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The Global Outlook for Gas Demand in a $6 World

OIES Paper: NG 202

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Executive Summary

The long-expected wave of LNG supply is now almost upon us and is increasingly expected to outstrip the likely rise in demand for LNG at the global level. Spot prices in European and Asian markets may well respond to the overhang of LNG supply by moving to more short-run pricing – as was seen in 2019 and 2020 – and, as a result, prices could be closer to $6 per MMBTU rather than $8 per MMBTU, reflecting more long-run pricing. If prices were to fall to the $6 level, what might the demand response be? Our focus is on the existing and potential major importing regions – Europe, China, India, Japan/Korea/Taiwan, Emerging Asia, Africa, and Latin America. North America, the Middle East, and Russia were not considered as they are low-price markets, with prices already well below $6 per MMBTU.

The potential demand response is considered both for the short run and the long run. The short run assesses how much demand is switchable with an immediate response to changing gas prices relative to competing fuels. This is typically in the power sector where, in many markets, there is a choice between burning coal and gas (and even oil in some markets). The long run considers the situation where the gas price level is sustained at $6 per MMBTU for a number of years, and how much additional gas demand might therefore be added on a 'permanent' basis, either by displacing coal and oil in the power sector or by potentially slowing the roll out of renewables.

The approach taken in the analysis and assessment for each country/region is more a subjective assessment on the likely demand response to lower gas prices, rather than the result of any econometric or statistical analyses of price elasticity of demand, which generally have a poor track record of assessing elasticity. In any case, price elasticity is not linear over a wide range; the demand response to a 25 per cent fall in prices from $8 to $6 will be very different to a 25 per cent fall in prices from, say, $20 to $15.

For the regions and countries under consideration, the short-run demand response, in respect of the impact on LNG imports, is estimated at between 26.5 bcm and 94 bcm, with a midpoint of 60.5 bcm. This is equivalent to between 3.5 per cent and 12 per cent of projected global LNG imports in 2030. The long-term response is higher, ranging from 62.5 bcm to 177.5 bcm, with a midpoint of 120 bcm. This is equivalent to between 7.5 per cent and 21 per cent of projected global LNG imports by 2035, where more time is available for longer run switching. Broadly half the short-run and long-run response is in the power sector, with the increase in JKT and Emerging Asia almost wholly in power. The response in the buildings and transport sectors is focused in China and India and shows an increase over time with the opportunity to invest in more gas-fired equipment. There is also a significant response in industry in China, India, and C&S America.

Europe
The role of gas in Europe is changing more towards use as a backup for intermittent renewables. While gas demand may be supported a little as coal-fired power is phased out, switching between coal and gas is declining, as coal plants are closed. Buildings demand is not price sensitive, at the price levels being assessed here, and industrial sector demand has shown limited recovery from the demand destruction in 2022. A short-run uplift to demand with $6 gas is modest at between 5 to 9 bcm. In the long run, the coal-to-gas switching response declines further, but there is the potential for a slowdown in the roll out of offshore wind, which could add some 10 to 16 bcm of demand.

China
Gas has a relatively limited role in the power generation sector, but it is significant in industry and becoming increasingly important in buildings. Gas demand is expected to continue growing and low prices, especially if sustained, could boost demand. A short-run response in the 16 to 70 bcm range is possible by 2030, with half of this being in industry. The long-run response range for total gas demand in China is between 25 and 115 bcm in 2035, but given the Chinese authorities apparent desire to maintain domestic production at between 50 per cent and 60 per cent of total demand, maybe only half of this would feed through to LNG imports.

India
Gas demand growth is picking up in India and is expected to accelerate over the next ten years, with the rate likely to be boosted by lower gas prices. The response in power is expected to be minimal in the short-run but there is some potential in the long-run with better economics for stranded plants and a greater peaking role. The industry response is bigger in the short-run but in the long-run the largest response would be in the CGD buildings and transport sectors, including the possibility of LNG trucking. The short-run response range is between 4.6 and 11 bcm and in the long-run between 17 and 35 bcm – with most of the significant potential uplift coming from the expansion of gas demand in city gas distribution and transport.

Japan, Korea and Taiwan
The traditional LNG-importing countries are going through different phases of gas demand. Taiwan is phasing out coal and nuclear and will become increasingly dependent on gas-fired power. Korea has shown some growth over the past few years, but Japanese gas demand has been in decline as its nuclear plants restart. Given the number of oil-fired as well as coal-fired plants in Japan and coal-fired plants in Korea, the potential for coal and oil to gas switching is strong, even without a meaningful carbon price. A short-run response range is between 3 and 14 bcm, with the long-run calculated at between 3 and 32 bcm. This is all coming from the power sector, with much of the response in Japan.

Emerging Asia
The Emerging Asia markets have some of the highest potential to absorb the wave of LNG supply, with rapidly rising demand and stagnant or declining production. There is widespread use of coal for power in the region, but no additional coal-fired power capacity is expected beyond 2030. Gas-fired power growth is benefiting from the rapid growth in electricity demand in the region, but the potential additional demand response from lower prices may be limited, given the strong growth already anticipated. The short-run response range of 6 to 16 bcm is all in the power sector and would arise with slightly higher load factors for gas-fired power at the expense of coal. The long-run response range of 6 to 20 bcm might be boosted through a slower roll-out of expensive offshore wind in those countries where there is potential.

Africa
Very little LNG is currently imported into the African continent, with supplies mainly going to Egypt to alleviate gas shortages. There are, however, a number of countries, including South Africa, which have plans to import LNG in the future. Much of the growth in gas demand in Sub-Saharan Africa has come from the switch from oil-fired power to gas-fired power, as has recently happened in Ghana. However, the management and mitigation of project risks remains more important to investors than gas prices where the development of commercially viable gas projects in Africa is concerned. No short-run or long-run demand response is anticipated in Africa, at least as far as any move from $8 to $6 gas prices is concerned. Prices at $8 or even slightly above are low enough to generate oil to gas switching in Africa.

Central and South America
The region covers a wide range of very small to much larger gas markets. The potential demand response is concentrated, at least in the short term, in the larger gas markets of Argentina, Brazil, Chile, Colombia, and the Dominican Republic. The short-run response could be up to 9 bcm with much of this coming from industry, largely in Brazil, with a switch away from fuel oil, while there is less of a shift in the power sector. The long-run response is between 14 and 17 bcm, with the potential for more in power, as well as industry, particularly in some of the new LNG-importing Caribbean countries, as well as the larger gas markets. In both the short and long run, the demand response to lower imported LNG prices may be limited by the relatively high marketing and transportation charges in some countries.

The short-run response is projected to run through to 2030 after which the market will have had time to adjust to potentially lower prices and begin a long-run response. Figure 1 illustrates the range of the short-run and long-run response in comparison to the Base Case (shown by a continuous red line) for LNG imports, relative to LNG export capacity.

The midpoint of the range is the red dashed line which is plotted as the average of the low and high response – short-run up to 2030 and long-run for 2035. This is not a forecast, but instead provides an illustration of the impact of the price shift, given the high levels of uncertainty. The 2030 midpoint for additional demand is around 60 bcm and the 2035 midpoint for additional demand is around 120 bcm. Figure 1 indicates that the upper end of the range is at the LNG export capacity level in 2030 and well above it by 2035. These levels would clearly not be either achievable or indeed sustainable at a $6 gas price.

The percentages in Figure 1 indicate the utilization rates of available LNG export capacity. In the Base Case, the utilization rate is some 85.5 per cent in 2030 and 86.5 per cent in 2035. However, this is not an equilibrium solution, as in an over-supplied market, prices would fall, generating an increase in demand. This rebalancing of the market would result in utilization rates of 92 per cent in 2030 and 99 per cent in 2035, if we use the midpoints of the ranges. While a 92 per cent utilization rate might be broadly consistent with $6 gas in 2030, a 99 per cent utilization rate by 2035 is inconsistent with $6 gas, since it is close to the high utilization levels seen in the last few years. Capping LNG demand at some 900 bcm from 2032 onwards, which results in 95 per cent utilization in 2035, would seem to be more consistent with a $6 price.

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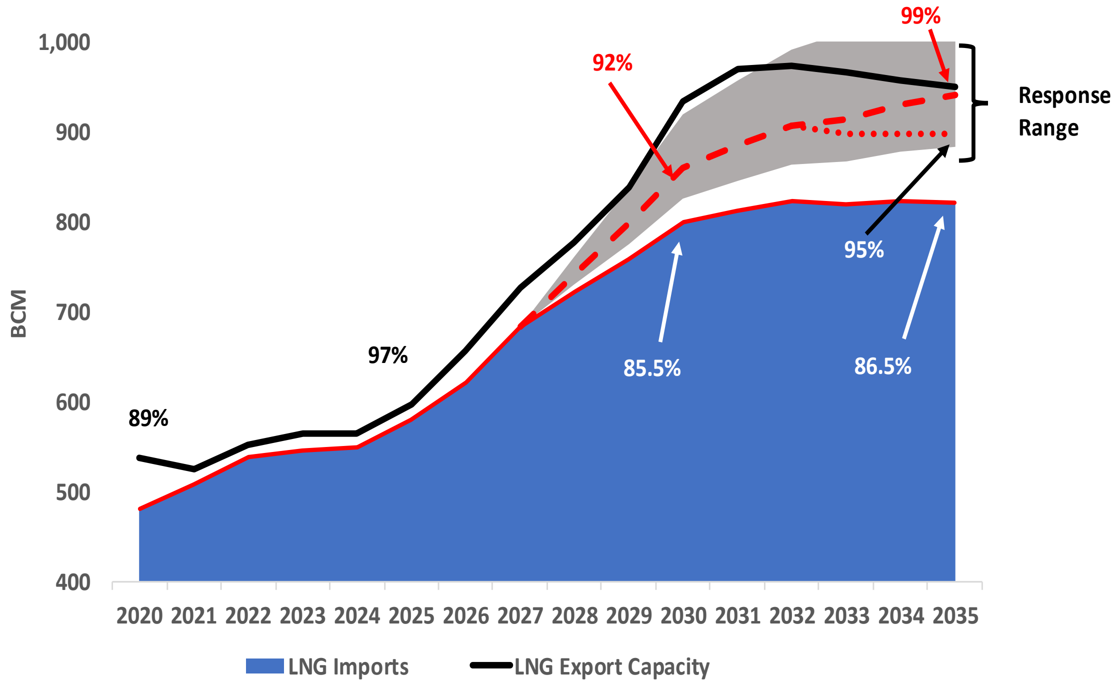
Figure 1: The response range to $6 Gas



Source: IEA, NexantECA World Gas Model

The 2030 response outcome represents a 60 bcm increase in demand compared to the Base Case. This outcome, where rising supply exceeds the rise in demand, is broadly comparable to 2019, where there was around a 75 bcm increase in available LNG export capacity (a rise of some 16 per cent), with LNG imports rising less and a utilization rate of LNG export capacity of some 92 per cent. In 2019, TTF prices averaged just over $6 per MMBTU, falling from around $9.30 in 2018 (real 2024 prices). The price and short-run response by 2030, therefore, looks similar to what happened in that year. The 2035 long-run response is based on a sustained period of prices at $6, but there is no real comparison of a similar sustained period of low prices at the global level.[1]

The analysis in this paper represents an initial assessment by OIES research fellows of the potential short-run and long-run price responsiveness of gas demand to a 25 per cent lower spot gas price by 2030 and beyond into the next decade. As prices start to decline in the next few years – assuming the growth in LNG supply outpaces the underlying level of demand as we anticipate – then more evidence of the price responsiveness may become apparent, possibly altering our conclusions.

Finally, it should be noted that the projected fall in spot prices from $8 to $6 is predicated on the OIES bottom-up assessment of the underlying level of demand in the selected countries and regions. The large excess supply this leads to, puts downward pressure on prices, eliciting a demand response to rebalance the market with broadly 900 bcm of global LNG imports in the early 2030s, but at $6 spot gas prices in Europe and Asia. Clearly, the OIES view of the underlying level of demand could be too pessimistic, and the underlying demand for LNG could be higher and reach 900 bcm without the assistance of prices as low as $6 per MMBTU. The real question, therefore, may not be what the LNG import level will be in the early 2030s, but at what price does the market balance and clear? Is it at $6 per MMBTU, because lower prices are needed to generate more demand, or at $8 per MMBTU or even a different price, because the level of underlying demand is much stronger than we think?

[1] The closest comparison may be the impact of the shale revolution in the US which led to sustained low Henry Hub prices and a dramatic squeeze on coal in the power sector.

Preface

The history of commodity markets is one of regular cyclicality, with the timescales within which supply adjusts to meet expected demand often diverging. Global LNG has already been through a couple of identifiable surges in supply, pushing benchmark prices down until the utilization of liquefaction capacity can come back as demand for LNG rises. This report, led by OIES Senior Research Fellow Mike Fulwood with other OIES Gas Programme research fellows, covers the key regions and demand sectors. It sets out to explore the market impact of the impending new wave, which will between 2024 and 2030 add some 370 bcm of LNG supply if all projects planned and underway are delivered in a timely manner. All other things equal, this major leap in supply will reduce prices, prompting higher demand in existing LNG markets as well as help draw new buyers for the fuel.

The extent to which LNG demand – existing and incremental - is sensitive to price is at the heart of the investigation in this paper. This will depend upon pricing for competing fuels; energy regulation and governments' net zero commitments; as well as broader energy transition planning. Some regions will be looking to boost gas-led industrial production and some may put more emphasis on security of supply, both elements of the longstanding energy trilemma which frames the prism through which most energy and gas policy is still judged. To provide the background for this paper, a Base Case, giving a range of gas prices, was generated in line with the Declared Policies Scenario we use in our medium-term modelling. The objective was to establish the nature of demand responsiveness to price, within a range, rather than conducting an elaborate statistical analysis, which has a poor track record in estimating the price elasticity of demand. The results of the modelling show that China and other Emerging Asia remain big growth targets amid lower gas prices, with industrialized economies in Europe and North Asia somewhat less responsive. Beyond the high-level analysis, it is the region and sector-specific analysis that offers the most useful insight here, helping explain the variable response to lower prices. Please contact the authors for any follow-up on this paper or for more details about the OIES Gas Programme, please contact me on the details below.

Bill Farren-Price
Head of Gas Research, OIES

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1. Introduction

The upcoming wave of new LNG capacity is set to have a transformational impact on the global gas market. However, the rise in supply over the period to 2030 looks likely to exceed the rise in demand for LNG, especially in Asian markets. As a result, this could lead to significantly lower spot and hub prices than in a more 'balanced' gas market. If gas prices do respond to the supply overhang, then a key question relates to what impact this might have on gas demand in different countries and regions, i.e. how price sensitive is gas demand? The hypothesis, as outlined in Section 2, is that spot prices, in European and Asian markets, will respond to the overhang of LNG supply by moving to more short-run pricing – as was seen in 2019 and 2020 – and, as a result, prices could be closer to $6 per MMBTU rather than $8 per MMBTU, which would reflect more long-run pricing.

The question of price sensitivity has two dimensions. Firstly, how much demand is switchable in the short term, with an immediate response to changing gas prices relative to competing fuels. This is typically prevalent in the power sector where, in many markets, there is a choice between burning coal and gas and even oil in some markets. This can also be true in the industry sector. The switchability, in this case, reflects the existing stock of fuel burning infrastructure. Secondly, if the gas price level is sustained at relatively low levels, such as $6, for a number of years, and this is expected to continue, how much additional gas demand might be added on a 'permanent' basis, either by displacing coal and oil in the power sector or by potentially slowing the roll-out of renewables.

The approach taken in this paper to assess the price sensitivity of gas demand avoids the use of statistical techniques. (In the conclusions, there are estimates of implied elasticities of demand, but these are only in the case of the change in prices discussed in Section 2 of this paper.) Rather we use a much more subjective analysis and assessment, drawing on the knowledge and expertise of the author of each section.

This paper considers both these questions. The focus is largely on the period from now until 2035, although the longer-term impacts could be sustained beyond 2035. The focus will be on the main importing, or potentially importing, countries and regions. North America, the Middle East and Russia and the FSU countries are not, therefore, considered. Apart from North America, where there has been demonstrable price sensitivity in the past in the power sector, the Middle East and the FSU are mainly regulated pricing markets, with little or no sensitivity to global price changes. In addition, as Figure 2 shows, the latest IGU Wholesale Price Survey[2] recorded wholesale price levels predominantly below $3 per MMBTU in North America, the Middle East and the Former Soviet Union, suggesting an analysis of the demand response to a $6 gas price is not relevant.

Section 2 of the paper sets the outlook for the Base Case including the possible price range for spot prices in Europe, Asia, and other impacted regions. Subsequent sections will address the question of short and long-term price sensitivity for the following regions or countries:

- Europe – drafted by Anouk Honore;
- China – drafted by Michal Meidan;
- India – drafted by Parul Bakshi;
- Japan, Korea and Taiwan – drafted by Graeme Bethune;
- Emerging Asia – drafted by Mike Fulwood;
- Africa – drafted by Mostefa Ouki; and
- Latin America – drafted by Ieda Gomes.

[2] https://www.igu.org/igu-reports/wholesale-gas-price-survey-2025-edition

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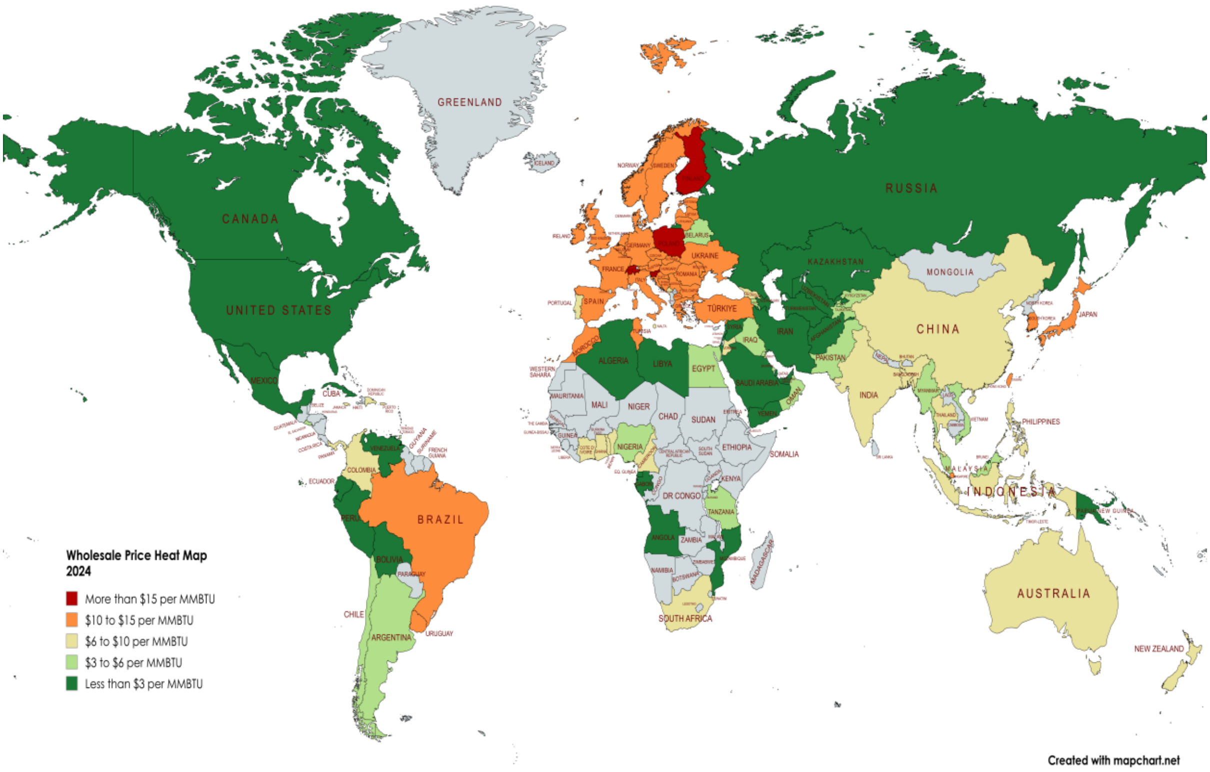
Figure 2: Wholesale price heat map 2024



Source: International Gas Union Wholesale Gas Price Survey 2025

A final section will draw together the conclusions for each country/region, together with an overall assessment. The Conclusions and Section 2 on the Base Case Outlook have been drafted by Mike Fulwood.

In assessing the short and long-term price sensitivity for the different countries and regions, the approach taken in each section will differ, depending on the availability of data, prior analysis, and any published plans and reports.

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2. Base Case Outlook

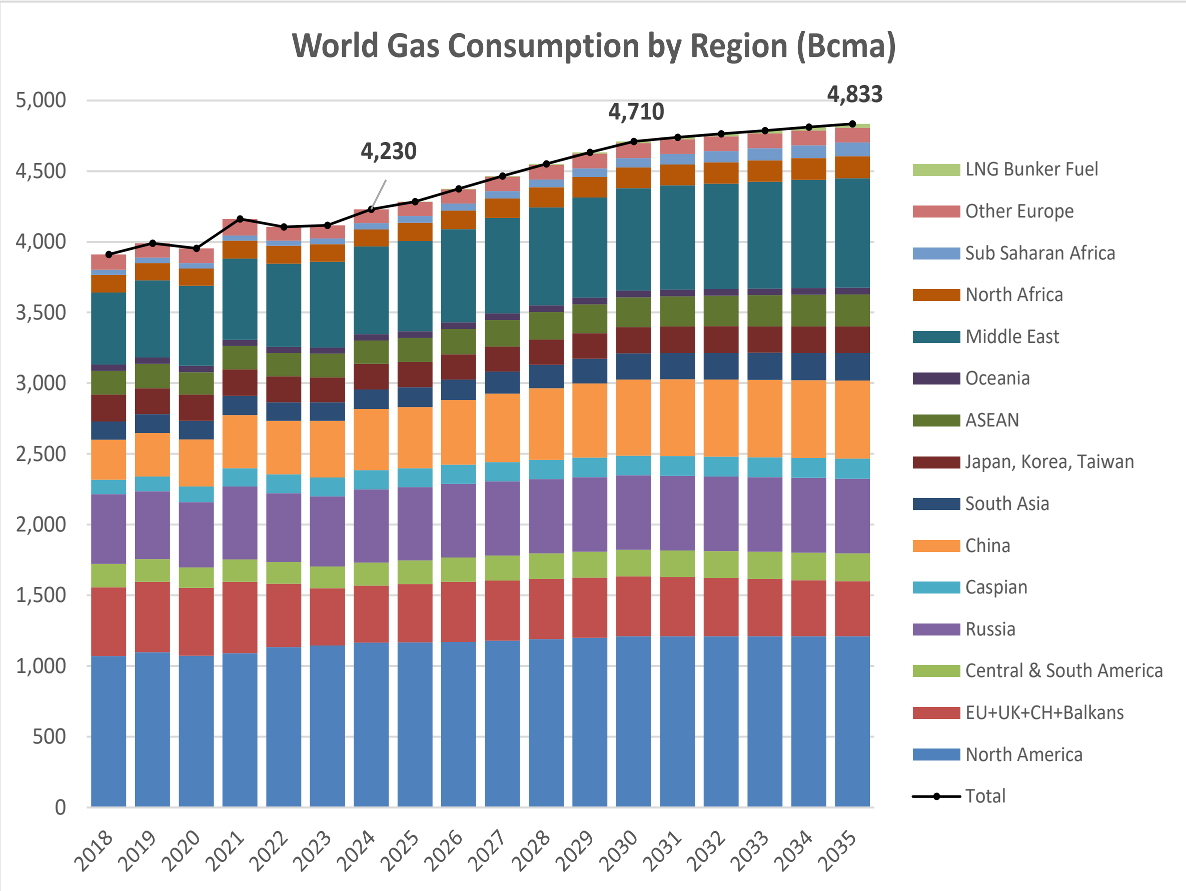
This Base Case Outlook is a brief summary of the OIES reference case scenario known as our Declared Policies Scenario (DPS). This represents an expected outlook to 2035, based broadly on countries stated policies regarding the energy transition, as per the IEA Stated Policies Scenario (STEPS), but adjusted if it is believed that other policies might also impact the outlook to 2035. This is not designed as a scenario on a path to net zero by 2050 or one which will limit the global temperature rise to 1.5 degrees C. The baseline assumption is that Russian pipe imports into Europe post-2024 are only through Turkish Stream and that the EU's proposed ban is either not implemented or is unenforceable.

The projected global demand by region will be discussed and the general trend in demand for the key regions and countries will be analysed. This will be followed by a review of the growth in LNG export capacity and LNG trade to 2035 and then a projection of spot prices in the DPS based on the NexantECA World Gas Model. There will be further sub-sections discussing the different gas price mechanisms in the focus regions and countries, and the short- and longer-term economics of gas versus other fuels.

a) Global and Regional Demand

Global gas demand is projected to grow by some 613 bcm (+15 per cent) between 2024 and 2035, of which 45 per cent is in the Middle East and China. Growth in demand over the period is concentrated in the power generation (+335 Bcm) and industrial (+155 Bcm) sectors, which will account for 80 per cent of growth between 2024 and 2035. In contrast, there is virtually no growth in gas demand for residential and commercial (buildings) at a global level. Growth in buildings demand in China is offset by declines in Europe and North America.

Figure 3: Global gas demand



Source: NexantECA World Gas Model, IEA

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These overall projections are somewhat less important than assessing the potential price responsiveness, using these projections as a Base Case. In order to set the scene, however, for the rest of the paper, the projected demand for the countries and regions being assessed are:

- **Europe**[3] - demand is marginally higher at some 467 bcm in 2035, compared to 461 bcm in 2024. Higher demand in power generation, as coal is phased out, offsets lower demand in buildings.
- **China** – demand grows by some 120 bcm from 426 bcm in 2024 to 548 bcm in 2035. Growth is across the board in all sectors. Over 100 bcm of the growth is in the period to 2030 with a slowdown thereafter.
- **India** – demand grows by 40 bcm from 75 bcm in 2024 to 115 bcm in 2035. Power and industry account for most of the growth but transport also strong.
- **Japan, Korea, and Taiwan** – Demand in Japan falls by some 10 bcm, from 89 bcm in 2024 to 79 bcm in 2035, Korean demand rises from 60 bcm in 2024 to 65 bcm in 2035, and Taiwan grows by some 10 bcm from 31 bcm in 2024 to 41 bcm in 2035. Changes in the power sector are largely responsible for the differential growth.
- **Emerging Asia** – ASEAN demand growth is up some 60 bcm from 157 bcm in 2024 to 217 bcm in 2035. Vietnam, Indonesia, and Malaysia lead the way. Strong growth comes from industry as well as power. In the South Asia market, there is no growth in Pakistan gas demand, but Bangladesh gas demand rises from 32 bcm in 2024 to 43 bcm in 2035, with growth coming from power and industry.
- **Africa** – North African demand grows strongly from 121 bcm in 2024 to 155 bcm in 2035, dominated by Algeria and Egypt. There is a near-doubling of demand in Sub Saharan Africa from 43 bcm in 2024 to 98 bcm in 2035, led by Nigeria, South Africa, and Mozambique. In both sub-regions the power sector leads the way.
- **Latin America** – Demand in Central and South America is up by 33 bcm from 162 bcm in 2024 to 195 bcm in 2035. Argentina, Brazil, Chile, and Colombia are the key growth hubs. Power accounts for almost all the growth.

Power generation demand for gas is generally the main driver for gas demand growth but industry is also important in China and Emerging Asia.

b) LNG Export Capacity and Trade

The LNG wave is now upon us and OIES is projecting cumulative growth in LNG export capacity of some 400 bcm between 2024 and 2035. Some three-quarters of this growth has taken FID and is under construction, with more FIDs imminent in the next 12 - 18 months. Half of this growth is in North America and another quarter in Qatar, followed by some 15 per cent from Sub Saharan Africa.

Total LNG import growth between 2024 and 2035 is around 273 bcm, of which 27 bcm is growth in LNG as bunker fuel. ASEAN has the most significant increase (89 bcm) as production declines and demand grows. China’s growth peaks around 2030 at 137 bcm, declining to 127 bcm by 2035 (29 bcm growth in 2024-35). Europe sees a growth of 48 bcm as production and pipe imports decline. South Asia shows strong growth as prices stimulate demand.

[3] Europe is defined as the EU27 plus UK, Norway, Switzerland, the non-EU Balkans, and Turkey.

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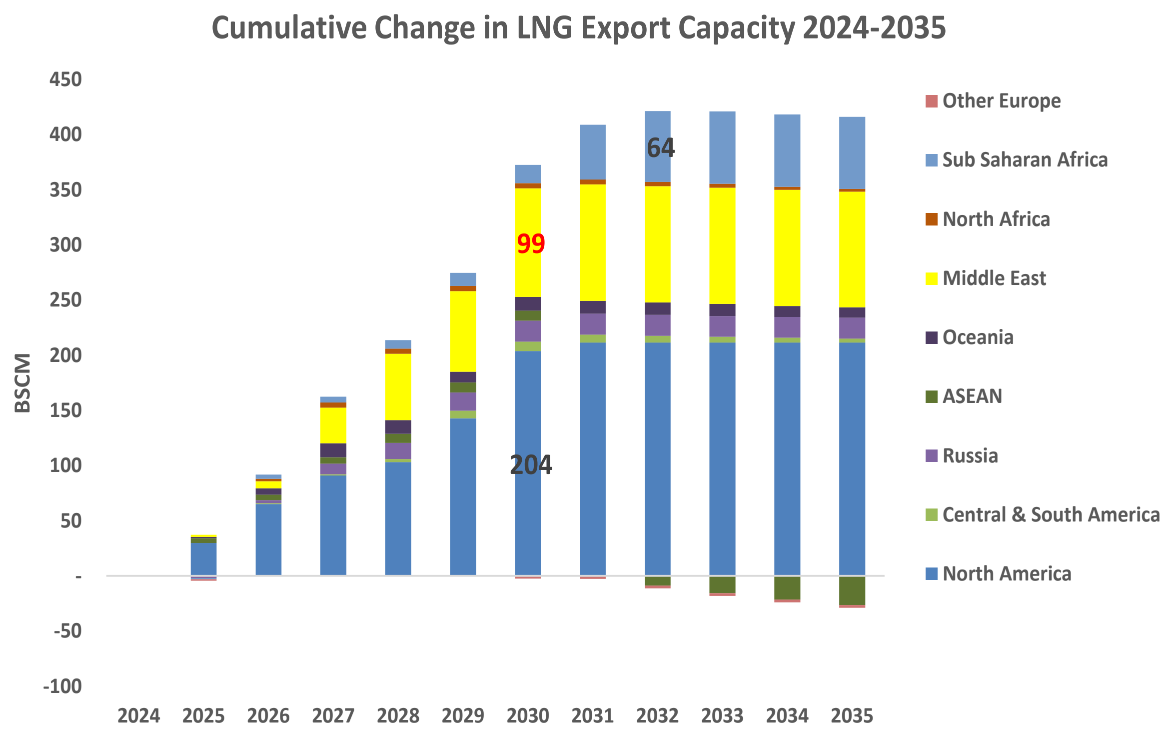
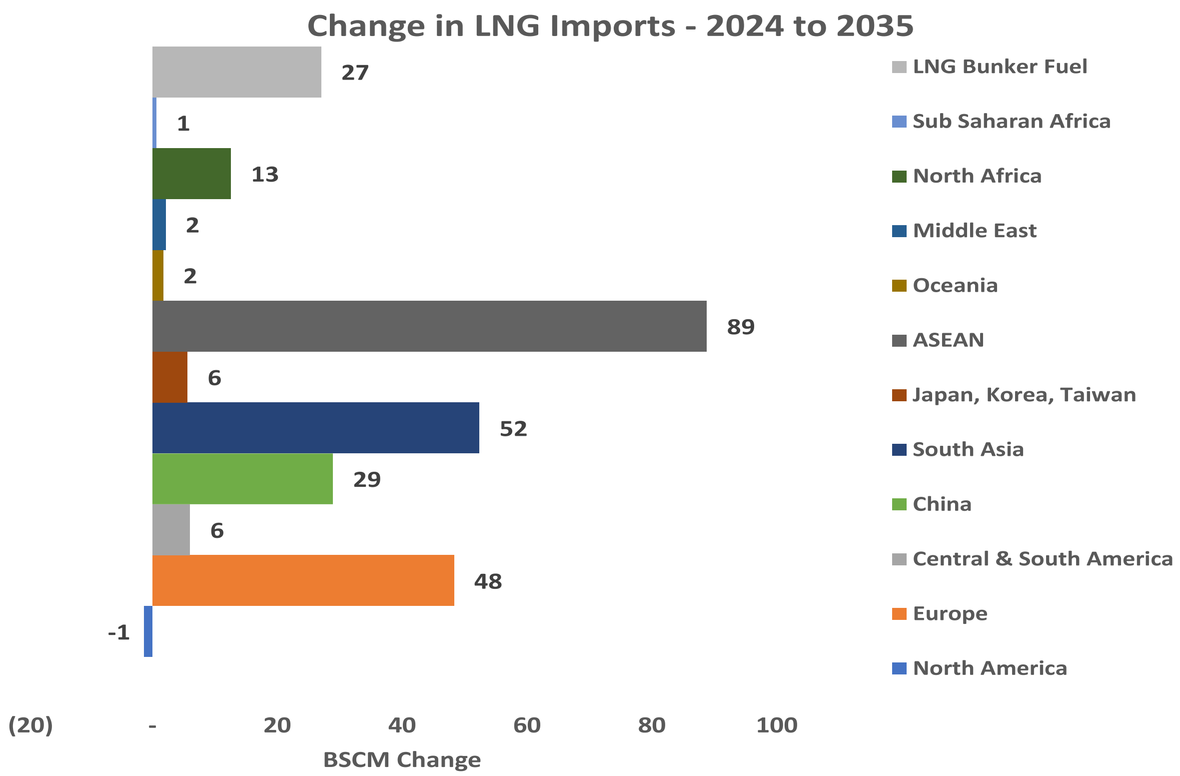
Figure 4: LNG export capacity growth



Source: NexantECA World Gas Model, OIES assumptions

Figure 5: LNG import growth



Source: NexantECA World Gas Model, OIES assumptions

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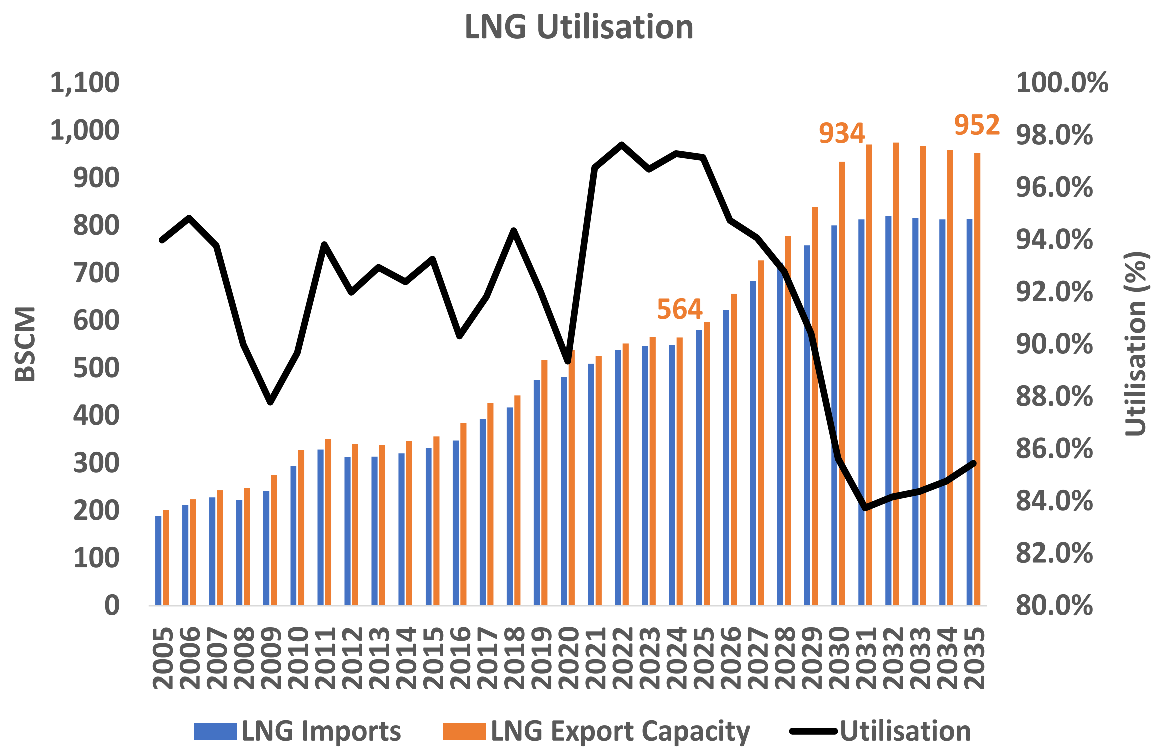
c) Spot Prices

The growth in LNG export capacity is expected to outstrip the growth in LNG imports.

Figure 6: LNG capacity utilization



Source: NexantECA World Gas Model, OIES assumptions

LNG utilization, defined as imports divided by available LNG export capacity,[4] is currently at very high levels (98 per cent, effectively full capacity) following the Russian invasion of Ukraine. Utilization is not expected to begin declining until 2026 when the anticipated surge in LNG supply starts to materialise. The growth in available supply then outstrips the growth in demand for LNG imports, and utilization, based on the projected demand and available supply, falls to 86 per cent by 2030, 84 per cent in 2031 before rising marginally back to 86 per cent by 2035. By comparison, in 2009 (after the 2008 financial crisis) and in 2020 (COVID), utilization was 89 per cent. Based on these projections, utilization could fall to even lower levels, with downward pressure on prices.

Between 2030 to 2035 inclusive the average utilization is predicted to be around 85 per cent with the volume of unused LNG export capacity being some 140 bcm a year. Utilization of 100 per cent is not possible since the LNG export capacity has to provide for boil off gas and any losses. If 98 per cent is taken as the maximum capacity utilization, then the difference between 85 per cent average utilization and 98 per cent average utilization is some 120 bcm per year – which represents just under 10 bcm for every 1 percentage point of capacity utilization.

The level of LNG imports in the OIES Base Case is around 800 bcm in 2030 and 822 bcm in 2035. This compares with the IEA STEPS figures of 690 bcm in 2030 and 725 bcm in 2035, both of which are significantly lower than our Base Case. However, the Shell 2025 LNG Outlook[5] has 782 bcm in 2030

[4] Available LNG export capacity is nameplate capacity adjusted for scheduled and unscheduled maintenance, technical issues, feedgas issues and the ability of some plants to produce more than nameplate. Total nameplate capacity is currently around 10 per cent higher than calculated available capacity.
[5] Shell LNG Outlook….

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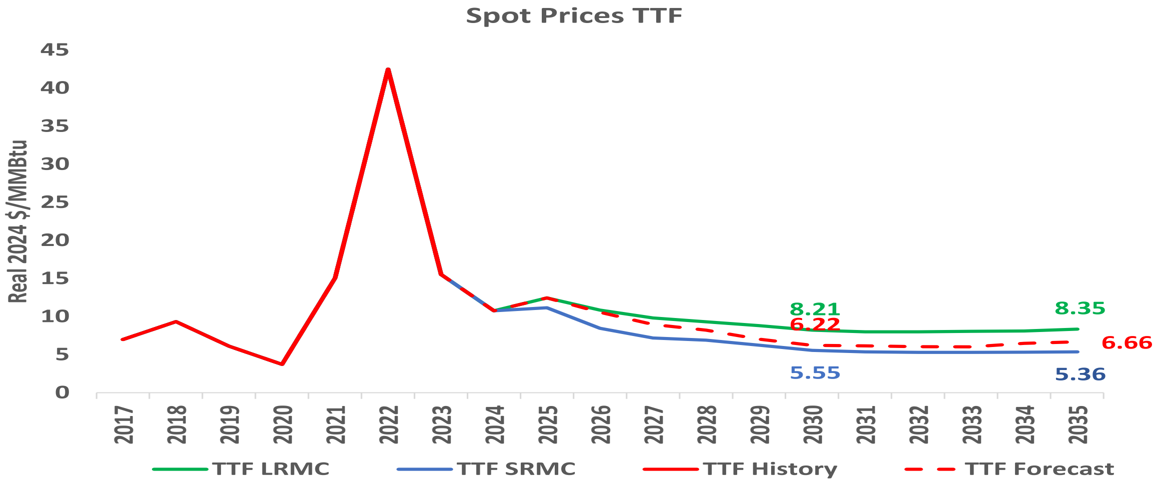
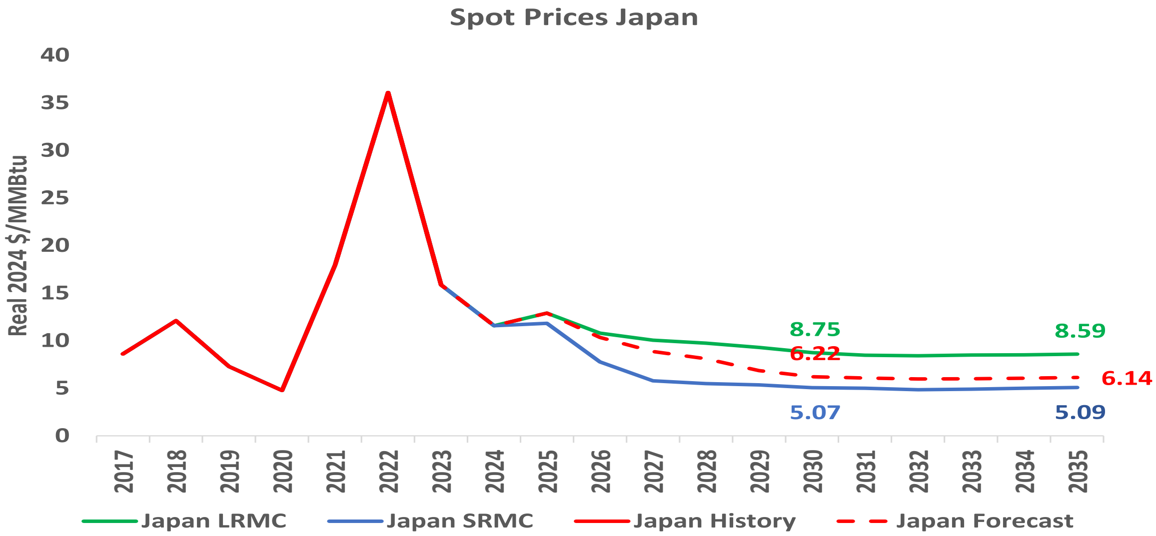
and 857 bcm in 2035, while its Archipelagos[6] scenario has 758 bcm in 2030 and 853 bcm in 2035. The recently published BP Energy Outlook[7] (Current Trajectory) has 800 bcm in 2030 and 850 bcm in 2035. Thus, it would seem that the IEA STEPS may be a bit outdated now (and will be updated in the next WEO), so the OIES level of 800 bcm in 2030 looks a reasonable consensus, while our 822 bcm in 2035 is some 30 bcm lower than the BP and Shell figures. An extra 30 bcm in 2035 would raise the utilization by 3 percentage points but would still leave utilization at below 90 per cent, meaning the market remains oversupplied.

Figure 7 shows the spot price projections for TTF and Japan spot prices, from the NexantECA World Gas Model. The projections are arrived at by running the model in long-run marginal cost (LRMC) mode and then in short-run marginal cost (SRMC) mode, by removing all the fixed costs. With the global market becoming oversupplied, as the LNG wave exceeds the growth in LNG import demand, the utilization of LNG export plants begins to decline to below 90 per cent by the end of this decade. The last time utilization was at these levels was in 2019 and 2020 and European and Asian spot prices were $5 per MMBTU or less.

Figure 7: European and Asian spot prices





Source: NexantECA World Gas Model, Argus Media

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6 https://www.shell.com/news-and-insights/scenarios/the-2025-energy-security-scenarios.html
7 BP

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Under LRMC, spot prices in Europe and Asia are around $8 from the late 2020s through 2035. Under SRMC prices drop below $6. The dotted red lines are the outcome for spot prices when the LRMC and SRMC projections are blended, depending on how tight the global gas market is. In a supply-long market, prices will tend towards the SRMC projected price, whereas, in a tighter market, prices will tend towards the LRMC projected price. With an oversupplied market expected, the blended price – which could be interpreted as the forecast – is closer to the SRMC price curve at some $6 or so.

As a comparison, the TTF forward curve for 2029 is just under $9 per MMBTU, in nominal prices, which equates to around $8 per MMBTU in real 2024 prices. The JKM forward curve is some 20 - 30 cents higher. These forward curves[8] are broadly comparable, therefore, to the green line LRMC projections.

The prospect of $6 per MMBTU prices (or less) is very real and the implications of this projection for gas demand are considered in subsequent sections. However, the decline to $6 or less is for spot prices and spot prices are not necessarily the relevant pricing mechanism in all the markets under consideration.

OIES has been commenting on and writing about the size and impact of the LNG wave for a number of years now and, looking back, our views have been very consistent. In 2023, OIES published a post-Russia invasion of Ukraine paper entitled 'A New Global Gas Order',[9] which assessed the outlook to 2030. This incorporated the LNG wave, but at a slightly lower rate, and also with slightly lower demand. The outcome for spot prices, by 2030, was in the $5 to $8 per MMBTU range, on a SRMC and LRMC basis.

It should be recognized though that, while the OIES view along with others such as BP and Shell, suggest an oversupplied market by 2030 and beyond, it is possible that underlying demand could be higher, and the $6 gas price is not reached. The simple supply-demand schematic in Figure 8 below illustrates how different assumptions can lead to different outcomes.

The intersection of demand curve D1 and supply curve S1 gives a price – volume intersection of P1V1. This can be considered as the initial Base Case partial equilibrium, with the gas price at $8. However, this can only be the final equilibrium if some supply is withheld from the market, supporting the $8 price. If all the available supply is put on to the market, then the supply curve is S2 and the price – volume intersection is P2V2, with P2 being $6 and V2 being higher demand. The purpose of this paper is to estimate what this additional demand might be.

However, the level of demand (and supply) at V2 could also be achieved if underlying demand is higher, largely eliminating the projected oversupply. This is shown as demand curve D2, with the price – volume intersection being P3V2, with P3 being a bit higher than, say, $8. It remains the OIES view that the oversupply will lead to lower prices and stimulate demand, but alternative outcomes are possible. It should be noted that this schematic is simplified and shows linear demand and supply curves, whereas the supply and demand for gas is not linear as was discussed in the OIES paper 'What drives international gas prices in competitive markets?' published in 2024.[10]

[8] Forward curves from Argus and CME as at October 8 2025.

[9] A New Global Gas Order? (Part 1): The Outlook to 2030 after the Energy Crisis. Mike Fulwood, July 2023. OIES NG 184

[10] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/10/NG-195-What-Drives-International-Gas-Prices-in-Competitive-Markets.pdf

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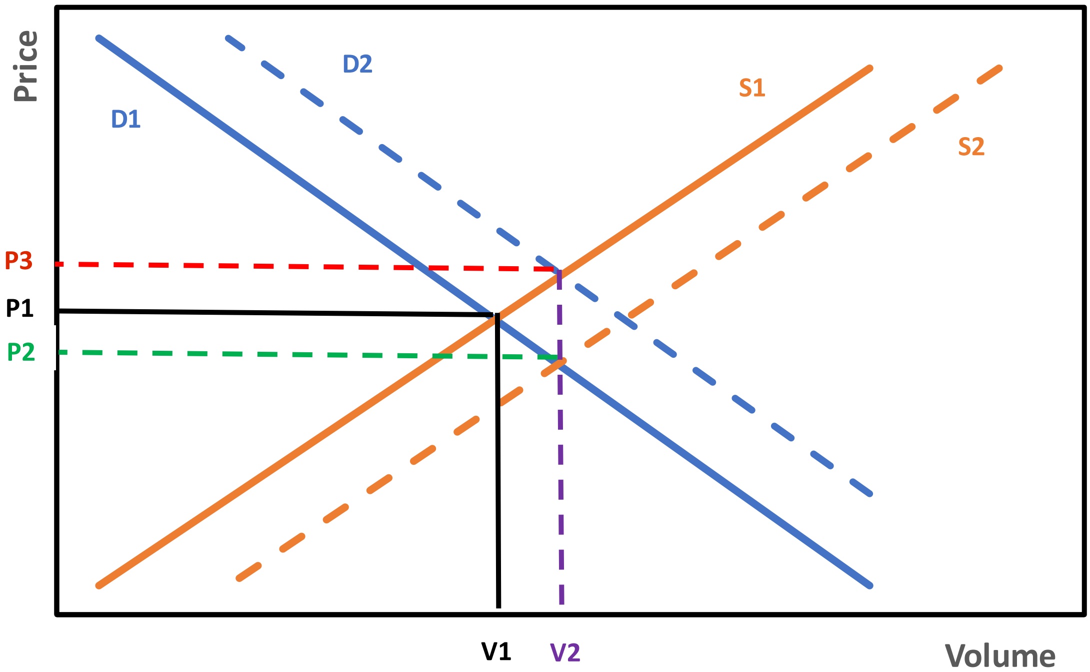
Figure 8: Supply-Demand schematic



Source: OIES

d) Price Formation Mechanisms

To understand the relevance of spot prices in the various markets, we can draw on the International Gas Union's Wholesale Gas Price Survey, the latest edition of which was published in June 2025.[11] In respect of markets where spot prices are a key element, these would be included in the category called gas-on-gas competition (GOG). Figure 9 shows the percentage of GOG in both total demand and LNG imports for 2024.

While there is some GOG at the total demand level in nearly all countries and regions, outside Europe, it is not the majority pricing mechanism. In Europe, GOG dominates and to the extent there is any price response in demand, then prices at $6 or less might be expected to have some impact. However, the price response is a response at the margin, and in most countries, LNG tends to be the marginal fuel, so lower prices might be expected to lead to a demand response.

The larger LNG importers in Asia – China, India, and JKT – all have significant shares of GOG, largely in price-responsive spot LNG cargoes. In the ASEAN region, GOG in LNG imports has grown significantly in the last few years, as LNG imports have grown, although volumes remain small. In the other emerging Asia countries of Pakistan and Bangladesh, GOG only really appears in Bangladesh, with Pakistan using almost all oil-indexed contracts. Latin America has widespread GOG in the domestic gas markets in Argentina, Chile, and Colombia, as well as in almost all LNG imports over the whole continent. The LNG volumes are not large but at the margin they are important in terms of additional demand. The bar for African LNG imports shown in Figure 9 for 2024 is slightly misleading as it refers entirely to Egyptian imports while the GOG in total demand is largely in Nigeria.

[11] https://www.igu.org/igu-reports/wholesale-gas-price-survey-2025-edition

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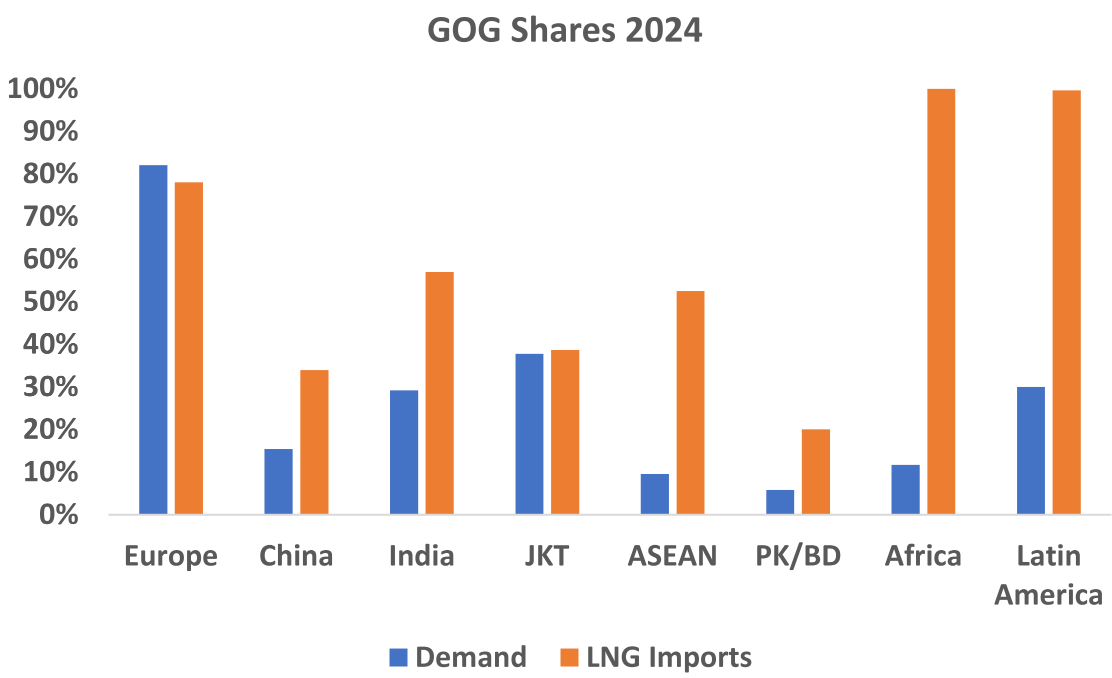
Figure 9: Gas-on-Gas competition in selected countries and regions



Source: International Gas Union Wholesale Gas Price Survey 2025

In conclusion, the importance of GOG pricing in LNG imports, especially in Asian markets, suggests that lower prices have the potential to stimulate demand. This is true of Europe, clearly, and also Latin America. Africa at this stage is somewhat different, as the possibility of LNG, at the margin, might displace imported oil in power generation in a number of countries.

e) Short and Longer-Term Economics of Gas

The short- and longer-term price response of countries will depend on the economics of gas relative to other fuels, principally in the power sector but also in the industrial sector in some countries. The short-term economics are in respect of the variable cost of, for example, gas-fired generation compared to coal-fired generation – in effect the fuel cost, including, if applicable, any carbon price or tax. The long-term economics are dependent on investing in new capacity so the key will be the levelized cost of gas-fired generation against, for example, renewables and coal.

On a variable cost basis, assuming 33 per cent efficiency for a coal-fired plant and 50 per cent efficiency for a CCGT, then gas is some 50 per cent more efficient than coal in generating electricity.[12] With an assumed coal price of $100 per tonne, this converts to $4.22 per MMBTU,[13] and converting to an equivalent competing price against gas of some $6.33 per MMBTU, a 50 per cent uplift for efficiency. This is without a carbon price or tax, which currently seems a reasonable assumption for Asian markets. With a carbon price, the equivalent coal price increases significantly. For every $1 per tonne of a carbon price, the additional carbon cost of coal is some 4.22 cents per MMBTU, so at a carbon price of $80 per tonne (70 euros per tonne), the additional cost of coal is some $3.38 per MMBTU, increasing the base coal cost to $7.60 per MMBTU. Once uplifted for efficiency, the equivalent competing price against gas of some $11.40 per MMBTU.

A $6 per MMBTU gas price, therefore, is very competitive against coal in a market like Europe which has a significant carbon price. In an Asian market, where there is no carbon price or tax, the economics

[12] Average efficiencies from US EIA.
[13] 25 GJ/Tonne and 947.82 TJ per MMBTU

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are more marginal, but gas could become seriously competitive against coal. Clearly the economics depend on assumptions about coal prices and relative plant efficiencies. It also assumes little or no difference between the wholesale coal and gas prices and the prices actually paid by generators for the fuels, a reasonable assumption in European and US markets where power generators can buy efficiently on the wholesale market, with minimal transportation costs. It may be less true in other markets.

Looking at the longer-term economics, the all-in or levelized cost of gas versus renewables is likely to be the key, but also possibly coal costs, especially where there is a carbon price. Calculations of the levelized cost can produce a wide range of answers depending on assumptions made on capital costs, operating costs, fuel costs, discount rates, asset lives, operating utilization rates, etc. The IEA published a report in 2020 on 'Projected Costs of Generating Electricity',[14] with all the costs in real 2018 prices which included a wide range of OECD countries plus a few non-OECD countries. For CCGTs and renewables the economics are summarised here:

CCGTs

- Mean overnight (capital) costs were $823 per KWe, fixed O&M was $50 per KW, and the mean capacity was 762 MW. This would give a total capital cost of $627 million and total annual O&M of $38 million.
- At 57 per cent operating efficiency and an 85 per cent load factor as base load, this gave a total levelized cost excluding fuel costs of some $19.32 per MWH, at a 7 per cent discount rate and 30-year operating life. Fuel costs, at an average of around $7.70 per MMBTU ($22.62 per MWH), came in at $39.56 per MWH, taking into account operating efficiency, giving a total of $58.88 per MWH.
- At real 2024 prices this would be around $71.83 per MWH in total – an uplift of some 22 per cent - with the net capital and O&M levelized cost at some $23.57 per MWH. At a 50 per cent load factor this adds some $24.88 per MWH to the levelized cost in real 2018 prices, to give a total of some $83.76 per MWH, or in real 2024 prices, $102.19 per MWH, of which fuel costs would be some $48.26 per MWH, leaving a net capital and O&M levelized cost of $53.93 per MWH.
- A $6 per MMBTU gas price ($17.58 per MWH), at a 57 per cent operating efficiency, gives a fuel cost of $30.85 per MWH. With an 85 per cent load factor the total is $54.42 per MWH and at a 50 per cent load factor the total is $84.78 per MWH (all in real 2024 prices).

Offshore Wind

- Mean overnight (capital) costs were $2,876 per KWe and fixed O&M was $100 per KW.
- At a 7 per cent discount rate and a 40 per cent load factor the average levelized cost was some $85 per MWH at real 2018 prices.
- Uplifting by 22 per cent to real 2024 prices, gives a levelized cost of $103.70 per MWH, although this does not take into account any real technological efficiencies.

Onshore Wind (over 1MW)

- Mean overnight (capital) costs were $1,391 per KWe and fixed O&M was $40 per KW.
- At a 7 per cent discount rate and a 35 per cent load factor the average levelized cost was some $62 per MWH at real 2018 prices.
- Uplifting by 22 per cent to real 2024 prices, gives a levelized cost of $75.60 per MWH, although this also does not take into account any real technological efficiencies.

[14] Projected Costs of Generating Electricity, IEA/NEA. 2020

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Solar (Utility Scale)

- Mean overnight (capital) costs were $995 per KWe and fixed O&M was $20 per KW.
- At a 7 per cent discount rate and a 20 per cent load factor the average levelized cost was some $52 per MWH at real 2018 prices.
- Uplifting by 22 per cent to real 2024 prices, gives a levelized cost of $63.45 per MWH, again not taking into account any real technological efficiencies.

Other evidence is also available on wind costs from Wind Europe.[15] The IEA report summarizes the 2024 auctions in Europe. The UK CfD Allocation Round 6 had prices ranging between EUR 92 - 99 per MWH. They were as low as EUR 76 per MWH in Germany and Italy for onshore wind, but mostly in the EUR 90 per MWH plus range for offshore wind. In $ per MWH this is equivalent to $105 per MWH. This is a similar level to the IEA broad levelized cost for offshore wind.

The strike prices set by the UK government in the latest auction round 7,[16] were set at £113 per MWH ($145) for offshore wind, £92 per MWH ($120) for onshore wind and £75 per MWH for solar ($98), all at real 2024 prices. These are the strike prices though and the bids are likely to come in lower.

These calculations do not include any carbon price or tax on gas-fired power, which would raise the overall levelized cost for gas. On the basis of this very broad analysis, gas at $6 per MMBTU looks very competitive with offshore wind, even at 50 per cent load factor for CCGTs. However, gas is less competitive against onshore wind and utility-scale solar. The assumed load factors for gas-fired power and renewables are an important assumption in determining the levelized cost. Compared to historically achieved load factors, the assumed load factors from the IEA report for gas, offshore wind, onshore wind, and solar all seem high, which reduces the levelized cost across the board, but does not necessarily alter the relative economics.

Adding a carbon tax to the gas prices, as there is in Europe, results in higher effective prices in the longer term, to compete with renewables. Assuming 50kg of CO2 emissions per MMBTU of gas gives an additional 5 cents per MMBTU of cost per $1 per tonne of CO2 price or tax. At the broad current price of 75 euros per tonne for the EU ETS price – some $85 per tonne – this is an additional cost of $4.25 per MMBTU, raising the effective cost of gas to just over $10 per MMBTU from $6. This equates to some $29.31 per MWH, which, at an operating efficiency of 57 per cent, is a fuel cost of $51.41 per MWH – around $21 per MWH higher than with no carbon price. At current carbon prices, therefore, this would make gas-fired power broadly comparable with the levelized cost of offshore wind at just over $100 per MWH.

In respect of the levelized cost economics of coal versus gas, gas at $6 is likely to be very competitive against coal where there is a carbon price and also without a carbon price, since the capital costs of coal-fired plants are generally higher per MW than for gas. However, with coal being phased out in many countries, including in Asia, there are few new coal plants being built. The long-run prospects of gas versus coal, therefore, are likely more a continuation of the short-run variable cost comparison, where a carbon price improves the economics of gas.

The very broad comparative economics, discussed above, provide an overview and individual projects in different countries may have different relative economics. However, the overall conclusion, that in most markets, gas-fired power at a $6 price for gas is economic versus offshore wind, even with a carbon price, but more expensive than onshore wind and utility scale solar.

[15] Wind Energy Europe, 2024 Statistics and the outlook for 2025-30. Wind Europe. 2025
[16] https://assets.publishing.service.gov.uk/media/6880ff3f9fab8e2e86160f7a/ar7-contract-allocation-framework.pdf

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3. Europe

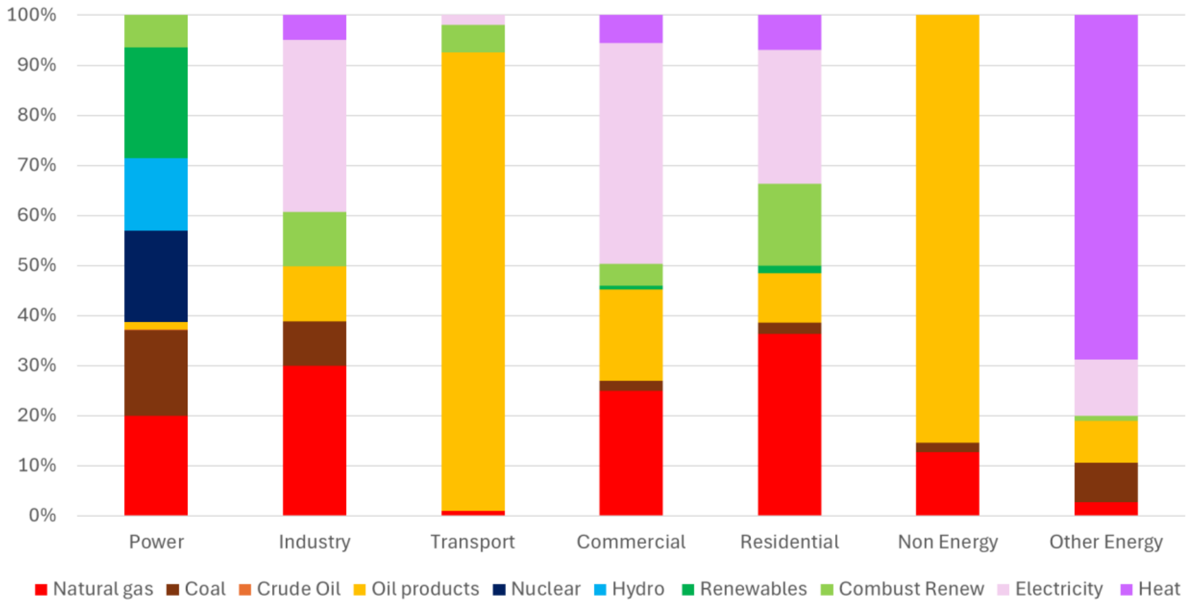
a) Introduction

For the purposes of this analysis, the European region covers 37 countries, encompassing the 27 members of the EU,[17] the UK, Norway, Switzerland, non-EU Balkans,[18] and Turkey.

In 2024, natural gas accounted for 23 per cent of total primary energy supply in the region and has seen its share relatively stable since the early 2000s.[19]

Gas had a key role in the residential sector (36 per cent of energy used in 2022), followed by the industrial sector (30 per cent), the commercial sector (25 per cent), and the power sector (20 per cent) as illustrated in Figure 10.

Figure 10: Energy supply mix by sector in Europe, shares in 2022 (per cent)



Source: Data from International Energy Agency. Chart by the author

The European energy market has been on a roller coaster ride over the past five years, from the COVID -19 pandemic in 2020 and impacts of lockdowns on countries' economies to the subsequent recovery in 2021, and then the Russian invasion of Ukraine in early 2022, which triggered a seismic shift in natural gas flows.

The severe disruption in Russian gas supplies and the need to attract LNG cargoes to Europe pushed gas prices up to record levels in mid-2022, as illustrated in Figure 11, with cascading effects on electricity prices, energy-intensive industrial production, commercial activities, and residential consumers. The overall impact was disastrous for the region as a whole, and the natural gas market in particular.[20] The average benchmark month-ahead TTF gas price was still around $13 per MMBTU in the first eight months of 2025,[21] much higher than pre-crisis levels (2019-2020) when average prices were $6 per MMBTU or less.

[17] Austria, Belgium, Bulgaria, Croatia, Republic of Cyprus, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden

[18] Albania, Bosnia and Herzegovina, Kosovo, Montenegro, North Macedonia, Serbia

[19] The share of gas in TPES ranged between roughly 23 per cent and 26 per cent between 2000 and 2024. Calculated using data from IEA Energy Balances.

[20] See our Quarterly Gas Market Review series for more information, or publications from Anouk Honore on our website: www.oxfordenergy.org

[21] Argus data.

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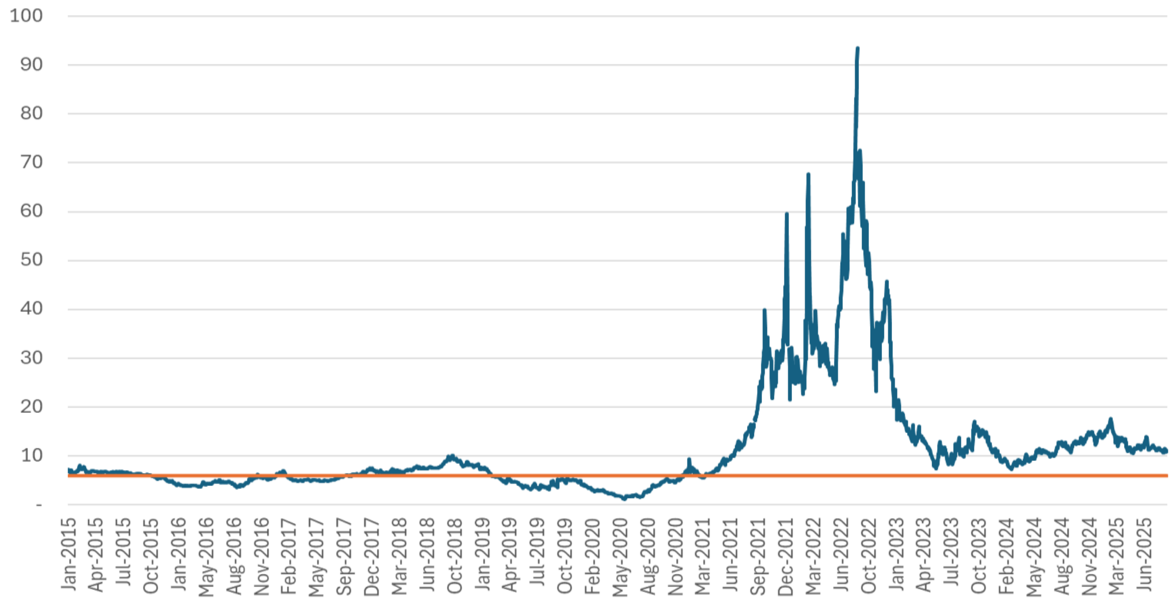
The region struggles with the impossible conundrum of the need to secure energy and gas supplies by investing in gas import infrastructure and attracting LNG cargoes, while at the same time following its net-zero ambitions by reducing fossil fuel energy demand, including natural gas, and rolling out renewables. The EU in particular has set itself ambitious mid-term targets for 2030 and is in discussion for 2040 targets.

Figure 11: Natural gas prices on the TTF, month 1, $ per MMBTU



Source: Data from Argus. Chart by the author

The following section takes a closer look at the current situation and trends in European gas demand before turning to future gas consumption and the possible impacts of a gas price drop to around $6 per MMBTU in the late 2020s, compared to the Base Case scenario, which was detailed in Section 2 of this paper, and works on the assumption of a gas price of $8 per MMBTU.

b) Three years on, gas demand remains well below pre-crisis levels

Overview of gas demand in Europe

Despite a decline in gas prices, gas demand in Europe remains well below pre-crisis levels. It reached 460 bcm in 2024, roughly 108 bcm lower than in 2021 (a drop of 19 per cent).

However, 2021 saw some recovery after the impact of the COVID-19 pandemic and it was also a particularly cold year, boosting the use of gas for heating across Europe, so is not a good comparator. A better comparison would be to use the level of gas demand in 2019 (around 550 bcm), the last 'normal' year before the massive market disruptions detailed above. Gas prices in 2019 were also around or below the $6 per MMBTU mark, the main gas price assumption used in this paper to analyse the potential impact on gas demand in the short- and mid-term horizon.

In 2024, gas demand in Europe was still 89 bcm below 2019 levels (-16 per cent). The steep decline in gas burn in the power sector has been the main driver of this fall, accounting for 34 per cent of the decline in 2019-2023, with the rest coming from the residential sector (21 per cent) and the industrial sector (17 per cent), as shown in Figure 12.[22]

[22] In Europe, gas use is highly concentrated in four sectors: the power sector (30 per cent in 2023), in the residential sector (27 per cent), in the industrial sector (22 per cent), and finally in the commercial sector (11 per cent).

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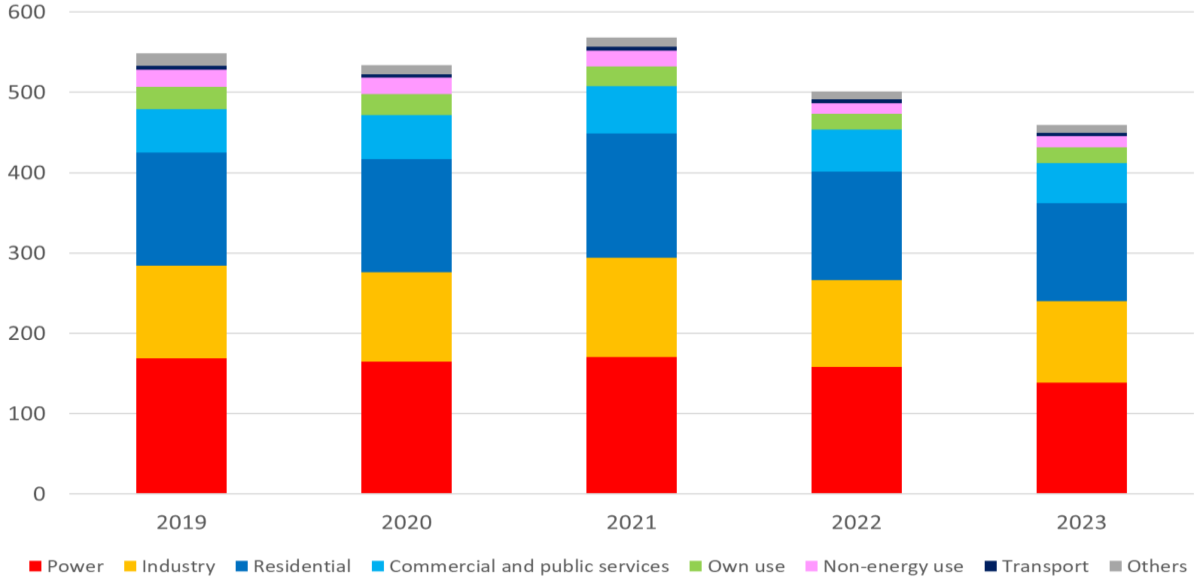
There are many moving parts in the gas demand puzzle, and a complex range of factors influence the dynamics in the European natural gas market, especially considering the wide diversity of the 37 markets that comprise the European region in this paper.

Figure 12: Natural gas demand by sector in Europe, 2019-2023 (bcm)



Note: The IEA classifies refineries in the transformation sector, not as part of the industrial sector in its energy consumption data definitions. In this chart, refineries are therefore included in the 'own use' category.
Source: Data from International Energy Agency. Chart by the author

Nine markets alone accounted for over 83 per cent of gas usage in 2024: Germany (17 per cent), Italy (13 per cent), the United Kingdom (13 per cent), Turkey (12 per cent), the Netherlands (7 per cent), France (7 per cent), Spain (6 per cent), Poland (5 per cent) and Belgium (3 per cent). The other 28 countries represented less than 17 per cent of total gas demand (and consumed less than 10 bcm each).[23]

The big nine have all registered a decline in gas demand since 2021, but only seven of them had a lower gas use in 2024 relative to 2019. The notable exceptions were Poland (+7 per cent since 2019 driven by the power sector as gas replaces decommissioned coal plants, and also the residential sector) and Turkey (+18 per cent driven by the power sector to cover electricity demand growth, the residential, and the commercial sectors) as illustrated Table 1**.**

Even within the big nine, there are important differences in economic structure, energy mix, and the share of gas in primary and final energy, transition targets, and pathways, and of course, the split in sectoral gas demand, as illustrated in Figure 13 and the electricity generation mix (Figure 14*)*. All of these influence the level and variations of gas demand, including its price sensitivity. For instance, gas used in the residential sector is essentially used for heating in winter and fluctuations primarily follow the changes in temperatures, while gas consumed in the industrial sector and for electricity generation tends to be more influenced by gas prices, although other factors may limit their impact, including hedging of price risks by large industrials at times when gas prices are low or, even more importantly, the availability of switching options in the power sector.

[23] Data from IEA.

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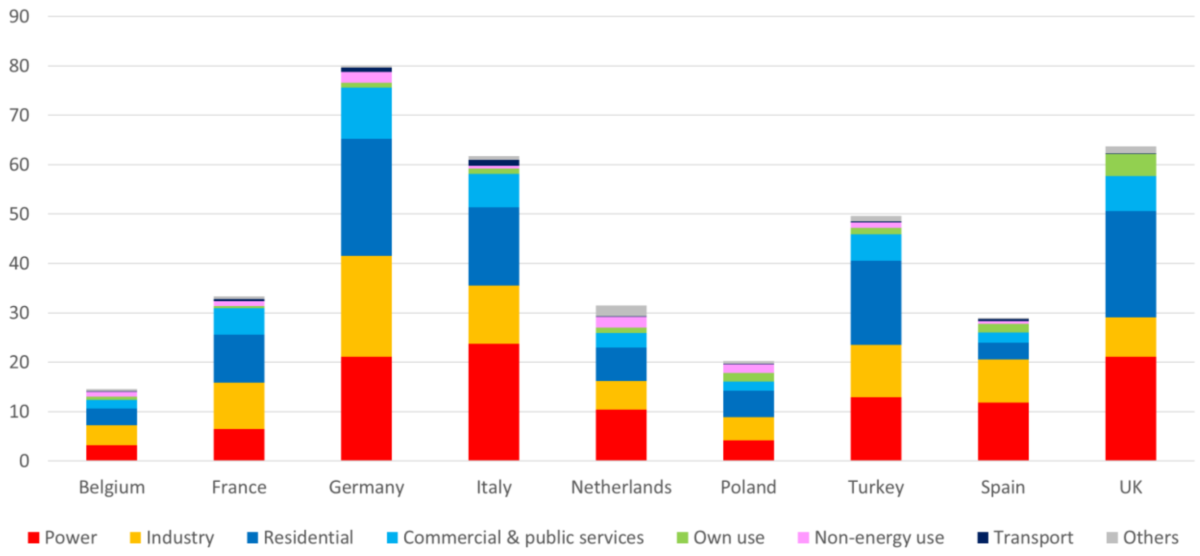
Table 1: Observed gas demand in Europe, 2019-2024 (bcm and per cent)

	2019 (bcm)	2020 (bcm)	2021 (bcm)	2022 (bcm)	2023 (bcm)	2024 (bcm)	Change 2019-2024 (%)	Change 2021-2024 (%)
Germany	96	93	99	87	80	78	-18	-21
Italy	74	71	76	69	62	62	-16	-19
United Kingdom	79	74	78	72	64	62	-21	-20
Turkey	45	48	60	52	50	53	18	-11
Netherlands	45	44	42	33	31	32	-29	-24
France	42	39	41	38	33	31	-25	-24
Spain	35	32	34	33	29	28	-21	-18
Poland	21	21	23	20	20	22	7	-3
Belgium	19	18	18	16	15	14	-23	-23
)thers (28 countries)	93	93	97	82	76	77	-17	-21
TOTAL	**548**	**533**	**568**	**501**	**460**	**460**	**-16**	**-19**

Source: Data from International Energy Agency. Table by the author

Figure 13: Gas demand by sector in the nine major European gas markets in 2023 (bcm)



Note: The IEA classifies refineries in the transformation sector, not as part of the industrial sector in its energy consumption data definitions. In this chart, refineries are therefore included in the 'own use' category.
Source: Data from International Energy Agency. Chart by the author

The power sector: rapid transformation of the electricity mix and the use of gas plants

The continued build-out of wind and solar capacity is galvanising structural changes in the power sector, with renewables covering about 50 per cent of electricity generation in 2024. Wind and solar generation alone rose by 60 per cent between 2019 and 2024. Their combined shares grew from 16 per cent to 26 per cent of the electricity mix over the same period, displacing fossil fuels, including coal (which fell from 16 per cent to 12 per cent) and gas power plants (20 per cent to 16 per cent) as illustrated in Figure 14.[24]

[24] Calculated from data from the International Energy Agency

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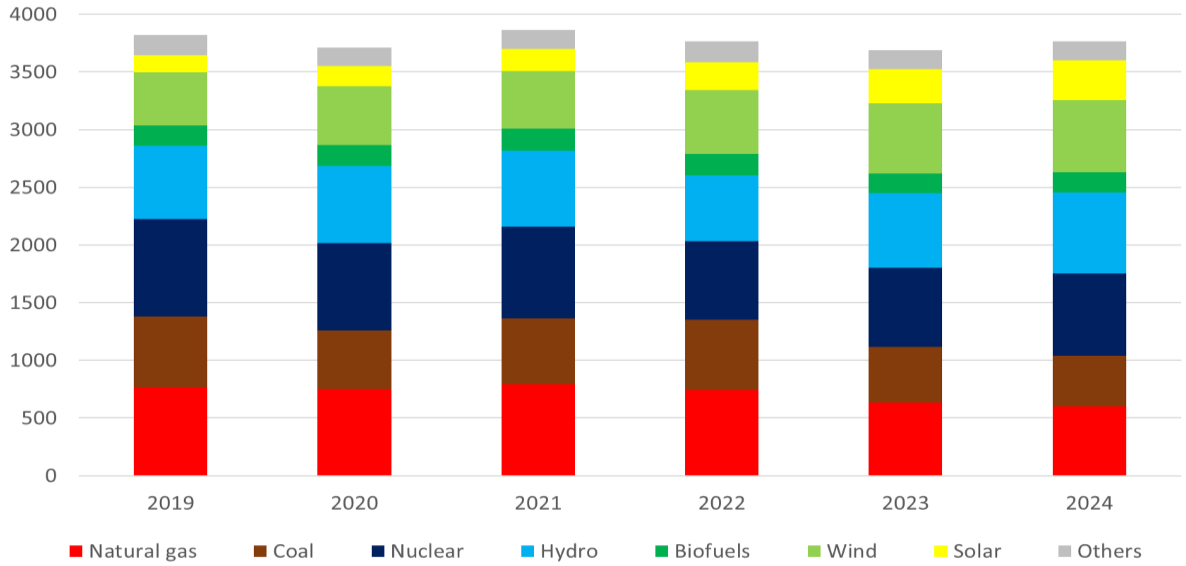
Figure 14: Power sector generation by fuels in Europe, 2019-2024 (TWh)



Source: Data from International Energy Agency. Chart by the author

However, dispatchable generation capacity remains essential to integrate such a large share of intermittent renewables and gas plants in particular still play a major role in balancing power grids as other options such as demand side response and/or batteries have not yet been developed at scale. It is a slow process, which has not kept pace with the development of intermittent renewable generation.

At the regional level (national pictures are more varied), the daily generation mix clearly shows a correlation between renewables (wind in particular) and gas generation: when wind availability is good, the use of gas plants is low, and conversely, when wind is limited, gas plants ramp up to make up for the shortfall.[25]

There are some important consequences from this ongoing structural transformation of the power sector, which is being driven by the energy transition, rather than a consequence of the recent crises and/or high gas prices:

1. Weather-related patterns have become the main driver for gas (and coal) demand in the power sector, not prices. Fluctuations in short-term gas demand are more uncertain than ever, especially during the winter when the combination of cold temperatures and days with low wind availability inevitably drive short-term spikes in gas use for which size and duration are hard to predict (as witnessed in winter 2024-2025).[26]
2. The impact of gas prices on the level of gas demand in the power sector is fading rather quickly. With nuclear plants used for baseload and the rapid addition of renewables, the share of gas and coal in electricity generation is decreasing quickly, down from 46 per cent in 2010 to 28 per cent in 2024 at a regional level, and even less in some major countries as seen in Figure 15.
3. Coal/gas competition now occurs within a shrinking share of the energy mix and this is not what it was in the 2010s. Limiting factors include coal plants closures (for economic reasons or due to political decisions to phase-out coal) and the use of coal/gas plants to back-up intermittent renewables rather than baseload or even mid-merit generation plants. In other words, at times of low renewables availability, a tight market will call on most available plants, limiting the extent of coal-gas competition; while at times of high renewables availability, competition between coal

[25] At lesser levels, similar trends can also be observed between renewables (wind in particular) and coal plants. In other words, coal plants also provide some back-up for the intermittency of renewables.
[26] For more information, see https://www.oxfordenergy.org/publications/dunkelflaute-driving-europe-gas-demand-volatility/

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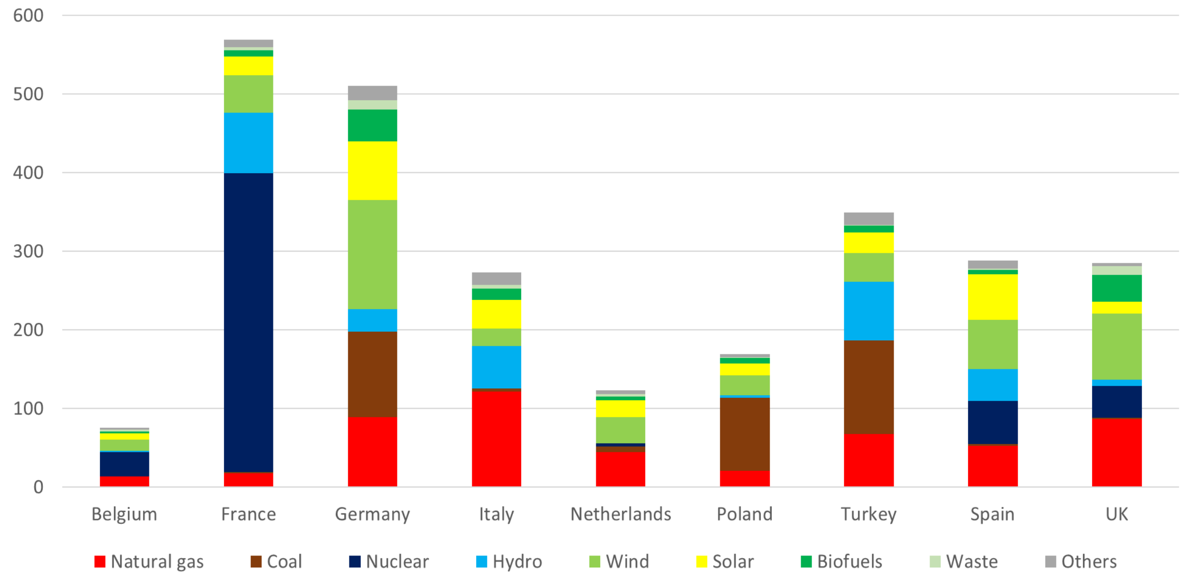
and gas plants might be fierce but the amount of electricity needed from them is small (and therefore the impact on gas demand limited). Finally, the length of the periods with high/low renewables availability may influence which plants are being called on (after batteries and other demand response measures have been exhausted), with gas plants generally more flexible than coal plants, as they have a faster ramp up time.

Figure 15: Electricity generation by fuels in the nine major European gas markets in 2024 (TWh)



Source: Data from International Energy Agency. Chart by the author

Industrial sector: the most price-responsive sectoral demand in 2022

Industrial gas demand in Europe is concentrated in a handful of sectors: chemical and petrochemical production (22 per cent of gas used in 2023); food and tobacco (18 per cent), non-metallic minerals, which include glass and cement manufacturers (17 per cent); and iron and steel production (10 per cent).[27] Other significant gas-consuming sectors include paper and pulp manufacturing (7 per cent) and machinery (7 per cent). Gas used in refineries, which is under the 'own use' section in IEA data, consumed the equivalent of about 8 per cent of industrial gas demand (Figure 16).

The industrial gas sector, which uses gas either for power and heat generation or as feedstock, was the most responsive sector to high prices in 2022, benefiting from options which included switching to other fuels (for instance, LPG in refineries, coal in electricity and heat generation or even renewables when possible), improved operational efficiency and/or curtailing production. However, this sometimes involved increased production outside Europe and imports to the region, seen with nitrogen-based fertilizer production).

Price-responsive demand reductions in the industrial sectors which compete globally emerged in 2022, despite gas prices rising from mid-2021, as large industrials are likely to have hedged their price risk before the rise when prices were lower, which kept them afloat for a few months before being fully exposed to higher gas prices.

All in all, industrial gas demand decline was largely limited to 2022, but lower gas prices from 2023 onward have not led to a noticeable recovery. When compared with pre-crisis levels, gas use in the industrial sector remained 13 per cent lower in 2023 (the last available data from the IEA with sectoral split at the time of writing[28]) than in 2019.

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[27] Data from IEA
[28] September 2025

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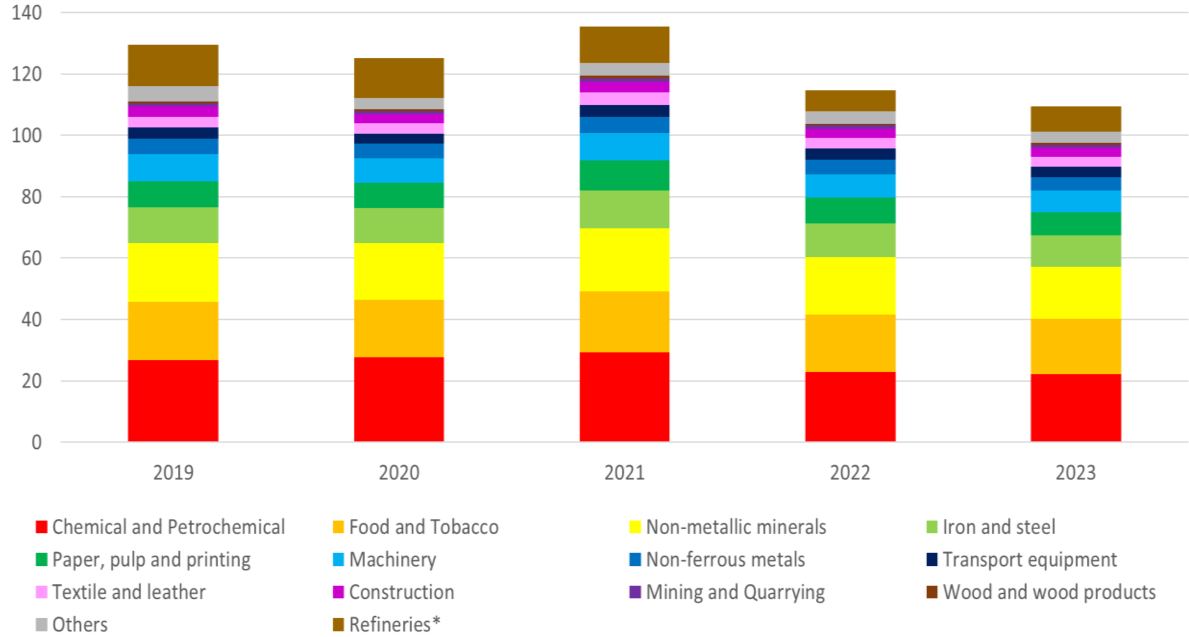
The decline would be 16 per cent lower if we included refineries in the industrial sector. In this extended definition, the loss of just over 20 bcm between 2019 and 2023 came primarily from refineries (27 per cent), chemical and petrochemical (22 per cent), non-metallic minerals (11 per cent), machinery (8 per cent), and iron and steel (7 per cent).

With the exception of food and tobacco, which is less exposed to international competition, all the major gas-intensive industrial sectors have registered a significant decline in gas demand since 2019 and have not displayed any major recovery despite lower prices.

Signs of a small rebound were visible from mid-2023 until the end 2024[29] but it was essentially driven by just two sectors: refineries (switching back to gas) and fertilizer production (a sub-category of the chemical sector, where several producers have the ability to switch production between regions depending on international cost competitiveness). Industrial gas use in other gas-intensive sectors remained weak, raising concerns of permanent industrial demand destruction (i.e. plant closures or a shift in production outside Europe, due to lost competitiveness from high energy costs) rather than simple temporary reduction due to the crisis.

Figure 16: Industrial gas demand by sector in Europe, 2019-2024 (bcm)



Note: Refineries have been added to the industrial sector by the author
Source: Data from International Energy Agency. Chart by the author

Resilient demand in the residential and commercial sector

Natural gas is the single largest source of heat in buildings in Europe.[30] The impact of winter temperatures on European gas demand is therefore important, particularly in the residential and commercial sector where three quarters of annual gas use occurs between October and March (the first quarter alone typically covers 40 - 45 per cent), and gas use for heating remains the most important driver of seasonal (and even annual) fluctuations.

The rollout of alternative heating systems (such as heat pump installations) and renovations across Europe has been slow with only a marginal impact on winter demand of a few bcm, much less than

[29] Data calculated by the author for EU27 + the UK. See our Quarterly Gas Market Review for more information: https://www.oxfordenergy.org/publication-topic/quarterly-gas-review/
[30] See Eurostat data for more details

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changes in temperatures would create: a normal winter (as opposed to the two mild winters of 2022/23 and 2023/24) can boost total gas demand by at least 8-10 bcm and a cold one by at least 20-25 bcm.

Gas demand in the residential sector is not usually the most price-responsive, but it was – surprisingly - a key determinant in the first winter of the crisis (2022/23) and accounted for a reduction of at least 10 to 15 bcm year-on-year. The combination of higher gas prices that progressively fed through to retail prices, strong energy-saving campaigns to moderate heating, and particularly mild temperatures helped reduce gas demand for heating over that winter. Over the next two subsequent winters, demand response seems to have eroded in parallel with the decline in gas prices.

The commercial sector displays a relatively price-sensitive gas demand, which is similar to that seen in the industrial sector, albeit without the time lag, with fluctuations typically loosely mirroring fluctuations in gas prices.[31]

c) Would a $6 per MMBtu gas price from the late 2020s trigger additional gas demand in Europe?

The next couple of years: limited upside for gas demand in Europe in the short term

The gas market has evolved over the past two to three years in Europe, with a deterioration in demand flexibility, while changes in demand seem rather limited in the short term. This certainly applies to any demand reduction (most of the low hanging fruit of energy savings in all sectors have probably been harvested after three years of low gas demand), and any rebound in demand as well. As of September 2025, there were no strong signals for any robust recovery in gas demand for the rest of the year or even 2026, but instead lots of uncertainties. Lower gas prices *alone* (compared to last winter) are unlikely to trigger more than a small rebound in gas demand, a few bcm in the commercial sector and possibly also in the industrial sector.

Growing renewables and good availability of nuclear limit the need for gas

In the power sector, the growth of renewables and good availability of nuclear energy in France [32] limit the role of gas most of the time, both in winter and in the summer when demand for air conditioning boosts electricity use. Gas plants are moving further away from providing baseload power and increasingly towards a role as back-up providers, whose utilization is determined by the availability of other power sources.

In addition, a gloomy economic outlook for the rest of 2025, and potentially into 2026 (Figure 17),[33] will temper any strong recovery in electricity demand, limiting the requirement for gas (and coal) power plants essentially to back-up and/or balance the system.

Gas demand in the power sector has therefore become more volatile, somewhat less predictable and, importantly, less responsive to higher prices. This trend is also supported by the progressive phase-out of hard coal and lignite-fired generation capacity around Europe, which leaves little room for coal /gas switching in either direction, and constrains any short-term impacts of lower gas prices (and/or change in competitiveness between coal, gas, and carbon prices).

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[31] Data calculated by the author for EU27 + the UK. See our Quarterly Gas Market Review for more information: https://www.oxfordenergy.org/publication-topic/quarterly-gas-review/.

[32] In 2022, the French utility EDF faced a wave of repairs on pipes affected by stress corrosion and delays to its scheduled 10-year maintenance due to the COVID pandemic (as well as strikes in France in October), which forced a record number of reactors offline for most of the year. As a result, French nuclear generation was down by 23 per cent in 2022, lifting thermal power generation in the country and in neighbouring markets. French nuclear generation has been back to (or above) pre-crisis level since early 2024. See our Quarterly Gas Market Review for more information: https://www.oxfordenergy.org/publication-topic/quarterly-gas-review/.

[33] https://www.imf.org/en/Publications/WEO/Issues/2025/07/29/world-economic-outlook-update-july-2025

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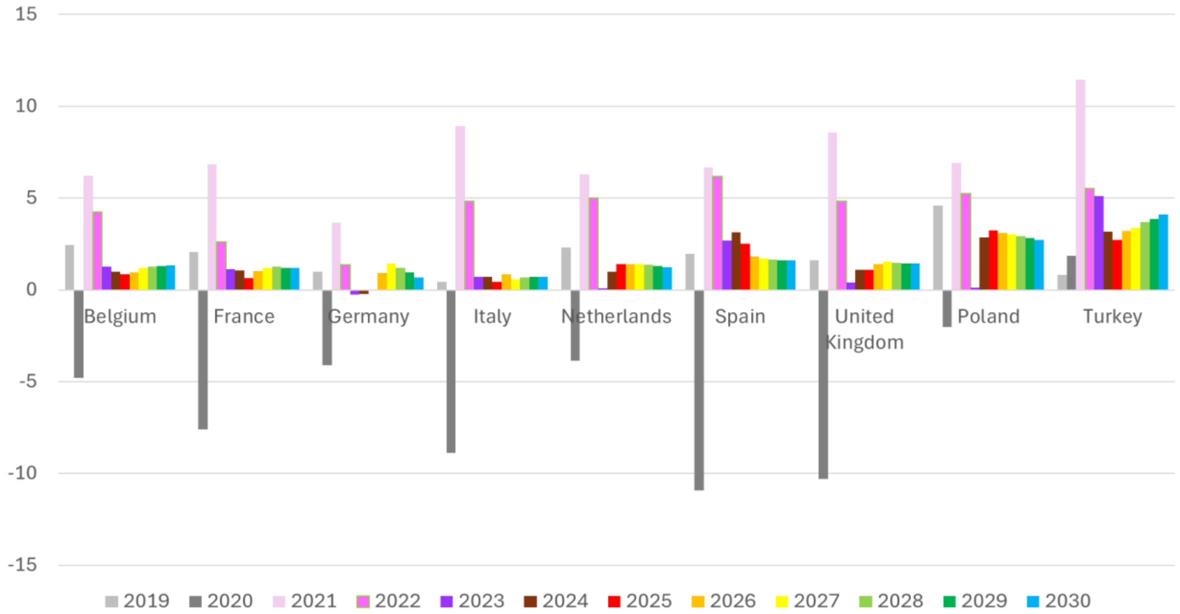
Figure 17: European Gross domestic product (constant prices), year-on-year change (per cent)



Source: Data from International Monetary Fund, World Economic Outlook Database, April 2025. Chart by the author

Industrial gas demand to remain muted amid global tariffs and policy uncertainty

A progressive recovery for European industry was anticipated for the remainder of 2025, but is now likely to be delayed to 2026, at best, with similar consequences for gas demand, as a result of three main drivers.

First, after three years of industrial crisis, EU manufacturing output in most energy intensive sectors (including the large gas consumers, such as 'chemicals and chemical products', 'non-metallic minerals', and 'iron and steel') remains well below pre-2021 levels as shown in Figure 18 (EU27 example).[34]

Secondly, US tariffs and geopolitical uncertainties are likely to limit economic growth. This could also affect supply chains and consumer spending in Europe despite lower inflation and interest rates, which are nonetheless also still higher than pre-crisis levels. A decline in exports will hurt investment decisions in those sectors most reliant on exports to the US.[35] Lower production in these sectors would also have a knock-on effect on other sectors in Europe that supply them. In other words, the current macroeconomic and geopolitical situation will impact overall GDP growth in Europe.

Lastly, US tariffs on imported goods from China could have a similar impact on the Chinese economy and resulting weaker national demand may translate into more exports of manufactured goods from China, competing with more expensive European products.

European industries, including most energy-intensive sectors, face a double whammy with demand for end-products limited by low consumer spending and risks to supply chains. All in all, geopolitical tensions, trade frictions, and a worsening of the economic outlook are likely to continue to limit prospects of a rebound in European industrial gas demand in the coming months, even in the case of lower gas prices, except via fuel switching in the refining sector and/or increased ammonia production. The commercial sector, on the other hand, is more price responsive, and a rebound is likely, as was seen in 2023-24.

[34] The food sector, which is less exposed to international competition, remains the exception. Data calculated from Eurostat.

[35] In 2024, the most exported manufactured goods from the EU were "machinery & vehicles", followed by "chemicals" and "other manufactured goods". The three largest exporters to the US were Germany, Ireland and Italy. Based on Eurostat data

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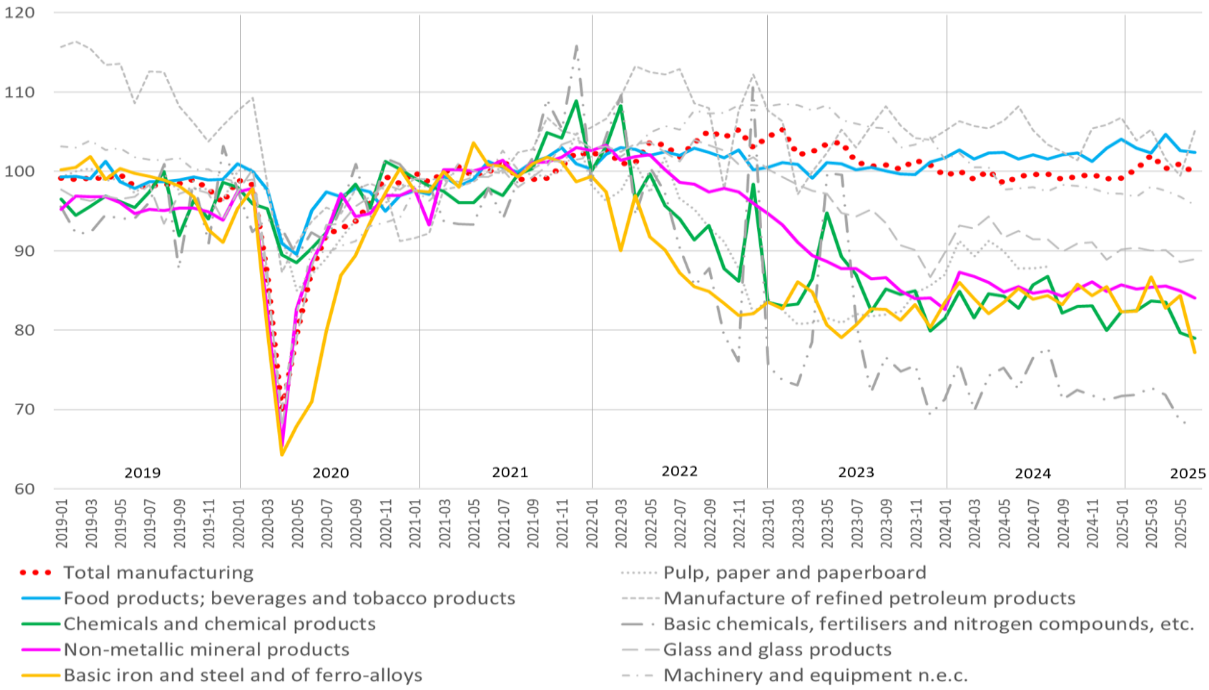
Figure 18: Production in industry, EU27, index: 2021=100



Source: Data from Eurostat. Chart by the author

Mid-term demand (2028-2030): closure of coal plants and electrification to support gas for power demand

Towards the late 2020s, it is projected that gas prices will decline toward the $6 per MMBTU mark, an important drop within a relatively short time frame.

Continued growth in renewable capacity around Europe[36] implies structurally weaker gas demand in the power sector in the future. However, the closure of coal-fired power plants and anticipated higher electricity demand could sustain the use of gas-fired power plants in the mix (at least) in the 2020s.

By 2030, coal plants will remain in only eleven countries (compared to twenty-one in 2024), with just three countries responsible for 76 per cent of installed capacity: Germany, Poland, and Turkey. Of the roughly 126 GW of coal-fired capacity in mid-2025,[37] about 37 GW is expected to be decommissioned by 2030, and a further 26 GW by 2035. To put this in perspective, coal represented around 10 per cent of electricity generation in the first half of 2025, and about two thirds of this production came from plants that will close by 2030.[38]

This estimate reflects the situation as of September 2025, but the timetable and prospects for coal plant closures may change in the future. For instance, policies and regulation affecting the energy sector, including the electricity mix, are under review in Germany and Poland following elections earlier this year.[39]

- In September, Chancellor Friedrich Merz announced that Germany may delay the closure of its remaining coal-fired power plants until new gas-fired units are ready to replace them, and

[36] In the EU27, the revised Renewable Energy Directive, adopted in 2023, raises the EU's binding renewable energy target for 2030 to a minimum of 42.5 per cent of energy consumption, and the REPowerEU plan (May 2022) aims for 69 per cent of electricity to come from renewables by 2030.

[37] Data on coal plant capacity in Europe vary between sources depending on definitions, especially for dual fuels power plants This is this author's estimate.

[38] Author's calculations

[39] Federal elections were held in Germany in February 2025, and presidential elections were held in Poland in June 2025.

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Bnetza (the grid regulator) has not ordered any statutory reductions of coal plants for 2028, the second year in a row that this has happened. [40] Germany is set to phase out coal-fired power generation by 2038 (at the latest).[41]

- In Poland, high-emission coal power plants[42] should not have been given any support under the capacity market or other similar mechanism since July 1, 2025, due to EU regulations. Poland has however already secured support until the end of 2028, deferring the first major wave of coal closures until the end of the 2020s. Poland is the only country in the EU which has not set a date for its coal phase-out.
- In Turkey, the long-term climate strategy focuses on increasing energy from renewables and efficiency,[43] but does not include a commitment to a coal phase-out (despite a net-zero target of 2053), and no major change in coal capacity is expected by 2030. The introduction of a carbon price from 2026[44] could change coal/gas competitiveness, but it is still uncertain whether the carbon price will be high enough to trigger coal-gas switching within the timeframe of our analysis. In 2019, a TTF price at about \$6 per MMBTU did not trigger any increase in gas generation vs coal, and there was in fact a strong decline in gas generation during that year (down 38 per cent year-on-year), due to good hydro availability, while coal generation remained the same. In 2021, despite higher TTF prices, gas generation rose by 57 per cent to make up for low hydro production, while coal generation remained flat. These two examples highlight the limited impact TTF prices have had so far on gas used for power generation in the country.

Despite important differences and challenges at a national level, the anticipated combination of relatively low gas prices – projected to reach \$6 per MMBTU by 2030 - and higher carbon prices, particularly from 2026 onward in the EU, is expected to accelerate the phase-out of coal-fired power plants potentially ahead of schedule at the regional level.

This will also happen in the context of energy transition, leading to further electrification of the economy. The IEA World Energy Outlook 2024[45] anticipates a rise in electricity demand of 21 per cent between 2023 and 2030 in its STEPS scenario and 29 per cent in its APS scenario for OECD Europe,[46] although the speed and extent of electrification remain uncertain. The EU Clean Industrial Deal, passed in February 2025, set a target of 32 per cent in 2030 but electrification within the EU as a whole has been stagnating at around 20-25 per cent for the past fifteen years.[47]

Nonetheless, lower coal plant capacity, higher electricity demand, and the forecast lower gas prices of \$6 per MMBTU will contribute to sustaining gas demand in the power generation sector in the coming years, even alongside the rapid growth of renewables.

The Base Case scenario in this paper uses the following assumptions for 2030: TTF gas prices of \$8 per MMBTU, a carbon price in the EU and in the UK of \$85/t, electricity demand at 4719 TWh[48] (21 per cent higher than in 2023) with coal and gas accounting for a share of 22 per cent and renewables at 62 per cent. In this scenario, gas demand in 2030 amounts to 160 bcm.

Assuming a gas price of \$6 per MMBTU, with the same assumptions as above, coal power plants subjected to carbon pricing become largely uncompetitive compared to gas-fired alternatives. In countries where coal capacity persists - excluding combined heat and power (CHP) plants - this leads

[40] https://www.argusmedia.com/es/news-and-insights/latest-market-news/2730792-germany-mulls-slowing-coal-fired-plant-closures
[41] https://www.bundesregierung.de/breg-en/service/archive/kohleausstiegsgesetz-1717014
[42] Plants emitting more than 550 kg of CO_2 per megawatt-hour (MWh)
[43] 2022 National Energy Plan (2024–2035); 2024 National Energy Efficiency Action Plan (2024-2030)
[44] https://icapcarbonaction.com/en/ets/turkish-emission-trading-system
[45] https://www.iea.org/reports/world-energy-outlook-2024
[46] There is no details at the national level, but OECD Europe is a good proxy for the 37 countries included in the European region in this paper.
[47] https://www.europarl.europa.eu/RegData/etudes/BRIE/2025/772851/EPRS_BRI(2025)772851_EN.pdf
[48] This is taken from the STEPS scenario in the IEA WEO 2024 for OECD Europe.

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to additional switching from electricity plants using hard coal in EU countries (and some using brown coal), which results in gas demand rising to 163 - 167bcm – an increase of between 3 and 7 bcm in the power sector compared to the Base Case scenario.

$6 per MMBTU gas prices likely to slow down the decline in gas demand in the 2030s, at least in the first half of the decade

Looking toward the 2035/2040 horizon, a prolonged $6 per MMBTU environment would help keep gas in the energy mix for longer, but a return to organic demand growth is unlikely in the context of the energy transition.

The EU has set itself targets to progressively reduce its GHG emissions and be the first net-zero continent by 2050, with intermediary targets for 2030 and proposals for 2040, all of which are expected to contribute to a swift fall in natural gas demand.[49] The UK is expected to follow a similar path while Turkey's net zero ambitions do not include a clear pathway toward reducing gas consumption, while its ambition to become a gas hub goes some way to indicating the contrary.

Slow down of investments in low-carbon alternatives?

Lower gas prices toward the end of this decade will reduce the economic incentive to switch rapidly to cleaner, alternative energy sources or technologies, such as hydrogen, biomethane, and offshore wind farms, adding to existing political and economic challenges and fueling uncertainty on planned investments.

In the power sector, Europe is aiming for 300 GW of installed offshore wind capacity by 2050, with specific targets for the North Sea region (Belgium, Denmark, Germany, France, Ireland, the Netherlands, Norway, and the UK) set at 120 GW by 2030.[50]

Germany has a national target of 30 GW by 2030, representing a quarter of this overall North Sea region expansion. However, the Energy Transition Monitoring report,[51] which was commissioned by the German government and published in September 2025, will likely result in lowering the country's ambitions for the rollout of renewables in order to cut costs. The government has also abandoned the requirement that new gas power plants need to be hydrogen-ready from the outset,[52] further indicating a likely deceleration in energy transition investments in the coming years.

Delays in European offshore wind projects are also being noted in other countries[53] (Netherlands France, Italy, the UK, etc.), for a variety of reasons, including regulatory uncertainty, slow and complex permitting processes, grid connection bottlenecks, insufficient grid infrastructure, and of course, deteriorating market conditions, which are impacting project costs and profitability. These will only worsen in a $6 per MMBTU gas world.

In the IEA scenarios published at the end of 2024 (STEPS and APS respectively), the share of renewables accounts for 66 per cent and 70 per cent of the electricity mix in OECD Europe in 2030, and 76 per cent and 81 per cent by 2035.

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[49] The 'Fit for 55' legislative package and the REPowerEU plan aim to significantly reduce gas demand by 2030 through increased energy efficiency, deployment of renewables, electrification, and renewable hydrogen: -.116 bcm between 2019 and 2030 in Fit for 55 and -310 bcm in REPowerEU according to the European Commission. https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52022SC0230
The EU Impact Assessment for the 2040 targets proposals expects gaseous fuels to decrease by between 54 per cent and 68 per cent between 2020 and 2040; and even more to 2050. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52024SC0063

[50] https://assets.publishing.service.gov.uk/media/65ae7a62fd784b0010e0c65d/ostend-energy-ministers-declaration-north-sea-as-green-power-plant.pdf

[51] https://www.bundeswirtschaftsministerium.de/Redaktion/DE/Publikationen/Energie/energiewende-effizient-machen.pdf?__blob=publicationFile&v=20

[52] https://www.cleanenergywire.org/news/merz-signals-germany-may-scale-back-plans-renewable-rollout-cut-costs

[53] https://www.windtech-international.com/industry-news/offshore-wind-delays-and-cancellations-reach-300-gw-amid-policy-and-economic-setbacks

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However, it is likely that these targets will not be reached on time. This assumption seems to be confirmed by the recent Renewables 2025 report from the IEA,[54] which expects offshore wind capacity to grow 57 GW in the EU by 2030, 9 GW lower than expected in last year's Renewables 2024. According to the report, the "*reduction reflects an increasingly challenging business case for planned projects and extended project timelines. Rising costs, supply chain constraints and uncertainty around future electricity prices have raised concerns about project viability, impacting over 5 GW of the forecast*".[55] Consequently the share of renewables has been revised down in this paper:

- For 2030, the share of renewables in power generation stands at 62 per cent for both the Base Case scenario and the $6 per MMBTU gas scenario.
- For 2035, the share of renewables rises to 72 per cent in the Base Case scenario. In the $6 MMBTU scenario, the share of renewables reaches only 69 per cent of the mix, reflecting the offshore wind capacity update for 2030 reported in the IEA Renewables 2025 mentioned above. The impact was extended to 2035 and works on the assumption that lower gas prices may further delay projects that have not yet started or secured support. Although the marginal cost of renewables (the wholesale price) is cheaper than for gas plants (even at $6 per MMBTU), the full cost of developing renewables remains high if the cost of subsidies, grid balancing, backup from the capacity market, and the extension of the grid to connect remote wind (especially offshore wind) and solar farms are added.
- Overall electricity demand remains the same as provided by the IEA scenarios (STEPS), therefore the electricity generated by renewables will continue to grow, but the share covered by renewables will not grow as fast as anticipated, with gas power plants essentially filling the gap.

Forecasts predicting the share of renewables to account for 66-70 per cent of the electricity mix in 2030 (IEA scenarios, STEPS and APS) and 76-81 per cent in 2035, may, therefore, be out by a few years.

The Base Case scenario for 2035 uses the following assumptions: TTF gas prices of $8 per MMBTU, a carbon price (in the EU and in the UK) of $90/t, electricity demand 5508 TWh[56] (42 per cent higher than in 2023) with the share covered by coal and gas of 14 per cent and renewables of 72 per cent. In this scenario, gas demand reaches 155 bcm.

Using the same assumptions regarding carbon prices and electricity demand, but with a gas price of $6 per MMBTU, and with coal and gas share at 16 per cent and renewables at 69 per cent, then gas demand could climb to 165-171 bcm. This is an increase of about 10-16 bcm compared to the Base Case scenario, coming from lower renewables use and additional switching from remaining electricity plants using both hard coal and brown coal. The bulk of this additional switching is expected in Germany in the low case scenario and both in Germany and in Turkey in the high case scenario. In Turkey, coal-to-gas switching could be facilitated by the introduction of a carbon price envisaged to be introduced in the late 2020s. There is only limited coal-to-gas switching in countries not affected by a CO_2 price.

An important outcome of this scenario is the significant impact of renewable availability on gas demand: should the share covered by renewables change by only 1 per cent compared to our assumption for 2035, then the additional impact on gas demand could be plus or minus 8-10 bcm compared to our Base Case results.

Industry remains at a disadvantage compared to other regions

The effect of lower gas prices would ripple through various parts of the economy (the opposite of the 2022 price rise) and would favourably impact end-user demand and boost production in energy-intensive

[54] https://www.iea.org/reports/renewables-2025, published in October 2025
[55] IEA, Renewables 2025, Analysis and forecasts to 2030, p. 30, https://www.iea.org/reports/renewables-2025
[56] This is taken from the STEPS scenario in the IEA WEO 2024 for OECD Europe.

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industries across the region and thus increase gas demand. However, after the last five difficult years (since 2019), and based on historical trends, any strong recovery is unlikely, but a rebound is possible.

Even in a $6 environment, the main concern is Europe's competitiveness as it remains at a disadvantage compared to other regions due to higher energy-related input costs (carbon prices for instance) and more stringent environmental regulations. The cost of emitting CO2 through the EU ETS (or UK ETS) is expected to increase as the cap on emissions decreases to support the 2030 emissions targets.[57]

In addition, the phasing out of free allowances to regulated industries in the EU means that more businesses will need to purchase carbon allowances, although from late 2025, a carbon border price mechanism (CBAM) will apply a carbon price to imports of certain goods (iron and steel, cement, fertilizers, aluminum, hydrogen production, electricity will be covered in the first phase) to help prevent carbon leakage and ensure that imported goods face similar carbon costs as those produced within the EU.

In the context of energy transition and moving toward net zero targets, industries will progressively turn toward low carbon sources wherever technically (and economically) possible, driven by regulation, high carbon prices and/or governments' support,[58] which will supersede the attraction of low (unabated) gas prices, although the speed and extent to which this happens will differ between countries.

Reducing gas demand in the building sector: a long and complex process

One sector not yet mentioned is the building sector. Natural gas is the largest single fuel source for heat in buildings in Europe.[59] A number of options to decarbonize are already widely available, such as heat pumps, district heating, or extensive renovations to improve energy efficiency.

Achieving the proposed 2040 targets for emission reductions in the EU relies on a fast and extensive transformation of the building sector and the decarbonization of heat (with a focus on heat pumps and renovations).[60] However, the task is enormous and current implementation efforts are progressing too slowly.

Despite strong growth in recent years, heat pump sales are still falling short of the 3 million a year needed to meet the EU's target to have nearly 60 million heat pumps installed by 2030. Sales slowed in 2024 for the second year running, dropping 22 per cent compared to 2023 with just 2.31 million heat pumps installed.[61] High upfront costs, persistent elevated interest rates, policy uncertainty (and even a downward revision of support in various markets), and inflation are the main reasons behind the fall. Lower gas prices would certainly present another challenge to the process.

In other words, although lower gas prices at $6 are unlikely to trigger additional gas demand in buildings via new connections and additional sales of gas boilers in most countries (especially in the EU), it is probable that low gas prices will maintain the status quo and the role of gas in buildings for longer, at least until the replacement of a broken gas boiler is made impossible with a ban on the installation of new gas boilers, which is already in place in several countries,[62] or until the impacts of the EU ETS2 which sets a carbon price for the building sector (and other smaller installations and commercial activities) and starts in 2027, makes gas too expensive again despite low wholesale prices.[63]

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[57] https://climate.ec.europa.eu/eu-action/carbon-markets/eu-emissions-trading-system-eu-ets/about-eu-ets_en

[58] Like the multi-billion euros German State aid schemes in 2024 and 2025 to help industries decarbonize. https://ec.europa.eu/commission/presscorner/detail/ga/ip_24_1889 and https://ec.europa.eu/commission/presscorner/api/files/document/print/es/ip_25_846/IP_25_846_EN.pdf

[59] For more information, see https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/02/OEF-135.pdf

[60] https://climate.ec.europa.eu/eu-action/climate-strategies-targets/2040-climate-target_en

[61] https://www.ehpa.org/news-and-resources/news/towards-2030-and-beyond-how-to-boost-the-european-heat-pump-market/

[62] A number of European countries are phasing out fossil fuel and gas boilers to improve energy security and achieve climate goals. Countries such as Denmark, Norway, and the Netherlands have already banned new installations, while France, Ireland, and Germany, have set bans for new builds and are phasing out new fossil fuel heating systems in existing buildings as well.

[63] The EU ETS2 will become fully operational in 2027 and cover GHG emissions from the combustion of fuels in buildings and road transport, impacting gas demand by increasing the cost of fossil fuels for heating through a similar 'cap-and-trade' system applied upstream to fuel suppliers. https://climate.ec.europa.eu/eu-action/carbon-markets/ets2-buildings-road-transport-and-additional-sectors_en.

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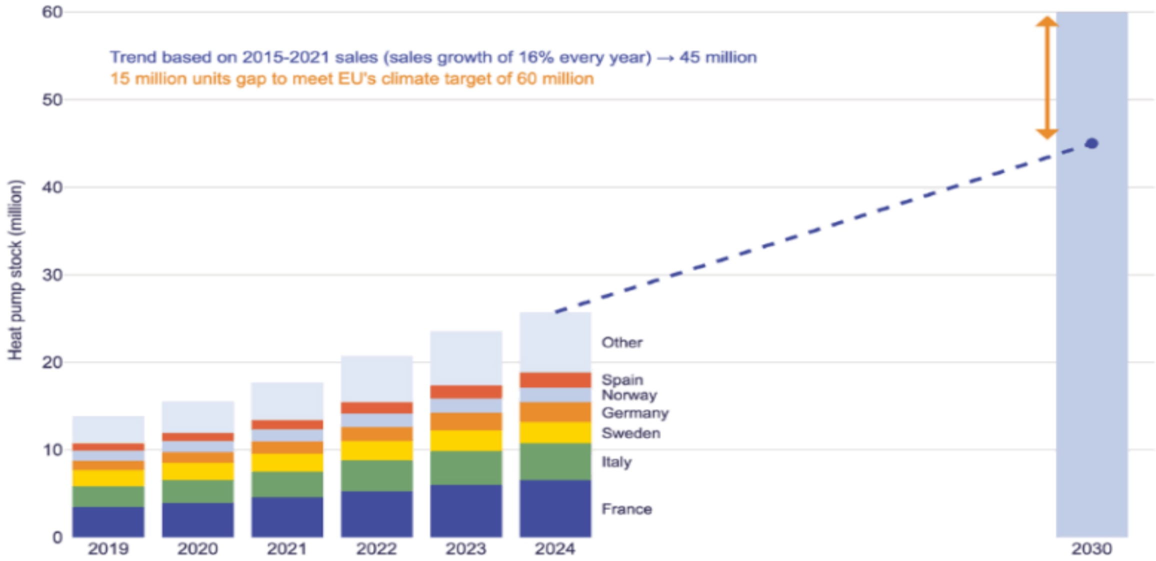
In some countries, such as Turkey, the expansion of the national distribution network[64] will support natural gas demand growth in this sector for the foreseeable future.

Figure 19: Potential heat pump stock growth scenario in Europe (millions)



Note: based on 2015-2021 actuals
Source: https://www.ehpa.org/news-and-resources/news/towards-2030-and-beyond-how-to-boost-the-european-heat-pump-market/

d) Conclusions

Over the next couple of years, gas demand in Europe still faces tremendous challenges, with no clear argument towards a strong recovery. On the contrary, it could even be lower than the base-case scenario presented earlier, as illustrated in Figure 17.

Lower gas prices from 2028 onward would lessen the rate of decline and keep gas in the energy mix during the first half of the 2030s. Gas demand in the three main sectors (power, industrial, and residential) would surpass the Base Case scenario until the end of the 2030s, with most price-driven changes occurring in the power sector with additional coal switching up to 2035 and delayed renewables in the early 2030s. The impact of lower prices in the commercial sector would be limited by the introduction of the EU ETS2 in the EU and the imposition of carbon prices from 2027 onward.

- In the Base Case scenario detailed in Section 2, gas demand in Europe rises to 488 bcm in 2030 and then falls to 467 bcm in 2035.
- Using the same assumptions except for a gas price of $6 per MMBTU from 2028 onward, gas demand reaches 493-497 bcm in 2030 (in other words, there is additional price demand response of 5-9 bcm compared to the Base Case).
- With potential delays in the construction of offshore wind capacity and additional coal-to-gas switching, gas demand reaches 477-483 bcm in 2035 (10-16 bcm higher compared to the Base Case scenario).

Robust electricity demand to support decarbonization in the economy coupled with new gas uses could disrupt these scenarios and drive gas consumption even higher, especially in a $6 per MMBTU world.

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[64] The Turkish grid grew to provide access to 1.1mn new users in 2024. A total of 913 districts had access to gas in early 2025, with plans to add 90 this year and 44 in 2026. https://www.argusmedia.com/en/news-and-insights/latest-market-news/2661926-turkish-gas-demand-hits-all-time-highs

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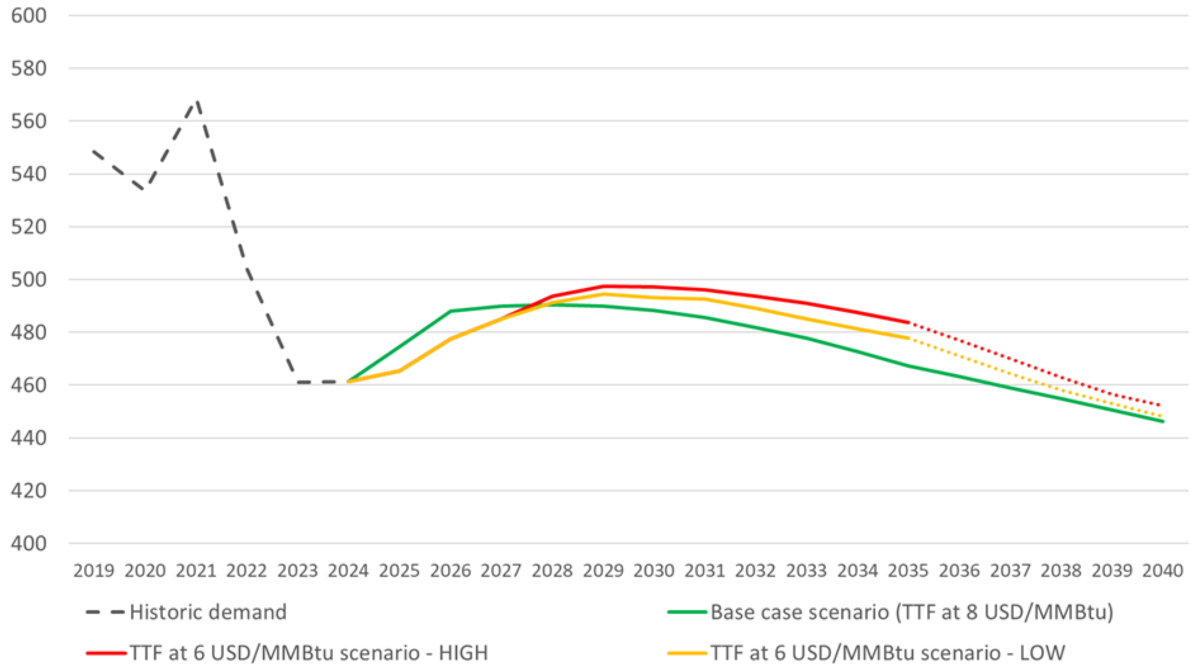
It will be worth paying attention to the construction of data centres, their location, and preferred source of energy. Additional electricity demand (or even direct connection to the gas grid from these centres) could support future gas demand in Europe over the coming ten to fifteen years, although the range of impact, at the time of writing, is still highly uncertain. Another challenge comes from the Turkish gas market (where gas demand has grown by 18 per cent between 2019 and 2024) and it also remains to be seen whether lower gas prices would support higher economic growth and faster switching from coal to gas than anticipated in the 2024 WEO scenarios and in this paper.

Figure 20: Europe natural gas demand, scenarios to 2040 (bcm)



Source: Historical data from International Energy Agency, Base Case scenario from NexantECA World Gas Model. Chart by the author

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4. China

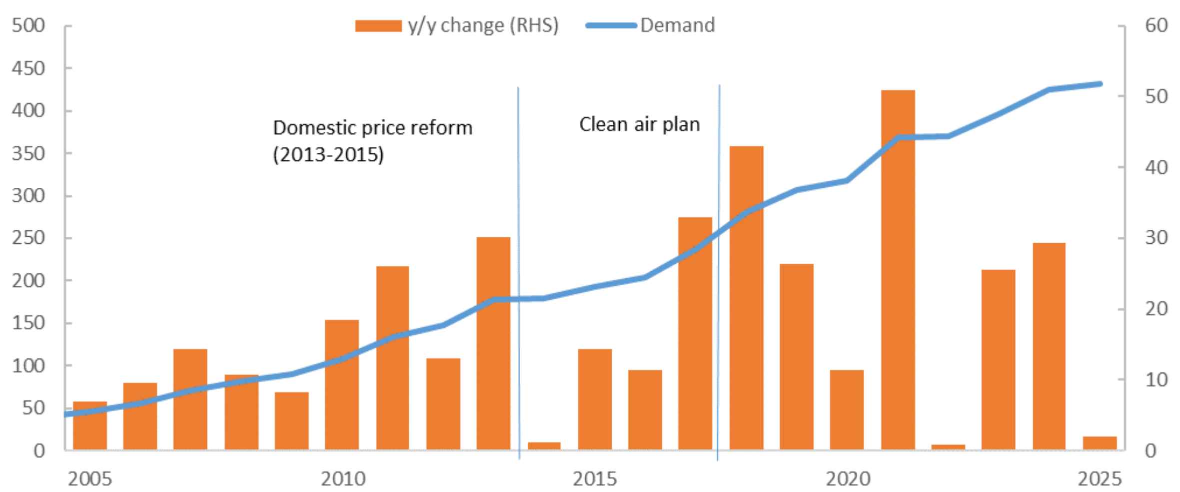
China's gas consumption has grown almost three-fold since 2010, rising from 125 bcm that year to 427 bcm in 2024, with annual average growth rates of 12 per cent. These strong increases mask significant variations in annual increments and volatility in sectoral trends, because demand growth is driven by a combination of policies, macroeconomic changes, and price movements.

This first section will analyse policy attitudes towards gas. The second section will then discuss briefly the evolution of China's domestic pricing mechanism. The third section will cover the various demand sectors and will help assess in which sectors and regions LNG priced at $6 per MMBTU could support demand growth before analysing the obstacles to higher demand.

a) China's gas demand is policy-sensitive

Over the past two decades, even as China's gas consumption has increased ten-fold, annual growth has seen significant swings. Gas demand has seen four large surges: in 2010-2011, due to a combination of strong economic growth resulting from the country's large stimulus after the global financial crisis, policies to improve local air quality by switching from coal to gas, and subsidies favouring gas over other fuels.[65] The second boost occurred in 2018, following the government's coal-switching mandate and then again in 2021, in the post-COVID economic boom. Conversely, gas demand growth slowed in 2015 due to a combination of slowing economic growth and high gas prices relative to coal and oil (following a round of gas price reform). It also slowed in 2019 and then declined in 2022 due to economic weakness and the slowdown in coal-to-gas conversions (Figure 21).

Figure 21: China gas demand (bcm)



Source: GAC, NBS, OIES

While annual demand has been volatile, sectoral demand has also seen swings related to the same factors: policy changes, price differentials, and economic volatility.

[65] Ting Wang, Boqiang Lin, "China's natural gas consumption and subsidies—From a sector perspective", Energy Policy, Volume 65, February 2014, pp. 541-551; Xin Li, "Natural gas in China: a regional analysis", OIES Paper: NG 103, November 2015, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2015/11/NG-103.pdf

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The guiding principles for gas use are laid out in the government's Natural Gas Utilization Policy. The document, issued first in 2007[66] and then updated in 2012[67], 2017[68] and 2024,[69] represents the guiding regulatory framework prioritising sectoral gas demand within the broader context of energy security and environmental objectives. It is promulgated by the National Development and Reform Commission (NDRC), China's highest decision-making body, and this policy has undergone systematic revisions to reflect evolving supply conditions, environmental priorities, and macroeconomic circumstances since its initial introduction.

At the outset, the aim was to allocate relatively scarce gas supplies among competing end-use sectors through a tiered priority system. The policy categorizes gas into 'priority, 'permitted', 'restricted', and 'prohibited' groups with residential users, public facilities, and strategic industrial applications receiving preferential access during supply shortages.

After the initial publication in 2007, the guidance was revised according to changing supply-demand dynamics and policy priorities. The first iteration included four priority sectors, nine allowed, four restricted, and three prohibited categories. Priority status was granted to urban residential gas (cooking, domestic hot water), public service facilities (airports, government buildings, hospitals, schools), natural gas vehicles (especially dual-fuel), and central heating users in urban core areas. Industrial fuels received 'allowed' status for projects replacing oil and LPG in manufacturing sectors. Notably, all new synthetic ammonia and nitrogen fertilizer projects using natural gas were classified as 'restricted', reflecting concerns about large-volume industrial consumption.

The 2012 revision increased the priority categories to twelve, reflecting anticipated supply increases from domestic shale gas and LNG imports. New priority areas also reflected new environmental mandates and included distributed cogeneration projects, air conditioning, coalbed methane power generation, and LNG-fueled transport vehicles (trucks and intercity buses). Additional industrial applications were 'allowed', essentially using natural gas to replace coal, as long as the projects had 'good environmental and economic benefits' while oil-to-gas substitution projects maintained their position.

Following severe winter shortages, the 2017 revision temporarily reduced the priority categories from twelve to four, emphasizing residential use, public services, central heating, and natural gas vehicles, highlighting the need to prioritize residential users, which now also accounted for a larger share of demand, as well as basic services over industrial expansion. Since China's domestic shale development was not expanding as rapidly as expected, the potential for low gas prices - which could fuel new demand sectors - also led the government to limit gas utilization.

The final iteration of the policy, issued in 2024, reflects an emphasis on emissions reductions, a view on hydrogen applications, and an expectation of growing supplies. The number of priority categories has risen back to twelve, including several new designations: rural clean heating projects, oil-gas-electricity-hydrogen integrated energy systems, natural gas-hydrogen blending demonstrations, and 'new business forms of safe and efficient utilization', a vague and broad definition suggesting that where gas is available and cost-competitive, and not in restricted categories, its use is allowed. Transport also receives enhanced status with a specific inclusion of 'trucks and other transport vehicles fueled by natural gas' and marine applications using LNG as their sole fuel. Meanwhile, the number of 'prohibited' categories fell from three to one.

The most significant downgrades have been in chemicals use. New synthetic ammonia projects have been consistently 'restricted' across all versions, while methanol production has seen progressive tightening, moving from 'allowed' status in early policies to 'restricted' classification in 2024. Gas-fired power generation has been subject to regional restrictions. The 2012 and 2017 policies prohibited baseload gas power in 'thirteen large coal bases' and in 2024, this evolved into restrictions covering

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[66] https://www.ndrc.gov.cn/xwdt/xwfb/200709/t20070903_957752.html
[67] https://www.ndrc.gov.cn/xxgk/zcfb/fzggwl/201210/t20121031_960743.html
[68] https://www.ndrc.gov.cn/xxgk/zcfb/tz/201707/t20170704_963000.html
[69] https://www.ndrc.gov.cn/xxgk/zcfb/fzggwl/202406/t20240619_1387036.html

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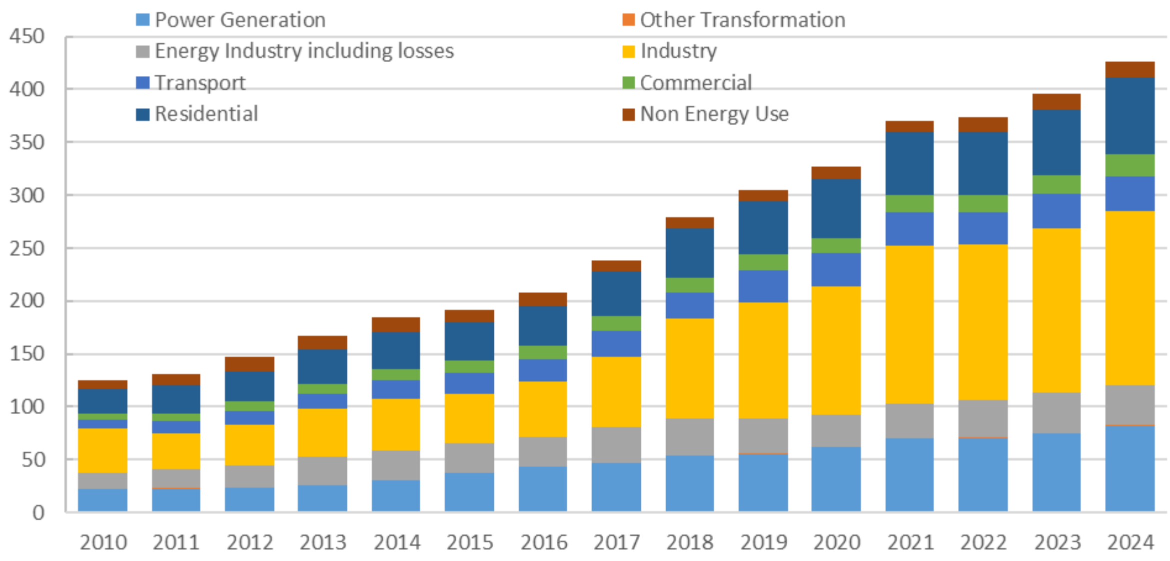
fourteen coal-producing regions, while allowing peaking and cogeneration applications with economic viability requirements. Industrial applications have remained 'allowed' or 'permitted', albeit with tightening requirements.

Finally, the 2024 policy introduces slightly more detailed hydrogen-use categories with 'interruptible natural gas hydrogen production projects' receiving priority status while 'new natural gas hydrogen production projects other than those stated in permitted category' are restricted. These guiding principles reflect the priorities laid out in the Five-Year Plans and have been accompanied by additional regional policy schemes either to encourage or discourage gas use based on local endowment or the availability of imported gas. But within the general policy framework, developments in gas demand have also been driven by broader macroeconomic changes—with the greatest impact on industrial demand and gas in power—and by price dynamics.

Figure 22: China gas demand by sector (bcm)



Source: IEA, OIES

b) The evolution of pricing policies

China's natural gas pricing mechanism has undergone numerous reforms since 2010, evolving from a rigid cost-plus system to a hybrid framework that, while market-oriented in structure, has inadvertently created a price floor of around $10-12 per MMBTU.

The original pricing framework operated on cost-plus principles with field-specific, ex-plant prices based on production costs plus designated profit margins. The simple additive formula meant that city gate prices were designed based on the wellhead price, processing fees, and pipeline transportation tariffs, and while this worked when most of China's gas came from domestic production, it proved inadequate for accommodating expensive imports. The state-owned majors sold imported gas at a loss, given much lower city-gate prices, impacting their profitability and ability to invest in the domestic upstream.[70]

In December 2011, the NDRC issued pilot programs in Guangdong and Guangxi provinces, introducing netback pricing based on international fuel oil prices, that were weighted at 60 per cent of the price and LPG (40 per cent) with a 0.9 discount factor to promote gas consumption over competing fuels.[71] In

[70] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/07/NG-89.pdf; https://eneken.ieej.or.jp/data/5818.pdf
[71] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/07/NG-89.pdf; https://dspace.mit.edu/bitstream/handle/1721.1/102605/MITJPSPGC_Rpt282.pdf?sequence=1&isAllowed=y

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2013, the NDRC expanded the pilot program nationwide. The reform introduced a two-tier pricing system with separate prices for base volumes, set at 2012 consumption levels and incremental supply aimed at gradually raising prices toward international levels[72].

The NDRC implemented progressive price adjustments starting in September 2014 by increasing non-residential prices. The following year, existing demand prices were increased and incremental demand prices were reduced, which saw the first nationwide gas price reduction, with prices falling by approximately 15 per cent. But at the same time, oil prices had declined by 60 per cent and this led to a slowdown in gas demand growth. As a result, in November 2015, the NDRC reduced non-residential city gate prices and moved from a price ceiling to a price benchmark. Under the new system, which still exists today, city gate prices can be negotiated up to 20 per cent above the benchmark with no floor, creating space for market-based pricing within regulated parameters.[73] In June 2018, the NDRC merged residential and non-residential city gate prices, ending decades of cross-subsidization. From June 2019, residential prices were raised to match non-residential levels, albeit with a RMB 0.35/m³ cap, expanding the full negotiability, up to 20 per cent above the benchmark to the residential sector.

Based on this, the current pricing system includes four interconnected pricing levels with increasing market orientation. City-gate benchmark prices are set based on the Shanghai benchmark described above, although changes to the benchmark rate are infrequent and increasingly opaque. The benchmark aims to cover conventional and tight gas wellhead prices and pipeline transmission tariffs. The city gate price, as described above, can fluctuate within 20 per cent of the benchmark. Local distribution companies then add their margin, regulated by the local government, but sell at the government-set retail price which is sector-specific and still subsidised for residential users. In addition to the residential users who have tiered pricing based on levels of consumption, commercial and industrial users pay higher rates, with large users able to negotiate direct supply contracts. Meanwhile, power generators have sector-specific (and at times plant-specific) pricing. Transport prices are increasingly deregulated, reflecting local supply-demand dynamics

Meanwhile, unregulated gas includes LNG imports, offshore, and unconventional gas supplies as well as post-2015 pipeline imports. Prices for this gas is set based on the contract price, regasification costs for LNG, and pipeline transmission costs or trucking costs if pipelines are unavailable. Over time, with more LNG supplies and new pipeline flows, there will be more unregulated gas in the Chinese market. Within these policy and pricing parameters, gas demand has grown over the past two decades. Future growth and the upside for demand in a $6 per MMBTU world are also informed by policy mandates and pricing structures, as well as by changes to the broader macroeconomic environment.

c) Sectoral Demand

Industry

Industry is the biggest consumer of gas in China and is highly susceptible to policy, price, and the macroeconomic environment. Between 2010 and 2024, demand grew four-fold but was extremely volatile. Gas is used both as a fuel and as feedstock for the fertilizer, petrochemical, and refining industries. The biggest industrial consumers are oil and gas extraction, chemical products manufacturing, petroleum, and nuclear fuel processing. From 2016 to 2018, the coal-to-gas switching mandates, which targeted industrial boilers and manufacturing processes, led to historic demand surges. Key sectors driving this growth included steel and non-ferrous metallurgy, chemicals, textiles, ceramics, food processing, and petroleum refining (see Figure 23). These were target industries for the fuel switching campaigns and benefited from subsidies, accelerated infrastructure development (especially pipelines and regas terminals), and tax incentives.

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[72] Stephen O'Sullivan, China's Long March to Gas Price Freedom: Price Reform in the People's Republic. Oxford Institute for Energy Studies, NG 138, https://www.oxfordenergy.org/publications/chinas-long-march-gas-price-freedom-price-reform-peoples-republic/

[73] Stephen O'Sullivan, China's Long March to Gas Price Freedom: Price Reform in the People's Republic. Oxford Institute for Energy Studies, NG 138, https://www.oxfordenergy.org/publications/chinas-long-march-gas-price-freedom-price-reform-peoples-republic/

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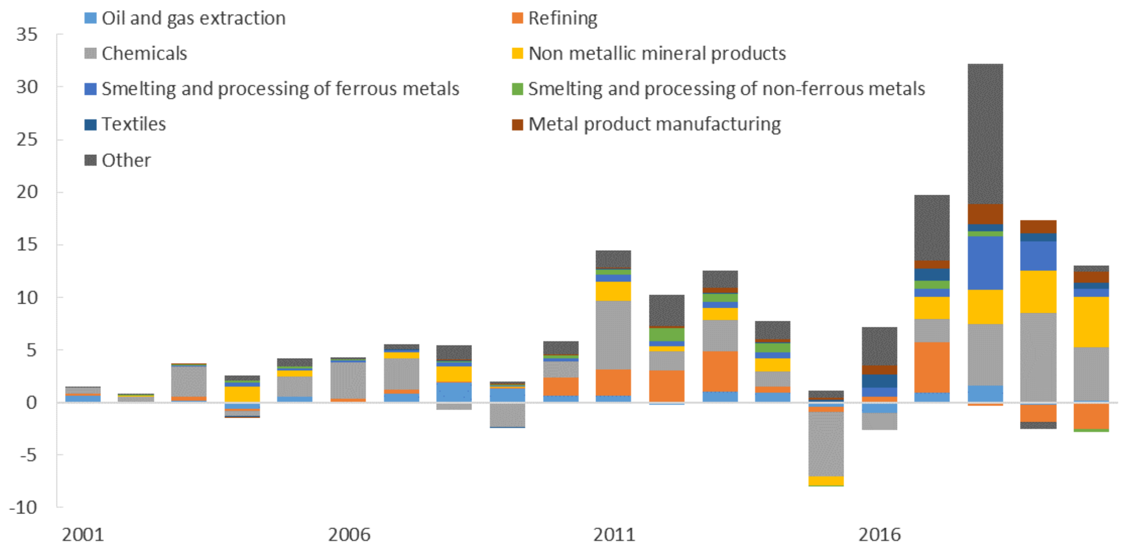
But the rapid demand expansion in 2017-2018 led to supply shortages and sharp price rises. The government then adjusted the policy mandate from coal-to-gas switching to coal-to-electricity. At the same time, the broader economic slowdown due to the US-China trade war impacted energy-intensive sectors like chemicals, while the end of the 13th Five-Year Plan led to targeted shutdowns in a bid to meet environmental targets. Finally, gas in industry also faced competition from coal-based processes.

Figure 23: China gas demand by industry sector (bcm)



Source: NBS, OIES

The COVID-19 pandemic and subsequent supply chain restructuring revived demand in petrochemicals and high-value manufacturing from 2020 onwards, but gas demand growth softened as policy priorities shifted towards carbon emission targets and energy security. Moreover, the 14th Five Year Plan, issued in 2021, included few concrete targets to support gas consumption. Industrial gas demand fell y/y in 2022 due to the lockdowns across China, but recovered in 2023-2024, as economic activity expanded. Moreover, in 2024, lower gas prices enabled accelerated coal-to-gas switching policies in manufacturing sectors. But toward the end of 2024, demand fell as gas prices increased. The weakness in the real estate sector was now compounded by rising overcapacity and weak margins in the 'New Three' industries: solar panels, electric vehicles, and batteries. In 2025, as these trends continued and the US-China trade war limited manufacturing in H1, China's Natural Gas Development Report estimated that industrial demand growth would slow to just over 1 per cent over the previous year.

In the short term, at $6 per MMBTU, a number of industrial gas applications would become competitive with coal-based alternatives especially in the steel industry, chemical manufacturing, textiles, and ceramics as well as food processing. Given that the infrastructure is already in place, lower cost gas could lead to higher utilization rates. That said, the economic downturn, the weakness in the real estate sector, and efforts to rein in overcapacity are limiting the outlook for steel and ceramics demand. Other industries could, however, see an uptick in demand, assuming that coal prices do not fall too.

The complex pricing mechanism and different regional demand trends make it hard to estimate the range of demand response. Chinese academic research on price elasticity trends is somewhat dated and, more importantly, pre-dates some of the more recent price reforms.[74] The existing academic

[74] 李兰兰， 诸克军， 杨娟, 天然气需求价格弹性研究综述, 北京理工大学学报, vol. 14, no. 6. Dec 2012; 成金华.刘 伦, 王小林, 肖建忠, 天然气区域市场需求弹性差异性分析及 价格规制影响研究, China population resources and environment, vol 24, no. 8, 2014

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research assumes high price elasticities which look implausibly high at -3 to -4. At the same time, there is limited academic research or empirical evidence about the percentage of industrial facilities that are capable of switching fuels rapidly.

Assuming more realistic elasticities of -0.7 and -1.2 and using different estimates of how much industrial capacity can switch to gas quickly (ranging from a 15 per cent with a limited switching ability, 35 per cent moderate switching and 60 per cent of industrial facilities that can switch rapidly), the potential ranges from 9 bcm to 60 bcm of incremental gas demand. But given the broader macroeconomic trends, i.e. the slowdown in the real-estate sector and overcapacity in a number of industries, the demand upside is likely to be in the moderate to limited ranges – some 9 to around 35 bcm in 2030, or 5 - 20 per cent of projected industrial demand in the Base Case.

Going forward, should gas prices remain at $6 per MMBTU, there is scope for fuel switching, as discussed above. Utilization rates at existing infrastructure would increase, depending on the broader economic context and the cost of coal. But it remains unclear if the government would adopt more aggressive policies favouring gas. The broader structural shifts in the Chinese economy are leading the country toward a more consumption-led economic model and therefore structural reductions in steel and cement demand. Moreover, current industry plans to reach net zero already include alternative pathways to both coal and gas. China's Cement Association expects solid-waste fuels, biomass, hydrogen, and electricity to replace coal in cement production processes.[75] The steel sector's path to net zero relies on electricity and hydrogen pathways that involve electric arc furnace (EAF)-based secondary steelmaking and hydrogen-based direct reduced ironmaking (DRI).[76] For gas to have a role in this transition, steel-makers would need to invest in gas-based DRI but seem less likely to opt for this route given the rapid development of electrification in China and of alternative routes, without strong government guidance and support to pursue gas-based pathways. That said, a more consumer-oriented economy would see increased demand in the food and beverage sector as well as textile industries, offsetting some of the declines in other industrial applications. On balance though, it seems likely that a concerted policy change would be required to give rise to any real increase over and above the short-run 9 - 35 bcm range noted above. A long-run range of maybe 15 - 40 bcm incremental demand would seem plausible.

Residential

Gas penetration in the residential and commercial sector is low compared with developed countries due to insufficient pipeline connections. Residential and commercial gas use were at 23 bcm and 7 bcm respectively in 2010 but by 2024, they had grown to 73 and 21 bcm respectively. The substantial rise in consumption has been heavily linked to government policies. Initially, increases came from central government plans to raise natural gas penetration rates from 44 per cent of the total urban population in 2015 to 57 per cent in 2020. Since 2010, the urban population with access to gas grew at an average rate of 10 per cent replacing coal, coal gas, and LPG, although since 2020, those rates have dropped to 5 per cent. To facilitate these penetration rates, pipeline infrastructure was expanded dramatically, growing from 175,000 to over 1 million kilometres, connecting 471 million households by 2023. Within this total, however, there are significant regional variations. For instance, penetration rates in Beijing and Shanghai are around 80 per cent, while less developed provinces like Yunnan and Guizhou remain below 25 per cent.

The biggest uptick in residential gas demand was driven by the 'clean heating' campaigns which targeted coal-to-gas conversions in the Beijing-Tianjin-Hebei region and '2+26' cities, resulting in unprecedented residential switching that contributed to overall gas demand growth of 28.5 per cent in 2017, the highest single-year increase on record. That year, even though the 2+26 cities over-achieved their coal replacement targets, the massive coal-to-gas switching exacerbated gas shortages. As the shortages escalated in December 2017, the government released the Winter Clean Heating Policy for 2017-2021, which expanded the target area for fuel substitution beyond the 2+26 cities to the whole of northern China but emphasised that clean heating included electricity if gas supplies were unavailable.

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[75] https://ieefa.org/sites/default/files/2024-06/IEEFA%20Report%20-%20LNG%20is%20not%20displacing%20coal%20in%20China%27s%20power%20mix.pdf
[76] https://www.oxfordenergy.org/publications/decarbonising-chinas-steel-sector-challenges-and-opportunities/

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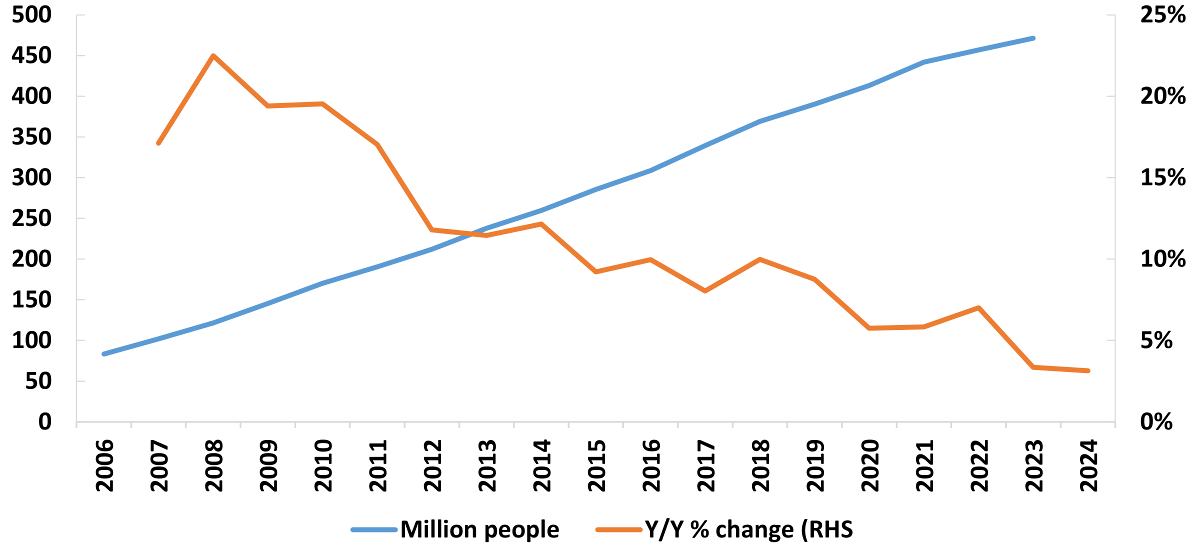
Figure 24: Population with access to gas (million people), y/y change (RHS, per cent)



Source: NBS

Government subsidies were essential to the fuel-switching mandate, including reduced gas connection fees (although these fell to RMB 1,800 in the 2017-2021 Clean Heating Plan, compared to RMB 3,000–4,000 range previously), VAT cuts, and direct financial incentives for conversions. After 2018, higher gas prices relative to alternatives, combined with local government budget pressures, led some regions to prioritise electricity conversions over gas. Post-2020 dual carbon targets shifted focus towards renewables and electrification, though residential demand continued growing through improved living standards and urbanization.

While residential prices are subsidised, they are currently estimated to range between $6-$15 per MMBTU suggesting that the availability of lower cost gas could spark greater demand. But this would be contingent on the government reforming prices and allowing greater cost transmission to end-users. The limited academic research points to lower price elasticity in the residential sector, so that any short-term upside from lower prices would be constrained. Assuming elasticity of -0.7 to -1.2, the demand response could be 15-28 bcm, but these elasticity ranges would require full cost pass through to end users, which is unlikely. The midstream companies may try to take some of the benefit of lower prices in their margins, so, at best, only a partial transmission of the lower costs may be achieved, limiting the potential demand response to 7 - 14 bcm in the short-run.

For residential use going forward, lower gas prices could encourage increased connectivity and higher demand, assuming price reforms, but residential use would still face competitive pressure from heat pumps and other solutions. The country's 14th Five-Year Plan Renewable Heating targets aimed for non-electrical renewable heating sources (geothermal, biofuel district heating, solar) to provide the equivalent of 60 million tonnes of coal by 2025, with renewables preferred for heating in northern China depending on local circumstances. In March 2025, the Chinese government issued its first national-level policy dedicated to advancing heat pumps,[77] marking a significant milestone in clean heating strategy. The plan calls for heat pumps to 'play a major role in promoting energy conservation and reducing carbon emissions' and specifically encourages 'replacing coal-fired boilers with heat pumps' and 'replacing residential fossil gas water heating with heat pumps where conditions are right'. What is more, China is already the world's largest manufacturer of heat pumps globally with the new Action Plan promising to focus China's manufacturing sector on further developing manufacturing capacity and reducing costs.

[77] https://www.gov.cn/zhengce/zhengceku/202504/P020250402477391648460.pdf

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And although the 2024 Natural Gas Utilization Policy maintains ‘rural clean heating projects’ as a priority category, indicating continued policy support for gas-based rural heating solutions, it also notes that these priority projects should have already been included in national planning. At the same time, rural heating electrification, particularly through heat pumps paired with distributed solar PV, is already cost competitive in key provinces like Shandong, Henan, and Jiangsu.[78]

These longer-run pressures towards more heat pumps and electrification represent offsetting pressures to the lower gas price, and while eventually the midstream companies may be forced to pass on the lower gas price, the long-run price response range may only be around 10 - 20 bcm.

Power

Gas use in the power sector has also increased almost fourfold from 2010 to 2024, from 22 bcm to 82 bcm, but the share of gas in China’s electricity stack is extremely small, at around 6 per cent of installed capacity. While power accounts for approximately 18 per cent of total national gas consumption, it remains constrained by the importance of coal and renewables in the power mix and by price competitiveness.

Indeed, policy has provided both opportunities and limitations for gas power development. Environmental regulations, particularly air pollution control measures, initially supported gas expansion as a cleaner alternative to coal. The 13th Five-Year Plan promoted gas power as part of the national strategy to increase the gas share from 6 per cent to 10 per cent of the country’s primary energy mix. The gas shortages following the coal-to-gas switch in 2017 led to policy recalibration, with reduced emphasis on aggressive gas-for-coal switching in power generation. The 14th Five-Year Plan adopted a more cautious approach, prioritizing renewable energy and energy security over rapid gas expansion. As a reflection of this, the government’s latest Natural Gas Utilization Policy limits gas use for baseload electricity in fourteen coal-producing regions.

Despite policy constraints, gas-fired power capacity additions reached close to 20 GW in 2024, bringing total capacity to approximately 153 GW in 2024. Similar levels of capacity additions are expected in 2025. Gas producers in China have been lobbying for an additional 70 GW of new gas capacity by 2030,[79] representing a 50 per cent increase from 2025 levels. The proponents of more gas in power argue that as the country adds over 200 GW of wind and solar capacity every year, gas will be required to manage the intermittency of renewable sources. However, the 14th FYP has mandated coal-plant retrofits so that these plants can be used as a source of flexibility.

Gas in power is concentrated in a handful of provinces.[80] Seasonal patterns remain important, with summer cooling demand driving peak generation requirements. China's air conditioner stock rose from 531 million in 2015 to 862 million in 2023, creating substantial seasonal electricity peaks that favour flexible gas generation. But even with seasonal power needs, gas power utilization remains limited, with capacity factors averaging 2,500 hours/year (just under 30 per cent utilization) versus over 4,000 hours for coal plants (45 per cent utilization). As such, gas represents roughly 4 per cent of the country’s power generation, compared to around 60 per cent for coal.

Industrial activity directly impacts gas power demand. The 2024 economic recovery, with 6.8 per cent power demand growth alongside the country’s 5 per cent GDP expansion, supported increased gas generation for peak-load and flexibility. However, industrial power demand slowed in the second half of 2024 as manufacturing activity suffered from overcapacity in a number of industries and declining profits. In 2025, industrial power demand has, to date, also been weak, limiting demand for gas in power.

With fuel costs accounting for roughly 70 per cent of gas power generation expenses, they have been a determining factor in gas power economics. The wholesale cost of coal, both imported and

[78] https://www.oxfordenergy.org/publications/synergies-between-chinas-whole-county-pv-program-and-rural-heating-electrification/
[79] https://www.bloomberg.com/news/articles/2025-06-10/china-s-gas-sector-lobbies-for-more-power-plants-to-boost-demand
[80] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/12/Insight-80-Natural-gas-in-Chinas-power-sector.pdf

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domestically produced, is estimated at $4-5 per MMBTU, making it extremely competitive with gas.[81] In respect of the levelized cost of renewables, the IEA report[82] suggested that for China, solar, onshore wind, and offshore wind were some 10 per cent below the global average, suggesting a levelized cost of some $90 per MWH for offshore wind. However, in contrast to other parts of the world, especially Europe, China's cost of renewables has continued to fall, and could be up to one third lower by now, making gas-fired power less attractive. The economic viability of Chinese gas power plants depends largely on local government support.[83] Even China's carbon market has minimal impact on power generation economics due to free allowances and generous benchmarks.

LNG priced at $6 per MMBTU could lead to higher gas use but would also depend on the levels of coal prices given the above discussion. While lower cost gas would not lead to coal-fired plants closing or being converted to gas, it could allow gas-fired power plants to run at higher utilization rates, at the margin. Assuming that utilization rates increased to 3,000 hours (35 per cent utilization), gas demand would increase by 15 bcm, a 17 per cent increment on the current fleet generation. Utilization rates on par with coal-fired plants would lead to an uptick of close to 50 bcm but this seems unlikely, and actual volumes would also depend more broadly on electricity demand (in light of the broader macroeconomic situation) and the various competing fuel sources.

Going forward, expectations of persistently lower cost gas could accelerate government efforts to phase out coal in favour of gas, or to allow coal-fired power plants to run at lower utilization rates while gas plants ramped up. But the main policy choices would be made at a local level. Chinese companies are also developing indigenous gas turbine capabilities through China United Gas Turbine Company to reduce dependence on expensive foreign technology, targeting 300 MW F-class turbine completion by 2023 and 400 MW G/H-class by 2030.[84] The availability of domestic turbine capabilities combined with lower cost gas could lead to a slightly larger role for gas in power. At the very high end of the additional capacity range, the industry is pushing for an additional 70GW which would represent an additional 25 per cent or so of gas-fired capacity on top of the anticipated 246 GW in 2035, according to the IEA STEPS. This is already double the 2023 level of capacity. Assuming no change in utilization this could add some 30 bcm to gas demand in power. However, a sharp increase in capacity is also likely to lead to lower utilization rates, maybe limiting the rise in gas demand in power to some 25 bcm in 2035.

Transport

Gas in transport is the smallest consumer of gas in China but demand has also increased fourfold between 2010 and 2024, from 8 bcm to 34 bcm. Policy factors have been significant for gas in transport too: the implementation of China VI emission standards has been the primary policy driver for LNG adoption in heavy-duty transport starting in 2019.[85]

These support mechanisms were also included in the 14th Five-Year Plan (2021-2025) which mandated phasing out diesel trucks for cleaner alternatives and offering substantial subsidies for scrapping old vehicles. The 2025 scrappage program provides subsidies of 10,000–140,000 yuan per truck for upgrading to China VI-compliant LNG or electric models. The Natural Gas Utilization Policy also categorized heavy-duty vehicle transport as a priority sector for LNG fuel, which in turn unlocks financing for LNG trucks in commercial fleets alongside support for LNG refuelling infrastructure. As a result, China's LNG truck fleet has nearly tripled since 2019, reaching approximately 1 million vehicles in 2025.

Despite government support, LNG refuelling infrastructure remains geographically limited. Local authorities' decisions on LNG refuelling network expansion depend on economic viability and affordably priced gas availability, which has meant that to date most of the refuelling infrastructure is in gas-producing regions.

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[81] https://ieefa.org/sites/default/files/2024-06/IEEFA%20Report%20-%20LNG%20is%20not%20displacing%20coal%20in%20China%27s%20power%20mix.pdf
[82] Projected Costs of Generating Electricity, IEA/NEA. 2020
[83] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/12/Insight-80-Natural-gas-in-Chinas-power-sector.pdf
[84] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/12/Insight-80-Natural-gas-in-Chinas-power-sector.pdf
[85] https://theicct.org/wp-content/uploads/2021/06/China_VI_Policy_Update_20180720.pdf

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In addition to policy support, however, the major increase in LNG trucking demand was driven by price differentials with diesel. The surge in LNG truck sales in first half of 2024 (104 per cent year-over-year growth) was driven by falling LNG prices relative to diesel. With greater share of LNG trucking as part of the freight fleet, LNG in transport becomes increasingly sensitive to changes in logistics and manufacturing activity too. However, when LNG prices rose in the second half of 2024, new LNG truck registrations fell. Because of the local nature of LNG trucking and price variations across provinces, in some regions, LNG trucks are facing rising competition from heavy-duty electric vehicle sales, which increased from roughly 3,000 in 2020 to 35,000 in 2023, while electric trucks captured 20 per cent of HDV sales in Q1 2025. Battery electric trucks offer longer ranges in some applications and faster 'refuelling' through battery swapping and fast-charging infrastructure.

For $6 per MMBTU gas to lead to a similar increase in freight demand, as in 2024, diesel prices would need to maintain a wide differential with LNG. Given that LNG demand in freight is concentrated close to gas producing provinces, the LNG would need to be competitive. Gas demand in transport could rise rapidly, as it did in 2024, alongside sales of LNG trucks. Taking 2024 as an example, for just under 180,000 LNG heavy duty trucks added, China is estimated to have added close to 6 bcm of gas demand. The extent of the upside would therefore depend on the differential with LNG and on ongoing supportive government policies for truck trade-ins. Given that gas in transport has now been included in the priority categories in China's Gas Utilization Policy, further fuel switching in transport is possible. This could be of the order of an incremental 5 bcm or so a year, for five years or more, which would almost double the use of gas in transport, until competition from electric heavy vehicles kicks in. The potential long-run increase in demand in transport is therefore some 30 bcm.

d) Policy Constraints

Policies will continue to play a supportive role in China's future gas demand. Just as the 13th Five Year Plan introduced targets for gas demand and supported infrastructure investments, in a low-cost gas world, the Chinese government could include more priority areas in the Gas Utilization Policy and signal to investors that gas has a role to play, especially in the power sector and industrial decarbonization. Local governments could also support gas penetration, but coastal provinces would be most likely to take advantage of lower prices, first and foremost to increase utilization rates of current capacity before investing in new capacity. Lower prices could also spur further price reforms and allow the central government to remove subsidies, especially if the economy continues to slow and local governments continue to seek ways to cut expenses.

At the same time, the government's preoccupation with energy security and the importance of domestic supplies could limit its appetite for lower cost gas. The availability of $6 per MMBTU gas would reduce the competitiveness of domestic production delivered to coastal provinces. And given China's vast manufacturing industries, in renewables and heat pumps, the government may still prefer to focus on home-grown industries that can help accelerate the country's energy transition and its emission reduction targets.

Finally, even if corporate buyers would want to lock in $6 per MMBTU supplies, many buyers have already signed long term LNG SPAs or pipeline supplies. The availability of lower cost spot gas would require them to optimise their portfolios. However, if the buyers are already taking above their TOP levels, then some optimisation should be possible, but without deeper domestic market reforms, high levels of optimisation could be challenging.

e) Conclusions

The short-run and long-run range of price response is shown in Table 2, with the percentage of Chinese demand in 2030 for the short-run and 2035 for the long-run level. Industry exhibits the largest potential response, although that is the largest sector. The response in power is more limited. The potential growth in transport, in percentage terms, is the largest but the progress towards electrification may limit that growth. In overall percentage terms, the short-run range is between 3 per cent and 13 per cent, of 2030 projected demand, and in the long-run the range is between 4.5 per cent and 21 per cent of 2035 demand.

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However, in contrast to other countries and regions, where the marginal molecule of gas is highly likely to be LNG, this is not necessarily the case in China, where the role of domestic production is important. Historically, domestic production has been around 60 per cent of total gas demand, and China, for security of supply reasons, seems intent on maintaining this broad division between imports and domestic production. As a consequence, the most likely range of LNG imports in response to $6 gas is around half of the total potential change in demand. This gives a short-run range of between 8 and 35 bcm and a long-run range of between 12.5 and 57.5 bcm.

Table 2: Short and long run China price response (bcm)

Sector	Short Run		Long Run	
	Low	High	Low	High
Industry	9.0	35.0	15.0	40.0
Residential	7.0	14.0	10.0	20.0
Power	-	15.0	-	25.0
Transport	-	6.0	-	30.0
Total	16.0	70.0	25.0	115.0
China Demand	538.6	538.6	552.9	552.9
% of Demand	3.0%	13.0%	4.5%	20.8%
LNG Imports Impact	8.0	35.0	12.5	57.5

Source: NexantECA World Gas Model, OIES

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5. India

Over the decade to 2023, India's natural gas consumption grew at a compound annual growth rate (CAGR) of about 2.5 per cent, slower than China's 9 per cent but above the global average of 1.7 per cent.[86] However, natural gas in the country has had a stop-start trajectory, marked by spurts of growth followed by plateaus or declines.

In 2024, natural gas accounted for about 6.2 per cent of India's total primary energy consumption; underscoring its relatively minor role in India's energy mix. The IEA projects that India is now at an inflection point, as demand is expected to increase substantially through 2030, driven by a rapid rollout of gas infrastructure, a rebound in domestic output, and an anticipated easing of global gas market conditions.[87]

Natural gas production surged in the mid-2000s to 2010 driven by new offshore developments, particularly in the Krishna-Godavari (KG-D6) basin. Since then, production has stagnated due to maturing fields and limited new commercially viable finds. By 2024, domestic output was ~37–38 bcm, while in comparison India produced nearly fifteen times more coal than natural gas in 2023.[88]

Domestic gas from older onshore fields is priced under the Administered Price Mechanism (APM), linked to 10 per cent of the Indian crude basket and capped at $6.75 per MMBTU since April 2025. Gas from deep and ultra-deepwater fields is priced to market ceilings set against alternative fuels. In 2024, approximately 64 per cent of domestic supply was priced under the APM.[89]

A major share of APM gas is allocated to priority sectors such as cooking gas suppliers and fertilizer manufacturers, forcing power utilities and other industries to rely on higher-cost LNG imports. This gap is unlikely to close in the near term, with domestic output projected to trail demand until at least 2030, effectively doubling LNG import requirements.[90]

India's LNG imports grew from negligible volumes in 2000 to matching domestic production by 2024.The commissioning of Dahej terminal in 2004 was a turning point, anchoring LNG in India's energy mix. As a result, total gas supply in 2024 reached over 70 bcm, highlighting the country's growing reliance on imported gas.

India has traditionally favoured long-term LNG procurement and in 2024 alone, Indian buyers signed a record 10 MTPA of new long-term contracts. It has set a target to raise gas's share of primary energy from 6.2 per cent today to 15 per cent by 2030, equivalent to 182.5 bcm (500 mcm/d). Reaching this goal would require consumption to almost quadruple from current levels, with far-reaching implications for sectoral demand growth and infrastructure investment.

We begin by reviewing historical and current sectoral demand trends to identify where price elasticity is most pronounced. Next, we assess how a $6 per MMBTU environment might influence short-term consumption patterns, drawing on existing forecasts to highlight the factors beyond price that shape fuel-switching potential. In the long term, we assess how structural changes could unfold if $6 gas persists into the mid-2030s, using government ambitions as a benchmark. The analysis suggests that while certain sectors remain structurally constrained, sustained low prices could permanently anchor higher demand in city gas, transport, and industry, pushing India's trajectory closer to, if not beyond, the most optimistic official scenarios by 2040.

a) Energy Demand by Sector

Natural gas consumption in India is concentrated in a few key sectors, with notable shifts over time. According to Petroleum Planning & Analysis Cell (PPAC) data, total consumption stood at 68.8 bcm in

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[86] John Kemp, 'India's Gas Use and Imports Predicted to Surge by 2030', *JKempEnergy.Com*, 19 November 2024.
[87] IEA, *India Gas Market Report* (2025)
[88] IEEFA, *Can LNG Displace Coal Demand in India* (2025).
[89] IEEFA, *Can LNG Displace Coal Demand in India*.
[90] IEA, *India Gas Market Report*.

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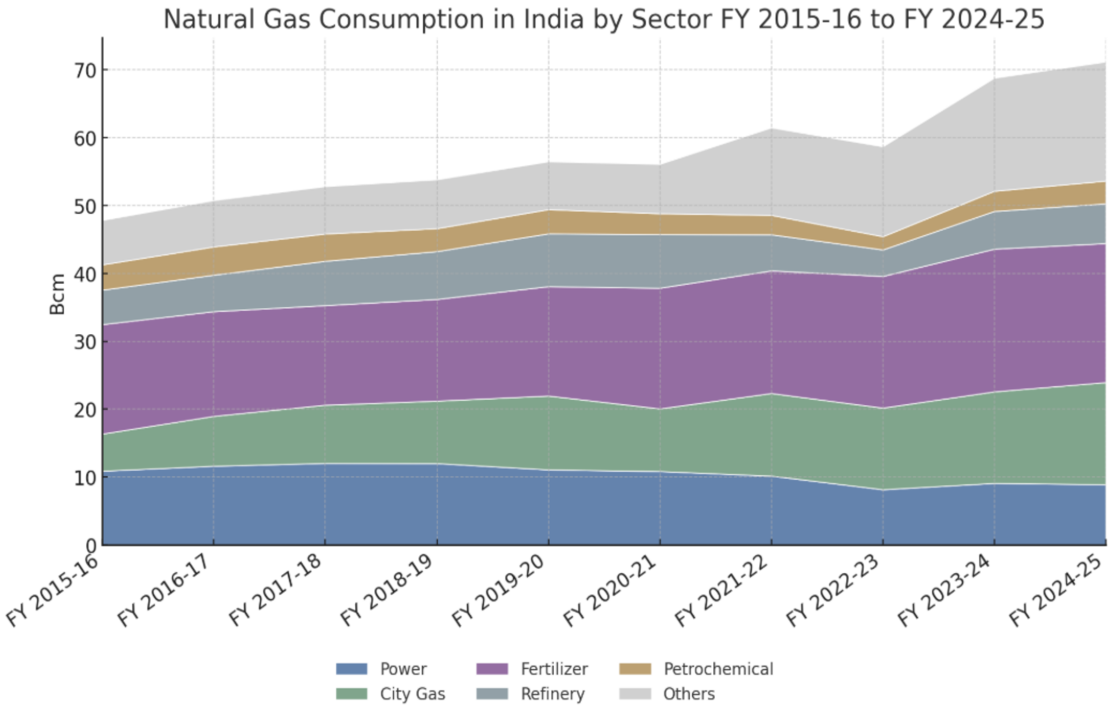
the fiscal year (FY) 2023-24.[91] Fertilizers remained the largest consumer (21.04 bcm), followed by city gas distribution (CGD) (13.49 bcm). The power sector accounted for 9.08 bcm, a much-reduced share compared to the early 2010s as coal and renewables dominate electricity generation. Refineries used 5.55 bcm, while the petrochemical sector consumed 2.98 bcm and various industrial and internal uses made up the remainder.

Figure 25: Natural gas consumption in India by sector



Source: PPAC data updated 10 June 2025, FY 2024-25 data is provisional

Figure 26 shows the different pricing levels in the Indian gas market. LNG import prices are now similar to the deepwater ceiling prices, but above the main APM prices, which are now linked to oil prices, rather than spot prices. Assuming this oil linkage remains then a $6 LNG import price would be competitive with domestic prices.

[91] FY denotes India's fiscal year, which runs from 1 April to 31 March; for example, FY 2023–24 runs from 1 April 2023 to 31 March 2024

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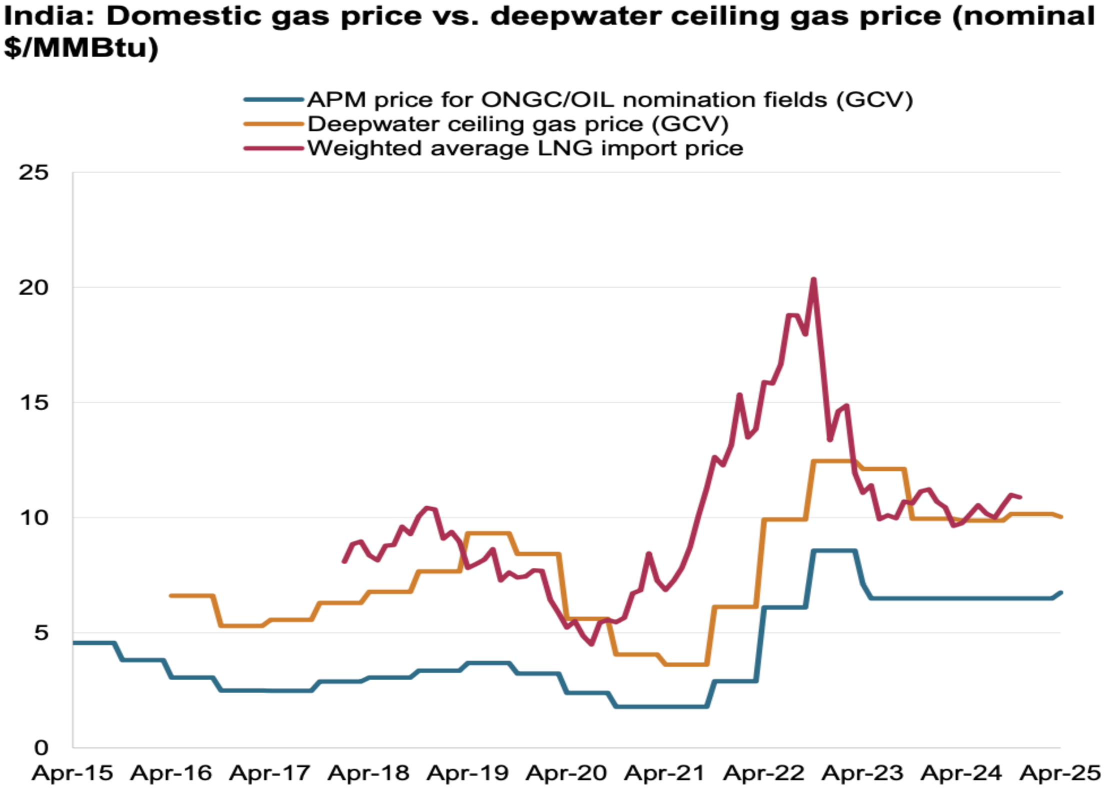
Figure 26: Natural gas pricing in India



Source: S&PGlobal

These historic patterns provide the baseline for the sector-wise assessment that follows, which examines consumption trends and underlying drivers in each segment:

Fertilizer

The fertilizer industry has consistently been the single largest consumer of natural gas in India, accounting for close to one-third of total demand in recent years. In FY 2023–24, the sector consumed 21 bcm, representing about 31 per cent of national demand up from about 16 bcm in FY 2015-16. During FY 2023-2024 the sector posted 8.48 per cent growth year-on-year compared to 19.40 bcm consumption in FY 2022-2023.[92]

Natural gas here is primarily used as feedstock for ammonia and urea production, making the sector highly sensitive to both availability and pricing. Since the early 2010s, policy has ensured priority allocation of lower-cost APM gas to fertilizer units, insulating them from global LNG price swings. This has stabilised domestic output, but the sector's reliance on imported LNG has still risen during supply shortfalls. Based on PPAC data, Regasified LNG (RLNG) use has nearly tripled since 2015/16 from 6.4 bcm to 18 bcm in FY 2023–24 underlining growing import dependence.

Given that urea is sold at fixed prices to farmers, the government absorbs any upstream cost volatility, especially driven by imported LNG. In FY 2022–23, this translated into an enormous subsidy bill of ₹2.3–2.5 lakh crore (US $31 billion). The burden eased slightly in FY 2023–24 to ₹1.91 lakh crore (US $23 billion) yet still remains historically high.[93]

[92] M Azizur Rahman, 'Indian Gas Consumption Hits Highest-Ever Annual Level', *Gas Outlook*, 2025.
[93] PIB, 'Amrit Kaal: Empowering India's Farmers Through Strategic Fertilizer Policy', 2025.

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Policy-driven revival schemes and approvals for new fertilizer plants in recent years have reinforced the structural dependence of the sector on gas. This, combined with volatile spot LNG exposure during high import years, has kept subsidy burdens elevated whenever global prices spiked.

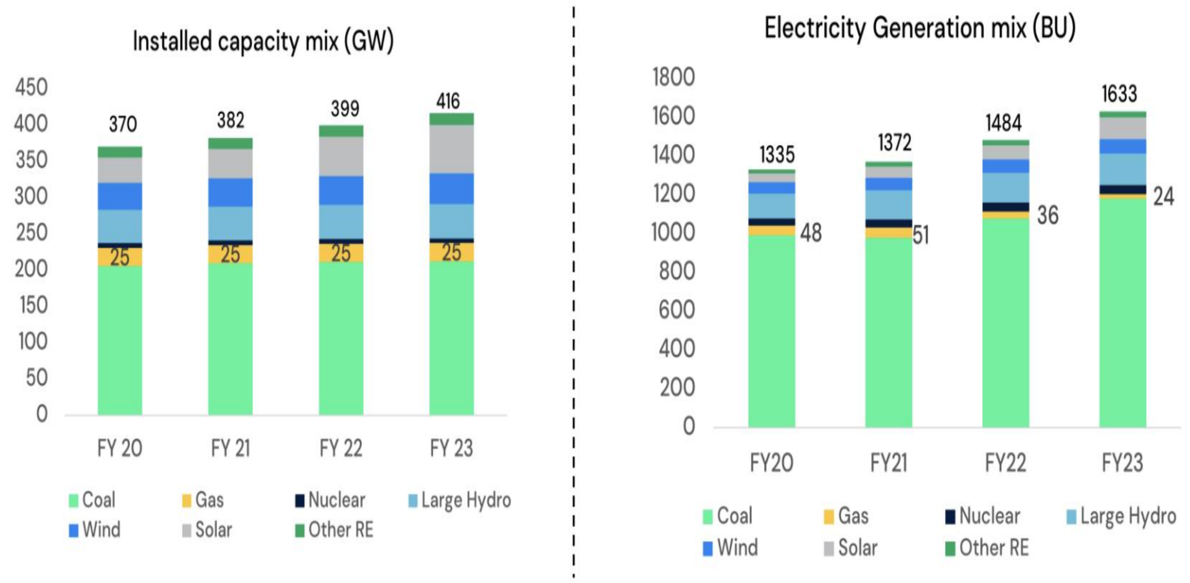
Power

Despite India becoming the world's third-largest producer of electricity in 2019, the power sector's share of natural gas consumption has contracted sharply over the past decade. While the sector accounts for roughly 70 per cent of national coal consumption, gas contributes less than 2 per cent to the generation mix, a steep drop from about 13 per cent in FY 2010.[94]

According to the Central Electricity Authority, gas-fired units made up around 6 per cent of installed capacity in FY 2022–23 but generated less than 3 per cent of electricity.[95] Coal and renewables now dominate baseload generation, with gas-fired plants relegated to peaking or balancing roles, providing rapid ramp-up capacity during demand surges or when renewable output dips.

High LNG prices in 2021–22 severely curtailed gas-based power generation, pushing plant utilization to historically low levels. Generation from gas-based plants has halved since FY 2020, with the average plant load factor (PLF) plunging from 22 per cent in FY 2020 to just 11 per cent in FY 2022–23, even as PLFs for other fuels rose. Out of 62 gas-fired plants (24 GW) assessed, 39 (16 GW) recorded PLFs of below 5 per cent. Within this, 28 units (9.3 GW) are classified as stranded, while 11 (6.7 GW) remain technically operational but highly underutilised.[96] Of this, 5.3 GW has been retired as of April 2025 due to inoperability, leaving only 20.1 GW in service.[97]

Figure 27: India's installed capacity and generation mix



Source: PNGRB

At prevailing tariffs, coal-based power is available below ₹5/kWh ($0.060/kWh) and renewables around ₹2.5/kWh ($0.030/kWh), compared to gas-based costs exceeding ₹6/kWh ($0.071/kWh) even with lower cost APM.[98] This disadvantage is compounded by global fuel price differentials. In FY 2024, average LNG landed prices were nine times higher than domestic coal and more than twice those of imported Indonesian coal.[99]

[94] The Economic Times, 'Explainer: Why LNG Is Struggling to Displace Coal in India's Biggest Sectors', 2025.
[95] Kemp, 'India's Gas Use and Imports Predicted to Surge by 2030'.
[96] PNGRB, *Empowering Oil & Gas Markets through Shared Knowledge* (2025).
[97] The Economic Times, 'India Trims Gas-Based Power Generation Capacity to 20.13 GW as of April', 21 May 2025
[98] PNGRB, *India's Natural Gas Demand Projection for 2030-2040* (2025).
[99] IEEFA, *Can LNG Displace Coal Demand in India*.

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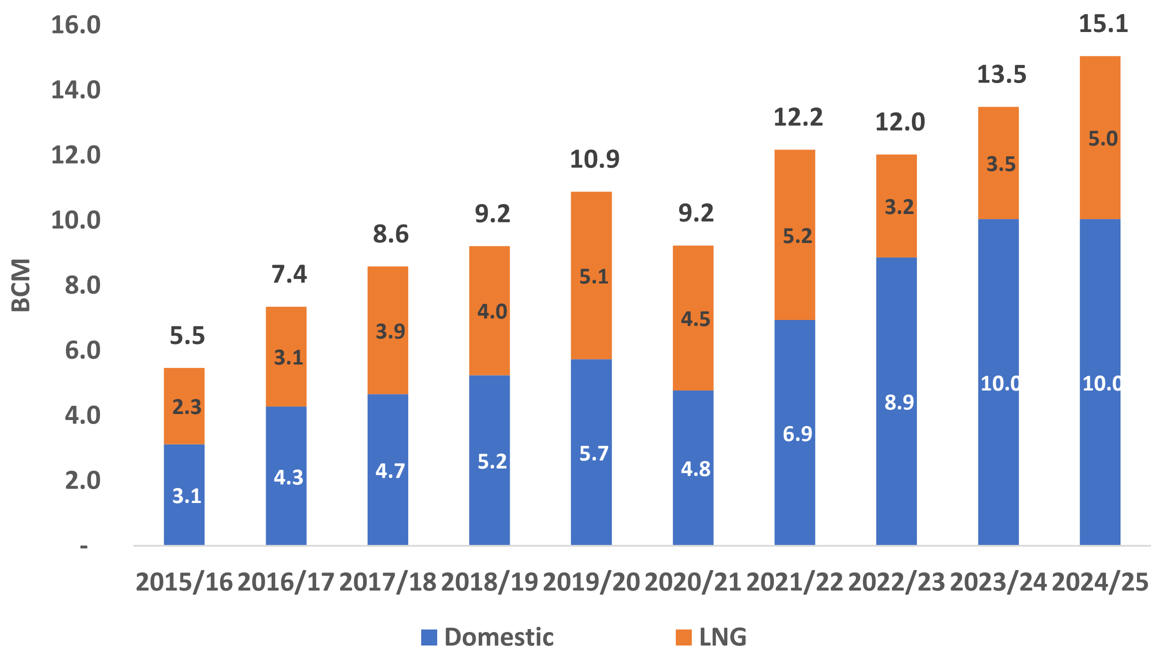
The sector's trajectory underscores a structural decline in gas-based power. Without policy or market interventions, gas-fired plants are likely to remain marginal players, constrained by high costs, fuel volatility, and poor competitiveness relative to coal and renewables.

City Gas Distribution

The City Gas Distribution (CGD) sector has emerged as the second-largest consumer of natural gas, with a share of about 13.49 bcm (19.6 per cent) in FY 2023–24. The segment encompasses piped natural gas (PNG) for domestic and commercial use and compressed natural gas (CNG) for transport.

While most traditional sectors have stagnated, CGD consumption has grown by about 9.6 bcm since FY 2016, driven mainly by a 6.9 bcm increase in domestic gas supply, with growth in RLNG contributing around 2.7 bcm.

Figure 28: India CGD consumption by source



Source: PPAC

Growth has been driven by policy-backed expansion of geographical areas (GAs), with the Petroleum and Natural Gas Regulatory Board (PNGRB) auctions since 2018. Following 12 bidding rounds, the network expanded from 53 to 307 GAs, and coverage jumped from 13.3 per cent to nearly 100 per cent population-wise and from 5.6 per cent to around 100 per cent area-wise by 2025.[100]

Priority allocation of cheaper APM gas has helped sustain PNG and CNG's competitiveness relative to petrol, diesel, and LPG, anchoring both urban CNG adoption and steady growth in household PNG connections. Yet progress remains patchy when set against government targets: by 31 May 2025, household PNG connections stood at about 15.3 million against a 120 million target, while CNG stations numbered 8,154 against the 17,500 required.

In transport, consumption increased from 1.6 bcm in 2010 to just under 4.5 bcm in 2023, but its future is clouded by the rapid penetration of EVs, which rose from a mere 0.3 per cent of new sales in 2016–17 to 7 per cent in 2023–24.[101] Between rising EV adoption and volatile LNG pricing, CNG's foothold in urban transport is far from assured. By contrast, LNG trucking remains at the pilot stage, with only a handful of long-haul trucks and refuelling stations deployed so far, contributing insignificantly to current consumption figures.

[100] PIB, 'Indias Energy Landscape', 22 June 2025.
[101] Bureau of Energy Efficiency, Ministry of Power, *INDIA ENERGY SCENARIO FOR THE YEAR 2023-24* (2024).

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CGD also shows some seasonal demand variability, with spikes in winter due to heating needs in certain regions. Over the medium term, its continued growth hinges on further infrastructure scaling (city gate stations, distribution pipelines) and regulatory pushes for cleaner urban fuels. However, reliance on high-cost LNG remains a cost pressure for non-priority segments, where sharp LNG price movements (even small ones) can erode margins and slow deployment in areas not covered by APM buffer.

Petrochemicals & Refineries

The petrochemicals and refinery sectors have been consistent, though smaller, contributors to India's overall gas demand. From FY 2015–16 to FY 2023–24 their combined consumption fluctuated between 6–9 bcm annually, representing 13–16 per cent of total sectoral demand in most years.

In FY 2023–24, the petrochemical sector consumed about 3 bcm (4 per cent of national demand), using gas primarily as feedstock for producing methanol, ethylene, ammonia derivatives, and other intermediates. Refineries accounted for 5.5 bcm (7 per cent), deploying gas mainly for hydrogen production in hydrocracking and hydrotreating units, as well as for process heat.

Unlike fertilizers or power, demand in these sectors is driven more by industrial output cycles and refinery throughput than by government policy. Petrochemical gas use fell during FY 2020–21 amid pandemic disruptions but has since recovered to near pre-COVID levels. Refinery gas demand has tracked crude processing and export-oriented product output more closely, remaining relatively resilient.

Industry & Other Uses

The wider industrial segment, including glass, ceramics, textiles, metals, and food processing consumed about 10.46 bcm of natural gas in FY 2023–24. Demand in this segment is often concentrated in clusters with pipeline connectivity, such as Gujarat, Maharashtra, and parts of Uttar Pradesh.

Historically, industrial gas use has been the most price-sensitive of all major segments, with rapid demand erosion during spot LNG price spikes. During 2021–2022, many smaller units reverted to cheaper fuels like furnace oil, naphtha, or coal. Limited domestic gas allocation for most industrial users means dependence on spot or contracted RLNG is high, making them more price-exposed, leading to demand volatility.

On the other hand, iron and steel, India's second-largest coal-consuming sector, has also shown a negligible shift toward gas. Since FY 2016, gas demand has grown by only 0.63 bcm, of which 87 per cent was domestic gas. One if the key factors is that despite India being the world's largest direct reduced iron (DRI) producer, about 80 per cent of DRI still comes from coal-fired rotary kilns.[102]

In recent years, gas demand from the 'other' category has been flat, with minor year-on-year fluctuations driven by plant maintenance cycles and seasonal variations in LPG recovery economics.

Regasification

While India's gas consumption shows highlight sectoral imbalances, the country's responsiveness to future LNG price declines will also hinge on the infrastructure that delivers imported LNG into the market. Regasification capacity and utilization, therefore, remain critical supply-side determinants.

Terminal utilization rates fell from 82 per cent in 2018 to just 46 per cent in 2023, before recovering modestly to 56 per cent in 2024. Of the seven operating terminals, only Dahej currently runs above 50 per cent utilization, underscoring the chronic underuse of capacity.[103]

Meeting India's goal of raising the share of gas in the energy mix by 2030 will require regasification capacity to almost double, from 60 MTPA today to 125 MTPA. With 17–24 MTPA of new projects under construction, including Chhara and Dhamra, total capacity is expected to reach 77–84 MTPA. On paper, this appears sufficient to meet projected LNG demand in the early 2030s, but actual adequacy will hinge on utilization rates and the resolution of infrastructure bottlenecks.

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[102] IEEFA, *Can LNG Displace Coal Demand in India*.
[103] Natural Gas Intelligence, 'Indian Natural Gas Demand Growth Challenged By LNG Terminal Rates, Regulatory Agency Says', 2025.

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Conclusion

India's gas demand landscape is shaped by uneven sectoral growth, structural reliance on domestic supply, and chronically underutilized LNG infrastructure. Over the past decade, LNG has lost ground in energy-intensive industries, squeezed out by high spot prices and cheaper alternatives. Yet, the anticipated global supply overhang and $6 per MMBTU pricing could offer a rare opening. If matched by expanded regasification capacity and efficient utilization, India could secure a deeper and more durable LNG role in its energy mix. The distribution of India's demand response will vary across sectors with some capable of switching quickly, others able to lock in medium-term consumption, and many remaining structurally resistant.

b) Demand Projections

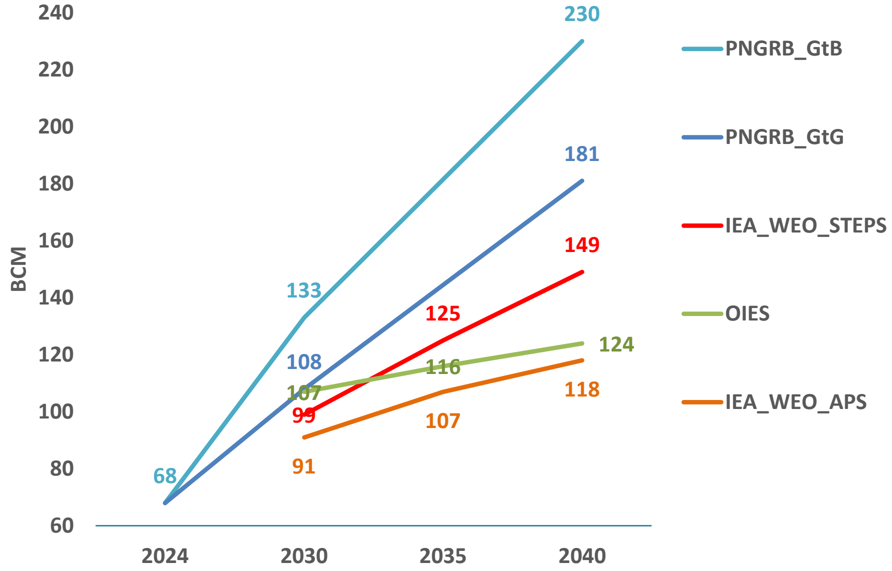
To assess India's potential short-term response to LNG prices easing toward $6 per MMBTU in the early 2030s, we first set the baseline demand trajectory. That structural outlook is the reference against which 'switchable' (price-sensitive) demand can be evaluated across key sectors.

In June 2025, PNGRB released projections for 2030 and 2040, under two scenarios for each decade. The Good-to-Go (GtG) scenario assumes moderate growth based on current trends, existing commitments, and expected developments, while the Good-to-Best (GtB) scenario reflects an accelerated pathway driven by favourable policy implementation, and enhanced investments leading to higher-than-expected growth.

In GtG, demand rises to 108 bcm by 2030 and 181 bcm by 2040; in GtB it reaches 133 bcm by 2030 and 230 bcm by 2040. These imply a near-term CAGR of roughly 8 per cent through 2030, slowing to 5 per cent thereafter.[104] Sectorally, growth is dominated by fertilizer and CGD, with incremental roles for refinery and steel, while LNG transport becomes material only after 2030.

Meanwhile, the IEA in its India Gas Market Report 2025, projects demand could roughly rise by 60 per cent by 2030, reaching around 103 bcm under its baseline scenario, with the possibility of 120 bcm under stronger policy support. Domestic production is expected to expand only modestly by about 8 per cent to 38 bcm by 2030, with the upside contingent on regional infrastructure expansion, economic growth, and further fiscal or gas pricing reforms.[105] On the import side, the IEA indicates LNG receipts could approach 65 bcm by 2030.[106]

Figure 29: India natural gas demand projections



Source: PNGRB, IEA, OIES

[104] PNGRB, *India's Natural Gas Demand Projection for 2030-2040*.
[105] IEA, *India Gas Market Report*.
[106] IEA, *India Gas Market Report*.

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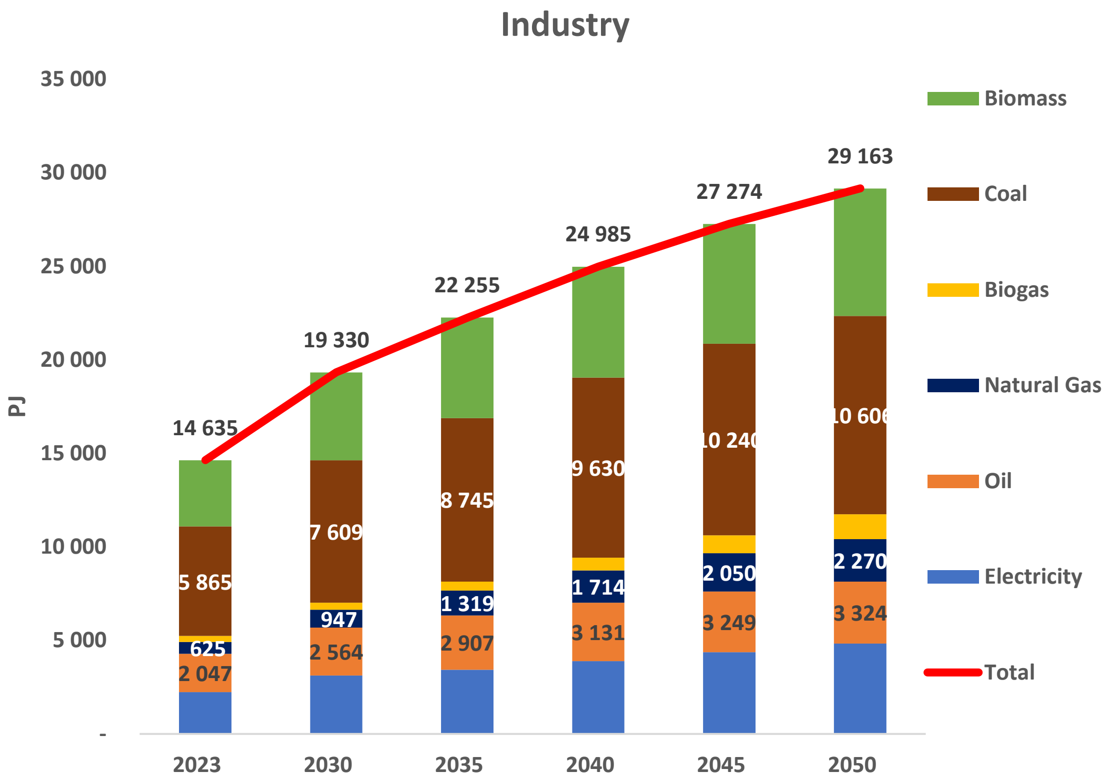
Figure 30: India industry energy demand STEPS



Source: IEA World Energy Outlook 2024

Similarly, the IEA's World Energy Outlook (WEO) projects India's natural gas demand to reach about 99 BCM under the Stated Policies Scenario (STEPS) by 2030, rising further to 149 BCM by 2040. Industry is the main driving force behind the demand growth for gas in India, more than doubling by 2035 and rising another 70 per cent by 2050, as shown in Figure 30. Coal and oil demand also rises, suggesting some scope for gas to gain more market share.

S&P Global expects spot market demand to decline over the next two years as buyers pivot toward medium- and long-term deals, potentially limiting the immediate volume of demand that can adjust to falling prices from 2027 onward.[107] India's contracted LNG volumes, about 22 mmtpa (30 bcm) in 2024, will rise to 27 mmtpa (37 bcm) by 2026 with the new SPAs signed in 2024.[108] While this enhances supply security, it also reduces flexibility, potentially hindering India's ability to capture short-term spot price swings. India has, however, previously pushed to renegotiate long-term LNG contracts, such as with Qatar in 2015, when spot prices fall.

[107] S&P Global, 'Indian LNG Demand Shift to Long-Term Contracts Weighed with Risks', Commodity Insights, 27 February 2025.

[108] Business Standard, *India Shifting towards LNG Term Contracts despite Falling Spot Prices: S&P*, 6 March 2025.

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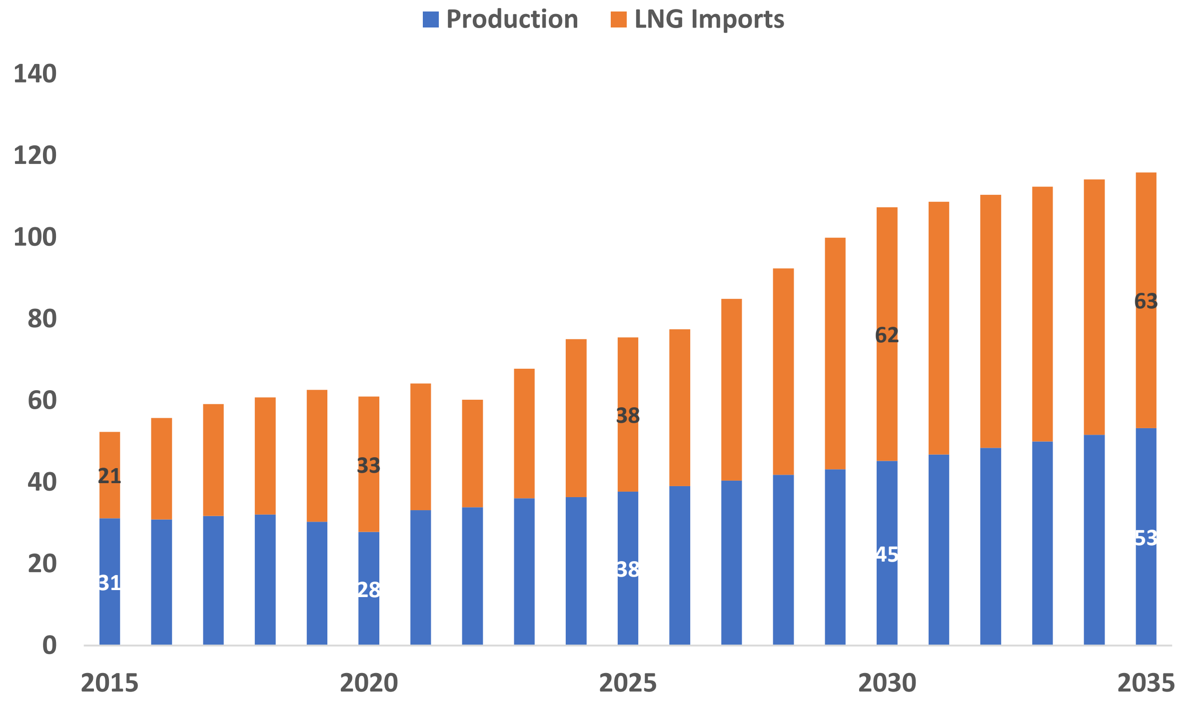
Figure 31: India projected gas consumption by supply source



Source: OIES Estimates

OIES presents a similar trajectory, estimating 107 bcm demand by 2030 and 116 bcm by 2035, with domestic production contributing 45.2 bcm in 2030, implying LNG demand of 62 bcm by 2030 indicating that the post-2024 demand increase is therefore dominated by imported LNG. Rystad Energy is more conservative, projecting 85 bcm by 2030 and 114 bcm by 2040.[109]

Compressed biogas (CBG) is being promoted as an alternative to reduce LNG dependence under the SATAT scheme, which targets 5,000 plants with 15 MTPA (20.4 bcm) capacity.[110] As of August 2025, progress is limited with only 1,144 plants registered, of which 152 operational, and 200 under construction.[111] Even with an optimistic 50 per cent utilization by 2030, output would reach just 0.8 bcm, too small to meaningfully displace LNG, given financing, land, feedstock, and city-gas integration hurdles.[112] [113]

Putting these together, most credible scenarios place 2030 demand at 103–120 bcm, versus PNGRB's 108–133 bcm. With domestic production plateauing at 38–45 bcm, India faces a structural LNG requirement of 60–65 bcm around 2030. The next step is to quantify how much of this demand could respond quickly to a $6 per MMBTU environment. By examining sector-wise elasticity at $6, we can distinguish the structural baseline from incremental, short-term volumes that lower prices could unlock.

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[109] Rystad Energy, 'India's Domestic Gas Demand to Double by 2040, Local Production Falls Short', Rystad Energy, 2024.
[110] PNGRB, *India's Natural Gas Demand Projection for 2030-2040*.
[111] Government of India, 'GOBARdhan Unified Registration Portal', accessed 16 August 2025, https://gobardhan.sbm.gov.in/.
[112] IEA, *India Gas Market Report*.
[113] CBG produced under SATAT is intended for injection and blending into the CGD network rather than for standalone local use. The Compressed Biogas Blending Obligation (CBO), introduced in 2023, mandates phased blending of CBG into CNG (transport) and PNG (domestic), with targets rising gradually toward 5 per cent by 2028–29.

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c) Short-Term Price Response Potential

The potential short-term switchability is summarised in the table below.

Table 3: Short-term switchability analysis

Sector	Short term Switchable Potential & Constraints	Illustrative Historical Sensitivity
Fertilizer	Primarily APM-fed feedstock for urea; little scope for short-term switch unless subsidy or allocation policy changes.	Historically inelastic - subsidies shield producers, with no evidence of demand increasing when LNG prices dropped
Power Generation	Coal-to-gas possible if LNG spot nears landed coal parity but hampered by weak PLFs and poor pipeline reach to coal states.	Gas-fired output briefly doubled in May 2024 when spot LNG narrowed the fuel cost gap.
Industry	Clusters (e.g. Morbi ceramics, glass) can switch from oil/petcoke; constrained by domestic gas allocation and LNG transport costs.	Demand in these clusters spiked during FY 2019–20 when spot LNG declined but retreated sharply above $10/MMBtu.
CGD	Highly sensitive to delivered price; $6 LNG allows pass-through to CNG/PNG users, boosting short-term uptake.	CNG volumes surged in 2020–21 on cheap feedstock, reversed as prices rose in 2022.
Petrochem & Refineries	Base-load users with low upside elasticity; switch downwards to oil/naphtha when LNG high but rarely expand on dips.	Cut consumption by 25 per cent during the FY 2022–23 price spike.
Transport (CNG, LNG trucking)	Some diesel substitution possible; EV growth and low LNG trucking penetration reduce impact.	Small CNG uptick in 2019–20 low-price period; muted in 2023 despite softer prices.
Other Uses (LPG, misc.)	Small industries/households shift between LPG and gas, but largely policy-driven not price-driven	Flat across price cycles; tied to subsidy and LPG recovery economics.

Fertilizer

Between 2019 and 2024, India added two new urea plants and revived four idle units, causing gas demand for fertilizer production to rise quickly. Looking ahead, a new 1.27 MTPA urea plant in Assam is planned but unlikely to be operational before 2030. India also imported 7 Mt of urea in FY 2024, suggesting additional capacity may be needed to meet the self-sufficiency goal, but the small pipeline of new gas-based urea projects and policy efforts to curb chemical fertilizer growth mean gas demand in this sector is unlikely to rise significantly by 2030.[114]

Despite its scale, the fertilizer sector is structurally insulated from LNG price volatility. Nearly all gas supplied to plants is priced under APM, while LNG imports for shortfalls are covered through government subsidies. While some units retain contingency capability to run on naphtha or fuel oil, policy and energy-norms penalise such use; with priority APM gas and subsidies in place, such ‘oil switching’ occurs only during supply disruptions, not as a routine response to spot LNG price moves. Lower global prices therefore reduce the subsidy burden but do not incentivise higher consumption. Urea is sold to farmers at fixed, heavily subsidised prices, leaving demand policy-driven rather than market-driven.

[114] IEEFA, *Can LNG Displace Coal Demand in India*.

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Looking ahead, gas demand growth will be capped both by limited new urea capacity additions and by emerging competition from hydrogen-based feedstocks, with 5.8 MTPA of green ammonia capacity under construction for expected delivery from 2027.[115] However significant execution risks mean that only part of this capacity is likely to materialise within that timeframe.

In summary, the fertilizer industry will remain a policy-driven APM consumer, showing little responsiveness to $6 LNG, even as import reliance deepens. The price signal will register primarily in subsidy savings, not in higher demand.

Power

At $6 per MMBTU spot LNG, delivered gas to Indian power plants would still cost around $8–9 per MMBTU after regasification and taxes. This is well below the $14–20 per MMBTU highs of 2022, yet still implies variable generation costs of ₹5.5–7.0/kWh ($0.066–$0.085/kWh), which are above coal (typically below ₹4/kWh≈$0.048/kWh) and higher than renewables with storage in recent tenders.[116] The IEA estimates that fuel costs would need to fall to $5–5.75 per MMBTU for gas-based power to be competitive on a variable cost basis.[117]

Some stranded or underutilised gas plants can re-enter dispatch during seasonal coal shortages, monsoon disruptions, or grid-balancing windows. In June 2024, for instance, mandated dispatch lifted fleetwide utilization to nearly 25 per cent, only for it to fall back below 10 per cent in winter, illustrating how such rebounds remain short-lived.[118] Without capacity payments or a dedicated peaking market, most plants would still lack dispatch priority and therefore see limited operating hours.

Looking ahead, no new large-scale gas-fired capacity is planned through to at least 2032 due to stranded asset risks.[119] Policy and investment momentum is also firmly behind renewables, storage, and flexible coal operations. Renewables, including large hydro, now account for 234 GW, or roughly half of installed capacity, underlining the direction of system planning. [120]

Thus, the most likely outcome of $6 per MMBTU spot is short-lived demand spikes during seasonal coal shortages, monsoon-related supply disruptions, or grid-balancing needs unless policy or market design explicitly shifts to favour it. OIES projects total gas use for power generation, including auto producers, in the range of 31–38 bcm by 2030–35.

If we add seasonal or peak-driven upside of 1–3 bcm in strong-demand years, it would still remain bounded within 32–40 bcm, close to OIES projections (including auto producers). At $6 LNG, the market reaction would therefore be elastic but contained, producing seasonal swings rather than a structural shift.

City Gas Distribution

PNGRB identifies CGD as the single largest driver of natural gas demand growth in India through 2030 and 2040, contributing ~29 per cent of total demand by 2030 and nearly 44 per cent by 2040. From a 2024 baseline of 13.5 bcm, CGD demand is projected to reach 31.8 bcm under the GtG case and 46 bcm under the GtB case by 2030. Nearly half of India's incremental gas growth this decade thus hinges on CGD.

This step-up reflects three reinforcing drivers: the rapid expansion of authorised geographical areas (300+ GAs covering nearly all population/areas), continuing roll-out of city-gate stations and distribution pipelines, and a policy preference that allocates priority domestic APM gas to CNG (transport) and PNG-domestic, keeping retail prices competitive versus petrol/diesel/LPG and underpinning demand.

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[115] IEEFA, *Global LNG Outlook 2024-2028* (2024).
[116] Andy Colthorpe, 'SECI Tender a "Game Changer" for Low-Cost Renewables and Energy Storage in India', *Energy-Storage.News*, 2024.
[117] IEEFA, *Can LNG Displace Coal Demand in India*.
[118] IEEFA, *Can LNG Displace Coal Demand in India*.
[119] IEEFA, *Can LNG Displace Coal Demand in India*.
[120] PIB, 'India's Renewable Rise: Non-Fossil Sources Now Power Half the Nation's Grid', 14 July 2025.

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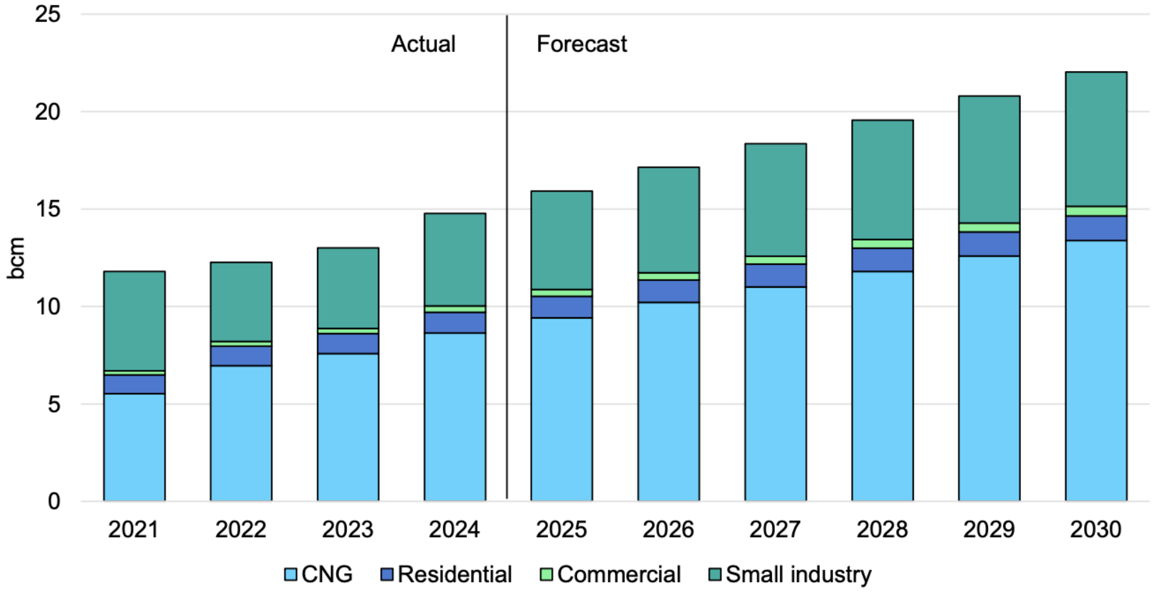
Figure 32: India natural gas demand in the city gas distribution sector projection



Source: IEA

Yet demand growth has lagged behind the infrastructure rollout. Between FY 2020 and FY 2024, CNG stations grew by 250 per cent and PNG household connections by 108 per cent, but total CGD gas use rose by only 24 per cent.[121] This reflects underutilization in late-awarded GAs where pipelines remain under development. As of May 2025, only 12.5 per cent of the government's 120 million PNG connection target for 2030 had been achieved.

Government allocates cheaper APM gas to CNG and PNG (domestic), keeping retail prices attractive relative to petrol, diesel, and LPG. However, when domestic output dipped between May 2023 and November 2024, allocations to CGD were cut, driving up retail prices. PNGRB estimates suggest that delivered LNG prices below $9.5 per MMBTU can help offset the impact of such allocation cuts, restoring competitiveness for CNG in particular.[122]

However, infrastructure remains a bottleneck. Operational gas pipelines expanded from 15,340 km in 2014 to 25,124 km in 2025, with a 2030 target of 35,000 km.[123] Investors are backing this expansion alongside expectations of lower LNG prices. For instance, Japan's Osaka Gas plans to grow its Indian city gas sales nearly tenfold to 3.5 bcm by 2030 while doubling CNG stations with Indian partner AG&P Pratham.[124]

Hence at $6 per MMBTU, RLNG backfilling APM shortfalls would make PNG more competitive against subsidised LPG and support deeper uptake in commercial/industrial segments. From a 4.5 bcm 2023 base, a short-term rise of 0.5–1.0 bcm is plausible, provided vehicle additions and refuelling grow as planned, though EV adoption will cap the upside.

At $6 per MMBTU, the most immediate impact would be greater utilization of existing PNG networks (especially small commercial and light industrial users) and stronger uptake of CNG where low-cost RLNG can offset APM allocation cuts. Thus, cheap gas in the short run could accelerate CGD growth, bridging some of the gap toward PNGRB's high-case trajectory by 2030

[121] IEEFA, *Can LNG Displace Coal Demand in India*.
[122] PNGRB, *India's Natural Gas Demand Projection for 2030-2040*.
[123] PIB, 'Indias Energy Landscape'.
[124] The Japan Times, 'Osaka Gas Plans to Boost Sales of City Gas in India Tenfold'.

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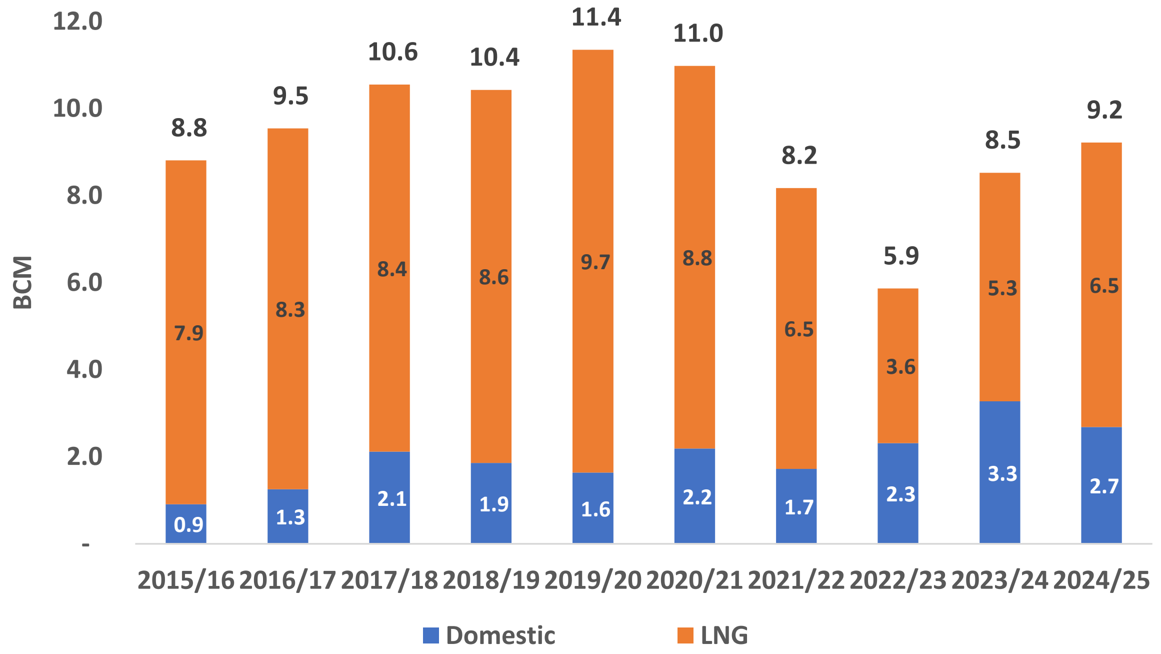
In this setting, total CGD demand could plausibly move toward the upper end of PNGRB's 2030 baseline projections, adding 2–4 bcm in the short term compared with today. This upside would be concentrated in CNG vehicles and commercial PNG customers most exposed to LNG price swings, while household PNG remains slower to ramp up due to connection rollout.

Petrochemicals & Refineries

Petrochemicals and refineries have shown sharp downside sensitivity to LNG price spikes. During the 2021–23 price spikes, several facilities cut back output or switched to alternate fuels, while refineries have prioritised gas for hydrogen and essential processing.

Between FY 2017 and FY 2024, petrochemical gas demand fell from 4.2 bcm to 2.7 bcm, while LNG demand dropped even more sharply.[125] IEEFA notes that the retreat from imported LNG predated the 2022–23 volatility, underscoring that feedstock choices (naphtha vs gas) hinge on global spreads, not just price spikes. Similarly, refiners switched to cheaper fuel oil or petroleum byproducts as LNG consumption plummeted from 6.7 bcm in FY 2020 to 2.4 bcm in FY 2023, even as domestic gas use rose steadily.[126]

Figure 33: India natural gas consumption petrochemicals and refineries



Source: PPAC Data

Looking ahead, expansions to 307 MMTPA of refining capacity and integrated refinery–petrochemical complexes could provide some feedstock optionality, though new gas demand will be uneven and slow to materialise tied to project timelines and gas grid extensions.[127] The main potential anchor for gas demand in refineries lies in hydrogen co-production, where natural gas may serve as a bridging feedstock depending on policy incentives and green H_2 rollout.

If spot LNG settles near \$6 per MMBTU, the cost curve improves materially versus 2022–24, lowering variable costs for hydrogen and fired heaters. The short-term demand response is moderately elastic: petrochemicals could see around 0.3 - 0.8 bcm of uplift as cheaper RLNG draws back some furnaces and methanol units that had switched to LPG or fuel oil, though India's cracker slate remains naphtha-based until at least 2035. Refineries could add 0.5 to 1.5 bcm as sites shift part of the H_2/fuel balance

[125] IEEFA, *Can LNG Displace Coal Demand in India*.
[126] IEEFA, *Can LNG Displace Coal Demand in India*.
[127] PIB, 'India's Petroleum Industry', 2025.

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toward gas, particularly at coastal complexes with RLNG tie-ins. Still, capacity constraints, competing off-gases, and green H_2 obligations, whose large-scale materialisation remains uncertain, could limit the upside.

A $6 scenario could lift combined petrochemical and refinery demand by 0.8 to 2 bcm above the recent 8.5 bcm baseline in strong-run years. This uplift is meaningful but not transformative; its magnitude is bounded by infrastructure and contract constraints, as well as by policy signals that gradually steer hydrogen away from fossil routes over the 2030s.

Industry & Other Uses

If spot LNG is near $6 per MMBTU in the early 2030s, industry could see the quickest rebound within existing infrastructure.

Lower prices materially improve PNG/RLNG competitiveness for ceramics, glass, textiles, and small manufacturing clusters in Gujarat, Maharashtra, and western UP, reversing part of the 2021–22 shift to propane, LPG, and fuel oil. From a FY 2023–24 baseline of 10.5 Bcm, a short-term uplift of 1.0 to 2.0 is plausible in strong years. Yet margins remain thin: gas accounts for 30–40 per cent of production costs, so any drift back toward $8–9 per MMBTU ($10–11 delivered) would quickly erode the upper boundary. Much of this demand is likely to appear as opportunistic spot purchases rather than durable reconnection to gas.

In iron and steel, near-term elasticity is minimal. Around 80 per cent of output comes from coal-based kilns and blast furnaces, where legacy technology and contractual structures limit switching. Even at $6 LNG, the practical short-term swing is 0 to +0.2 bcm, directionally positive but immaterial at the national level.

The ‘other’ bucket has been broadly flat and is driven more by plant cycles and seasonal recovery economics than by price alone. Even with cheaper LNG, the incremental swing is limited to ~0 to +0.2 bcm.

Taken together, a $6 per MMBTU price window could add 1.8 - 3 bcm of short-term industrial demand relative to FY 2023–24. It also depends on pass-through effects (taxes/levies), RLNG availability at city gates, and timely last-mile build-out. Any move back to $8–9 per MMBTU would quickly cap the range. Ultimately, a $6 LNG window is best seen as a temporary breather, with clustered gains in ceramics, glass, and textiles, but structurally coal-anchored steel limits any wider uptake. The result is an uneven, opportunistic rebound that remains vulnerable to renewed price firming.

India’s baseline demand trajectory, as per PNGRB, places national gas demand at ~108 bcm by 2030 under GtG and ~133 bcm under GtB, rising to 181–230 bcm by 2040; the IEA projects ~103–120 bcm by 2030, while OIES puts demand at ~107 bcm in 2030 (and ~116 bcm by 2035). Sectoral assessments suggest that if spot LNG prices soften to $6 per MMBTU in the early 2030s, an incremental short-term uplift of ~+5 to +11 bcm could materialize above whichever 2030 baseline materializes. This situates India firmly within PNGRB’s GtG/GtB corridor, skewing toward the upper end if the price window endures.

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Table 4: India short-term switchable potential

Sector	Incremental Demand Potential
Fertilizer	Structurally insulated; ~0 bcm
Power	+0–2 bcm (short bursts, weather/grid driven; fades outside peaks)
CGD (CNG + PNG-Commercial)	+2–4 bcm (if pass-through holds)
Petrochemicals & Refineries	+0.8–2.0 bcm (feedstock/process substitution)
Industry & Other	+1.8–3.0 bcm (ceramics, glass, textiles; steel stays coal-anchored)
Total	+4.6–11.0 bcm (roughly 5-10% above GtG baseline)

The elasticity, however, depends heavily on cost pass-through after regas, taxes, and levies, alongside last-mile build-out. Any drift back toward $8–9 per MMBTU would erode much of the swing, especially in CGD and industry. In effect, a short-term $6 per MMBTU spot price should be seen as a supportive breather that could lift India's 2030 demand by roughly 5-10 per cent above GtG baseline, but it does not fundamentally change the longer-term trajectory. The upside remains incremental, not transformational.

d) Long-Term Price Response Potential

If Asian spot LNG prices were to stabilize around $6 per MMBTU through the 2030s, the prolonged affordability could trigger structural shifts across multiple sectors, resulting in a more durable uptick in natural gas demand. This section examines how sustained low prices could unlock additional demand across key sectors by 2035–2040 and assesses whether such growth could even outpace the PNGRB's most optimistic GtB scenario projections.

Fertilizer

India's fertilizer industry already relies heavily on natural gas as feedstock and has been the main driver of LNG import growth in recent years. Sustained low prices have two key effects here: (1) They ease the government's subsidy burden, potentially encouraging the government to allow higher production or build new plants, and (2) they ensure that even inefficient or older plants remain viable on gas rather than switching to naphtha or shutting down.

PNGRB projects fertilizer-sector gas consumption to rise only modestly from about 21 bcm in 2024 to 25 bcm in 2030 (GtB), reflecting limited new capacity, but in a low-price environment actual demand could edge higher if upcoming projects such as the Talcher fertilizer plant operate continuously or if additional capacity is sanctioned to reduce import dependence. Under such conditions, the sector could stabilize at 27–28 bcm by the late 2030s, consistent with PNGRB GtB if planned units achieve high utilization or new plants are approved.

At $6 per MMBTU, gas delivers clear financial gains by lowering feedstock costs for producers and subsidies for government, while also reinforcing the sector's structural dependence on gas. Although some older units retain technical capability to switch to naphtha or fuel oil, such 'oil switching' is already rare and discouraged by policy, so low prices do not generate new demand but rather secure existing use. In the longer term, gas may face competition from hydrogen-based alternatives, but fossil-gas-based urea and ammonia retain a strong cost advantage, meaning any displacement of demand is likely to remain marginal through the 2030s.

Essentially, cheap gas secures full utilization of the fertilizer sector's gas allocation on a more permanent basis. But since fertilizer demand itself grows slowly, any long-term volumetric upside is likely confined to the spread between PNGRB's GtG and GtB cases (roughly 1–3 bcm by 2040), rather than exceeding the high-case scenario.

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Table 5: India sectoral natural gas demand projections – OIES (BCM)

Sector (OIES)	2030	2035	2040
Power Generation	30.74	38.30	46.08
Energy Industry (incl. losses)	4.45	4.45	4.45
Industry	34.39	34.39	34.17
Transport	6.29	7.11	7.48
Commercial	3.88	3.88	3.88
Residential	2.45	2.59	2.59
Non-Energy Use	25.18	25.18	25.18
Total	**107.39**	**115.90**	**123.82**

Gas demand projections – PNGRB (BCM)

Sector (PNGRB)	2024	2030 (GtG)	2030 (GtB)	2040 (GtG)	2040 (GtB)
CGD	13.47	31.79	46.03	78.99	98.84
Power	9.20	13.03	14.60	15.88	19.27
Refinery	8.03	15.84	18.58	19.13	21.10
Fertilizer	21.17	23.83	25.29	26.61	29.38
Steel	1.17	1.57	1.86	2.34	3.39
LNG Transport	0.00	1.42	2.41	9.60	23.98
Others (Tea plantation, Industries, LPG Shrinkage)	15.33	20.91	24.31	28.07	34.05
Total	68.26	**108.41**	**133.23**	**180.68**	**229.95**

Source: PNGRB and OIES

Power

With LNG stabilising at around $6 per MMBTU, gas-based electricity would become structurally more competitive than at any time in the past decade. At this price, delivered fuel costs of ~$9–10 per MMBTU would allow India's many underutilised gas plants to run at materially higher capacity, potentially doubling or tripling utilization relative to today's single-digit levels.

Gas is unlikely to replace coal in baseload generation, but its role as a flexible complement strengthens under a $6 regime. Most of the upside lies in reviving India's ~25 GW of stranded gas-fired capacity rather than new builds, though sustained low prices combined with policy support (e.g. GST rationalisation, capacity payments, carbon pricing) could make combined-cycle plants attractive replacements for ageing coal units in the 2030s.

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PNGRB's GtB case already projects power-sector gas demand rising from 14.6 bcm in 2030 to 19.3 bcm in 2040. With prolonged low LNG prices, actual demand could push this total to 22–23 bcm by 2040, reflecting higher utilization rates and expanded peaking roles. In a policy-supported upside, demand could stretch further to 25–27 bcm. This would allow gas to recover ~5 per cent of generation in the central case and as much as 8–10 per cent in the upside case, compared with ~2 per cent today.

Cheap gas would likely not derail India's clean-energy trajectory, as utility-scale solar PV and onshore wind remain the lowest-cost sources of bulk energy on an energy-only (non-firmed) basis and continue to receive policy priority. Gas may reduce the near-term need for storage at the margin by providing cheaper balancing power, while also enabling higher renewable penetration by backing up periods of low solar and wind output.

On balance, a prolonged $6 per MMBTU environment would anchor a larger, more stable role for gas in India's power system, smoothing the integration of renewables. This dynamic is reflected in PNGRB's outlook where even in the high-gas scenario, renewables still expand significantly while gas grows moderately.

City Gas Distribution

CGD is poised to be the single largest beneficiary of sustained low LNG prices. With a $6 per MMBTU, retail CNG and PNG remain strongly competitive against gasoline, diesel, and LPG.

PNGRB projects CGD consumption rising to 32 bcm by 2030 (GtG) and 46 bcm (GtB), and further to 79 bcm (GtG) and 99 bcm (GtB) by 2040. These optimistic figures hinge on network build-out and supportive policy, assumptions that become more credible if gas remains affordable.

Sustained low prices would encourage high utilization of PNG connections, keeping PNG cheaper than subsidised LPG for households and competitive for small commercial and light industrial users. Low prices therefore help lock in high utilization of new networks and avoid the under-performance seen in 2022–23 when expensive LNG blunted CGD uptake.

They also stabilise CNG economics, encouraging wider adoption in cars, taxis, and buses. Execution risks remain, such as uneven rollout of late-awarded GAs, tax/levy pass-through, and rising EV penetration but a $6 path strengthens the case for demand to land in the upper half of PNGRB's 2040 range (~90–100 bcm).

For freight, PNGRB foresees LNG trucking demand at 1.4–2.4 bcm by 2030 and up to GtB 24 bcm by 2040, implying 200,000–500,000 trucks. At $6 per MMBTU, the economics improve sharply, but station build-out, OEM supply, and fleet turnover remain critical. A prudent outlook is ~2 bcm by 2030 and with an upside to ~10 bcm (GtG) by 2040 if execution is strong.

Altogether, sustained low LNG prices would anchor CGD and LNG trucking as the dominant swing factor in India's gas demand. Unlike industry, where demand rebounds opportunistically, CGD's gains are structural - once households connect or fleets convert, demand is locked in. This positions CGD to absorb more than 40 per cent of national gas demand by 2040, making it the pivotal driver of India's long-term gas trajectory under a $6 per MMBTU regime. The sector has the potential to permanently shift urban energy use and freight transport away from oil and toward gas especially if aggressive policies piggyback on cheap gas.

Petrochemicals & Refineries

According to the IEA, gas demand in the petrochemical sector is expected to reach 3.5 bcm by 2030, while demand in the oil refining sector rises to more than 9 bcm by 2030. PNGRB's projections are higher: 16 bcm in 2030 (GtG), with a high-case (GtB) of 18 bcm, rising modestly to 19 bcm (GtG) and 21 bcm (GtB) by 2040.

Sustained low LNG prices would underpin this trajectory by ensuring gas consistently outperforms alternative fuels such as fuel oil and naphtha, both in cost and in environmental profile. Refineries would be encouraged to maximize gas use for hydrogen production (via steam methane reforming) and for heaters and boilers, displacing dirtier residuals. In petrochemicals, particularly methanol and fertilizer intermediates, reliable low-cost gas strengthens the case for feedstock substitution away from naphtha and for operating gas-fed plants at higher load factors.

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While the upside is unlikely to be transformational (most large sites already use gas when available), sustained $6 LNG would lock in usage and reduce reversion to fuel oil in downturns. It could also support a few incremental gas-fed projects and greater reliance on gas for SMR hydrogen and process heat at RLNG-connected refineries. Thus, demand likely lands near the top of PNGRB's ambitious range, with any additional uplift (+1–2 bcm above GtB by the late 2030s) contingent on RLNG tie-ins, hydrogen strategy, and supportive policy.

Overall, the effect is incremental but durable. By the late 2030s, sustained $6 per MMBTU pricing would keep refinery and petrochemical gas use around PNGRB's GtB level (21 bcm), with a plausible stretch to 22–23 bcm if gas is leaned on more for hydrogen co-production before green H_2 scales up and a handful of new gas-based units come online.

Industry & Other Uses

In the broader industrial segment, sustained low gas prices could drive meaningful switching away from coal and liquid fuels. Sectors such as ceramics, glass, food processing, textiles, and cement could steadily migrate boilers and furnaces to natural gas where pipelines are available.

At $6 per MMBTU, gas can be cost-competitive with furnace oil or even coal, especially once pollution-control costs and operational convenience are factored in. Smaller industries that currently rely on truck-delivered coal or oil would find gas an attractive alternative if supply becomes reliably cheap, creating a more 'locked-in' industrial demand base rather than short-term opportunistic switching.

PNGRB groups these miscellaneous industries under 'Others'. Consumption in this category is projected to reach 21 bcm by 2030 (GtG), 24 bcm in the GtB case, and further expand to 28 bcm (GtG) and 34 bcm (GtB) by 2040. With prolonged low prices, achieving the upper end of these ranges becomes realistic, and a modest overshoot is plausible as grid expansion unlocks new industrial clusters. Coal-to-gas switching, though historically rare in India, becomes more probable in a stable low-price environment, provided infrastructure rollout keeps pace.

Steel is treated separately in PNGRB's projections, rising from 1.6 bcm in 2030 (GtG) to 3.4 bcm by 2040 (GtB). Sustained $6 LNG could enable a higher uptake of gas-based DRI and greater natural gas injection into blast furnaces, nudging consumption modestly above these projections if supported by policy incentives or carbon pricing. However, competition from hydrogen-based steelmaking is likely to cap the upside beyond the late 2030s.

Overall, in a $6 per MMBTU world, the industrial sector's gas use shifts from cyclical rebounds to structural embedding. 'Others' demand is likely to reach PNGRB's GtB projection of 34 bcm by 2040, while steel could edge 3 bcm. Cheap gas therefore provides a durable uplift to India's industrial energy mix, ensuring more permanent integration of gas in industries traditionally dominated by coal and oil.

The PNGRB's GtB scenario already assumes an exceptionally ambitious pathway to 133 bcm by 2030 and 230 bcm by 2040; well above other 2040 projections such as OIES (~124 bcm) or WEO STEPS (149 bcm). GtB projections assume accelerated progress on infrastructure, policy, and investment but not necessarily a prolonged ultra-low global gas price. If $6 per MMBTU LNG persists as the new normal, it provides a powerful tailwind, boosting demand toward the upper end of these projections.

Key segments like CGD and transport could meet and possibly overshoot PNGRB's GtB volumes. With a strong price advantage, CGD demand (excluding LNG trucking) could climb past 46 bcm in 2030 and approach 90-100 bcm by 2040, while LNG trucking, projected at ~24 bcm in the GtB case by 2040, could be met if execution accelerates, bucking current trends. Industrial gas use might also top forecasts if low prices prompt deeper coal displacement in factories and wider adoption across smaller sectors.

At the same time, some sectors are inherently capped; fertilizer demand will not jump simply because gas is cheap, and the pace of infrastructure rollout remains a limiting factor. Achieving GtB levels (i.e. 230 bcm) would require exceptionally favourable conditions: less volatile sustained low prices alongside swift policy action to remove bottlenecks.

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Table 6: India long-term switchable potential

Sector	Incremental Demand Potential under Sustained $6/MMBtu
Fertilizer	+0–2 bcm (higher utilization of new plants like Talcher; capped by slow capacity growth)
Power	+3–8 bcm (revived stranded plants, higher peaking role; upside if policy support for gas-based generation)
CGD (CNG + PNG + Freight LNG)	+10–20 bcm (high household/commercial uptake; LNG trucking could add ~10 bcm with strong execution)
Petrochemicals & Refineries	+1–2 bcm (feedstock substitution, more gas for hydrogen in refineries)
Industry & Steel	+3–5 bcm (coal-to-gas switching in ceramics, glass, textiles; modest steel uptake)
Total	≈ +17–35 bcm (long-term uplift, broadly keeping demand near PNGRB's GtB scenario by 2040)

For perspective, the IEA's Accelerated case for India, with enhanced policy support for gas in power, transport, and CGD, pegs 2030 demand at 120 bcm, well above its base estimate of 103 bcm and broadly aligned with PNGRB's high-case trajectory (133bcm). This suggests that with the right push, India could indeed exceed 'moderate growth' expectations.

If cheap LNG endures into the late 2030s, national demand could plausibly reach 211-230 bcm by 2040, particularly if progress continues toward the government's ambition of a 15 per cent gas share in the energy mix, a daunting goal without the anchor of prolonged affordable gas. This means a potential addition of 31-50 bcm over GtG scenario and 87-106 bcm over current OIES projections, highlighting how much pricing plus policy/execution would need to deliver.

A crucial caveat is that while Indian gas demand is highly price elastic, the supporting infrastructure and downstream assets are capital intensive. Large-scale investments like LNG terminals, pipelines, CGD networks, gas-based plants will still face financing hurdles without clear offtake contracts and policy guarantees.

In summary, a sustained $6 per MMBTU environment in the 2030s could embed natural gas more deeply in India's energy system bringing it closer to today's most optimistic projections. It could be instrumental in lifting 2040 demand to 211–230 bcm, decisively above GtG and at/near GtB, with the largest durable gains in CGD (including freight LNG) and measured but real gains in power and industry. But realizing this upside will hinge on two complementary factors: infrastructure expansion and policy action. If these align, the 'low-price bonus' could surpass baseline demand by 2040, locking in a more permanent higher trajectory for India's gas economy.

e) Conclusions

Gas demand is expected to grow significantly in India over the next ten years and beyond. The OIES projection in 2030 is similar to the PNGRB's Good to Go (GtG) but much slower thereafter and well below the PNGRB's Good to Best (GtB). Conversely, it is higher than the IEA STEPS forecast for 2030. This give a wide range of potential demand, suggesting there is scope for higher demand at lower price levels.

The short-term price response is considered to be 4.6 to 11 bcm, which would be some 4 - 11 per cent of the OIES 2030 demand level. The longer-term uplift for lower prices, however, is much bigger ranging between 17 and 35 bcm which is a 15 -35 per cent increase on the OIES 2035 demand level, bringing demand above the PNGRB's GtG but below GtB levels.

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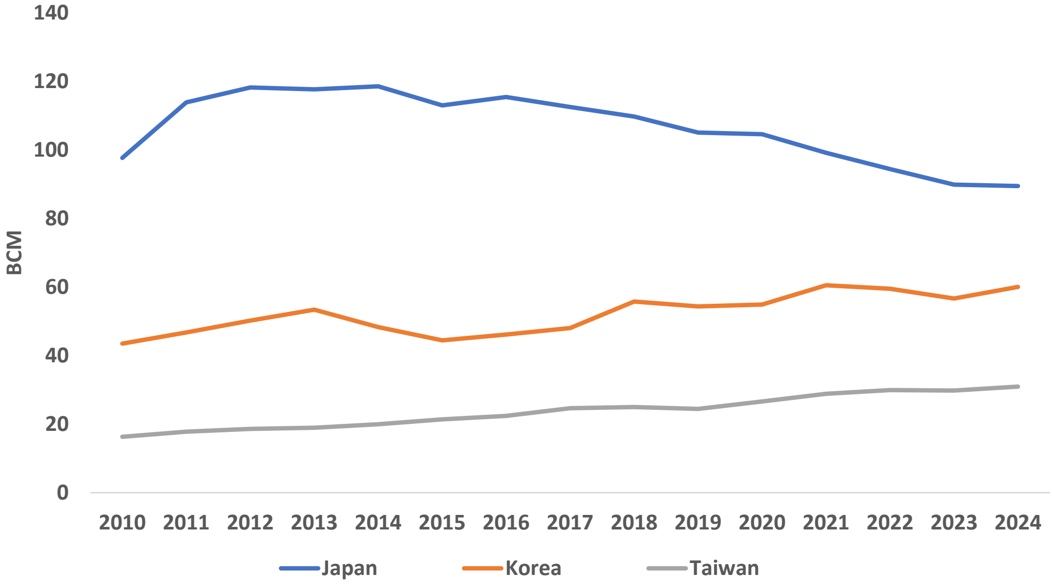
6. Japan, Korea, Taiwan

Japan, Korea and Taiwan are all major LNG importers but with quite different circumstances. Gas demand in Japan is falling as nuclear plants restart on top of already weak demand for electricity. By comparison, demand is growing in Korea and Taiwan, which have expanding economies and populations (Figure 34). The closure of nuclear generators in Taiwan is providing an additional boost to demand. The imposition of US tariffs is likely to hurt all three economies, but it is still too early to assess the likely impact.

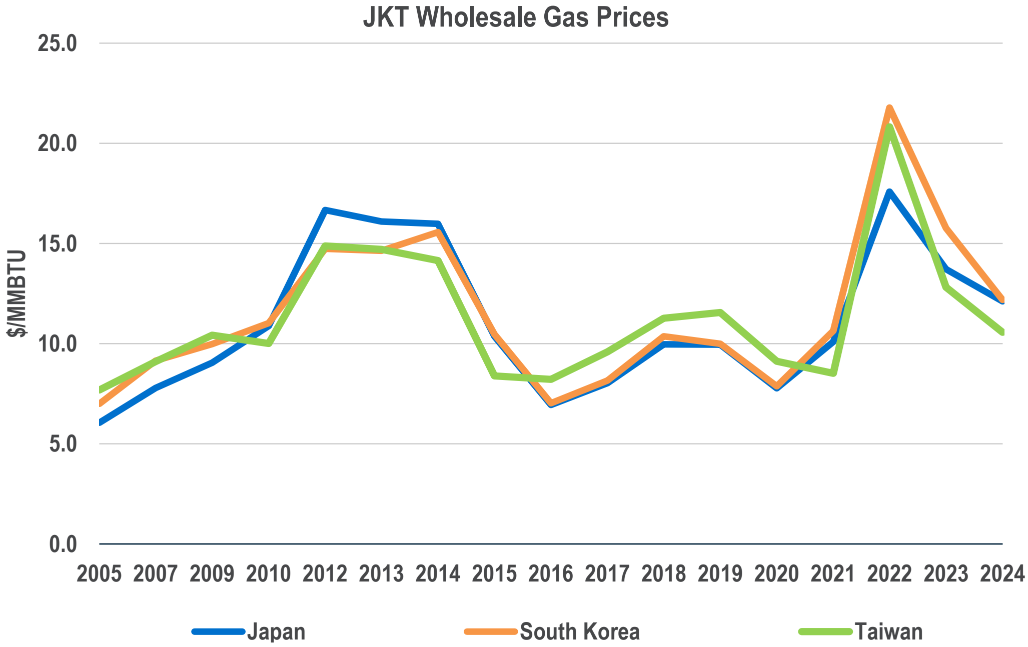
Figure 34: Historical gas demand, Japan, Korea, and Taiwan (Bcm)



Source: IEA

In terms of gas pricing, as LNG importers all three countries have moved more towards gas-on-gas pricing and away from oil indexation, with the gas-on-gas share having risen to almost 40 per cent in 2024 – as noted in Section 2.

Figure 35: Average wholesale gas prices – Japan, Korea, and Taiwan



Source: International Gas Union Wholesale Gas Price Survey

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The average wholesale gas price levels in the three countries have traditionally been very similar (see Figure 35), and have been driven by a combination of oil-indexed contract prices and - increasingly - spot prices, notably in 2019 and 2020 when spot prices were well below oil-indexed prices, and also in 2022 when spot prices spiked following the Russian invasion of Ukraine. For most of the period since 2010 wholesale prices have been well above $10 per MMBTU.

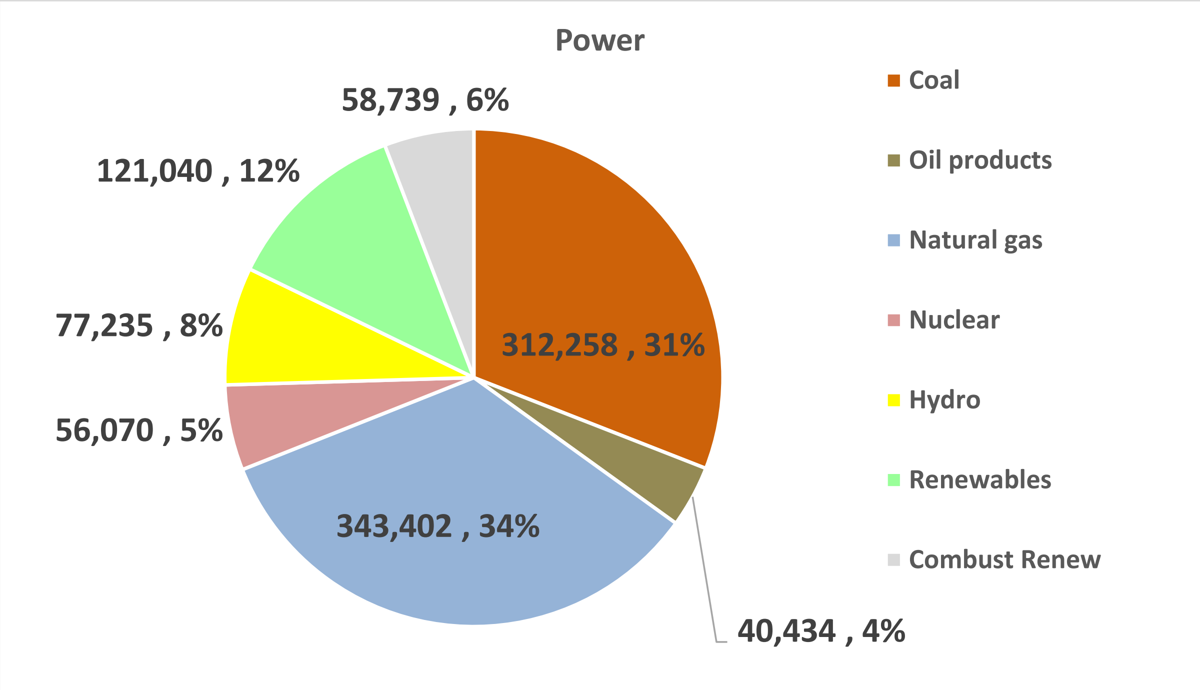
a) Japan

Japan's electricity demand peaked in 2008 and has been falling since, affected by population decline and low economic growth. Expectations of continuing decline are now beginning to be reversed driven by expansion in the technology sector, data centres, semiconductor fabrication, electrification, and AI adoption.[128] However, while generation increased slightly in the last couple of years, the overall trend has been a decline of 0.4 per cent per annum over the last decade.

Within this declining sector, Japan has ambitious targets to replace fossil fuels with renewables and nuclear but Japanese power generation is still dominated by coal and gas. Gas had a 34 per cent share in power generation in 2022, while coal, the other major source of power generation, accounted for 31 per cent of the total in 2022 (Figure 36).

Nuclear is gradually returning, reaching a 5 per cent share of power generation in 2022. Renewables comprised 12 per cent in 2022 and are still growing, with solar up 15 per cent per annum over the last decade. However, growth in wind has been slower (8.7 per cent per annum) and, overall, the growth in low-emission energy is not fast enough to meet Japan's emission reduction targets[129].

Figure 36: Japan power generation by fuel (GWH and percentage)



Source: IEA World Energy Stats and Balances

[128] https://www.reuters.com/sustainability/climate-energy/japan-could-face-potential-power-supply-crunch-2050-grid-monitor-says-2025-06-25/

[129] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/04/Insight-148-The-role-of-LNG-in-the-North-Asian-energy-transition.pdf Japan also has substantial geothermal potential but has challenges and currently contributes less than 1 per cent of Japanese electricity production.

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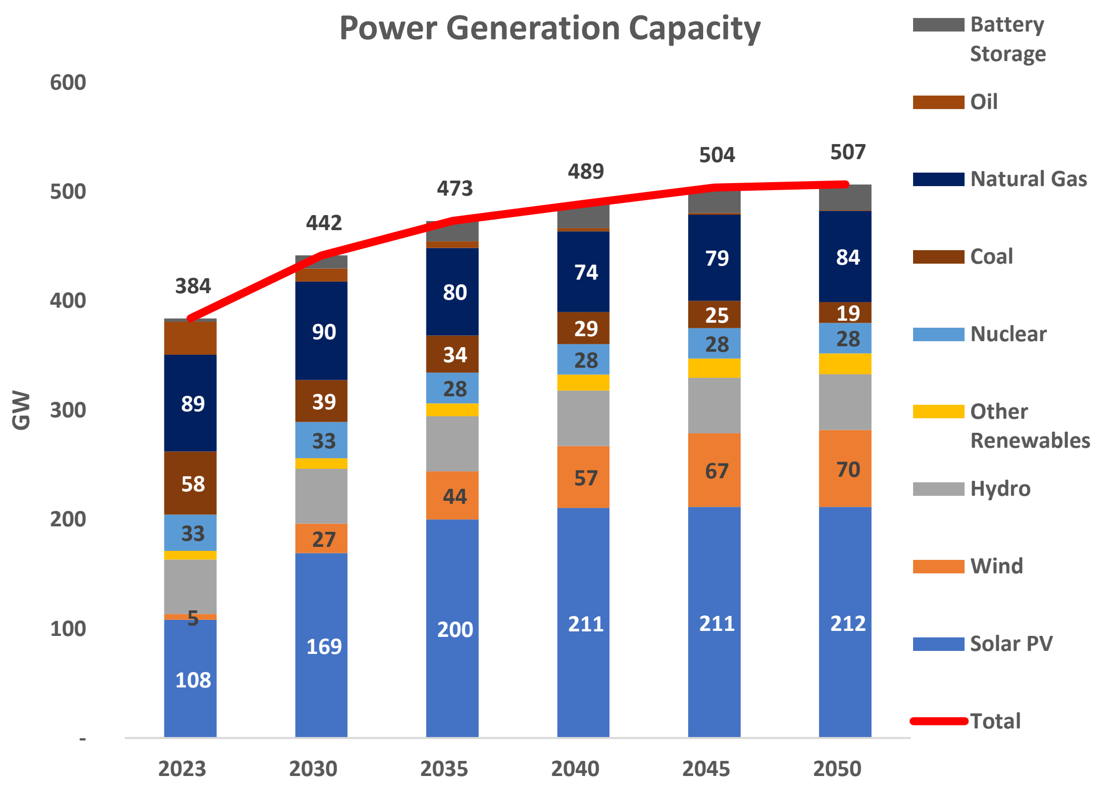
Developments in the electricity sector have important implications for gas, two-thirds of which was used for power generation in 2023. Even if total electricity demand may be beginning to increase, the share of gas is still expected to fall as gas-fired power generation capacity is not forecast to increase and will decline in the early 2030s, with the load factor declining from 42 per cent in 2023 to 26 per cent in 2030 and dropping below 20 per cent in 2035. Coal utilization rates do not fall as rapidly as gas, suggesting that there is scope for gas to gain market share if it is competitively priced. It should be noted that Figure 37 is taken from the IEA WEO 2024 STEPS and Japanese gas demand in this scenario is lower than in our Base Case scenario. The STEPS demand in 2030 is some 61 bcm for Japan against our 83 bcm and 41 bcm in STEPS (2050) compared to our 65 bcm. This difference can probably be largely accounted for by the IEA's projected decline in the utilization of gas-fired power, combined with a slower than expected resurgence in nuclear capacity.

The 7th Strategic Energy Plan[130] has recently been published in Japan. This projects a range of 53 to 61 Mt of gas demand in 2040/41 (72 to 82 bcm) in their 73 per cent GHG emissions reduction scenario and 73 Mt (99 bcm) in their 61 per cent GHG emissions reduction scenario for 2040/41. Our 2040 number is 73 bcm, placing it at the lower end of the 7th Strategic Energy Plan higher GHG emissions reduction scenario. The IEA STEPS number for 2040 is around 45 bcm but the forthcoming 2025 WEO is likely to see this level increased.

Figure 37: Japan power generation capacity and utilization



[130] https://www.spglobal.com/commodity-insights/en/news-research/latest-news/lng/021725-japan-projects-53-mil-74-mil-mt-gas-supply-need-for-fy-2040-41-in-strategic-energy-plan

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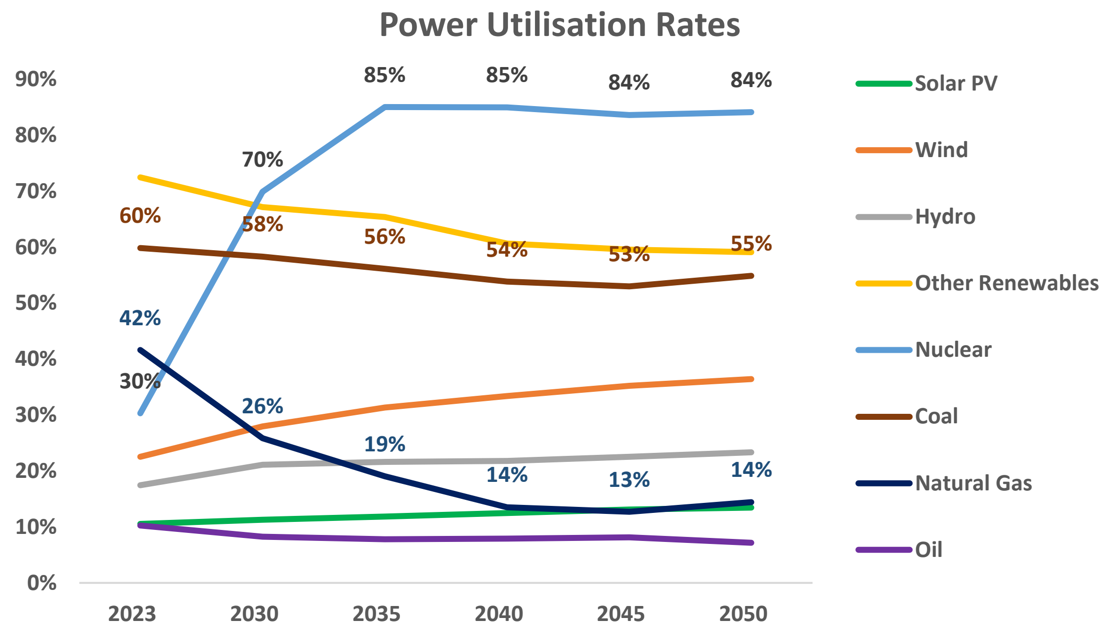

Source: IEA WEO 2024

Figure 38: Japan demand and gas-use in power generation

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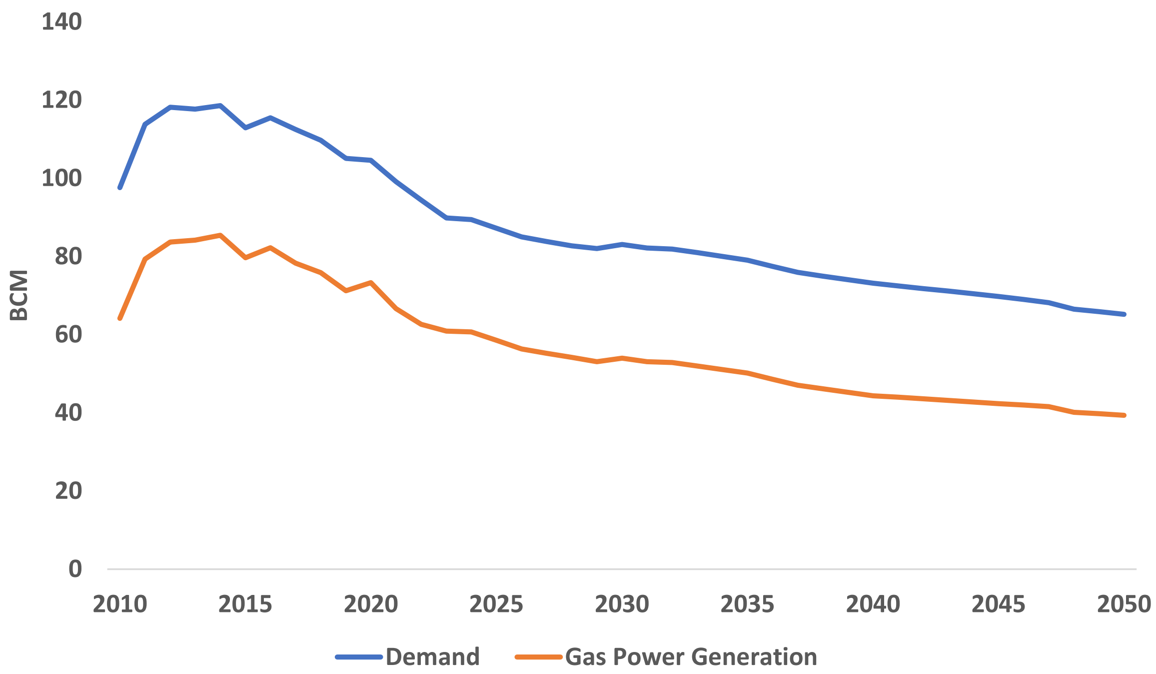

Source: NexantECA WGM and OIES

Short-Term Price Response

Would gas prices of $6 per MMBTU reverse this trend? Could gas take market share from coal in the short run or from renewables or nuclear restarts in the long run? Although consumption of gas has lower emissions than coal, gas in the form of LNG is currently more expensive and more emissions-intensive than renewables and nuclear.

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According to the Energy Institute's 2025 Statistical Review of World Energy[131] the import price of coal to Japan in 2024 was $115/tonne ($0.115/kg). Assuming 24 MJ/kg of imported coal the cost per megajoule (MJ) is $0.00479/MJ. Also, assuming that existing coal-fired generation has an average efficiency of 40 per cent (a heat rate of 9), the cost per kWh of existing coal generation is $43/MWh

Turning to LNG the 2024 import price was $11.73 per MMBTU or $0.01173/MJ. Assuming 50 per cent efficiency (a heat rate of 7.2) the cost of LNG is $80/MWh, roughly twice the cost of coal.

How would this change with $6 per MMBTU gas? Using the same assumptions, the cost of generation with LNG would also be $43/MWh, parity with coal. This suggests that even in the absence of a meaningful carbon price (not the case in Japan) there would be a case for switching from coal to gas, with lower emissions.

Increased use of gas would not be impeded by limited LNG import terminal capacity or limited gas generation capacity. Indeed, excess gas infrastructure capacity means that gas could readily replace a significant volume of coal. Japan's LNG terminals have the capacity to import more than 200 Mtpa, while actual 2024 imports were only 66 Mt. There are widely varying estimates of existing gas-fired generation capacity in Japan, ranging from 40 to 80 GW. Operating at 90 per cent of capacity, this implies available capacity of 350-700 TWh. In 2024 Japanese gas-fired generators produced 318 TWh so there does not appear to be a shortage of capacity. Japanese companies such as JERA also claim to have a surplus of LNG contracted[132] although this is likely to be at much higher prices than $6.

What would be the possible LNG demand response in the short run to a $6 per MMBTU gas price scenario, effectively halving imported gas prices? Gas demand depends on a range of factors in addition to price and in the past, Japanese gas demand has moved counterintuitively to price movements, making it difficult to separate out the impact of price changes alone.

Another approach is to see how the market has responded to exogenous shocks, of which a $6 gas price would be one. One historical exogenous shock was the Fukushima disaster in 2011, when nuclear generation was stopped virtually overnight. LNG demand was 12 per cent higher in 2011 than 2010 and 27 per cent higher in the following five years between 2011-2015 compared with 2006-2010. When prices then fell sharply in 2020, gas increased its share in power by 1.8 percentage points, resulting in a near 5 per cent increase in gas demand in power, compared to the 20 per cent increase in gas demand in power in 2011. In terms of total Japanese gas demand these translate into possible increases of between 3.5 per cent and 13 per cent, or some 3 to 11 bcm.

Longer-Term Price Response

Would sustained low gas prices slow the growth of renewables or nuclear restarts? The answer is most likely yes. The official 7th Strategic Energy Plan (2025)[133] for Japan does not provide a single fixed LCOE (Levelised Cost of Electricity) figure for LNG or renewables but gives indicative cost ranges, with the LCOE of renewables lower than LNG. Solar PV is quoted as $60-100/MWh, onshore wind $70-120/MWh, nuclear restarts $70-100/MWh and LNG $90-130/MWh. We do not have the assumptions underlying these estimates so it is not possible to precisely estimate an LCOE for LNG with $6 gas but it is likely that LNG would be competitive with renewables and nuclear restarts in terms of cost. It is also not clear whether the LCOE for LNG takes account of the existing surplus capacity in LNG import terminals and gas-fired generation.

The focus above has been on gas use for electricity. However, gas is also important for industry (Figure 39). Gas comprises 14 per cent of industrial energy demand, much less than oil or coal. Gas is likely to have a limited ability to substitute for oil or coal, as any such substitution will require major investment in plant and equipment. Industrial use of oil includes transport and refining, for which gas is not a ready

[131] https://www.energyinst.org/statistical-review
[132] https://www.woodmac.com/news/opinion/japans-lng-challenge/ https://ieefa.org/articles/churn-and-earn-how-japan-cashes-resales-australian-lng-local-gas-users-expense
[133] https://www.enecho.meti.go.jp/en/category/others/basic_plan/pdf/7th_outline.pdf

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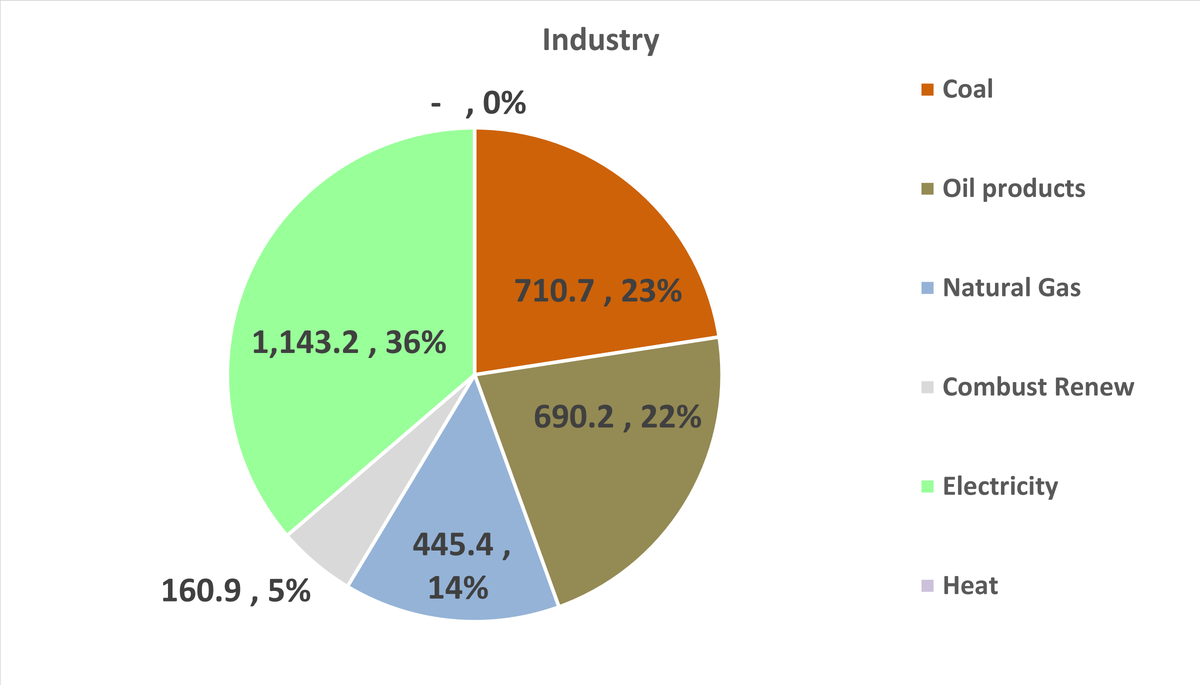
substitute, and the industrial use of coal includes hard-to-heat sectors like steelmaking. The focus in these sectors is the replacement of fossil fuels with green substitutes such as green hydrogen or green ammonia rather than with cheaper - but still emitting carbon - gas.

Figure 39: Japan industrial demand by fuel 2022 (PJ)



Source: IEA World Energy Stats and Balances

In summary, in a scenario of a sustained $6 imported gas price, Japanese LNG imports could potentially be another 25 bcm higher in the long run other things being equal, particularly coal prices. This would increase our 2035 demand number from 79 bcm to around 104 bcm – an increase of some 30 per cent, demand at 2019/2020 levels. This would come at the expense of coal, some nuclear, and renewables.

b) Korea

Like Japan, South Korea's electricity generation is heavily dependent on gas and coal but nuclear energy plays a more prominent role, at least for now. Renewables have a smaller share than in Japan (Figure 40). Over the last decade, Korean electricity demand has been growing at an annual average rate of 1.5 per cent, a trend expected to persist due to ongoing industrial expansion and electrification. As in Japan, fossil fuels - coal and gas - supply nearly 60 per cent of power generation. However, nuclear is more important in Korea (29 per cent of generation in 2022) and is continuing to expand. In 2022 solar only contributed 5.2 per cent of generation and wind a mere 0.5 per cent.

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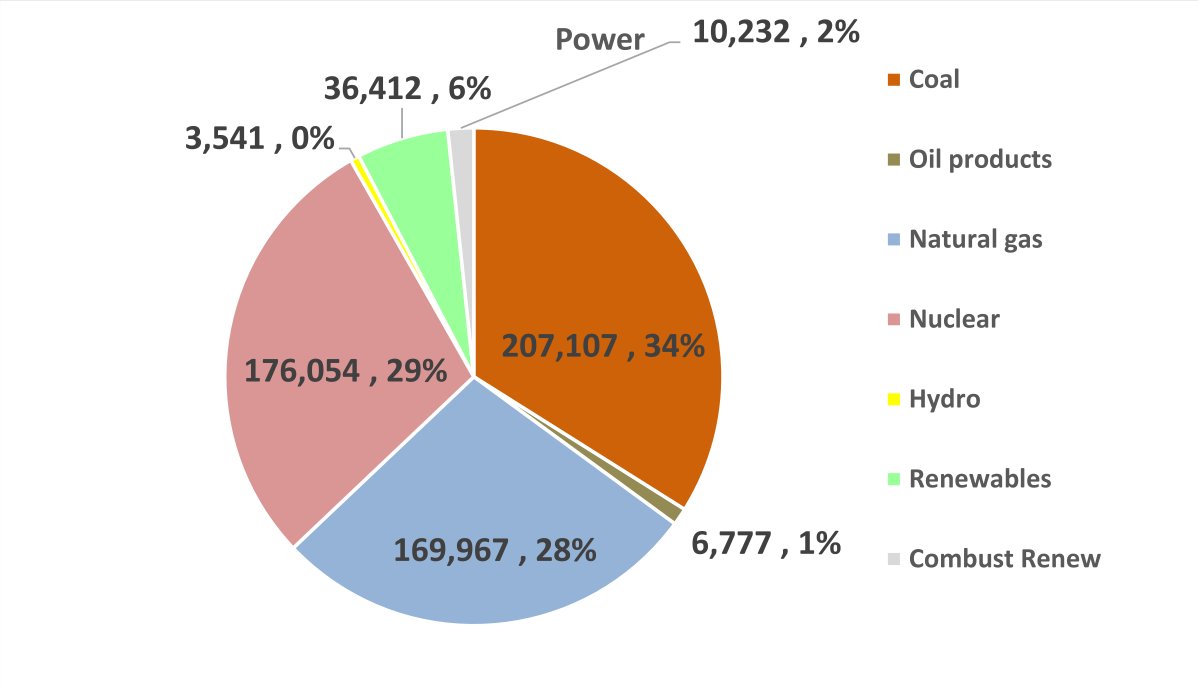
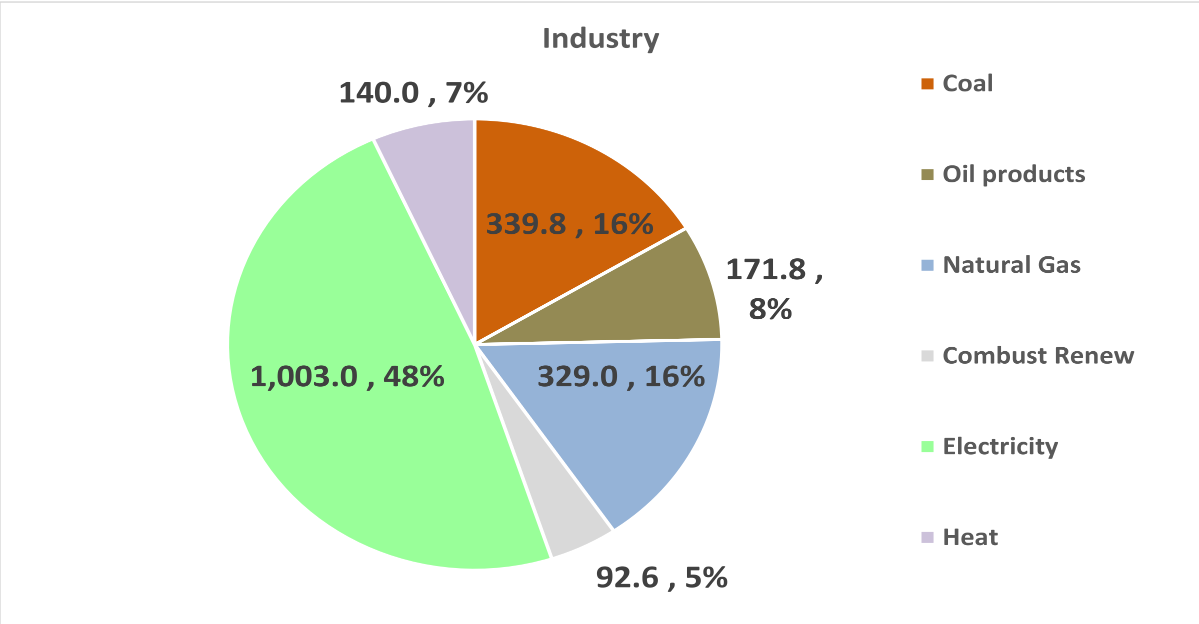
Figure 40: Korea power generation by fuel 2022 (GWh)



Source: IEA World Energy Stats and Balances

Gas use in Korea is also dominated by the power generation sector (over 50 per cent of gas demand) but has larger industrial and residential shares than in Japan. As in Japan, the relative short-run costs of gas-fired generation at $6 and the cost of coal are likely to be similar, but Korea - unlike its neighbour - has ambitious plans to close coal-fired power stations. This is likely to lead to increased LNG demand, particularly if gas is $6, given that is approximately half the current landed price and that there is surplus LNG importing and gas-fired generation capacity in the country. In 2022 Korean electricity generation was 170 TWh, 72 per cent of total capacity of 236 TWh. LNG imports in 2024 were 63 bcm, compared to a regasification capacity of 208 bcm and plans to add a further 50 bcm of capacity.

Figure 41: Korea industrial demand by fuel 2022 (PJ)



Source: IEA World Energy Stats and Balances

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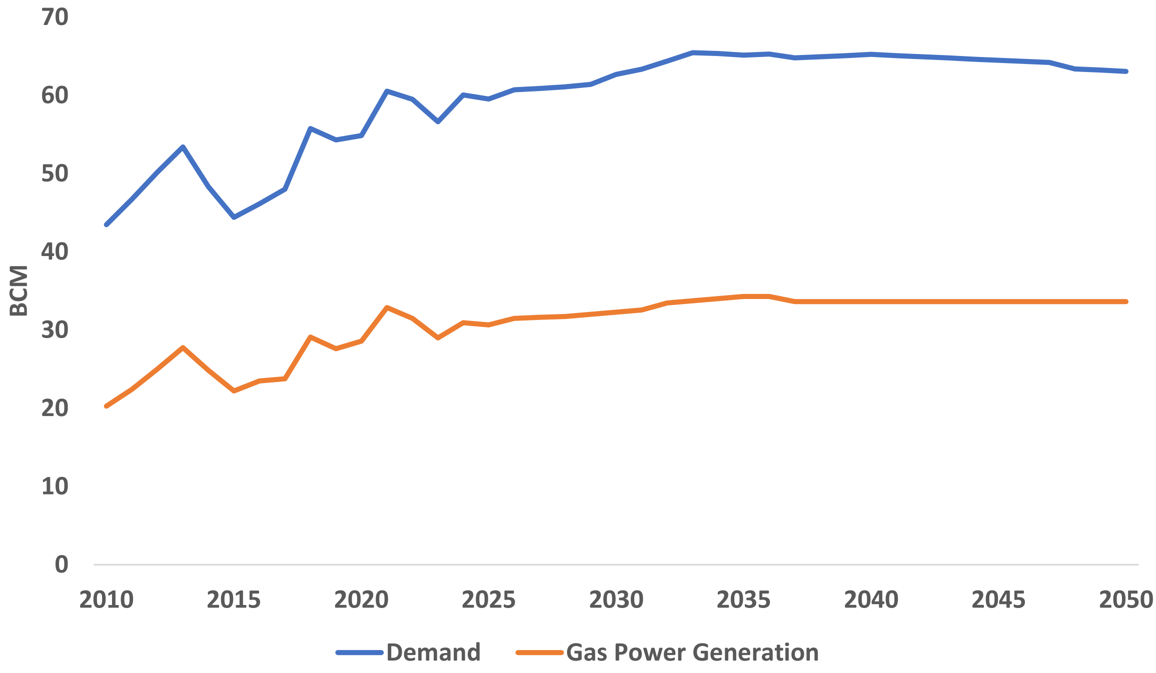
Gas and coal are both important for industry, but the scope to substitute gas for coal in industry is limited in the short-term for the same reasons as in Japan.

Korean LNG demand and electricity demand are both expected to continue to grow modestly (Figure 42). This suggests that the phasing out of coal is destined mainly to benefit renewables.

Figure 42: Korea LNG imports and gas-use for power generation (bcm)



Source OIES

Shorter-Term Price Response

What would be the short-run impact of a fall in the price of imported LNG to $6? As noted in the case of Japan, this would be an exogenous shock to the gas market. Gas would likely become competitive with coal, as noted earlier, at least at the margin in terms of spot LNG imports. The most recent examples of a possible price response came in 2020 during Covid-19, where gas use in power jumped 13 per cent, against only a 1 per cent increase in overall electricity demand. This was largely at the expense of coal, as nuclear and renewables also increased their share of demand. Average wholesale prices in Korea fell by 25 per cent but these included an element of oil-indexed contracts which were more stable than the spot price of gas which was at lower levels in 2020. A 10 per cent response in the use of gas in power generation amounts to some 3 bcm of gas use – or 5 per cent in comparison to total demand.

Longer-Term Price Response

In the long run, South Korea is not planning to build more coal power plants and plans to shut down forty coal plants by 2038. These are expected to be replaced by LNG (with some coal plants being converted to gas), renewables, and hydrogen. The 11th Basic Electricity Plan[134] foresees a large increase in renewables, especially offshore wind. Korea is also expanding nuclear power significantly as part of its long-term energy strategy. The Plan presented a goal of increasing renewable energy power generation capacity from 30 GW in 2023 to 78 GW in 2030 and 121.9 GW in 2038. The renewable capacity is focused on offshore wind and large scale solar. LNG at $6 is very competitive against offshore wind, assuming no carbon price. Two new 1.4 GW nuclear reactors are also planned but are not yet under construction, nor are they likely to be completed until around 2039. The LCOE for new

[134] https://www.yna.co.kr/view/AKR20250221070600003

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nuclear is significantly higher than for gas. Between the slow uptake of renewables, the closure of coal and the cost and likely delays of nuclear, there is significant potential for increased LNG penetration. This vindicates the expansion of LNG import capacity. Substituting gas for new nuclear (1,400 MW) would increase LNG demand by around 2 bcm. Substituting gas-fired power for offshore wind – say 12GW – could increase gas demand in power by around 15 per cent or some 5 bcm. The total response would boost total Korean gas demand by 7 bcm - or some 10 per cent by 2035.

c) Taiwan

Taiwan's electricity demand has been growing at an average annual rate of 1 per cent over the last decade and is set to grow steadily, driven by the semiconductor and AI industries.

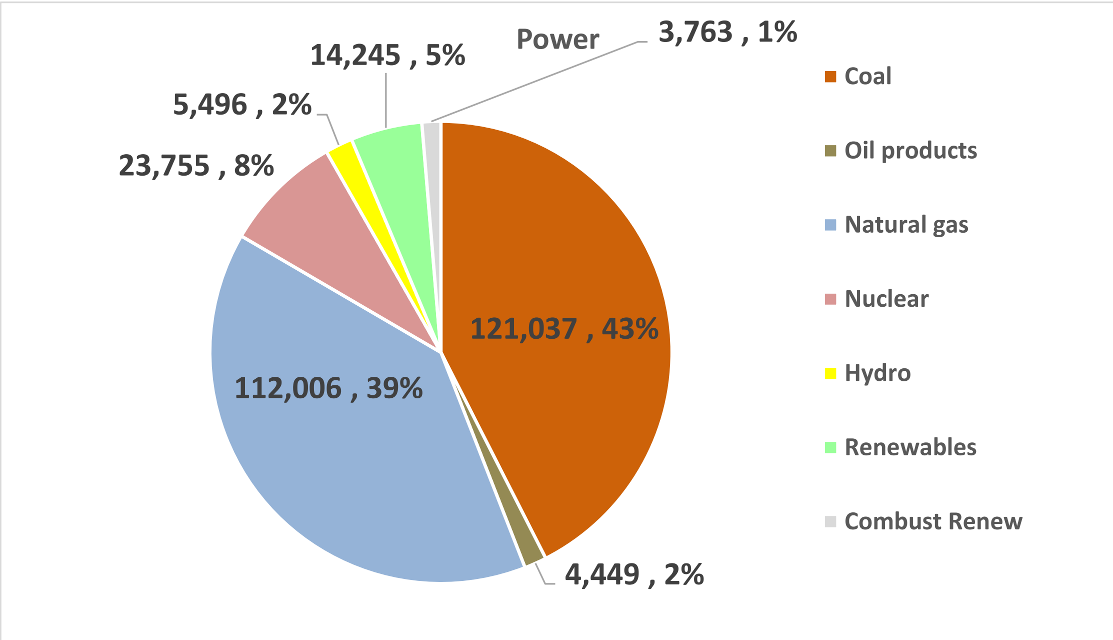
As in Japan and Korea, power generation is still dominated by fossil fuels. Gas had a 43 per cent share in 2022, while coal came in slightly lower at 39 per cent. As was confirmed by the recent referendum, Taiwan has taken the decision to phase out nuclear power, which supplied 8 per cent of power in 2022, with the last remaining nuclear plant due to be decommissioned this year.[135] Renewables made only a modest contribution of 5 per cent in 2022, but this percentage has increased since then, with solar accounting for a 5.1 per cent share in 2024 and wind 3.6 per cent. There is a target to phase out coal-fired generation by 2034.

Growing electricity demand, the closure of nuclear and coal and the modest penetration of renewables are likely to increase demand for gas generally, all supplied by LNG.

Short-term increases are likely to be constrained by limited LNG import capacity. In 2024 Taiwan imported 29 bcm of LNG, even though nominal import capacity was only 25 bcm, which suggests that the existing regasification plants can import well above nameplate capacity. There are currently two new import terminals under construction, with nominal capacity of 12 bcm. There is more latitude with gas-fired power stations: in 2024 Taiwan generated 122 TWh from gas-fired plants with nominal capacity of 165 TWh and with rapidly increasing power demand, new gas-fired plants are under construction.

Gas use in Taiwan is dominated by power generation which represents 75 per cent of total gas demand currently, and gas use is expected to grow over the long term (Figure 44), as coal and nuclear are progressively phased out.

Figure 43: Taiwan power generation by fuel (GWh)



Source: IEA World Energy Stats and Balances

[135] https://www.bloomberg.com/news/articles/2025-08-24/failed-nuclear-power-vote-adds-to-taiwan-s-energy-conundrum

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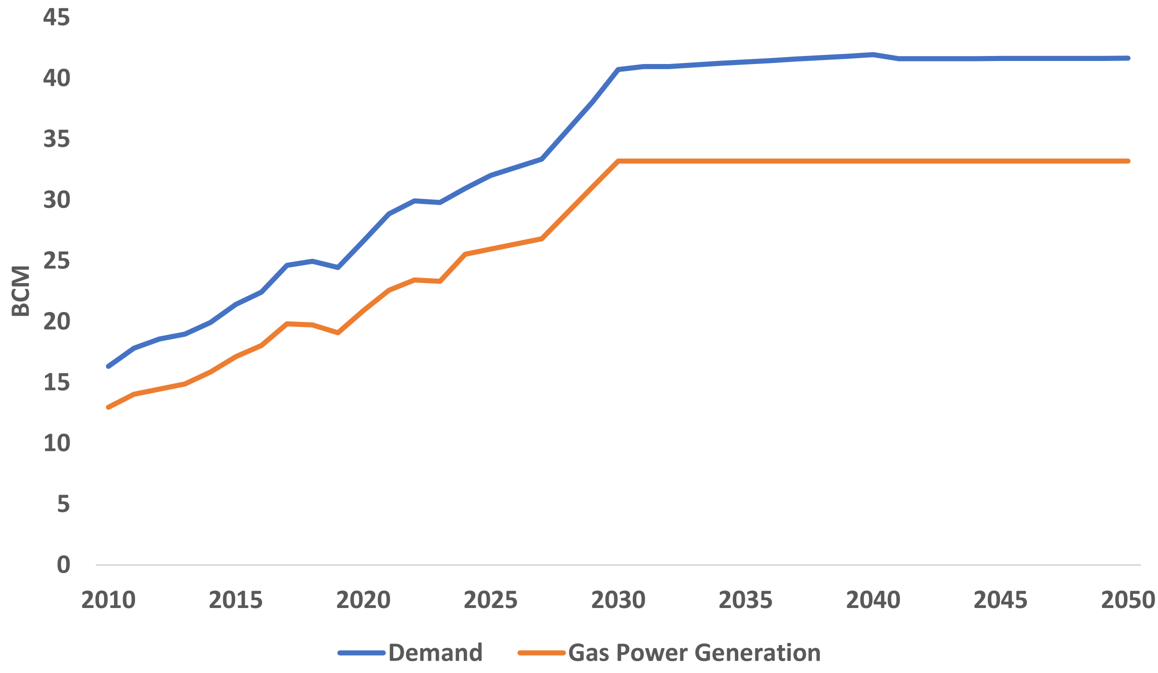
Figure 44: Taiwan LNG imports and gas-use for power generation



Source: NexantECA WGM and OIES

Over the long-term, Taiwanese primary energy supply could become wholly reliant on LNG and renewables. Even with $6 gas the cost of LNG is likely to be higher than onshore wind and solar but could be competitive against offshore wind. Renewables are also challenged by limited land for large-scale solar farms, slow adoption of rooftop solar, grid connection delays, and local opposition to offshore wind. Offshore wind is being developed in Taiwan, with some 5GW online in 2025. However, with gas dominating the power generation mix, as coal and nuclear close down, there may be limited scope for any replacement of offshore wind developments with even more gas, even if the economics make sense.

d) Conclusions

The prospects for gas demand in Japan, especially in the power sector, have changed significantly with the new 7th Strategic Energy Plan. The short-term price response, relative to total demand, could be an uplift in the range of 3.5 - 13 per cent and the longer-term response up to 30 per cent. For Korea, the comparable responses could be some 5 per cent as a short-term response and 10 per cent as a longer-term response. For Taiwan, with the phaseout of coal and nuclear, any short- or long-term price response is likely to be negligible. The short-term response, in total for these three countries, is in the 3 - 14 bcm range and the longer-term response up to 32 bcm.

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7. Emerging Asia

The countries in Emerging Asia are defined as the ASEAN[136] countries plus Pakistan and Bangladesh. In respect of the ASEAN countries, the focus is on Indonesia, Malaysia, Philippines, Singapore, Thailand and Vietnam. There are other countries in ASEAN which are not considered – Brunei and Myanmar which produce and consume natural gas but wholly from domestic production' and Cambodia and Laos who do not consume any natural gas, although there are reportedly plans for Cambodia to import LNG. In addition, Sri Lanka is not considered either, although there are also plans for the import of LNG.

a) Current Situation

The main sectors which consume natural gas in the eight countries are power generation and industry. In some of the countries, natural gas is also used as a feedstock, mainly for fertilizer production, and this is classified as non-energy use. Bangladesh and Pakistan have material gas demand in residential and commercial, and Bangladesh, Pakistan, and Thailand also have some gas demand in transport, although this has been in decline recently.

Table 7: Emerging Asia power generation by fuel 2022

POWER									
GWH	Bangladesh	Indonesia	Malaysia	Pakistan	Philippines	Singapore	Thailand	Vietnam	Total
Coal	5,663	248,576	87,584	27,487	66,430	571	36,500	111,113	583,924
Crude Oil	-	-	-	-	-	-	-	-	-
Oil products	25,811	8,309	1,013	28,666	2,519	1,485	10,516	180	78,499
Natural gas	69,215	51,426	64,180	46,978	17,884	52,544	104,868	29,410	436,505
Nuclear	-	-	-	26,914	-	-	-	-	26,914
Hydro	789	27,295	31,101	34,635	10,085	-	6,790	95,929	206,624
Renewables	871	17,477	2,193	7,243	13,277	955	8,106	37,487	87,609
Combust Renew	-	23,723	1,228	876	1,322	1,795	19,195	2,297	50,436
Total	102,349	376,806	187,299	172,799	111,517	57,350	185,975	276,416	1,470,511
Coal	5.5%	66.0%	46.8%	15.9%	59.6%	1.0%	19.6%	40.2%	39.7%
Crude Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oil products	25.2%	2.2%	0.5%	16.6%	2.3%	2.6%	5.7%	0.1%	5.3%
Natural gas	67.6%	13.6%	34.3%	27.2%	16.0%	91.6%	56.4%	10.6%	29.7%
Nuclear	0.0%	0.0%	0.0%	15.6%	0.0%	0.0%	0.0%	0.0%	1.8%
Hydro	0.8%	7.2%	16.6%	20.0%	9.0%	0.0%	3.7%	34.7%	14.1%
Renewables	0.9%	4.6%	1.2%	4.2%	11.9%	1.7%	4.4%	13.6%	6.0%
Combust Renew	0.0%	6.3%	0.7%	0.5%	1.2%	3.1%	10.3%	0.8%	3.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: IEA World Energy Stats and Balances

Natural gas is the main fuel for power generation in Bangladesh, Pakistan, Singapore, and Thailand, and has an important share in Malaysia. Indonesia, Philippines, and Vietnam have material shares of natural gas in power, but coal currently dominates these markets. It is noticeable that Singapore is almost wholly reliant on natural gas as the fuel for power generation. Renewables are strongest in Indonesia (solar), Philippines (mainly wind) and Vietnam (mainly wind), while Thailand and Pakistan also have some wind power. Wind is not a suitable source of power generation for countries close to the Equator – Indonesia, Malaysia, and Singapore - and Bangladesh also has no wind power. Only Pakistan has nuclear power at the moment. Hydro is also important in many countries, especially in Malaysia, Pakistan, and Vietnam. Coal also plays a significant role in Pakistan and Thailand. It is noticeable that oil products still play an important part in power generation in Bangladesh, Pakistan and, to a lesser extent, Thailand. Historically, the displacement of oil in power by natural gas has been a key driver for the growth of gas demand. Singapore moved from almost 100 per cent oil-fired generation in 1990 to almost 100 per cent gas-fired generation by 2015 – having reached 75 per cent gas-fired generation by 2005.

[136] Association of South East Asian Nations

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Table 8: Emerging Asia industry by fuel 2022

INDUSTRY									
PJ	Bangladesh	Indonesia	Malaysia	Pakistan	Philippines	Singapore	Thailand	Vietnam	Total
Coal	60	1,209	33	319	78	8	355	811	2,872
Oil products	19	298	123	61	76	153	161	75	966
Natural Gas	194	423	372	302	-	58	177	45	1,570
Renewables	-	0	-	-	-	-	-	-	0
Combust Renew	-	352	-	138	38	-	309	214	1,051
Electricity	147	582	289	123	104	76	319	460	2,099
Total	420	2,863	816	943	296	295	1,320	1,605	8,557
Coal	14.2%	42.2%	4.0%	33.9%	26.2%	2.8%	26.9%	50.5%	33.6%
Oil products	4.6%	10.4%	15.1%	6.4%	25.8%	51.9%	12.2%	4.6%	11.3%
Natural Gas	46.2%	14.8%	45.5%	32.0%	0.0%	19.5%	13.4%	2.8%	18.3%
Renewables	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combust Renew	0.0%	12.3%	0.0%	14.7%	12.8%	0.0%	23.4%	13.4%	12.3%
Electricity	35.0%	20.3%	35.4%	13.1%	35.1%	25.9%	24.2%	28.6%	24.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: IEA World Energy Stats and Balances

In Industry, natural gas has large shares in Bangladesh, Malaysia, and Pakistan, with smaller shares in Indonesia, Singapore, and Thailand. Coal is a key resource in Indonesia, Pakistan, Philippines, Thailand, and Vietnam. Oil products have significant shares in Indonesia, Malaysia, Philippines, Singapore, and Thailand. As in the power sector, the growth of natural gas in Industry around the world has often been at the expense of oil products for steam-raising processes.

Table 9: Emerging Asia non-energy use by fuel 2022

NON-ENERGY USE									
PJ	Bangladesh	Indonesia	Malaysia	Pakistan	Philippines	Singapore	Thailand	Vietnam	Total
Coal	-	-	-	-	4	-	-	-	4
Oil products	8	92	76	19	50	257	860	85	1,448
Natural Gas	61	182	390	182	-	-	89	41	945
Total	69	274	467	201	54	257	948	126	2,397
Coal	0.0%	0.0%	0.0%	0.0%	7.1%	0.0%	0.0%	0.0%	0.2%
Oil products	11.8%	33.6%	16.3%	9.3%	92.9%	100.0%	90.7%	67.6%	60.4%
Natural Gas	88.2%	66.4%	83.7%	90.7%	0.0%	0.0%	9.3%	32.4%	39.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: IEA World Energy Stats and Balances

Non-energy use is largely oil products and natural gas, with natural gas being used as feedstock in the production of fertilizer. Indonesia, Malaysia, Pakistan, and Vietnam are amongst the world's largest producers of fertilizer. Oil is also used as a feedstock for fertilizer, but its use is more noted in the petrochemical industry in, for example, the production of plastics, synthetic fibres, rubber, solvents, and detergents. Natural gas is less suitable as a substitute for oil in these processes.

b) Wholesale Gas Prices

Figure 45 shows average wholesale prices for the emerging Asia markets since 2005 using data taken from the IGU Wholesale Gas Price Surveys. The prices represent average prices from all sources of supply to each country, whether it is domestic production, pipeline imports, or LNG imports. The average will, therefore, mask some of the differences in prices. Pipeline and LNG import prices in the region have generally been higher than the wholesale price for domestic production. This is, to some extent, reflected in the higher average prices for Singapore, Philippines, and Thailand, where prices have been linked to oil prices and/or spot LNG prices.

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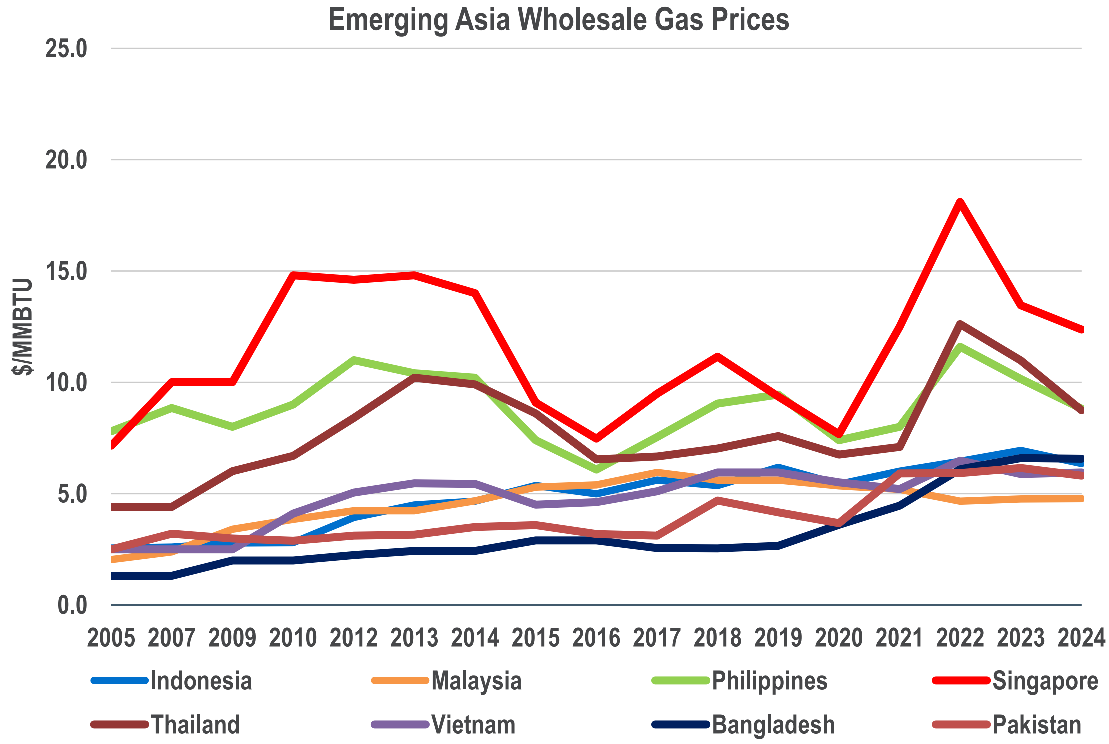
Figure 45: Emerging Asia average wholesale gas prices 2005 to 2024



Source: IGU Wholesale Gas Price Survey 2025

It is noticeable, however, that, possibly apart from Malaysia, average wholesale prices in Indonesia, Vietnam, Bangladesh, and Pakistan, are now around the $6 per MMBTU level. This suggests that, at the margin, spot LNG prices around this level would be consistent with domestic price levels in these countries.

c) Projected Gas and Energy Demand

The projected gas demand was summarised in the Base Case outlook. ASEAN demand growth is expected to increase by some 60 bcm between 2024 and 2035, from 157 bcm to 217 bcm. Vietnam, Indonesia, and Malaysia lead the way, with strong growth in industry as well as power. In the South Asia market, there is no growth in Pakistan gas demand, but Bangladesh gas demand rises from 31 bcm in 2024 to 43 bcm in 2035, the increase coming from the power and industry sectors.

After 2035, demand begins to plateau out to 2050 in most countries. In IEA STEPS, the projection for ASEAN countries is very similar to our Base Case scenario, with growth of some 56 bcm between 2024 and 2035. Thereafter, however, IEA STEPS has continued growth in the ASEAN region, with another 30 or so bcm of additional demand by 2050, whereas demand is unchanged in our Base Case. It is possible that the IEA includes some additional demand in Myanmar, Cambodia, and Brunei which is not included in the emerging Asia countries covered in this paper, although this is not considered to be material.

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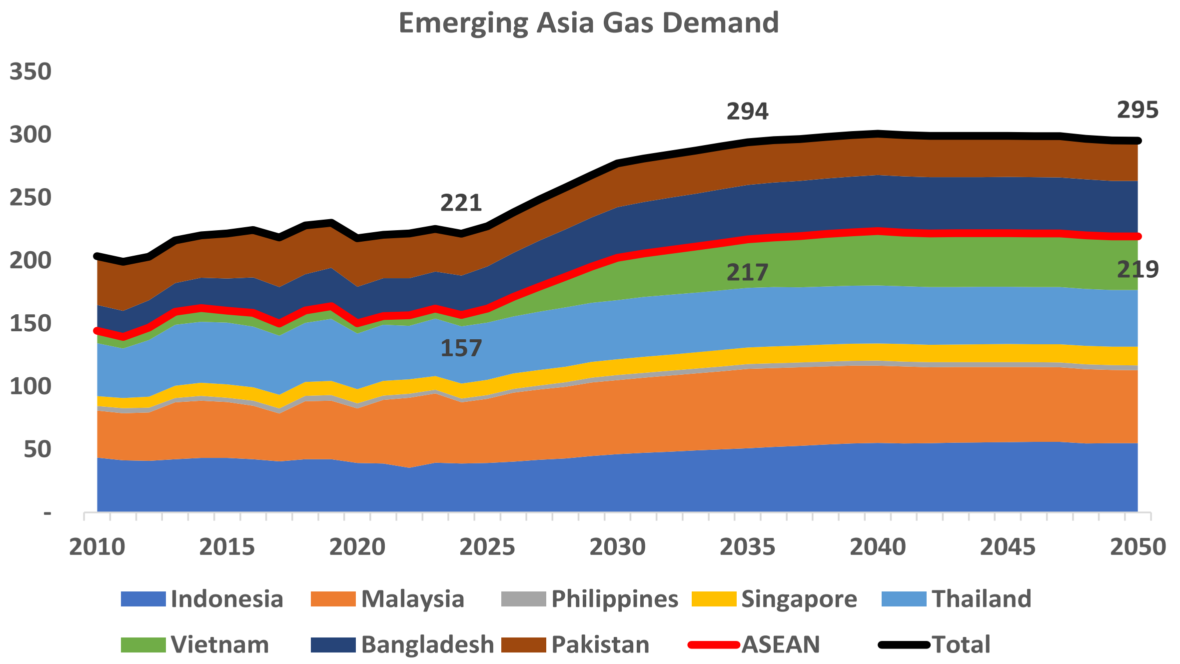
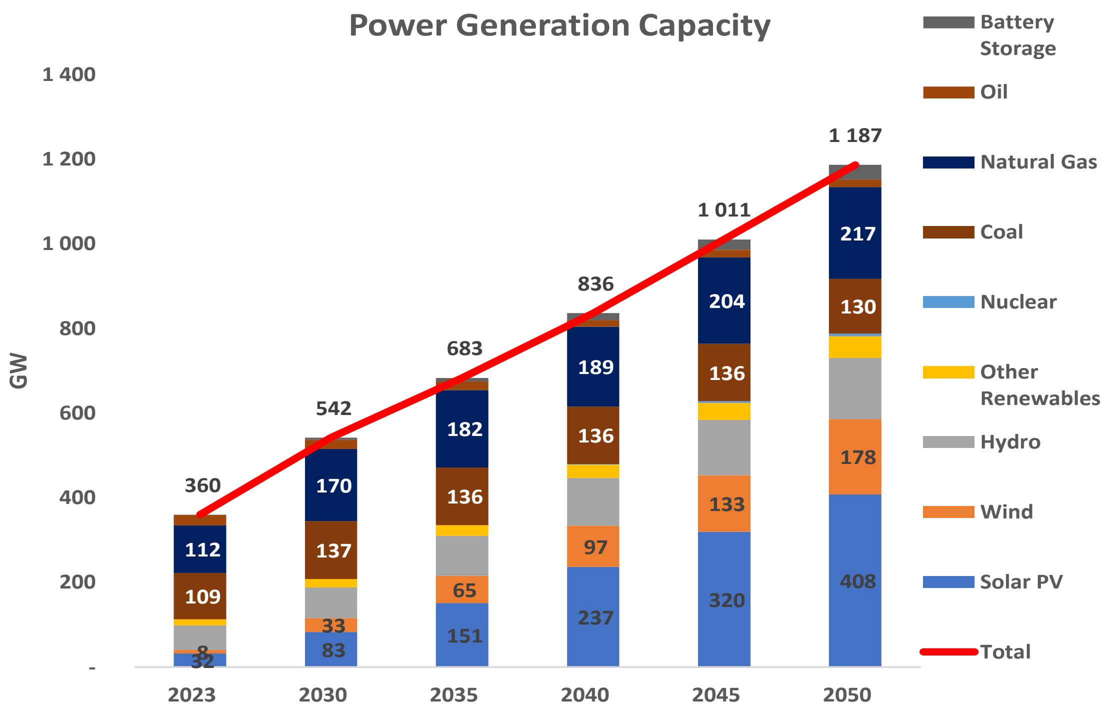
Figure 46: Emerging Asia gas demand growth



Source: NexantECA World Gas Model, OIES

Figure 47: ASEAN power generation capacity



Source: IEA WEO 2024

As noted earlier, the power and industry sectors are the key areas of gas demand, with significant shares in power in all countries, and in industry in all countries apart from Philippines and Vietnam. In IEA STEPS, ASEAN is projected to be one of the fastest growing regions for power in the next twenty-five years.

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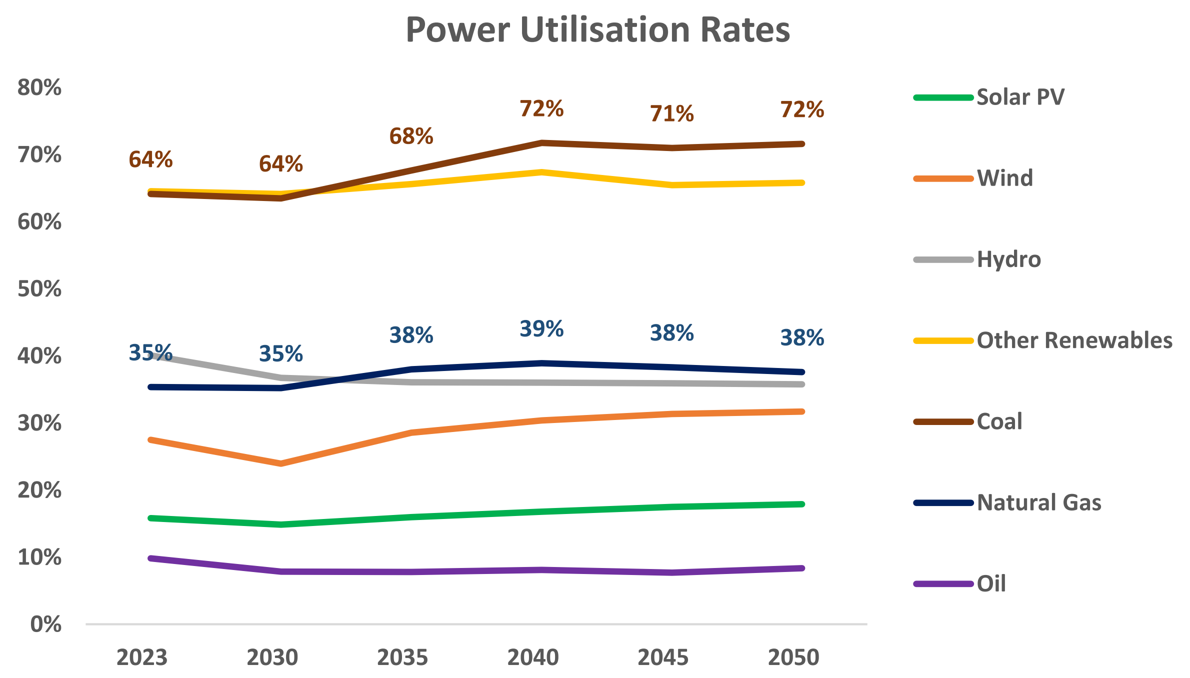
Total power generation capacity grows by 5.5 per cent per annum between 2023 and 2035 and then 3.7 per cent per annum to 2050. Wind and solar show the strongest growth with 19 per cent and 14 per cent per annum growth through 2035 with both at 7 per cent per annum thereafter. Gas-fired power generation capacity grows by 4 per cent per annum through 2035 and has doubled by 2050. The continued rise in power generation capacity in gas after 2035, accounts for the difference between our Base Case and STEPS. Coal power plant capacity increases through 2030 as projects underway are completed but there are no net additions after 2030.

Figure 48: ASEAN power utilization rates



Source: IEA WEO 2024

Coal remains the predominant fuel for base load generation, along with Other Renewables (biomass), which is relatively small. Solar, wind, and hydro remain intermittent and gas, together with oil, is the main balancing source, although gas is also baseload in some countries, such as Singapore, Thailand, and Bangladesh and some Indonesian provinces.

While gas finds it hard to compete with coal on economic grounds, with no effective carbon price or tax and low prices in the $6 range, there could be some scope to increase the share of gas. It is noticeable that the utilization of coal increases between 2030 and 2035 from 64 per cent to 68 per cent and carries on increasing to 2040. Gas utilization also increases from 35 per cent to 38 per cent but there could be scope for further increases if gas is competitive. The increase in coal from 64 per cent to 68 per cent in 2035 is equivalent to some 50 TWh a year. Mathematically if all the 50 TWh was added to gas, this would increase gas utilization to 41 per cent and add some 8 per cent to gas demand in the ASEAN power sector in 2035 or another 10 bcm.

Oil-fired generation is mainly in Pakistan and Bangladesh and to a lesser extent in Thailand. With low gas prices there might be some scope for gas to gain share. If some half of the oil-fired generation switched to gas, in these three countries, this could add some 30 TWh or so to gas-fired power, around 6 bcm.

In the Industry sector, energy demand grows around 2.5 per cent per annum to 2035 and 1.25 per cent per annum thereafter. This growth seems to be broadly consistent across all fuels, with only electricity growing slightly faster. Gas largely maintains its share of total industrial energy demand at some 12 per cent. Oil and gas are used in similar industrial sectors – chemicals and petrochemicals (both steam-raising and as a feedstock) and in smaller industries. Coal is predominantly in iron and steel, non-ferrous

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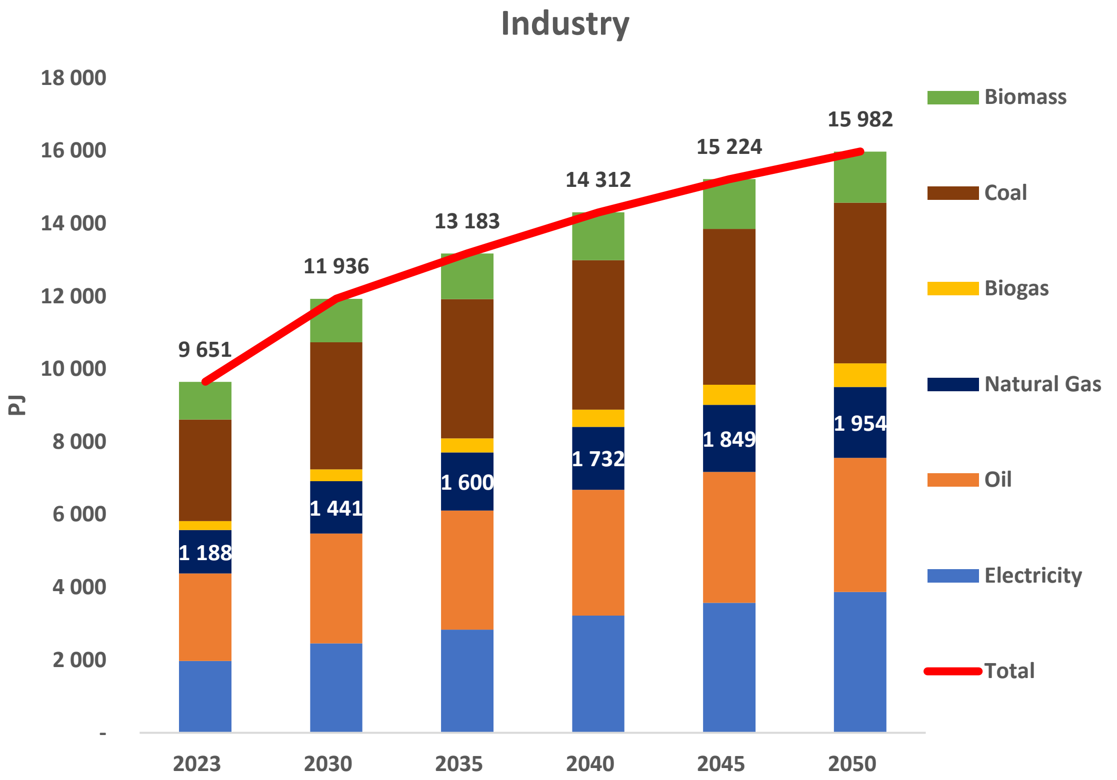
metals, and non-metallic minerals (e.g. cement). The gas share in industry has not changed significantly over the last 20 years or so, and while lower gas prices might help to gain share in steam-raising, the ability to switch may be limited, except possibly in smaller industries, which are, or can be, connected to the gas pipeline system.

Figure 49: ASEAN industry energy demand



Source: IEA WEO 2024

d) Short Term Price Response

The analysis in the previous section suggests little scope for imported gas – such as LNG priced at $6 or below - to significantly expand its market share in the short term in industry or the feedstock non-energy use sector. The largest scope would appear to be in the power sector in most countries, apart from Singapore where gas already dominates the power sector. Gas also has a large share in the power sector in Bangladesh and Thailand, so the scope for a big increase in the gas share here may be limited – although Bangladesh still uses a lot of oil. In Thailand the gas share has recently come under pressure, notably in 2022, when gas lost share to power and this year when low coal prices, relative to $13 LNG, saw coal gain share against gas. $6 gas could significantly change this perspective.

It was noted in the previous sub-section that, if coal utilization in power in ASEAN did not increase from 2030 and gas benefitted fully from this then additional gas demand, with low gas prices, could, theoretically, be 10 bcm higher in 2035. In addition, against oil, gas could be very competitive and gain share by some 6 bcm. If this total of 16 bcm is seen as the maximum short-term price response then maybe a range from 6 to 16 bcm would be reasonable, equating to some 2.5 per cent to 6 per cent of 2030 Emerging Asia demand.

e) Long Term Price Response

The possible long-term prices response is more about the rate of infrastructure growth to supply growing energy demand, especially in the power sector. In the emerging Asian market, power generation capacity is expected to grow rapidly to 2050. Gas-fired power generation almost doubles by 2050 but wind and solar growth is especially rapid. The growth in wind generation capacity is particularly strong, which is surprising as only Philippines, Thailand, and Vietnam have any wind generation currently and

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this is likely to remain the case in the future. Indonesia, Malaysia and Singapore are too close to the equator, where wind prospects are too poor to justify any investment. Wind power capacity in ASEAN is projected to grow to 65GW by 2035, compared to 8GW in 2023, according to IEA STEPS WEO 2024. This growth in wind power looks over-optimistic anyway, but more so if coupled with sustained low prices for gas. Much of the wind power is expected to be offshore, especially in Vietnam, the most promising, and that would look very expensive on a levelized cost basis compared to gas-fired CCGT plants with wholesale gas prices at $6 per MMBTU or less.

If wind power simply grew in line with solar power, which is much more promising in the ASEAN region, then wind capacity would be 25 GW lower by 2035 – this translates into 70 TWh reduced wind power in 2035. If all of this was replaced by natural gas, then this would be around 14 bcm additional gas demand in 2035. This gap could widen to 145 TWh by 2040 – equivalent to an additional 30 bcm of gas demand in power generation. On top of this, the additional 6 bcm from industry could also be added to this, giving an additional 20 bcm by 2035, rising to 36 bcm by 2040. The range in percentage terms would be some 2 - 6.5 per cent of total Emerging Asia gas demand in 2035.

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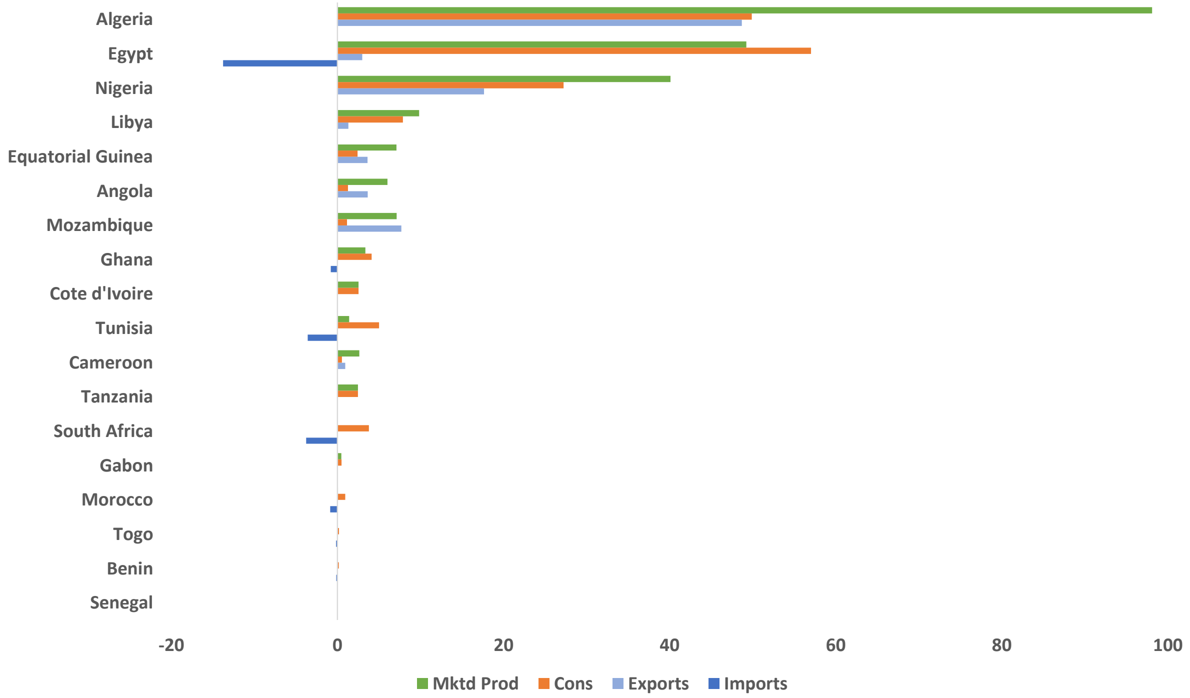
8. Africa

a) Background

The purpose of this paper is to assess the impact of a fall in international natural gas hub prices on the demand for gas in different countries and regions. As outlined in the introduction, this raises two fundamental questions; what would be the short-term gas price sensitivity and what is the fuel 'switchability' potential if low gas price levels are sustained in the long term? To address these two issues in the African context, it is important to start with a brief overview of the natural gas supply, demand and trade situation for this continent.

Africa is a very diverse region containing more than fifty countries and its endowment in natural resources varies dramatically from one subregion to another. Natural gas reserves, production and consumption are highly concentrated in a few subregions or countries. At present, five countries (Nigeria, Mozambique, Algeria, Egypt, and Libya) account for over 90 per cent of Africa's proved natural gas reserves. North Africa (Algeria, Libya, and Egypt) and Nigeria in West Africa currently represent 85 per cent of all the gas produced and consumed in Africa. Three countries (Algeria, Nigeria, and Mozambique) cover about 90 per cent of the continent's gas exports and Egypt is Africa's largest importer of gas supplies from outside the region (see Figure 50).

Figure 50: Africa natural gas production, consumption, exports and imports (bcm) – 2024



Source: International Gas Union & Other

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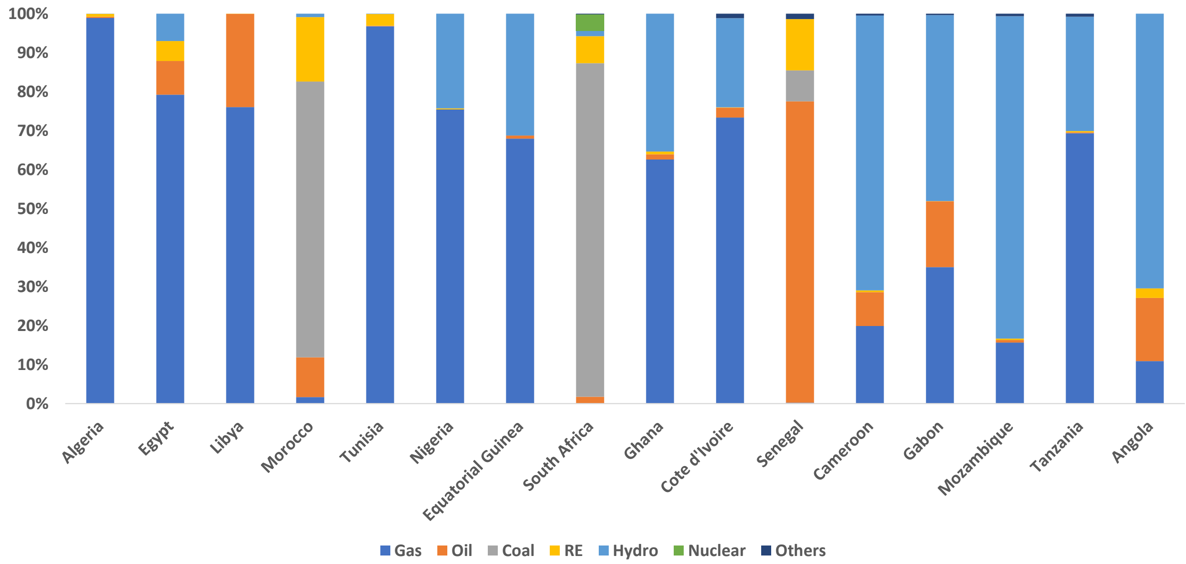
b) Energy or fuel mix

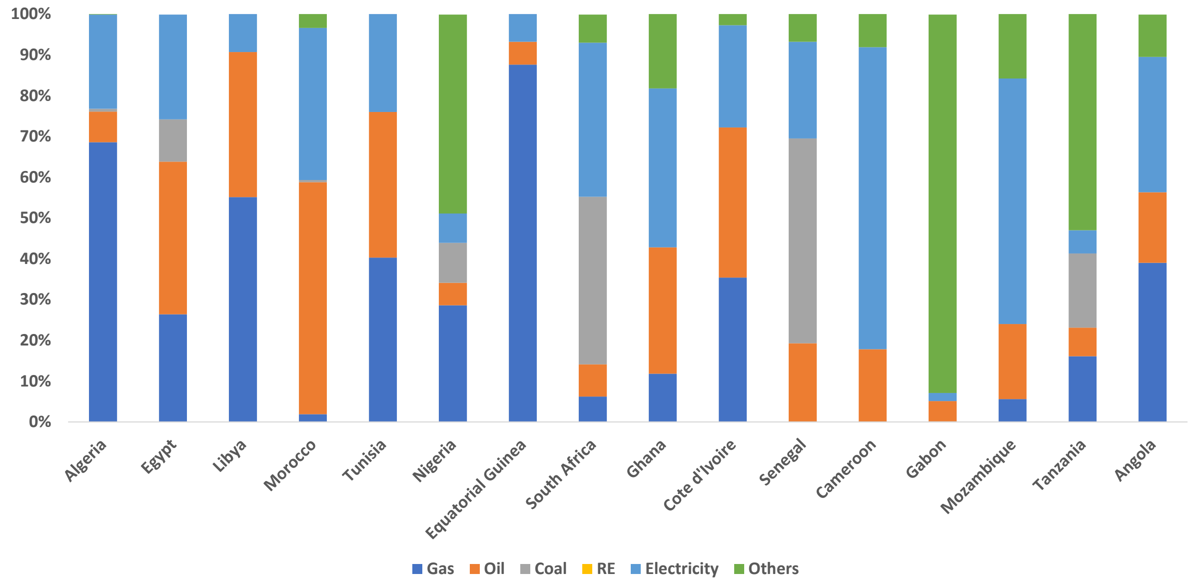
The structure of the energy or fuel mix in African countries reflects their level of endowment (or not) in energy resources. This is clearly illustrated in the energy or fuel share distribution for the two key energy and fuel consuming sectors, electricity generation and industry (see Figures 51 and 52)

Figure 51: Africa energy or fuel shares in electricity generation – 2022[137]



Source: IEA World Energy Stats and Balances

Figure 52: Africa energy or fuel shares in industry (final consumption) – 2022[138]



Source: IEA World Energy Stats and Balances

In Africa's leading gas producing countries, natural gas as a generating fuel accounts on average for over 80 per cent of all the electricity generated. In Libya, constrained indigenous gas production has forced the authorities to increase oil products consumption to generate electricity. For some countries,

[137] Latest disaggregated data available from the International Energy Agency.
[138] Idem.

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like Tunisia which has relatively easy access to sources of gas supplies (imports and transit gas from Algeria), gas occupies a large share of the fuel generation mix. However, in Mozambique, a large gas reserve holder, the country's hydroelectricity supply accounts for over 80 per cent of all the electricity produced.

In South Africa and Morocco, coal is by far the dominant electricity generating fuel, as shown in Figure 51. Morocco has a relatively large renewable energy capacity but has also been planning for the development of an LNG import and power project. This year it launched an invitation for expressions of interest to develop an energy infrastructure project that includes the construction of a new gas import terminal. [139]

In Industry, only a few African gas producers have a significant share of natural gas use in this sector's final energy (and feedstock) consumption. It mainly represents consumption by gas-based industries such as fertilizers. In several African countries, there is a non-negligible share of electricity in the industrial sector's final energy consumption. In gas producing countries the bulk of this electricity is generated with gas supplies. This shows the wider and significant role of natural gas in these countries' economies.

c) Africa's gas pricing formation

The price sensitivity of natural gas demand in Africa, where energy prices are heavily regulated or controlled, is quite different from that seen in liberalised gas markets (e.g. Europe and the US).

According to the latest survey of wholesale gas prices conducted by the International Gas Union,[140] in 2024, only about 12 per cent of Africa's gas consumption was priced based on gas-on-gas competition (GOG), as shown in the Figure 53. This compares to 82 per cent in Europe and about 50 per cent globally. However, this 12 per cent share conveys a distorted view of gas-on-gas competition in Africa, as it covers only three countries: Nigeria, where gas pricing in some non-strategic segments of the domestic gas market has been liberalised; Egypt, where pricing of a few billion cubic metres (bcm) of imported gas consumed by certain industries are categorised as GOG; and Morocco which imports small LNG volumes (about 1 bcm in 2024) from international markets via Spain which are shipped in reverse flow through the Gaz Maghreb Europe cross-border gas pipeline linking Morocco to Spain. Thus, apart from segments of Nigeria's domestic gas market, there is no real gas-on-gas competition in gas pricing formation in Africa.

About 50 per cent of the gas consumed in Africa is priced below cost, with only 20 per cent of the gas used priced at cost of service. Modelling and quantifying the long-term price sensitivity of gas demand in Africa under a much less regulated and controlled environment or scenario would require a very elaborate process that assumes a timely implementation of effective market and pricing reforms in African domestic energy markets, which is a challenging proposition.

Average wholesale gas prices in North Africa are split between those markets – Algeria and Libya – where prices are heavily subsidised, and the importing markets of Tunisia, Morocco, and Egypt (for some non-power users), where prices are at much higher levels.

In Sub-Saharan Africa, gas pricing is varied. Nigeria, Tanzania and some other gas producers have lower prices as indigenous gas production supplies all domestic users. Ivory Coast and Cameroon have higher gas prices, as does Ghana, where gas supply is a mixture of domestic production and imports. It is noticeable, however, that average wholesale gas prices in some Sub-Saharan African countries are currently at $7 or not far from our $6 price scenario level.

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[139] Crisp, Wil (2025). "Morocco seeks contractors for LNG terminal and power station", *MEED*, 25 June. https://www.meed.com/morocco-seeking-contractors-for-major-gas-project

[140] IGU (2025). "Wholesale Gas Price Survey 2025 Edition", 25 June. https://www.igu.org/press-releases/2025-wholesale-gas-price-survey

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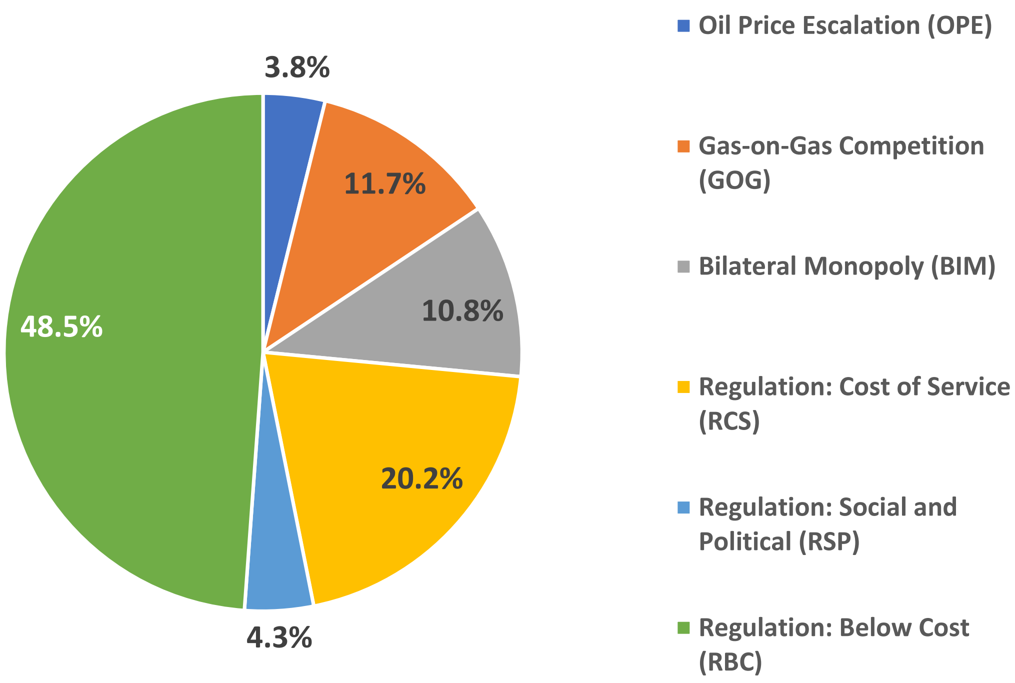
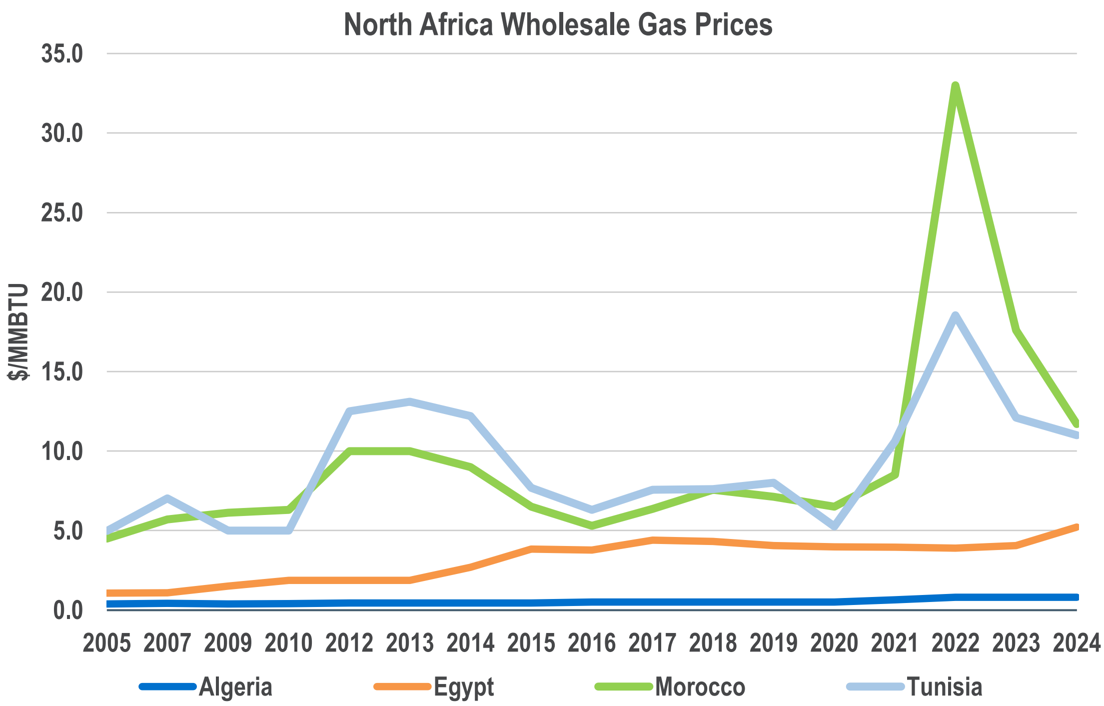
Figure 53: Gas pricing mechanisms in Africa – 2024



Source: International Gas Union Wholesale Gas Price Survey 2025

Figure 54: Africa average wholesale gas prices



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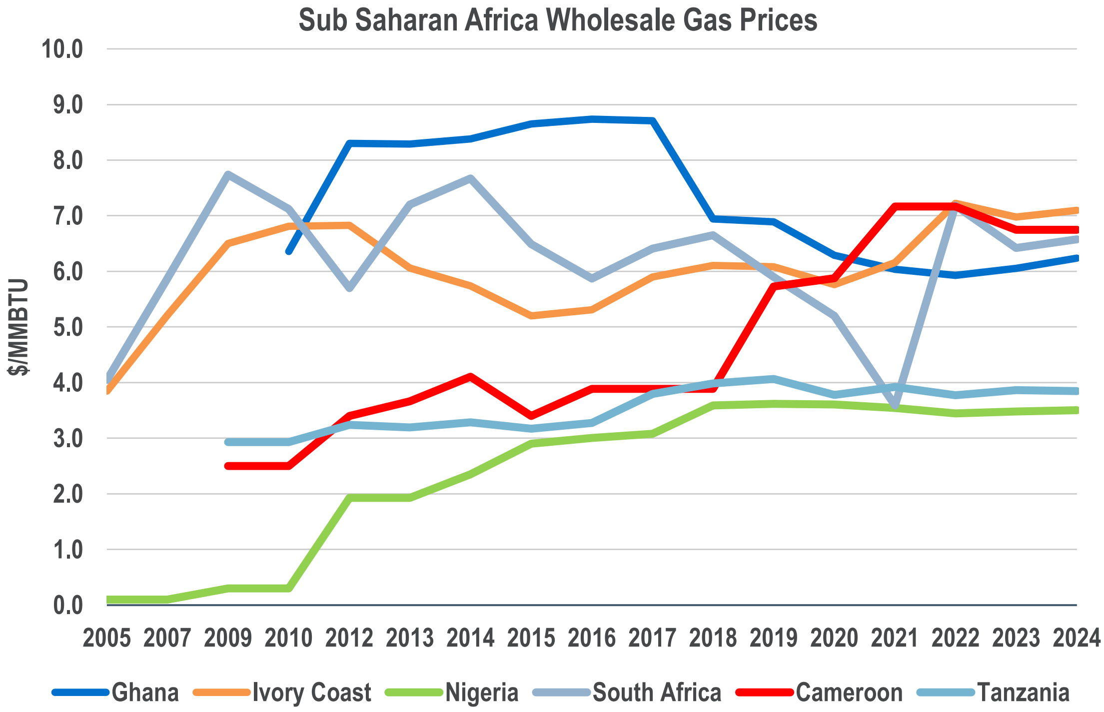

Source: International Gas Union Wholesale Gas Price Survey 2025

d) Energy and Gas Demand Growth

This paper's modelling exercise focuses on the impact of lower international gas hub prices on natural gas demand. It assumes that announced and planned gas development projects are implemented, which is another challenging assumption for ambitious African gas projects that are far from the final investment decision milestone and where financing remains a major obstacle.[141] But the aim of this exercise is to understand how gas demand will respond to gas price changes, if announced policies, project plans, etc. are implemented.

The STEPS scenario of the IEA's World Energy Outlook (WEO) 2024 foresees a rapid growth in electricity generation capacity in Africa, driven largely by solar and wind, but it also shows growth in gas-fired capacity. Coal-based capacity, which is only in South Africa, Botswana, Zimbabwe, and Morocco, declines. Gas is largely, therefore, in competition with renewables, and displacing oil-fired generation.

The results of this gas flow analysis presented in Figures 56 and 57 for North Africa and Sub-Saharan Africa, show moderate growth in gas demand in North Africa over the 2024 – 2035 period. This is due to a projected stagnating indigenous gas production in this subregion over the same period and the already very high levels of natural gas use in electricity generation in North Africa (except in Morocco).

However, in Sub-Saharan Africa, natural gas demand is shown to increase significantly over the 2024 - 2035 horizon, especially for the power sector. This reflects a significant growth in indigenous gas production over the same period to 2035, driven mainly by a notable jump in Nigeria and Mozambique's gas production. This could appear a counter-intuitive result, since low gas prices – if sustained for a long period - could provide limited or no incentives for international upstream investments, especially in high-risk areas. The model simulations show also a noticeable growth in gas demand for the industrial sector (including the energy industry), but it remains limited to few countries.

[141] Ouki, Mostefa (2024). "Financing gas projects in Sub-Saharan Africa", in "Gas to 2030: Transition, Supply Risk and Market Uncertainty", Oxford Energy Forum, Issue 141, Oxford Institute for Energy Studies, September 2024. https://www.oxfordenergy.org/publications/gas-to-2023-transition-supply-risk-and-market-uncertainty-issue-141/

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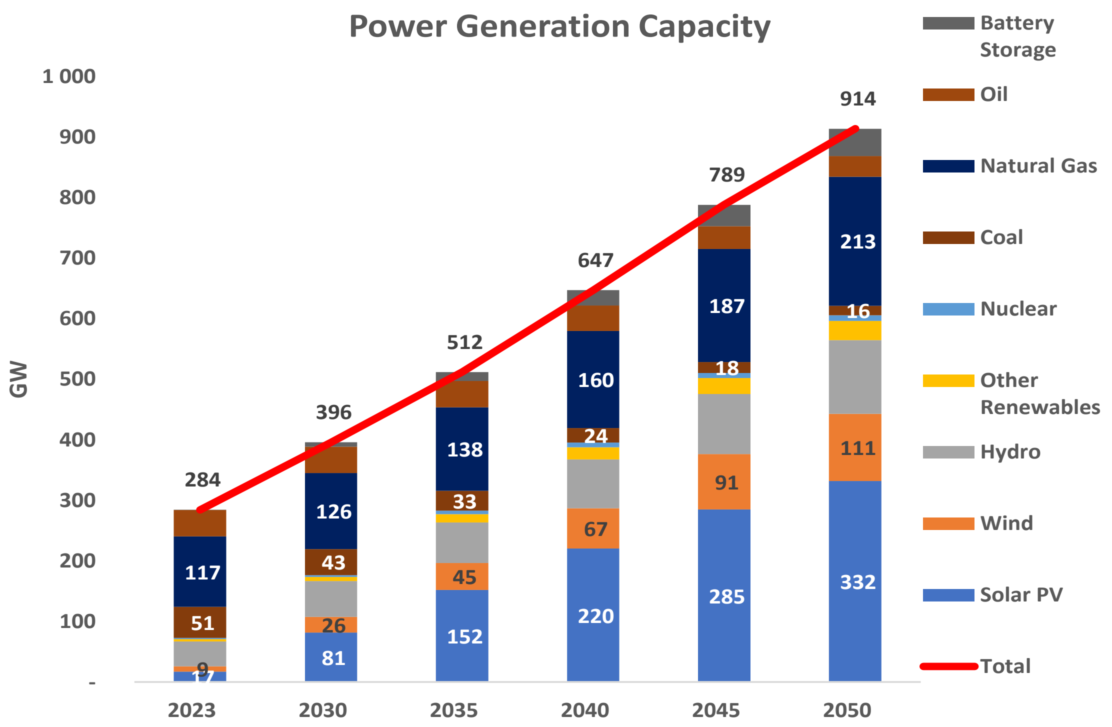
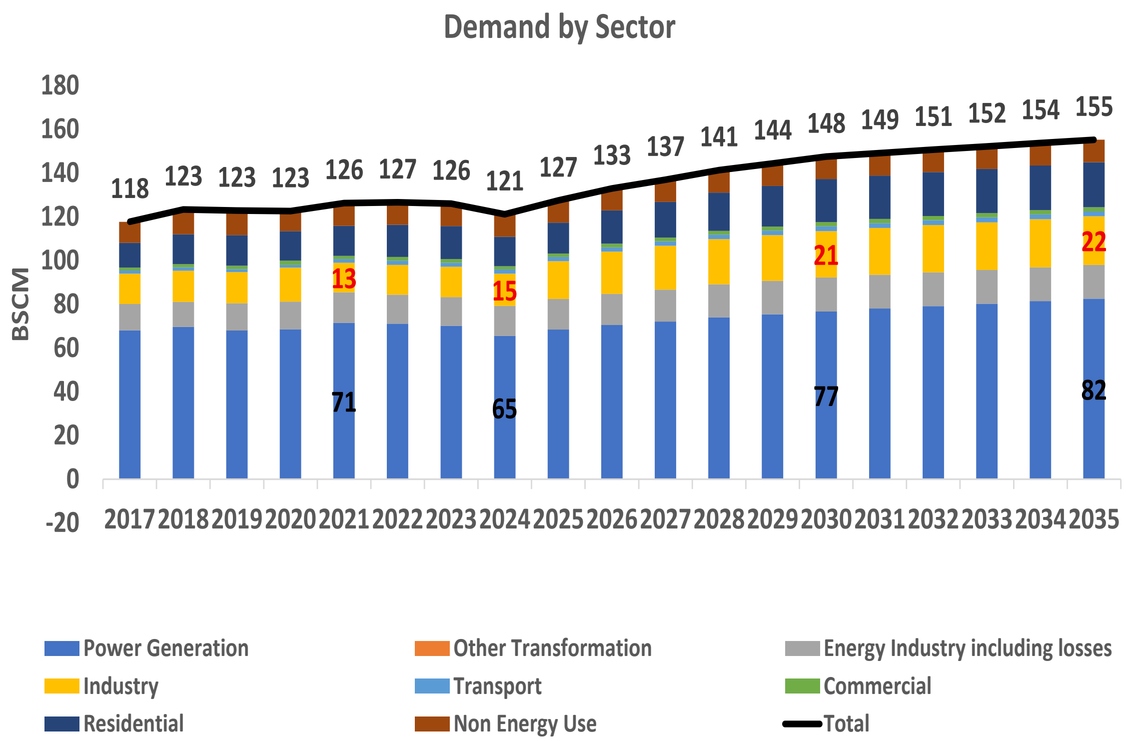
Figure 55: Africa power generation capacity



Source: IEA WEO 2024

Figure 56: North African gas demand by sector: 2024 – 2035 (bcm)



Source: NexantECA World Gas Model, OIES

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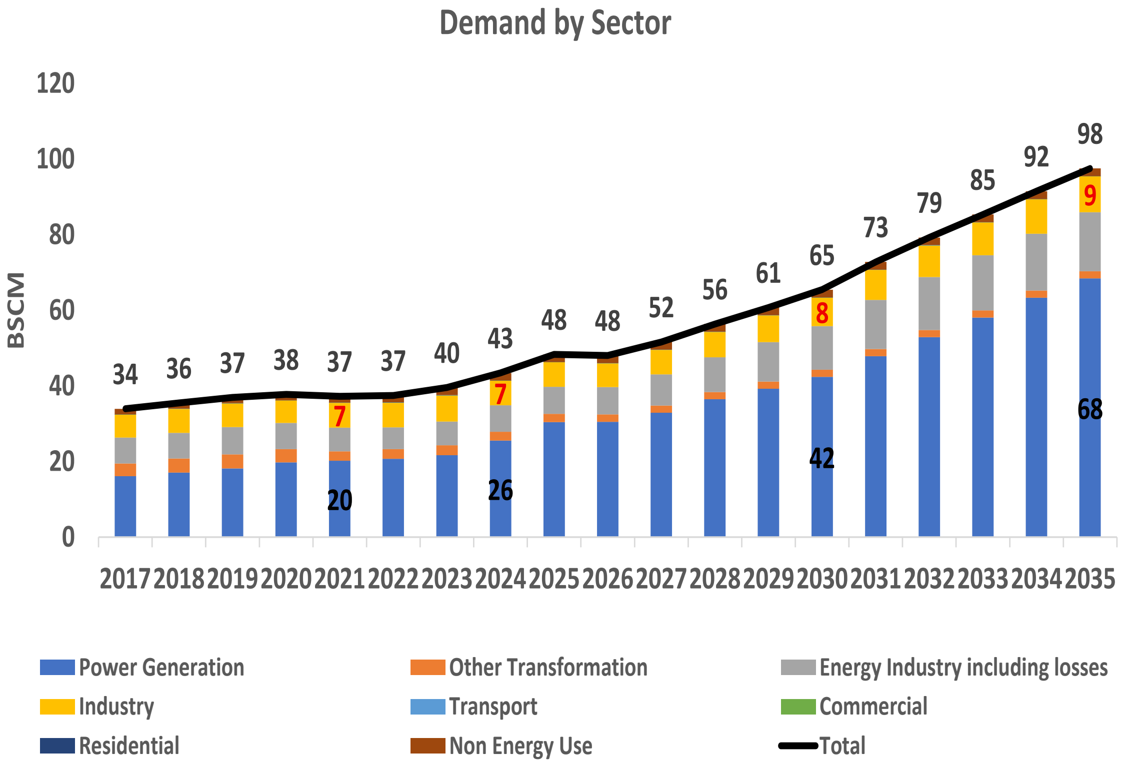
Figure 57: Sub Saharan African gas demand by sector: 2024 – 2035 (bcm)



Source: NexantECA World Gas Model, OIES

e) Switching to Natural Gas

The concentration of natural gas reserves in a few subregions of Africa limits the expanded use of gas, or move to gas, in the power sector across the continent. Some African economies have gradually managed to switch to natural gas for the generation of electricity by monetising their indigenous gas reserves. The case of Ghana represents an example of the possible development of gas in the power sector, where over ten years ago, hydro accounted for about 70 per cent of the country's electricity supply. The share of natural gas in the electricity generation mix was then about 12 per cent, with oil products representing 20 per cent of the fuel mix (see Figure 58).

This changed radically over the years as Ghana started to use its own natural gas with additional supplies imported from Nigeria through the West African Gas Pipeline. At present, close to two-thirds of the electricity generated in Ghana is based on the use of natural gas as a generating fuel. The share of oil products dropped substantially to less than 2 per cent and the contribution of hydroelectricity declined to about a third of total. It should be noted that part of this decline is due to a drop in dam water levels because of severe droughts.

Developing Ghana's natural gas market, which is closely linked to the country's financially fragile electricity market, has not been an easy process and the country's energy sector continues to face some serious financial challenges. Several LNG import proposals were in the past submitted to the Ghanaian government, driven partly by the previous large drop in international gas hub prices.[142] which resulted in the construction of the Tema LNG import terminal in Tema, Ghana's industrial centre. But no LNG imports have yet taken place. It is rather the development of Ghana's indigenous gas reserves and, to a certain extent, imports from Nigeria that have enabled the country to switch to natural gas.

[142] Fulwood, Michael (2020). "$2 gas in Europe is here: who will blink first?", Oxford Institute for Energy Studies, March. https://www.oxfordenergy.org/publications/2-gas-in-europe-is-here-who-will-blink-first/

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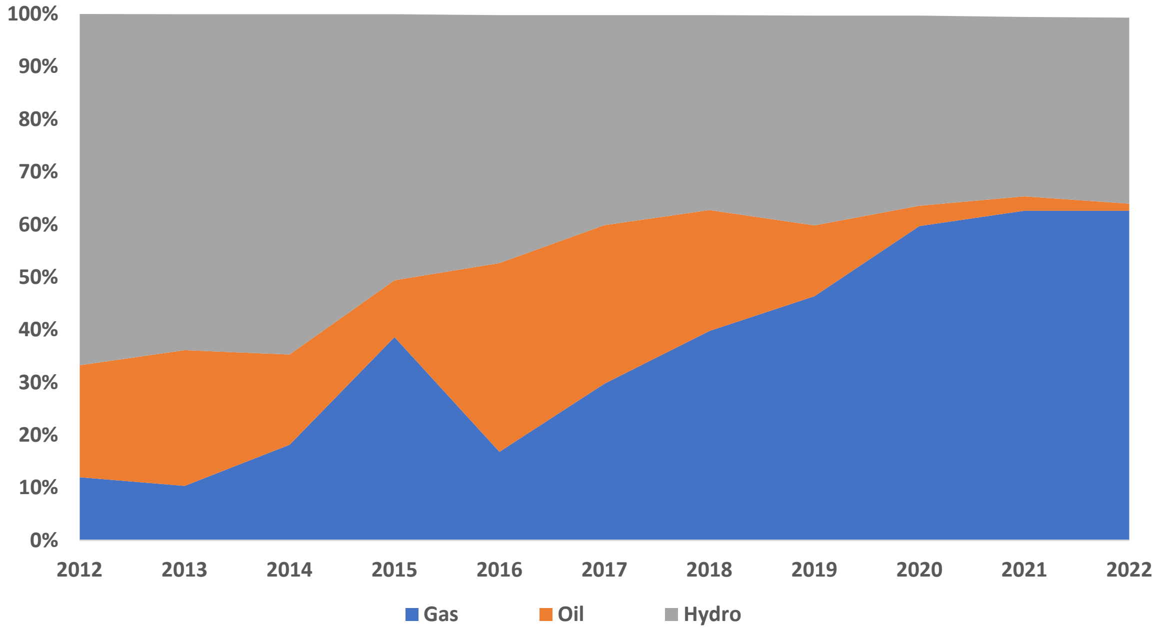
Furthermore, for a long time the contribution of (non-hydro) renewable sources of energy to the generation of Ghana's electricity supply remained well below the 1 per cent mark. Efforts have been deployed to increase the use of solar energy, but its share in the country's generation mix is still very modest and still just below 1 per cent.

Figure 58: Ghana - fuel shares in electricity generation: 2012 – 2022



Source: International Energy Agency

The switch to natural gas could be complicated, even if a country is potentially endowed with natural gas resources and could potentially have access to imported LNG supplies. For example, in Africa's largest economy, South Africa, the generation fuel mix continues to be heavily dominated by coal which accounts for about 90 per cent of this mix. Over the last ten years, there has been a consistent increase in the share of renewable sources of energy in South Africa's electricity supply mix. But the share of these green sources of energy remains limited and below 10 per cent. It should be noted that the modest contribution of renewable energy in the electricity generation mix is a common feature in most African countries. This is mainly explained by the lack of investments, especially in Sub-Saharan Africa. At present, Africa receives only 2 per cent of clean energy investments despite accounting for 20 per cent of the global population.[143]

With respect to natural gas, there have been several planned projects to develop South Africa's indigenous natural gas resources, as well as different plans to import LNG supplies, including a recent project to import LNG from neighbouring Mozambique (Matola LNG). South Africa currently imports gas from Mozambique through the cross-border gas pipeline, Rompco, that links Mozambique's Temane and Pande gas fields to South Africa's industrial centre in Secunda. As production from these maturing fields declines, planned LNG supplies which will be shipped via Rompco are expected to gradually compensate for this fall in production in Temane and Pande.

A long-term drop in international gas hub prices may help South Africa focus more on a switch to natural gas use in both industry and electricity generation. But it is unlikely to happen quickly and drive large LNG imports into South Africa. The country is still facing financial, political, and social challenges to transit away from coal[144] to both natural gas and renewables.

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[143] International Energy Agency (2025). "World Energy Investment 2025", June. https://www.iea.org/reports/world-energy-investment-2025

[144] Latta, Rafiq (2025). "South Africa's Struggle to Transition from Coal", *Energy Intelligence,* 13 August. https://www.energyintel.com/00000198-9ebd-db4e-a9bd-9fbf10e60003?utm_campaign=Conversation+of+the+Century%2C+August+18%2C+2025&utm_medium=email&utm_source=sendgrid.com&utm_term=20250818Z

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f) Conclusions for Africa

In Africa, the impact of a drop in international gas hub prices both in the short term and up to 2035 will be quite different from those regions of the world where gas markets are liberalised. It is important to note that presently only one African country, Egypt, imports LNG supplies directly (Senegal started importing very small LNG volumes this year, but on a temporary basis, while Morocco purchases small volumes of LNG that are shipped via Spain's gas pipeline interconnection with Morocco). Thus, Egypt and to a certain extent Morocco, are the only African countries currently exposed to international gas hub prices in their LNG purchases. Furthermore, gas-on-gas competition price formation affects only some non-strategic segments of Nigeria's domestic gas market. In North Africa, gas-to-power capacity is already very high, and, in some countries, there is even excess power capacity. Consequently, the increased use of gas in the power sector would be limited. Prospects for higher gas demand growth are more likely to materialise in Sub-Saharan Africa.

In the short-term, the fall in international gas hub prices is unlikely to affect Africa's existing or potential new gas importers and quickly increase its gas imports. Most of Africa's economies, where energy prices are regulated or controlled, do not have the necessary energy market and infrastructure flexibility and capacity to respond to short-term gas price opportunities. In Africa's potential gas importing countries, it would take a long time to plan for and implement an LNG import project.

During the second half of the last decade and up to 2020, when gas hub prices collapsed, more than ten LNG import projects were announced in various subregions of Africa. But none of these schemes was fully implemented. [145] The drastic drop in gas prices seen back then did not result in a rise in Africa's gas imports in the short or even medium term. In fact, the high gas hub price volatility that emerged at the end of last decade and beginning of this decade has been one of the key factors to negatively affect planned gas import projects.[146] Even now, it is unlikely that potential African LNG importers will purchase LNG supplies on a spot basis for long periods of time and be exposed to gas hub price volatility.

If a structural gas price transformation ensures that gas prices remain sustainably low over the long term (a challenging assumption), the switch to gas in the African context will not only depend on natural gas prices, but - more importantly - on how the project risks that investors continue to face to develop commercially viable gas projects in Africa will be managed and mitigated.

[145] As indicated previously, the infrastructure for the Tema LNG import terminal in Ghana was built, but no LNG supplies were received by this terminal. Senegal imported this year 2 LNG cargoes as a temporary measure. From 2026, Senegal is expected to be supplied with indigenous gas.

[146] Ouki, Mostefa (2022). "Africa's LNG import prospects in an era of high volatility and uncertainties", Oxford Institute for Energy Studies, June. https://www.oxfordenergy.org/publications/africas-lng-import-prospects-in-an-era-of-high-volatility-and-uncertainties/

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9. Central and South America

There are 33 sovereign countries in Central and South America (C&SA), if one includes the countries of the Caribbean islands. There are also several islands which are territories of France, The Netherlands and the US.

Argentina, Brazil, Chile, Colombia, and Venezuela account for 76 per cent of the energy demand in Central and South America. These five countries have indigenous natural gas production but all of them import natural gas and LNG (except for Venezuela) to meet domestic demand in the power and industrial sectors. Some Caribbean and Central America countries import LNG, such as Panama, El Salvador, Dominican Republic, Jamaica, Nicaragua, and Honduras, mostly to meet demand in the power sector.

The lack of comprehensive pipeline infrastructure hampers further penetration of natural gas in the region, particularly in countries with incipient industrialisation.

There are currently nine FSRU's in operation in Brazil, most of them with significant idle capacity; in 2024 the utilization rate was 15.6 per cent. Chile has two LNG terminals, one onshore and the other is a hybrid onshore/FSU, while Colombia and Argentina also have a single FSRU each.

In the wake of international sanctions and due to economic issues, Venezuela is an isolated gas market, and local demand is supplied by domestic production.

There are other countries in C&SA with relatively significant gas demand, such as Peru and Trinidad & Tobago, but both countries are LNG exporters and already rely on lower than US$ 6 per MMBTU wholesale gas prices. Bolivia is a pipeline gas exporter to Brazil and Argentina, but gas reserves are depleting fast due to low investment in exploration.

Current Situation

Natural gas in the region is primarily used in the industrial and power sectors. However, Argentina and Colombia have a large number of residential consumers due to gas massification programmes implemented many years ago. In the case of Argentina, the residential sector represents 24 per cent of gas demand, with large swings in winter versus summer; for example, in February 2024, residential demand averaged 12.2 MMm3/day whilst in August it jumped to 66.2 MMm3/day.

Chile currently has an installed capacity of 4930 MW of natural gas-fired power plants, comprising 3880 MW of combined-cycle plants, 100 MW of cogeneration, and 950 MW of open-cycle plants, according to consultants Wood Mackenzie. Roughly half of Chile's gas-fired generation capacity is located in the northern region and supplied mostly with LNG. In addition to LNG, Chile imports pipeline gas from Argentina in the north, central, and southern regions, but there is no pipeline infrastructure connecting Chilean regions from north to south. Solar and onshore wind have been growing fast and accounted for 28 per cent of the power supply in 2022.

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Table 10: C&S America power generation by fuel 2022

Power					
GWh	Argentina	Brazil	Chile	Colombia	Venezuela
Coal	6557	14233	21517	5159	0
Crude Oil	0	0	0	1189	0
Oil products	1902	10304	3060	1619	5708
Natural gas	125495	42110	16088	13895	12107
Nuclear	47723	14559	0	0	0
Hydro	5640	427114	20684	62248	64513
Renewables	93710	111758	25074	592	97
Combust Renew	41065	56820	4595	2341	0
Total	322092	676898	91018	87043	82425
Coal	2%	2%	24%	6%	0%
Crude Oil	0%	0%	0%	1%	0%
Oil products	1%	2%	3%	2%	7%
Natural gas	39%	6%	18%	16%	15%
Nuclear	15%	2%	0%	0%	0%
Hydro	2%	63%	23%	72%	78%
Renewables	29%	17%	28%	1%	0%
Combust Renew	13%	8%	5%	3%	0%
Total	100%	100%	100%	100%	100%

Source: IEA World Energy Stats and Balances

In Chile, coal is still largely consumed in the power sector, accounting for 24 per cent of demand in 2022; in 1H25 it dropped to 18 per cent, due to the government's plans to shut down eight plants by 2024/2025. Natural gas is the predominant fuel source in Argentina's power sector, accounting for 39 per cent of the generation, whilst in Brazil and Colombia, hydropower is predominant, representing 63 per cent and 72 per cent of power demand respectively. This reliance on hydro has caused significant issues during dry seasons, in Brazil (2021) and Colombia (2023-2024) when both countries had to step up LNG imports, mostly on a spot basis to cope with power shortages and increased demand for air conditioning caused by heatwaves.

Due to South America's abundant natural resources, renewable energy, in particular onshore wind and solar PV, is playing an increasingly important role in Argentina, Brazil, and Chile.

Oil products still play a significant role in the industrial sector in the region, particularly in Chile. Natural gas is largely used in Argentina and Colombia, whereas in Brazil high gas prices and deindustrialization are big deterrents – in addition to the sugar/ethanol industries which use sugar cane bagasse as a byproduct fuel, there is evidence that a large number of industries are using cheaper wood for low temperature processes.

In Argentina, industrial consumers have to resort to consuming oil products and LNG in winter, when priority residential demand increases dramatically, because, despite an abundance of unconventional gas resources, there is insufficient pipeline infrastructure to transport gas from Vaca Muerta, in Neuquen province, to the main demand centres in Buenos Aires and the North.

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Table 11: C&S America industry by fuel 2022

Industry					
TJ	Argentina	Brazil	Chile	Colombia	Venezuela
Coal	55	331	9	66	2
Oil products	99	388	170	30	22
Natural gas	319	382	44	60	224
Renewables	0	1	0	0	0
Combust Renew	65	1567	60	55	6
Electricity	306	787	169	45	60
Heat	25	0	0	0	0
Total	870	3458	452	256	314
Coal	6%	10%	2%	26%	1%
Oil products	11%	11%	38%	12%	7%
Natural gas	37%	11%	10%	23%	71%
Renewables	0%	0%	0%	0%	0%
Combust Renew	8%	45%	13%	21%	2%
Electricity	35%	23%	37%	18%	19%
Heat	3%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%

Source: IEA World Energy Stats and Balances

Table 12: C&S America non-energy use by fuel 2022

Non-Energy					
TJ	Argentina	Brazil	Chile	Colombia	Venezuela
Coal	2	6	0	0	0
Oil products	184	593	30	7	4
Natural gas	14	41	15	6	0
Renewables	0	0	0	0	0
Combust Renew	0	0	0	0	0
Electricity	0	0	0	0	0
Heat	0	0	0	0	0
Total	200	640	44	13	4
Coal	1%	1%	0%	0%	0%
Oil products	92%	93%	67%	54%	100%
Natural gas	7%	6%	33%	46%	0%
Renewables	0%	0%	0%	0%	0%
Combust Renew	0%	0%	0%	0%	0%
Electricity	0%	0%	0%	0%	0%
Heat	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%

Source: IEA World Energy Stats and Balances

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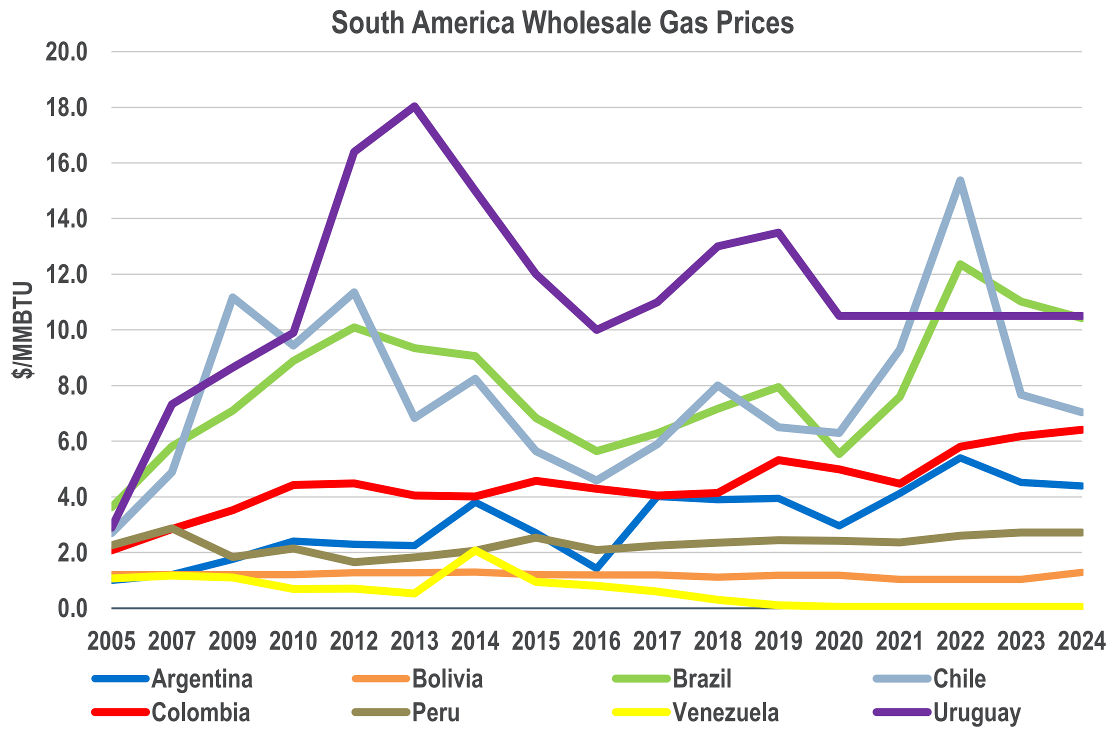
Non-energy uses, particularly as a feedstock for petrochemicals and fertilizers, are mostly dependent on oil products, particularly naphtha, and rarely use gas as natural gas is either not available, or it is not price competitive. Natural gas is also used in refining operations as the main feedstock for hydrogen production via steam methane reforming (SMR). In Argentina, the main non-energy use of oil products is in the chemical and petrochemical industries, producing items like plastics, detergents, pharmaceuticals, lubricants, etc., with significant use of both oil derivatives and local natural gas.

Gas Pricing

According to the IGU Wholesale Gas Price Survey 2025, average natural gas prices in C&SA have been at or around $6-7 per MMBTU, except for in Brazil, Uruguay (which imports small amounts of pipeline gas from Argentina) and some Caribbean countries, which import small volumes of LNG. In the case of Brazil, the price of gas is set around 11-13 per cent Brent, but prices for consumers, large and small, include transportation and distribution fees of around $4 per MMBTU, resulting in actual prices of $14-17 per MMBTU for large consumers.

Higher wholesale gas prices reflect either situations of hydro distress (Brazil, Colombia), or high seasonal electricity demand (Argentina, Jamaica, Panama) which cause increased imports of LNG, mostly on short term or spot prices. In the case of Colombia, gas prices have spiked over the last two years, as a consequence of very dry seasons and the fact that domestic gas reserves have been depleted in the wake of the government moratorium on new exploration licenses and the need to import LNG. Gas prices in Central America have generally been higher than in South America, reflecting their import dependency, and dependence on spot and hub-priced LNG.

Figure 59: Average wholesale gas prices in C&SA



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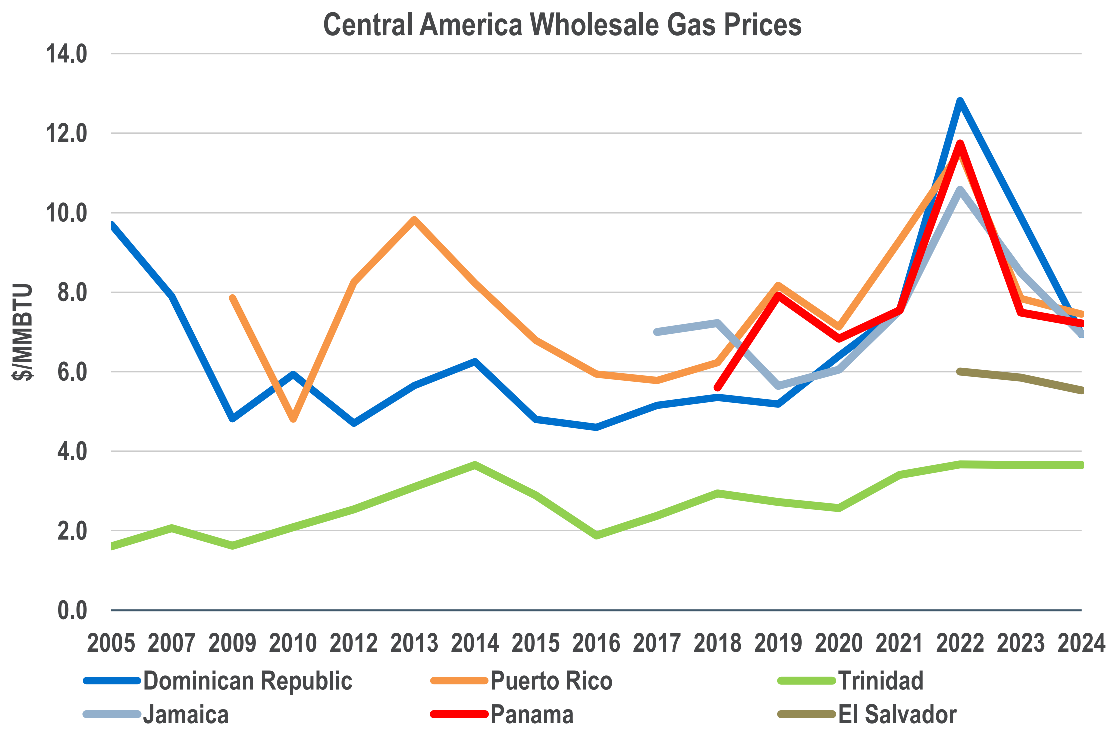
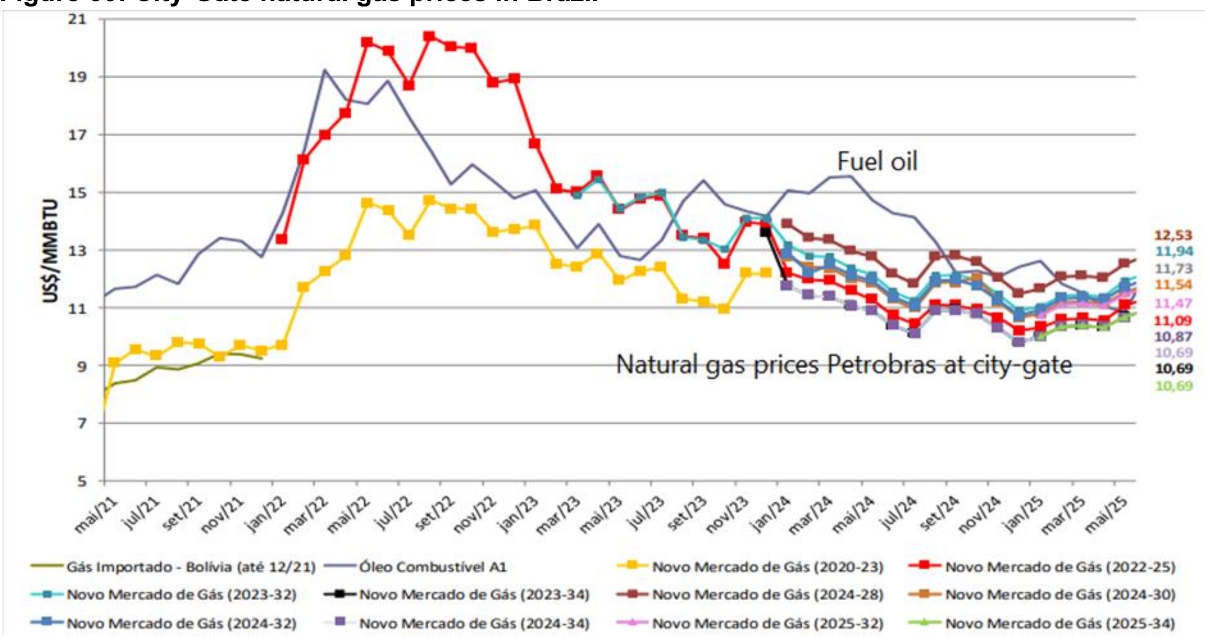


Source: IGU Wholesale Gas Price Survey 2025

Figure 60: City-Gate natural gas prices in Brazil



Source: Brazil's Ministry of Mines and Energy

Figure 60 shows historic gas prices and new contract prices between Petrobras and Local Gas Distribution Companies (LDCs) at the city-gate level, in comparison to fuel oil prices (Oleo Combustível A1). Each gas price line refers to a different contract, for example Novo Mercado 2024-2028 refers to a 4-year contract, from 2022 to 2025, whereas Novo Mercado 2025-2034 refers to a 9-year contract, from 2025 to 2035. City-gate prices include two components: the commodity price and transportation fees. Petrobras has recently tried to respond to increasing competition from other producers, so the 2024-2028 city gate price is $12.53 per MMBTU versus $10.69 per MMBTU for the 2025-2035 contracts.

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In Chile, the Government is planning to accelerate the phase-out of the remaining coal plants from the original deadline of 2040 to 2035. Between 2019 to 2026, coal-fired plant capacity is expected to shrink from 5625 MW to 1683 MW, with most of the capacity being replaced by renewable energy or battery systems - low duration battery storage systems (BESS) are expected to reach 3.9 GW by 2030.

By 2026, only 377 MW will be converted from coal to natural gas, and another 352 MW could either be converted to biomass or natural gas. If the Government implements a full retirement of the remaining coal-fired plants by 2035, there is scope to convert another 832 MW to natural gas in Mejillones and Tocopilla, which are served by the Mejillones LNG terminal. By 2035 this could add another 1.13 bcm/yr to gas demand in Chile. Gas substitution in the industrial sector, even at cheaper wholesale prices, faces two key hurdles: a) Chile's natural gas pipeline network is underdeveloped, particularly in southern regions where manufacturing activity is prominent; and b) high retail gas prices, driven by markups in transportation and distribution fees, make oil products more appealing for cost-sensitive industries.

In Brazil, cheaper natural gas could boost industrial, petrochemical, and fertilizer demand, sectors which are very sensitive to prices and face competition from countries where domestic gas prices are low. Brazil imports most of its nitrogen-based fertilizers from Russia, but the government wants to reduce the dependency on imported fertilizer. Petrobras has announced that they will re-open three ammonia/urea plants, which have been mothballed since 2022, due to high gas prices. With lower gas prices there is a possibility to complete a fourth plant whose construction was halted in 2015 and also to build a fifth plant in Minas Gerais state.

From 2027, low gas prices would increase consumption, due to higher capacity factors in the petrochemical industry, increased uptake by manufacturing industries, and the reactivation of idle fertilizer plants. Post 2030, lower gas prices would encourage investment in new industrial and non-energy use capacity, potentially adding 11.9 BCM by 2030. Power generation would be less impacted due to the predominant growth of renewable energy, but natural gas will be required as insurance against intermittency and to provide supply reliability to new data centres, which are expected to grow by 11 per cent from 2024 to 2029.

In Argentina, wholesale gas prices are already below $6 per MMBTU, except when it is necessary to import LNG in winter due to insufficient domestic pipeline infrastructure. It could be argued that lower gas prices, if cheaper than oil products, would result in fewer imports of diesel and fuel oil in winter. This could add around 1 bcm of industrial gas demand post 2026. There is the possibility to increase the use of gas in petrochemicals, which will depend on investment on enabling infrastructure, such as pipelines, processing plants, and terminals. There is a possibility of two potential urea projects, totaling 2.5 MM tons/annum, which could add 1.2 bcm of gas demand from 2031.

In Colombia, gas prices spiked to $10-13 per MMBTU in the summer months of 2024-2025 due to constraints in domestic supplies, in the wake of the government's decision to halt new permits for oil and gas exploration. Even if wholesale gas prices drop to around $6 per MMBTU this might not result in additional demand because domestic supplies are expected to drop by 20 per cent by 2026 and 70 per cent by 2030, thus any new gas supply would cover existing demand. Colombia's only LNG terminal (SPEC LNG) is operating at full capacity during very hot months, and the owners are increasing its capacity from 11 MMm3/day to 15 MMm3/day by 2027. Two other smaller terminals have been announced, adding 5.4 MMm3/day of regasification capacity, but are struggling to attract investors. Colombia's hopes lie on future offshore gas production, the Sirius project, which could deliver 4.1 bcm/yr by 2029-2030. But the combination of LNG and offshore supplies will merely fill the gap of depleted domestic reserves.

Dominican Republic's energy policy combines renewable expansion, development of new natural gas power plants, and mandatory storage systems to ensure grid stability. Renewable energy share is projected to exceed 25 per cent by 2025 and approach 30 per cent by 2030. The government is also implementing an ambitious gas-for-transport programme and private companies are installing small LNG supply plants near hotels and industrial facilities. Most of the new demand will come from the power sector, with new capacity of 1300-2000 MW by 2030. A second LNG terminal in the north and three new gas-fired power plants (820 MW) are expected to be operational in 2025-2026.

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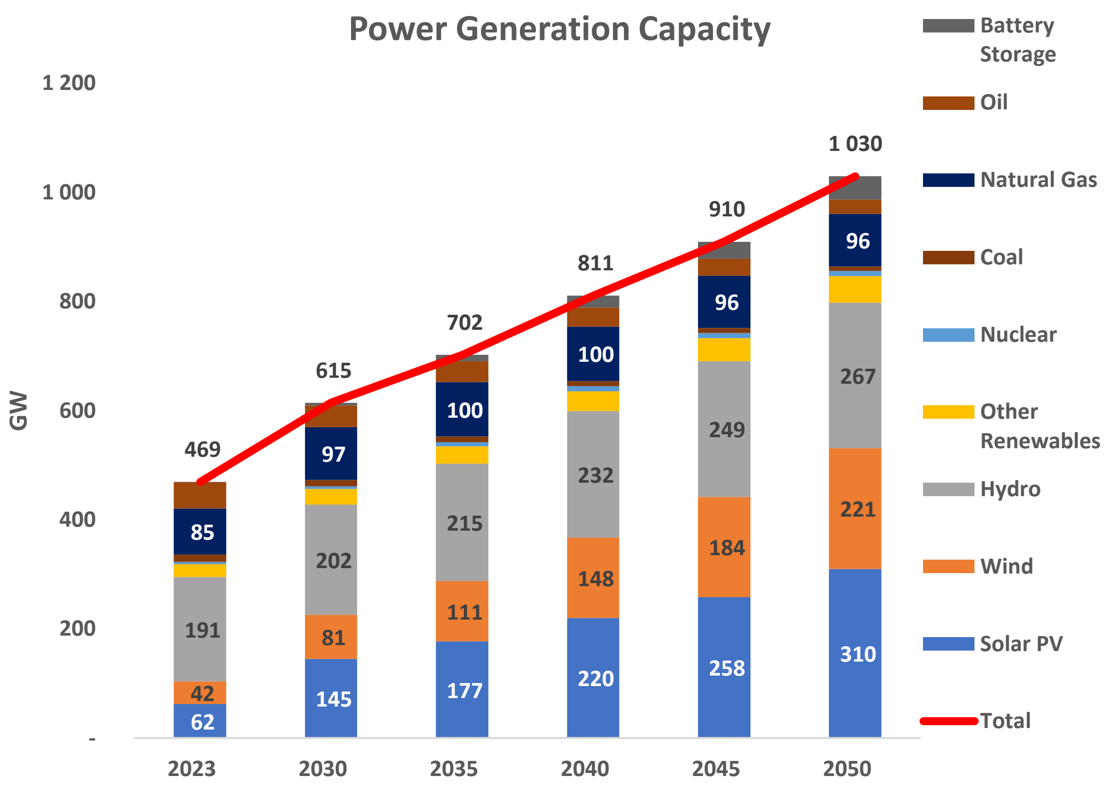
Other Caribbean islands import small amounts of LNG from the US by ISO containers (Bahamas, Barbados, Antigua and Haiti), totaling only 0.03 BCM in 2024, with averages prices of $10.02 per MMBTU. Due to the small size of these markets and expensive infrastructure it is unlikely that demand in these islands will increase significantly.

Demand Scenarios

The IEA WEO 2024 STEPS expects significant growth in power generation capacity, but this is driven by solar and wind, with gas growing to 2030, and then plateauing. This scenario is reliant on an increase in battery storage, and a significant uptick in hydro capacity, which might be hampered by environmental licensing issues.

Figure 61: C&S America power generation capacity



Source: IEA WEO 2024

The Base Case demand scenario projects an overall regional demand of 176.5 bcm/yr in 2027, 186.5 bcm/yr in 2030 and 195.84 bcm/yr in 2035, coming from Brazil and Argentina. The original Base Case was overly optimistic about the increase in gas demand from the power sector, but this did not materialize in 2024-2025 because the consumption in the power sector continues to be dictated by the availability of hydro and other renewables and there is no base load power generation.

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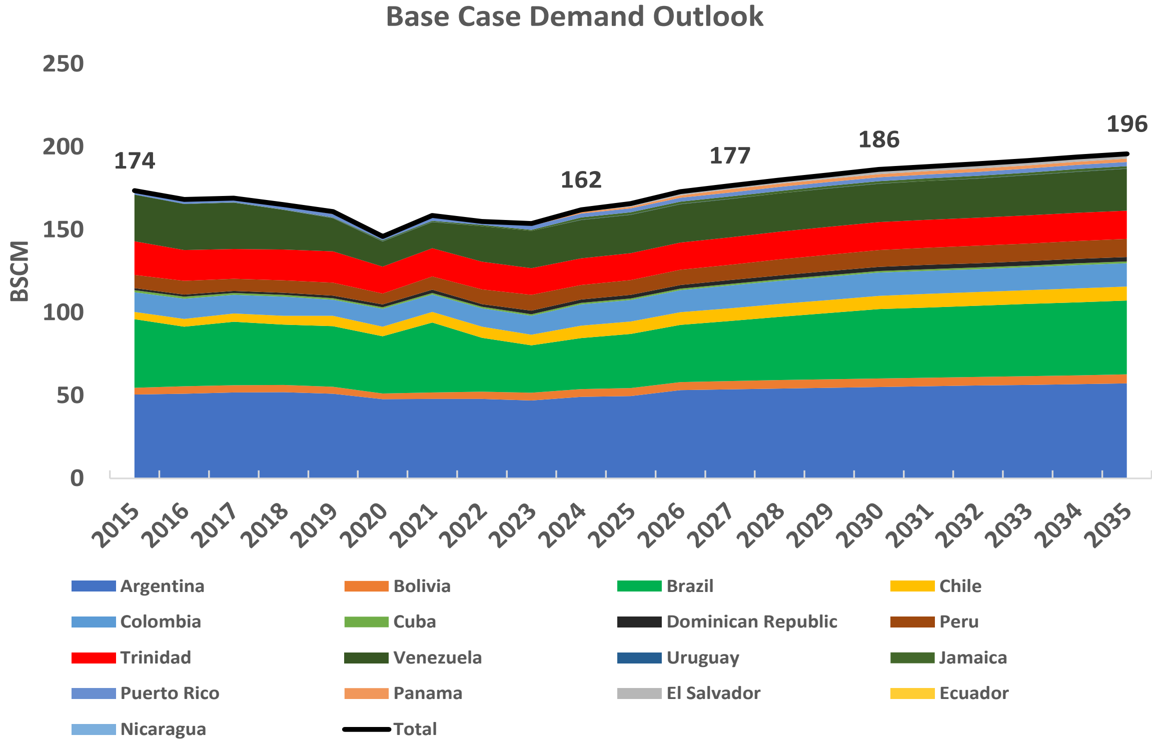
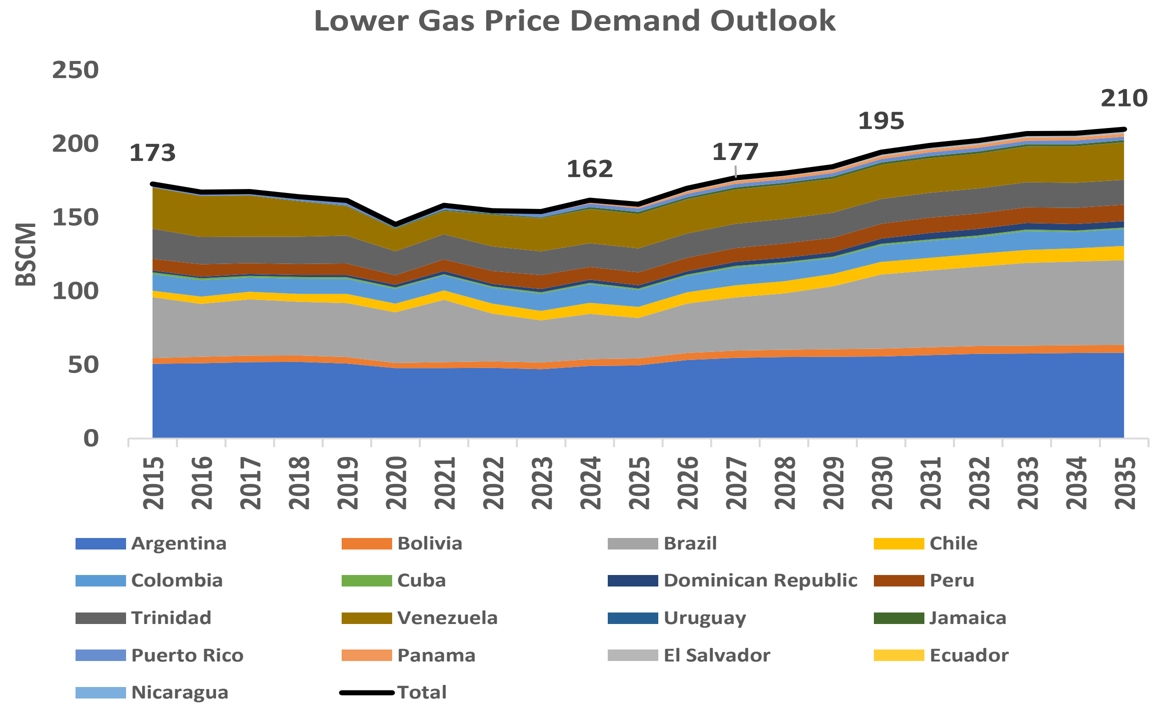
Figure 62: C&S America Base Case demand scenario



Source: NexantECA World Gas Model, IEA

Figure 63: C&S America lower gas price scenario



Source: OIES elaboration based on NexantECA World Gas Model, IEA

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In the Lower Gas Price Scenario, demand is projected to grow to 177 bcm/yr in 2027, 194.57 bcm/yr in 2030 and 209.99 bcm/yr in 2035. Most of the additional increase in demand is slated for Brazil with some growth in Chile, Argentina, and Dominican Republic. In this scenario, Colombian demand actually decreases when compared to the Base Case, due to dwindling domestic supplies.

Short-term Response

Short-term response refers to the demand outlook in 2027. Looking at Argentina, Brazil, Chile, Colombia, and Dominican Republic, the aggregated demand with lower gas prices does not change much, but this is because Brazil's Base Case overestimated demand in the power sector in 2024 and 2025.

In Dominican Republic, the commissioning of a fast-track LNG terminal and new gas-fired power plants will contribute to an increase in demand when compared to the Base Case.

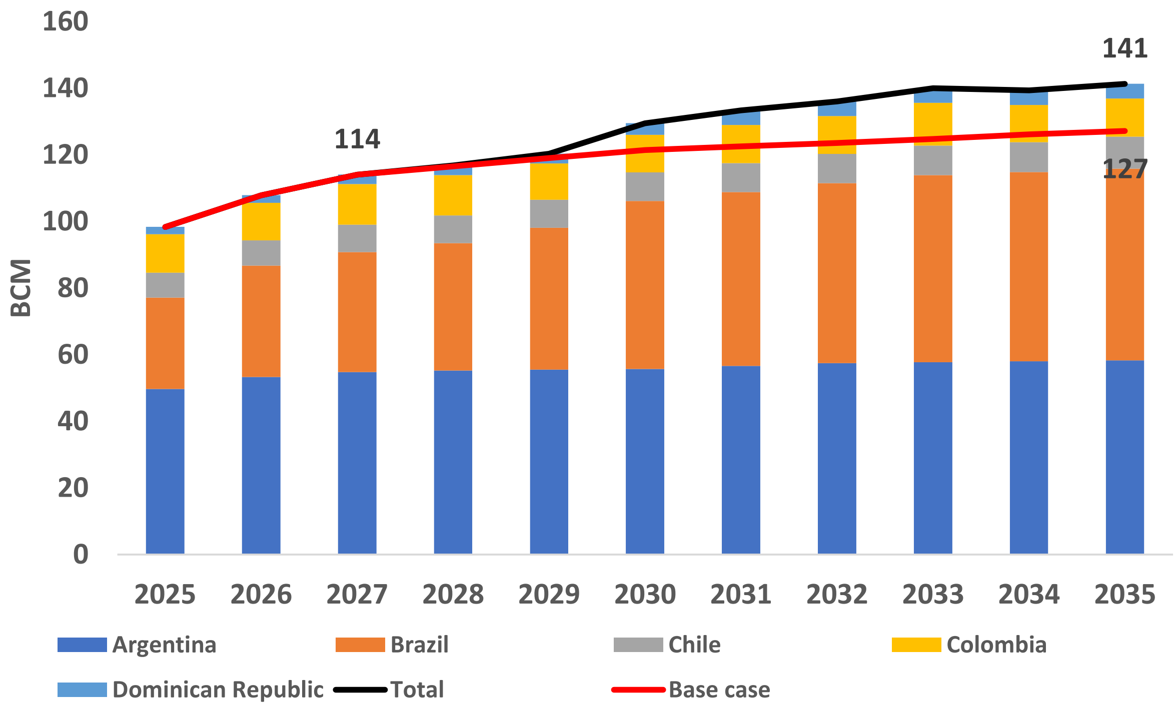
In a lower gas price scenario, gas demand in Brazil could potentially increase from 27 to 36 bcm/yr (2025-2027), due to higher capacity factors in the industrial and petrochemical sectors, the reactivation of four fertilizer plants, and higher dispatch of power plants due to increased load factors and extreme climate events.

In Argentina, there is an increase of approximately 1 bcm/yr due to increased substitution of fuel oil, whereas in Colombia, demand decreases by circa 1 bcm/yr, compared to the Base Case, due to a reduction of domestic supplies and lack of additional LNG capacity until late 2027.

Pipeline infrastructure, environmental permitting, and high financing costs will hamper growth in demand in the short term, despite favorable gas prices. It is worth note that hub prices of $6-7 per MMBTU in countries like Brazil and Chile, will not translate to such low prices for industrial and power consumers, due to high transportation and distribution tariffs, which also impact large consumers.

The highest short-term response we could expect therefore is maybe up to 10 bcm or some 5 per cent of 2030 demand.

Figure 64: Comparative demand outlook: selected C&SA countries



Source: OIES elaboration based on NexantECA World Gas Model, IEA

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Medium and Long-Term Response (2030-2035)

In the period 2030-2035, consistently low gas prices would elicit investment in infrastructure, resulting in demand of some 210 bcm/yr by 2035, compared to the Base Case aggregated demand of 196 bcm/yr. Although it is expected that renewable energy will continue to grow in the region, there is substantial use of fuel oil and some coal in the industrial sector, which could be replaced by natural gas if lower prices persist for a longer period.

Also, gas-fired power plants will be needed to complement increasing wind and solar supply and the lack of additional large hydro capacity, resulting in higher capacity factors for existing gas plants or more usage during dry or low wind periods.

There is also a potential to replace fuel oil and coal in power generation and industries in other Central American and Caribbean countries, which were not the subject of the above analysis.

In Central America, LNG terminals are being commissioned in Nicaragua, El Salvador, Panama, and Honduras, aiming initially to supply power plants, but this could extend to industrial consumers if prices are low enough to facilitate the construction of infrastructure. As of 2022, fuel oil and coal demand for power and industry in those countries was respectively equivalent to 1.7 and 3.3 bcm/yr.

In the Caribbean, fuel oil consumption in Jamaica and the Dutch Antilles islands totaled respectively 0.3 and 0.6 bcm/yr of natural gas equivalent. In total, there is an aggregated potential demand of 6.1 bcm/yr of natural gas in those Central American and Caribbean countries. If half of this aggregated demand was met by natural gas, this would be equivalent to another 3 bcm/yr in the long term. This could result in a total gas demand in the C&SA region of approximately 213 bcm/yr by 2035.

The 14 bcm higher gas demand that could be expected in a $6 world is focused in a few LNG importing countries – Argentina, Brazil, Chile, Colombia, and Dominican Republic, representing 11 per cent of their total demand, but only some 7 per cent of total C&SA gas demand in 2035. Adding Central America and Caribbean markets would result in an additional demand of 17 bcm when compared to the Base Case. As in the short-term, the high marketing and transportation fees, to deliver imported LNG to end-users, may limit the demand response to lower prices.

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10. Conclusions

a) The LNG Wave and $6 Gas

The wave of additional LNG supply is now beginning, with the OIES projecting cumulative growth in LNG export capacity of some 400 bcm between 2024 and 2035. Some three-quarters of this growth has taken FID and is under construction, with more FIDs imminent in the next 12 to 18 months. Half of this growth is in North America and another quarter in Qatar, followed by some 15 per cent from Sub Saharan Africa. In contrast, total LNG import growth between 2024 and 2035 is some 262 bcm. As a consequence, the utilization of available LNG export capacity declines to around 85 per cent, on average, between 2030 and 2035, compared to the 2024 level of over 97 per cent. The last time utilization was below 90 per cent was in 2020 during Covid.

This easing of the global gas market leads to a decline in global spot prices to around $8 per MMBTU (real 2024 prices) for both TTF and Asia spot LNG prices. However, this modelling result is an initial partial equilibrium – based on a bottom-up demand analysis – and with that volume of potential unused available supply (on average some 120 bcm a year between 2030 and 2035 inclusive, after allowing for boil off gas) would most likely elicit a significant price response, forcing prices down. Clearly, if a significant volume of that increased supply was to be held back from the market, then an $8 price might be sustained. However, if the supply is made available, as in a second model run in short-run marginal cost mode, this results in TTF and Asian spot prices going below $6 per MMBTU. Such a scenario is consistent with the 2019 and 2020 outcomes, following the wave of LNG supply in 2019 and the impact of Covid in 2020. If these lower prices resulted in higher demand for LNG, then utilization of LNG export plants would increase. Every 1 percentage point rise in utilization is worth just under 10 bcm of incremental LNG demand.

There are clearly discussions and debates to be undertaken regarding the increase in LNG export capacity and the likely level of demand for LNG in various LNG importing countries. Various organisations, companies, and consultants produce different scenarios and forecasts. There is broad agreement on the magnitude of the LNG wave, since it is mostly under construction already, but possibly less agreement on the level of demand for this increased LNG supply. However, this paper is less concerned with what is the ‘best’ forecast of the supply-demand balance over the next ten years, focusing more on a ‘what-if’ analysis if the oversupply is significant, and looking at any consequential response of demand to the lower prices.

If TTF and Asian spot prices do go to $6 or below, the extent to which there will be a demand response is dependent on the volume of LNG being imported into the relevant markets, which is priced at spot. Europe is dominated by gas-on-gas (GOG) pricing, and the major Asian importing markets all have significant proportions of GOG pricing for LNG imports. The importance of GOG pricing is also increasing in the ASEAN region, but is lower in Pakistan and Bangladesh, although there is still the potential for increased spot LNG supply for these countries. Latin America’s LNG imports are almost all GOG priced. Currently, in Africa, the only country that imports gas directly is Egypt (Morocco purchases LNG supplies via Spain and Senegal started importing very small volumes of LNG on a temporary basis), but there is potential for LNG imports into the region.

If $6 gas is realised by the end of this decade, the demand response is dependent on the relative economics of gas to other fuels, including renewables. The short-run response – which compares the economics of the marginal fuel costs utilising existing infrastructure – is largely comparing the relative costs of gas against coal in the power sector but also against oil in the industrial sector. A $6 per MMBTU gas price would appear to be very competitive against coal in a market like Europe with a significant carbon price. In an Asian market, where there is no carbon price or tax, the economics are more marginal, but gas could become seriously competitive against coal, depending on the level of the coal price in the various markets.

The long-run response, which includes the cost of building new infrastructure, represents a different calculation, called the levelized cost, which includes the capital investment cost as well as operating costs. Without any carbon price or tax, gas at $6 would seem to have a significantly lower levelized cost than offshore wind, except possibly in China, and be broadly comparable with onshore wind, but above

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the cost of solar. If there is a carbon price, as in Europe, then at current EU ETS prices, the levelized cost of offshore wind and gas-fired power, at a $6 gas price, is broadly comparable. There is a secondary consideration for the long-run response, however, in that in a number of markets, the load factor of gas-fired power plants is in the 30-40 per cent range, and there is some scope to increase these load factors, either by displacing coal in existing plants and/or delaying the construction of renewables, especially offshore wind. Gas could become more base-load and take less of a balancing role in these markets.

b) Short Run Response

As noted above, the short-run response is a more immediate reaction of demand to lower prices, relative to other fuels, notably coal in the power sector. The analysis of the short-run response has focused on the perceived reaction in different sectors for 2030, when the $6 gas price is expected – based on our analysis – to be reached in Europe and Asia.

It is notable that in **Europe**, which historically has exhibited significant competition between coal and gas in the power sector, coal-to-gas switching is now becoming more restricted with the closure of coal plants. Consequently, the likely range of a short-run response is between 5 and 9 bcm, all of which is in the power sector.

For **China**, the power response is more limited than in other countries or regions, with industry, transport, and buildings providing more of the short-run response. The range for total China demand is projected at between 16 and 70 bcm. However, generally around just over half of Chinese demand comes from domestic production and it seems likely that the Chinese authorities would try and maintain the proportion of domestic production to total demand and imports, possibly limiting the short-run response range to between 8 and 35 bcm.

In **India,** the short-run response is estimated to range between 4.6 and 11 bcm, representing some 4-10 per cent of Indian gas demand in 2030. No real response is expected in the fertilizer sector, where gas is used as a feedstock, and there may only be a very small response in power at particular peak times. There may be more of a response in the CGD sector in CNG for vehicles and the commercial sector, which are more exposed to the LNG market. The wider industrial sector, which includes petrochemicals and refineries, has a slightly larger response than the CGD sector, in the more energy intensive industries. The short-run price response in India is much more about gas in competition with oil products rather than coal.

The traditional LNG importing countries of **Japan, Korea, and Taiwan**, exhibit different price responses. The total short-run response is between 3 and 14 bcm, representing some 1.5 per cent and 7.5 per cent of total gas demand in the three countries. Most of the short-run response is in Japan, with only a relatively small response in Korea, and it is all in the power sector in competition with coal. Taiwan is phasing out both coal and nuclear, so the potential price response between gas and coal is being removed, as has happened already, for example, in the UK power market.

The **Emerging Asian** countries comprise ASEAN plus Bangladesh and Pakistan, and the range of short-term response is assessed in the 6 to 16 bcm range – between 2 - 5.5 per cent of total demand in 2030. Around 40 per cent of this is in industry with $6 gas being very competitive with oil, while the balance is the possibility of gas displacing some coal, as utilization of gas plants increases sooner than expected.

Currently **Africa** imports very little LNG, mostly into Egypt, although for a number of years, there have been plans for LNG imports terminals in Ghana, Morocco, South Africa, Namibia, Cote d'Ivoire, and other countries, but none have yet come to fruition. The narrative on gas in Africa is all about power, but not, in this case, against coal. Coal only features in South Africa, Botswana, Zimbabwe, and Morocco. The prospects for gas are, in the short-term, mainly displacing oil in power generation. An example of this has been seen in Ghana, with initially imports of pipeline gas from Nigeria and then the development of its own gas resources, which led to the almost complete replacement of oil-fired power with gas. However, it does not require the gas price to go to $6 to displace oil in power, with any displacement largely being incorporated in the Base Case.

The final region is **Central and South America**, which comprise a whole range of countries from the Caribbean to the Southern Cone. The potential short-run response for gas amounts to some 9 bcm - 5

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per cent of total demand in 2030, and this is almost all in respect of oil displacement, and an increase in underutilized capacity in the industrial sector and, to a lesser extent, in power. The response to $6 LNG, in some countries in C&S America, may be limited by the high marketing and transportation fees to deliver gas to end-users.

The overall impact, for the countries and regions covered, is summarized in Table 13. In total, the estimated short-run response to $6 gas ranges between 26 and 95 bcm, representing some 1.3 per cent to 4.7 per cent of total gas demand for the relevant countries and regions. However, in respect of the global LNG market, this represents between 3.3 per cent and 11.9 per cent of total global LNG imports in 2030.

Table 13: Short-run response summary

Country/Region	Demand		2030 LNG	BCM Range		% of Demand 2030		% of LNG Imports	
	2024	2030	Imports	Low	High	Low	High	Low	High
Europe	461.3	488.4	232.0	5.0	9.0	1.0%	1.8%	2.2%	3.9%
China	431.5	538.6	133.9	8.0	35.0	1.5%	6.5%	6.0%	26.1%
India	75.0	107.4	62.2	4.6	11.0	4.3%	10.2%	7.4%	17.7%
Japan, Korea, Taiwan	180.4	186.5	182.4	3.0	14.0	1.6%	7.5%	1.6%	7.7%
Emerging Asia	229.1	285.4	121.6	6.0	16.0	2.1%	5.6%	4.9%	13.2%
Africa	164.6	213.0	15.2						
C&S America	162.1	186.5	21.7		9.0	0.0%	4.8%	0.0%	41.5%
Total	1,704.0	2,005.8	769.0	26.6	94.0	1.3%	4.7%	3.5%	12.2%
Global Total			800.0	26.6	94.0			3.3%	11.8%

Source: OIES Analysis

c) Long Run Response

The long-run response is more about the construction of new power generation facilities, taking into account the full, levelized cost of different sources of power generation. This is essentially the relative cost of gas-fired power against mainly offshore wind – with and without a carbon price – and possibly onshore wind. A secondary consideration also lies with sustained $6 gas prices allowing existing gas-fired power to increase load factors, especially against coal. In addition, in the industrial sectors, a view of sustained low gas prices could encourage more gas use instead of oil. It should, however, be noted that the ability to build new gas-fired power generation in a timely manner may be compromised by lengthening order books for gas turbines, which could limit the demand response, even by 2035.

Europe's long-run response is more limited than for the short-run in respect of coal to gas switching, given the continued closure of coal plants. However, the potential for a slowdown in the roll out of offshore wind could boost the long-run price response to a total range of 10 to 16 bcm, with sustained $6 prices, even with higher carbon prices.

China's long-run response is more evenly spread across the main sectors of industry, power, buildings and transport, with the projected response in transport being especially strong, since sustained $6 gas prices would provide a greater incentive to invest in more LNG and CNG vehicles. The total long-run response in China is some 25 to 115 bcm (5 - 20 per cent of total gas demand), but as with the short-run case, the potential impact on LNG imports would be only half of this, ranging between 12.5 and 57.5 bcm.

India is projected to have significant gas demand growth over the next ten years, but there is a wide range of uncertainty in the different demand sectors. The long-run response in the industrial sector is more a reinforcement of the short-run response, but at a slightly higher level based on sustained low prices. For fertilizer and power, there may be a small long-run response with plants using more gas on a regular basis, but the largest potential lies in the CGD sector with more penetration in the household and commercial sector and potential for more adoption of LNG trucking as in China. The range for the long-run response is between 17 and 35 bcm – some 15 - 30 per cent of 2035 Base Case India gas

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demand. Gas displaces some coal but, as with the short-run response, it is predominantly oil which is displaced, and firewood in the case of households.

As with the short-run response, the long-run for **Japan, Korea, and Taiwan** is largely about Japan, and to a lesser extent, Korea. The range is between 3 and 32 bcm – some 2 per cent to 17 per cent of total gas demand in the three countries. At the top end of the range some 7 bcm could be attributable to Korea, displacing nuclear and offshore wind, and the balance to Japan, displacing coal and nuclear restarts but also offshore wind.

For **Emerging Asia,** the range is some 6 to 20 bcm – between 2 per cent and 6.5 per cent of total gas demand. At the top end of the range, 6 bcm relates to industry, and the displacement of oil, and the balance is gas increasing in power, with a slower roll out of offshore wind.

For **Africa**, as with the short-run response, there would not appear to be any potential long-run response because of $6 gas, as gas demand is expected to grow and is not reliant on lower prices.

In **Central and South America**, the long-run response is focused on a few LNG importing countries – Argentina, Brazil, Chile, Colombia, and Dominican Republic, totalling some 14 bcm, which is 11 per cent of their total demand, but only some 7 per cent of total C&SA gas demand in 2035. The higher gas demand is arrived at through displacement of mainly fuel oil, but also some coal, depending on the country, slowing the introduction of renewables. Lower gas prices will also encourage the construction of new plant capacity in petrochemicals, fertilizers and hot bracketed iron, adding another 3 bcm. However, as in the short-term, unless the high marketing and transportation fees charged, in some countries, to deliver gas to end-users, are reduced, the demand response may be limited.

The overall impact, for the countries and regions covered, is summarized in Table 14. In total, the estimated long-run response to $6 gas ranges between 62.5 and 177.5 bcm, representing some 3 per cent to 8.5 per cent of total gas demand for the relevant countries and regions. However, in respect of the global LNG market, this represents between 7.5 per cent and 21 per cent of total LNG imports in 2035.

Table 14: Long-run response summary

Country/Region	2035 Demand	2035 LNG Imports	BCM Range		% of Demand		% of LNG Imports	
			Low	High	Low	High	Low	High
Europe	467.4	207.8	10.0	16.0	2.1%	3.4%	4.8%	7.7%
China	552.9	127.2	12.5	57.5	2.3%	10.4%	9.8%	45.2%
India	115.9	62.7	17.0	35.0	14.7%	30.2%	27.1%	55.9%
Japan, Korea, Taiwan	185.6	181.7	3.0	32.0	1.6%	17.2%	1.7%	17.6%
Emerging Asia	309.3	181.6	6.0	20.0	1.9%	6.5%	3.3%	11.0%
Africa	252.8	13.7						
C&S America	195.8	22.6	14.0	17.0	7.1%	8.7%	62.0%	75.3%
Total	2,079.6	797.2	62.5	177.5	3.0%	8.5%	7.8%	22.3%
Global Total		839.5	62.5	177.5			7.4%	21.1%

Source: OIES Analysis

d) Overall Conclusions

Both the short-run and long-run response to $6 gas varies between countries and regions. From the analysis, it can be seen that this is not just about coal-to-gas switching in the power sector, but also that the lower gas price provides significant potential for the displacement of oil in industry and also, in some countries, in the power sector. In the long-run response, there is some displacement and deferral of offshore wind, as well as the extension of gas in buildings and transport in India, and higher utilization of gas-fired power at the expense of coal.

The short-run response is projected to run through to 2030 and, thereafter, the market has had time to adjust to potentially lower prices and begin a long-run response. Figure 65 illustrates the range of the short-run and long-run responses, in comparison to the Base Case for LNG imports relative to LNG export capacity.

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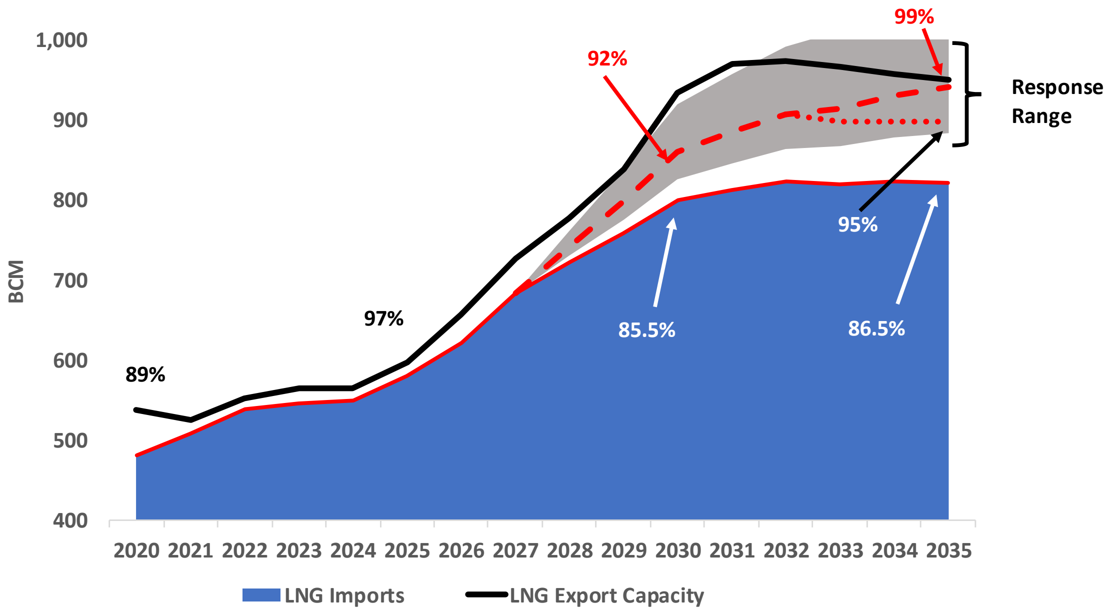
The response range is the short-run response for 2030 and ranges between 26.5 and 94 bcm, and the long-run response for 2035 which ranges between 62.5 and 177.5 bcm. The midpoint of the range is plotted as the average of the low and high response, not as a forecast but to provide an illustration of the impact. The 2030 midpoint additional demand is some 60 bcm and the 2035 midpoint additional demand is some 120 bcm – double the 2030 potential uplift. Figure 65 shows the upper end of the range is at the LNG export capacity level in 2030 and well above it by 2035. These levels would clearly not be either achievable or certainly sustainable for a $6 gas price.

Figure 65: The response range to $6 Gas



Source: IEA, NexantECA World Gas Model

The percentages in the figure are the utilization rates of LNG export capacity. In the Covid year of 2020 utilization was some 89 per cent but rose in 2021 and 2022 and in the last few years has been around 97 per cent. In the Base Case, the utilization rate is 85.5 per cent in 2030 and 86.5 per cent in 2035. However, as noted initially in this paper, this was not an equilibrium solution, as in such a supply-long market, prices would fall, generating an increase in demand. This rebalancing of the market, would result in utilization rates of 92 per cent in 2030 and 99 per cent in 2035, using the midpoints of the ranges. While a 92 per cent utilization rate might be broadly consistent with $6 gas in 2030, a 99 per cent utilization rate by 2035 is inconsistent with $6 gas, since it is close to the high utilization levels seen in the last few years. Capping LNG demand at some 900 bcm from 2032 onwards, which results in 95 per cent utilization in 2035, would seem to be more consistent with a $6 price.

The 2030 response outcome, with a $6 gas price, leading to 92 per cent utilization, represents a 60 bcm increase in demand compared to the Base Case. This outcome where rising supply exceeds the rise in demand, is broadly comparable to what happened in 2019, where there was around a 75 bcm increase in available LNG export capacity (a rise of some 16 per cent), with LNG imports rising less at some 58 bcm – some of which ended up in European storage – and a utilization rate of LNG export capacity of some 92 per cent. In 2019, TTF prices averaged just over $6 per MMBTU, falling from around $9.30 in 2018 (all in real 2024 prices). The price and short-run response by 2030, therefore, looks similar to what happened in 2019. The 2035 long-run response is based on a sustained period of prices at $6, but there is no real comparison of a similar sustained period of low prices at the global level for comparison.[147]

[147] The closest may be the impact of the shale revolution in the US which led to sustained low Henry Hub prices and a dramatic squeeze on coal in the power sector.

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The Base Case represents the OIES view that rising LNG supply will outpace the rise in LNG demand, but this leads to historically low utilization of LNG export capacity. This is not an equilibrium solution, as the Base Case was generated on a long-run marginal cost basis, and in periods of oversupply, short-run pricing tends to predominate. The initial Base Case is based on a bottom-up demand analysis and is not consistent with spot gas prices at $8 or above, assuming all LNG supply is made available to the market. Generating an alternative scenario, based on short-run marginal cost, results in prices in Europe and Asia falling to the $5 to $6 per MMBTU level, compared to above $8 in the Base Case with long-run marginal cost pricing. The analysis in this paper suggests that $6 gas generates additional demand and leads to higher utilization of LNG export capacity. The adjusted additional demand (lower than the midpoint by some 30 bcm) in 2035 is some 80 bcm higher than the Base Case – an increase of 10 per cent on the Base Case demand.

The implied elasticities of demand can be calculated from the assessments of the short-run and long-run responses to $6 gas as shown in Table 15. The implied elasticities are calculated on the change in total demand in each country/region, divided by minus 25 per cent (i.e. the change from $8 to $6), and not by individual sectors. Some sectors, such as buildings, will have low or zero price elasticity, while in others, most likely power, the elasticity will be higher. In addition, for individual countries in a region, the countries will have different elasticities. For example, it was found that Taiwan has zero price response, so the price response for Japan, Korea and Taiwan, is focused particularly on Japan. These implied elasticities are also only valid in respect of the fall in prices from $8 to $6, which is a 25 per cent decline. Price elasticity of demand is not linear, and the same response would not be expected if it was a 25 per cent price fall from $20 to $15 or even $10 to $7.50.

Table 15: Implied elasticities

Country/Region	Short Run (2030)		Long Run (2035)		Midpoint	
	Low	High	Low	High	SR	LR
Europe	-0.04	-0.07	-0.09	-0.14	-0.06	-0.11
China	-0.12	-0.52	-0.18	-0.83	-0.32	-0.51
India	-0.17	-0.41	-0.59	-1.21	-0.29	-0.90
Japan, Korea, Taiwan	-0.06	-0.30	-0.06	-0.69	-0.18	-0.38
Emerging Asia	-0.08	-0.22	-0.08	-0.26	-0.15	-0.17
Africa						
C&S America	0.00	-0.19	-0.29	-0.35	-0.10	-0.32
Total	-0.07	-0.26	-0.19	-0.67	-0.16	-0.43

Source: OIES Analysis

Note: The China implied elasticities are calculated on total change in China demand not on the expected impact on LNG imports, which is half the total demand response

Asia is seen to be the most price responsive market, led by India, China, and Japan. Europe is now seen as much less price responsive, with the closure of coal plants leaving much less room for any coal to gas switching. Emerging Asia seems to have a lower price elasticity, which, in part may be a result of the rapid growth in power sector gas demand embedded in the Base Case outlook, leaving limited room for any additional price responsive demand.

Based on the midpoint of the response range, Table 16 shows the breakdown of the response by sector for each country/region. Broadly half the short-run and long-run response is in the power sector, accounted for almost wholly by JKT and Emerging Asia. The response in buildings and transport is focused in China and India and increases in the long-run with the opportunity to invest in more gas-fired equipment. There is also a significant response in industry in China, India, and C&S America.

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Table 16: Midpoint response by sector

SHORT RUN RESPONSE					
Country/Region	**Power**	**Industry**	**Buildings**	**Transport**	**Total**
Europe	5.00	2.00			7.00
China	3.75	11.00	5.25	1.50	21.50
India	1.00	4.00	2.00	1.00	8.00
Japan, Korea, Taiwan	8.50				8.50
Emerging Asia	11.00				11.00
Africa					-
C&S America	1.50	3.00			4.50
Total	30.75	20.00	7.25	2.50	60.50
%ages	51%	33%	12%	4%	100%

LONG RUN RESPONSE					
Country/Region	**Power**	**Industry**	**Buildings**	**Transport**	**Total**
Europe	11.00	2.00			13.00
China	6.25	13.75	7.50	7.50	35.00
India	5.50	5.50	7.50	7.50	26.00
Japan, Korea, Taiwan	17.50				17.50
Emerging Asia	10.00	3.00			13.00
Africa					-
C&S America	9.00	6.50			15.50
Total	59.25	30.75	15.00	15.00	120.00
%ages	49%	26%	13%	13%	100%

,

Source: OIES Analysis

The analysis in this paper represents an initial assessment by OIES research fellows of the potential short-run and long-run price responsiveness of gas demand to a 25 per cent lower spot gas price – specifically the gas price reducing from $8 per MMBTU to $6 by 2030 and beyond into the next decade. As prices start to decline in the next few years – assuming the growth in LNG supply outpaces the underlying level of demand as we expect – then more evidence of the price responsiveness may become apparent, possibly altering our conclusions.

Finally, as noted in Section 2, on the Base Case outlook, our hypothesis that the market clearing price is likely to fall to $6 per MMBTU, compared to $8 per MMBTU, in 2030 and beyond, is predicated on the underlying level of demand being well below the available LNG export capacity. An alternative, also plausible, scenario is that the underlying level of demand will be higher, mostly eliminating the excess supply, with the market clearing at closer to the LRMC pricing levels as opposed to SRMC pricing levels. As an example, the OIES underlying level of demand, in 2035, is some 820 bcm, compared to 950 bcm of available LNG export capacity – an 86 per cent utilization rate. The assessed price responsiveness adds some 80 bcm to underlying demand in 2035, bringing it to 900 bcm, with a utilization rate of 95 per cent which may be consistent with $6 spot gas. However, stronger underlying demand by 2035 could drive LNG imports to 900 bcm anyway, without the need for lower prices to generate price responsive demand in key markets. An LNG import level of 900 bcm in 2035, may well be the 'most likely' outcome, given the level of available LNG supply reached. The question then becomes whether underlying demand growth takes us to that level – and the market clears at $8 – or, if underlying demand growth is lower, the 900 bcm level of LNG imports can only be achieved with the assistance of lower prices, clearing the market at $6.

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