, buoyed most recently by lower prices and rebounding GDP growth.

This gas-focused issue of the Oxford Energy Forum surveys the outlook for gas across four key areas. First, it offers a snapshot of global gas markets and dives into two less well-known regional markets in South America, where rainfall for hydro-power is one of the biggest determinants of gas demand and the East Mediterranean, where Egyptian gas and power demand growth continue to soak up regional supply, limiting broader export potential. Second it addresses the gas production outlook in very different settings: Norway, a crucial pipeline supplier to Europe; the US, from where much of the LNG supply growth to 2030 will derive; and Turkmenistan, the fading star of central Asian gas as it faces Russian competition in its key export markets. Third, the critical focus on regulation of energy transition policies attempts to measure the success of European decarbonization and methane regulation, prospects for future gas use in north Asia amid tightening emissions limits there and the broader political and geopolitical landscape's influence on the industry. Finally, the issue investigates Chinese and Indian gas policy - two major and fast-growing gas markets - and investigates the challenges of financing gas projects in Africa.

The thematic takeaways that tie these explorations together is that the outlook for global gas demand is increasingly divergent geographically and developmentally; that the market has worked in balancing demand with supply but destabilizing risks lurk in the form of policy-making and geopolitics; that regulation and climate policy are squeezing gas markets but possibly in an unsustainable manner; and that upstream prospects are more dependent on access to finance and regional market dynamics than the global price benchmarks that dominate the headlines.

The first article looks at global LNG, where the industry is experiencing a relative calm before the surge of new liquefaction starts to emerge in the 2025-2028 period. As Jack Sharples writes, the main challenge beyond 2030 will be whether and how swiftly the US Department of Energy unfreezes non-FTA licenses for new US LNG projects and whether there is any realistic prospect for the slate of new Russian liquefaction projects to come onstream as long as western sanctions remain in place.

The following articles dive into two regional gas markets in South America and the East Mediterranean. In the former, Ieda Gomes charts the impact of the El Niño phenomenon on rainfall, hydropower and the resultant need for LNG in Argentina, Brazil, Chile and Colombia in 2023-24. In the case of Argentina, the country's worldclass shale gas project at Vaca Muerta has alleviated the need for LNG imports, while healthy Brazilian rainfall alleviated LNG import requirements despite spiking gas demand during heatwaves. Colombia on the other hand experienced the opposite – low rainfall and hydro levels requiring a surge in LNG imports through late 2023 and early 2024. The article makes clear the impact of less predictable global weather patterns and rainfall on gas demand and the subsequent requirement for LNG imports.

The East Mediterranean market is smaller, more concentrated and highlights the challenge of emerging energy dependencies between gas-rich Israel and its neighbours Egypt and Jordan with Cyprus still on the sidelines and limited options for accessing international markets. Julian Bowden explores the instability of these relationships and the extent to which Egypt's mothballed LNG projects represent realistic egress options for regional gas developers as Egypt struggles to contain surging domestic gas demand. The article underlines the risk to gas exports from those producing countries who underestimate long-term domestic demand growth, as Egypt has done.

The second theme is upstream supply with a focus on Europe's key pipeline supplier Norway, followed by a look at the growth from the US shale patch which continues to drive associated gas supply growth and finally Turkmenistan, which is struggling to win fresh upstream investment as its key central Asian and China markets face the certainty of pent-up Russian gas supply offered to those buyers at competitive prices.

First, Norway, has seen a recent wave of upstream investment in the North Sea aimed at maximizing volumes available to European buyers, following a shift in its export strategy from a pre-crisis focus on swing capacity to a post-crisis emphasis on contracted reliable volumes. This focus on secure volumes, which has also involved a reduction in gas allocated for reservoir



support in mature oil fields and instead directed to exports, has been rewarded by the market. Norwegian gas export revenues rose fourfold from the 2016-2020 average to an average NOK 950bn (\$100bn) in 2021-23.

The following article looks at US shale production. Given the US dominant position in the build-out of global LNG over the last decade, we have included an article by Trisha Curtis contextualizing recent oil supply growth in North America. Associated gas is a significant component of US gas production, so the growth in liquids output is directly relevant to the gas available to existing and future US liquefaction projects.

Finally, looking to central Asia, we have also dived into Turkmenistan's supply outlook, in particular the challenge of further building out exports in central Asia and China given Russia's long gas position after the 2022 loss of most of its European export market. Landlocked Turkmenistan has opted for creative export solutions including gas swaps with Iran and added value strategies including building new gas-driven fertilizer and petrochemical projects.

The third theme for this issue is policies and regulation of energy transition. Bill Farren-Price discusses the shifting political drivers for climate policy and the failure so far in 2024 of right-of-centre parties to derail existing climate policies in major elections, in part perhaps because centrists and progressives have subsumed climate policies into affordability and security of supply policies. Yet away from party politics, geopolitical conflict and its potential resolution meanwhile present an oft-overlooked influence on supply. As long as Middle East tensions remain high, the outlook for gas supply is less certain. Yemen's Houthis have proven the effectiveness of low-cost disruption to key shipping routes, while a combination of contract expiry and a recently more dynamic Ukraine battlefield pose risks to remaining Russian gas flows into Europe.

The following articles focus on regulation, starting with Katja Yafimava, who assesses the EU's plans to decarbonize the gas network, based on twin decarbonized methane and green hydrogen grids. She asks whether the regulatory framework will be up to the challenge of facilitating such a landmark shift, whether in terms of flexibility given the uncertain nature of future hydrogen markets; or whether the changes to the gas market will undermine supply security.

A reality check on Europe's hydrogen strategy follows, in which Martin Lambert and Aliaksei Patonia run the rule over Europe's policy aimed at increasing energy self-reliance through hydrogen and renewables. They report that progress on green hydrogen is well short of targets, in terms of production, infrastructure and demand.

The final piece in this trilogy of European regulation is focused on the EU methane regulation. Maria Olczak and Jonathan Stern dissect the impact of looming tighter environmental standards for LNG supply chains feeding the EU under the bloc's Methane Regulation.

The following article moves away from Europe as Graeme Bethune assesses the outlook for LNG imports into Japan, South Korea and Taiwan, three key north Asian markets who are committed to decarbonizing power but are well behind in terms of implementing renewables and other low carbon options.

Finally, Mike Fulwood pans out to focus on long-term global transition scenarios and the role of gas in this changing energy landscape. He reviews recent modelling of three long-term scenarios for gas demand, including a net zero with CCS view and a fragmented scenario, where various regions proceed towards decarbonization, but progress is far from consistent globally.

The last section focuses on gas in developing countries, starting with China. Michal Meidan charts the strong growth in Chinese gas demand but also explains how policy has sometimes hindered the development of the sector by over-promoting gas and causing price spikes. This explains the wide ranges in Chinese gas demand forecasts – gas demand will grow but will remain bookended by the sharp renewables build-out and the domestic abundance of coal, she concludes.

A second article on gas by Shuai Wang and Ji Chen dives deeper into Chinese gas regulation and how the state has dealt with unbundling the gas verticals that have historically dominated.

Moving west, Nitin Zamre examines the historical scope of energy liberalization in India, assessing the scope for gas-led growth and the price sensitivity that appears to be a major constraint.

Finally, Mostefa Ouki discusses the challenges of financing new gas upstream in sub-Saharan Africa, calling for an improvement in market design and regulation as the key to unlocking a potential doubling in regional gas consumption by 2050.



## RIDING THE NEXT WAVE OF LNG – OPPORTUNITY AND UNCERTAINTY

### **Jack Sharples**

In the first half of 2024, the global LNG market was relatively finely balanced between supply and demand. Global gross exports (including re-exports) and global net imports (net of re-exports) grew by 1 per cent year-on-year, in the context of growing LNG demand outside Europe (+17.7 Bcm year-on-year) and the ongoing decline in European imports (-15.0 Bcm year-on-year in H1 2024). This tightening of the global LNG market underpinned the counter-seasonal price rally in European and Asian LNG benchmark prices between late February and early June 2024.

The near-term outlook for the rest of 2024 is one of very limited new supply, with just three new liquefaction projects launched this year: Congo FLNG loaded its first cargo in February 2024, Altamira (Mexico) achieved first LNG production in July, which suggests that its first LNG cargo loading is imminent, and Greater Tortue Ahmeyim (Senegal-Mauritania) is expected to load its first cargo in Q4 2024. Those three projects have a combined nameplate capacity of 4.5 Mtpa (just over 6 Bcma). Given the launch dates of these projects, which mean they will not operate for the whole of 2024, they will add 1.2 Bcm of liquefaction capacity for 2024 as a whole.

Therefore, the near-term outlook is one of limited supply growth, growing demand outside Europe and the year-on-year decline in European imports balancing the market. This situation will not change until the next wave of new supply reaches the market between 2025 and 2030. In this context, it is worth addressing several key questions regarding this growth in global LNG liquefaction capacity:

1. What volume of new capacity will be added, and how will the growth be spread across the period 2025-2030? How much of that capacity is certain to be launched (post-FID and currently under construction) and how much is 'planned' (pre-FID with construction not yet begun)?
2. Where is that new capacity located?
3. Are there any further projects that have been proposed but not yet added to the 'planned' category, which could be added?
4. What are the challenges that could yet cause some of the new projects to be delayed or cancelled?

### **New liquefaction capacity in 2025-2030**

As the figures in this chapter illustrate, the expected growth in global LNG liquefaction capacity is relatively evenly spread across the period, with two distinct surges in 2025-2026 and 2028-2029, with somewhat lower growth in 2027 and 2030. In the period 2025-2029, most new capacity will be from projects that have taken a Final Investment Decision (FID) and are currently under construction, while the growth in 2030 will be from projects that have not yet taken FID but are likely to do so.

These figures account for both the quarter in which a project is planned for launch and the ramp-up of those projects over the quarters following launch. As can be seen in Figure 1, the year-on-year change also accounts for the decline in liquefaction capacity at existing infrastructure. Between 2026 and 2030, 21.3 Bcma of liquefaction capacity is set to come offline, of which 70 per cent is in Algeria and at the North-West Shelf liquefaction plant in Australia. These declines reflect the decommissioning of liquefaction capacity in line with declining feedgas availability.

### **Where is the new capacity located?**

As Figure 3 illustrates, the majority of growth in global LNG liquefaction capacity between 2024 and 2030 will be in the United States and Qatar, with a small amount of growth in Australia. These three countries are the three largest LNG exporters, each with exports of 105-120 Bcm in 2023. The world's fourth-largest LNG exporter, Russia, exported 44 Bcm in 2023. Between them, the US, Qatar, and Australia accounted for 60 per cent of global LNG exports – and global LNG liquefaction capacity – in 2023 and in H1 2024. The substantial growth in liquefaction capacity in the US and Qatar, combined with more limited growth elsewhere, means that these three exporters could account for 70 per cent of global liquefaction capacity by 2029-2030.

The growth in liquefaction capacity in the United States includes new projects at Golden Pass Trains 1-3, Plaquemines Trains 1-2, Rio Grande Trains 1-3, and Port Arthur (under construction), and expansions of existing projects at Corpus Christi Phase 3 (under construction), Cameron Train 4 and Calcasieu Pass Phase 2 (both planned).



In the rest of North America outside the United States, projects in Canada include LNG Canada (Kitimat) Trains 1-2 and Woodfibre (under construction) and Cedar FLNG (planned), while in Mexico Energia Costa Azul Phase 1 is under construction and at Saguaro Energia Trains 1-2 are planned.

In Qatar, the new capacity under construction at Ras Laffan includes Trains 1-4 (North Field East) and Trains 5-6 (North Field South) and planned new capacity at Trains 8-9 (North Field West).

In the rest of the world, roughly 28 Bcma of additional LNG liquefaction capacity is under construction or planned between 2024 and 2030, mostly concentrated in Africa. Small projects are planned for launch in 2026 at Cap Lopez (Gabon) and Congo FLNG II (Republic of the Congo). In Nigeria, Nigeria LNG is constructing Train 7 and working on debottlenecking Trains 1-6, both for launch in 2027. At the end of the decade, Mozambique LNG is planned for launch in 2029. Outside North America, Qatar, and Africa, the only project under construction is a second train at Pluto (Australia) for launch in 2026, and the only planned projects are the small-scale Sabah ZLNG in Malaysia (2027) and PNG LNG trains 1-2 in Papua New Guinea (2030).

### Other potential projects

In addition to the substantial volume of new capacity under construction and planned in the US, as listed above, the US Energy Information Administration lists several more projects that have been approved by the Federal Energy Regulatory Commission (FERC), have received a non-FTA export licence from the Department of Energy (DoE) and are undergoing or have completed Front End Engineering and Design (FEED).

These projects – which are not included in the ‘planned’ category in Figures 1-3 below – are: Lake Charles Trains 1-3, Driftwood Trains 1-5, Freeport Train 4, Texas LNG, Rio Grande Trains 4-5 and Gulf LNG Trains 1-2. Together, these projects have a proposed nameplate capacity of 73.35 Mtpa (99.8 Bcma). Beyond this, the proposed Alaska LNG (20 Mtpa or 27.2 Bcma) has FERC approval and a non-FTA export licence from the DoE but has not begun FEED. Finally, the 12 Mtpa (16.3 Bcma) Delfin FLNG project has FERC approval, but its DoE non-FTA export licence has expired and the decision on an extension is pending.<sup>1</sup> It is unlikely that all 143.3 Bcm of this capacity will be built, especially given that the DoE export commencement deadlines for all these projects (except for Alaska LNG) are in 2025-2027, which is too soon for projects that have not yet taken FID.

### Challenges to new liquefaction projects

The main challenge to US LNG export projects concerns the non-FTA export licences granted by the DoE. It is a standard procedure for projects to secure approval from FERC and a licence to export LNG to countries with whom the US does not have a Free Trade Agreement (FTA) before taking FID. The project company then has a time window of seven years from the granting of the non-FTA export licence to the commencement of exports. If the project will not be launched on time, the project company may apply for an extension to that seven-year deadline.

In April 2023, the DoE announced a policy revision. Non-FTA export licences will now only be extended if a) construction has commenced, and b) the project company can demonstrate that “its inability to comply with the existing export commencement deadline is the result of extenuating circumstances outside of its control”. If these conditions cannot be met, the project company may submit an entirely new application for a non-FTA export licence.<sup>2</sup>

In January 2024, the DoE announced a pause in considering pending or newly filed applications for non-FTA export licences, “while the Department works to update the economic and environmental analyses that inform DOE’s determination whether such applications are in the public interest”.<sup>3</sup> Crucially, this applies to both new applications and applications for extensions. It also impacts LNG liquefaction plants in Mexico that import natural gas by pipeline from the US for liquefaction.

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<sup>1</sup> Energy Information Administration, 2024. *U.S. liquefaction capacity, 2Q 2024 (release date 27 June 2024)*. <https://www.eia.gov/naturalgas/data.php#imports>

<sup>2</sup> US Department of Energy Office of Fossil Energy and Carbon Management, 2024. Policy Statement on Export Commencement Deadlines in Natural Gas Export Authorizations. *Press Release*, 17 July. <https://www.energy.gov/fecm/articles/policy-statement-export-commencement-deadlines-natural-gas-export-authorizations>

<sup>3</sup> US Department of Energy Office of Fossil Energy and Carbon Management, 2024. The Temporary Pause on Review of Pending Applications to Export Liquefied Natural Gas. *Press Release*, 23 February. <https://www.energy.gov/fecm/articles/temporary-pause-review-pending-applications-export-liquefied-natural-gas>



Therefore, there are two uncertainties pertaining to new US LNG liquefaction capacity. Firstly, there is the possibility that a project may not commence exports before the deadline set in its DoE non-FTA export licence. Secondly, a project that has not yet received its non-FTA export licence will be delayed by the pause in consideration of pending applications.

Of the US and Mexico export projects requiring non-FTA export licences that have already reached FID and are under construction, Golden Pass has the export commencement deadline that expires soonest (30 September 2025) and Port Arthur the deadline that expires latest (18 June 2028). These projects are likely to commence on time, as are Energia Costa Azul (deadline 29 March 2026), Plaquemines (deadline 16 October 2026), Corpus Christi Phase 3 Trains 1-7 (deadline 10 February 2027). Rio Grande (16.2 Mtpa) expects first exports from Train 1 by the end of 2027,<sup>4</sup> while its non-FTA export commencement deadline is 10 February 2027, meaning an extension may be required.

Of the two non-FID projects included in the 'planned' section of this outlook, Cameron Train 4 (6.75 Mtpa) received FERC approval in March 2023 and plans to take FID in 2025.<sup>5</sup> However, it faces a DoE export commencement deadline of 5 May 2026, and is therefore likely to require an extension.

The second non-FID projects included in the 'planned' section of this outlook, Calcasieu Pass 2 (20 Mtpa<sup>6</sup>), is an example of a project that could be delayed by the pause in considering applications for non-FTA export licences. The project received FERC approval in June 2024.<sup>7</sup> Venture Global applied for a non-FTA export licence for the project in 2021,<sup>8</sup> but it had not yet been granted by the time of the January 2024 'pause' in considering such applications. This outlook assumes that Phase One of the proposed capacity (10 Mtpa) is available during the timeframe examined here. However, Venture Global remains publicly confident, stating in March 2024 that "First LNG is expected in 2026 should the federal government act without further delay to approve CP2".<sup>9</sup>

Taken together, the volumes at Rio Grande (16.2 Mtpa), Cameron Train 4 (6.75 Mtpa) and Calcasieu Pass 2 (10 Mtpa) total 32.95 Mtpa (45 Bcma). These are the volumes at risk of delay.

Elsewhere, the challenges are different. In Nigeria, work continues on Train 7 and the debottlenecking of Trains 1-6, but although the liquefaction plant as a whole operated close to its 22 Mtpa capacity in 2017-2020, utilisation fell in subsequent years, with exports falling to 13.5 Mt in 2023.<sup>10</sup> This raises doubts over whether there will be sufficient feedgas to make use of the additional 7.6 Mtpa of liquefaction capacity generated by 2027, as a result of the expansion.

In Mozambique, while the offshore Coral South FLNG launched in November 2022, TotalEnergies declared force majeure at the onshore, 13 Mtpa Mozambique LNG project in April 2021, following an attack linked to Islamic State.<sup>11</sup> Although TotalEnergies have not set a date for the restart of construction work (which reached FID in 2019), previous indications of a 2024 restart may have been undermined by fresh attacks in May 2024.<sup>12</sup>

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<sup>4</sup> NextDecade, 2024. *Corporate Presentation (May 2024)*. <https://nextdecade.gcs-web.com/static-files/14ee1011-a160-45e7-b881-c45458d76ada> (see page 18)

<sup>5</sup> LNG Prime, 2024. Sempra targets Cameron LNG expansion FID in H1 2025. *LNG Prime*. <https://lngprime.com/americas/sempra-targets-cameron-lng-expansion-fid-in-h1-2025/106069/>

<sup>6</sup> Venture Global, 2024. *CP2*. <https://ventureglobalng.com/cp2-lng/>

<sup>7</sup> Reuters, 2024. US regulators approve Louisiana LNG plant over climate objections. *Reuters*, 27 June.

<https://www.reuters.com/business/energy/us-regulators-approve-louisiana-lng-plant-over-climate-objections-2024-06-27/>

<sup>8</sup> US Department of Energy Office of Fossil Energy and Carbon Management, 2024. *Venture Global CP2 LNG, LLC - FE Dkt. No. - 21-131-LNG*. 28 May 2024. <https://www.energy.gov/fecm/articles/venture-global-cp2-lng-llc-fe-dkt-no-21-131-lng>

<sup>9</sup> Venture Global, 2024. Statement from Venture Global LNG regarding further FERC delay. *LinkedIn*. March.

[https://www.linkedin.com/posts/venture-global-lng-inc\\_statement-from-venture-global-lng-regarding-activity-7174169977741029377-E5hl/](https://www.linkedin.com/posts/venture-global-lng-inc_statement-from-venture-global-lng-regarding-activity-7174169977741029377-E5hl/)

<sup>10</sup> Data from Kpler LNG Platform. Subscription required.

<sup>11</sup> TotalEnergies, 2021. Total declares Force Majeure on Mozambique LNG project. *Press Release*, 26 April.

<https://totalenergies.com/media/news/press-releases/total-declares-force-majeure-mozambique-lng-project>

<sup>12</sup> Sampson, P., 2024. Fresh Mozambique Attacks Throw Doubt on Total's LNG Plans. *Energy Intelligence*, 14 May.

<https://www.energyintel.com/0000018f-7701-dc18-a38f-77bbb9ab0000> [subscription required]



In Papua New Guinea (home to PNG LNG Trains 1-2), the 4 Mtpa Papua LNG project (led by TotalEnergies, ExxonMobil, and Santos)<sup>13</sup> announced in April 2024 that FID would be delayed to 2025.<sup>14</sup>

Russian LNG projects are absent from this supply growth outlook. Aside from existing LNG export projects at Yamal LNG, Portovaya, Vysotsk and Sakhalin II, Novatek has developed the Arctic LNG 2 project on the Gydan Peninsula, on the opposite side of the Gulf of Ob to the port of Sabetta (home to Yamal LNG). Although Train 1 is complete, the lack of ice-class LNG carriers means that cargoes cannot be loaded. Of the 21 LNG carriers ordered for the project, the orders for 16 have been cancelled and the remaining five LNG carriers are both incomplete and are now subject to US sanctions. Novatek is highly unlikely to risk using ice-class LNG carriers from its Yamal LNG project for fear that they will be sanctioned. Moreover, western sanctions on Novatek's Floating Storage Units (FSUs) at the Eastern and Western ends of the Northern Sea Route prevent their use for transshipment and EU sanctions will prohibit the transshipment of Russian LNG cargoes for onward delivery to non-EU destinations from March 2025. Moreover, US sanctions have also been placed on the project companies that Novatek created to pursue other LNG export projects, at Arctic LNG 1 & 3 and Murmansk LNG (the latter does not require ice-class LNG carriers). For these reasons, while Russian LNG exports from existing plants are set to continue, this outlook assumes no growth in LNG liquefaction capacity in Russia.

Having highlighted the projects that could face challenges, it is worth noting that of the 65.6 Bcm of 'planned' new capacity to be added in 2029-2030 (Figure 3), 16.6 Bcma is accounted for by Mozambique LNG and 3.1 Bcma by Papua LNG – these two projects that could face delays pushing them past 2030 account for a combined 19.7 Bcma. By contrast, a further 15.2 Bcm of 'planned' new liquefaction capacity in 2030 is accounted for by Qatar's North Field West Trains 7-8, which despite not having yet reached FID, are almost certain to go ahead on time.

### Conclusions

As Figure 4 illustrates, the wave of growth in global LNG liquefaction capacity will start to make itself felt in summer 2025, with quarterly liquefaction capacity roughly 10 per cent higher year-on-year in Q3 2025. The year-on-year growth in quarterly capacity could peak in Q1 2026 (+20 Bcm year-on-year).

Even if only the post-FID projects are included, global liquefaction capacity will grow by 215.5 Bcm (37.6 per cent) from 573 Bcm in 2024 to 788 Bcma in 2030. Of the 80.5 Bcma of 'planned' new liquefaction capacity, even if roughly 23 Bcma of new capacity in Mozambique and Papua New Guinea (75 per cent of the planned capacity growth outside North America, Australia, and Qatar) are delayed past 2030 and the 10 Bcma expansion in Nigeria is rendered ineffective by insufficient feedgas, global LNG liquefaction capacity could still grow to 835 Bcma by 2030 – an increase of 262.5 Bcma (46 per cent) compared to 2024. Such delays would impact capacity growth in 2029-2030. In the US, the regulatory challenges appear more likely to delay new liquefaction capacity rather than cause projects to be cancelled but could affect up to 45 Bcma of capacity in the timeframe considered here.

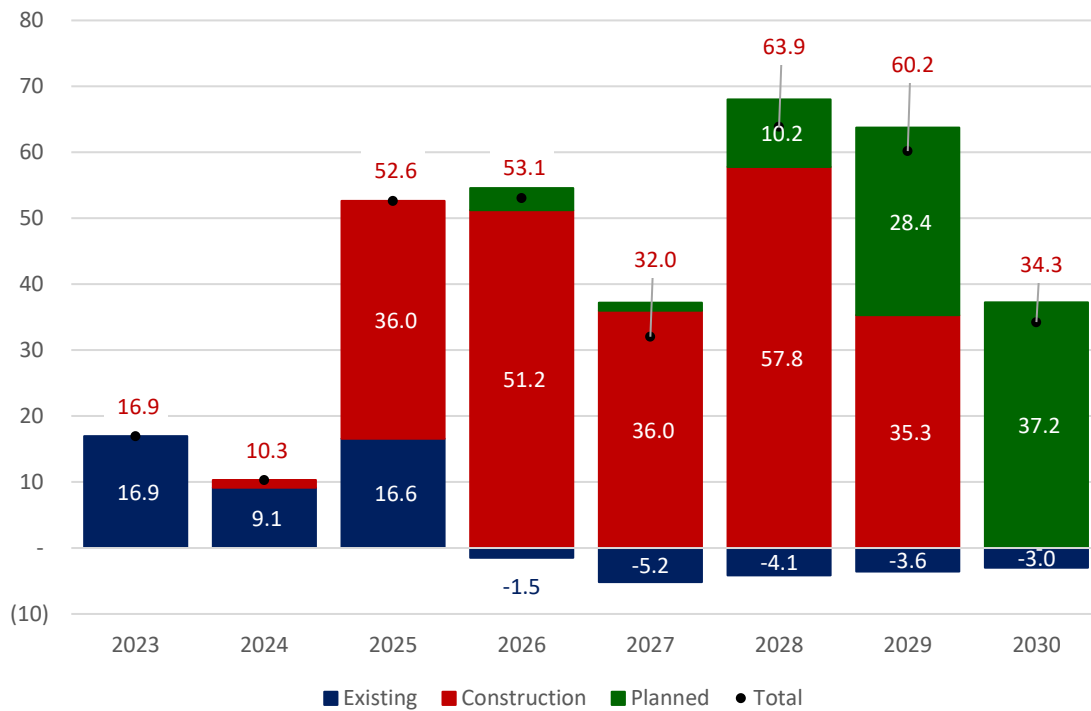
To conclude, the wave of new LNG liquefaction capacity will be substantial, and sufficient to cause structurally lower prices on the global LNG market in the second half of the decade, even if demand continues to grow in Asia as noted earlier. The main risks are to projects aiming for launch in 2025-2027 being delayed but still launching in the timeframe considered here and to projects aiming to launch in 2029-2030 being delayed to post-2030. Yet even delays such as these will not reduce the volume of new capacity sufficiently to change the overall picture of a supply-long market in 2026-2030.

<sup>13</sup> Papua LNG, 2024. *The project*. <https://papualng.com/pg/papua-lng/project/>

<sup>14</sup> TotalEnergies, 2024. Joint Statement of the Independent State of Papua New Guinea and TotalEnergies. *Press Release*, 8 April. <https://totalenergies.com/news/press-releases/joint-statement-independent-state-papua-new-guinea-and-totalenergies>

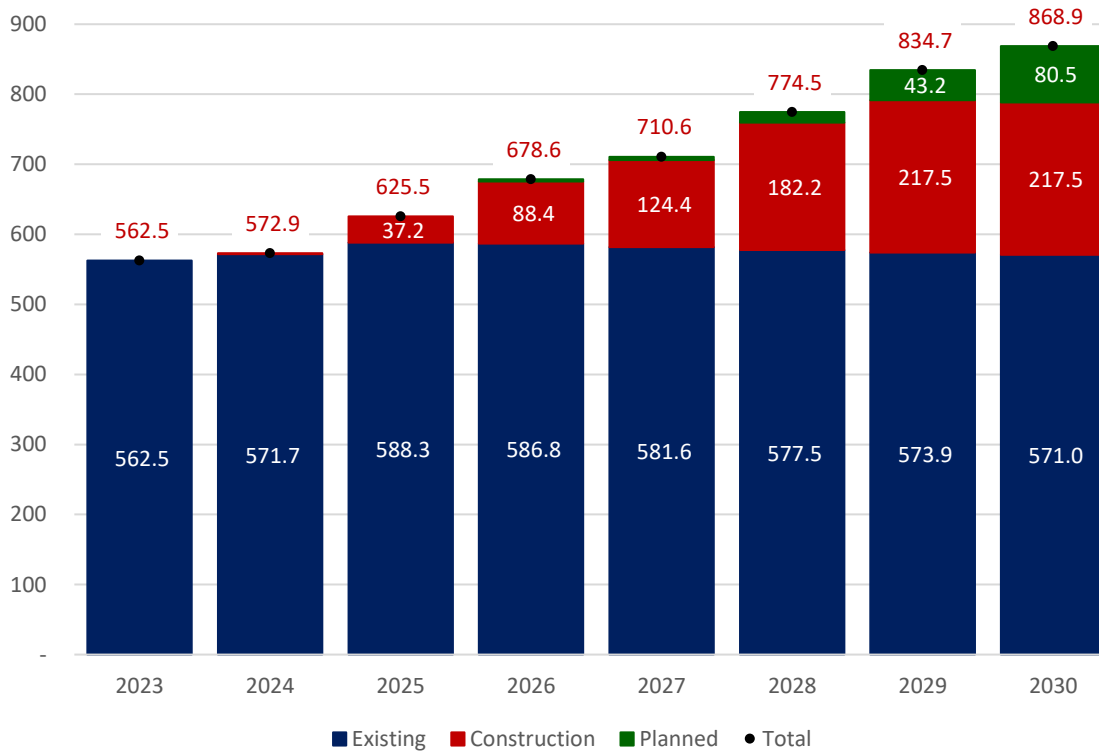


Figure 2: Year-on-Year Change in Global LNG Liquefaction Capacity (Bcma)



Data source: Nexant World Gas Model (WGM); OIES.

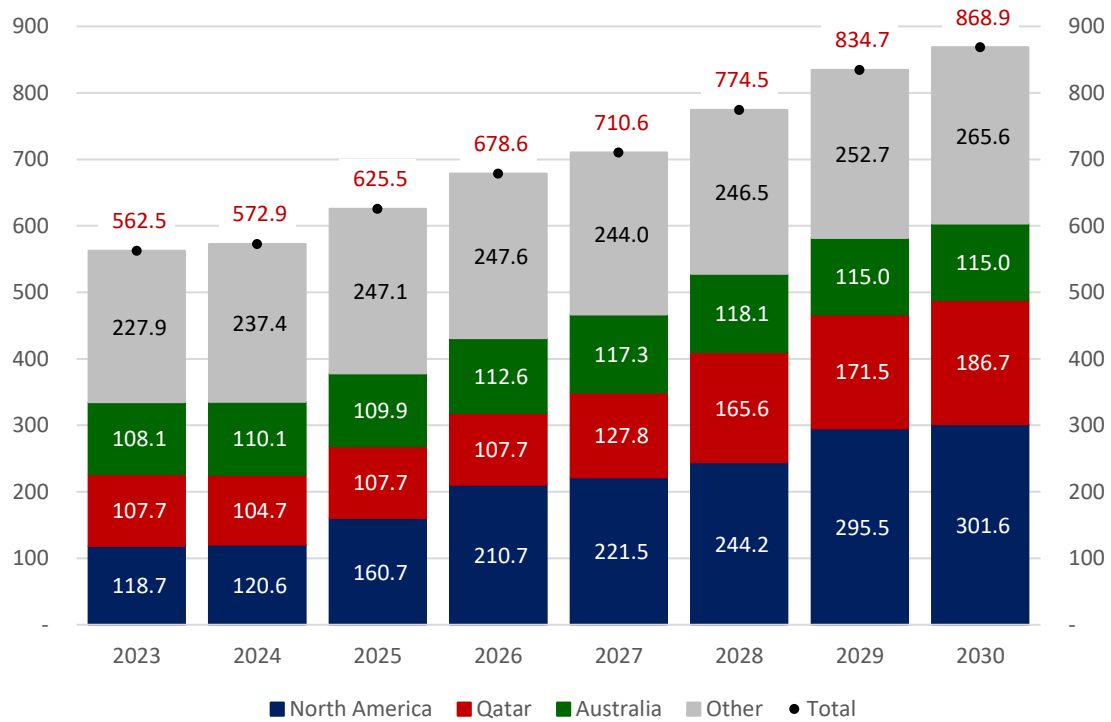
Figure 3: Global LNG Liquefaction Capacity (Bcma)



Data source: Nexant World Gas Model (WGM); OIES.

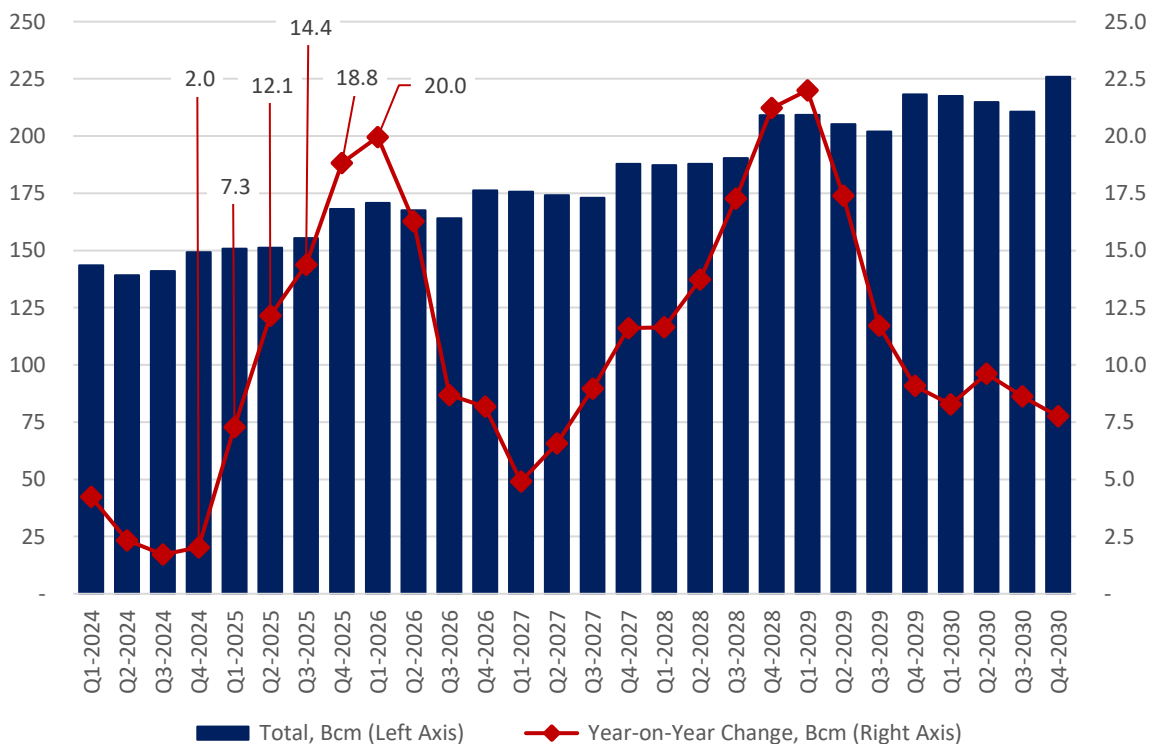


Figure 4: Global LNG Liquefaction Capacity by Location (Bcma)



Data source: Nexant World Gas Model (WGM); OIES. Includes 'Under Construction' and 'Planned'.

Figure 4: Global Quarterly LNG Liquefaction Capacity and Year-on-Year Change (Bcm)



Data source: Nexant World Gas Model (WGM); OIES. Includes 'Under Construction' and 'Planned'.



## NATURAL GAS IN SOUTH AMERICA: CLIMATE EVENTS AND IMPACT ON LNG DEMAND

**Ieda Gomes**

According to the World Meteorological Organization, 2023 was the warmest year on record in Latin American and the Caribbean (State of the Climate in Latin America and the Caribbean 2023, <https://wmo.int/publication-series/state-of-climate-latin-america-and-caribbean-2023>). The 2023-2024 El Niño phenomena, which ended in June 2024, had significant repercussions for South America, with uneven consequences in different countries.

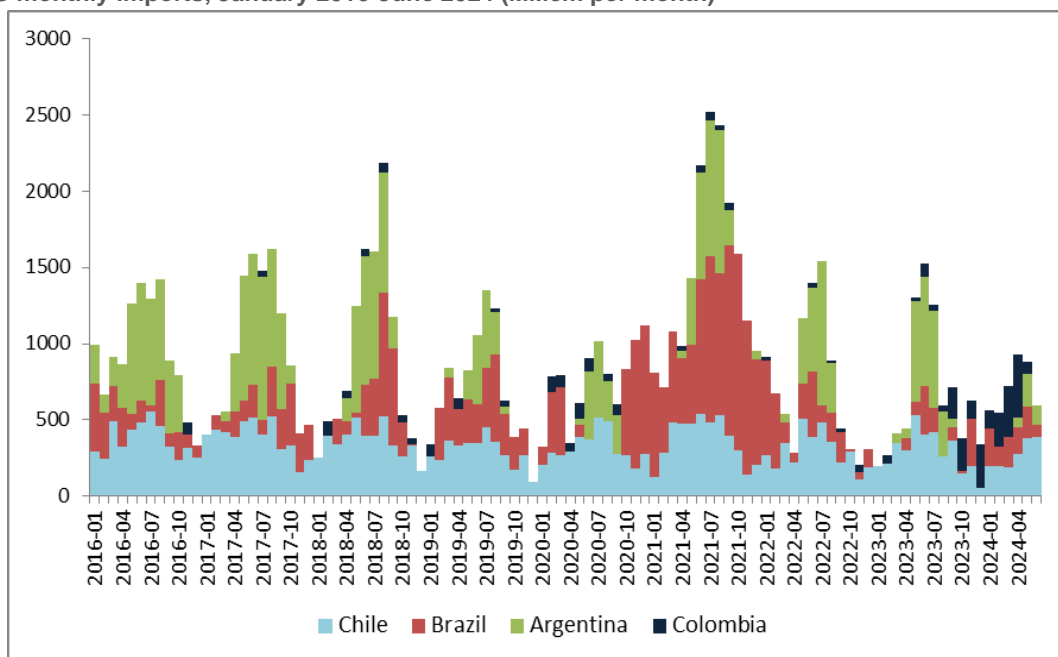
Whereas coastal areas of Peru, Ecuador and south Brazil had suffered unprecedented rainfall, the northern and central parts of the continent, such as Colombia and northern Argentina and Brazil have endured severe droughts. This is particularly important for the power sector, because Argentina, Brazil, Chile and Colombia are significantly dependent on hydroelectricity but, learning from past events, have also built LNG import terminals for security of supply reasons. There are currently 12 LNG terminals in operation, two in Chile, eight in Brazil, one in Colombia and one in Argentina, of which 10 are FSRUs and two are shore based (Chile).

In the case of Argentina, in 2022 the government decided to fund a crucial pipeline to evacuate unconventional gas from Vaca Muerta in the Neuquén basin to the demand centres around Buenos Aires, thus alleviating the need for LNG imports. In Brazil, high water levels in the southeastern hydro reservoirs have contributed to lower LNG imports, but heatwaves in 3Q2023 and 1Q2024 forced the dispatch of CCGT-generated electricity for a few peak hours during the day, requiring LNG terminals to maintain and replenish storage in case they were called on to dispatch at short notice by the National System Operator (ONS).

Chile continued to import gas by pipeline from Argentina, therefore maintaining a stable consumption of LNG, whereas in Colombia the hydro reservoirs reached a low level of 31% in 3Q2023 resulting in an unusual growth in LNG imports from September 2023 to April 2024.

Despite the impact of El Niño on temperatures and hydroelectricity generation, the four countries have shown resilience due to the availability of LNG import capacity, pipeline connections between Argentina and Chile and the growth of renewable electricity in Brazil, Argentina and Chile. The displacement of cleaner hydroelectricity for LNG contributed to higher electricity costs and additional CO2 emissions in Colombia, whereas in Chile, Brazil and Argentina, the impact on CO2 emissions was minimal or even negative, due to higher availability of renewable electricity (<https://www.energyinst.org/statistical-review>).

**Figure1: LNG monthly imports, January 2016-June 2024 (MMcm per month)**



Data from Kpler LNG Platform



## Argentina

Argentina's strategy to reduce LNG, liquid fuels and Bolivian gas imports is underpinned by the construction of the NKPL (Nestor Kirchner Pipeline), connecting Vaca Muerta's shale resources in Neuquén to the Buenos Aires region and the reversal of the NGP (Northern Gas Pipeline) with an additional capacity of 9 MMcm/d, allowing domestic gas to replace gas imported from Bolivia.

Phase 1a (573 km) of the NKPL was completed in July 2023, connecting Tratatayen in Neuquén province to Salliqueló in the Greater Buenos Aires region, allowing the flow of an additional 11 MMcm/d of gas from Neuquén. This would be followed by phase 1b, consisting of the installation of two compressor stations, which were expected to be commissioned by September 2023, increasing NKPL capacity to 21 MMcm/d. Phase 2, yet to be tendered, consists of 473 km connecting Salliqueló to San Nicolás in Buenos Aires province and an additional capacity of 20 MMcm/d.

According to industry sources, the compressor stations were delayed to August 2024, whereas the reversal of the NGP is expected to be completed by September 2024. The delay was caused by macroeconomic factors, the acceleration of inflation and a change of government. The aforementioned delays, coupled with a cold winter spell in May 2024 caused a crisis that forced a curtailment in natural gas supplies to vehicles and industries.

In March 2024, state company ENARSA (Energia Argentina SA), which is responsible for natural gas and LNG imports, issued a tender to procure 10 cargoes of 56,000 cm of LNG for the Escobar terminal, but these volumes proved insufficient to meet winter demand, in face of the cold weather and delays to the commission of the pipelines. In response to the supply crisis, ENARSA resorted to the following measures to sort out the supply crisis (<https://www.energia-argentina.com.ar/> and <https://buenosairesherald.com/business/energy/argentina-buys-more-gas-from-bolivia-to-ward-off-winter-shortages>)

- It increased LNG imports to 28 cargoes, including an emergency cargo bought from Petrobras, totalling 0.95 Bcm;
- Extended the term of the Bolivian gas supply agreement from July to September 2024, with supplies of up to 4 MMcm/d;
- Signed an MOU with Petrobras allowing for swaps of gas from Bolivia destined to Brazil with LNG supplies; and
- Reached an agreement to import natural gas from Chile's state-owned Enap, from the Mejillones LNG terminal in the north of Chile.

Figure 2 depicts the decreasing volumes of imported gas and LNG; the latter is considerably lower than the volumes imported in 2023 and 2022 for the winter season, respectively 2.47 and 2.30 bcma. Due to the challenging macroeconomic environment, industrial and transport demand shrunk 7.2 per cent and 4.2 per cent in the first quarter of 2024, when compared to the same period in 2023, alleviating the need for imports (<https://www.argentina.gob.ar/sites/default/files/t12024.pdf>).

The completion of pipeline construction will allow Argentina to end Bolivia gas imports and reduce LNG purchases in the 2025 winter season, but without the construction of NKPL phase 2, the country might need LNG injections of 15-17 MMcm/d in July, if demand follows the same pattern as 2023.

## Brazil

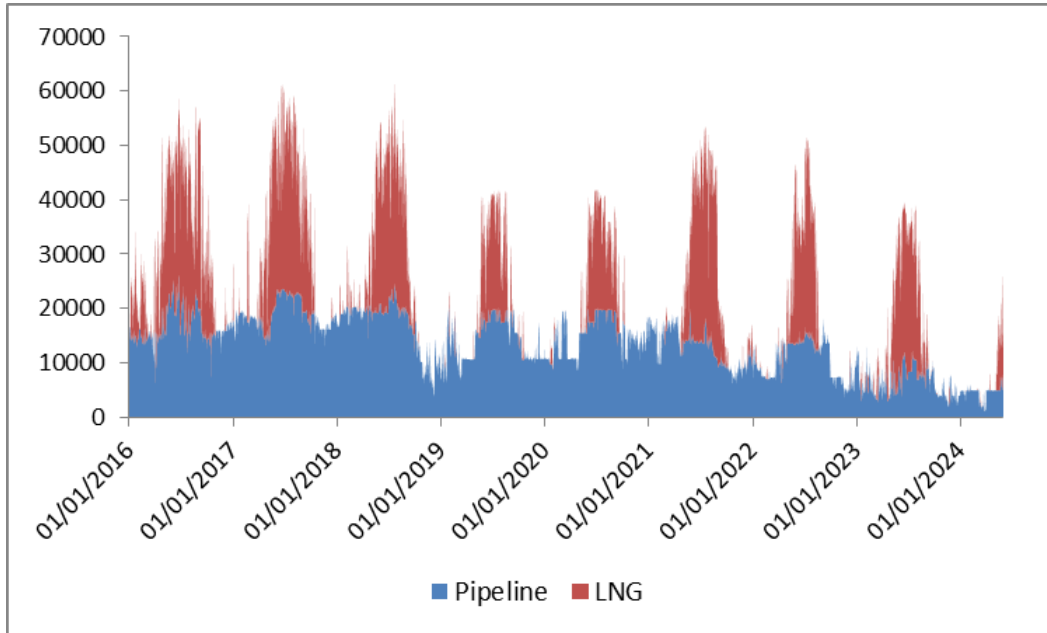
In 2023, LNG imports fell to 0.92 Bcm, with regasification levels falling to 0.6 bcma (Boletim de Acompanhamento do Gas Natural, 2024, MME Brasil). Sharply lower demand from the power sector, down 70% from 2021 at 4.7 bcma in 2023 was mostly met by domestic gas supplies. El Niño lifted water levels at hydro reservoirs in southeast Brazil, maintaining comfortable levels throughout 2023 and the first half of 2024, coupled with an increase in solar and wind power availability. According to the National System Operator ([https://www.ons.org.br/Paginas/resultados-da-operacao/historico-da-operacao/geracao\\_energia.aspx](https://www.ons.org.br/Paginas/resultados-da-operacao/historico-da-operacao/geracao_energia.aspx)), thermal power plants, which also include biomass, accounted for only 9.4 per cent of energy generated in the Integrated National System (SIN) in 2023.

However, El Niño also caused a surge in heatwaves in Brazil. There were nine heatwaves in 2023 and four in 2024, with temperatures reaching 45°C in some regions. The surge in air conditioning demand sent energy consumption to new record highs, with peak demand at 102,478 MW in March 2024, according to data from the ONS (National Electric System Operator). In November 2023, the dispatch of gas-fired power plants increased by 74% in the period 12-17 November, with CCGT plants required to dispatch power for just a day or two.



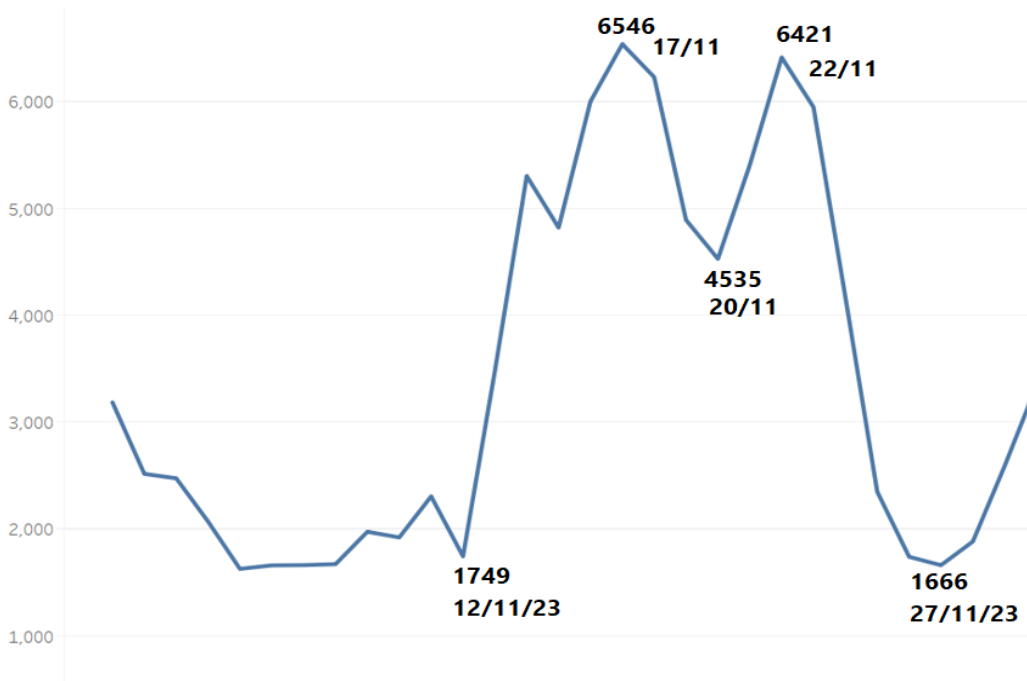
Although the hydro reservoirs in southeast Brazil maintained a comfortable level of 67.6 per cent as of 29 June 2024 (<https://www.ons.org.br/paginas/energia-agora/reservatorios>), the rapid growth and intermittency of renewable energy generation coupled with bottlenecks in transmission capacity will require the sub-optimal dispatch of thermal power plants during heatwaves. The ONS has announced that they will continue to deploy thermal power plants to meet peak demand during the second half of 2024 (<https://megawhat.energy/geracao/ons-muda-operacao-e-vai-usar-estoques-dos-reservatorios/>)

**Figure 2: Argentina’s natural gas and LNG imports, 2016-2024 (Mcm/d)**



Data from Enargas (<https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp-consulta.php?tipo=importaciones>)

**Figure 3: Brazil: dispatch of gas power plants, heatwave November 2023 (MWaverage)**



Source: Author elaboration, data from ONS ([https://www.ons.org.br/Paginas/resultados-da-operacao/historico-da-operacao/geracao\\_energia.aspx](https://www.ons.org.br/Paginas/resultados-da-operacao/historico-da-operacao/geracao_energia.aspx))



## Chile

As of the latest data available in 2023, hydropower accounted for approximately 29 per cent of Chile's electricity generation, a significant decrease from earlier decades when hydropower contributed over 50%. The decline is due to substantial investment in renewable energy sources and natural gas. In 2023, solar and wind accounted respectively for 19.9 and 11.8 per cent whereas natural gas and coal represented respectively 20.7 and 17.9 per cent of the electricity generation mix (<https://lowcarbonpower.org/region/Chile>). The government's long-term energy strategy focuses on increasing the share of renewable energy to 80 per cent by 2030.

The 2023-2024 El Niño events have brought drought conditions, particularly affecting central Chile where many of the country's hydropower facilities are located. But this has had a modest impact on natural gas and LNG imports. In 2023, Chile imported 3.54 Bcm of pipeline gas from Argentina and 3.45 Bcm of LNG via the Quintero and Mejillones terminals. This compares to 3.49 Bcm via pipeline and 3.45 Bcm of LNG in 2022. The opportunity for LNG/natural gas imports will rise following the planned decommissioning of 3.6 MW of coal-fired power plants by 2040, although most of the capacity will be replaced with solar, wind and existing idle gas-fired capacity.

The main power generators - AES, Engie, Enel and Colbun – have announced plans to retire a substantial amount of their coal plants by 2026, with most of them replaced by renewable power, with only one announcement from Engie, with plans to convert its 375MW power station Infraestructura Energética Mejillones to LNG (<https://www.bnamericas.com/en/news/chiles-coal-fired-generation-exit-the-state-of-play>).

## Colombia

According to Colombia power system operator XM (<https://www.xm.com.co/>), Colombia's installed capacity in 2023 totalled 18,626 MW, of which hydro accounted for 12,494 MW (67 per cent), gas 2,827 MW, coal 1,649 MW, liquid fuels 1,180 MW and the balance (2.6 per cent) made up of solar, wind and bagasse cogeneration. Historically, the supply from hydroelectric plants fluctuates around 70%, even reaching in some cases up to 85% of the total energy supply, but during the occurrence of El Niño, hydroelectric output was below 45%, leaving thermal plants to work at maximum capacity.

According to Colombia's power generation association, electricity demand has increased annually on average by 2.6 per cent over the last 10 years, but new capacity increases have been delayed due to macroeconomic factors and the lack of a clear regulatory framework for renewable energy (<https://www.eltiempo.com/mas-contenido/colombia-esta-preparada-para-un-proximo-fenomeno-de-el-nino-sin-apagones-de-energia-3353725>). In addition, in 2022 the newly-elected President Gustavo Petro has declared a moratorium for new hydrocarbon exploration permits. Over the period 2018-2023, natural gas reserves have fallen from 9.8 to 6.1 years of demand cover (<https://www.anh.gov.co/es/operaciones-y-regal%C3%ADas/datos-y-estadisticas>), which underlines the need to step up renewable energy projects plus additional LNG imports.

In 2016, Colombia commissioned an LNG terminal (SPEC) owned by the Colombian company Promigas, which comprises an FSRU operated by Hoegh in the Caribbean port of Cartagena. The contractual LNG send out is 11.3 MMcm/d; in March/April 2024 it has been dispatched at full capacity. In 2023, Calamari LNG, the sole LNG import agent in the country, bought 29 LNG cargoes, from a total of 64 cargoes since the terminal was commissioned in 2016. In December 2023, peak demand for natural gas reached 39.6 MMcm/day, of which 11 MMcm/d was supplied via SPEC and 28.6 MMcm/d via domestic gas sources.

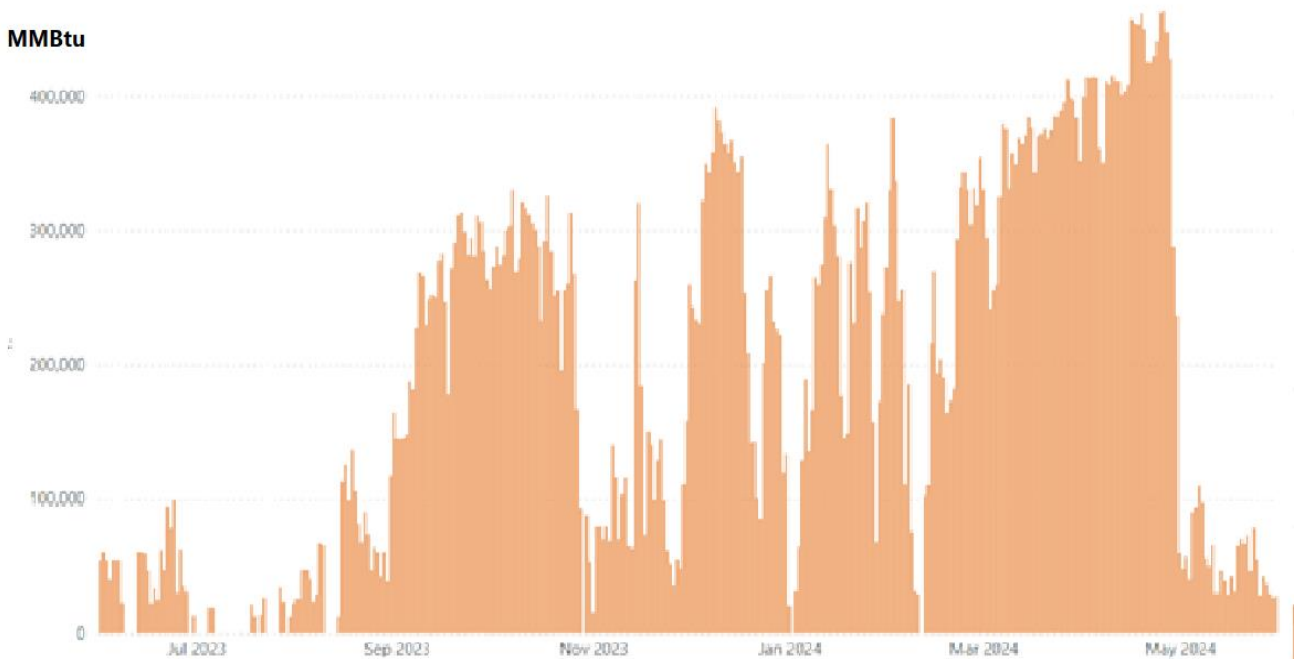
In January 2024, Hoegh and SPEC announced that they have reached an agreement to increase the dispatch to 15.1 MMcm/d, starting with 1.50 MMcm/d in 2024 and another 2.3 MMcm/d in 2025 ( according to industry sources this step up is due to the need to increase capacity in the pipeline system out of the FSRU).

In 2022, Colombia published its roadmap for offshore wind development. The best-case scenario envisions 1GW of capacity by 2030 and 3GW by 2040. In total, the country aims to install 2.5 GW of solar, wind and biomass energy but transmission infrastructure has been delayed.

In the meantime, potential production from domestic sources is expected to decline to 24% by 2032 of production capacity in 2023, according to the Ministry of Mines and Energy. If this scenario materializes and if demand continues to grow annually at 2.6 per cent, then a gap will emerge in 2024. If demand is managed to prioritize the requirements of the residential, commercial and industrial sectors, then a gap will emerge in 2029, requiring a second LNG terminal and/or the revamping of the existing facility.

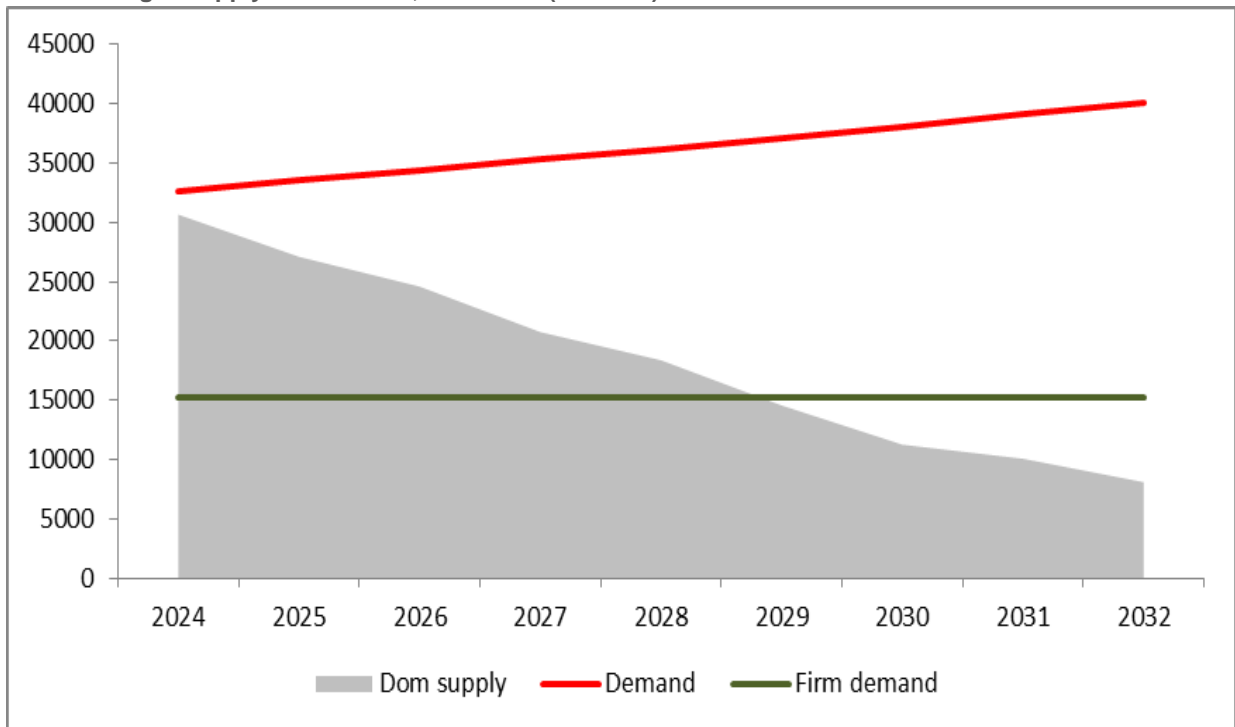


Figure 4: Daily dispatch of Colombia’s SPEC LNG terminal, July 2023-May 2024 (MMBtu)



Source: <https://www.bmcbec.com.co/informaci%C3%B3n-operativa/cantidad-declarada-por-comercializadores-de-gas-importado-y-no-inyectada-al-snt>

Figure 5: Natural gas supply and demand, 2024-2032 (MMcm/d)



Source: Author elaboration based on data from Gestor del Mercado de Gas Natural en Colombia (<https://www.bmcbec.com.co/informes/Informes-Anuales>)

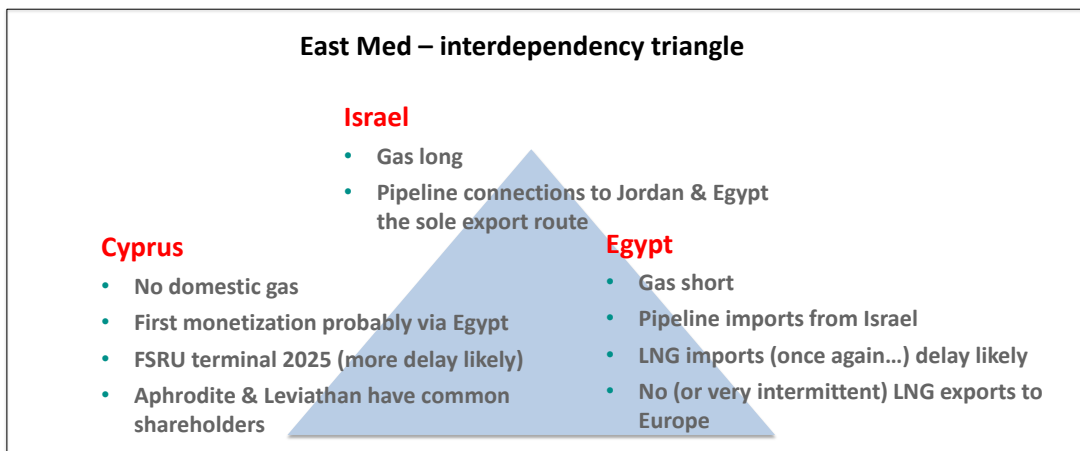


## EAST MED GAS: BREAKING THE TRIPARTITE BONDS

**Julian Bowden**

Over the last two to three years a series of gas interdependencies has emerged between Israel, Egypt and Cyprus, raising the question how sustainable these links are. The assertion here is that they are not, at least not in their present form. These relationships are inherently unstable and will require a number of country policy interventions and new infrastructure in order to establish a more robust regional gas market - mainly through additional gas monetisation options and better export connections to the global market.

The chart below summaries some key characteristics of each country’s gas sector and the foundations of the interdependency triangle. In essence, pipeline connections allow the Israeli gas surplus to be exported to help solve Egypt’s gas deficit. Cyprus, with a large undeveloped resource base, is being drawn by the Egyptian short position and its two underutilised LNG plants as its primary monetisation route.



Meanwhile, the EU is looking at the region as an incremental source of supply to assist in replacing Russian gas. In this, because of the Egyptian deficit and its inability to export LNG for probably two or three years or even longer, the EU will be frustrated. The sections below describe the main elements of the triangle, starting with the gas fundamentals of each of the three countries and the regional gas flows.<sup>15</sup>

### I. Fundamentals

#### a) Israel

Major gas discoveries offshore have transformed the Israeli energy sector, catapulting it over a short 4-5 year period into a significant gas player. Production is from three fields and combined output from Leviathan, Tamar and Karish in 2023 rose 15 per cent to 25.5 Bcm. This production base has enabled Israel to remove most coal from its energy mix and gas now accounts for 45 per cent of the country’s domestic energy needs. Production is divided between the domestic and export markets almost equally now: in 2023, 46 per cent of Israeli supply went to exports. Israeli gas supplies most of Jordan’s 3 bcma demand and some 8.7 Bcm went to Egypt in 2023. In terms of Egypt’s demand, imports from Israel met 15 per cent of Egypt’s domestic demand in 2023 (or 13 per cent if the gas feed to the LNG plants is included).

	Production	Demand	Exp / Imp	
Israel	25.3	13.7	11.6	(2.9 Bcm to Jordan, 8.7 Bcm to Egypt)
Egypt	57.1	60.0	2.9	(8.7 Bcm from Israel)
Jordan	0.2	3.3	3.1	(2.9 Bcm from Israel)

<sup>15</sup> This piece is based on an OIES paper Julian Bowden & Elad Golan East Mediterranean gas: a triangle of interdependencies, Energy Insight 151, May 2024



**b) Egypt**

One global surprise in 2023 was the rapid decline in Egypt’s gas production. Led down by the Zohr field, which accounts for some 40% of the country’s output, Egypt’s output fell 11.5 per cent or by 7.5 Bcm. The relatively sudden Egyptian gas supply deficit was met by increased imports from Israel and a 50 per cent cut in output from the two LNG plants. In 2024 it looks certain that Egypt will fully flip from being an LNG exporter to a net importer. Gas balance convention is that gas feedstocks to LNG plants are omitted from the domestic demand number. If they are added back into the balance for 2023, then the importance of the imports from Israel in achieving gas balance can be immediately seen.

Egypt 2023 balance inc LNG feedstock		
	2023	
	in Mtes	bcm feed
LNG exports (in Mtes)	3.3	5.1
<b>Egyptian balance</b>	<b>in Bcm</b>	
domestic demand	60.0	
LNG feedstock	5.1	
<b>total gas demand</b>	<b>65.1</b>	
Production	57.1	
<b>Gas deficit</b>	<b>-8.0</b>	
imports from Israel	8.7	

**c) Cyprus**

There is no gas in the Cyprus domestic energy mix. It is the only EU Member State where the domestic mix is dominated by oil and thermal generating capacity runs entirely on oil. The Aphrodite gas field was discovered in 2011 and encouraged both further exploration and ideas for bringing gas into the domestic mix. While there have been more discoveries and the resource base is now approaching 20 tcf, there have been no project commitments made on the upstream. An FSRU project is also under construction to bring gas to the power plants and the FSRU vessel *Etyfa Prometheas* is completed, but the project has been delayed several times, with 2025 now being the completion target. But there is a growing possibility that it may never even happen: the Chinese contractor for the jetty has recently left the project, there are corruption rumours and in July the European Public Prosecutor’s Office (EPPO) opened an investigation on the import terminal project “on suspicion of procurement fraud, misappropriation of EU funds and corruption.”<sup>16</sup>

**II. Interdependency remains the same in 2024**

The first half of 2024 has seen positive news for Israel, while Egypt’s gas balance problems mount and Cyprus developments have stayed becalmed. Essentially, though, it is more of the same: more Israeli gas exports to Egypt; Egypt’s production falling, debt to the upstream being repaid slowly and LNG imports addressing the deficit; Cyprus making no progress.

**a) Israel**

Leviathan partners took FID on expansion from 12 Bcm/a to 14 Bcm/a in mid-2023. In June 2024 the Israeli Ministry of Energy gave preliminary approval for additional exports from Leviathan and this should set the scene for an announcement on further expansion to 21 Bcm/a soon.<sup>17</sup> In August, partners announced they have agreed to start FEED work on this major 50% expansion project to 21 Bcm/a. Tamar received approval for additional exports in December 2023 and had already announced FID on an expansion.

Both these fields are operated by Chevron, which also has a 35% stake in Cyprus’ Aphrodite field. Assuming that the expansion projects go to timetable, by 2030 Israel will be producing around 38 Bcm (ie up 13 Bcm from 2023 levels). With domestic

<sup>16</sup> European Public Prosecutor’s Office press release 25<sup>th</sup> July 2024 at <https://www.eppo.europa.eu/en/media/news/cyprus-epo-investigates-project-liquefied-natural-gas-import-terminal>

<sup>17</sup> [https://newmedenergy.com/wp-content/uploads/2024/06/NewMed-Immediate-Report-Leviathan-FID-26.6.2024\\_שמונוג.pdf](https://newmedenergy.com/wp-content/uploads/2024/06/NewMed-Immediate-Report-Leviathan-FID-26.6.2024_שמונוג.pdf)



demand rising slowly, and this mainly due to coal substitution, then in 2030 Israel will have around 18 - 20 Bcm available for export. Subtracting the exports to Jordan, assumed steady at the 3 Bcm/a level and recognising that in this timescale it is highly doubtful that any other export route can be built and on-stream, then the only market through the medium-term will be more exports to Egypt. Exports to Egypt would roughly double, rising from 8.7 Bcm in 2023 to something like 15 – 17 Bcm/a by 2030.

Exports to Egypt for early 2024 have been reported up, with Leviathan exports in particular up from 1.5 Bcm in 1Q 2023 to 1.8 Bcm in 1Q 2024 and Israel total exports running at the 1 bn cf/d rate (approximately 10.5 Bcm/a annualised).<sup>18</sup> However, longer-term there is uncertainty on Egypt's gas demand requirements, due to likely attempts to deal with subsidised domestic prices and the prospects of the ambitious renewables programme being rolled out.

### **b) Egypt**

It does not appear that Egypt's gas production will recover quickly. Production in April 2024 was at 5.1 bn cf/d, which if annualised would mean around 53 Bcm for 2024. The current exploration campaign has got off to a poor start. For instance, hopes were that a Zohr-like structure on the North East Hap'y offshore block drilled by ENI and Energean could be a significant 10 tcf resource, but in March 2024 it was announced that the its Orion exploration well had not made a discovery.<sup>19</sup> Subsequently, Energean announced in June 2024 a major portfolio change, with its assets in Egypt, Italy and Croatia being divested to Carlyle, leaving it with close to \$1 billion in cash from this divestment and its active assets in the wider region remaining centred on Karish (Israel) and the undeveloped Anchois field 40kms offshore Morocco's Atlantic coast.<sup>20</sup>

The production decline is creating serious repercussions both to the domestic market and LNG exports. On the domestic market, there are reports of power cuts and supply problems extending to industrial gas consumers, in particular urea and petchem producers. Meanwhile, upstream companies have been complaining of rising levels of unpaid receivables and poor payment performance. In May, Prime Minister Mostafa Madbouly instructed the country's finance and petroleum ministers to pay 20-25% of outstanding debts.<sup>21</sup>

Moreover, LNG exports have come to a virtual halt. Over the first four months of 2024, total LNG exports were 0.5 million tonnes. LNG industry reports suggest Egypt is looking to import 17 cargoes over the summer 2024. At prevailing prices, (Platts has reported the East Med DES price in June is just under \$11 MMbtu) then 17 cargoes would cost around \$700 million.<sup>22</sup> This price is substantially higher than the current gas price which a gas producer in Egypt can expect to pay. Prices across the various projects vary, but the highest price appears to have been secured by Zohr for a Brent-related price of \$6.20 MMbtu, when Brent is at or above \$70 bbl.<sup>23</sup>

Unsurprisingly, there have been political repercussions and casualties: in July, both petroleum Minister Tarek El Molla and the electricity minister Mohamed Shaker were not reappointed to the new cabinet.

### **c) Cyprus**

In April 2024 the Cyprus authorities told Aphrodite partners that the latest development plan was not acceptable. The field partners were asked to start FEED work within six months, in which case extensions to the licence would be granted.<sup>24</sup> Since then there has been no further news. There has also been no progress on the FSRU project at Vasilikos. The FSRU vessel *Etyfa Prometheas* remains in Shanghai. The jetty at Vasilikos remains unfinished and there is now possibility of official fraud investigations.

<sup>18</sup> [https://newmedenergy.com/wp-content/uploads/2024/05/NWMD\\_1Q24\\_Vf.pdf](https://newmedenergy.com/wp-content/uploads/2024/05/NWMD_1Q24_Vf.pdf) and MEES 7<sup>th</sup> June 2024 Israel Tamar outage causes Egypt gas and power chaos

<sup>19</sup> <https://www.energean.com/operations/egypt/north-east-hap-y/> and

<sup>20</sup> <https://www.energean.com/media/5836/strategic-sale-of-egypt-italy-and-croatia-portfolio.pdf> and <https://www.egypt-business.com/web/details/2411-egypt-drilling-orion-flops-as-shell-kicks-off-six-well-wddm-campaign/432015>

<sup>21</sup> <https://www.egypttoday.com/Article/3/132605/PM-Madbouly-instructs-ministers-to-begin-repayment-of-Petroleum-Ministry> and MEES 21<sup>st</sup> June 2024 reported that ENI is owed \$1.6bn

<sup>22</sup> Platts European Gas Daily 19<sup>th</sup> June 2024. Assuming an average cargo size of 160,000 cubic metres on LNG, that would equate to almost 0.1 Bcm, so 17 cargoes would amount to 1.7 bcm.

<sup>23</sup> MEES 7<sup>th</sup> June 2024 published a table of gas prices for Zohr, Shell WDDM, West Nile etc.

<sup>24</sup> NewMed Energy update on Aphrodite 1<sup>st</sup> May 2024 at <https://newmedenergy.com/wp-content/uploads/2024/05/NewMed-IR-Aphrodite-1.5.2024-מזוגש.pdf>



### III. Building sustainability

The triangle of interdependencies and no other market optionality outside the triangle clearly is full of market risk for the exporters. The intention here is not to prescribe remedies, but there are potential improvements to this closed system of interdependencies, with the now short Egyptian market being the magnet for Israel's current and future exports and likely anchor market for first development of the Cyprus offshore.

With Egypt's market representing the greatest risk for both price and volume and the ability to utilise the country's two LNG plants reliably, then risk contained within this triangle should not provide a confident environment for large investments. A key signpost here will be the marketing options that the Leviathan FEED for the expansion to 21 Bcm/a comes up with.

Remedies are very hard to see for the short-term, but there are alternatives. A first priority is to utilise existing infrastructure as far as possible and here there are underutilised upstream facilities on the Egyptian offshore fields and plenty of spare capacity at its two LNG plants. Establishing some control for the exporters over how gas is allocated in Egypt to the domestic market and the global market through these LNG plants would be a first step.

Egypt is not a sustainable market where a domestic producer might secure \$6.20 MMBtu but where the marginal supply (imported LNG) is currently (late June 2024) around \$11 Mmbtu. Egyptian policy should include gradual alignment of the pricing difference seen by a domestic producer and the LNG opportunity.

Israeli producers have long talked about FLNG. NewMed writes on the Leviathan expansion that "While the current development is strictly based on the Israeli natural gas grid and on a pipeline network, Phase B of the project is expected to include a significant liquefaction component, that will expand Leviathan's customer base beyond the Eastern Mediterranean, to Europe and the Far East. To that end, commercial negotiations are being held with two existing liquefaction facilities in Egypt, while an option for liquifying natural gas on a floating facility anchored in the Israeli EEZ is being explored."<sup>25</sup>

An FLNG scheme would be a major capital commitment and take time to build. For example, the BP- Kosmos FLNG Senegal-Mauretania project Phase 1 for 2.5 Mtes received its FID in Dec 2018 and now due on-stream at end-2024, at a capex variously reported at around \$5 billion. If it happens, therefore, it would be a project delivered around 2030 at the earliest.

There are other possibilities also. Onshore LNG gasification in Cyprus could emerge when the geopolitical landscape has become clearer once the Israel-Hamas conflict is resolved. The East-Med gas pipeline to Europe has been strongly pushed in the past and remains on the EU's latest PCI list, although its promotion efforts seem to have gone quiet.<sup>26</sup> Also, the Israel-Cyprus-Greece power interconnector, recently getting a project name-change from EuroAsia Interconnector to Great Sea Interconnector is on the list and, in contrast to the pipeline idea, is being more actively discussed.<sup>27</sup> But for the near future, it looks like there is no change in prospect to the gas flow patterns that we see today.

<sup>25</sup> <https://newmedenergy.com/operations/leviathan-phase-b/>

<sup>26</sup> Project code PCI/PMI 15.2, at [https://ec.europa.eu/energy/infrastructure/transparency\\_platform/map-viewer/main.html](https://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html)

<sup>27</sup> Cyprus Business News 26<sup>th</sup> June 2024 at <https://www.cbn.com.cy/article/2024/6/26/782864/decision-on-great-sea-interconnector-after-study-is-received-energy-minister-says/> and <https://www.great-sea-interconnector.com>



## NEW PRIORITIES IN NORWEGIAN RESOURCE MANAGEMENT AND GAS EXPORTS

### *Marshall Hall*

The severe disruption to Europe's gas markets before and after the full-scale Russian invasion of Ukraine in February 2022 unexpectedly brought Norwegian gas supply to the forefront of both short-term efforts to replace Russian gas and longer-term thinking about European energy security and the energy transition. It also accelerated some existing trends in the management of hydrocarbon resources on the Norwegian Continental Shelf (NCS) and prompted a wave of new upstream investment on the NCS to meet the increased post-crisis demand for Norwegian gas. As supply patterns have gradually adjusted to the curtailment of Russian gas, Norwegian gas has emerged from the crisis with a somewhat different role than before, one that emphasises reliable volume, not the maintenance of capacity and supply flexibility. This may have as yet unseen consequences for both European hub-price formation and price volatility. In the longer run, the enhanced role of Norwegian gas in EU energy security promises to involve Norway's state-owned or state-controlled companies much more closely in the shape and timing of the energy transition in major gas-consuming EU countries.

For much of the decade before the full-scale Russian invasion, Norway had often been overlooked in the discussion of European gas supply amid the politically-charged competition between Russia and US LNG. Norway itself was largely content to play a low-key, secondary role as a reliable supplier of term contract gas to European buyers and as a seller of flexible, uncontracted gas to hub markets as it successfully pursued a strategy which exploited the operational flexibility within the NCS upstream sector and the commercial flexibility in Equinor's gas marketing and trading. This strategy was first described in 2010 by Equinor, which markets about 75% of NCS gas exports, as a strategy of 'value over volume'. It was designed to promote the long-term value of NCS gas resources to Norwegian society and served as a moderating or stabilising market influence by deferring production at times of weak demand or low prompt prices, as in 2016 and 2020, and increasing output at times of market tightness.

Norway never sought to become Europe's largest gas supplier but it had achieved this position by the end of 2022 as the government relaxed annual field-level gas production permits and operators postponed planned maintenance following the full-scale invasion of Ukraine. This political and economic response raised total NCS output by 10 bcm in the 12 months following the invasion. Uncontracted LNG imports, mainly from the US, provided by far the largest contribution to replacing Russian pipeline exports to Europe but Norway provided the visible, secure, short-haul pipeline supply. Understandably, its new position as Europe's principal supply source, via seven major pipeline routes to EU and UK terminals, has brought even greater market scrutiny of planned and unplanned outages in NCS upstream production and the Gassco-operated pipeline system. Unsurprisingly, since 2022, European hub prices for prompt delivery have exhibited a new, heightened sensitivity to unexpected changes in NCS pipeline export flows as uncontracted LNG is now the principal price-setting source of European supply.

Like all gas producers, Norwegian producers and the state reaped a huge windfall gain from the crisis; the value of gas exports increased fourfold from an annual average of NOK 230bn in 2016-20 to NOK 950bn per annum in 2021-23, peaking in 2022 at NOK 1,545 bn (\$160bn).

Part of the financial windfall which accrued to NCS operators and the Norwegian state in 2021-22 has since been re-invested in new NCS field developments, a renewed exploration effort and further upstream GHG emission reduction. According to the Norwegian Offshore Directorate (NOD), total upstream investment rose from NOK 183 bn in 2022 to NOK 227 bn in 2023 and is expected to reach NOK 240 bn in 2024, reflecting greater confidence in oil and gas values, increased demand for NCS gas and the temporary fiscal stimulus for new field development approvals granted in 2020. The NCS is enjoying today another period of high offshore activity and expenditure comparable to the last investment 'boom' of 2012-15.

A decade ago, concern was expressed outside Norway about whether it could possibly maintain gas exports at 110 bcm per annum since there had been no significant gas discoveries since 1998 and the Ormen Lange and Asgard fields in the Norwegian Sea had joined more mature North Sea fields in long-term production decline. As Figure 1 shows, gross gas production did indeed peak in 2015-2017 but annual sales and exports of gas have been maintained at 115-120 bcm by the progressive reduction in the re-injection of gas at mature oil fields such as Oseberg, Troll, Gullfaks and Visund. As oil resources at mature fields were depleted, re-injection of gas for long-term oil recovery no longer represented the highest value of produced gas. Between 2015 and 2020 total annual NCS gas re-injection fell from 38 bcm to 27 bcm, as shown in Figure 1. This allowed



NCS *net* gas production (net of re-injection) to reach 124 bcm in 2017, a level repeated in 2022. The Russia-Ukraine crisis accelerated and extended this trend towards lower gas re-injection and higher sales as the realised price of gas on the NCS rose above the price of liquids between 3Q 2021 and 1Q 2023; relative gas and oil values were restored to familiar pre-crisis levels only in 1Q 2024. In 2022, total gas injected on the NCS fell to just 13 bcm and edged only slightly higher to 15 bcm in 2023 as gas prices fell back. Gas is still being injected at mature oil fields such as Oseberg, Grane and Snorre and at remote fields such as Goliat in the Barents Sea with no existing connection to the export pipeline system, so a further large reduction in gas re-injection may not be imminent or economic.

**Figure 1: NCS Gas Production and Sales 2002-23**



Source: Norwegian Offshore Directorate, 2024

The loss of Russian gas from the European market not only raised demand for NCS gas and the value of existing NCS gas resources but it also triggered a desire by many continental European buyers to sign new term contracts with Equinor to replace those formerly held with Gazpromexport. Equinor markets not only its own equity production but also the output of the State’s Direct Financial Interests (SDFI) managed by Petoro and some volumes from smaller producers. Between 2012 and 2020, the volume of Equinor’s term sales contracts had declined progressively from more than 60 bcm to about 40-45 bcm per year and the tenor of such contracts had shortened as oil-indexation was replaced by hub price-related pricing. The progressive loss of Russian gas from central Europe beginning in 2Q 2021, well before the invasion and the sabotage of the undersea Nord Stream pipeline in September 2022, suddenly raised demand for new bilateral contracts from Norway and the early extension of existing contracts.

Between June 2022 and December 2023, Equinor reached agreements with numerous existing customers to increase contractual volumes; it also signed a new 10-year contract with Poland’s PGNiG to supply 2.4 bcm per annum through the new Baltic Pipe from Denmark to Poland which was commissioned in late 2022. Its largest new term commitment was made in December 2023 to supply SEFE, the new state-owned company that inherited Gazprom Germania’s assets, with 10 bcm of gas each year from 2024 to 2033, extendable to 2038. This represented the largest gas sales contract signed in Europe since the Troll agreements signed in 1986. The signing of new term sales contracts in 2022-23 has increased Equinor’s term sales volumes towards 50 bcm per annum in 2024-25, thereby reducing the volume of uncontracted gas it expects to deliver to European hub markets and restricting somewhat the operational and commercial flexibility it enjoys in its gas marketing. Equinor has, at the margin, given up some flexibility in return for more secure gas sales volumes and export revenues.

Interestingly, Equinor’s new agreements with SEFE and RWE were accompanied by non-binding agreements concerning possible joint investment in hydrogen supply to Germany, wind generation and offshore CO<sub>2</sub> storage. This suggests that the

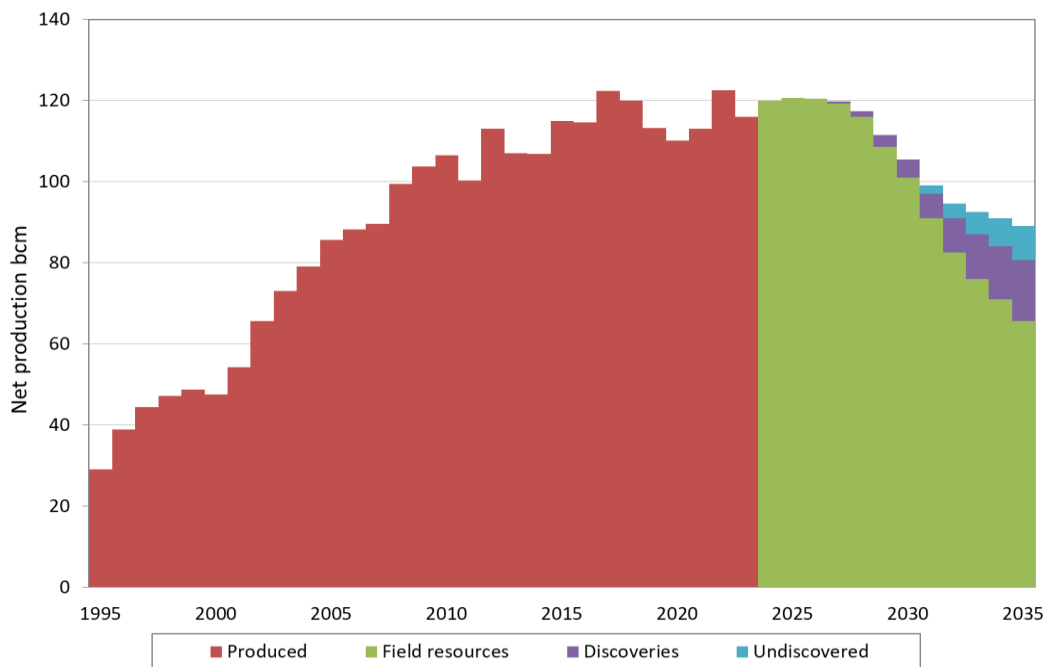


course of decarbonisation in Germany may in future be influenced by indirect Norwegian state investment not only in primary gas supply, but also in low-carbon electricity and hydrogen generation as a way of sharing or mitigating some of the energy transition risks for both gas exporting and importing countries.

The shift in Norway’s gas marketing was made possible by investment and the change in operations at the giant Troll field. At the end of 2023, Troll’s proven gas reserves of 605 bcm accounted for 44% of total reserves on the NCS. In 2018, approval was granted for the Troll Phase 3 project to produce gas from the Troll West gas cap of almost 350 bcm. The first stage of Phase 3 started-up in August 2021 just as the Russia-Ukraine crisis began to intensify. This allowed an increase in the annual production permit at Troll to 38 bcm in 2022-23 and to a record of 40.5 bcm in the current gas year 2023-24. The benefits of this investment are already clearly visible; in the six months November 2023 – April 2024, Troll production averaged 125 mcm/d, close to its new daily capacity of 129 mcm/d. The second stage of Phase 3, approved in May 2024 and due to be implemented by 2027, will provide access to a further 55 bcm of Troll reserves through eight new producing wells and will add a further 7 bcm to projected future annual production. The fundamental change to the management of Troll’s remaining resources represented by the Phase 3 project will consolidate annual Troll production at or above 40 bcm per year, extend plateau production by 5-7 years and prolong its producing life beyond 2050.

In its latest five-year projections, the NOD expects that the NCS will be able to sustain annual gas production at 120 bcm until 2027 before a reduction beginning in 2028. Its record of projecting NCS production capability and exports has been good in the last decade. The outlook to 2035, reproduced in Figure 2 below, is less optimistic, setting out a progressive decline to about 90 bcm in 2035, including a small contribution from fields not yet discovered. This more sanguine outlook for the 2030s reflects the growing maturity of the NCS gas resource base, the lack of major gas discoveries since 1998 and the recent decline in exploration drilling in the Barents Sea which accounts for almost two-thirds (1,040 bcm) of estimated undiscovered gas resources on the NCS (1,635 bcm). Furthermore, only about half the undiscovered gas in the Barents Sea lies in areas currently open for exploration.

**Figure 2: Projected NCS Gas Production to 2035**



Source: Norwegian Offshore Directorate (NOD) 2024

By raising demand for NCS gas for the foreseeable future, or until such time as reform in Russia permits some limited return of Russian gas exports, the Russia-Ukraine crisis has strongly incentivised a new exploration effort in the Barents Sea. At stake is an answer to the decade-old question whether or not gas exists in sufficient quantities in that area to support commercial



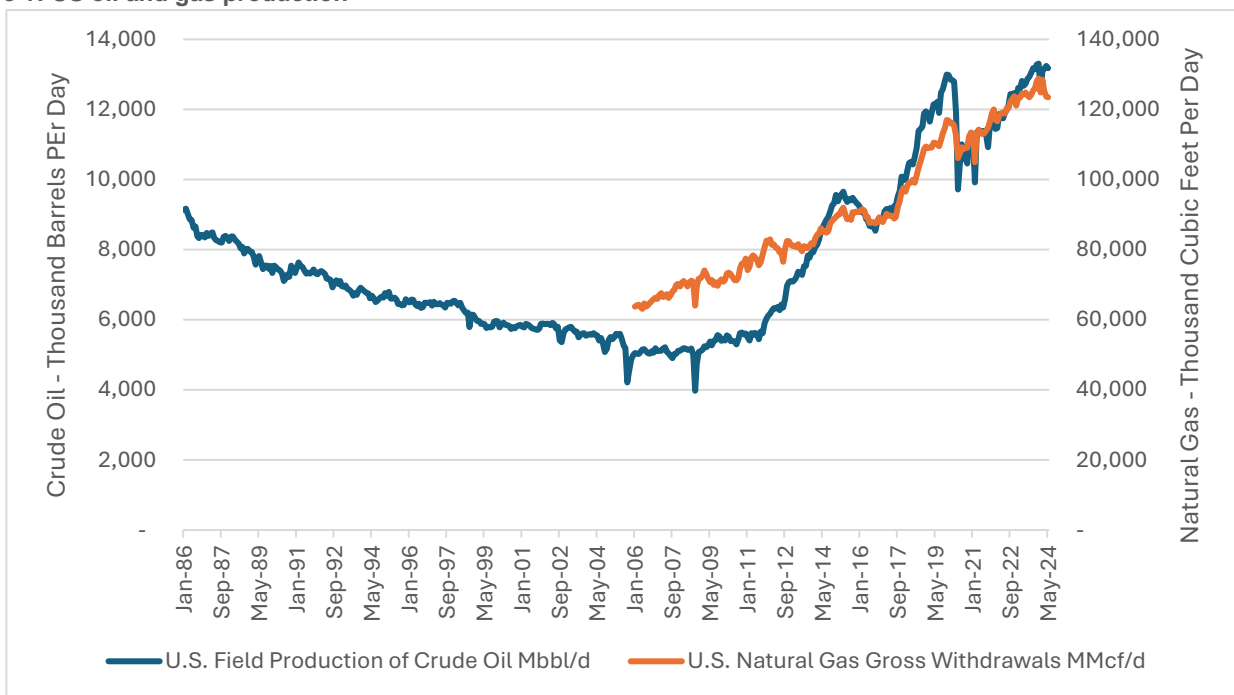
development via LNG or a new northward extension of the export pipeline system. The future of the Snohvit LNG plant has recently been secured to 2040 by approval in 2023 of new emission reduction investment (the 'Snohvit Future' project) but the viability of new long-term gas supply to the plant from the Barents Sea remains in doubt. In 2023, for the first time since 2009, no exploration wells were drilled in the Barents Sea. This temporary neglect has already been corrected by the centre-left government which remains committed to 'develop, not phase out' its offshore resources and by the release of new acreage in recent annual licensing rounds. This year will mark the beginning of a new sustained wave of Barents Sea exploration drilling to seek to firm up new gas resources and to bring existing small discoveries closer to economic viability.

## US SHALE OIL - RELENTLESSLY RESILIENT

**Trisha Curtis**

The resiliency of US shale continues to confound skeptics. Despite fewer rigs drilling and fewer wells drilled, US oil production hit 13 million barrels per day (mbd) in July of 2023 and remained above 13 mbd for the last five months of 2023. These production levels, 12.97 mbd on average for full year 2023, are above the pre-Covid record highs of 2019. US oil production dipped slightly in January 2024 and is now back above 13 mbd despite a significantly lower rig count, which has fallen from an average of 687 in 2023 to under 600 in August 2024. This suggests the US Energy Information Administration (EIA), which has historically underestimated oil supply growth, may have again published production forecasts for 2024 (13.2 mbd) and 2025 (13.7 mbd) that will likely be exceeded.

**Figure 1: US oil and gas production**



Source: EIA

Note: Oil production is on the left axis and gas production is on the right axis

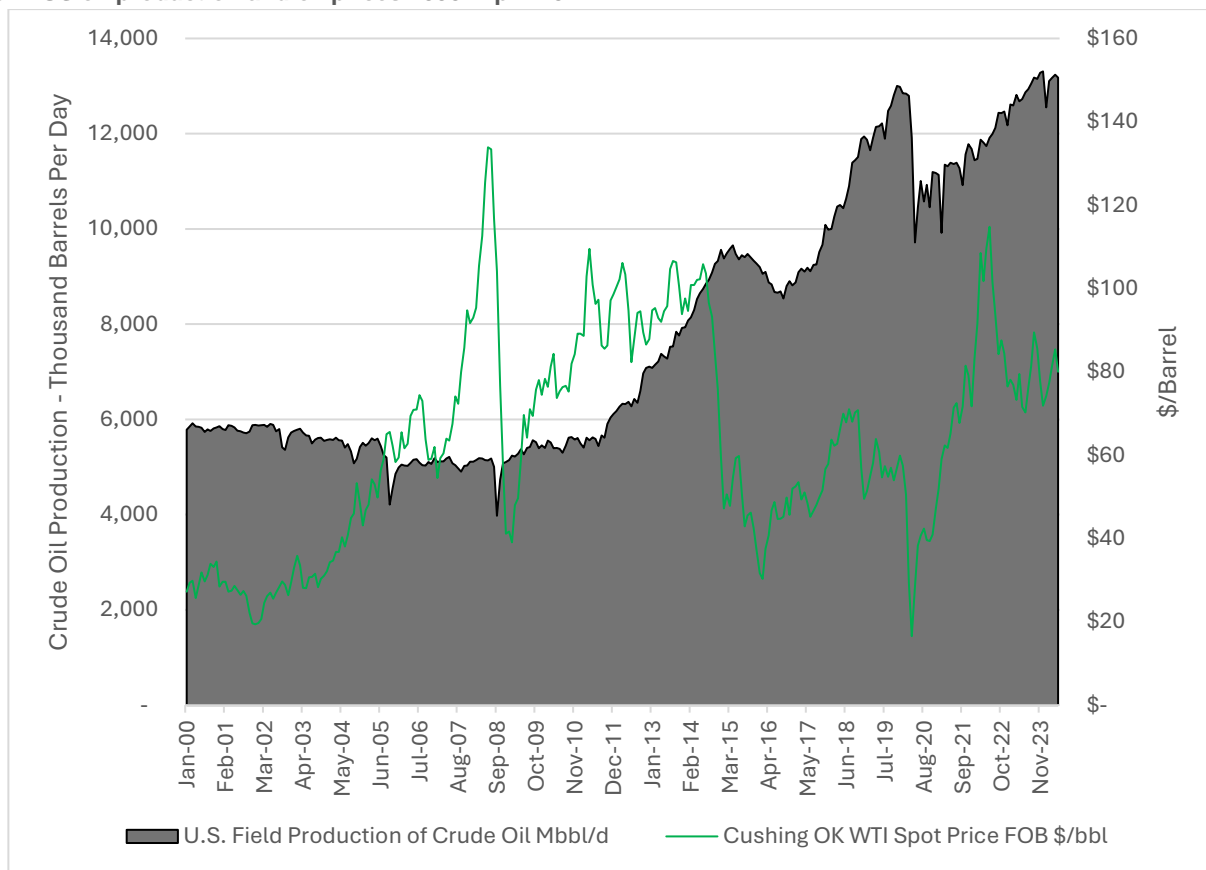
US shale's defiance of markets and prices since 2020 is all the more remarkable in light of market headwinds: soft oil prices, extreme movements and divestments in oil and gas by shareholders, the loss of the retail and generalist investor, US policies discouraging oil and gas production especially on Federal land, increased capital discipline among operators, incredibly low natural gas prices and a materially lower rig count.

The charts tell the story. Despite declines in oil prices since early 2022, US oil production has largely moved upwards. Even with the Covid-related collapse of 2020, which sparked brief negative oil prices and unconventional well shut-ins, wells



continued to be drilled and completed and production continued to increase. An abiding issue for US shale, especially from skeptics, is that of inventory. How much inventory is there? How many wells are actually left to drill? What about the quality of the acreage and the so-called “tiers”? Even if the shale story continues longer than most had expected, the conventional wisdom is that good inventory must be drilled up at some point and production will decline.

**Figure 2: US oil production and oil prices 2000- April 2024**



Source: EIA

**Confluence of drivers for production growth**

US shale oil has continued to defy the skeptics because of a combination of factors: The strength and growth of private operators, the spike in natural gas prices in 2022, service sector achievements and longer laterals; and now sustained high NGL prices in combination with high oil prices, all of which have incentivized incremental production growth. The incentives for incremental growth combined with operators showing greater costs discipline by prioritizing margins has produced better wells, a feature that is reflected by public as well as private operators. Both operators (producing companies) and service companies involved in drilling and completing the wells are better at their jobs than they were only five years ago. The operators understand the rock better, drillers are drilling faster and staying in zone. Completions and frac crews are better at executing and extracting oil by deploying significantly longer laterals. The average lateral length for US horizontal wells has risen from 8,000 feet in 2019 to over 10,000 feet in 2024, as shown in figure 3. For these reasons US production continues to grow, with fewer wells and rigs and arguably lower tiered acreage.

The last five years of shale, which encompasses the post-COVID era, differ from the previous decade for US shale in that operations and operators are largely profitable, for both public and private companies. What has not changed from previous downturns and recoveries are the efficiency gains, increased knowledge of the rock, and the service sector which continues to allow shale production to increase, productivity to hold up, and previous limitations of US shale and unconventionals to be stretched. As operators have reduced activity and focused on profitability, the service sector has responded in kind, with

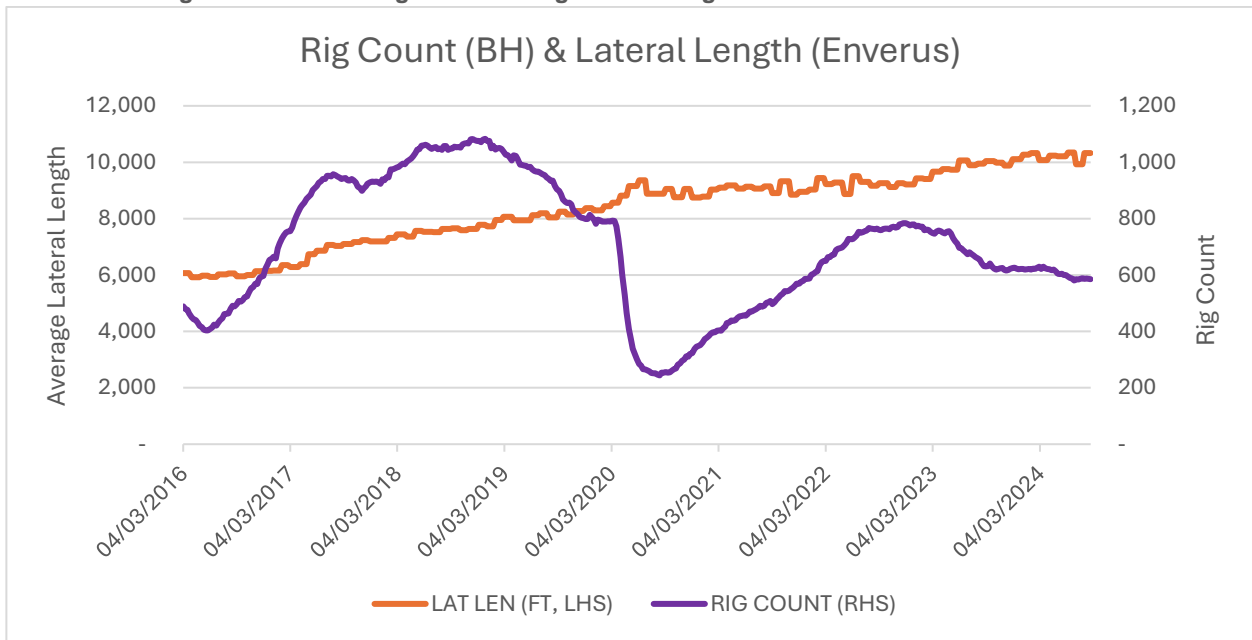


incredible efficiency gains in the speed of drilling and completing wells. As operators have consolidated acreage, especially in the Permian Basin but also across the US, longer laterals can be drilled, greatly enhancing efficiencies and reducing costs, allowing more liquids production for fewer overall wells and rigs.

**Rig count no longer a proxy for supply**

The US rig count, often seen as a proxy for supply, is therefore no longer correlated with the growth of US shale production. The rig count continues to decline, but oil production growth has been maintained. The rig count has declined from nearly 800 rigs in November of 2022 to just under 600 rigs in August of 2024, while production increased by 1 mbd during the same period. After each major oil price drop and subsequent price recovery, the rig count drops and then recovers, but it recovers at significantly lower levels than previous highs. The dramatic decline in the rig count in 2020 wiped out the least efficient rigs when day rates for rigs plummeted. Then, as activity ramped up in 2020 and 2021, the best, most efficient, and most technologically capable rigs were put to work. This technological rig bump and concentration, along with lower oil prices and pressure for returns, meant that wells could be drilled faster, with execution key. Faster drilling times mean fewer rigs are required. The speed at which operators and drilling companies are drilling wells is continuing. Operators took a month to drill a two-mile-long lateral in the Delaware Basin several years ago and now drill those same wells from spud to total depth in roughly seven days, often less. Lateral lengths also continued to grow in 2020, especially in the most well-known and least risky plays such as the Midland Basin in western Texas, part of the Permian Basin. Lateral length growth for horizontal wells has continued to rise incrementally across US shale plays, but has risen substantially in the Permian Basin, leading to speed and efficiencies on the drilling side, as well as for completions. Longer laterals also mean fewer rigs are needed.

**Figure 3: Total US rig count for oil and gas and average lateral length**



Source: Baker Hughes Rigs, Enverus Lateral Length

**Longer laterals defines efficiency gains**

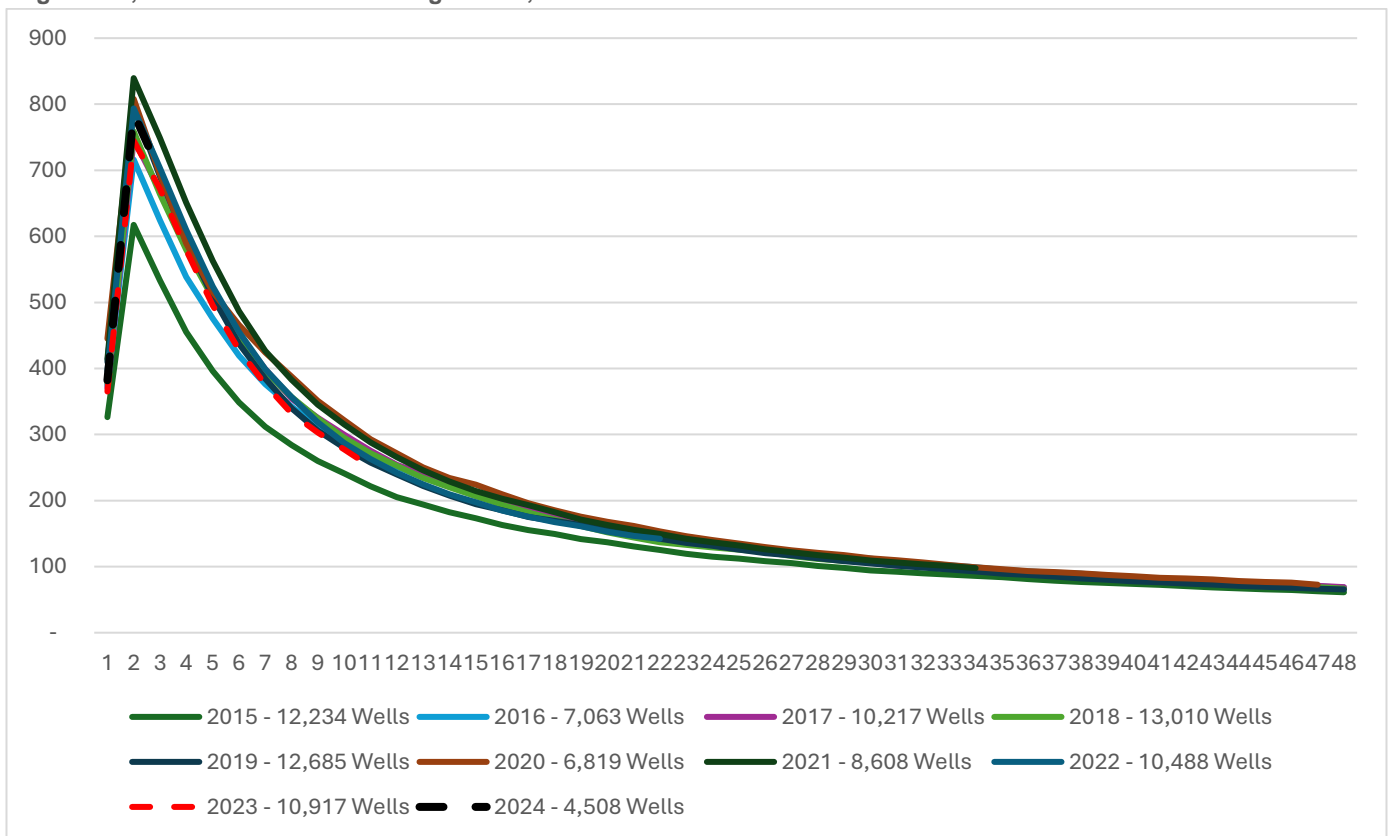
Longer laterals have a cascading impact across the US shale sector, from completions to production. A few years ago, drilling a three-mile-long lateral would have been a riskier endeavor. Rigs and the drilling teams were capable of drilling that far, but there was concern about completing the end or “toe” of that well, making sure the last stretch was properly fraced and productive.

Operators and service providers have now become more comfortable with drilling out plugs and effectively completing laterals as long as three to four miles on a regular basis. The impacts to business include fewer rigs, but a heightened need for capable services companies on the drill outs. In addition, greater execution is required to complete the far toe of that well, ensuring the longer lateral contributes to overall production and does not diminish marginal returns.



The decline curves, normalized for lateral length, are not showing a material drop or decline in productivity despite these significantly longer laterals. This is evident in overall production growth and the incredibly low rig count compared to 2019 levels. The number of wells completed and brought online is also lower than pre-COVID levels and the 2019 high, which means the wells coming online are now longer and productivity is holding up. This achievement is even more impressive considering the pressure on oil and gas for returns, the volatility in natural gas prices, the so-called “lesser” or non-core acreage being drilled, and the growth and maintenance of private operators stepping out of the so called “core” acreage, largely held by the majors and largest independents.

**Figure 4: Decline curves for all major shale oil basins in the US: Permian, Williston, Powder, DJ, Uinta, Anadarko, and Eagle Ford, normalized for lateral length at 10,000 feet**



Source: PetroNerds, Eneverus Raw Data, Normalized for 10,000 feet

The role of private oil and gas companies, like much of the industry in 2020, proved not only resilient, but robust. As larger public oil companies felt the pressure of the political environment, the energy transition push, the policies of the current administration and US government, the vilification of the industry, and the public mood turned against the oil and gas industry, private operators raised capital and put the drill bit back into the ground. The result was a robust response by private operators to the oil price gains out of 2020 and significant private capital flowing into hundreds of private operators. The strength of private operators and their ability to access capital was unforeseen by many analysts. In 2019 certain large equity firms were convinced that the number of private operators would dwindle and 2020 turned that view on its head.

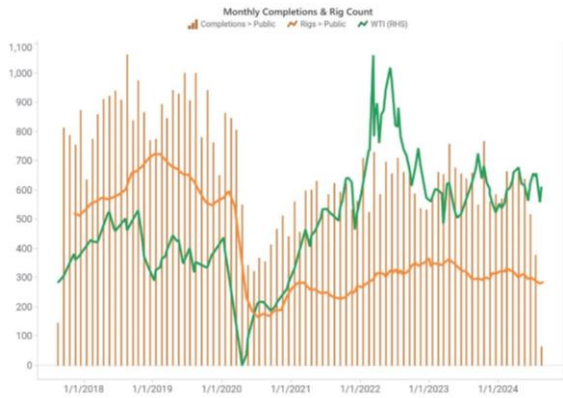
Despite this resiliency and achievements made in the face of price volatility and 2020 headwinds, questions remain for many analysts and observers: how much oil and gas is left to be produced from unconventional and how many wells are there left to drill? Can these production levels be maintained? Could production continue to grow? How much oil is left in the ground? How many laterals are there left to drill? These are valid questions, but the answers continue to evolve just as the US shale patch evolves. Production growth has continued and defied analysts, even those at EIA as the rig count declined, but lateral lengths increased, and productivity was maintained.



Figures 5 and 6: Horizontal wells completed, rig count for public and private operators and WTI oil price

Figure 5

Figure 6



Source: PetroNerds, Enverus Raw Data (Completions data (bars) lag several months)

The number of wells left to drill continues to change as operators gain knowledge of their reservoirs and the rock. Inventory also changes and widens when a company sells acreage it does not want to a smaller player, often private company willing to take more risk, who purchases that acreage and breathes new life into the asset. This derisking and delineating is happening across US shale basins and has been prolific since covid as prices have risen. Operators in the Permian today will say there are tens of thousands of wells left to drill. This inventory means increased production, but it does not take into account the potential of maintaining production levels through secondary recovery, enhanced oil recovery, refracing wells, or simply tinkering with wells and working on basic production enhancements. There are tens of thousands of horizontal wells in the US with the potential for production increases and production maintenance. So much if the shale boom has been about drilling and completing wells and not about maintaining and enhancing production from existing wells.

At present, US unconventional shale production is recovering under 10 per cent of the oil in place. Wells are relatively close together and laterals are wine raked across reservoirs and up and down stacked pay. This is maximizing the recovers and pay of acreage, but this spacing, timing of drilling and completion, and type of completion is still being tinkered with and adjusted. Unconventional production, like older vertical stripper well production, is something that can be nurtured and maximized at minimal cost. Smaller production companies are actively purchasing older horizontal wells and breathing new life into these assets. Refracing or essentially recompleting these wells in the future is another option. Why have there not been more recompletions or refracs to date? There have been some, but as long as an operator has plenty of inventory there is little incentive to refrac given the cost. In sum, operators still have a lot of inventory left to drill in their portfolios and this tends to increase not decrease as operators better understand their acreage and reservoirs and increase inventory and production through organic means rather than purchasing more acreage. When thinking about inventory and production potential in the US, a number of factors need to be considered, including the ability to get more from the rock at present than ten percent, refracing existing wells, and increasing production from current wells

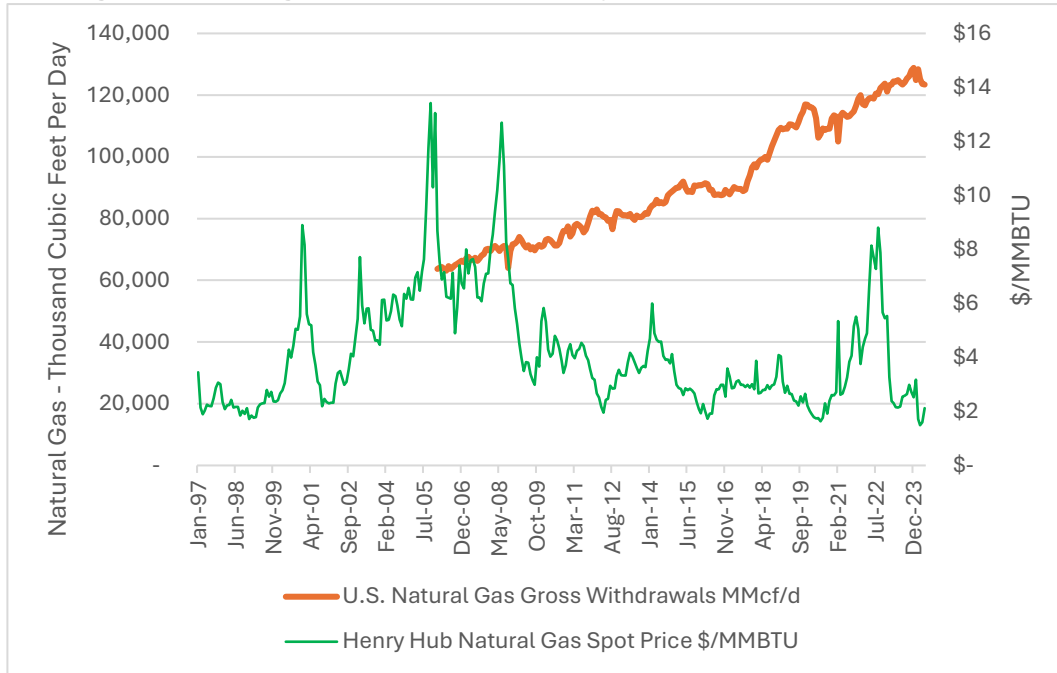
**Natural gas continues to grow despite price**

Natural gas is another fundamental part of the US shale story. Some observers have underestimated the role of natural gas as the driver of oil production as well as the US' huge productive capacity for gas. Unlike oil production which is reactive to prices, US natural gas production has increased regardless of price – as a much smaller molecule than oil, it is relatively easy to frac and produce. When wells age they typically produce more gas when they hit the bubble point in the reservoir.

Natural gas also drives oil production. In the heart of the Delaware Basin, in the Permian Basin in southern New Mexico and far west Texas, the natural gas present in deep, thermally mature and pressured rock, provides oil wells with a robust production driver for bringing the oil out of the ground. Moreover, while gas is not affected by weaker prices, price spikes have prompted operators to prioritize gassier plays. In 2022 when natural gas prices touched \$10/mcf (thousand cubic feet) in the US in August and averaged \$6.50/mcf, operators shifted to gassier areas of their oil plays, both to capture the gas price uplift, but also to gain additional support for the oil they were producing.



Figure 7: US natural gas production, gross withdrawals and Henry Hub price



Source: EIA

Production from natural gas plays with adequate egress (pipeline capacity) surged in 2022. Moreover, private operators were stepping out of known acreage to wildcat gas wells, something not seen since the onset of the unconventional revolution when high natural gas prices spurred the fracking boom in 2006. When private operators take risks on lesser acreage or new and unknown acreage, they are essentially derisking these assets and adding more meat to the pie, more wells and inventory to be drilled in the future.

Current natural gas production and gross withdrawals comprise over 123 Billion Cubic Feet per day, over one quarter of the world’s supply and demand, and more than double that of Russia, the second largest gas producer in the world. This production is coming from the major dry gas plays like the Marcellus and the Haynesville, but also the associated gas in the Permian Basin, the Bakken in North Dakota, and elsewhere across the US. Such production levels combined with slightly warmer winters, have created a buildup in natural gas storage in the US and around the world. [The US consumes 80 Bcf/day and exports 14 Bcf/day in LNG (exports roughly equal to Qatar and Australia) and an additional 10 Bcf/day via pipeline to Canada and Mexico. The balance goes into inventories, which drove the price of natural gas down in 2023 and 2024 as production continued to rise faster than consumption and exports.]

Due to the current dynamics of higher oil prices and low natural gas prices, this trend is largely set to continue unless there is a change or increase in U.S. demand from power generation, greater exports via LNG, or cold snaps which draw down inventory.

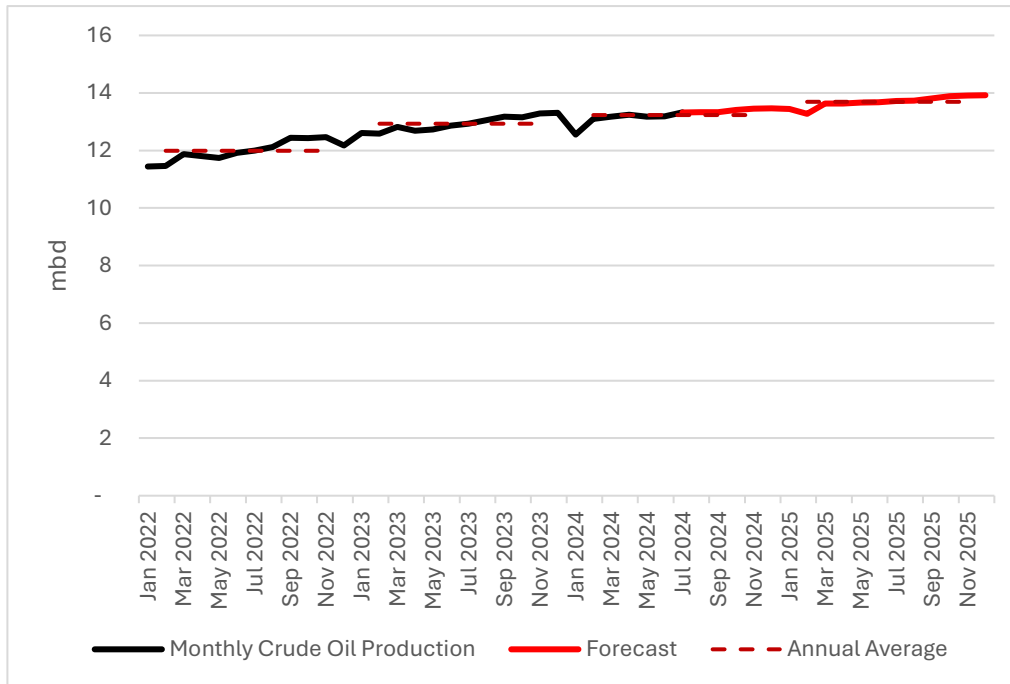
Healthy WTI prices around \$80 mean that oil drilling will continue, along with associated gas production growth. NGL prices, largely tied to oil, are holding up well and incentivizing liquids-rich natural gas production in richer gas areas with higher propane and butane content, also helping to keep natural gas prices depressed. This all supports higher production volumes in oil and condensate in the US and continued production growth in natural gas.

**Conclusion**

The EIA is forecasting modest US oil production gains in 2024 and 2025. These seem not only achievable but somewhat low given current production levels in the US of 13.2 mbd as of May 2024, continued pressure on the rig count, and incrementally longer laterals. The EIA was well under target in previous short-term energy outlooks and annual outlooks for 2023, suggesting it both underestimated and misunderstood the impact of longer laterals and productivity maintenance on production growth.



Figure 8: EIA Oil Production Forecast 2024-2025



Source: EIA August 2024 Short-Term Energy Outlook

## TURKMENISTAN: PIPELINE GAS EXPORTS VERSUS ADDED VALUE

**Danila Bochkarev**

Turkmenistan’s economic and social development is primarily dependent on energy exports, with natural gas accounting for 77 per cent of the total export value. China receives three-quarters of the exported pipeline gas and the sales price paid by the Chinese buyer is nearly double that of Turkmenistan’s other export routes. Energy export revenue also helps to fund the national economy, as the private sector accounts for only 10 percent of total investment. Furthermore, China is expected to utilise Gazprom’s cheaper pipeline supplies as a bargaining chip in future price negotiations with Ashgabat. Turkmenistan is therefore not likely to focus exclusively on supply to China and will explore two other monetization tactics: gas exports via Iran and exports of petrochemicals/fertilizers. The logic is compelling: first, the infrastructure is already in place, so no expenditure is required to export gas via Iran. The second option is (relatively) capital expensive but adds value to Turkmenistan’s gas resources.

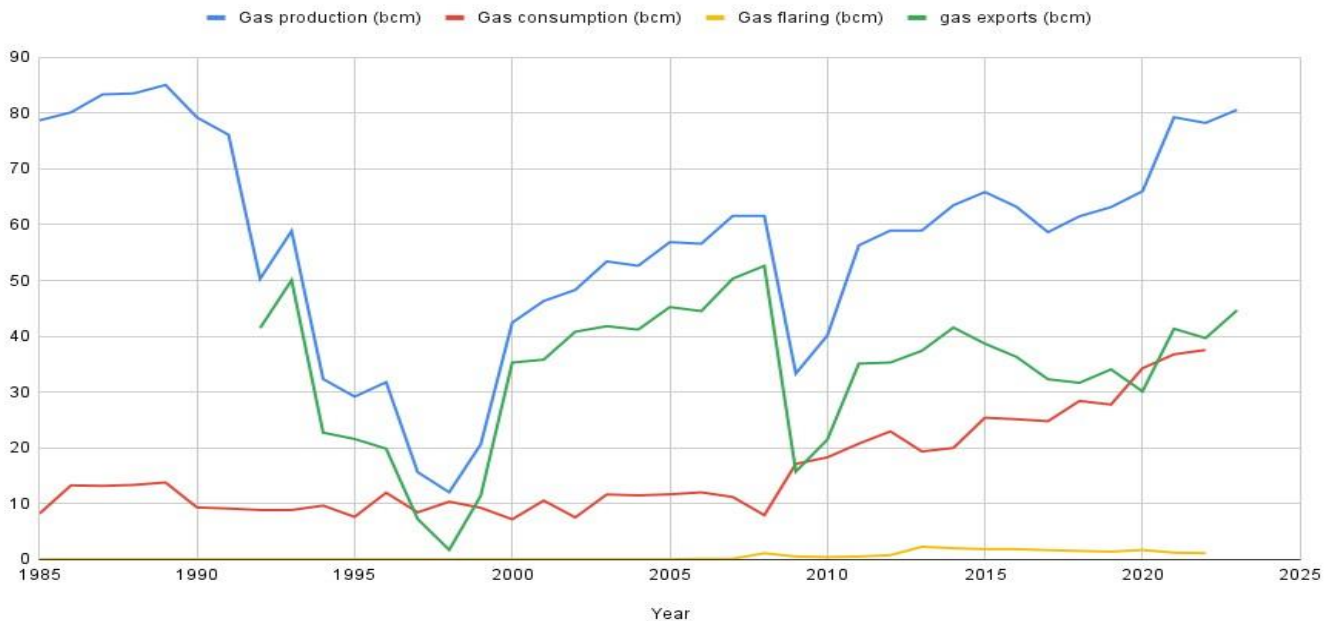
### Large proven reserves but low production growth

Official gas reserve claims by Turkmenistan have always exceeded independent estimates. The country’s gas reserves have been estimated as high as 24.3 tcm (trillion cubic metres) at end of 2011, but are currently estimated both by BP and Cedigaz at 13-14 tcm.<sup>28</sup> Nevertheless, the country still did not manage to match the output records of the Soviet era. Natural gas production started in 1966 and peaked in 1989 at an output of 85.1 bcm (billion cubic metres). After independence, gas production hit a low point in 1998 (12 bcm) to reach the post-Soviet record of 80.6 bcm in 2023.<sup>29</sup>

<sup>28</sup> BP Statistical Review of World Energy consolidated dataset, <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/xlsx/energy-economics/statistical-review/bp-stats-review-2022-consolidated-dataset-panel-format.xlsx>; Cedigaz data.

<sup>29</sup> Ibid.

Figure 1: Turkmenistan's gas balance



Source: BP Statistical Review of World Energy, Turkmenistan official data

Two main problems prevent a rapid rise in gas production and exports:

- Underinvestment in the upstream and midstream due to significant restrictions on foreign investment;
- A confluence of economic, geopolitical and policy factors influencing Turkmenistan's capacity to increase and diversify its exports.

Turkmenistan remains a very closed economy and only allows limited access through service contracts to its onshore gas upstream sector. The sole known exception to this norm is CNPC's Bartyrlyk PSA (Product sharing agreement). This PSA was a component of a larger agreement between China and Turkmenistan, wherein China committed to funding and building the CACP (Central Asian Gas Pipeline). Investors may apply for PSAs in the less resource-rich offshore Caspian fields, as these blocks are subject to more lax regulation. Turkmenistan currently lags behind Kazakhstan in terms of accumulated FDI (foreign direct investment) stock despite the global importance of the country's energy sector. Total FDI in Kazakhstan and Turkmenistan in 2023 was \$157.2 billion and \$42.9 billion, respectively.<sup>30</sup> The dynamics of FDI inflows into resource-rich nations directly reflect investment in the dominant industries (energy sector) of such countries, even though World Bank statistics do not always accurately capture energy-related investment flows.

### Geopolitical and legal challenges hit supply growth

A raft of geopolitical and legal headwinds have made it challenging for Turkmenistan to deliver gas supply and export growth over the last decade or so. The planned TAPI (Trans-Afghanistan Pipeline) supported by the ADB (Asian Development Bank) was intended to transport up to 33 bcma (billion cubic metres per annum) of gas from Turkmenistan to South Asia through Afghanistan. The project was initially intended to be completed in two stages, the first of which would have involved operating the pipeline (with a limited 11 bcma capacity) **without any compression outside Turkmenistan**.<sup>31</sup> However, the pipeline construction was hampered by the regional geopolitics and it seems improbable that even a restricted version of the TAPI will now be realized given the regional economic and geopolitical context.

Following the drastic reduction of Russian gas supplies to Europe, the political concept of a trans-Caspian pipeline link has re-surfaced in the EU and Central Asian political debate. In 2018, the leaders of the Caspian littoral states signed the Convention

<sup>30</sup> UNCTAD's World Investment Report 2024, [https://unctad.org/system/files/official-document/wir2024\\_en.pdf](https://unctad.org/system/files/official-document/wir2024_en.pdf)

<sup>31</sup> <https://www.adb.org/projects/52167-001/main>

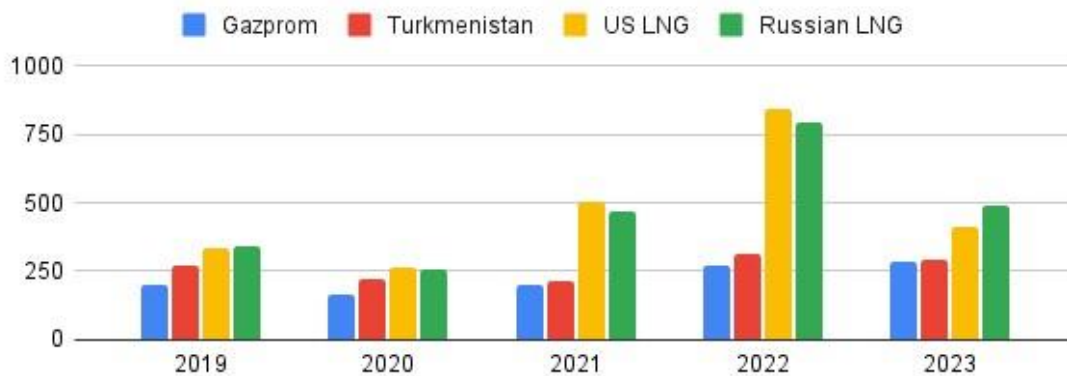


on the Legal Status of the Caspian Sea. This document confirmed that a pipeline route requires “agreement only between countries through which the pipeline crosses”. This should have in principle facilitated the implementation of new projects like the TCP (Trans-Caspian Pipeline). However, there are still significant geopolitical, financial (such as the cost of moving gas from the Caspian to Europe) and environmental obstacles and it thus seems unlikely that this pipeline route will be completed very soon.<sup>32</sup>

**Competition from other suppliers**

When it comes to gas, Turkmenistan’s primary export market is China, whose significance has significantly increased in the past decade. Gas supply from Turkmenistan to China increased from 21.3 bcm (52 percent of the country’s total exports) in 2012 to 32.9 bcm (81 percent of total exports) in 2022. In the meantime, Russia’s Gazprom has emerged as a significant new exporter to China. **The company’s pipeline supply (via the Power of Siberia pipeline) to China grew quickly, from 0.3 bcm (0.23 percent of Chinese imports) in 2019 to 22.7 bcm (13.7 percent of Chinese imports) in 2023.** In 2025, the company’s pipeline gas supply to China is expected to exceed 38 bcm.<sup>33</sup> Even though, the Power of Siberia-2 schedule is still unclear, Gazprom’s supply is already putting downwards pressure on the future price of Turkmenistan gas deliveries to China. Russia’s pipeline export monopoly Gazprom lost a substantial portion of its share in Europe after February 2022. As a result, Gazprom’s natural gas shipments to the EU-27 decreased from 150.2 bcm in 2021 to 25.1 bcm in 2023.<sup>34</sup> As a consequence, Gazprom’s projected 117 bcm of spare production capacity has surfaced again.<sup>35</sup> Following the loss of its previous market, the company was forced to look for new customers in the FSU and Asia and is apparently willing and able to propose significant price discounts. The gas previously supplied to Europe was a low-cost legacy gas from Western Siberia, akin to Turkmenistan in production costs (below \$30 per 1,000 cm). Russian gas has continuously been less expensive than Turkmenistan gas since Gazprom’s supplies began in 2019.

**Figure 2: China border/DES price of Russian, Turkmenistan pipeline gas and US, Russian LNG (in \$ per 1000 cm)**



Source: China customs data, Interfax, Turkmenistan official data

However, Turkmenistan will have to accept price discounts from China (at least for future supply via Line D of the CACP) as China intends to push for price reductions in order to make Turkmen gas competitive with Gazprom’s gas. This is part of China’s broader plan to balance LNG (liquefied natural gas) with pipeline supply from Russia and Turkmenistan.

<sup>32</sup> “The Convention on the Legal Status of the Caspian Sea - A sea or not a sea: that is still the question”, Norton Rose Fulbright, September 2018, <https://www.nortonrosefulbright.com/en/knowledge/publications/5f222b95/the-convention-on-the-legal-status-of-the-caspian-sea---a-sea-or-not-a-sea-that-is-still-the-question>

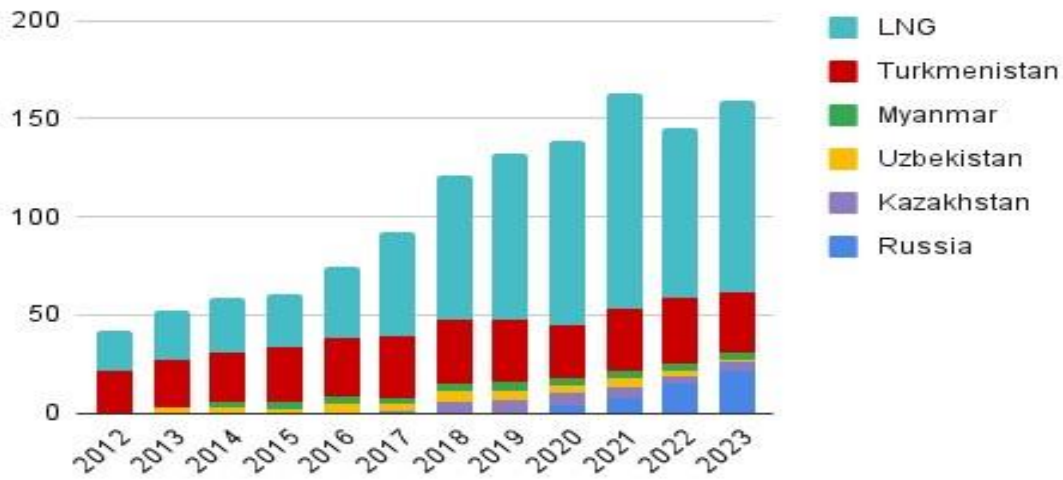
<sup>33</sup> <https://tass.com/economy/1692575>

<sup>34</sup> EC Quarterly Report on European Gas Markets 4Q2021, [https://energy.ec.europa.eu/document/download/d99eef32-84db-4eb0-99b9-a61cc0cd1419\\_en?filename=Quarterly%20report%20on%20European%20gas%20markets\\_Q4%202021.pdf](https://energy.ec.europa.eu/document/download/d99eef32-84db-4eb0-99b9-a61cc0cd1419_en?filename=Quarterly%20report%20on%20European%20gas%20markets_Q4%202021.pdf); Council of the European Union. <https://www.consilium.europa.eu/en/infographics/eu-gas-supply/#:~:text=Bar%20chart%20showing%20how%20gas,to%2056.2%20bcm%20in%202023>

<sup>35</sup> Vitaly Yermakov, 2023, “Catch 22” for Russian gas: plenty of capacity among disappearing market’, Oxford Institute for Energy Studies, <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/01/Catch-22-for-Russian-gas.pdf>



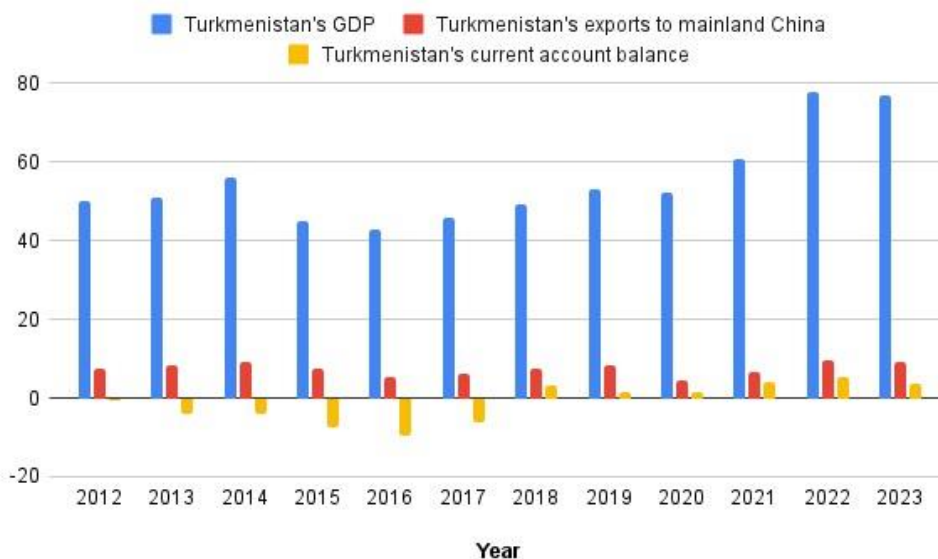
Figure 3: China gas imports by origin (bcm)



Source: BP Statistical Review of World Energy, The Energy Institute Statistical Review of World Energy

Natural gas sales account for three-quarters of the country's overall exports and prices therefore have a significant impact on the trade account and public finances. Gas sales to China represent alone over two thirds of the country's total exports. Even though China pays the highest price for Turkmenistan gas, an excessive dependence on one export market or commodity could jeopardise the country's financial stability. According to Fitch, Turkmenistan would face a fiscal deficit as early as 2025 if energy prices fall.<sup>36</sup> Maintaining a positive current account is strategically important for Turkmenistan, as the government bears 90 per cent of all national investment costs.

Figure 4: Importance of trade with China for Turkmenistan's financial stability



Source: UNCTAD, China customs data, Turkmenistan official statistics

Turkmenistan will continue to increase its exports to China and Uzbekistan if market conditions permit. Uzbekistan has a combined dilemma of dwindling gas reserves and fast expanding population: from 21 million in 1991 to 35.6 million by 2022

<sup>36</sup> <https://www.fitchratings.com/site/pr/10260592>



according to World Bank data.<sup>37</sup> To offset potential shortages, Uzbekistan began importing gas from Russia (daily volumes corresponding to 2.8 bcm/year) and Turkmenistan (expected annual volumes - 2 bcm/year) in 2023.<sup>38</sup> According to *Kommersant*, Russian gas supplies were priced at \$160 per 1,000 cm (with a breakeven price \$138 per 1,000 cm) and the transit of Gazprom's gas via Kazakhstan to Uzbekistan are set to reach 11 bcm in 2026.<sup>39</sup> Turkmenistan's gas appears to have a limited yet lucrative market niche here as Turkmen gas can supply cheaper gas due to the short transport distance between the country's major gas fields and Uzbekistan's main consumption centers. However, recently signed long-term gas supply contract between Russia and Uzbekistan, which may feature a take-or-pay clause, as well as the supply and demand dynamics of the local gas market might limit Turkmenistan's gas expansion into Uzbekistan.

Turkmenistan may theoretically export up to 20 bcm per year to Azerbaijan, Turkey, Europe and Iraq through existing pipeline links with Iran and eventual expansion of the Trans Anatolian (TANAP) pipeline. In November 2021, Azerbaijan, Iran and Turkmenistan signed a trilateral gas 1.5-2 bcm/year swap agreement to that end.<sup>40</sup> According to data provided by Azerbaijan's State Statistics Committee reports the country imported 1.51 bcm from Turkmenistan or a 77 per cent year-on-year increase.<sup>41</sup> In October 2023, Turkmenistan also agreed to supply Iraq 9 bcma under a swap agreement involving Iran.<sup>42</sup> According to publicly available data, the price of gas supplied via Iran is lower than Turkmenistan's pipeline deliveries to China. In January 2024, the border price of Turkmenistan's gas supplied to Azerbaijan reached \$150 per 1000 cm.<sup>43</sup>

As an alternative method of monetizing its gas, Turkmenistan has initiated a number of projects in the petrochemical, fertilizer and GTL domains, backed by international investors. In 2022, petroleum products (\$1.28 billion) and fertilizers (\$0.585 billion) were second and third most valuable of Turkmenistan's exports, respectively, behind natural gas (\$9.21 billion). The fertilizer industry is seen as a new gold rush for Turkmenistan, allowing the country to get over physical and virtual export barriers. Fertilizer production costs are low in comparison to their sales price (\$150-\$200 per tonne or less, which is 2.5-3 times cheaper than the FOB fertilizer price), making this strategy particularly appealing to Turkmenistan as a low-cost gas producer, as well as for foreign investors. In 2022, Hyundai and Daewoo signed MoUs with Turkmenistan for fertilizer plants, confirming the interest of large multinationals in the development of Turkmenistan's petrochemical sector.

## POLITICAL PRIORITIES SET TONE FOR GAS TO 2030

### *Bill Farren-Price*

The political priorities of industrialized gas consumer countries are starting to play a bigger role in the prospects for gas demand in the medium term to 2030, one of two key political drivers with geopolitics for medium-term gas demand. The surge in support for right-of-centre parties in major European countries largely failed to convert into electoral success in 2023/2024 elections, which means that the broad drift of European climate policy remains intact, even if delivery of low-carbon energy solutions is unlikely to meet what have become increasingly political and hard-to-achieve deadlines. Europe's energy markets did not just endure but enabled a supply response to the Ukraine war crisis of 2022. While the price both literally and figuratively for that crisis has been high, the market system delivered. In the aftermath of the crisis, it is EU and national government energy and climate policies that are now back in the driving seat and will help define the timing of any regional peak in gas demand.

The second profound influence on gas will be the outcome of geopolitical conflicts affecting major global gas and LNG producers, an area that generally receives less focus than regulation. The ability of the Ukraine-Russia war to reduce gas supply to Europe further is now limited to the 25-30 bcma of supply delivered via Ukraine transit and Türkiye. A resolution of that

<sup>37</sup> <https://data.worldbank.org/indicator/SP.POP.TOTL?locations=UZ>

<sup>38</sup> <https://kun.uz/en/news/2023/08/25/turkmenistan-to-supply-up-to-2-billion-cubic-meters-of-gas-to-uzbekistan-per-year>.

<sup>39</sup> <https://www.kommersant.ru/doc/6553261>

<sup>40</sup> <https://eurasianet.org/azerbaijan-turkmenistan-and-iran-reach-gas-trade-deal>

<sup>41</sup> <https://daryo.uz/en/2024/04/24/azerbaijan-increases-imports-of-turkmen-gas-via-iran>

<sup>42</sup> <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/102523-turkmenistan-to-supply-9-bcm-year-of-gas-to-iraq-under-diversification-drive>

<sup>43</sup> <https://caspianbarrel.org/en/2024/04/in-january-2024-azerbaijan-increased-imports-of-turkmen-gas-by-2-5-times/>



conflict could see over time prospects for a limited restart of some of those Russian gas flows into southeast Europe where companies still have long-term gas contracts with Gazprom and/or limited options for supply diversification, although the infrastructure in Germany and Poland that carried Russian gas to Europe is no longer available and there is no enthusiasm in Brussels to rebuild any reliance on Russian energy.

### **European centrists retain power, climate policy unmoved**

As of August 2024, the prospect of a rightist-led rolling-back of climate change policies, which would all other things equal have meant gas retaining more market share for longer, seems to have been dispelled. European elections have returned centrist administrations and kept those right of centre voices calling for a reversal of climate change commitments firmly on the sidelines. The right is still there and possibly more influential in several key constituencies including farmers and industrial workers. But it is not in power.

Across the Atlantic, the outcome of the US presidential election in November 2024 could shift US energy priorities. Even there however, considerable progress in building out renewables in red states will make a wholesale reversal of the Inflation Reduction Act, which set out the most aggressive western policy commitment to decarbonization, a difficult needle to thread for a putative second Trump administration. The Trump 2024 campaign has promised to reverse the Biden administration's freeze on new LNG projects<sup>44</sup>, scrap methane emission fees for operators, expand offshore drilling and withdraw again from the 2016 Paris agreement.

In Europe as elsewhere however, it is not climate policy for its own sake that is altering the trajectory of gas demand in the medium term, but rather alternative policy frameworks that have risen to prominence in an industrial world that is less comfortable with the basic tenets of globalization and all it entails: free trade, global markets and the rule of law governing these spaces.

For Brussels, the Ukraine crisis response was driven by a reluctance to allow critical energy import dependency, in this case on Russian gas, to dominate the bloc's energy relationships. As such the resulting RepowerEU pledges are aimed at promoting security of supply in the power sector by achieving a swift build-out of renewables, while also seeking to reindustrialize the bloc's economies according to a green template.

### **Climate strategy subsumed under voter-friendly policies**

In the UK, the new Labour government is explicit on this point. It acknowledges climate change as one of the greatest long-term challenges but sees climate policy, particularly the build-out of renewables and low carbon gases as an approach that will also "generate growth, tackle the cost-of-living crisis and make Britain energy independent once again"<sup>45</sup>. In other words, the renewables build-out is a means to lower consumer energy costs and wean the economy off imported hydrocarbons, whose prices are set by international market factors.

These are lofty ambitions but significant in that the political price for climate policy has become the cloak of industrial policy, affordability and energy security – factors that have won public support in this year's elections. This pragmatism, which also allows concessions to consumers on issues such as heat-pumps versus gas boilers, has drawn the sting from public disquiet with the cost and structural change to energy systems required to address the long-term challenge of carbon emissions.

While the consumer-facing elements of climate policy remain sensitive, there is plenty of evidence that this political strategy is delivering. Renewables are having a significant impact on gas demand in the power sector, even though the fuel remains critical in covering for renewables' systemic intermittency. In Europe, which is enduring its third year of contracting gas demand in 2024, gas for power had fallen by 15 per cent year-on-year in the first half of 2024, while renewables in that sector have accounted for 17 per cent of growth, an additional 100 TWh versus H1 2023. The same picture has emerged in the UK: renewables continue to displace gas in the power sector, providing a record 46 per cent of UK power in 2023, while fossil fuels accounted for 37 per cent. Renewables plus nuclear and other low-carbon generation accounted rose to a record 60 per cent in the year.<sup>46</sup>

<sup>44</sup> <https://www.oxfordenergy.org/publications/what-next-for-us-lng-exports/>

<sup>45</sup> <https://labour.org.uk/change/make-britain-a-clean-energy-superpower/>

<sup>46</sup> <https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2024>



But the steady wind and solar-led progress towards decarbonizing the power sector is not matched elsewhere. Efforts to replace methane for process heat in industry are more mixed, with alternative low carbon gases (biogas, blue or green hydrogen) still in their infancy as energy sources. Elsewhere, the challenge of decarbonizing and electrifying residential gas users (space and water heating and cooking) is compounded by the cost of heat pumps and the need to properly insulate older housing stock before they can be installed, replacing gas boilers. Europe has prioritized the regulation of infrastructure for low carbon hydrogen - but regulations are clearly running ahead of private/public investment in its production.

While methane-derived blue hydrogen should be a good option when coupled with carbon capture and storage, renewable-powered electrolysis to produce green hydrogen looks like a distant option until power grids are fully decarbonized and ample surplus renewables generation capacity exists. The pace of the renewables build-out is impressive in China, US and Europe but the surplus capacity needed to run large scale electrolysis is not realistic this decade. Final investment decisions on gigawatt-sized electrolysis projects are yet to be made, deepening the gulf between political aspiration and reality.

### **Conflict, the ultimate supply risk**

Policy and regulation aside, the less predictable arena of global geopolitics and its impact on markets is also driving gas production, trade, prices and ultimately medium to long-term gas demand. Russia's invasion of Ukraine and the subsequent disruption to Russian gas flows to Europe created a market crisis in 2022 that played out with gas prices spiking to record levels and a resulting surge in LNG flows to Europe. European policy-makers announced demand-side management and storage policies which over time have helped reverse that market impact. But it was a classic supply squeeze and the market behaved predictably, with high prices crimping demand regardless of government targets.

Despite the fact that only a fraction of former Russian gas flows to Europe remain, of which some volumes ironically transit Ukraine, Kyiv's August 2024 incursion into Kursk Oblast, where gas exports from Russia enter Ukraine, has prompted a fresh price spike, albeit only a shadow of the 2022 market event. The 12 bcm of Russian gas that flows into central eastern Europe via Ukraine is not generally expected to continue beyond the current contract that expires on 31 December 2024. Even so, the market's mini spike in early August is a reminder that the geopolitics of conflict have the capacity to keep energy markets on edge when they involve major producers or energy transportation.

As ever, Middle East conflicts have the capacity to influence hydrocarbon prices. Beyond the awful human toll, the Israel-Gaza conflict that was sparked in October 2023 set off a cascade of regional gas industry impacts – some direct and others more oblique.<sup>47</sup> The conflict shuttered some regional gas production and cross-border trade initially. But the more significant impact for global gas was the decision by Yemen's Houthi opposition to target ships transiting the Red Sea and Gulf of Aden, which forced LNG carriers heading from the Gulf to the Atlantic basin to use the longer Cape route.<sup>48</sup> In this case, the impacts were still limited since production itself was unaffected, only transportation logistics.

Barring a widening of the Middle East conflict to involve Iran and its proxies and put fresh restrictions on Gulf shipping or gas production, the prospects for a global supply squeeze to match the 2022 Ukraine crisis appear limited. The planned wave of new liquefaction projects that should come onstream in 2025-2028 imply looser global gas balances, which will soften prices in any case. An end to the Ukraine conflict could over time involve some limited restart of Russian gas exports to some parts of Europe although a wholesale restart is unlikely given the outstanding lawsuits between European gas buyers and Gazprom on the one hand; and the strategic decision to reduce reliance on imported fossil fuel energy on the other.

In conclusion, while the strategic push for decarbonization is irreversible, the inertia of a continental gas-based energy system is enormous. While European policy-makers have moved swiftly on developing policy and regulation to prepare the playing field for the investments that are needed in low carbon energy solutions, they have yet to provide sufficient incentives to unlock the scale of private and public investment that will be needed to replace the gas system that has underpinned European industrial competitiveness. While progress on building out renewable power has been a bright spot, replacing methane with low carbon gas in residential/commercial heating and industrial process heat still looks very challenging. Moreover, if gas is to be retained in some of these key uses, major investment in carbon management will be needed – another area where progress is well below that required to meet near or medium-term emissions targets.

<sup>47</sup> <https://www.oxfordenergy.org/publications/east-med-gaza-crisis-tightens-regional-gas-balances/>

<sup>48</sup> <https://www.oxfordenergy.org/publications/lng-shipping-chokepoints-the-impact-of-red-sea-and-panama-canal-disruption/>



## DECARBONIZING THE EU GAS NETWORK: IS THE NEW EU REGULATORY FRAMEWORK UP TO THE CHALLENGE?

**Katja Yafimava**

The EU gas system is undergoing a significant transformation in line with the EU decarbonization policies aimed at achieving legally-binding net-zero GHG emission targets by 2050. The EU views its future gas system as consisting of two separate systems – one for (progressively decarbonized) methane and another for hydrogen – both developing in parallel and co-existing, as part of ongoing European energy system decarbonization. This vision is reflected in the EU Renewable and Natural Gases and Hydrogen (RNGH) Directive and the RNGH Regulation – otherwise known as the Decarbonized Gas and Hydrogen Package. The RNGH Directive and the RNGH Regulation were published in the EU Official Journal on 15 July 2024 and entered into force on 4 August 2024. Together with the TEN-E Regulation (adopted in 2022), they constitute the new regulatory framework, governing construction of, and access to, hydrogen networks, and the re-purposing and de-commissioning of, and access to, natural gas networks in the EU.

This framework is aimed primarily at the development and operation of the hydrogen system while it also amends existing rules for the natural gas system. The framework will be of paramount importance for governing the process of upcoming gas network transformation and ensuring that it adheres to the EU vision. The scale of transformation is enormous given that at present the EU gas system consists primarily of the natural gas system (networks, storage, LNG import terminals) with very little hydrogen infrastructure yet in place. As far as the network component is concerned, there are 200,000 km of transmission and over 2,000,000 km of distribution natural gas pipelines, and only ~2,000 km of hydrogen networks (mostly privately owned, small capacity, unregulated lines). The new framework faces the challenge of enabling and supporting the development of the EU hydrogen system – including hydrogen networks – without stifling the (as yet non-existent) hydrogen market.

There are two key criteria that the framework must meet to overcome this challenge. First, it must provide flexibility, enabling a step-by-step development of hydrogen networks, whose topology, scale and size will depend on the supply and demand for hydrogen (which is at present highly uncertain) and on the decarbonisation pathways chosen by (mostly) industrial users (i.e. via renewable and/or low - carbon hydrogen), while also enabling the required evolution of natural gas networks. Second, it must provide assurance that gas network decarbonisation – constituted by phasing out natural gas networks and phasing in hydrogen networks – will take place in a co-ordinated manner across the EU without negatively affecting the security of natural gas supply.

### Examining the EU regulatory framework's flexibility

Examination of the provisions of the RNGH Directive and the RNGH Regulation governing the operation of natural gas and hydrogen systems provides an insight into the EU regulatory framework's flexibility. Both documents preserved central principles governing the **natural gas market** (unbundling models, regulated access to networks and LNG terminals, negotiated access to storage, regulated tariffs), while adding new provisions aimed at decarbonisation and security of supply. As far as decarbonisation is concerned, the RNGH Directive prohibits the signing of new long-term contracts (LTCs) for unabated fossil gas with a duration beyond 2049, with no exemptions allowed – in sync with the EU's 'net zero' 2050 target. The RNGH Regulation facilitates access of renewable and low carbon gases to the natural gas system by mandating tariff discounts at the entry points from production facilities and at the intra-EU Interconnection Points (100% for renewable and 75% for low carbon); it also mandates discounts at the entry points from, and the exit points to, storage facilities (100% for both renewable and low carbon). However, national regulators are allowed not to apply such discounts or set lower rates. As far as measures aimed at security of supply are concerned, the RNGH Regulation incorporates some 'emergency' legislation, adopted during the 2021-23 energy crisis. This includes:

- mandating certification of storage system operators (SSOs),
- enabling regulators to apply a tariff discount (of up to 100 per cent) in respect of natural gas at entry points from and exit points to storage facilities and at entry points from LNG facilities until 31 December 2025 and potentially beyond,
- establishing the EU Energy Platform for demand aggregation and joint purchasing, and
- amending gas sharing (solidarity) rules.

Some measures that could interfere with market functioning were softened (e.g. demand aggregation and joint purchasing were



not made mandatory) whereas others (e.g. mandatory gas storage filling targets/trajectories and demand reduction) were not included. Yet the Regulation's permission for regulators to abolish tariffs at the IPs could potentially enable market distortion. Guided by the REPowerEU Plan, some measures were specifically directed against Russian gas, such as enabling national regulators to introduce (pipeline and LNG) import capacity restrictions and excluding Russian gas supplies from the EU Platform. While existing capacity allocation mechanisms (CAM) and congestion management procedures (CMP) have been preserved, changes are expected as part of the CAM network code revision, aimed at more efficient utilisation of existing capacity in view of changed flow patterns in the aftermath of the crisis, whereas an incremental (new) capacity allocation procedure could be eliminated altogether. Should this happen, an exemption regime – requiring the approval of national regulators and ultimately the EC – would become the only way to build new natural gas infrastructure. Thus, while the regulatory framework for the natural gas market has been largely preserved, the planned changes would introduce some uncertainty in respect of future capacity allocation.

The RNGH Directive and the RNGH Regulation have largely extended the rules governing the (mature) natural gas market onto the (nascent) **hydrogen market**. The Directive requires hydrogen transmission network operators (HTNOs) to be unbundled under the same model as natural gas TSOs (Ownership Unbundling, Independent Transmission Operator (integrated HTNO), or Independent System Operator (independent HTNO)). It also mandates horizontal legal unbundling (allowing natural gas network operators to operate a hydrogen network within a framework of a separate legal entity), with regulators empowered to provide derogations. It stipulates regulated access to (onshore and offshore) hydrogen networks, regulated access to hydrogen storage and negotiated access to hydrogen (ammonia) terminals. This regulatory straight-jacket was partly loosened by introducing a transition period for implementing regulated access to hydrogen networks and storages (making it mandatory from 1 January 2033) as well as by allowing an ITO unbundling model to be used indefinitely.

Some regulatory flexibility was provided by establishing an exemptions and derogations regime. The Directive allowed the regulators to grant some potentially indefinite **derogations** for:

- existing hydrogen networks belonging to a vertically integrated undertaking from the provisions of the Directive on network access, unbundling of HTNOs, unbundling of HDNOs, certification of HTNOs and from some of the provisions of the RNGH Regulation, for instance on access to networks and regional cooperation within ENNOH, for as long as the existing network is not connected to another network and not expanded by more than 5%;
- existing and new hydrogen networks transporting hydrogen within a geographically confined, industrial or commercial area from the provisions of the Directive on vertical unbundling of HTNOs, unbundling of HDNOs, and certification for HTNOs, for as long as the network does not include hydrogen interconnectors, does not have direct connections to hydrogen storage facilities or terminals, primarily supplies hydrogen to directly connected customers, and is not connected to any other hydrogen network.

The Regulation allows the regulators to grant exemptions for a defined period for:

- major new (or significant increases in existing) hydrogen infrastructure (interconnections, import terminals and underground storages) from the Directive's provisions on vertical unbundling of HTNOs, access to networks, terminals and storages, and from some of the Regulation's provisions (e.g. access to networks), subject to the EC's approval.

### Examining the EU regulatory framework's coordination provisions

Examination of the RNGH Directive, the RNGH Regulation and the TEN-E Regulation's provisions governing national (NDPs) and EU-wide (TYNDPs) network development plans provides an insight into the EU regulatory framework's ability to guarantee coordinated network decarbonisation across the EU, without negatively affecting security of supply. While network development coordination has previously been achieved through the biannual EU-wide natural gas TYNDPs, the RNGH Regulation mandates development of two separate TYNDPs – one for natural gas and another for hydrogen – splitting responsibility between ENTSOG and ENNOH (yet to be established in 2025). ENTSOG will remain responsible for developing both TYNDPs until ENNOH assumes responsibility for developing the hydrogen TYNDP 2028. From then, ENTSOG will only be responsible for developing the natural gas TYNDPs. ENTSOG has not been obliged to develop natural gas CBA methodology since 2022, when the TEN-E Regulation made natural gas infrastructure, except that which is associated with repurposing, ineligible for a PCI status. It will no longer be obliged to develop any CBA methodology once the responsibility for developing hydrogen CBA methodology shifts to ENNOH. This applies to hydrogen projects, including natural gas projects associated with repurposing but



not any other natural gas projects. This makes it unclear which methodology – if any – will be applied by ENTSOG for analysing the existing and prospective natural gas infrastructure in its future gas TYNDPs, including in respect of security of supply. This problem could be overcome if both the EC and ACER were to recommend ENTSOG develop such methodology. It is not legally required to do so but is not prohibited from doing so either.

Significant and growing inconsistency between the EU-wide TYNDPs and national NDPs presents another problem for coordinated network development across the EU. This is demonstrated by the TYNDP 2022, where only 17% of hydrogen infrastructure projects were included in the NDPs. The decision to include many projects identified through the REPowerEU Plan rather than through NDPs, which would have been the normal procedure, was the key reason for TYNDP 2022–NDP inconsistency. Subsequently, many of these projects have been included in the first EU hydrogen PCI/PMI with only a light-touch assessment based on the EC's simplified CBA methodology. While some accepted projects reflect the reality as they are planned to be located in or connect existing industrial clusters, others appear to reflect EC desire to 'fill in' the REPowerEU Plan hydrogen import corridors rather than genuine readiness to invest.

TSOs and HTNOs are obliged to include information on natural gas infrastructure that can or will be decommissioned, and on hydrogen infrastructure that can or will be repurposed, in their separate or integrated NDPs. NRAs are obliged to ensure coordinated development of networks at national level and through cross-border coordination with adjacent NRAs. It is paramount therefore that only those projects that have been included in the national NDPs are also included in the TYNDPs. Negative impacts of TYNDP-NDP inconsistency will probably be more pronounced in the future than in the past, as the EU gas system is undergoing a profound transformation caused by EU decarbonisation policies. This inconsistency could potentially endanger security of natural gas supply by preventing hydrogen networks from being phased in and natural gas networks from being phased out in a coordinated manner across the EU.

#### **Examining the EU regulatory framework's financing provisions**

Finally, it is not clear yet how the transformation will be financed. As re-purposing of existing natural gas networks to transport hydrogen is expected to play a significant role in developing the European hydrogen network, the rules governing the transfer of natural gas assets for repurposing – including how their transfer value is determined – will be of key importance. While the RNGH Regulation mandates separate RABs for natural gas, hydrogen and electricity assets, it ultimately allows cross-subsidization between different regulated services – e.g. natural gas and hydrogen transportation – in the form of a dedicated charge, which could only be applied to end-users within the same EU member state and subject to regulator's confirmation that the network financing through access tariffs paid by its users only was not viable. This would limit cross-subsidization to the national level, with regulators approving the size and duration of the transfer charge, the value of transferred assets and inter-temporal cost allocation in line with the rules to be stipulated in the EU Network Codes for hydrogen developed by the end of the 2020s. It would also allow hydrogen network operators to spread the cost recovery over time. The TEN-E Regulation has enabled financial support for different categories of cross-border infrastructure, relevant for the development of the European hydrogen network – such as new onshore and offshore hydrogen pipelines and repurposed natural gas pipelines, hydrogen storage facilities, hydrogen (ammonia) import terminals, CO<sub>2</sub> pipelines and storages – by making them eligible for a PCI/PMI status and hence EU CEF funding. Although the CEF energy infrastructure budget is constrained (5.84 bn euros during 2021–27), a project that has received funds under CEF may also receive funds from other EU funding programmes.

#### **Conclusions**

Regulatory flexibility, built into the EU regulatory framework by means of establishing a transition implementation period, allowing exemptions and derogations for existing and new hydrogen infrastructure and enabling financial and regulatory support via a PCI/PMI status, is far from certain to be sufficient for enabling the EU hydrogen market to develop at scale. The transition period allowed – until 1 January 2033, when regulated access to networks and storages becomes mandatory – is likely to prove to be too short, in which case an avalanche of applications for exemptions and derogations can be expected. The framework also does not guarantee that phasing in hydrogen networks and phasing out natural gas networks – either through re-purposing or de-commissioning – will be carried out in a coordinated manner across the EU, without negatively affecting the security of natural gas supply.

Overall, the framework appears to be built on the premise that the EU hydrogen market will develop fast and at scale, while it lacks the "safety cushion" – including in respect of re-purposing the natural gas networks that could still be needed – should the



hydrogen market roll-out be slower and more gradual. However, as the speed and the scale of the hydrogen market development in the EU becomes more apparent, the regulatory framework could be adjusted. The framework is not complete yet, as more rules will be established in the upcoming EU Network Codes for hydrogen (and the amended Network Codes for natural gas) in the 2020s, as the hydrogen market rolls out (or fails to do so) in the EU. Thus, the framework will continue to evolve and remain 'work in progress' at least until 2030 and possibly beyond.

## EUROPE'S REPOWEREU HYDROGEN PLAN TWO YEARS ON: A PROGRESS UPDATE

*Martin Lambert and Aliaksei Patonia*

In March 2022, shortly after the Russian invasion of Ukraine, the European Commission published its initial communication "Joint European Action for more affordable, secure and sustainable energy", referred to as "REPowerEU"<sup>49</sup> with the high-level objective to "make Europe independent from Russian fossil fuels well before 2030". In May 2022, this was followed by a further package of documents putting more detail around the aspirational targets set in the initial publication. The package contained a wide range of measures including increasing energy efficiency, diversifying energy supplies and accelerating renewable electricity production. For renewable hydrogen, it set a target of producing 10 million tonnes per year (mtpa) within the EU and importing a further 10 mtpa by 2030. In August 2022, OIES published a short comment<sup>50</sup> assessing the feasibility of the renewable gas (hydrogen and biomethane) targets, which concluded that it was "difficult to see how there could possibly be a sufficiently rapid ramp-up in additional renewable power generation and electrolyser capacity in order to achieve the renewable hydrogen targets." Two years on, progress is clearly well short of the aspirations and this short article makes an assessment of some of the key challenges which contribute to this and what could be done to stimulate further investment. It considers in turn each key element of the supply chain: (a) hydrogen production, (b) midstream infrastructure and (c) hydrogen demand. The charts in this article are taken from a recent OIES publication drawing on data and input from various organisations "2024 State of the European Hydrogen Market"<sup>51</sup> which contains further detail.

### Hydrogen Production

**Figure 5: Low Carbon Hydrogen supply project status May 2024 (Source: Bloomberg NEF)**

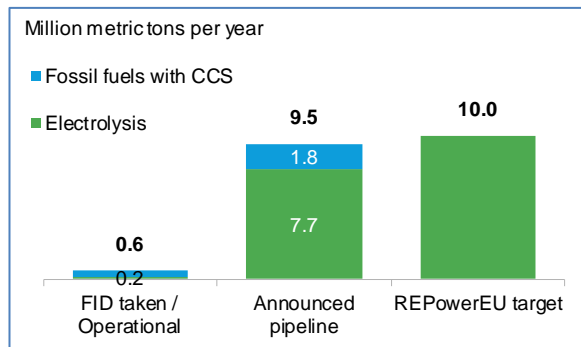


Figure 5 shows that while announced low-carbon hydrogen supply projects in the EU could be nearly sufficient to meet the 10 mtpa target, only 0.8 mtpa is operational or past final investment decision (FID). Given a two to three year construction time for a hydrogen supply project, it is still technically possible that the target could be met, but this would require a rapid acceleration in the number of FIDs which appears unlikely at this stage. In the following paragraphs we highlight four key challenges to be addressed to promote more rapid scale up of hydrogen production.

Firstly, the EU hydrogen framework is not technology neutral, with a strong preference for electrolytic hydrogen using renewable electricity, with complex rules in order for the hydrogen to qualify as "Renewable Fuels of non-biological origin". In the last 12 months there are some indications that the EU is now more open to consideration of carbon

capture and storage (CCS), which is to be welcomed, although it may take some time before this is translated into actual CCS-enabled hydrogen projects starting construction.

Secondly, and partly related to the previous point, the full terms of the EU hydrogen regulatory framework including the definition of low-carbon hydrogen, are still being developed, which leads to continuing uncertainty for investors and in turn a reluctance to commit significant money to start building projects until there is more clarity. In April 2024, the European Parliament adopted the hydrogen and gas decarbonisation package, which is a positive step forward, but a Delegated Act which will define low-carbon hydrogen (expected to cover both electrolytic and CCS-enabled hydrogen) is not expected until Q2 2025 at the earliest.

<sup>49</sup> European Commission: RePowerEU ([https://ec.europa.eu/commission/presscorner/detail/en/ip\\_22\\_1511](https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511))

<sup>50</sup> <https://www.oxfordenergy.org/publications/repowereu-can-renewable-gas-help-reduce-russian-gas-imports-by-2030/>

<sup>51</sup> <https://www.oxfordenergy.org/publications/2024-state-of-the-european-hydrogen-market-report/>



Thirdly, for the foreseeable future, low-carbon hydrogen is higher cost than existing high-carbon hydrogen produced from fossil fuels without carbon capture and storage. Typically, high-carbon hydrogen costs 1-2 \$/kg, adding carbon capture and storage adds an additional cost of at least 0.5 \$/kg, depending on location and electrolytic hydrogen using renewable power costs at least 5 \$/kg. A small number of customers may be willing to pay a price premium for a low-carbon product, but typically a hydrogen production project will need government subsidy in order to be feasible. In April 2024, the European Hydrogen Bank (EHB), a European Commission subsidy scheme, announced the results of its first auction providing €720 million of support to seven renewable hydrogen projects in Europe<sup>52</sup>. Interestingly, and perhaps surprisingly, even though the supporting information confirmed the typical price for renewable hydrogen being in the range 5-10 €/kg, the winning bids were all to receive less than 0.5 €/kg subsidy from the EHB. It is assumed that the customers of those projects are willing to pay the additional premium required, so it will be interesting to track the progress of the winning projects towards FID over the coming months. By contrast the winning projects in the UK's first hydrogen allocation round (HAR1) had a strike price equivalent to around 9 €/kg, so, other things being equal, there may be a higher chance of FIDs happening in the UK rather than in the EU. Time will tell.

Finally, many of the announced hydrogen production projects are being developed by relatively small companies which are likely to need external finance. Achieving subsidy support, for example, through the EHB or HAR1 is clearly a step in the right direction, but in order to secure financing, projects will also need to have a secure offtake contract and, in some cases, the necessary midstream infrastructure in order to link supply and demand, as discussed below. Only when the entire supply chain is in place to reassure financiers that there is line of sight to a robust revenue stream will it be feasible for the project to proceed.

Overall, therefore, while progress is being made it is difficult to see sufficient FIDs in the next 2-3 years to be consistent with achieving the ambitious 2030 production targets.

### Midstream Infrastructure

There is a lack of clarity around the nature and quantity of midstream hydrogen infrastructure which will be required in future and this is delaying investment. Most low-carbon hydrogen projects which are operational or under construction are expecting to supply their product to customers very close to the point of production, within so-called industrial clusters. Examples of this are H2 Green Steel in Sweden, Holland Hydrogen 1 in the Netherlands and Sinopec's Kuqa project in Xinjiang, China.

Existing natural gas transmission system operators in Europe have made extensive lobbying efforts to promote the so-called European Hydrogen Backbone to connect suppliers and off-takers of clean hydrogen. They envisage a pan-European pipeline network developed by conversion of significant parts of the existing natural gas network. With the need for long-distance transport of low-carbon hydrogen not yet clear, the business case for investment in this midstream infrastructure is not yet compelling and has not led to any significant pipeline investments (currently only a 30km pipeline is under construction in the Rotterdam industrial cluster). In April 2024, the German government agreed a funding framework to guarantee private investors a fixed rate of return for building a 9,700km hydrogen network at an estimated cost of €20bn, but delayed the target completion date by 5 years until 2037. Similarly, the need for significant imports of hydrogen and/or its derivatives (like ammonia or methanol) is not yet clear. Some plans for hydrogen import terminals potentially combined with facilities to transform ammonia or methanol back into gaseous hydrogen are under development, but the path to a firm investment decision remains uncertain.

Storage remains an important but challenging part of hydrogen midstream infrastructure. Storage will be essential in order to bridge between intermittent production, based on intermittent renewable power and customer needs for a steady supply of hydrogen. Storage is also likely to be required if hydrogen is to fulfil its expected role for long-term energy storage. A recent study by the UK Royal Society estimates a need for over 60 TWh of underground hydrogen storage to balance the British electricity system in 2050<sup>53</sup>, while a study of the EU by Gas Infrastructure Europe<sup>54</sup> sees a need for 45 TWh by 2030 rising to nearly 300 TWh by 2050. The only proven technology for storing hydrogen in large quantities is underground salt caverns, which are only feasible in a limited number of locations with suitable geology. Consideration is also being given to storing hydrogen in depleted hydrocarbon reservoirs and other geological structures, but it is not yet certain whether challenges of such structures like potential contamination can be successfully managed. The GIE study notes that even if all currently announced storage projects were completed by 2030, they would only result in 9TWh of storage, compared to the perceived need of 45

<sup>52</sup> [https://ec.europa.eu/commission/presscorner/detail/en/IP\\_24\\_2333](https://ec.europa.eu/commission/presscorner/detail/en/IP_24_2333)

<sup>53</sup> <https://royalsociety.org/news-resources/projects/low-carbon-energy-programme/large-scale-electricity-storage/>

<sup>54</sup> GIE: [https://www.gie.eu/wp-content/uploads/filr/9697/RPT-EU\\_Underground\\_Hydrogen\\_Storage\\_Targets-090424-CLEAN.pdf](https://www.gie.eu/wp-content/uploads/filr/9697/RPT-EU_Underground_Hydrogen_Storage_Targets-090424-CLEAN.pdf)



TWh, and, as in the case of production projects, it is highly unlikely that all announced projects will actually be constructed. The study also notes that lead time for storage projects is typically 6 to 11 years, much longer than for a production project.

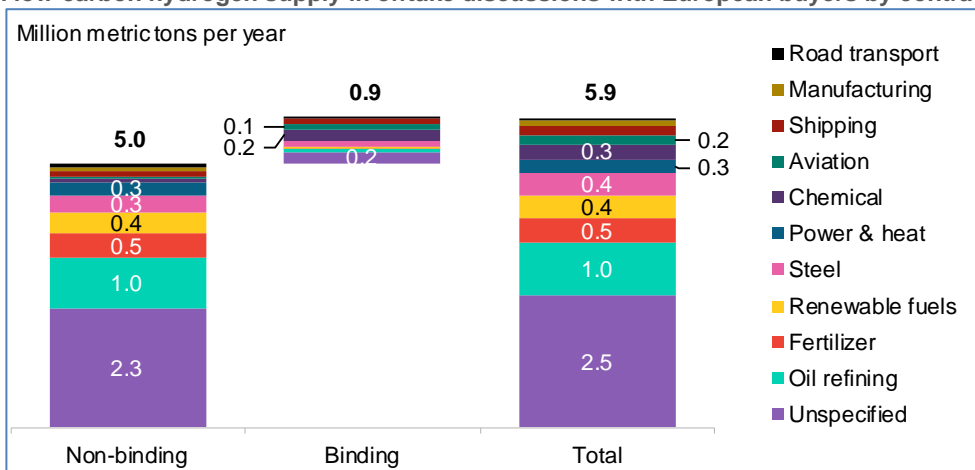
For all midstream infrastructure, whether it be pipelines, terminals or storage, there is something of a “chicken and egg” problem. There will not be a compelling business case to invest in such infrastructure until investors have line of sight to the production and consumption which will wish to make use of the infrastructure. Similarly, it will be difficult for producers and consumers to enter contracts for supply of hydrogen requiring midstream infrastructure until there is line of sight to the infrastructure being available. In order to unlock the problem, it is likely to be necessary for governments to underwrite initial infrastructure investments, although care will need to be taken not to overbuild and so result in stranded assets.

**Demand for low-carbon hydrogen**

Much of the focus in recent years has been on looking for ways to incentivise low-carbon hydrogen production, but there is now increasing realisation that a key to unlocking the value chain is creation of demand.

Figure 2 shows the volume of potential low-carbon hydrogen production which is currently under discussion or with a binding offtake agreement with European buyers. Less than 5% of the volume required to meet the REPowerEU target of 20 million tonnes has a binding offtake agreement.

**Figure 2: Annual low-carbon hydrogen supply in offtake discussions with European buyers by contract type**



Source: BNEF

There are, however, some encouraging developments on the demand creation side. In the latest update to the Renewable Energy Directive (RED III), it states that 42 per cent of hydrogen used in industry should be “RFNBOs” by 2030. If fully implemented, that would result in a demand from existing refineries and ammonia plants for around 4 million tonnes of low-carbon hydrogen by 2030. There are however two important caveats. Firstly, as an EU Directive, it is up to the individual member states to pass specific implementation legislation and it is possible that the obligation will be watered down in that process. Secondly, the increased cost of hydrogen as a result of the requirement may result in a reduction in hydrogen demand as industry moves overseas. This impact had already been seen in the fertiliser industry when gas prices rose significantly in 2022 and many European fertiliser plants stopped or reduced production in favour of production elsewhere (typically the US), where gas prices were lower.

**Conclusion**

REPowerEU sent a clear political message that Europe intended to move away as quickly as possible from an over-reliance on Russian gas and that rapid decarbonisation and an increased role for hydrogen was consistent with this objective. Despite the strong political will an analysis of the data shows that there is simply not enough progress being made in developing the required hydrogen projects, whether upstream, midstream or downstream, in order to meet the aspirational targets. Indeed, at the current rate of progress, the less ambitious targets set in the 2020 EU Hydrogen Strategy (40 GW electrolyzers within EU and 40 GW outside EU to supply imports) will not be met either. Despite the high level political will, the key challenge appears to



be that the detailed regulation and other policy measures which have been put in place are either too complex, too uncertain or insufficiently attractive to provide sufficient comfort to potential investors to allow projects to proceed at pace. There are some signs that this could change in the coming year or two, but at this stage a rapid acceleration in low-carbon hydrogen deployment is far from certain.

## THE EU METHANE REGULATION – WHAT WILL BE THE IMPACT ON LNG IMPORTS?

*Maria Olczak and Jonathan Stern*

Over the past two years, liquefied natural gas (LNG) has mostly been discussed in the context of security of supply. Europe's increased reliance on LNG provided the supplies needed to replace Russian pipeline gas in the aftermath of the invasion of Ukraine. But as the security crisis recedes and the gas market reaches a new equilibrium, discussions on decarbonization and the greenhouse gases associated with, particularly LNG supply chains, have again begun to attract increasing attention. Hence, the question arises: will its new global role enable the EU to impose stricter environmental standards on LNG market players and specifically, the standard proposed in the new Methane Regulation?

### EU as the major LNG importer

The 2022-23 energy crisis transformed the role of the European Union (EU), from a global gas balancing market via LNG to becoming the largest global importer of LNG with nearly 97 million tonnes (Mt) or roughly 134 billion cubic meters (bcm) of imports (121 Mt if the rest of Europe is included) in 2023.<sup>55</sup> The EU's surge of LNG imports requiring the development of significant new infrastructure was an aggregation of individual countries' decisions rather than a coordinated EU crisis response. While the EU Commission tried to promote greater coordination, e.g. through the establishment of the joint purchasing platform (AggregateEU), a recent report by the European Court of Auditors (ECA) concluded that the Platform's impact alongside the EU Commission's efforts to coordinate international outreach to global gas producers could not be demonstrated.<sup>56</sup>

Being a major gas importer is one thing, being able to use this leverage is another. The ECA found that the Commission lacks the tools and legal competences in international affairs to achieve these objectives. This situation illustrates a tension within the EU between long-term sustainability objectives set at the EU level and short-term security of supply concerns of member states. While these tensions may reduce as more LNG becomes available, the post-crisis response showed that member states, not the European Commission, have the leading role in negotiating with gas producing countries with gas procurement treated mostly as a national affair. Despite this situation, the recently adopted EU Methane Regulation puts the Commission at the helm of the negotiations on measurement, reporting and verification (MRV) equivalence with exporters of crude oil, gas and coal into the EU.

### The EU Methane Regulation

On 27 May, the Council approved the EU Methane Regulation, which will come into force over summer 2024.<sup>57</sup> The regulation imposes obligations on oil and gas operators, coal mine operators, importers and member states with regard to monitoring, measurement reporting and independent verification of methane emissions.

The EU is the first jurisdiction to set requirements for fossil fuel imports, which will be implemented gradually from 2025-30. The table shows this process will begin with information provision, followed by demonstrating MRV equivalence, then reporting, and finally ensuring that imports stay below maximum methane intensity thresholds. While the legal requirement to comply with these requirements is on EU importers, they will need to work with producers and exporters to provide CAs in Member States with information required under the Regulation. Measurement will then need to be subjected to verification by qualified and nationally accredited bodies which will report to the CAs.

The Regulation clearly aims at ensuring that companies exporting fossil fuels to the EU face the same MRV and mitigation requirements as EU operators. Companies failing to comply will face financial penalties set by member states and reputational damage with customers.

<sup>55</sup> ACER, 'Analysis of the European LNG Market Developments. 2024 Market Monitoring Report'.

<sup>56</sup> European Court of Auditors, 'Special Report: Security of the Supply of Gas in the EU'.

<sup>57</sup> Maria Olczak, Andris Piebalgs, and Jonathan Stern, 'Analysing the EU Methane Regulation'. OIES (2024).



The final version of the Regulation is considerably less ambitious than what was proposed in the Methane Strategy, which the EU published in 2020, and will take longer to achieve. Key methodologies and metrics defining equivalence and intensity have yet to be established and will require secondary legislation in the form of delegated and implementing acts (see table). Nevertheless, despite some disappointment, the EU has achieved a comprehensive regulatory framework for methane. Implementation is the next challenge.

TIMELINE	REQUIREMENTS	WHAT IF AN IMPORTER FAILS TO COMPLY?
By 04/2025	<b>All contracts:</b> Importers provide to competent authorities (CAs) information on methane emissions monitoring and mitigation measures set out in Annex IX	- Justify to CA and specify the actions undertaken - Financial penalty - Reputational damage
From 2027	<b>New/renewed contracts*:</b> Importers <u>demonstrate and report</u> to CAs that the imported coal, crude oil and gas is subject to equivalent MRV measures at the level of producer	- Financial penalty - Reputational damage
	<b>Existing contracts:</b> "importers shall undertake all reasonable efforts", e.g. contract amendment	- Justify to CA and specify the actions undertaken - Financial penalty - Reputational damage
By 2028	<b>New/renewed contracts*:</b> EU producers and importers <u>report</u> the methane intensity of the production of crude oil, coal and natural gas	- Financial penalty - Reputational damage
	<b>Existing contracts:</b> "importers shall undertake all reasonable efforts"	- Financial penalty - Reputational damage
By 2030	<b>All contracts concluded/renewed after Q2 2030:</b> EU producers and importers <u>demonstrate</u> that the methane intensity of the production < the maximum methane intensity values	- Financial penalty - Reputational damage

\*new and renewed contracts are those concluded after the entry into force of the Regulation. CA = competent authority  
Source: Olczak, Piebalgs and Stern, 'Analysing the EU Methane Regulation'.

DELEGATED ACTS	IMPLEMENTING ACTS
Art. 22(3) restrictions on <b>venting methane from ventilation shafts</b> for coking coal mines [2027]	Art. 12(4) <b>MRV reporting templates</b>
Art. 27(1) further information to be required from importers, <b>amending Annex IX</b>	Art. 14(7) <b>Minimum detection limits and detection techniques for LDAR surveys</b> , the thresholds applicable to the first step of LDAR surveys [2025]
Art. 29(4) the <b>methodology</b> for calculating, at the level of producer, the <b>methane intensity values</b> associated with imports [2027]	Art. 28(6) <b>MRV equivalence for third countries:</b> a) procedure and evidence requirements for establishing equivalence, b) decisions establishing/revoking equivalence
Art. 29(6) <b>maximum methane intensity values and classes</b> for crude oil, natural gas and oil	
Art. 32 EU COM can establish <b>mandatory standards or technical prescriptions</b> concerning e.g. measurement and quantification, LDAR	

Source: OIES

**LNG shipping emissions are covered under the EU ETS and FuelEU Regulation**

What may come as a surprise is that the Methane Regulation does not cover emissions associated with LNG shipping. As of 1 January 2024, maritime transport emissions, including these associated with LNG shipping, were incorporated under the EU's



cap-and-trade program – the Emissions Trading System (EU ETS).<sup>58</sup> As a result, shipping companies using European ports have to monitor and report their emissions and purchase and surrender EU allowances (EUAs) for each tonne of reported carbon dioxide (CO<sub>2</sub>) emissions. From 1 January 2026, this obligation will be extended to two short-lived GHGs – methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O). The ETS will cover 100% of emissions for domestic voyages, but only 50% of those associated with international voyages.

There are two important differences between the approach in the Methane Regulation and EU ETS. In contrast to the Regulation, shipping companies covered by the EU ETS can choose between the calculation approach (methods A, B and C) and measurement approach (D). So far, the calculation approach was the default choice of the companies covered by the EU ETS. In case operators fail to comply with the MRV or surrender obligations, the company will face not only financial penalties and reputational damage but may be denied access to the EU market.

Moreover, as of the 1 January 2025, shipping companies will also need to comply with the FuelEU Maritime Regulation, whose main objective is to promote the use of renewable and low-carbon fuels in maritime transport.<sup>59</sup> Although LNG has become an alternative marine fuel of choice for the sector, FuelEU specifies that the GHG intensity (CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O) of fuels used on board ships will need to gradually decrease by 2% in 2025, to 80% in 2050, below the baseline 91.16 g CO<sub>2</sub> eq per megajoule (MJ) (2020 fleet average GHG intensity of energy used on board ships).

### Crucial role of EU member states

This new wave of EU regulation targeting emissions associated with LNG will roll forward with revisions of both the Maritime Transport and EU Methane Regulations in 2028. Returning to our earlier question of whether its new role will enable the EU to impose stricter environmental standards globally: paradoxically, the energy crisis put the EU in a better position as the leading LNG importer, but as the competence of the EU is limited, it will require member states to play a more active role in the implementation and enforcement of the EU legislation and the outreach activities.

The fact that member states are mostly responsible for the implementation and enforcement of EU regulations and directives will be crucial for the success of the EU Methane Regulation. Hence, the effectiveness of policies will depend on how states implement them. For some governments it may give an opportunity to protect their domestic industries. And as revenue from the financial penalties associated with EU ETS and EU Methane Regulation stays largely in the member states, it may be considered by some governments as a potential source of additional revenue.

Energy (in contrast to e.g. competition policy) is an area of shared competence between member states and the European Commission. The latter's competence in international affairs, e.g. with regard to negotiations with non-EU countries, is even more limited. While the European Commission will be leading negotiations with gas producers and governments on how to define and achieve MRV equivalence under the EU Methane Regulation, it is clear that member states will have a major impact on how (and to what extent) its provisions will be implemented. Very important will be the institutions which states designate as 'competent authorities' to carry out many of the key MRV tasks. While national energy regulators may seem to be the obvious choice, many have little or no environmental competence and may require a substantial increase in qualified staff. Alternatively, states may designate more than one competent authority with tasks shared between energy and environmental regulators.

### Priorities for the new EU Commission

Regulation of methane fills an obvious gap in EU climate policies, but it remains to be seen how high this will be on the list of priorities for the new EU Commission and member states. Methane emissions reduction – a highly complex and technical topic – is not part of mainstream political discussions in Brussels and national capitals. If LNG demand remains strong in Europe and is seen as endangering EU climate objectives or the EU's image as a climate leader, more regulations and more assertive national and EU policies can be expected, as long as these measures are not seen by member states as compromising security of gas supply.

<sup>58</sup> Maria Olczak and Andris Piebalgs, 'The Decarbonisation of Maritime Transport'. OIES (2023).

<sup>59</sup> Regulation (EU) 2023/1805 of the European Parliament and of the Council of 13 September 2023 on the use of renewable and low-carbon fuels in maritime transport, and amending Directive 2009/16/EC (Text with EEA relevance). URL: <http://data.europa.eu/eli/reg/2023/1805/oj/eng>.

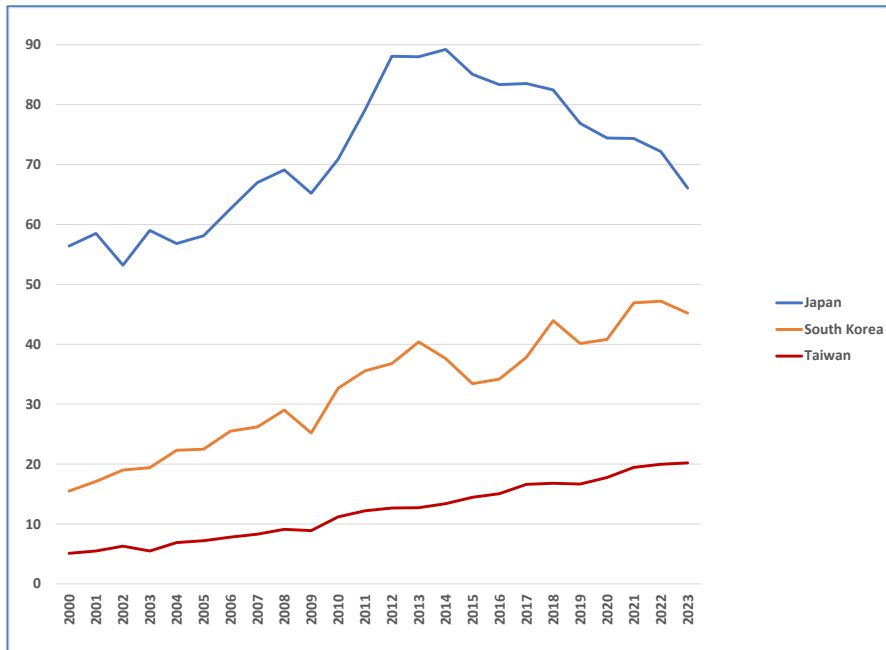


## LAGGING RENEWABLES IN NORTH ASIA MAY MEAN MORE LNG <sup>60</sup>

**Graeme Bethune**

The North Asian trio of Japan, Korea and Taiwan play a major role in global LNG markets. According to GIIGNL, they were the second, third and fifth largest LNG importers respectively in 2023 and collectively accounted for one third of global LNG imports<sup>61</sup>.

**Figure 1: Japan, Korea and Taiwan LNG imports 2000-2023 (Mt)**



Source: GIIGNL

However, they have been following different trajectories. Japanese LNG demand has been falling while demand has been growing in the other two countries (Figure 1). Will these trends continue, particularly in the light of the commitments by all three countries to cut their emissions?

Japan and Korea are aiming to cut their LNG imports by 2030 as part of their emission reduction strategies. Japan aims to cut the LNG share of power generation from 34% to 20% by 2030. Korea aims to cut it from 32% to 23% and then to 9% by 2036. Both countries plan to replace LNG (and coal) with renewables and nuclear. Only Taiwan is aiming to increase LNG as it phases out nuclear.

If implemented, these reductions would lead to a major shake-up in global LNG markets. Japanese LNG demand in 2030 would be around 47 million tonnes (Mt), down from 66 Mt in 2023. This assumes use of gas for other purposes (residential, industrial and commercial) remains flat. Korean LNG demand would fall from 45 Mt to 38 Mt in 2030 and 26 Mt in 2036. Phasing out nuclear in Taiwan would require additional LNG but only around 3 million tonnes per annum (Mtpa).

However, all three countries are highly dependent on imported fossil fuels and face headwinds in the swift expansion of cleaner alternatives. Failures to grow renewables in the power sector fast enough to meet end-of-decade emission targets mean that there will inevitably be recourse to LNG or even coal imports at higher volumes for longer.

<sup>60</sup> For a detailed analysis of the outlook for North Asian LNG see Oxford Institute for Energy Studies Energy Insight 148, "The Role of LNG in the North Asian energy transition: lagging renewables means more LNG for longer?" <https://www.oxfordenergy.org/publications/the-role-of-lng-in-the-north-asian-energy-transition-lagging-renewables-means-more-lng-for-longer/>

<sup>61</sup> <https://giignl.org/wp-content/uploads/2024/06/GIIGNL-2024-Annual-Report-1.pdf>



Renewables are growing but fossil fuels still supplied 82% of primary energy in Korea in 2023, 83% in Japan and 91% in Taiwan according to the latest energy statistics from the Energy Institute<sup>62</sup>. Development of renewables onshore is limited by high population densities, with 328 people per square kilometre in Japan, 521 in Korea and 667 in Taiwan. By way of comparison, population density in the United Kingdom was 279 people per square kilometre. Solar generation has been growing, reaching nearly 10% of Japanese generation in 2023 but it was still less than 5% in Korea and Taiwan in that year. Wind has lagged far behind solar. Of the three countries, wind made the greatest contribution to the power mix in Taiwan in 2023 at just 2.2% of generation.

Although Korea’s plans to sustain recent strong growth in nuclear look fair given new nuclear plants under construction, nuclear restarts in Japan remain a vexed political topic and therefore uncertain, while Taiwan’s commitment to winding down nuclear by next year means more LNG as electricity demand grows and its growth in renewables falls short.

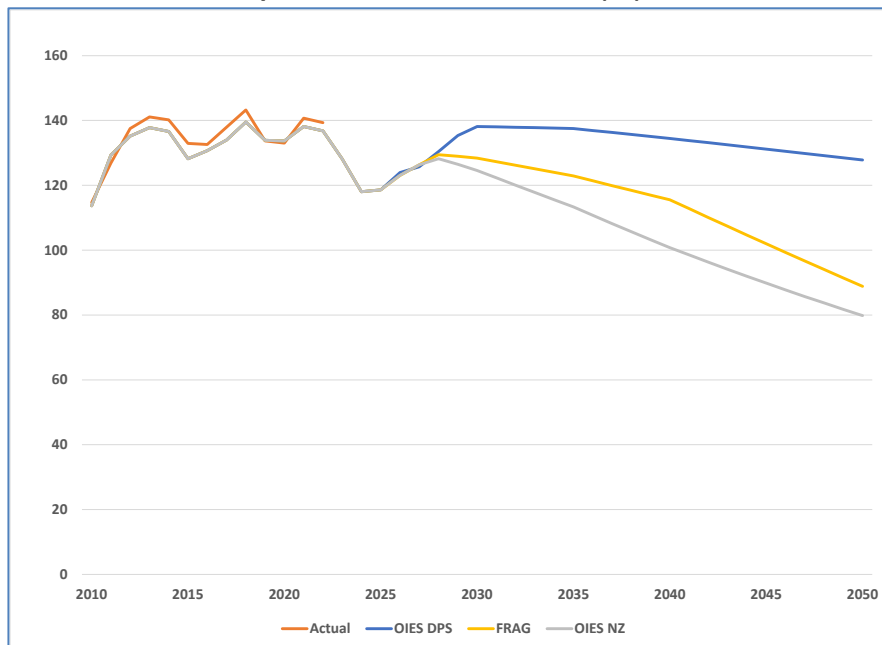
Setting aside the macro drivers for energy demand growth that will impact all supply sources, other things being equal we expect LNG is likely to maintain a stronger profile in the energy mix – closer to the OIES Declared Policy Scenarios (DPS) than the IEA or even some government targets.

The OIES models three global gas demand scenarios, a Declared Policy Scenario (DPS), a Net Zero with CCS Scenario (NZwith CCS) and a Fragmented Scenario (FRAG)<sup>63</sup>. While broadly similar in concept to IEA STEPS, DPS differs in that it is not assumed that all policies necessarily get successfully implemented. This is particularly true in Europe. Consequently, there are more fossil fuels in the mix and generally higher gas demand than in STEPS. This is particularly the case in Europe, China and other Asian countries, such as Japan.

NZwithCCS does not limit temperature rise to 1.5° C by 2050 but overshoots, with negative emissions post 2050 to get back to 1.5° C by 2100. It implies substantial volumes of CCS in Japan, Korea and Taiwan (JKT), 164 Mt in 2050. The FRAG scenario relaxes the assumption that net zero is achieved by 2050. This scenario acknowledges that NZwithCCS is not seen as realistic across the board. However, it still implies 43 Mt of CCS in JKT in 2050.

Figure 2 shows JKT LNG import scenarios under each of the three OIES scenarios. Under the OIES DPS, total North Asian LNG imports in 2050 are virtually the same as in 2023. Imports are lower under the other two scenarios but even in the NZwithCCS scenario imports are still 80 Mt in 2050, 38% lower than 2023 but still substantial.

**Figure 2: Japan, Korea and Taiwan LNG imports to 2050 OIES scenarios (Mt)**



Source: OIES

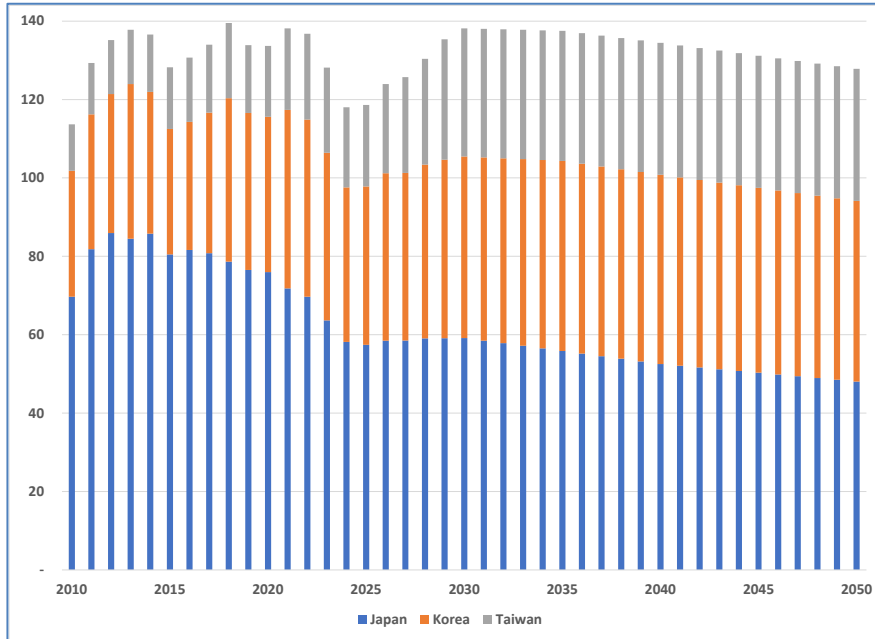
<sup>62</sup> <https://www.energyinst.org/statistical-review>

<sup>63</sup> <https://www.oxfordenergy.org/publications/energy-transition-scenarios-impact-on-natural-gas/>



As Figure 3 shows the DPS by North Asian country. There is a significant 25% fall in Japanese imports but offset by growth in Korea and Taiwan.

**Figure 3 Japan, Korea and Taiwan LNG imports 2010-2050 OIES DPS scenario (Mt)**



Source: OIES

Government reality checks on energy strategy may need to include relaxation of medium and long-term emissions targets. Whatever their targets, it is clear that in all three countries, whether through infrastructure investment or the push to renew long-term LNG contracts, preparations are underway to retain more LNG as part of the energy mix for longer, despite aggressive emissions targets.

The gap between emission reduction targets and reality was the focus of the March 2024 message from Mr Tatsuya Terazawa, Chairman and CEO of the Japan Institute of Energy Economics who gave his message the provocative title of, “The gap between aspiration and reality: the need for Plan B”<sup>64</sup>. As he noted, G7 members’ greenhouse gas emissions reductions are off-track from their Nationally Determined Contributions (NDCs) and carbon neutrality paths. The gap between aspiration and reality necessitates Plan B. Realistically Plan B is likely to require more LNG but if not, more coal.

**Japan – LNG and coal needed to offset lags in renewables and nuclear restarts**

As of 2023 Japan’s emissions from energy were down by 21.8% from 2013 but with a long way to go to reduce emissions by the target of 46% by 2030.

Japan’s current plan to reduce emissions assumes continued falling electricity demand and a significant change in the fuel mix for electricity generation. Japanese power demand peaked in 2008, which is also when Japan’s population peaked. Reflecting falling population and sluggish economic performance, electricity demand in 2023 was down 14% from its peak 16 years previously. METI has so far been assuming a further fall of around 10% by 2030. However, the continuing fall in power demand is increasingly uncertain. The country is currently developing its seventh basic energy strategy, which will set fuel targets to 2040. The new plan is to be released by March 2025 but electricity forecasts are already being revised upwards. A recent Japanese government forecast envisages the need for electricity output to rise 35% to 50% by 2050 due to growing demand from semiconductor plants and data centres backing artificial intelligence<sup>65,66</sup>. This will boost the need for LNG.

<sup>64</sup> <https://eneken.ieej.or.jp/en/chairmans-message/index.html>

<sup>65</sup> <https://www.reuters.com/business/energy/japan-sees-need-sharp-hike-power-output-by-2050-meet-demand-ai-chip-plants-2024-05-14/>

<sup>66</sup> <https://www.energyintel.com/0000018f-f23c-d947-af8f-ff7e8579000#:~:text=Japan%20is%20showing%20signs%20it,gathering%20in%20Tokyo%20last%20week.>



Japanese electricity generation continues to be highly dependent on fossil fuels. In 2023 65% of Japanese electricity was generated from fossil fuels, 30% from coal, 32% from gas and 3% from oil. Renewables contributed 15%, hydro 7% and nuclear 8%.

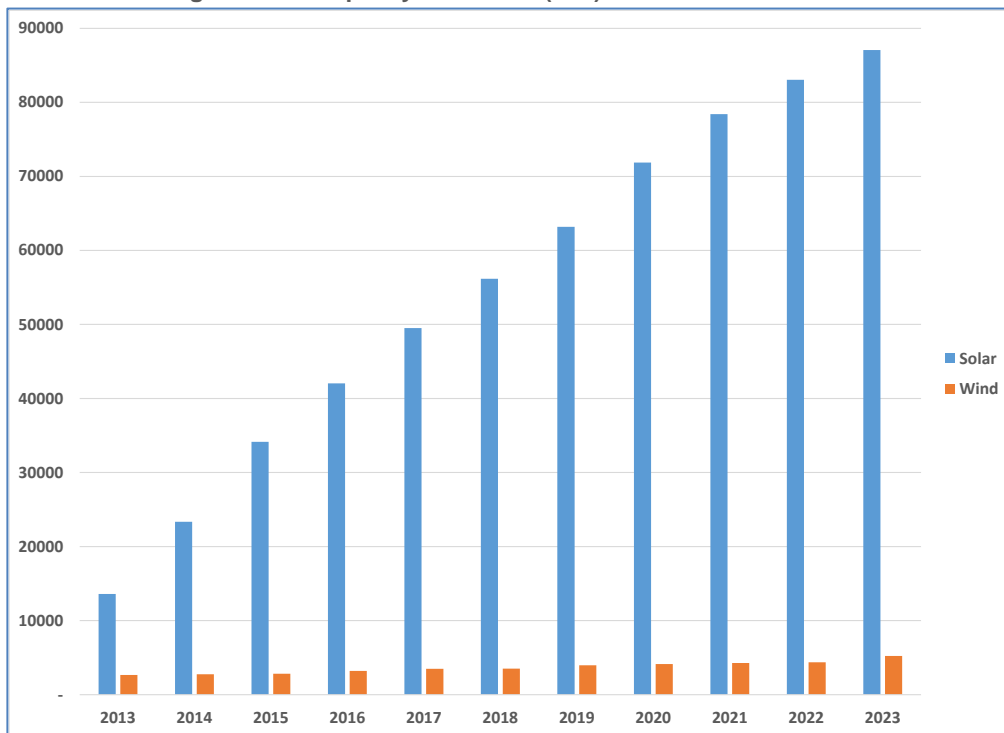
Around two-thirds of gas supply is used for electricity generation so the outlook for gas depends particularly on gas use for power generation.

As noted above, as part of its commitment to net zero by 2050, Japan plans to reduce the LNG share of power generation to 20% and coal to 19% by 2030, to be largely replaced by increased renewables and nuclear. This would imply LNG imports dropping from 66 Mt in 2023 to 47 Mt by 2030.

However, growth in both renewables and nuclear are lagging targets. Japan has made significant progress in solar. In 2023 it ranked 3<sup>rd</sup> in the world in solar capacity but notwithstanding this progress, solar only contributed 9.6% of generation in 2023, well below the 2030 solar target of 14-16%.

There has been much less progress with wind (Figure 4). In 2023 Japan only ranked 20<sup>th</sup> globally in wind capacity and wind only contributed 1% of generation. The 2030 target is 5%. There is believed to be significant potential for offshore wind but at higher cost. There was only 187 MW of capacity at the end of 2023. The country is now having to look at developing offshore wind in its Exclusive Economic Zone, outside its territorial waters. This is contested territory. There are disputes between China, Japan, Taiwan, and Korea over the extent of their respective exclusive economic zones in the East China Sea.

**Figure 4: Japan solar and wind generation capacity 2013-2023 (MW)**



Source: Energy Institute

The target for nuclear is to reach 20-22% of generation by 2030 but in 2023 nuclear accounted for only 8% of power generation. As an example of the challenges faced in growing nuclear, Japan’s Kashiwazaki Kariwa (KK) 8.2 GW nuclear plant, the world’s largest, is yet to restart. In 2017, two idled reactors at KK won approval from the nation’s nuclear regulator to resume operations, but neither the company nor the national government set a date on when that could happen since they have yet to secure the local government’s endorsement<sup>67</sup>.

<sup>67</sup> <https://www.bloomberg.com/news/features/2024-05-28/japan-s-energy-stalemate-leaves-world-s-biggest-nuclear-plant-idle>

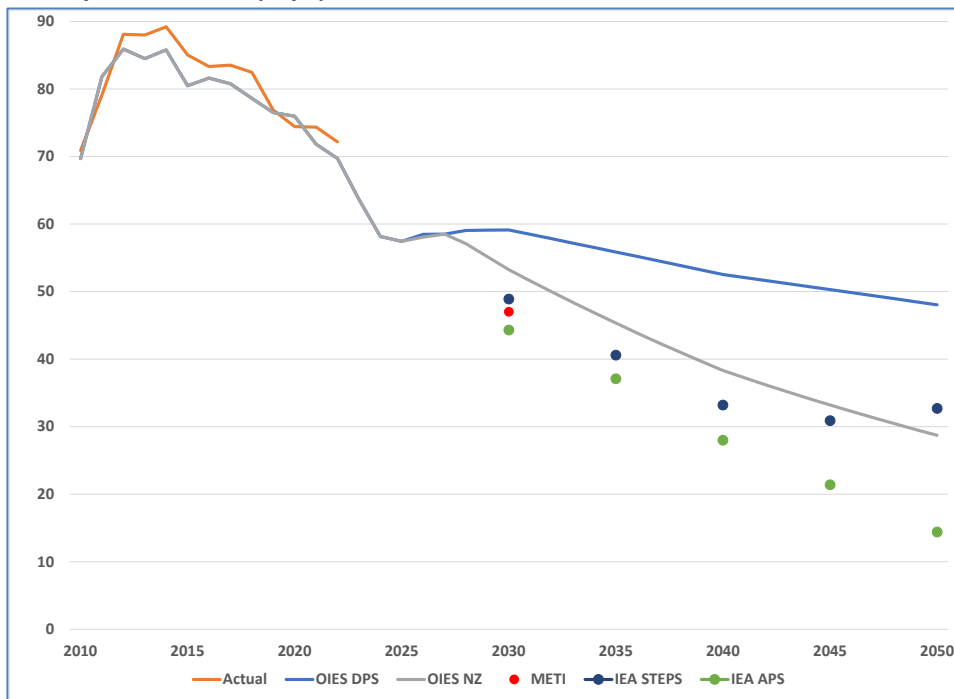


Japanese renewables and nuclear are not growing fast enough to offset the proposed reduction in fossil fuels, with coal and/or gas needing to make up the generation gap. In terms of emissions, maintaining the role of LNG with CCS would be preferable to coal but to date, gas has lost out to coal, with higher emissions as a result. Over the decade to 2023, coal consumption has fallen at an average annual rate of 1.1% but gas has fallen nearly three-times faster, averaging 2.9%.

However, many of the forecasts predicting a massive decline in Japanese gas demand are overdone. Figure 5 shows several scenarios for Japanese LNG demand. The OIES DPS and NZwthCCS scenarios both project declining LNG demand (reflecting falling population) but are significantly above the current METI target and the IEA STEPS and APS scenarios.

The OIES scenario of higher LNG demand is supported by industry actions to invest in and contract additional LNG. Japanese companies are reported to be in discussions with Qatar; LNG Japan and JERA have stakes in the Australian Scarborough LNG project; Mitsubishi is expecting expansion of the US Cameron LNG project; Kyushu Electric is considering investment in the US Lake Charles LNG project; and INPEX is set to progress the development of its Abadi LNG project in Indonesia.

**Figure 5 : Japan LNG import scenarios (Mtpa)**



Source: OIES

That is not to say that new investments and volumes contracted will necessarily go to Japan<sup>68</sup>. According to figures from the Japan Oil, Gas and Metals National Corporation (JOGMEC), LNG sales by Japanese companies to third countries have increased 2.5 times since FY2018, from 14.97 Mt to 38 Mt in FY2021. Although domestic sales have declined, the volume of LNG transacted by Japanese companies increased over that timeframe. Today, the volume of LNG sold abroad is nearly 50% of the volumes consumed domestically. Given the uncertainties of Japanese demand, Japanese companies are wise to have the option of selling into other markets.

JERA, Mitsubishi and Tokyo Gas have stepped up gas purchases since 2021 to on-sell 38 Mt of Australian LNG, equivalent to about half of Australian imports each year, to the Philippines, Vietnam and India, where they have invested heavily in distribution infrastructure<sup>69</sup>. On-sales of Japanese LNG to third Asian countries are a means of Japan increasing its influence in the region.

<sup>68</sup> <https://ieefa.org/resources/japans-largest-lng-buyers-have-surplus-problem>

<sup>69</sup> <https://www.afr.com/world/asia/japan-using-australian-gas-to-shore-up-regional-influence-20240514-p5jdggt#:~:text=Japanese%20power%20giants%20JERA%2C%20Mitsubishi,have%20invested%20heavily%20in%20distribution>



### **Korea – LNG likely to defy reduction targets amid renewables shortfall**

Of the three North Asian countries, Japan is the biggest LNG buyer. However, in 2023 Korea and Taiwan collectively imported as much LNG as Japan and, as shown in Figure 3, are expected to increase their LNG imports, offsetting any decline in Japan. In Japan, gas has been losing market share to coal but the opposite applies in Korea and Taiwan. In Korea gas consumption grew at an average annual rate of 0.9% over the decade to 2023 while coal declined by 2.3%. In Taiwan gas grew at 4.5% per annum while coal fell by 1.2% per annum.

Korea is planning to reduce its emissions by 40% below 2018 levels by 2030 but by 2023 emissions from energy were down by 13.3%, partly because there has been a reduction in coal use for power generation, with increases in gas and nuclear. Coal's share of power generation has fallen from 45% in 2012 to 33% in 2023 while gas has increased significantly, from 21% to 27%. The share of nuclear has been steady at 29% over the same period. The share of renewables has increased but only from 2% to 8%.

Like Japan, Korea aims to achieve its emission reduction targets with renewable energy and nuclear increasing steeply while coal and LNG decline. The use of LNG for power generation is targeted to decline from 29 Mt in 2021 to 22 Mt in 2030 to 10 Mt in 2036. Assuming LNG for other purposes remains constant, total LNG imports would decline from 47 Mt in 2022 to 38 Mt in 2030 and 26 Mt in 2036, the same as in 2007. The capacity of renewable energy in 2030 is expected to be 72.7 GW. This requires an additional 39.9 GW above existing capacity. Nuclear generation has been growing strongly in Korea (up by 24% between 2019 and 2023) and construction of two new nuclear reactors is resuming after being halted in 2017.

As in Japan, Korea's plans to reduce emissions also rely heavily on growth in renewables. Solar capacity is growing relatively quickly at about 2 GW per annum. However, in 2023 solar only contributed 4.7% of total generation. There has been even less progress with wind. Onshore wind capacity at the end of 2023 was only 1,821 MW and offshore capacity was only 146 MW (i.e. 2.0 GW in total)<sup>70</sup>. Wind contributed less than 1% of total generation. The Korean government is targeting 34 GW of installed wind capacity by 2036.

Notwithstanding the targeted reduction in LNG, there is currently substantial investment underway and proposed in Korean LNG infrastructure, regasification terminals and storage. Korean LNG buyers have been active in securing new long-term LNG contracts. This suggests that companies believe Korean LNG imports will need to grow, not decline.

### **Taiwan – LNG wins as nuclear winds down**

Taiwan is also committed to net zero by 2050 but is aiming to phase out nuclear by 2025 and increase the use of gas.

Coal-fired power generation accounted for 42% of its power mix in 2023, gas was 40%, renewables 7%, nuclear 6% and the remainder was accounted for by other sources including hydro. By 2025, the share of coal has to come down to 30%, gas has to reach 50%, renewables have to reach 15% and nuclear has to go to zero<sup>71</sup>. Taiwan is proposing a higher share for LNG to offset the impact of the final nuclear phase-out. These emissions will also need to be abated. Increasing the gas share of power generation to 50% would require an additional 3 Mtpa of LNG imports.

As in Japan and Korea, renewables are growing. Solar has been growing but as of 2022 had only achieved half of the 2025 target and less than one-third of the wind target. Achieving 50% gas-fired power generation in Taiwan's power mix by 2025 requires accelerated development of both gas-fired power plants and LNG receiving terminals.

### **Conclusion**

Japan, Korea and Taiwan are often lumped together in considering the outlook for energy demand, including LNG, in North Asia. However, while Japanese energy demand has been falling, it is growing in the other two countries. And while gas is losing market share to coal in Japan it is gaining market share in Korea and Taiwan.

All three countries are committed to significant reductions in emissions by 2030 but are also highly reliant on fossil fuels for electricity generation. Only in Korea is there strong support for increased nuclear while renewables are facing challenges, particularly offshore wind. In these circumstances, there will likely be recourse to LNG rather than higher-emission coal. This appears to be borne out by the active LNG investment and contracting currently underway by companies in all three countries.

<sup>70</sup> <https://gwec.net/strong-2023-offshore-wind-growth-as-industry-sets-course-for-record-breaking-decade/>

<sup>71</sup> [https://www.moea.gov.tw/MNS/english/Policy/Policy.aspx?menu\\_id=32904&policy\\_id=19](https://www.moea.gov.tw/MNS/english/Policy/Policy.aspx?menu_id=32904&policy_id=19)



## ENERGY TRANSITION SCENARIOS: THE IMPACT OF NATURAL GAS

### Mike Fulwood

The OIES Gas Programme has developed three scenarios which consider how the natural gas market may develop over the next 25 years or so. The Intergovernmental Panel on Climate Change (IPCC) have gathered and reviewed over 400 scenarios, of which some 85 or so are consistent with limiting the global temperature rise to 1.5° C. These give a very wide range of outcomes for natural gas demand by 2050. The IEA's net zero scenario (NZE) sees a rapid decline in global natural gas demand to very low levels. The IEA NZE is one of many scenarios which achieves net zero by 2050, but it is not the only pathway.

Three scenarios are considered, covering the period to 2050. None of these are forecasts, nor are they expectations of the most likely path to net zero, or some other decarbonization route. In that respect they are similar in construct to the IEA scenarios, which are also not a most likely pathway to any predetermined outcome. The three scenarios are:

- **Declared Policies Scenario (DPS):** broadly similar in concept to the IEA's Stated Policies Scenario (STEPS) with a global temperature rise over 2.0° C
- **Net Zero with CCS (NZwthCCS):** Net zero achieved by 2050 but does not limit temperature rise to 1.5° C
- **Fragmented (FRAG):** Net zero by 2050 not achieved but global emissions on a steep downward trajectory from 2030 onwards

Total energy demand in DPS is assumed to be the same as IEA STEPS, while for NZwthCCS and FRAG, energy demand assumed to be as in IEA APS (Announced Pledges). Different gas demand scenarios were generated by changing the fuel shares by sector.

NZwthCCS does not limit temperature rise to 1.5° C by 2050 but overshoots, with negative emissions post 2050 to get back to 1.5° C by 2100. The driver is to electrify as much as possible, but intermittency of renewables remains a major issue – batteries are not the solution so abated fossil fuel, especially gas, remains a material proportion of the power generation mix. There is widespread CCS. Hydrogen has an important role as a “clean” fuel but largely in industry and transport. It is localised and will not be transported over long distances due to cost. Blue hydrogen outweighs green hydrogen, except in China, where brown hydrogen dominates. All countries make steady progress towards net zero in a co-ordinated manner.

FRAG relaxes the assumption that net zero is achieved by 2050. This scenario acknowledges that NZwthCCS is not seen as that realistic across the board. FRAG has a higher temperature target due to higher CO<sub>2</sub> emissions by 2050. In a more fragmented world, different countries and regions move at different paces and with different methods of decarbonising. The commitment to decarbonization is strongest in the OECD economies, followed closely by China. On the low commitment end are Russia and Africa with C&S America, ASEAN and Middle East partially committed with India just behind.

### Gas Demand and Supply

Global gas demand rises in all three scenarios between 2022 and 2030. From a level of just under 4,100 bcm in 2022, demand reaches some 4,584 bcm by 2030 in DPS (12% growth), 4,392 bcm in FRAG (7% growth) and 4,322 bcm in NZwthCCS (6% growth). This is in marked contrast to IEA NZE where demand is down to 3,442 bcm by 2030 (16% decline). In the DPS scenario, gas demand peaks around 2040 and declines slowly after that. In FRAG and NZwthCCS, gas demand peaks around 2030 in both.

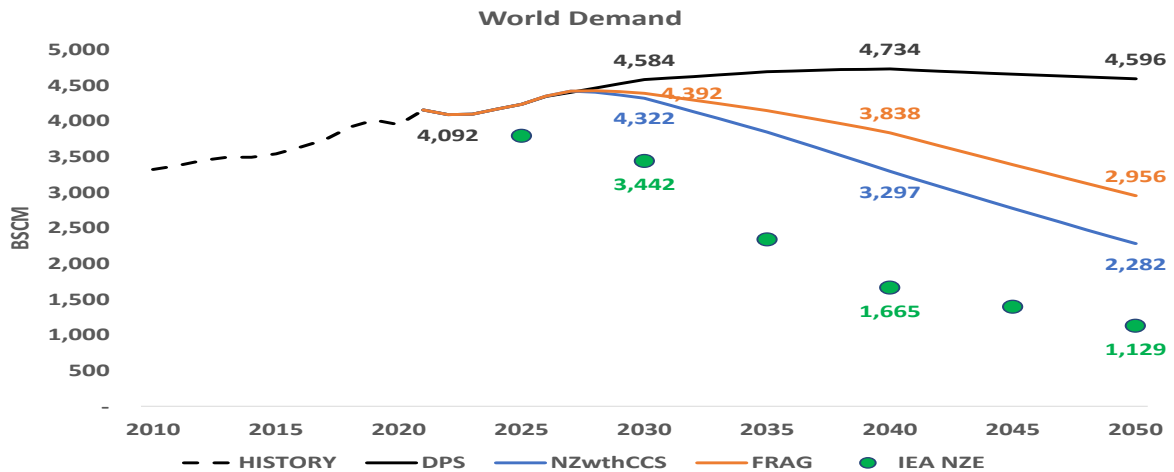
Power generation accounted for some 40% of global gas demand in 2022, with industry (including non-energy use) at some 25%. Residential and commercial are at 21% and transport at 4%. As electrification proceeds rapidly in NZwthCCS and, to a lesser extent in FRAG, the residential and commercial share (essentially buildings) falls to 2% in NZwthCCS and 6% in FRAG.

The power generation share rises in FRAG to almost half global gas demand by 2050 and declines a little in NZwthCCS to 35%. Industry share (including non-energy use) is maintained in both FRAG and NZwthCCS. However, the volume of gas demand in both industry and power generation is lower in 2050 than in 2022 since total gas demand is much lower.



The key change is in other transformation, which is essentially blue hydrogen, with a share of over 30% in NZwthCCS – with little competition from green hydrogen – and 10% in FRAG, where green hydrogen is relatively more important. Hydrogen use is predominantly in the high temperature “hard-to-abate” sectors and is focused around large industrial sites.

Figure 1: Global Gas Demand



Source: NexantECA World Gas Model, OIES Analysis

In DPS, gas demand is flat or weak in North America, Europe and Japan, Korea and Taiwan, as well as the Former Soviet Union countries. Demand is stronger in other regions, notably China, especially before the mid-2030s, together with the Middle East and Africa. There is also growth in ASEAN, South Asia and Central and South America.

In FRAG and NZwthCCS, gas demand falls sharply in North America, Europe, JKT and the Former Soviet Union countries, but also in the Middle East. In other regions, after growth to 2030 – and in FRAG to 2040 – declines do set in. However, in ASEAN, South Asia, Africa and Central and South America, gas demand in FRAG is higher or at a similar level in 2050 as in 2022. For Africa, even in NZwthCCS, gas demand is higher in 2050 than in 2022.

In respect of supply, the key drivers are the demand in the region and the export requirements. In DPS therefore, North America supply remains at a high level, with rising LNG exports offsetting weak domestic demand. Middle East and Africa supply rises even more strongly than demand, driven by LNG exports. China supply also grows in line with demand.

In FRAG and NZwthCCS, the supply picture is somewhat different. North American and Russian supply fall sharply – a combination of declining demand and exports. Supply holds up better in the Middle East – because of stronger exports – and Africa, with stronger demand. China supply declines sharply in both FRAG and NZwthCCS following the falling demand profile.

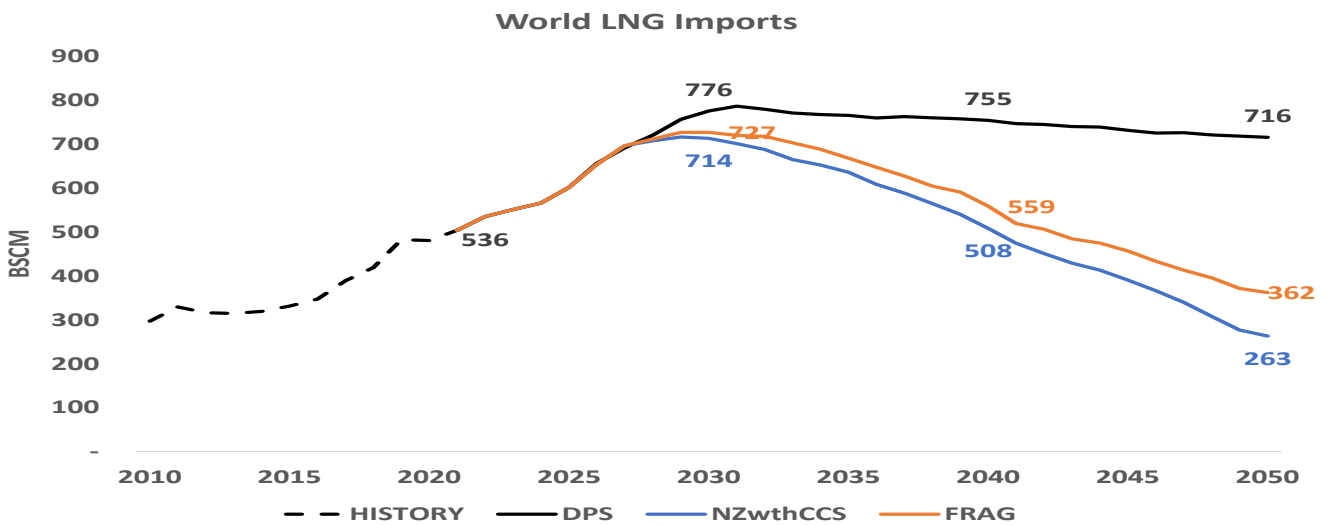
**LNG Trade**

LNG trade rises through 2030 in all three scenarios but then peaks. DPS LNG trade then plateaus to 2040 with a small decline thereafter. In contrast, sharp declines in trade set in in both FRAG and NZwthCCS post-2030, driven by the falling gas demand in key importing regions.

Europe is the largest importing region in DPS, with JKT, South Asia and ASEAN also remaining as key importers. China is one of the largest importers in 2030 but LNG imports decline in the 2030s and 2040s as stable, then declining, demand is met with rising pipeline imports from Russia – Power of Siberia 2 comes on in the early 2030s – and flat domestic production. In FRAG and NZwthCCS, all regions see declining LNG imports from 2030 on. The decline in Europe is especially sharp, but imports into JKT and ASEAN hold up somewhat better.



Figure 2: LNG Trade



Source: NexantECA World Gas Model, OIES Analysis

In respect of LNG exports, in DPS North America is the largest exporting region, followed by the Middle East (mainly Qatar). Russia LNG exports grow through 2030 as Arctic 2 eventually comes on, and Sub-Saharan Africa also grows volumes. Oceania and ASEAN see much reduced LNG exports as older plants close and contracts expire. The outlook in FRAG and NZwthCCS is very different. North American LNG exports fall away sharply, being a relatively high-cost producer in an oversupplied world. LNG export volumes elsewhere also decline and in NZwthCCS, Oceania and ASEAN completely cease exports by 2050 with plants closing. The only region not to follow this trend is the Middle East, essentially Qatar, where there is little or no difference in LNG exports in all three scenarios. As the lowest cost LNG exporter, Qatar always produces, whatever the scenario.

**Hydrogen**

In NZwthCCS there is strong growth in blue hydrogen, combined with a slower roll out of green hydrogen, which is almost totally locally produced. In FRAG, blue hydrogen is initially the primary low-carbon hydrogen, but then is gradually displaced by green hydrogen, which becomes more important from 2040 on, but still localised. Blue hydrogen is strong in North America, Europe and Middle East up to 2040, in both NZwthCCS and FRAG. Post 2040, blue hydrogen is expected to predominate in regions with ample CCS storage capacity. Outside China and India, the gas share (blue) of hydrogen is largely between 70% and 90% by 2050 in NZwthCCS. Brown hydrogen from coal is more important in China and India. The gas share (blue) of hydrogen in FRAG begins to reduce from 2040 onwards, as green hydrogen becomes more important. However, it still remains at up to 75% in 2050 in North America and Europe, 50% in Middle East and ASEAN, albeit lower elsewhere.

**Carbon Capture and Storage**

Some 3.4Gt of CO2 is captured from gas in 2050 in NZwthCCS, with some 2.2Gt captured in FRAG in 2050. There is generally a slower roll out of CCS in FRAG than in NZ50. However, there is still strong carbon capture in North America and Middle East, to some extent, in FRAG. In Russia there is minimal carbon capture in FRAG and also materially lower in C&S America, JKT, Africa and South Asia.

The IEA’s Net Zero Pathway has total CO2 capture in 2050 of 6Gt, of which 3.7Gt is from fossil fuels and industrial processes – the balance is bioenergy and direct air capture. OIES NZwthCCS has somewhat more CO2 capture from gas than IEA NZE but in FRAG, the CO2 capture rate is likely lower than in IEA NZE. IEA also note that the level of deployment of carbon capture in NZE is much lower than in other comparable 1.5 degrees C scenarios, which are in the range of 3.5Gt to 16Gt in 2050.

**Conclusions**

The OIES NZwthCCS scenario achieves net zero across the board everywhere but with a significant volume of CCS required in all countries/regions. The realism of this scenario can therefore be questioned. The FRAG scenario reflects a multi-paced world with some countries/regions more committed to decarbonization than others. There is still significant CCS which is required to



maintain a reasonable level of gas demand. At COP28, the prospect of the use of fossil fuels as transitional fuels was recognised. In that respect, it could be argued that the FRAG scenario is much closer to the COP28 outcome, with natural gas being a transitional fuel.

The key conclusion is that if gas is to remain a significant fuel in a rapidly decarbonising world, then the industry needs to invest in an enormous amount of CCS. The alternative is rapid decline, as is shown in the IEA NZE scenario.

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## **GAS IN CHINA: IT'S THE POLICY, STUPID!**

***Michal Meidan***

China's gas demand has increased by an annual average of 10% between 2013 and 2023, with consumption more than doubling from 177 bcm in 2013 to 395 bcm in 2023. This strong growth was driven by a combination of factors: the availability of domestically produced gas to fuel industrial activities alongside policies encouraging gas consumption. And when gas was available at competitive prices, policy makers sought to accelerate its use. But just as supplies, policy and prices have enabled gas consumption, they have also, at times hindered it. When overly ambitious fuel switching policies led to supply shortages and price spikes, appetite for gas waned. Global market volatility and concerns about import dependence could also slow the uptake of gas in the future, especially since China has abundant reserves of coal and increasingly, the largest renewable manufacturing base globally and has achieved rapid deployment of wind and solar.

In light of these uncertainties, estimates of the country's future demand range from a very conservative 406 bcm in 2030 to a more ambitious 617 bcm that same year. Views also diverge as to whether industry or power will be the main drivers of demand growth. For instance, Sinopec, China's second largest oil and gas company, estimates that demand will reach 524 bcm in 2030 and 610 bcm in 2040 with industry accounting for almost 80 bcm of the increment between 2025 and 2030, and power roughly 20 bcm<sup>72</sup>. Between 2020 and 2040, Sinopec estimates that industrial use will absorb 180-200 bcm of additional gas while the share of power in this growth will be more muted. CNPC, China's largest oil and gas company, reckons that gas demand will similarly reach around 520 bcm in 2030 and peak at 606 bcm in 2040 but that power will soak up almost 170 bcm of that increment through 2040.

This paper argues that while gas demand is likely to grow strongly in China because it is viewed as a partner fuel in the country's energy transition, it will still be constrained by the availability of both coal and renewables. Moreover, the policy environment in China is enabling for gas, but it is not supportive. This means that without a clear mandate to switch from coal to gas, the cost competitiveness of coal and renewables—both of which in Beijing's eyes offer greater supply security—will limit the growth potential for gas. Gas use will rise across the board, with the biggest gains in industrial consumption followed closely by the power sector, but it will always play second fiddle to coal and increasingly to renewables. China's gas demand is unlikely to reach 600 bcm in 2030, but is still poised for remarkable growth with as much as 50 bcm growth in 2024-2025. Policies, however, will remain the key driver.

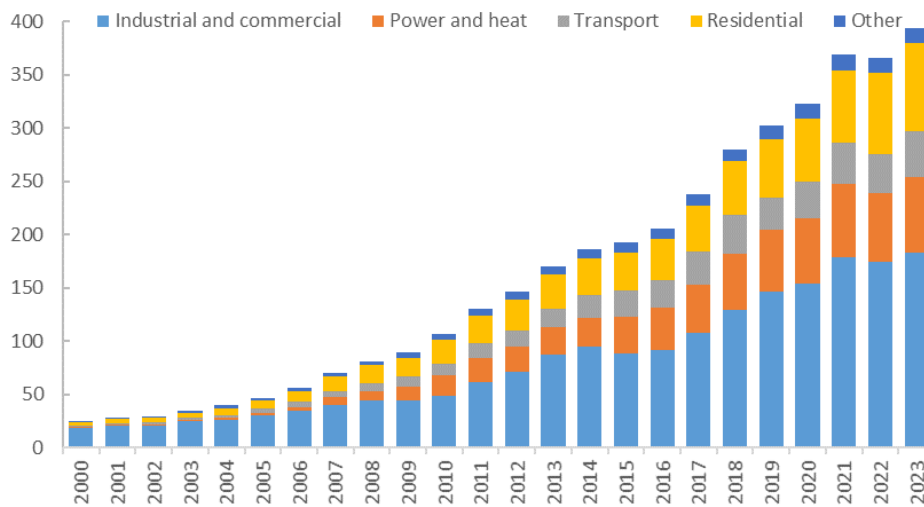
### **Cautious support for gas**

In 2000, China consumed 25 bcm of gas and produced 27 bcm. By 2023, the country consumed 395 bcm and back in 2016, government plans estimated that demand would reach 600 bcm by 2030. Industry accounted for two-thirds of China's gas consumption in the early 2000s, with its share gradually falling to 40% as residential (mainly for cooking and hot water) and power demand rose.

<sup>72</sup> Based on Sinopec EDRI 2060 outlook, 2024 edition



Figure 1: Chinese gas demand by industry, bcm



Source: NBS, NDRC, CNPC

The policy landscape for gas has evolved over the past two decades looking on one hand to encourage a greater role for it, especially as the government sought to diversify its energy mix away from coal and tackle local air pollution, but constrained, on the other, by growing import dependence and price volatility.

In the early 2000s, with demand rising strongly and domestic supplies struggling to catch up, the government prioritised residential consumption. In 2007, the government issued its first *Natural Gas Utilisation Policy*,<sup>73</sup> which divided gas use into four areas: priority, permitted, allowed and prohibited. The 2007 document prioritised residential gas for cooking and heating, natural gas vehicles as well as gas use in public facilities, meaning that local governments were expected to invest in supplies and infrastructure to enable greater gas consumption in these sectors. Industrial use, especially where it enabled fuel switching away from coal and oil products was allowed (but not prioritised) in building materials, electromechanical industries, textiles, petrochemicals and metallurgy while use in the power sector, especially in China’s large coal bases and in methanol production was strictly prohibited.

**Supply-driven demand policies**

The looming need to increase supplies in order to meet growing demand led to China’s first LNG imports in 2006 and to the signing of a number of pipeline supply deals from Central Asia. Initial deliveries began in 2010 and coincided with optimism about China’s own shale potential. As worsening local air pollution rose on the policy agenda, the government looked to encourage a more rapid uptake of gas use. The *Natural Gas Utilisation Policy* was amended in 2012<sup>74</sup> adding more sectors to the priority areas: it kept its focus on prioritising gas use in heating and cooking but also adding an encouragement to use it in central heating and air conditioning. The priority list now included more categories of natural gas vehicles, inland maritime transportation as well as distributed natural gas projects. It encouraged natural gas storage projects and even allowed some gas in power projects, although it maintained its ban on gas in power in the large coal-producing regions.

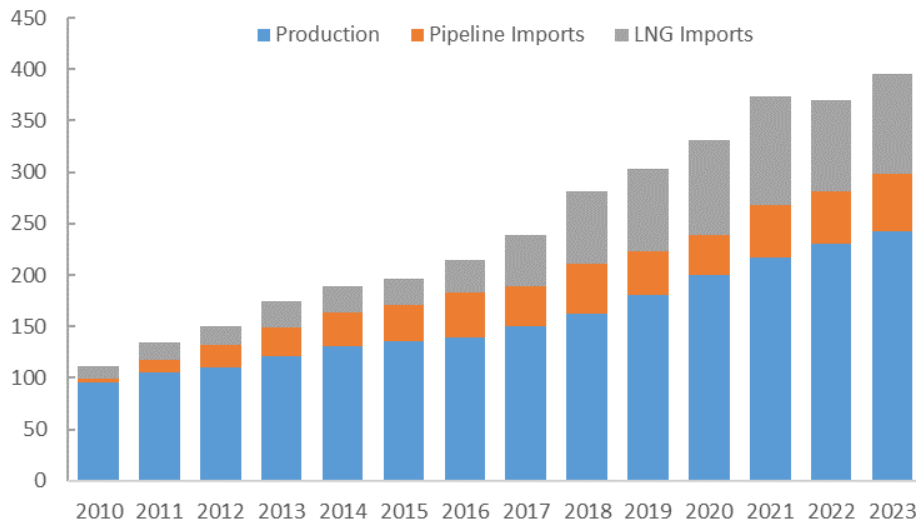
With domestic production growing at a healthy clip of around 10 bcma annually between 2010 and 2013, the 13<sup>th</sup> Five Year Plan (2016-2020) included ambitious targets for gas. The plan discussed a “natural gas security capacity” of more than 360 bcm by 2020, aiming for 30 bcm of shale gas production, 10 bcm of coal-bed methane output in addition to 207 bcm of conventional gas production by 2020. It also included a goal for gas in installed power generation capacity to exceed 110 GW (up from 55 GW in 2015) and for natural gas to account for around 8.3-10% of the primary energy mix, up from 5.9% in 2015.

<sup>73</sup> [https://www.gov.cn/zwqk/2007-09/04/content\\_736629.htm](https://www.gov.cn/zwqk/2007-09/04/content_736629.htm)

<sup>74</sup> [https://www.gov.cn/gongbao/content/2013/content\\_2313190.htm](https://www.gov.cn/gongbao/content/2013/content_2313190.htm)



Figure 2: China gas supplies, bcm



Source: NBS, China Customs, OIES

In 2012, as local air pollution worsened, the government introduced measures to control air pollution in urban centres and to use gas as a heating fuel<sup>75</sup>, aiming to switch households, commercial users and some industries from coal to gas by the end of 2017. But domestic production growth slowed from 2014 and the much-awaited shale revolution fell short of expectations. Meanwhile, demand was rising rapidly. In 2017, many local governments had not achieved their air quality targets and as the end of the plan loomed, they were under pressure to meet them. With almost 4 million households having to switch to cleaner fuels, local governments opted for gas over electricity as it was cheaper and quicker to lay pipelines than set up power grids, but they overshot their targets, looking to switch even more households than initially planned and failed to ensure supplies. With some industrial users also switching from coal to gas in order to comply with government mandates, the surge in gas demand during an unusually cold winter led to price spikes and supply shortages.

**A more cautious outlook**

The following iteration of the winter clean heating plan (2017-2021) loosened the gas requirements and allowed fuel switching from coal to electricity, in order to avoid another supply crunch. Local governments could replace loose coal (low quality coal with high ash and sulphur content) with a variety of cleaner alternatives including gas, but also electricity, geothermal, biomass and others.

But implementation of this second plan was less stringent as the country grappled with the aftermath of the COVID-19 pandemic, broader concerns about economic recovery and supply chain resilience. The 14<sup>th</sup> Five Year Plan that was issued in 2021 did not include many gas-specific targets, unlike the 13<sup>th</sup> FYP that included a dedicated Five-Year Plan for gas<sup>76</sup>. The 14<sup>th</sup> FYP did not include a demand outlook or a share of gas in the energy mix. What is more, many of the 13<sup>th</sup> FYP targets for 2020 had not been met or were adjusted. The production target of 207 bcm was met in 2022, shale gas production was roughly half of the target and the goal for 110 GW of gas-fired power generation was also reached only in 2022. The 14<sup>th</sup> FYP focused on a storage target for gas, calling for 55-60 bcm of storage capacity, up from 26 bcm in 2020, but did not include a sector-specific plan for natural gas.

Overall then, the policy environment became increasingly cautious. Following the Russian invasion of Ukraine and the volatility in global gas markets, the Chinese government tempered its enthusiasm for coal-to-gas conversions. The National Development and Reform Commission (NDRC) China’s most important government ministry, said in its 2023 work report that it will “strictly control the expansion of projects to replace coal with natural gas and ensure the steady supply of natural gas.”

<sup>75</sup> Action Plan for Air Pollution prevention and control was introduced in September 2013 and ended in 2017

<sup>76</sup> <https://www.ndrc.gov.cn/fggz/fzllgh/gjjzxgh/201706/W020191104624281237228.pdf>



### The urgency of emissions reductions

Yet falling international prices and a strong recovery in industrial activity in 2023 led to rapid increases in gas consumption. Moreover, new gas-fired power plants started up as the need to balance the intermittency of renewables also grew. In late-2023, an interim assessment of the 14<sup>th</sup> FYP highlighted that China was not on track to meeting its CO<sub>2</sub>- and energy- intensity targets for 2025. At the end of 2023 and in early 2024, the government issued a slew of policy documents aimed at increasing energy conservation and reducing emissions<sup>77</sup>, as well as another action plan to improve air quality by 2025<sup>78</sup>. These plans target energy-intensive industries and coal use, but also promote the “orderly” consumption of natural gas, meaning that gas consumption is preferable to coal, but only when supplies are available.

With gas seemingly back in vogue, the government also revised its natural gas utilisation policy from 2012, issuing a revised “Gas use regulation”<sup>79</sup> which highlighted throughout that if the planned conversion to gas is environmentally and economically more efficient, it should be allowed. The priority areas remain intact, with the addition of “economic” gas-fired, peak-shaving power plants. Meanwhile, gas-fired power plants in coal-rich areas are no longer prohibited, in recognition of the rapid rise of renewables in China and the need to balance intermittency. The new regulation also looks to limit hydrogen production from gas although refineries and chemical units using hydrogen can keep and expand their grey production. All other hydrogen production from gas should be restricted, to align policy goals on green hydrogen production from electrolysis and renewable power generation. The latest iteration of the *Gas Use Regulation* only prohibits ammonia production using natural gas.

### Is an enabling policy environment enough for gas use to grow?

The policy framework recognises that gas will play a role in China’s energy transition, prioritising its use in residential demand but also increasingly in the power sector and in certain industries that must switch away from coal. But the government’s attitude to phasing out coal is also mixed. Since China has abundant reserves of coal, it has been at the heart of the country’s industrial development. Coal accounted for 55% of China’s energy mix in 2023 and has been key in fuelling industrial processes as well as power generation. In theory then, as China looks to transition away from coal—given its pledge to peak carbon emissions by 2030 and reaching net-zero by 2060—gas use could rise dramatically<sup>80</sup>. But with large domestic production of renewable energy and the world’s fastest deployment of wind and solar, the limited availability of domestically produced gas and the volatility in global gas prices, the role of gas as a bridge fuel in China is increasingly being questioned<sup>81</sup>.

### The role of gas in the power sector will remain limited

In early 2024, China’s National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) released a policy notice that called for the construction of new gas-fired peak shaving facilities, specifying that gas supply must be secure and affordable. At the same time, the policy calls on refurbished coal assets to provide grid flexibility, along with dispatchable renewable energy. This means gas in power is set to rise, but it is important to put it in context: By the end of 2024, China’s installed wind and solar capacity is estimated to exceed 1,300 GW, on par with coal and by far exceeding the 150 GW or so of gas-fired capacity. What is more, generation from wind and solar has increased by 1,250 terawatt-hours (TWh) since 2015, while natural gas-fired generation has increased by just 140TWh. Meanwhile, coal generation has increased by 1,700TWh, but its share has fallen from 70% to 61%. Gas still accounts for under 5% of generation. Going forward, the government intends for renewables to account for power demand growth and while gas will play a role in balancing their intermittency, it will inevitably be very small and limited to the large gas-consuming provinces of Guangdong, Jiangsu, Zhejiang and Beijing. Moreover, gas struggles to compete with coal and renewables on a cost basis. The cost of power generated from coal in China has been two to three times lower than gas<sup>82</sup>, with onshore wind and solar rapidly becoming the country’s

<sup>77</sup> 国务院关于印发《2024—2025年节能降碳行动方案》的通知[https://www.gov.cn/zhengce/content/202405/content\\_6954322.htm](https://www.gov.cn/zhengce/content/202405/content_6954322.htm)

<sup>78</sup> ‘国新办举行空气质量持续改善行动计划国务院政策例行吹风会’[https://www.mee.gov.cn/czwj/zclcfh/202312/t20231212\\_1058873.shtml](https://www.mee.gov.cn/czwj/zclcfh/202312/t20231212_1058873.shtml)

<sup>79</sup> [https://www.ndrc.gov.cn/xxgk/zcfb/fzggwl/202406/t20240619\\_1387036.html](https://www.ndrc.gov.cn/xxgk/zcfb/fzggwl/202406/t20240619_1387036.html)

<sup>80</sup> Zhao et al. “Energy transition in China: It is necessary to increase natural gas utilization”, *Energy Reports*, Volume 10, November 2023, pp. 2439-2447; Shell LNG Outlook 2024, [https://www.shell.com/what-we-do/oil-and-natural-gas/liquefied-natural-gas-lng/lng-outlook-2024/\\_jcr\\_content/root/main/section\\_125126292/promo\\_copy\\_copy\\_copy/links/item0.stream/1709628426006/3a2c1744d8d21d83a1d4bd4e6102dff7c08045f7/master-lng-outlook-2024-march-final.pdf](https://www.shell.com/what-we-do/oil-and-natural-gas/liquefied-natural-gas-lng/lng-outlook-2024/_jcr_content/root/main/section_125126292/promo_copy_copy_copy/links/item0.stream/1709628426006/3a2c1744d8d21d83a1d4bd4e6102dff7c08045f7/master-lng-outlook-2024-march-final.pdf)

<sup>81</sup> IEA

<sup>82</sup> <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/12/Insight-80-Natural-gas-in-Chinas-power-sector.pdf>



cheapest sources of power<sup>83</sup>. Lower LNG prices would help increase gas penetration in the power sector, but only at the margins. And much would depend on the trajectory for both coal prices (which could increase as the government steps up its environmental policies) as well as the outlook for renewable costs.

That said, given expected power demand growth in China, even if the share of gas in power generation remains at around 5%, that would still represent large increases in gas consumption. The OIES estimate, based on the Nexant World Gas Model, suggests that gas use in power will increase by almost 50 bcm by 2030.

Industrial demand is another key driver of gas demand growth but it stems from a combination of economic growth and fuel switching. The government’s focus on industries of the future, including batteries, electric vehicles and solar panels are all supporting key gas-consuming industries such as metal smelting, glass and chemicals. Since industry is the biggest gas consumer in China, ongoing expansion leads to rising demand. But going forward, the key question is whether gas will be the key solution to efforts to decarbonise industry.

China’s industrial sectors account for 33% of the country’s coal consumption with a large share of industrial coal used in iron, steelmaking and cement. The downturn in the real estate sector and declining production in many heavy industries, along with structural shifts to the Chinese economy will phase out some coal use without the need for fuel switching to gas. Moreover, China has other options: China’s Cement Association sees solid-waste fuels, biomass, hydrogen and electricity replacing coal as a heat provider in cement production processes. In the steel sector, coal reductions could occur through electricity and hydrogen pathways that involve electric arc furnace (EAF)-based secondary steelmaking and hydrogen-based direct reduced ironmaking (DRI)<sup>84</sup>. This does not mean gas has no role to play in China’s industrial decarbonisation, but that it is one option among others. Given concerns about import dependency and supply security, gas is a ‘nice to have’ rather than a ‘must have’. According to the OIES Nexant model, industry is likely to account for over 60 bcm of incremental gas demand through 2030.

Overall then, gas will play a role in China’s energy transition, with roughly 150-170 bcm of demand growth between 2023 and 2030. But whether that demand will come predominantly from industrial consumption—due to economic expansion or fuel switching—or from the power sector, will depend on policies. These, in turn, are driven by the urgency of phasing out coal as well as the perceptions of the availability and cost of supplies. But barring a strong mandate to switch rapidly to gas, its future is likely to remain in limbo, peaking at no more than 13% of China’s energy mix.

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## CHINA'S NATURAL GAS MARKET PRICE SYSTEM: HOW FAR CAN THE TWO DUAL-TRACK SYSTEMS GO?

*Shuai Wang and Ji Chen*

The general idea behind China's natural gas market liberalization reform is to accelerate the marketization of natural gas prices and improve resource allocation efficiency. This involves deregulating the potentially competitive wholesale and retail prices, while at the same time enhancing the regulation of transmission and distribution charges, which are considered natural monopolies. This strategy is known as "controlling the middle and opening both ends." Currently, the natural gas price reform has achieved notable results. Transmission and distribution prices are based on cost-plus pricing, with the reasonable rate of return determined by the government. According to the latest policy, the allowed rate of return for transmission is 8%, and for distribution, it is no more than 7%. However, the retail prices of piped natural gas are still determined by local governments based on the sum of purchased gas costs of the city gas companies and distribution charges. The government has in particular adopted stricter regulations for residential gas prices. At the same time, in terms of wholesale gas prices, some gas prices are regulated while others are not.

We summarize this situation as two dual-track systems. One dual-track system of wholesale gas prices refers to the co-existence of regulated and non-regulated gas prices, with regulated gas prices often being lower. The other dual-track system of

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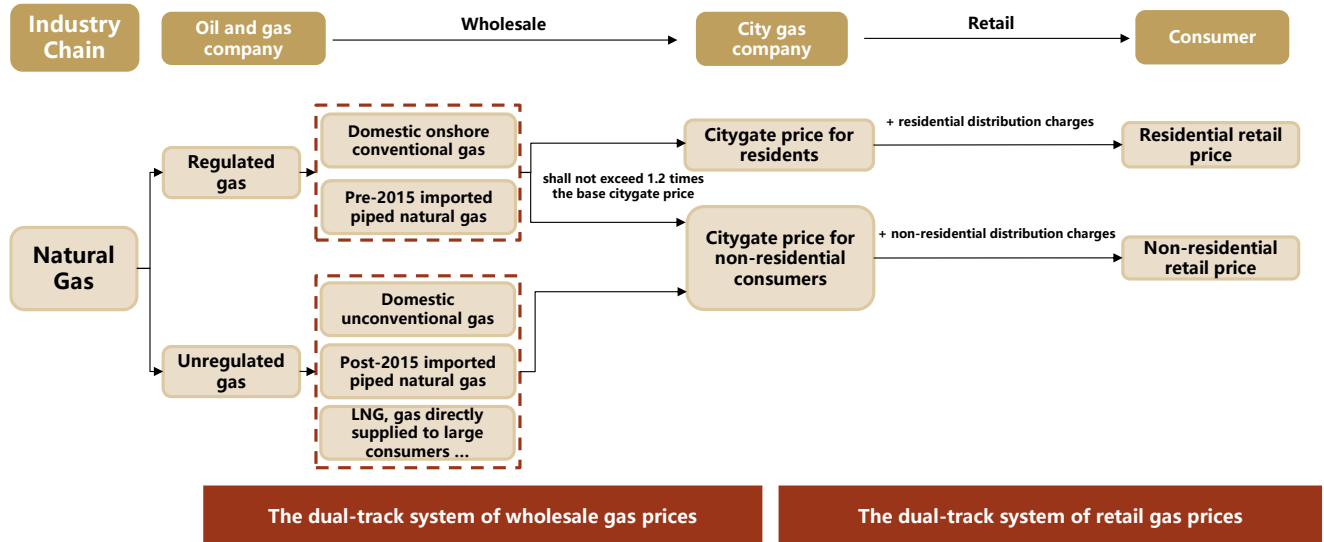
83 IEEFA Report - LNG is not displacing coal in China's power mix.pdf, <https://ieefa.org/sites/default/files/2024-06/IEEFA%20Report%20-%20LNG%20is%20not%20displacing%20coal%20in%20China%27s%20power%20mix.pdf>

84 Belinda Schäpe, Decarbonising China's Steel Sector: Challenges and Opportunities, <https://www.oxfordenergy.org/publications/decarbonising-chinas-steel-sector-challenges-and-opportunities/>



retail gas prices refers to the fact that the price of natural gas delivered to residential consumers is usually lower than that for non-residential consumers. To be sure, these dual-track systems are temporary in China's gas market liberalization reform, which objectively speaking has both advantages and disadvantages. We will analyze it in detail next.

**Figure 1: Two dual-track systems in China's natural gas market liberalisation reform**



Source: NDRC, CICC Global Institute

**An interim stage of the market liberalization**

The two dual-track systems actually reflect an interim status in market liberalization. The formation of two dual-track systems has historical inevitability. When the amount of imported gas was very small before 2010, the ex-plant price of onshore gas was regulated<sup>85</sup>. After 2010, China's natural gas imports increased gradually. A nationwide natural gas market liberalization reform was initiated in 2013, with a unified city-gate price for both domestic and imported gas, and the city-gate price was subject to maximum ceiling price management<sup>86</sup>. But the problem is that the cost of imported gas is often much higher than domestic gas, causing oil and gas companies to lose money on imported gas businesses. As a result, wholesale gas developed into a model where regulated and market-based prices co-existed. For residential gas, the ex-plant gas price for residents was not lower than that for industry before 2007, but in order to curb the rapid growth of natural gas used for industrial projects and narrow the price gap between natural gas and alternative energy, China raised the ex-plant industrial gas price by 0.4 RMB per cubic meter and kept residential gas price unchanged to prioritize people's livelihoods in 2007<sup>87</sup>. Since then, gas prices for residents have always been lower.

As a result of this evolution, for wholesale gas prices, China sets price ceilings on onshore conventional gas and pre-2015 imported piped natural gas. The actual city-gate prices shall not exceed 1.2 times the base city-gate prices determined by the government. Other than that, the prices of unconventional gas such as shale gas and coalbed methane, LNG, gas directly supplied to large industrial consumers, gas traded on trading platforms and gas stored in storage facilities are decided by the market and not subject to these ceilings; for retail gas prices, lower residential prices result from allocating more regulated low-priced gas to residents and stricter restrictions for the linkage between purchased gas costs and residential prices. This effectively amounts to subsidies, including cross-subsidies from industrial and commercial users to residential users and subsidies from city gas companies to residential users when the purchased gas costs rise but residential prices remain unchanged.

<sup>85</sup> [https://www.gov.cn/gongbao/content/2002/content\\_71443.htm](https://www.gov.cn/gongbao/content/2002/content_71443.htm)  
<sup>86</sup> [https://www.ndrc.gov.cn/xxgk/zcfb/tz/201306/t20130628\\_963914\\_ext.html](https://www.ndrc.gov.cn/xxgk/zcfb/tz/201306/t20130628_963914_ext.html)  
<sup>87</sup> [https://fzggw.cq.gov.cn/zwgk/zfxxgkml/jgxx/jgzc/202003/t20200304\\_5584367\\_wap.html](https://fzggw.cq.gov.cn/zwgk/zfxxgkml/jgxx/jgzc/202003/t20200304_5584367_wap.html)



### Pros and cons of the two dual-track systems

The dual-track system is essentially a price distortion. Compared to market pricing, the price ceilings transfer some producer surplus to consumers. This practice is conducive to promoting the use of natural gas, a cleaner fossil fuel. The dual-track system can reduce the average gas costs for customers, especially residents, for whom natural gas is a necessity. These are the benefits brought by the dual-track system.

However, a potential risk of the dual-track system is the supply-demand imbalance of regulated low-priced gas. In other words, although gas prices are regulated and suppressed, gas may be in short supply. The fundamental reason is that gas price control measures have weakened the role of price signals in balancing the supply and demand of gas.

The dual-track system of wholesale gas prices may lead to an insufficient supply of regulated low-priced gas. On the one hand, as gas resources continue to be exploited, the cost of exploration and development is rising. The return on new projects is declining due to the price ceilings on domestically produced onshore conventional gas. Shale gas and coalbed methane, however, not only can be sold at higher unregulated prices but also receive financial subsidies and are bankable on the whole<sup>88</sup>. On the other hand, regulated and unregulated gas is not classified purely on the basis of resource, but rather on multiple dimensions on both the resource and wholesale sides (e.g., gas directly supplied to large industrial consumers is unregulated wherever it comes from), which pose additional challenges for regulators.

The dual-track system of retail gas prices also runs the risk of an insufficient supply of low-priced gas for residents. Because city-gate prices for residents are lower than for non-residential consumers, disagreements may arise between oil and gas companies and city gas companies over residential gas contract volumes, leading to the risk of shortages. For example, the China Gas Association has reported that oil and gas companies reduce residential gas contract volumes by 5% to 20% annually, and some rural coal-to-gas projects are not included<sup>89</sup>. At the retail level, because of the price difference between residential and non-residential gas prices, city gas companies have an incentive to sell more gas to non-residential customers and less to residents, which also leads to the risk of insufficient supply of residential gas. And cross-subsidies will also increase costs for energy-intensive industries such as gas-fired power generation, chemicals, and metal smelting.

In addition, China's natural gas supply chain is characterized by a high market concentration in oil and gas production and a low market concentration in the city gas distribution. Chinese oil and gas companies, which are oligopolies, have pricing power in the supply chain for wholesale unregulated gas to city gas companies at higher prices. They also have the incentive to do that due to losses from the gas import business and the decline in transmission revenues after the establishment of the China Oil & Gas Pipeline Network Corporation. This, coupled with the difficulty of fully passing on cost increases to residents, ultimately leads to significant profit declines for city gas companies, increasing their cyclical fluctuations in profits. For example, during the significant increase in global natural gas prices in 2021 and 2022, the margins of major city gas companies generally declined from about RMB 0.6/cbm to about RMB 0.5/cbm, according to CICC Research. This directly affected the stability and safety of the gas supply.

These supply-demand imbalance risks are closely related to gas prices. That is, the higher gas prices, the more likely gas shortages will occur, as seen in 2022 after the Russia-Ukraine conflict.

### Low Gas Prices: The Essential Catalyst for Further Marketization

A favorable time to further promote reform and optimize the dual-track system may be when domestic and international gas prices are similar, i.e., international gas prices are low enough, based on the high costs of gas transportation, LNG liquefaction, and regasification. If imported gas prices are too high relative to domestic gas prices, deregulation will rapidly increase average gas costs for customers. Gas demand may shrink due to the affordability issues for downstream users.

Regulators also consider low gas prices to be a favorable environment for market-oriented reform. For example, in 2015, the National Development and Reform Commission (NDRC) noted that "declining energy prices provide a favorable condition to further deepen the reform of natural gas prices."

<sup>88</sup> [https://www.gov.cn/zhengce/zhengceku/2020-07/01/content\\_5523237.htm](https://www.gov.cn/zhengce/zhengceku/2020-07/01/content_5523237.htm)

<sup>89</sup> <https://finance.eastmoney.com/a/202303162663565056.html>



Next, we focus on the gas prices. China's natural gas mainly comes from domestic production, imported LNG and imported pipeline gas, accounting for 58%, 25%, and 17% in 2023, respectively<sup>90</sup>. Under the dual-track system, most domestically produced gas has limited price changes under government control. Therefore, the main variables are imported pipeline gas prices, imported LNG long-term contract prices and spot prices. Currently, China's imported pipeline gas and LNG long-term contract prices are primarily linked to oil prices. However, in recent years, there has been a trend for imported LNG long-term contract prices to be more linked to gas prices. Some of the new LNG long-term contract prices are tied to Henry Hub (HH) in the U.S.<sup>91</sup>. These prices are usually lower than those traditionally tied to the oil price due to a loose natural gas market in the U.S. The spot prices of imported LNG are dependent upon the interaction of global LNG supply and demand. Historically, due to the greater flexibility of spot purchases, China's LNG spot imports have increased when international LNG spot prices remained low.

### **What to expect for China's natural gas price reform?**

In the short term, further improvements are needed on the basis of keeping the framework of the dual-track system unchanged. The focus should be on easing the business pressure on city gas companies, which in a nutshell means considering supply chain security while subsidizing consumers. For example, from the second half of 2023 to the present, many local governments have improved the linkage mechanism for residential gas prices, including easier triggering conditions and shorter intervals between price adjustments. Hebei Province has provided some financial subsidies to local city gas companies for losses in rural coal-to-gas projects. In the past few years, many city gas companies have accumulated a lot of losses.

On the one hand, the contract prices from upstream oil and gas companies have been rising and spot prices have also been higher in the past few years. On the other hand, city gas companies have found it difficult to pass on higher purchased gas costs to residents, as many cities have not raised residential gas prices in the past few years due to COVID-19 and other reasons.

In the long run, for the dual-track system of wholesale gas prices, we believe that a competitive market is essential for price liberalization. Given China's high market concentration in oil and gas production, it may be necessary first to promote market liberalization in coastal areas and to determine benchmark prices. This is because the natural gas market in coastal areas is more mature, the gas supply is more diversified and competitive and infrastructure such as LNG terminals have developed well in recent years. In inland areas where market concentration is high, gas prices shall be equal to the benchmark prices minus transmission costs, otherwise, arbitrage opportunities will exist. Market liberalization in inland areas is achieved indirectly in this way.

For the dual-track system of retail gas prices, taking into account the affordability of residents, the reasonableness of the dual-track system still remains for the long term. Implementing the responsibility and strengthening supervision can ensure a stable supply for residents. If we want to fully marketize residential gas prices in the future, the prerequisites include the affordability of residents and the establishment of subsidy systems, such as regular subsidies for low-income groups and temporary subsidies during occasional gas price spikes.

Currently, imported LNG spot prices in China's coastal areas are low and close to the supply costs of domestic gas. We believe that the LNG prices will remain relatively low in the coming years against the backdrop of loose markets, with new LNG export capacity gradually coming on stream and demand in Europe and many other regions still weak. Low gas prices provide a favorable macro environment for coastal areas to try to promote natural gas market reform. However, it should not be ignored that, under the global geopolitical risks and policy uncertainty in exporting countries, the volatility of global oil and gas prices may increase in the future, which in turn will bring potential supply disturbances.

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<sup>90</sup> Source: National Bureau of Statistics of China

<sup>91</sup> [https://vip.stock.finance.sina.com.cn/corp/view/vCB\\_AllBulletinDetail.php?gather=1&id=7960029](https://vip.stock.finance.sina.com.cn/corp/view/vCB_AllBulletinDetail.php?gather=1&id=7960029)



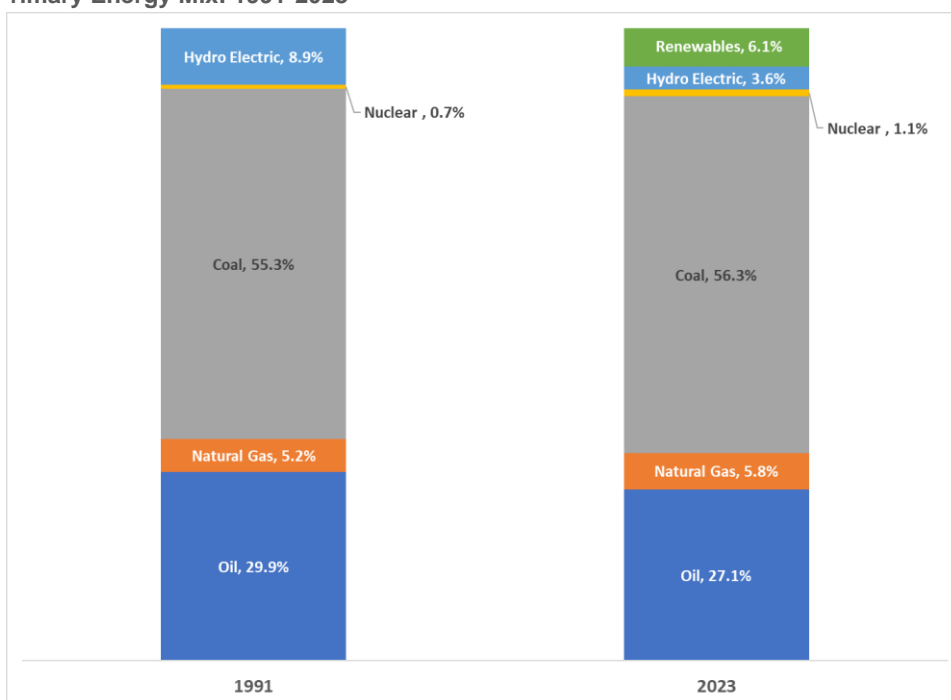
## INDIA'S ENERGY LANDSCAPE – PROGRESS, CHALLENGES AND OUTLOOK

### Nitin Zamre

India's energy landscape has evolved significantly since 1991 when the Indian government embraced liberal economic policies by opening up its markets. The consequent impact on the energy demand has been huge. From 1991 to 2023, primary energy consumption<sup>92</sup> grew from ~ 200 MToE<sup>93</sup> to ~ 950 MToE and India went from being the world's 10<sup>th</sup> largest energy consumer in 1991 to the third largest in 2023. During the same period, per capita primary energy consumption increased from about 235 KoE<sup>94</sup> to about 655 KoE.

However, the primary energy mix has remained broadly unchanged during the period. The biggest shift has been the addition of renewable energy, which accounted for 6 per cent by 2023. While natural gas consumption has increased from ~12 bcma in 1991 to ~63 bcma in 2023, its share has remained less than 6 per cent (Figure 1).

Figure 1: India's Primary Energy Mix: 1991-2023



Source: Statistical Review of World Energy, 2024

### Initial focus: augmenting energy supply

With the opening up of the economy, the immediate task was to increase energy supply to meet growing demand. Energy policies at that point focused on attracting private investment in supply, with a primary focus on ramping up electricity and fuel. The power sector saw generation capacity added through the Independent Power Produce (IPP) model. Similarly, private investment in upstream oil and gas was opened up through the New Exploration & Licensing Policy and Production-Sharing Contracts (PSCs).

With multiple private sector players, the need arose for regulatory oversight and this was provided for both the electricity sector (the central and state regulators) and the upstream oil and gas sector (the Directorate General of Hydrocarbons).

The Electricity Act 2003 deregulated power generation, provided open access to transmission systems, promoted competition and brought in transparency by unbundling the state-owned State Electricity Boards into generation, transmission and distribution entities. In the same period, investment in wind energy generation was promoted through fiscal incentives like accelerated depreciation.

<sup>92</sup> Source – EI Statistical Review of World Energy

<sup>93</sup> Million Tons of Oil Equivalent

<sup>94</sup> Kg of Oil Equivalent



Coal, the largest energy supply source saw relatively little activity. Coal consumers were allowed to develop coal mines for their own consumption but nevertheless the impact of a lack of investment was experienced in the late 2000s when India had to import coal to meet its power needs.

**Natural Gas**

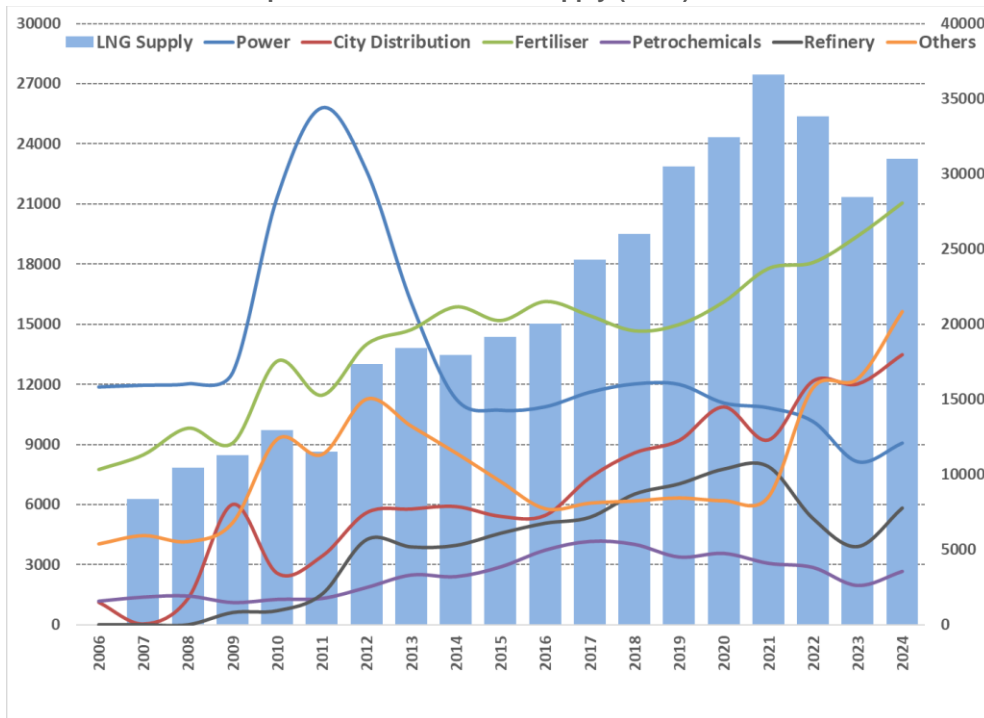
A swift boost to natural gas supply was very much part of initial deregulation efforts. Given the long lead time for bringing on new upstream production, a separate entity - Petronet LNG Limited (PLL) - was set up by India’s oil and gas majors to develop India’s first LNG import terminal. This brought India into the (then) elite club of LNG importers and more importantly, led to the development of pipeline infrastructure within the country. Early LNG supply was intended to meet the shortfall created by declining domestic gas production and targeted power generation but with little success. A couple of more LNG terminals followed.

The introduction of LNG and new domestic gas discoveries resulted in multiple prices for natural gas in India. Domestically-produced gas was priced very low at \$0.05/MMBtu, while the LNG price was linked to crude oil, with a floor and ceiling. Gas supply from new fields were offered at the ‘old’ domestic gas price by pooling the volumes and prices. Indian policymakers tried multiple combinations to keep the overall gas prices low for the consumer. While gas could replace oil products, it failed to compete with coal in power generation purely for commercial reasons. Natural gas continues to face an adverse fiscal regime compared to coal – coal consumption is taxed at 4 per cent whereas gas consumption is taxed at 5-26 per cent, undermining its competitiveness.

Figure 2 shows the trends in natural gas consumption for various sectors along with rising LNG supply. It highlights the price-sensitive nature of Indian gas consumers. As domestic gas supply increased from the KG D-6 field from 2009 to 2013, power sector consumption jumped significantly. However, as these supplies declined, gas-based power generation also declined despite an increase in the LNG supplies.

In contrast, fertiliser, residential consumers and industry continued to absorb LNG despite its higher prices as imported gas remained cheaper than oil products. India has long opted to prioritize domestic urea production for the fertiliser sector to ensure security of supply. So, gas demand from this sector is less sensitive to price given that the alternative feedstock is naphtha.

**Figure 2: Sectoral Natural Gas Consumption in India and LNG Supply (MCM)**



Source: PPAC, NITI Aayog, Statistical Review of World Energy, 2024



## The Climate Change Imperative

Despite increasing awareness of the need for action to counter climate change and expectations that gas would be a bridge fuel to reduce emissions in power generation, India's policymakers did not move in that direction, preferring to prioritize economic growth over energy transition and avoiding either a carbon tax or emission reduction targets. Instead, the government adopted an approach that focussed on reducing energy intensity and increasing renewable energy – neither of which directly encouraged the use of natural gas.

While India was a signatory to the Kyoto Protocol in 1997, there were no binding commitments to reduce emissions. However, by mid-2000, India's energy policies were increasingly designed to promote sustainable development. During the Copenhagen Climate Conference in 2009, India pledged to reduce the emissions intensity of its GDP by 20-25 per cent from 2005 levels by 2020.

Other climate policy way points include:

1. National Action Plan on Climate Change (NAPCC) was launched in 2008 and includes eight missions focusing on solar energy, enhanced energy efficiency, sustainable agriculture, water resources, the Himalayan ecosystem, forestry, sustainable habitat and strategic knowledge.
2. India ratified the 2016 Paris Agreement which included reducing the emissions intensity of GDP by 33-35 per cent by 2030, achieving 40 per cent cumulative electric power capacity from non-fossil fuel-based energy sources and creating additional carbon sinks.
3. Renewable Energy Targets: India aims to increase non-fossil energy capacity to 500 GW by 2030 and meet 50 per cent of energy requirements from renewable energy by 2030.
4. National Hydrogen Mission: This mission was announced in 2021 and promotes the production and use of green hydrogen as a clean energy source.

Despite expectations from gas suppliers, no explicit role was envisaged for natural gas in meeting the climate goals.

## The Current Landscape

The current Indian primary energy mix has non-fossil sources contributing about 11 per cent and continues to be dominated by coal and oil supplying more than 80 per cent of energy.

The government intends to increase the share of natural gas in the primary energy mix to about 15 per cent. However, in addition to being more expensive than other sources of energy, natural gas faces another key challenge. Efforts to increase domestic natural gas production have been only incrementally successful. There has been no significant increase in supply (except for a brief spurt from the KG D-6 field) and the geology doesn't inspire confidence in any future large discoveries. The government is implementing programs like the Compressed Bio Gas program (SATAT) to increase domestic supply but it is not expected to change the picture substantially. As such, any meaningful immediate increase in supply can only come from imports, which does not fit with the government's energy security strategy.

The drivers of the current Indian energy policies can be summarised as follows:

- **Energy Security:** Reducing dependence on imported energy sources is a strategic priority for India. Diversifying the energy portfolio is key to enhancing energy security. The focus on increasing renewable energy supply is a key element of this strategy. There are conscious efforts to transition to electric vehicles, both public and private, in order to reduce dependence on imported oil.
- **Access and Affordability:** India remains committed to providing energy to its rural, economically weaker sections of society at affordable rates.
- **Climate & Environmental Concerns:** Being aware of the environmental impact of its energy consumption, India has made conscious commitments at international fora and adopted policies guiding the shift towards cleaner energy sources.



- **Energy Efficiency:** India has successively implemented several energy efficiency programs to reduce the energy intensity of the economy. Notable among them are the appliance labelling program, the Perform-Achieve-Trade program for industries and the Super-Efficient Appliance program.

Some of the current programs being implemented reflect the drivers stated above:

- Production-linked incentive for solar, battery and green hydrogen manufacturing
- Faster adoption and manufacturing of electric and hybrid vehicles
- National program for rooftop solar to accelerate installation
- National smart grid mission to install 250 million smart meters
- National bioenergy mission to support compressed bio gas

### Primary energy outlook over the next decade

The accelerated expansion of renewable energy will continue to drive India's primary energy mix over the next decade. Solar energy is likely to play a dominant role and will garner significant investments in both grid-connected and decentralized solar projects. Adoption of energy storage technologies will be key in this transition, enhancing the reliability and integration of renewable energy into the grid.

In line with international commitments, decarbonization will be a fundamental theme over the next decade. The development and adoption of green hydrogen, produced using renewable energy, can be expected to revolutionize the energy landscape, subject to the pace and cost of development. Green hydrogen can decarbonize various sectors, including transportation, industry and power generation, contributing significantly to India's climate goals.

India's efforts to improve energy efficiency will continue as energy efficiency guarantees both enhanced energy security and emission reduction. The expansion of energy-efficient technologies and practices across industries, transportation and residential sectors will help reduce overall energy consumption and emissions. India will leverage its successful experience of current programs like Perform-Achieve-Trade and appliance labelling and expand their coverage and scope.

The current government has made it amply clear that ensuring energy security will remain a priority. Diversifying energy sources, enhancing the production of domestic resources and strategic international partnerships will play key roles. The government hopes that energy infrastructure will leverage technological innovations and digitalization. Smart grids, artificial intelligence and advanced analytics will optimize energy management, enhance grid stability and improve demand forecasting. At the same time, the adoption of electric vehicles and smart charging infrastructure will transform the transportation sector, reducing reliance on fossil fuels. These changes are already happening and will only accelerate over the next decade.

### Role of Natural Gas

Several major policy developments were introduced in the Indian natural gas sector over the last 25-30 years. In the last 10 years, formula-driven prices for gas, marketing and pricing freedom for some upstream producers, ease of doing business for operators and opportunities for investment in infrastructure have been introduced. Gas pricing and marketing reform were among the most critical ones that progressed. All of this is expected to result in an increase in domestic supplies.

India has publicly stated the aim of increasing the share of natural gas in primary energy to 15 per cent by 2030. However, that target will be met only if the power sector becomes a major gas consumer. Given the price-sensitive nature of the power sector and the inroads made by renewable energy, only a prolonged low gas price scenario will make that happen. Recent studies indicated that even in a low gas price scenario, the share of natural gas would be limited to just 16-18 per cent by 2040<sup>95</sup>. These studies also point out that gas is not as effective as renewable energy in reducing carbon emissions. So, in a carbon-constrained scenario, natural gas will likely lose its place to renewable energy.

Over the next decade, natural gas (either domestic production or LNG) can be expected to incrementally replace oil products like naphtha, fuel oil and diesel in industry depending on continued reforms.

<sup>95</sup> Energising India – NITI Aayog & IEEJ, 2017



## Key Challenges

Some of the key challenges that the energy sector will face over the next decade are:

**Managing emissions:** Given that coal will continue to be the mainstay of energy supply, India will have to increasingly adopt better technologies to reduce emissions. These technologies will be more expensive than existing ones. Gas may have a role to play in an accelerated 'emission reduction' scenario.

**Pricing and financing energy:** India's energy markets are still not fully competitive. The end-user prices are subsidised, cross-subsidised and government-controlled and there are tax anomalies. This affects the financial health of the players and therefore the whole chain. For example, despite reforms, power distribution companies continue to face financial challenges, affecting the overall health of the sector. Bringing parity in the fiscal structure for various energy sources is critical and if and when that happens, gas should benefit.

**Integration of Renewables:** Balancing grid stability with increasing penetration of variable renewable energy sources is an ongoing task. Given the issues related to the financial health of the distribution companies, this will require government intervention and close monitoring.

**Energy Access and Affordability:** Ensuring affordable and reliable power supply to all sections of society, particularly in rural areas will remain a challenge.

**Technology Adoption:** The sector will need to adopt and leverage emerging technologies such as energy storage, smart grids and AI for better grid management and efficiency. This will require capacity building in the workforce.

**Competitive markets:** This is an aspect that the Indian energy sector has only embraced in part. For example, there is a competitive market in power generation but not in fuel supply. On paper, the oil marketing companies are free to price gasoline and diesel but in practice, the government still plays a role. Coal prices are still not based on competition. Indian policy and decision-makers must open up the entire energy chain to competition and allow markets to function. This will improve the ability of the market to respond to economic signals and also improve energy security. This is a critical element.

## Summary

The evolution of the energy sector in India reflects the transition from a state-controlled, inefficient system to a more market-oriented, competitive and sustainable one. However, this transition will be an ongoing process. Reforms and policy initiatives will remain essential to address the challenges.

The next decade is likely to see gradual changes in India's energy mix, driven by economic growth, policy initiatives, technological advancements and climate imperatives. The focus on renewable energy underscores India's commitment to a sustainable energy future. While challenges remain, the strategic direction set by India's energy policies and technological innovations hold promise for a cleaner and more resilient energy sector. This transition takes care of not only India's developmental goals but also of the global climate equation, highlighting the importance of India's role as a large energy consumer in the global energy transition.

Natural gas can play a role in this transition. Enabling that will need policy support across the natural gas value chain. While natural gas has a clear edge over other fossil fuels, it has much tougher competition from renewable energy and battery storage.



## FINANCING GAS PROJECTS IN SUB-SAHARAN AFRICA

**Mostefa Ouki**

The production and monetisation of natural gas in Africa is presently dominated by a small number of producing countries in North Africa and West Africa. Gas discoveries and prospects in potentially new gas provinces in the Rovuma and Mafia Deep basins in eastern/southern Africa (Mozambique and Tanzania), the MSGBC (Mauritania, Senegal, Gambia, Guinea Bissau, and Guinea Conakry) basin in West Africa and the Orange basin in southern Africa (South Africa and Namibia) have revived interest in gas development projects in Sub-Saharan Africa. Even small Central African gas producers like Cameroon and Congo have emerged as new LNG exporters, whilst Gabon has taken a final investment decision for the development of a small LNG export project.

This interest in Sub-Saharan Africa's natural gas resources has been partly driven by the initial impact of the Russia–Ukraine war and the then urgent quest for non-Russian sources of gas supplies.<sup>96</sup> Two years on, apart from already existing and ongoing gas development projects such as the ones in Mozambique, Mauritania, Senegal and the above-mentioned small LNG export projects in Central Africa, there is limited funding flowing into new Sub-Saharan African gas development projects.

This is perhaps due to the global calls for reducing or halting investments in new fossil fuel projects to address the adverse impact of climate change. This could be an explanation for international financial institutions that have decided to move away from funding fossil fuel schemes and focus on green energy.<sup>97</sup> It could also be explained by the anticipated period of low international gas prices following the coming on stream of several LNG projects by the end of this decade. Nevertheless, over the last two years, whilst oil and gas upstream capital expenditure levels have remained constant in Africa, they have increased in other regions like North America.

The reality is that for several decades, most of Sub-Saharan Africa's energy markets have been suffering from insufficient levels of financing (loans and equity) and the causes have also been known for a long time. They range from the small sizes of these markets and inadequate legal/fiscal and regulatory frameworks to the issue of governance. This situation, however, is not irreversible and natural gas could still play a prominent role in the energy mix of Sub-Saharan African countries endowed with natural gas resources.

### Monetization priorities and challenges

Sub-Saharan Africa's gas demand is expected to grow significantly in the coming decades. According to scenarios formulated by the Oxford Institute for Energy Studies (OIES) on the impact of energy transition on the role of gas in different regions or subregions of the world, natural gas use in Sub-Saharan Africa could potentially double or more than double between 2022 and 2050 (see figure below). It should be noted that these are scenarios and not forecasts, but they provide an indication of possible long-term gas demand movements under different energy transition assumptions.

In a continent where over 40 percent of the population, almost all of it in Sub-Saharan Africa, do not have access to electricity supply, the use of indigenous gas resources would be allocated to the generation of electricity as a matter of priority. Especially, when investments in renewable energy capacity remain unfortunately very low. Africa, which accounts for 20 percent of the world's population will receive only 2 percent of total global clean energy investments in 2024.<sup>98</sup> Furthermore, these investments have largely been directed to a very small number of countries.

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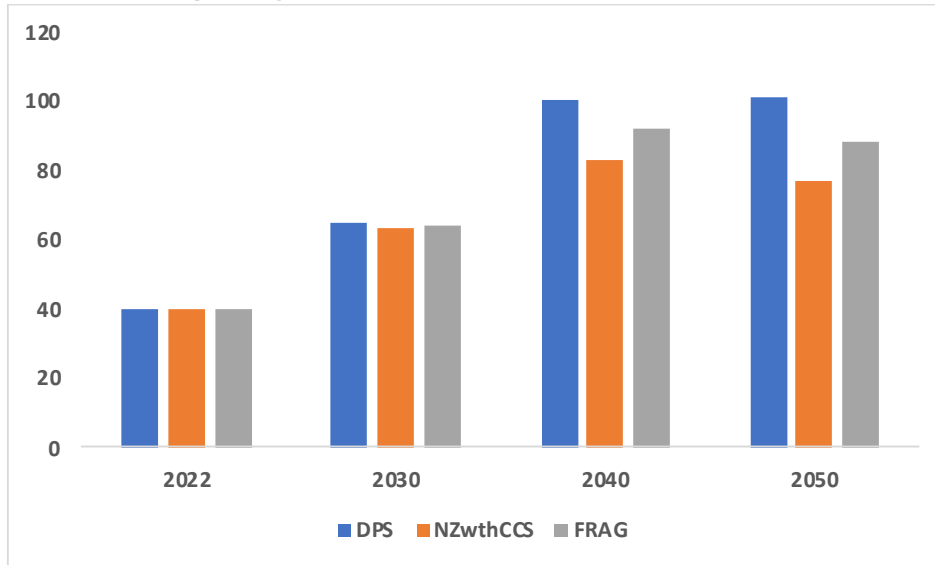
<sup>96</sup> Ouki, Mostefa (2022). "African gas supplies to Europe: between hopes and hard realities", Oxford Institute for Energy Studies, July. <https://www.oxfordenergy.org/publications/african-gas-supplies-to-europe-between-hopes-and-hard-realities/>

<sup>97</sup> African Energy Chamber (2023). "The State of African Energy – 2024 Outlook Report", 07 November. <https://energychamber.org/wp-content/uploads/The-State-of-African-Energy-2024-Outlook-Report3.pdf>

<sup>98</sup> International Energy Agency (2024). "World Energy Investment 2024." <https://www.iea.org/reports/world-energy-investment-2024>



Figure 1: Sub-Saharan Africa’s long-term gas demand scenarios (bcm)



Source: OIES<sup>99</sup>

Note: DPS: declared policies scenario; NZwthCCS: Net Zero with CCS scenario; FRAG: fragmented scenario

Therefore, it is understandable that policymakers in potential new gas provinces in Sub-Saharan Africa make strong calls for the right to develop and monetise their natural gas resources. Apart from relatively large economies, like South Africa and Ethiopia, one of the key challenges Sub-Saharan African countries face in attracting financing in gas monetisation projects is the limited to very limited size of their domestic market, whether the gas is used in power and/or in industry. Thus, where large natural gas reserves are identified, like in Mozambique, natural gas exports are the key monetisation option that would enable the development of the gas resources for both exports and domestic gas uses.

In new Sub-Saharan African gas markets, domestic use of natural gas in the power sector would also require investments in natural gas and power infrastructure (transportation networks and other facilities to deliver gas and electricity supplies) that are usually beyond the project boundaries of the gas development being financed. Such infrastructure would require funding from other sources, like a national natural gas transportation or gas infrastructure entity and the gas off-taker.

Since the purchaser of the gas or the guarantor of this gas purchase payment is most of the time a financially fragile public utility, there are calls on the country’s treasury, which is already stretched by financing needs from other sectors of the economy, to fund these infrastructure investments and/or guarantee gas payments. This is in addition to the government guarantees that could be included in power purchasing agreements for electricity supplied by independent power producers.

To enhance the project’s credit profile, separate guarantees are also provided by international institutions, such as the World Bank Group’s Multilateral Investment Guarantee Agency (MIGA) or the World Bank in the form of partial risk guarantees. But these guarantees require a government counter guarantee to be put in place first. This increases the country’s financial exposure.

The public utility’s poor financial situation, which is caused by subsidised or relatively low energy prices (because of the issue of price affordability), non-payment or delayed payment of electricity bills, transmission losses and thefts and poor management/governance, must be addressed at the outset. Leaving it to the state to provide sovereign guarantees in case of payment failures does not help and is not sustainable. Several Sub-Saharan African countries are already heavily indebted and the bailing out of public utilities would only worsen their debt situation and credit ratings, further harming their economies and, thus, project financing prospects.

<sup>99</sup> Fulwood, Mike (2024). “Energy Transition Scenarios: Impact on Natural Gas”, OIES, June. <https://www.oxfordenergy.org/publications/energy-transition-scenarios-impact-on-natural-gas/>



### Potential African financing sources

African policymakers have consistently pointed out the lack of adequate levels of financing for the development of their potential oil and gas resources or reserves. In recent years, this frustration has been exacerbated by international calls to significantly reduce or halt the financing of hydrocarbon projects to achieve net zero emission targets by 2050. This has raised the issue of fairness regarding how each region is treated relative to its total emission level. The whole African continent is only responsible for less than 4 percent of global greenhouse emissions. Sub-Saharan Africa's emission share is even much smaller, especially if you exclude South Africa.<sup>100</sup>

Traditionally, energy financing in Sub-Saharan African countries has been mainly provided and/or guaranteed by Western and Asian export credit agencies (ECAs) and multilateral development agencies. The few commercial banks that have participated in this financing have, in general, their loans covered by ECAs. However, financing from these traditional sources is expected to decline as they comply with stricter decarbonisation conditions in the financing of new energy projects. As a result of this, African countries have been looking within their continent for alternative sources of funding for their oil and gas projects.

In July 2024, the launching of the Africa Energy Bank established by the African Petroleum Producers' Organisation (APPO) and Afreximbank was announced. This new regional bank is expected to be operational in 2025 "with the aim of addressing the funding challenge that African oil and gas industry has come to face as a result of the energy transition, where the traditional financiers of the world's oil and gas industry have resolved to abandon the industry, especially in Africa."<sup>101</sup>

It should be noted that other African financial institutions, such as the African Development Bank, have participated in the financing of African energy projects, including major gas projects (e.g. Mozambique LNG).

### It is not only about energy transition constraints

The new Africa Energy Bank is a welcome development for potential new gas projects in Sub-Saharan Africa. This bank is likely to engage in co-financing partnerships with international financial institutions and probably attract new bank investors from the Middle East and Asia. Whether the financing sources are African or non-African, project funding will still require the same commercial viability conditions and level of scrutiny with respect to compliance with environmental, social and governance (ESG) guidelines.

Although, some institutions may decide to move away completely from fossil fuels, the factors constraining the adequate financing of energy projects in Africa and more acutely in Sub-Saharan Africa, are not only related to decarbonisation and energy transition issues. Some oil and gas companies and financial institutions may have financial exposure limits for some sub-regions or countries and require a more diversified portfolio of projects. Others may have profitability conditions that could only be met by certain oil and gas projects in different regions and countries. Also, some companies are better at managing risks in certain regions of the world, whilst others are more risk averse. As a result of all these situations, we have seen some large international oil and gas companies divesting from some areas or countries and independents, especially indigenous independent companies, acquiring these divested assets.

For companies and financing sources that are still interested in potential gas development projects in Sub-Saharan Africa, the key constraints remain the unfavourable internal investment conditions. These cover several areas, including existing legal, fiscal, and regulatory frameworks; administrative bureaucracy; creditworthiness of domestic energy utilities; domestic energy pricing policies; ESG issues; currency convertibility; and political and security issues.

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<sup>100</sup> Ritchie, Hannah (2023). "Sub-Saharan Africa emits a tiny fraction of the world's CO<sub>2</sub>", *Energy for Growth Hub*, 17 June.

<https://energyforgrowth.org/article/sub-saharan-africa-emits-a-tiny-fraction-of-the-worlds-co2/#:~:text=They%20are%20home%20to%201.1,vulnerable%20regions%20to%20its%20impacts>.

<sup>101</sup> African Petroleum Producers' Organisation (2024). "Communique of the 45th session of the APPO ministerial council held on Thursday 4th July 2024 (virtual)", press release, 04 July. <https://aposecretariat.org/2024/07/04/communique-of-the-45th-session-of-the-appo-ministerial-council-held-on-thursday-4th-july-2024-virtual/>



## Conclusion

The potential natural gas resources or reserves held by Sub-Saharan Africa's new gas provinces are unlikely to be as large as those of the Middle East. However, their prudent and sustainable development and monetisation would significantly and positively change this subregion's economies. This would require rapid, consistent and meaningful internal reforms addressing the above-mentioned multi-faceted financing constraints. Without these reforms, Sub-Saharan Africa's potential gas projects would continue to be considered as risky and only draw a limited pool of lenders and investors.

Deploying efforts to insist on Africa's right to a "fair energy transition" reflecting the principle of "common but differentiated responsibilities" are necessary. But it is also critical that Sub-Saharan Africa's policymakers focus on the internal reforms needed to de-risk gas development projects.

Finally, policymakers need to understand that they have a short time window to act, if they really want to attract a much wider group of financing players and facilitate the development and monetisation of their existing and yet-to-be discovered natural gas potential.



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