

TRILATERAL ENERGY SECURITY COMMITTEE

TESC Opinion Editorial: Near Term Oil and Gas Supply Surplus Uncertainties: A Glut, a Buffer, or Something Different?

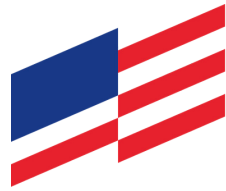
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TESC Opinion Editorial: Near Term Oil and Gas Supply Surplus Uncertainties: A Glut, a Buffer, or Something Different?

Reporting has suggested that we are headed towards a supply glut for both oil and gas by 2030. While this may appear as a normal part of the historical cycle for supply and demand gaps, larger than usual uncertainties exist not only on the supply and demand gap itself but also on other elements such as timing, duration, pricing and volatility. New geopolitical and market dynamics have reshaped the investment environment for oil and gas. These include decarbonization trends, sustained campaigns against fossil fuel use, aggressive policy directives (often with moving goal posts), restrictions by financial institutions on upstream investment, and stricter capital discipline among oil and gas companies. Together with the stranded assets narrative promoted by institutions such as the International Energy Agency (IEA) until recent years, these forces have all constrained the mid/long-term natural oil and gas investment cycles and introduced substantial uncertainty in the future market balance.

In this paper, we examine the demand assumptions embedded in the long-term outlooks of IEA and other leading agencies. We find that global oil and gas demand can swing dramatically depending on those demand assumptions alone, notwithstanding escalating geopolitical tensions and market dynamics. Given the inherently lower supply elasticity of oil and gas, especially liquified natural gas (LNG) which is a substantial part of the energy export mix from the U.S. to its partners such as the Republic of Korea (hereafter, South Korea) and Japan, we argue that the “supply surplus” the market currently takes for granted could easily turn into an extremely thin buffer.

For countries with limited strategic storage and high import dependency (e.g., South Korea, Japan, and much of Europe), the implication extends far beyond mere price high volatility; it is fundamentally an energy security issue. Conversely, for countries producing oil and gas resources (e.g., the U.S., where private companies respond primarily to market and price signals), it raises a critical challenge in maintaining market share against conventional producers that often benefit from substantial government-backing and directives including subsidies.

This paper argues that what is currently perceived as a near-term supply glut in oil and gas is better understood as a fragile and highly uncertain buffer that is vulnerable to changes in demand assumptions and investment behavior, as well as policies and geopolitics. These forces are particularly acute for LNG, which we highlight later in the paper. Fundamentally, uncertainty is amplified by unverified assumptions about the potential return of Venezuelan and Iranian oil (and potentially gas) to the market, which may encourage a more conservative approach to new investment elsewhere.

A. Analysis of Various Supply-Demand Forecasts:

Oil and gas supply and demand have been steadily growing over the years. Price fundamentals have been cyclical (**Figure 1**) with oil volatility driven by major crises/events. Oil's cyclical turnover has tended to be shorter than that of gas, which has been driven more by supply and demand market fundamentals instead. This phenomenon is rather natural given the difference in market size, use, contract terms, and market structure driven by product flexibility and storability. While historical price cycles provide useful context for how gas has become even more volatile than oil in recent years due to its limited supply elasticity, the more critical question today is how divergent long-term supply-demand forecasts have become under different demand assumptions.

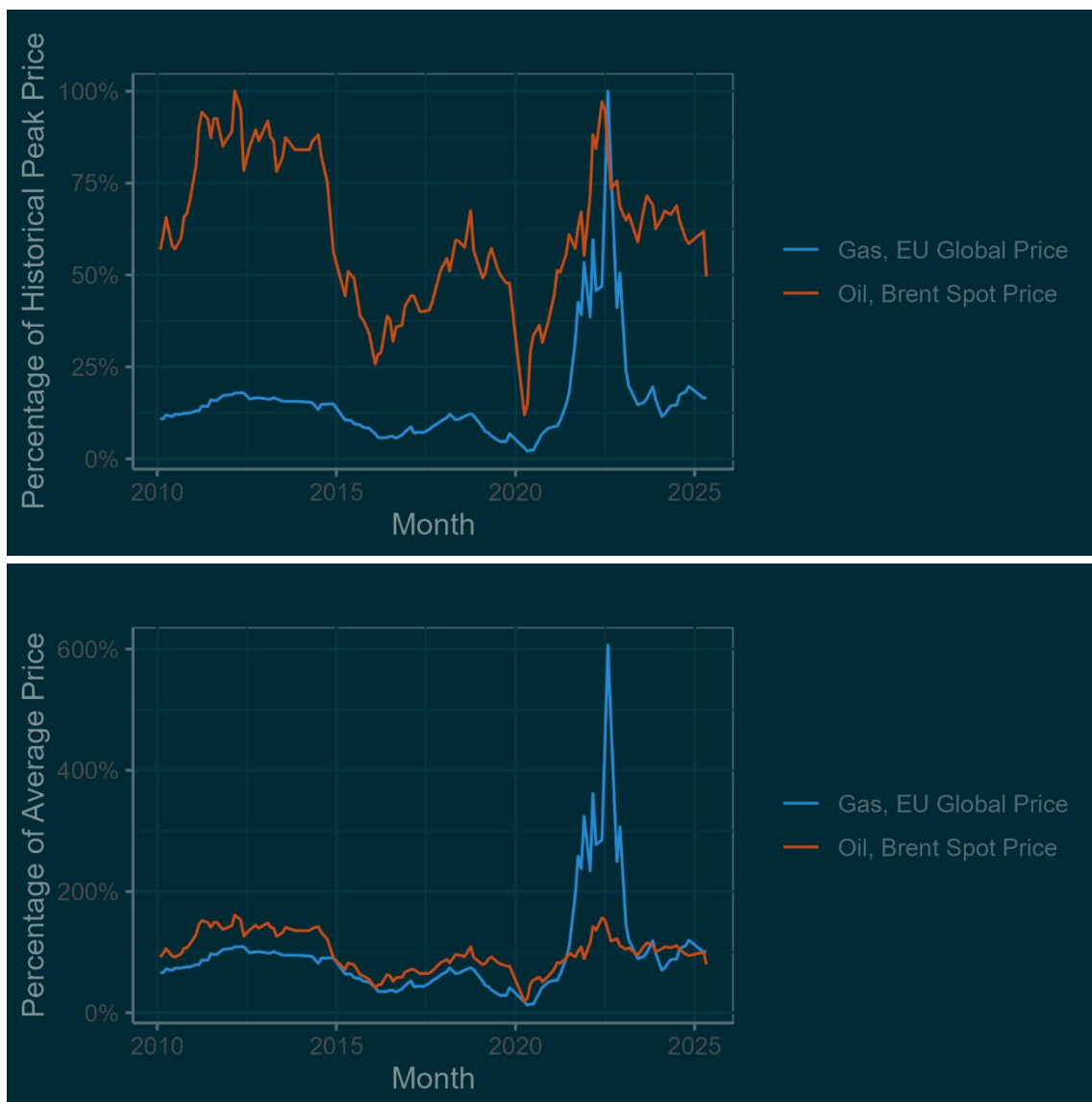


Figure 1: Price Graph – Oil vs. Gas (Source: Multiple)

Dynamics affecting both demand and investment appetite have led to a wide variance in supply forecasts. As shown in **Figure 2**, the spread between the highest and lowest demand projections by 2035 reaches

roughly 27million barrels per day (mbd) for oil and 148 billion cubic feet per day (Bcf/d) for gas (which LNG is part of) by 2035. This horizon is only 10 years away and does not include net-zero scenarios which would introduce even greater variance. Furthermore, even forecasts from the same forecaster include substantial variation from year to year. A case in point, **Figure 3** depicts a selection of base case scenarios. One reason why forecasts change so much from year to year is that they rely on difficult predictions, such as consumer behavior. For example, uptake of electric vehicles (EVs) in the future weighs heavily on oil demand forecasts, but this industry is relatively new and constantly shifting. In 2025, many forecasters observed slower-than-expected sales of EVs in the U.S., which caused them to revise oil demand in base case (i.e. status quo) scenarios significantly higher than 2024 forecasts.

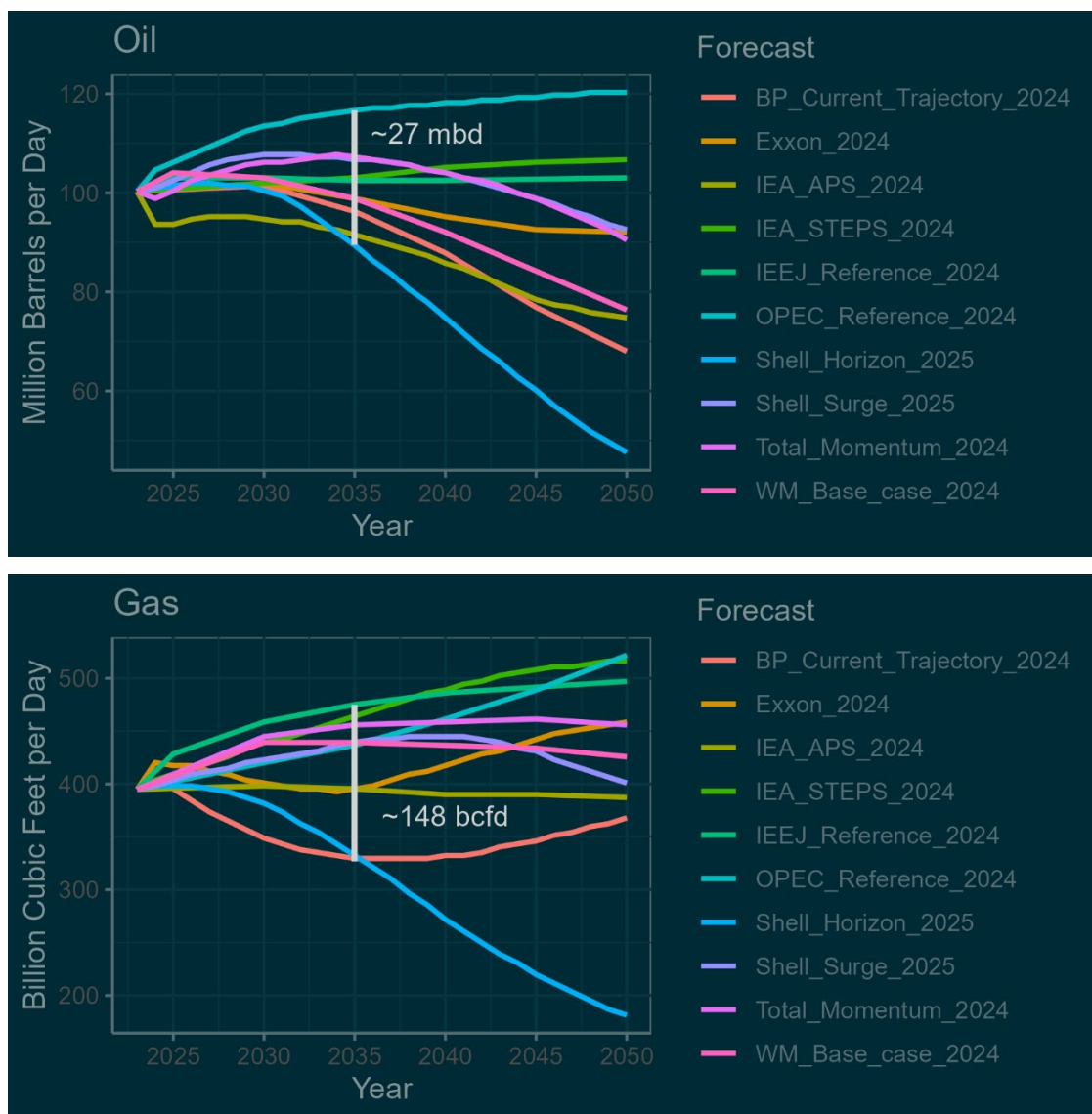


Figure 2: Selection of Oil and Gas Supply Forecasts (Source: Multiple)

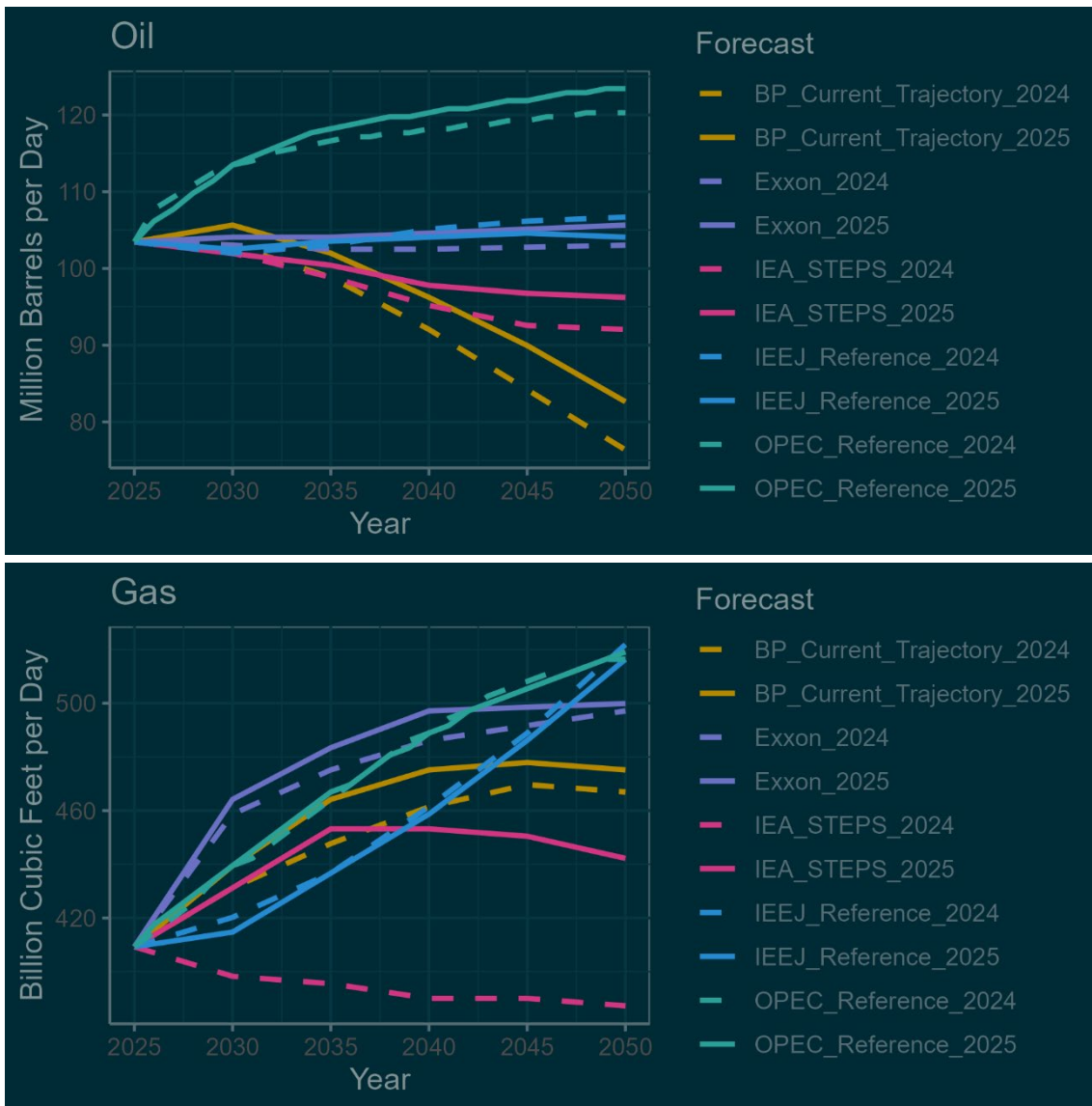


Figure 3: Base Case Oil and Gas Supply Forecasts (Source: Multiple)

By definition, forecasts and scenarios are generated using assumptions, therefore none of them are right or wrong. Nonetheless, it is necessary to understand how the drivers and assumptions of these views differ. Below we highlight some of the most important:

- Policy strength and enforcement
 - High-demand views (OPEC, Exxon, and some Energy Information Administration cases) assume slower policy tightening and technology diffusion whilst decline views (IEA Net Zero Emissions, Shell Sky, BP Accelerated/NZ, Equinor Renew, TotalEnergies NZ) assume fast decarbonization, EVs dominating light-duty vehicle markets, clean fuels in heavy transport, and efficiency everywhere.

- Sectoral substitution limits
 - Aviation, shipping, and petrochemicals anchor residual liquids demand; optimistic substitution (e-fuels, sustainable aviation fuel (SAF) scale-up, plastics circularity) drives steeper declines.
- Emerging market growth
 - Higher-demand projections lean on sustained growth in India, Africa, and Southeast Asia via vehicle fleet growth, industrialization, and slower infrastructure transitions.
- AI/Data Center demand, especially for gas.
- Technology and cost curves
 - Assumptions on battery costs, charging, hydrogen, carbon capture, utilization and storage (CCUS), and plastics circularity materially change the slope after the peak.

B. Replacement Ratio Dynamics

The appearance of U.S. shale and its market in addition to the rise of U.S. LNG and its current policies have introduced significant pieces to the puzzle. Shale oil and gas in the U.S. is produced according to market principles, unlike state-owned national oil companies in regions like the Middle East and South America where sovereign budget consideration is highly related. Given the considerable size of the U.S. shale oil and gas supply, the market became complacent and believed that we would no longer witness the oil shocks we saw half a century ago. This effectively placed a cap on oil prices and is seen as a prime example of why oil prices did not rise significantly in 2025, despite the geopolitical conflicts in the Middle East and Latin America involving major oil and gas producing countries.

Declining production from existing fields and rising consumption could quickly eliminate the current oversupply under current stated policies, which would require 25 mbd of new oil field development projects by 2035 to balance the market (Current Policies Scenario in the IEA's World Energy Outlook 2025). This is an ongoing threat with approximately 90% of upstream oil and gas investment in recent years being used to compensate for production declines, which limit the ability to address growing demand.

Investment in 2025 reached approximately \$570 billion. While a moderate increase in production is possible if current trends continue, reduced investment risks stagnation in supply. Furthermore, the production mix is rapidly changing, with tight oil and shale gas increasingly dominating as shown in **Figure 4**. Conventional oil fields accounted for 85% of oil production in 2000, but this fell to 61% by 2024, according to IEA. Approximately 70% of natural gas production is conventional, with the remainder coming from U.S. shale gas.

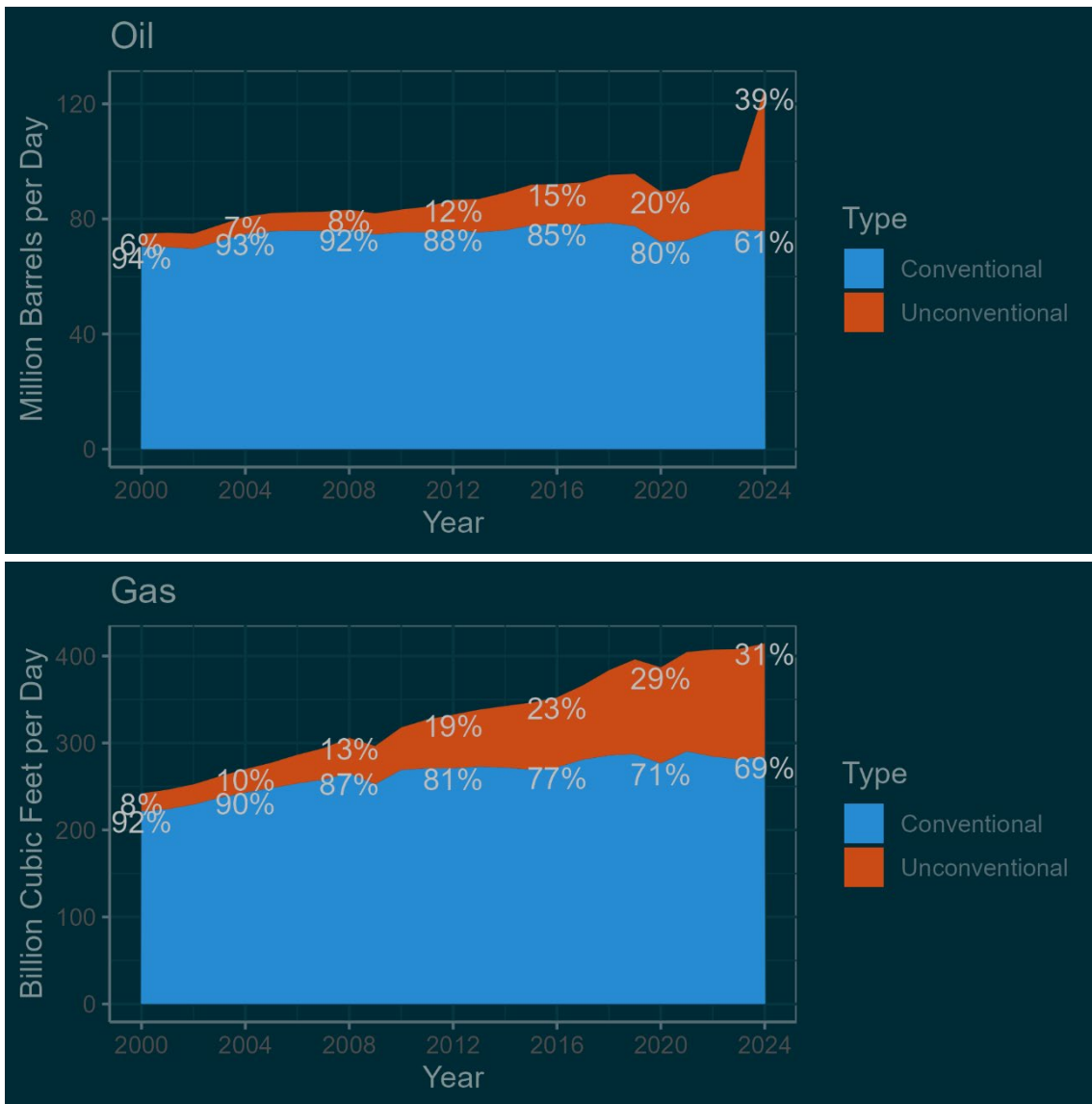


Figure 4: Conventional and Unconventional oil and gas (Source: IEA)

Global supply remains dependent upon large oil fields in the Middle East, Eurasia, and North America, which accounted for roughly half of global production in 2024. The annual decline rates since their peaks are 5.6% for conventional oil and 6.8% for natural gas. While large oil fields experience a modest decline of 2.7%, smaller fields experience declines of over 11.6%. Onshore oil fields show a high decline rate of 4.2%, and deepwater oil fields show a high decline rate of 10.3%. The Middle East has the lowest decline rate in the world at 1.8%, and Europe has the highest at 9.7%.

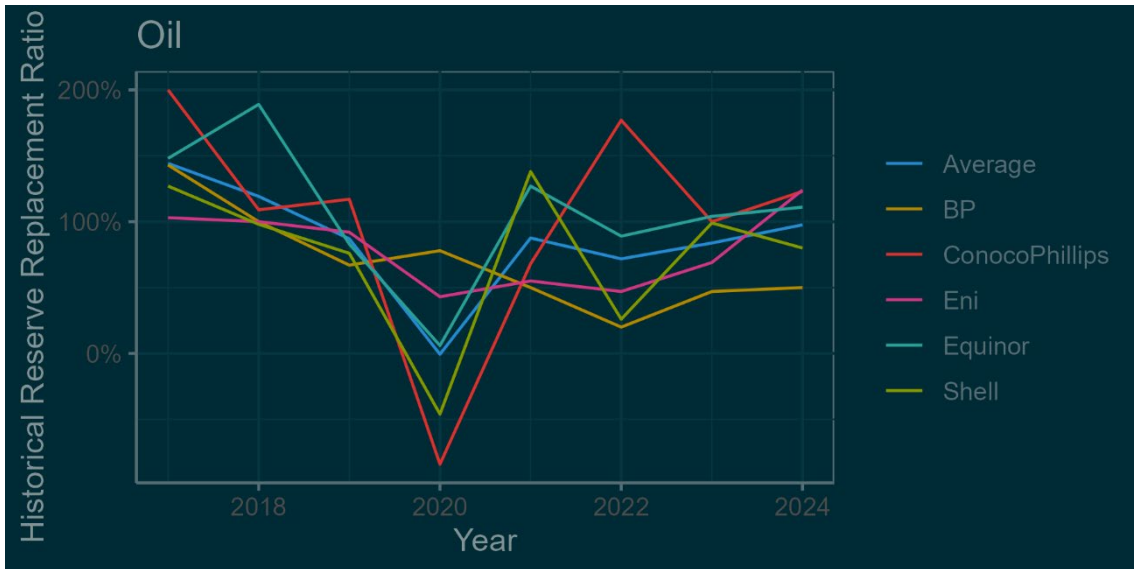
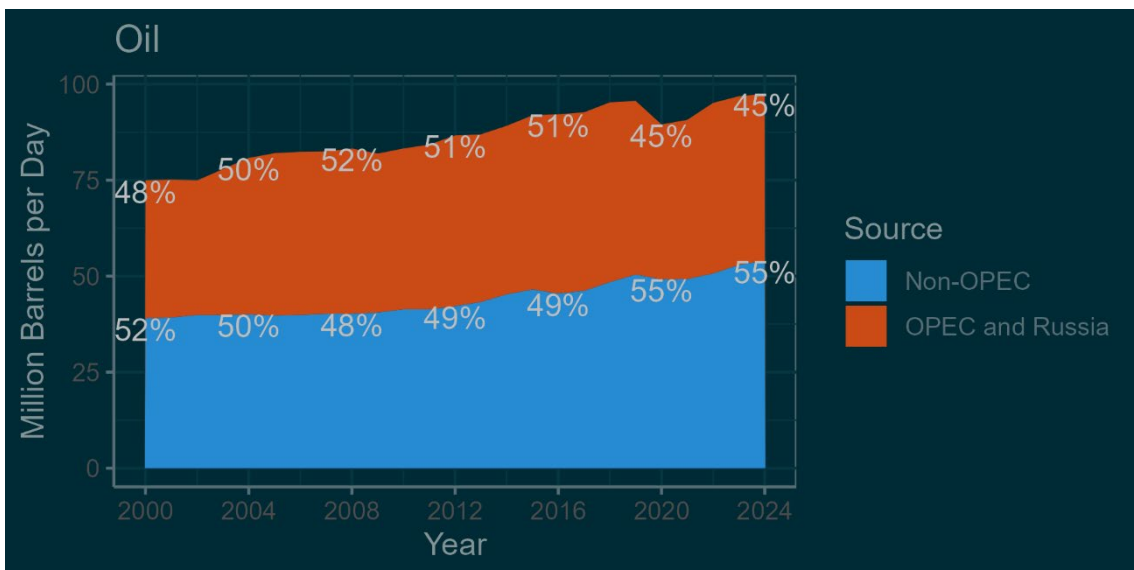


Figure 5: Selection of oil and gas companies organic reserve replacement rate (Source: Multiple)

If investment stagnates due to policy incentives, the natural decline rate will become even more rapid, with oil declining by 8% per year (approximately 5.5 mbd) and natural gas by 9% (approximately 270 billion cubic meters (bcm)). The organic reserve replacement rate has been somewhat slower in recent years compared to the trends in the previous decade (**Figure 5**). Unconventional resources will decline particularly quickly, with tight oil and shale gas declining by more than 35% per year. This decline would vary by supplier, with developed countries experiencing a 65% decline over 10 years while the Middle East and Russia would only experience a 45% decline. This would lead to supply being concentrated in the Middle East and Russia, which comes with increased energy security risks due to geopolitics (**Figure 6**).



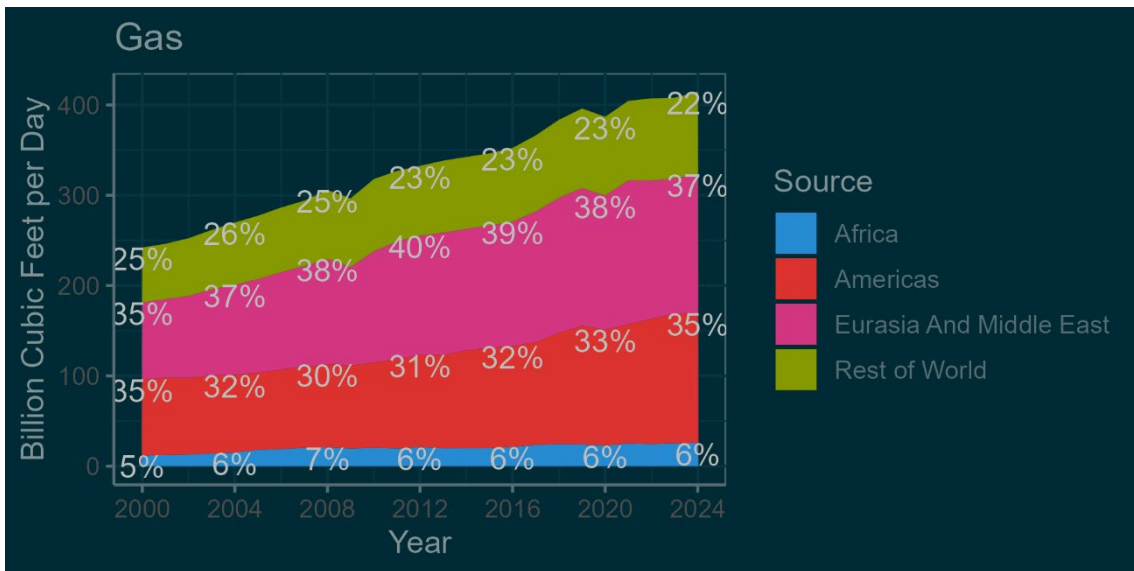
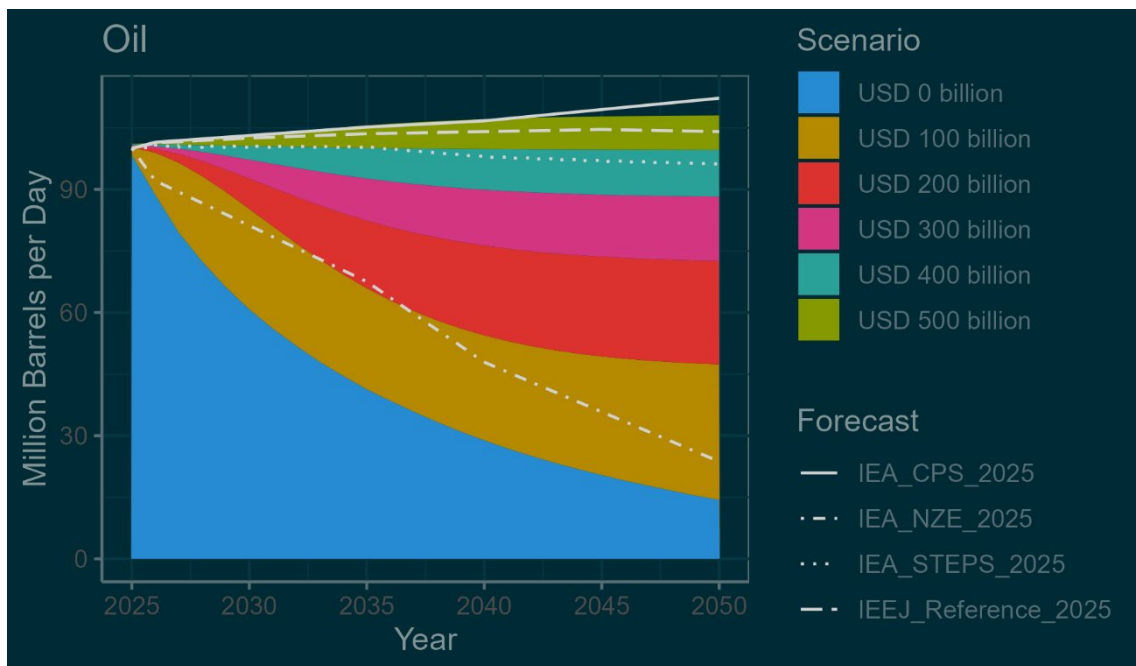


Figure 6: Oil and Gas Production by Source (Source: IEA)

To maintain the status quo, more than 45 mbd of new conventional oil fields and 2,000 bcm of natural gas will be needed by 2050 from new conventional fields. Undeveloped resources total 230 billion barrels of oil and 40 trillion cubic meters of natural gas, concentrated in the Middle East, Eurasia, and Africa. Developing these resources could add 28 mbd and 1300 bcm of natural gas by 2050. Furthermore, new discoveries of 10 billion barrels of oil and 1,000 billion cubic meters of natural gas are needed each year to maintain the current production level through 2050 (Figure 7).

However, action would need to start soon, as developing a new conventional project takes an average of 20 years, making long-term planning essential from exploration to the start of production, which has been disrupted in recent years.



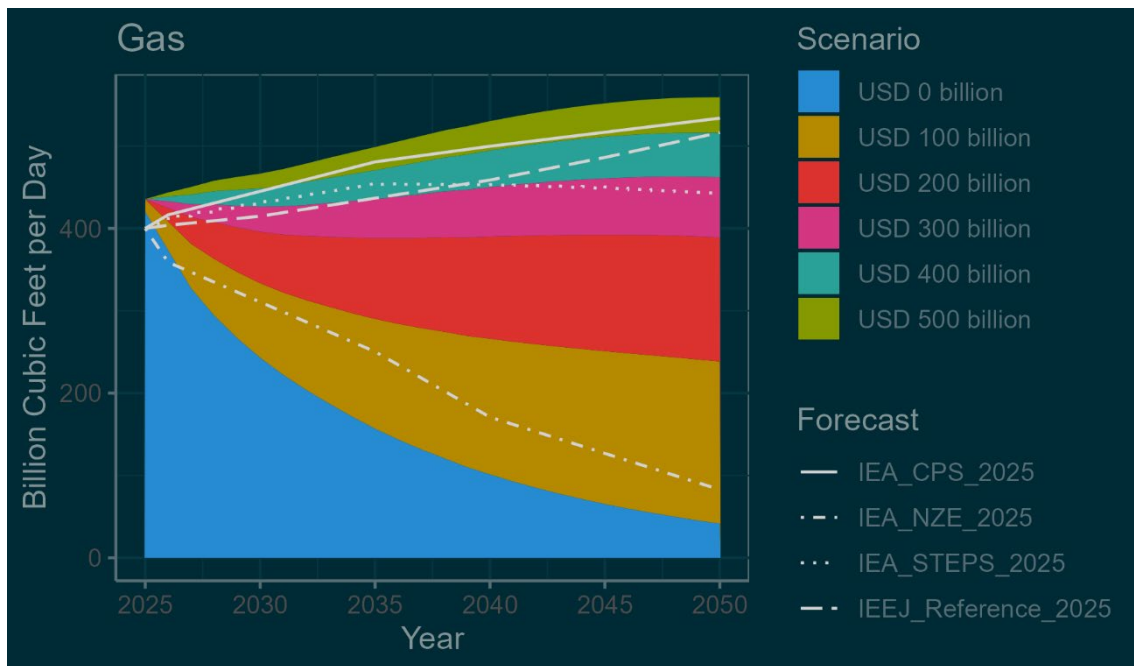


Figure 7: Investment vs. Demand Scenarios (Source: Multiple)

C. Discussion

Oil:

On the demand side, the description of “peak oil demand” is somewhat misleading as it does not necessarily suggest a “decline” after its peak but rather a long “plateau.” Oil demand could even grow in certain regions while declining in others, and thus an aggregate decline could be quite far off.

One key example is that the peak is highly dependent on the uncertain adoption of battery EVs (not necessarily hybrid or plug-in EVs) growth on the road which is different from the new car sales ratio with internal combustion vehicles. For example, as shown in **Figure 8**, Norway, one of the early adopters of EVs, achieved over 90% plug-in share (battery electric vehicles + plug-in hybrid vehicles) in new car sales in 2023, with EVs now outnumbering gasoline cars in the fleet. However, overall road fuel demand (gasoline + diesel) declined only modestly—around 10% from 2017–2019 levels to about 62,000 barrels per day (bpd) in early 2023—and remained relatively stable at 60,000–70,000 bpd. Passenger car fuel use dropped sharply (over 20% since 2016), but this was offset by persistent diesel demand from buses and trucks, where electrification lagged (e.g., only 7.6% of bus mileage and negligible heavy truck share was electric in 2022).

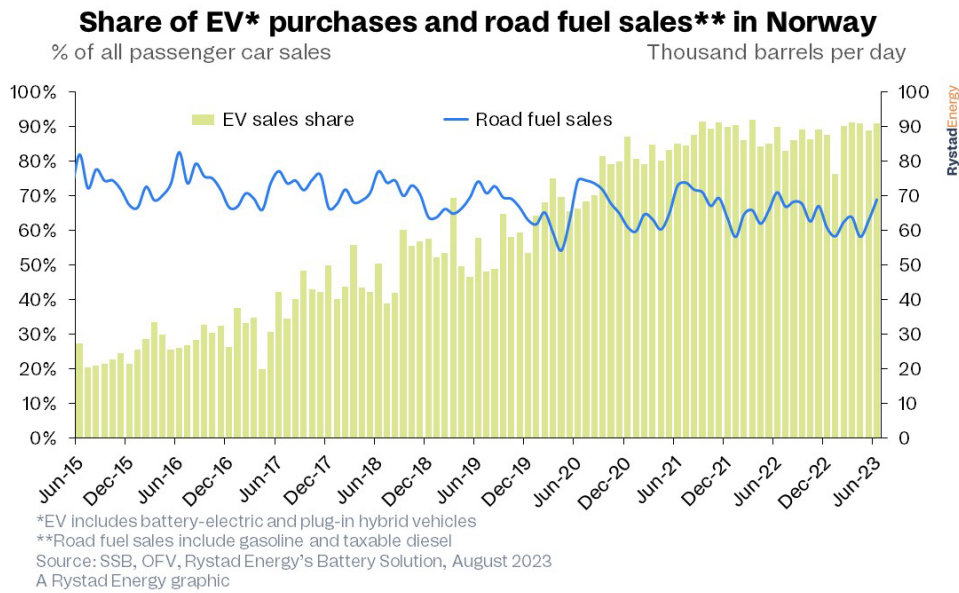
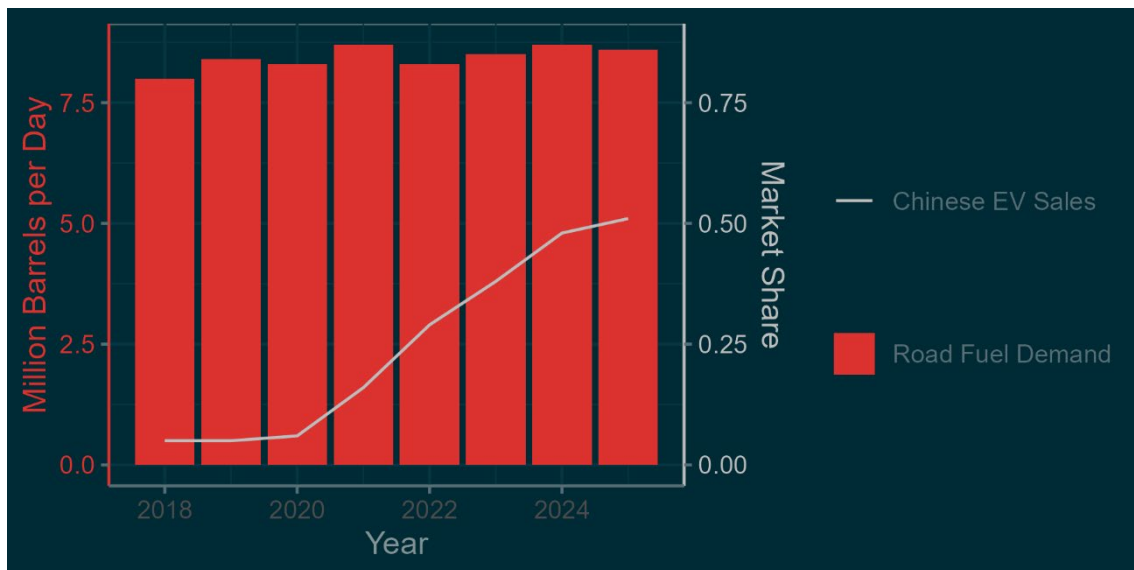


Figure 8: Rystad EV Report Graphic (Source: Rystad Energy)

Another example is China's case. EV sales surpassed 50% in both monthly and annual passenger car sales in 2024.¹ However, IEA data reveals a counterintuitive trend: China's gasoline demand has actually continued at higher than pre-2020 levels when EV adoption was negligible, and total petroleum product demand continues to follow an upward trajectory (**Figure 9**). This demonstrates that the EV sales ratio alone, which is often used as main reasoning for projected future oil demand decline, is an insufficient proxy for forecasting oil demand displacement. A holistic analysis must account for offsetting dynamics, such as the net increase in the total vehicle fleet, rising average vehicle miles traveled, and robust growth in non-transportation sectors, particularly the petrochemical feedstocks in the case of China.



¹ <https://www.iea.org/data-and-statistics/charts/electric-car-sales-in-china-2019-2024>

Figure 9: Chinese EV Sales and Fuel Demand² (Source: IEA)

As of 2025, China and India consumed more than 16 million bpd combined, making up a significant portion of global demand. China's proactive stockpiling absorbs excess supply in oil and gas, supported by its vast storage capacity and higher turnover rates, while India's steady demand provides consistent support to the market. This dynamic has kept prices in check, even as non-OPEC production rises and geopolitical uncertainties loom. However, as China continues building reserves into 2026 and India expands refining capacity, absorbing discounted oil from Russia, sudden shifts in their strategies could introduce new variables—potentially amplifying or dampening volatility depending on global supply trends. In essence, China's ability to set price boundaries through calculated imports and storage underscores its market power, with India reinforcing stability from the sidelines. While U.S. shale production volume has become the largest in the world, the decline rate is also high. Therefore, considerable investment is required just to maintain it, and it appears some companies are already formulating their strategies with the expectation that U.S. shale oil will soon reach a plateau. Non-OPEC supply is plateauing as shale oil declines at an increasing rate (5-6%), and, as a result, OPEC may regain market control.

While U.S. shale production has played a major role in global supply growth, it is important to recognize that this source is not inexhaustible. Unlike the Middle East, Russia, or most South American countries where state-owned enterprises adjust oil and gas production with major directives from the government, private companies in the U.S. adjust production based on prices and market sentiment and invest in underlying infrastructure. Therefore, we cannot assume that production will continue as steadily as it does now. The impact of the current oil price environment on most shale operators is covered in more detail in the **Appendix** which also applies to the associated gas analysis.

LNG:

Historically, LNG development has been driven by demand, reflecting a business model that requires significant upfront investment on both the supply and demand sides. Because projects are highly capital-intensive, material commitments from buyers are typically required before reaching final investment decision (FID). Despite the substantial growth of U.S. LNG, rising costs, shortages of experienced labor, and limited availability of key equipment—often competing with other industries—are beginning to constrain project development and timely delivery, particularly for projects that have not yet reached FID. As prices soften, balance sheet strength becomes increasingly important, and smaller and mid-sized LNG companies are likely to face consolidation or exit amid continued price volatility.

Temporary oversupply, as was observed from 2010 to 2012 and from 2016 to 2018, could occur again. While oversupply is typically absorbed within a few years, underinvestment, driven by a lack of appetite

² Road fuel includes motor gasoline, gas/diesel oil, and natural gas used for road transport.

for long-term commitments, can create prolonged supply gaps. These gaps produce periods of significant spot-market price volatility until sufficient investment catches up, and their volumes are brought to the market (**Figure 10**). Subsequent to energy commodity prices such the oil crash in 2014, LNG FIDs were very low, which created a heavy sentiment of substantial under supply in the early to mid-2020s despite the authentic LNG demand growth, especially in China. Consequently, this sentiment boosted contracting activities which led to 2019 being a record year for LNG FIDs that also included many delayed FID projects, as the market strained to catch up with the dent from this low period. This cycle of price and FID volatility is even more apparent in LNG than oil.

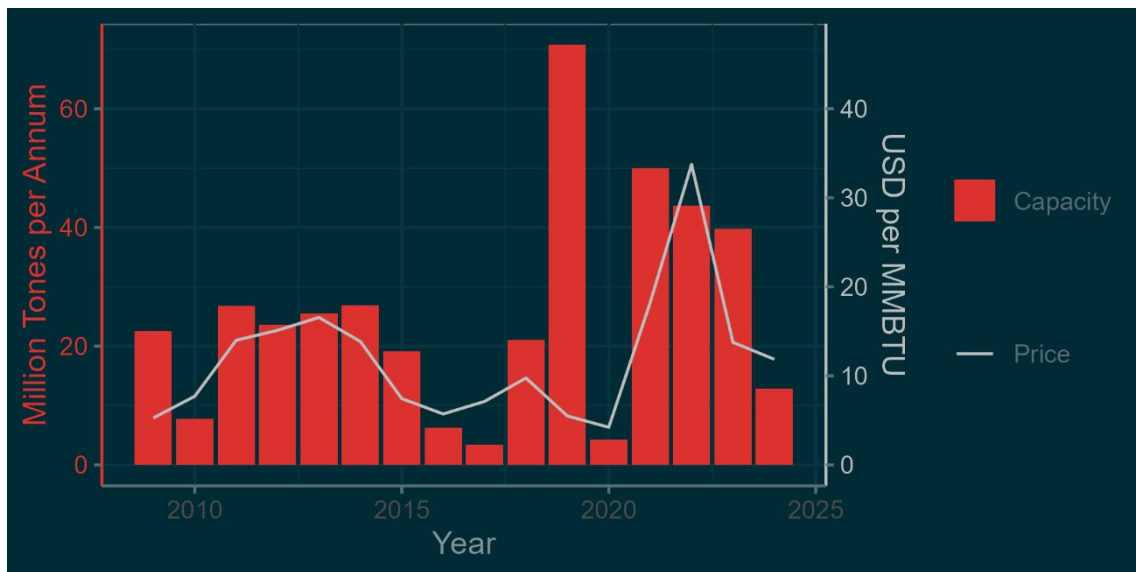


Figure 10: Historical LNG FID volume vs LNG price (Source: Multiple)

As in the oil market, China acts as the demand balancer in LNG. When prices are favorable, its large demand and deep market absorbs significant spot volumes, complementing domestic production and pipeline imports. China’s substantial—and still expanding—storage capacity further enables this role (**Figure 11**).

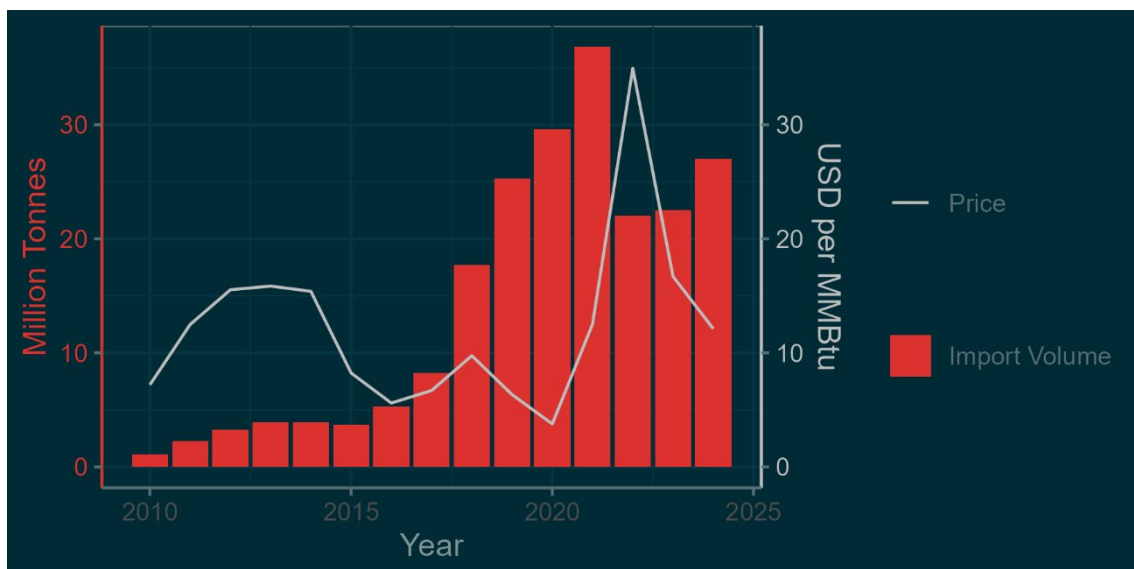


Figure 11: Historical LNG Spot price vs Chinese Short/Spot Procurement (Source: Institute of Energy Economics, Japan)

On the supply side, by contrast, no material supply buffer exists such as that of OPEC or U.S. drilled but uncompleted inventories (now much reduced) because LNG production is typically contracted close to full capacity. This means that even if LNG prices rise, there is even less capacity to quickly catch up on production.

Collectively, as the majority of LNG upstream investment is normally driven by long-term commitment of demand, the key question to an oversupply environment should be just how long it would last and when it would occur, rather than the oversupply environment itself. Moreover, those relying on the spot market would remain at the mercy of price volatility.

D. Conclusion

Aside from their individual demand growth uncertainties, sensitivity of a 1% percent difference in primary energy, which has a strong correlation with GDP growth, equates to more than 0.5% of oil/LNG growth today, which equates to roughly 0.5 mbd of oil and 2 million tons per annum of LNG. Intensified geopolitical tensions, such as the trade wars between China and U.S. and continuing wars/conflicts especially around Ukraine and the Middle East, are generating growing uncertainty, including about fundamental factors such as economic growth.

Temporary oil and LNG oversupply does occur, but its duration and scale remain uncertain from both supply and demand perspectives, especially when the market balance is artificially distorted. Uncertainties and perception gaps lead to severe price volatility, while adequate buffers would contribute to a healthier market, especially given heightened geopolitics tensions. Developing countries will be hurt the most due to affordability issues and complexity with their long-term strategies which in

turn will adversely affect demand, such as for LNG itself. By contrast, an adequate buffer would help sustain stable and affordable prices level with lower volatility. In turn, this would support healthier incremental demand growth, especially in countries that benefit from greater price predictability.

While the introduction of clean energy has made steady progress over the past few years, it has remained an "additional" energy source, rather than a "substitute" for existing energy sources. In fact, the share of hydrocarbons in the world's primary energy has declined very slowly, from approximately 81% to 80.5%. History also proves this. Even when new energy supplies are secured through new technologies, new demand is eventually created, and supply and demand tighten. This is a universal energy cycle.

The energy transition is not only a matter of changing supply but also of addressing demand, which is often less challenged. As long as global primary energy demand continues to increase and the world lacks sufficient alternative clean energy systems, maintaining an adequate supply buffer of fossil fuels, such as oil and LNG, will remain necessary to prevent potential energy shortages. Under these conditions, concerns about fossil fuel investments becoming stranded assets should be resolved by market forces rather than government policy assumptions. Energy systems must remain stable, sustainable, and affordable, while also ensuring investments remain viable. High-cost or unrealistic transition measures risk triggering public backlash and political division, trends that we are already seeing today.

Appendix: Consideration on U.S. shale

- It is important to recognize that the view that U.S. crude oil production may peak in the 2030s is fundamentally demand- and thus price-driven. It is reasonable to assume that reserve depletion and declining geological productivity are not the direct causes.
- If demand increases (rather than decreases) and reserves become physically insufficient, supply constraints will drive up WTI prices, which will economically increase the amount of reserves that can be developed at that price level.
- Meanwhile, there is still likely some room for improvement in shale oil productivity. ExxonMobil's publicly announced efforts (referenced below *) are a good example of this. The important point is that they are simultaneously pursuing (1) improving productivity per well and (2) reducing costs to extend the life of existing production (recovering stranded reserves) and expanding the developable area (reducing break-even prices).
- When it comes to medium-sized independent companies, they are conducting various new R&D projects. However, it is difficult to expect a significant improvement in productivity at this point, and it seems that they are particularly focusing on cost-cutting efforts. Cost reductions will enable development in previously high cost/sub-commercial areas, resulting in increased reserves and production. Specific examples from the industry include the following:
 - Productivity Improvement: R&D of new proppants, as ExxonMobil is doing, recovery of stranded reserves through refractory treatment of existing wells, etc.
 - Cost Reduction: Pursuing synergies through business integration, utilizing AI to improve operational efficiency and optimization, reducing CAPEX per unit well length through the development of ultra-long horizontal wells and U-turn wells, etc.
- However, activities such as cost-cutting and cost-reduction measures aimed at improving corporate resilience to survive in a low-oil-price environment appear to be largely limited to major oil companies. The Dallas Fed conducts a quarterly survey of about 200 oil and gas firms located or headquartered in the Eleventh District—Texas, southern New Mexico, and northern Louisiana—which operate regionally, nationally, or internationally.

- According to the results of the survey conducted in the fourth quarter of 2025, most respondents expect their key business metrics to remain the same or decrease compared to the previous year.

Response	Percent of respondents (among each group)			
	All firms	Large E&P	Small E&P	Services
Increase significantly	11	6	14	8
Increase slightly	26	24	29	21
Remain close to 2025 levels	24	35	22	24
Decrease slightly	19	24	14	24
Decrease significantly	20	12	20	24

NOTES: Executives from 86 exploration and production firms and 38 oil and gas support services firms answered this question during the survey collection period, Dec. 3-11, 2025. Small E&P firms produced fewer than 10,000 barrels per day (b/d) in fourth quarter 2025, while large E&P firms produced 10,000 b/d or more. Responses came from 69 small firms and 17 large firms. Percentages may not sum to 100 due to rounding.

- Meanwhile, the capacity of the pipelines transporting associated gas from the Permian to the Gulf region where most LNG plants are placed is limited, so unless these are expanded, the upper limit on associated gas transport volume will remain the same and it is safe to assume that this will also be a condition for oil production.
- In addition, in the Permian's Delaware Basin, which accounts for the majority of high-quality assets such as Exxon's, regulations on the disposal of so-called "produced water," such as water produced along with oil and water recovered from hydraulic fracturing, have been tightened in recent years, which could become an operational bottleneck. The main regulations are on water quality and injection depth of more than 12,000 feet, which increases the cost of well drilling and the cost of equipment and operating costs to slightly increase the injection pressure. Produced water has been transported to Texas, but in a short while, release of produced water outside the region will generally be prohibited.
- If the Permian gas transportation bottleneck is resolved and a +7 Bcf/D expansion is realized between 2025 and 2028, a considerable amount of gas is expected to flow into the Gulf region. However, the nitrogen content is high at 5 to 7% more or less, far from the 1 to 1.5% more or less required by LNG plants, making it unsuitable as raw material gas as it is.
- The impact on gas prices will depend on whether the technology in question is widely applicable. However, at present, there are also production bottlenecks for feeding LNG plants, as U.S. produces both unconventional and conventional hydrocarbons from sedimentary basins with diverse characteristics, connected by an extensive pipeline network.
- Therefore, from a short-term perspective, gas prices will not fall sharply in a short period of time, due solely to potential increased oil production. On the other hand, if these bottlenecks are resolved and gas production increases significantly, this will have an impact on gas prices.
- WTI prices of \$60-70 are a comfortable range for most U.S. upstream operators. As lower-cost supply continues, WTI prices are likely to face relative downward pressure compared to current expectations.

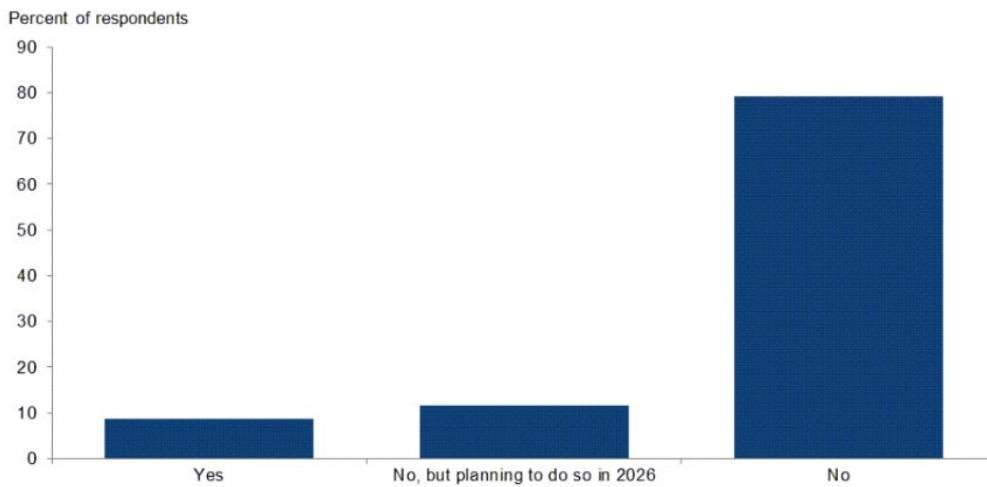
- More than 20 years have passed since the shale revolution, and the question of whether shale oil will head toward degradation and decline, or whether a reversal will occur like a Shale Revolution 2.0 or 3.0 will have a major impact on global crude oil prices.

(*)

- As a completion method for shale gas and oil wells, a special type of sand called "proppant" is injected into the fractures created by hydraulic fracturing to prevent them from closing naturally due to formation pressure. Exxon has announced that it will increase recovery rates by up to 20% in its Permian projects by adopting a proprietary proppant called "Lightweight Proppant" which is yet to be recognized as proven technology. If this is to be achieved, we can expect a significant increase in total production per well, but it is still not clear whether this will increase the daily production at the start of production, or whether this makes the decline gradual in the later stages of production, resulting in an increase in total production.
- Nevertheless, the adoption of such new technologies—including AI and lightweight proppants—is primarily being pursued and tested by large oil and gas companies and has not yet seen widespread experimentation across the industry, as evidenced by the results of the aforementioned Dallas Fed Energy Survey.

Has your firm conducted a trial using lightweight proppant in well completions?

This question was posed only to E&P executives who each said their firm drilled or completed a horizontal well in the past two years. Most executives (79 percent) report their firms haven't conducted trials using lightweight proppant in well completions. Nine percent of executives said their firms have already conducted trials, with an additional 12 percent reporting their firms are planning to conduct trials in 2026.



NOTE: Executives from 34 exploration and production firms answered this question during the survey collection period, Dec. 3–11, 2025. This question was posed only to executives who each said their firm drilled or completed a horizontal well in the past two years.

SOURCE: Federal Reserve Bank of Dallas.

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