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LNG-to-power in emerging Asia: A five-year review of project outcomes

LNG investments face rising costs, long lead times, and frequent cancellations in the Philippines, Vietnam, Thailand, and Bangladesh

Sam Reynolds, Research Lead, LNG/Gas, Asia
Christopher Doleman, LNG/Gas Specialist, Asia



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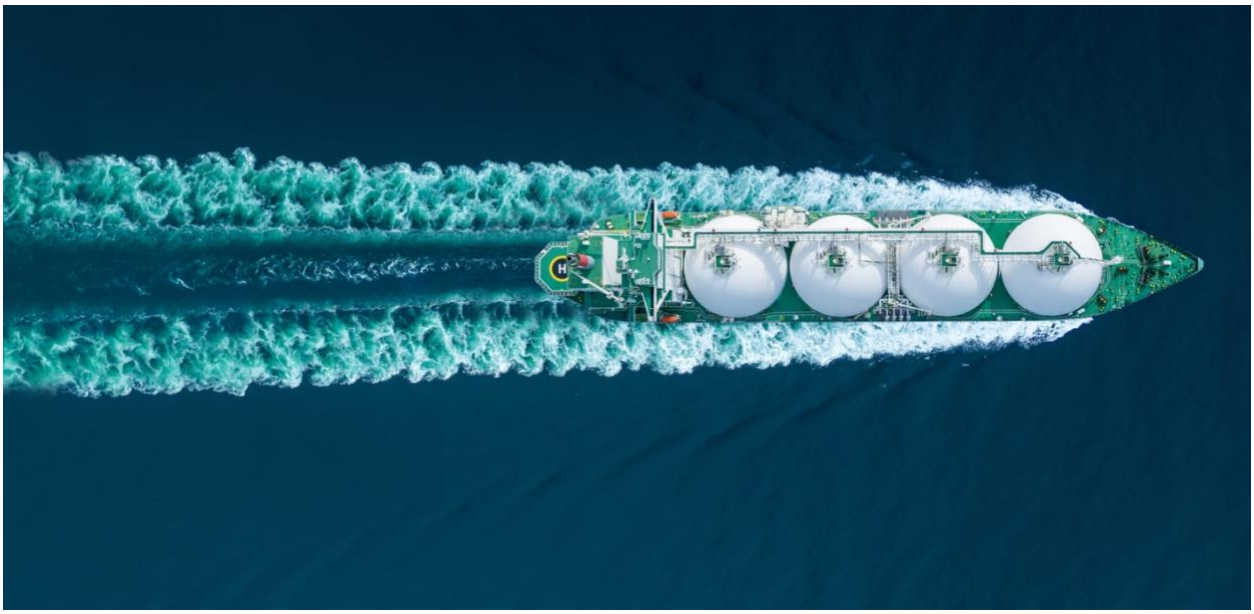
Key findings

Despite gas industry forecasts that South and Southeast Asia will drive global demand for liquefied natural gas (LNG), LNG-fired power plants and import terminal projects in these regions have advanced far more slowly than expected.

Between 2021 and 2026, more than half of LNG-fired power projects and import terminals in the Philippines, Vietnam, Thailand, and Bangladesh have been canceled or shown no notable progress.

Recent developments in global LNG markets, as well as equipment and currency markets, have exacerbated execution risks for LNG-to-power projects in emerging economies and weakened the revenue security on which non-recourse project financing depends.

Higher LNG costs and project execution risks, combined with falling renewable energy and battery storage costs, suggest that expectations of rapid, sustained LNG demand growth in emerging Asian markets warrant closer scrutiny.



Executive summary

In 2021, the Institute for Energy Economics and Financial Analysis (IEEFA) published a regional analysis of liquefied natural gas (LNG)-to-power project developments across seven Asian markets. The report found that despite billions of dollars in proposed investments in both LNG import terminals and power plants, only a small fraction was likely to materialize, due to fundamental constraints related to economics, financial capacity, infrastructure, and policy.[1]

This analysis is an update to the previous report. It examines the pace of progress on LNG developments in Asia, the drivers of success, and the outstanding challenges to getting projects off the ground. Coverage focuses on four prospective gas and LNG demand growth markets in Asia, namely Thailand, the Philippines, Vietnam, and Bangladesh.

In these four markets, IEEFA surveyed 92 proposed LNG-fired power projects worth an estimated USD109.2 billion and 44 LNG import terminals valued at USD21 billion. Key findings include:

- Based on IEEFA's assessment, over 50% of LNG-fired power projects and LNG import terminals in the four markets surveyed have been canceled, withdrawn, or shown no progress between 2021 and 2026.
- A total of 49 gas plants valued at USD56.1 billion were canceled, withdrawn, or inactive between 2021 and 2026, along with USD11.7 billion of regasification facilities, spanning 22 projects. The total capacity of these projects was 66.2 gigawatts (GW), along with 82 million tonnes per annum (MTPA) of LNG terminal capacity.
- Out of the 92 LNG-fired power plants surveyed, just 11% of total power capacity was successfully brought online over the last five years. Meanwhile, just 15% of the total capacity of proposed import terminals was completed. This is a substantially lower completion rate than IEEFA assumed in 2021.
- The total value of canceled or inactive LNG-fired power plants and LNG import terminals was nearly 4.5 times the value of completed projects. In all markets surveyed, a higher capacity of LNG-fired power plants and import terminals was canceled or inactive than completed.
- IEEFA estimates that the average completion timeline for LNG-fired power plants across the four markets was over seven years, from the first public development to commissioning. This far exceeds the three- to four-year lead times typically claimed by project developers for LNG-to-power facilities.
- Over the last five years, developments in global LNG markets, as well as equipment and currency markets, have exacerbated execution risks for LNG-to-power projects in emerging economies. Extreme LNG price volatility, higher costs and longer lead times for scarce gas

[1] IEEFA. Examining Cracks in Emerging Asia's LNG-to-Power Value Chain. 16 December 2021.

turbines, and local currency depreciation against the United States (US) dollar have all weakened the revenue security on which non-recourse project financing depends.

- As a result of skyrocketing LNG-to-power costs, countries in emerging Asia are reconsidering the role of the fuel in their energy future. Based on IEEFA estimates, surging fuel and equipment costs, along with weaker local currencies, could result in a 2.3-fold increase in the levelized cost of power from LNG-fired power plants compared to 2021 baselines.
- Such a potentially sharp increase in electricity costs undermines the economic rationale for many projects as originally conceived. Across emerging Asia, energy-sector development plans that rely heavily on LNG were often formulated on the assumption of persistently low fuel prices and relatively affordable capital and equipment costs.

Section 1 of this report provides an overview of recent developments affecting LNG demand growth across emerging Asia. It considers how recurring LNG crises, gas turbine shortages, and high currency requirements are impacting the viability of gas power plant projects and power development plans across Asia.

Section 2 begins with an overview of gas project developments since 2021 across the four countries surveyed, detailing the value of projects that were completed, canceled, inactive, or remain under development. It then provides a more detailed analysis of the project data for the four countries surveyed and highlights the country-specific challenges that ongoing projects must navigate to achieve completion.

Introduction

Emerging Asian economies are widely expected to be the largest growth markets for liquefied natural gas (LNG) demand in the coming decades. Global gas industry forecasts estimate that economies in South and Southeast Asia will account for the largest share of incremental global demand, driven by strong economic growth, rising energy demand, and falling domestic gas production across much of the region.[2, 3, 4] Increasingly, LNG traders are amassing large portfolios of contracted supply, expecting to resell those volumes profitably to emerging markets in the future.[5]

However, demand growth in these frontier markets will face significantly greater challenges than in the wealthier, traditional markets of Europe and Northeast Asia, where creditworthy offtakers — backed by mature regulatory regimes and predictable tariff-setting mechanisms — have long underpinned project bankability for LNG-to-power infrastructure.

By contrast, developers of LNG projects in emerging markets face a larger, often overlooked gauntlet of execution risks. Regulatory and policy instability, currency and convertibility exposure on dollar-denominated obligations, and the weak credit profiles of state-backed offtakers can all raise financing costs and erode project economics. Heightened sensitivity to volatile energy prices means that LNG price swings can quickly push delivered power costs to levels that utilities and price-sensitive end-users are unwilling to accept. In many cases, regulators may be hesitant to allow high prices to be fully passed through to consumers, undermining investment economics.

This is especially true amid rapid cost declines for renewable energy technologies, which avoid recurring dollar-denominated fuel purchases altogether and insulate economies from geopolitical risks to energy supply.

A 2021 report by the Institute for Energy Economics and Financial Analysis (IEEFA) on LNG-to-power plans across seven emerging Asian economies discussed these risks in detail and found that the pipeline of feasible LNG-related investments was likely to be far smaller than the frenzy of announced projects.[6] Since 2021, global gas market developments have worsened the outlook for new LNG projects in emerging Asia. These developments have been shaped by two major geopolitical crises, a shortage of gas turbines, and the depreciation of local currencies against the United States (US) dollar.

While analysis of Asian LNG demand growth often focuses on the scale of investment opportunities looking forward, less attention is given to how the pipeline of proposed projects has changed over time. Explicit project cancellations are rare; more often, projects may show little to no progress for

[2] Wood Mackenzie. Asia LNG Demand Assessment – Executive Summary of Report Prepared for Asia Natural Gas and Energy Association (ANGEA). October 2024. Page 2.
[3] Shell. LNG Outlook 2026. 6 August 2026. Page 4.
[4] BP. BP Energy Outlook 2025 edition. 25 September 2025. Page 43.
[5] IEEFA. Global LNG Outlook 2024-2028. 25 April 2024. Page 20.
[6] IEEFA. Examining Cracks in Emerging Asia's LNG-to-Power Value Chain. 16 December 2021.

multiple years before quietly fading from view. Meanwhile, project completion timelines can routinely extend up to a decade — far beyond the three to four years typically cited for LNG-fired power plants.

This report identifies and estimates the value of completed, canceled, inactive, and ongoing LNG-fired power plants and import terminal projects from 2021 to 2026 in the key demand-growth markets of Vietnam, the Philippines, Thailand, and Bangladesh. It begins with a discussion of global market trends shaping LNG demand growth in Asia over the past five years, then examines each country in turn — detailing project pipelines, cancellations, and the structural challenges that continue to hamper LNG project development.

Section 1: Key developments impacting LNG demand growth in emerging Asia

IEEFA's 2021 regional analysis of LNG projects in emerging Asia identified a fundamental tension between industry expectations of rapid demand growth and the exposure of prospective buyers to volatile global commodity markets.[7] It found that recurrent volatility would strain public-sector balance sheets, deplete US dollar reserves, and undermine the affordability and bankability of downstream LNG-to-power projects in key markets.

Since then, developments in fuel, equipment, and currency markets have amplified execution risks for LNG-to-power projects rather than alleviating them. Russia's full-scale invasion of Ukraine, followed by the Middle East conflict, has underscored Asia's continuing exposure to LNG supply disruptions and sharp shifts in competition for available cargoes. A global surge in orders for natural gas turbines, driven largely by data center demand in the US, has raised development costs and extended lead times for LNG-fired power plants in emerging Asia. The depreciation of local currencies in the region relative to the US dollar has also increased the domestic cost of dollar-denominated imports and debt servicing.

These challenges directly increase project financing risks, raising debt requirements and weakening the revenue certainty on which non-recourse LNG-to-power structures depend. Lenders and equity investors must closely assess whether projects can recover volatile, dollar-linked fuel costs through airtight, back-to-back contracts with creditworthy offtakers, and whether minimum output guarantees and capacity payments sufficiently support debt service.

Where tariff regimes do not allow the automatic pass-through of input costs to end-users, risks shift to the offtaker or the government through higher subsidy requirements or contingent liabilities, ultimately increasing counterparty risk and the cost of capital.

The result is that only the best-structured LNG-to-power projects — those with strong sponsor credit, government support, and fully aligned fuel contracts and power purchase agreements (PPAs) — reach financial close, while the broader pipeline faces delays, downsizing, or cancellation.

Global market prices

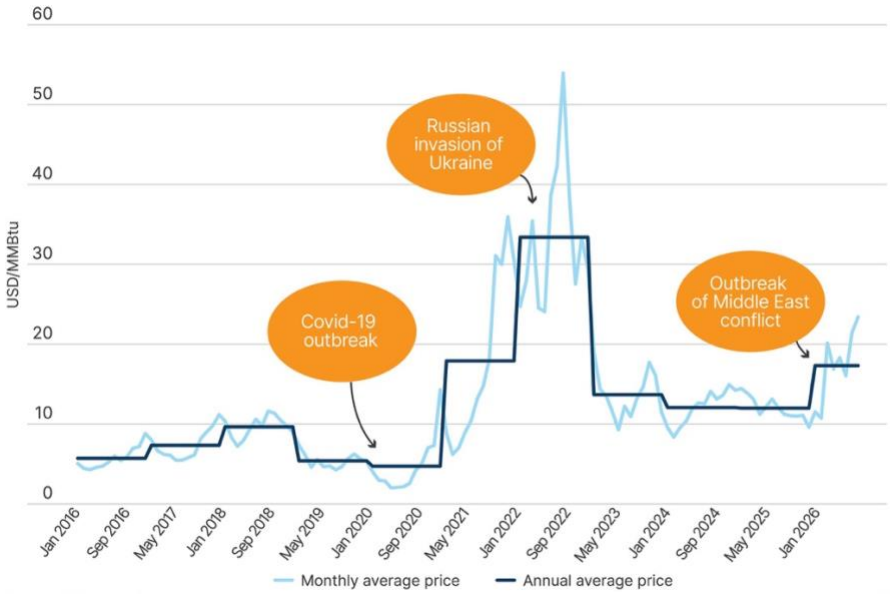
Between 2016 and 2020, LNG prices in Asian spot markets averaged USD6.56 per million British thermal units (MMBtu). However, beginning in late 2021, Russia began to curtail pipeline gas exports to Europe, and European buyers turned instead to seaborne LNG. Following Russia's full-scale

[7] Following LNG price spikes in late 2021, some emerging market buyers were unable to afford LNG cargoes, resulting in gas shortages and power disruptions. Even then, some analysts were already describing price fluctuations as "unprecedented." Reuters. LNG's massive spot prices in Asia are paid by few buyers: Russell. 7 October 2021.

invasion of Ukraine in February 2022, LNG costs increased sharply, averaging USD33.39/MMBtu for the remainder of the year.

Spot prices eased between 2023 and 2025 but remained well above pre-invasion levels (Figure 1). Although markets were widely expected to settle in 2026 with the onset of a new wave of LNG export facilities, the outbreak of the Middle East conflict and closure of the Strait of Hormuz in February 2026 effectively shut in 20% of global LNG supply.

Figure 1: Monthly and annual LNG spot prices in Asia (Japan-Korea Marker)



Source: IEEFA; Investing.com.

LNG markets have remained highly sensitive to efforts by the US administration and other parties to de-escalate the conflict and restore shipping through the Strait of Hormuz. The Islamabad Memorandum, signed in June to reopen the Strait and establish a 60-day ceasefire, quickly collapsed.[8] Iran has ruled out direct talks with the Trump administration and suggested it could wait until 2029 to resume negotiations.[9] The impasse has reinforced expectations of a more prolonged disruption to LNG supply.

Between late February and August 2026, LNG prices in Asia more than doubled, reaching USD27.5/MMBtu on September 18. At this price, IEEFA estimates that a single cargo of LNG would cost USD100.1 million. Running a 1-gigawatt (GW) LNG-to-power plant at baseload levels would require approximately 14 cargoes at a total annual cost of USD1.35 billion for the fuel alone.

[8] NPR. Read the full text of Trump's preliminary U.S.-Iran agreement to end the war. 18 June 2026.
[9] News18. Iran Rules Out Talks With Trump, Says Will Wait Until His Term Ends In 2029. 10 August 2026.

The impact of price volatility on Asia's LNG demand

Recurring geopolitical crises and ongoing volatility in LNG markets have constrained demand growth in Asia. After continuous growth between 2015 and 2021, the region's demand for the fuel fell by 7% in 2022.[10] Despite recovering in 2024, LNG demand declined again by 5% in 2025.[11] In 2026, analysts expect demand to decrease by up to 10% year-over-year.[12]

In Asia, LNG market shocks can trigger several short-term responses, including power sector fuel switching, industrial curtailment, and broader measures to limit energy demand. Market instability has also led to longer-term efforts to shift away from LNG dependence entirely, through measures that include:

- **Accelerating renewable energy development**: Many countries in Asia — including the Philippines[13], Vietnam[14], Thailand[15, 16], Indonesia[17], Cambodia[18], India[19], and South Korea [20]— have stated their intention to fast-track and remove barriers to renewable energy projects to ensure domestic energy security.
- **Restarting nuclear facilities**: Since the Middle East conflict began, South Korea and Taiwan have announced plans to restart nuclear facilities. In March 2026, the South Korean government announced it would restart and accelerate maintenance at six nuclear units, five of which had resumed operations as of September 2026.[21, 22, 23] After going nuclear-free in 2025, Taiwan has said it will restart two plants with a combined capacity of 3.84GW.[24] Japan was already restarting nuclear facilities before the conflict began, while Bangladesh began fuel loading at its first nuclear facility in April.[25]
- **The development of other natural gas sources**: Many countries are re-evaluating domestic gas production efforts and pipeline import projects to reduce reliance on

[10] IEEFA. Asia's lower LNG demand in 2022 highlights challenges for industry growth. 11 January 2023.
[11] IEEFA. Asia's falling LNG demand in 2025 defies investor optimism for rapid growth. 4 December 2025.
[12] Reuters. Asian LNG demand set to fall for second year as war shrinks supply. 17 September 2026.
[13] Renewables Now. Philippines speeds up 1.47 GW of renewables amid MidEast tension. 6 April 2026.
[14] Vietnam Energy Online. Vietnam issues Directive No. 10 to accelerate rooftop solar and strengthen electricity conservation. 2 April 2026.
[15] Mahanakhorn Partners Group. Thailand Strengthens Support for Renewable Energy and Sustainability Initiatives. 18 June 2026.
[16] Bloomberg. Thailand to Shift From LNG Toward Renewables in Wake of Iran War. 27 August 2026.
[17] Nikkei Asia. Indonesia's Prabowo vows quicker energy transition amid global oil crisis. 30 March 2026.
[18] The Star. Cambodia reduces import duties for EVs, electric stoves and solar devices. 29 March 2026.
[19] Reuters. India boosts renewable push amid gas supply disruptions, minister says. 30 March 2026.
[20] Guardian. How South Korea plans to use the Iran crisis to spur a renewables revolution. 15 April 2026.
[21] The six units planned for accelerated maintenance and restart included Shin Wolsong 1, Kori 2, Hanbit 6, Hanul 3, Wolsong 2, and Wolsong 3. Of those six reactor units, only Wolsong 2 remains offline as of September 20, 2026, according to Korea Hydro and Nuclear Power (KHNP). KHNP. Realtime Output on NPP. Date accessed: 20 September 2026; Chosun. South Korea boosts nuclear restarts, taps coal to brace for energy shock. 11 March 2026.
[22] Bloomberg. South Korea to Speed Up Nuclear Restart Amid Middle East Crisis. 11 March 2026.
[23] IEEFA. The Iran conflict is cutting the long-term role of LNG in Asia. 15 April 2026.
[24] Taipei Times. Lai reveals nuclear power revival plan. 22 March 2026.
[25] World Nuclear News. Fuel loading begins for Bangladesh's first nuclear power plant. 28 April 2026.

imports, including the Philippines, Vietnam, Bangladesh, China, Pakistan, and Malaysia. For example, China's higher domestic gas production and higher pipeline imports from Russia have been drivers of reduced LNG imports relative to 2021[26], while Malaysia's Petronas aims to reinvest oil revenues into domestic gas values to stimulate production.[27]

- **LNG project cancellations**: Perhaps the clearest sign of LNG demand destruction is the explicit cancellation of projects. For example, Vietnam's Vingroup expressed its intention to cancel a proposed 4.8GW plant, citing complications from the Middle East conflict.[28] Notably, the project was included in the country's power development plan and Vingroup had already signed initial agreements to procure gas turbines[29], but an annual LNG requirement of 5 million tonnes per annum (MTPA) was deemed untenable due to cost and currency exchange risks.

Gas turbine shortages raise capital costs and project lead times

Along with the extreme volatility in fuel markets, LNG-to-power project sponsors in emerging Asia must also navigate a challenging equipment market. A global shortage of gas turbines is widely expected to both increase costs for new power plants and delay the construction of numerous projects around the region.

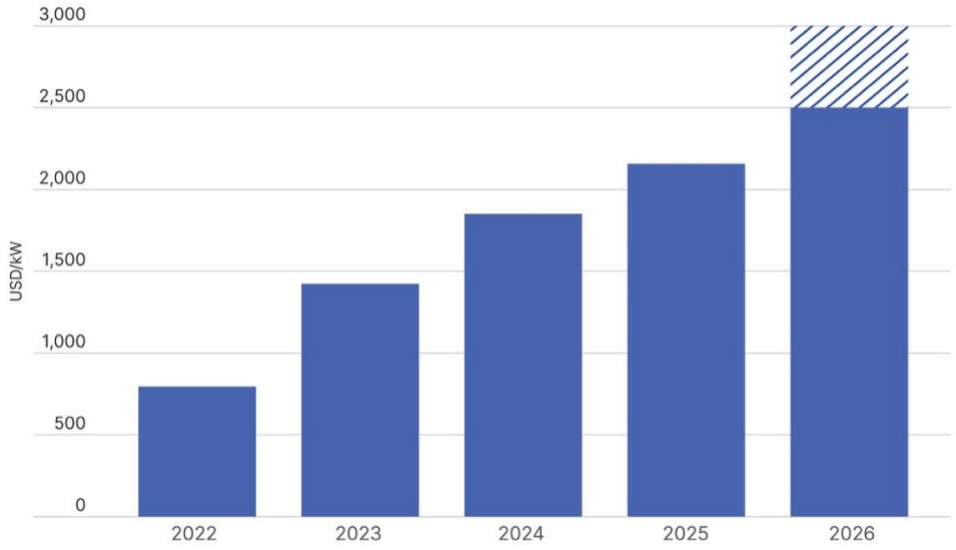
IEEFA has examined the impact of the global gas turbine crunch on Southeast Asia in previous reports.[30] Order backlogs at the three dominant original equipment manufacturers (OEMs) — GE Vernova, Siemens, and Mitsubishi Heavy Industries — are extending delivery timelines for heavy-duty frames to six years or more, according to Wood Mackenzie.[31] In 2025, turbine orders reportedly totaled 110GW of capacity, compared to an annual global production capacity of 60–70GW, creating a structural supply gap that is likely to persist through 2030.[32] In the second quarter of 2026, GE Vernova's order backlog reached 116GW, and the company was taking reservations for 2031 delivery.[33]

In line with IEEFA's October 2025 analysis, Wood Mackenzie also estimates that governments in Southeast Asia are targeting a total of 53GW of new gas-fired power capacity by 2030, but just 11GW of the pipeline has secured turbines.[34] As a result, the region is likely to realize far fewer gas and LNG-to-power projects than originally planned.

[26] IEEFA. Understanding the competitive landscape for China's LNG market. 10 April 2025.
[27] Business Times. Energy crisis triggered by Iran war pushes Asia to think twice before doubling down on LNG. 17 April 2026.
[28] Reuters. Vingroup proposes scrapping LNG-powered plant plan for renewables amid Iran war, document shows. 31 March 2026.
[29] GE Vernova. GE Vernova powers Vietnam's energy transition with key regional commitments at inaugural Energy of Change Summit. 10 March 2026.
[30] IEEFA. Global gas turbine shortages add to LNG challenges in Vietnam and the Philippines. 7 October 2025.
[31] Wood Mackenzie. Gas turbine prices soar 195% as market faces supply-demand crisis. 1 April 2026.
[32] Oil Price. Global Gas Turbine Orders Hit Record High as Power Demand Surges. 11 August 2026.
[33] Oil Price. The Gas Turbine Shortage Just Became AI's Biggest Constraint. 22 August 2026.
[34] Wood Mackenzie. Southeast Asia to deliver less than one-third of planned gas power capacity by 2030. 4 August 2026.

Longer lead times are materially increasing project costs through higher capital expenditure (capex) and schedule-related cost escalation. At a recent conference hosted by Bank of America, GE Vernova CEO Scott Strazik cited engineering, procurement, and construction (EPC) costs reaching between USD2,500-3,000 per kilowatt (kW) for new gas-fired power plants in the US[35], which accounted for half of new turbine orders in the second quarter of 2026. However, just four years ago, developers cited costs as low as USD785/kW[36], suggesting that costs have escalated nearly fourfold (Figure 2).

Figure 2: Capital costs for US gas-fired power projects



Source: NextEra Energy; BNEF; GE Vernova.

Moreover, OEMs are now typically requiring turbine customers to post advance, non-refundable payments to secure manufacturing slots, often years before final supply contracts are executed.[37] According to some estimates, these payments can equate to between 10% and 20% of the total cost of the turbines[38, 39], with the payments credited against the final purchase price if the contract is concluded but retained by the OEM if not. This forces developers to commit sizable cash payments long before project financial close, increasing pre-development risk exposure and eroding returns should the project proceed.

Higher capex and longer lead times for gas turbine deliveries increase debt requirements and create sequencing challenges. Since lenders typically require executed turbine supply contracts before debt can be drawn down, developers must commit substantial capital to non-refundable deposits for

[35] GE Vernova. Bank of America Global Industrials Conference 2026. 18 March 2026. Page 9.
[36] Gas Outlook. Costs to build gas plants triple, says CEO of NextEra Energy. 25 March 2025.
[37] Bloomberg. AI-Driven Demand for Gas Turbines Risks a New Energy Crunch. 2 October 2025.
[38] Bloomberg. AI Boom Has European Buyers Paying Extra to Secure Gas Turbines. 11 June 2026.
[39] Electron Economics. Slotting In the Future: Gas Turbine Reservations and the AI Power Land Grab. 16 December 2025.

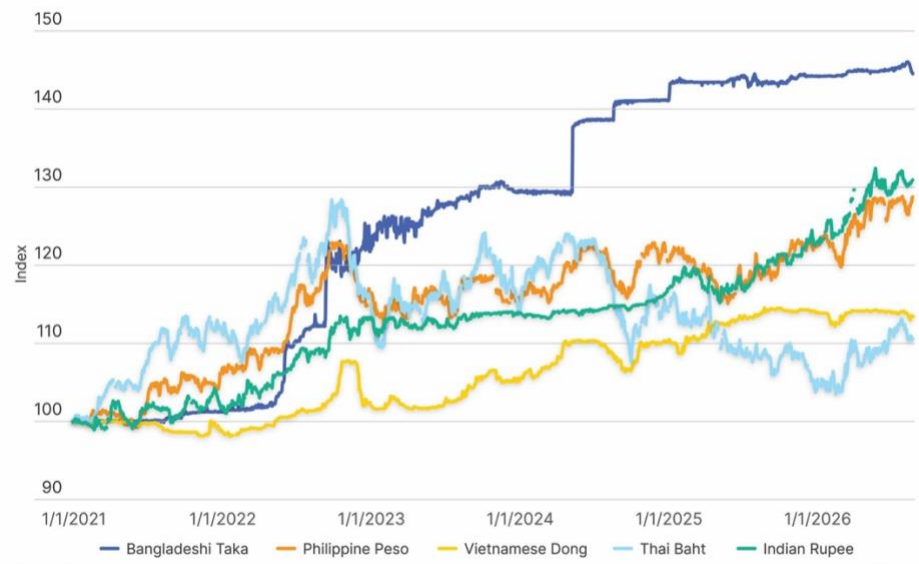
manufacturing slot reservations before debt financing is available. Final investment decisions (FIDs) are frequently delayed as sponsors chase equipment slots, arrange pre-FID capital, seek government support to mitigate development risks, or renegotiate PPAs to reflect later in-service dates and higher costs.

Local currency depreciation raises dollar-denominated costs

In addition to rising fuel and equipment costs, the depreciation of local currencies across Asia is compounding cost pressures for LNG-to-power projects. The costs of LNG exports, shipping, LNG receiving and regasification, and most power generation facilities are denominated in US dollars. However, end-user power tariffs in LNG-importing economies are collected in local currency, meaning revenues must be converted back into US dollars to pay commodity suppliers, lenders, and equity investors. As a result, exchange rate fluctuations can significantly impact the final invoice received by governments or consumers.

Since 2021, currencies in the emerging Asian economies of Bangladesh, India, Thailand, Vietnam, and the Philippines have depreciated by an average of 25.6%, though the extent varies widely across markets (Figure 3). In the wake of two major geopolitical crises since 2022, heightened risk has triggered recurring sell-offs in emerging-market currencies in favor of safe-haven assets such as the US dollar, while persistently high US interest rates have reinforced capital outflows.

Figure 3: Emerging Asian currencies against the US dollar



Source: Bloomberg.

This depreciation has increased the local-currency cost of US-dollar-denominated LNG imports and equipment purchases, adding to the impact of recurring fuel price spikes since 2021. Higher US-dollar-denominated fuel costs and weaker exchange rates put pressure on limited foreign exchange

reserves in emerging Asian economies, and the consequences can extend beyond the energy sector. Fuel suppliers, wary of non-payment, may reduce or halt spot deliveries, triggering rationing and demand destruction; governments may rely more heavily on International Monetary Fund (IMF) programs and emergency multilateral loans, limiting resources to address other macroeconomic needs; and ballooning fuel-import costs can crowd out essential social spending. As a result, energy import challenges can quickly evolve into broader macroeconomic vulnerabilities.

Energy security, therefore, becomes dependent not only on the diversity of fuel suppliers and procurement options but also on the adequacy of US dollar reserves, currency stability, and access to US dollar liquidity that many emerging markets cannot reliably control. Many of the largest potential LNG demand-growth markets highlighted by the global gas industry are those with significantly lower foreign exchange reserves than mature LNG importing markets.

Implications for LNG-to-power costs

The range of risks in fuel, equipment, and currency markets means that the final delivered price of electricity from LNG-to-power projects can vary dramatically. Figure 4 below shows this potential cost escalation according to various assumptions for a hypothetical 1GW project in Vietnam. The left-hand column shows the modeled levelized cost of an LNG-fired power plant, with regasified fuel prices of USD10/MMBtu and capital costs of USD917/kW at a baseline USD-VND exchange rate indexed to January 2021.

Assuming a weighted average cost of capital (WACC) of 8% and a capacity utilization of 70% results in an initial levelized cost of USD88 per megawatt-hour (MWh) (VND2,037 per kilowatt-hour [kWh]).

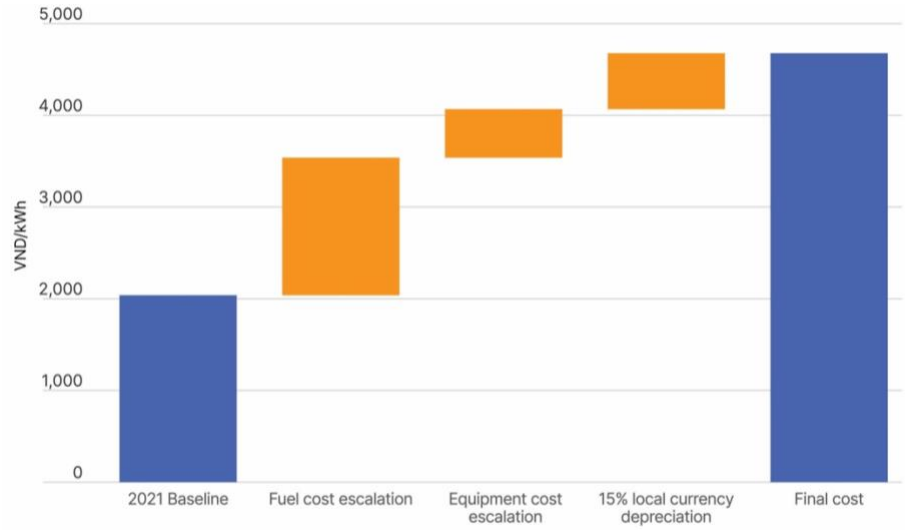
However, a doubling of regasified LNG prices to USD20/MMBtu — still less than spot market prices in Asia in September 2026 — increases the levelized cost to USD153/MWh (VND3,537/kWh).

Bringing the capital cost assumptions in line with more recent estimates of USD2,500/kW further increases the levelized cost to USD176/MWh (VND4,067/kWh).

Finally, a 15% depreciation of the Vietnamese dong between January 2021 and August 2026 raises the levelized cost in local currency to VND4,677/kWh. Importantly, the Philippine peso, Indian rupee, and Bangladeshi taka have depreciated between 30% and 45% over that timeframe.

Taken together, these risks could result in a 130% increase in the total levelized cost of power in local currency terms, compared to baseline project assumptions when initial planning took place in 2021. Moreover, high-end estimates for LNG-fired power costs would be more than double the average regulated retail power rate in Vietnam (discussed further on page 30)

Figure 4: Impact of fuel, equipment, and currency risks on LNG-to-power levelized costs



Source: IEEFA calculations. See text above for assumptions in each scenario.

According to Bloomberg New Energy Finance (BNEF), the 2026 levelized costs of solar and wind in Vietnam were USD44/MWh and USD78/MWh, respectively. This means that wind and solar were already significantly cheaper than LNG-fired power generation, even before considering the inflationary impacts of developments in fuel, equipment, and currency markets since 2021.

Moreover, IEEFA analysis has shown that current LNG prices make gas-fired power uncompetitive with firm solar plus storage, even after accounting for inflation-driven increases in capital costs for renewable projects.[40]

For LNG-to-power project financing in emerging Asia, these risks weaken both the short- and long-term outlook for the economic viability of LNG in the region. In the near term, turbine shortages are extending lead times and forcing developers to bear higher risk prior to financial close. Higher capital costs are increasing debt requirements, while extreme fuel cost volatility can undermine the cash-flow predictability lenders require to underwrite long-tenor debt.

Over the longer term, the rapid penetration of renewables in emerging Asian economies erodes the dispatch and revenue base LNG-to-power plants were designed to capture. Cheaper solar and wind are reducing the use of gas-fired power plants in baseload roles, while battery storage deployments threaten to shorten the periods when gas is needed to provide peaking power. Recent Wood Mackenzie estimates of levelized electricity costs found that four-hour battery storage is cheaper

[40] IEEFA. Iran tensions underscore the urgency of Asia's renewables pivot for macroeconomic stability. 12 March 2026.

than gas in peaking roles in all 43 countries modeled.[41] Together, these trends increase the risk of underutilization for the region's LNG infrastructure.

The consequences of these converging risks are already evident. Over the past five years, a growing number of LNG-to-power projects across emerging Asia have been canceled, shelved, or shown no notable progress since inception. The following section examines these cancellations, along with country-specific risks that are compounding the global market trends discussed above.

[41] Wood Mackenzie. Four-hour battery storage now beats gas peaking on cost globally. 8 October 2026.

Section 2: Assessing LNG-to-power project cancellations in emerging Asia since 2021

IEEFA surveyed 92 prospective LNG-fired power projects worth an estimated USD109.2 billion and 44 LNG import terminals valued at USD21 billion in the Philippines, Vietnam, Thailand, and Bangladesh.[42] Of these, 49 gas plants valued at USD56.1 billion were canceled or inactive between 2021 and 2026, together with 22 regasification facilities valued at USD11.7 billion.

Table 1: Summary of LNG-fired power projects surveyed since 2021

Project status	Estimated value (USD billion)	Number of projects	Capacity (GW)
Complete	12.0	10	13.5
Cancelled/inactive	56.1	49	66.2
Ongoing	42.5	33	47.4
Total	110.6	92	127.1

Source: IEEFA analysis.

Table 2: Summary of LNG import terminals surveyed since 2021

Project status	Estimated value (USD billion)	Number of projects	Capacity (MTPA)
Complete	3.2	5	21.5
Cancelled/inactive	11.7	22	82.0
Ongoing	6.2	17	38.6
Total	21.0	44	142.1

Source: IEEFA analysis.

Over that timeframe, the total value of canceled and inactive LNG-fired power plants and LNG import terminals was nearly 4.5 times the value of completed projects. Out of the 92 LNG-fired power plants surveyed, just 11% of total power capacity was successfully brought online over the last five years. IEEFA estimates that the average completion timeline for LNG-fired power plants across the four markets was over seven years, from the first public announcements to commissioning.

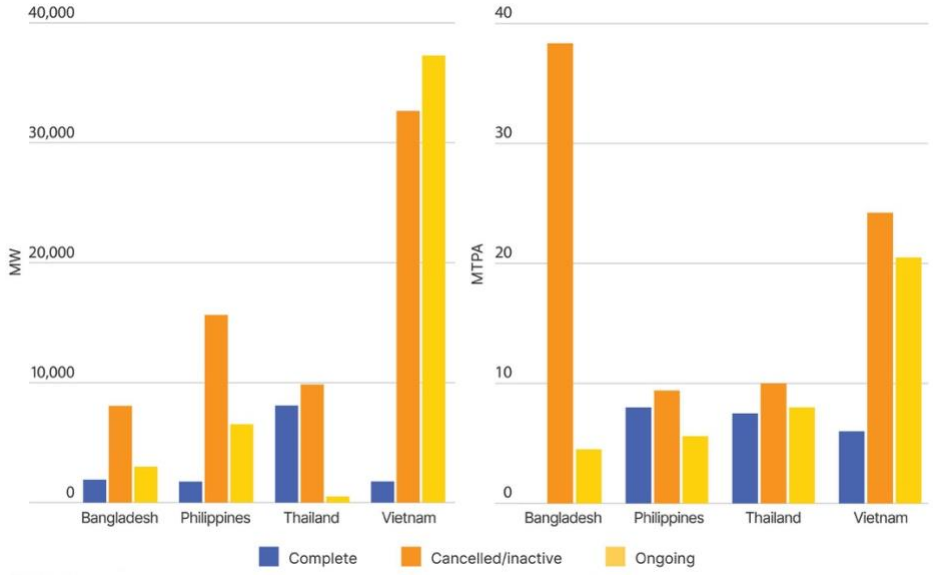
[42] All project valuations in this report are estimated by IEEFA using a standardized methodology. These valuations may differ from publicly reported investment figures.

Meanwhile, just 15% of the total capacity of proposed import terminals was completed across five projects.

Based on IEEFA's assessment, over 50% of LNG-fired power projects and LNG import terminals in the four markets surveyed have been canceled, withdrawn, or shown no significant progress over the last five years. In all markets surveyed, the capacity of LNG-fired power plants and import terminals that were canceled or stalled exceeded the capacity completed.

The current pipeline of projects still in development includes 33 power plants worth USD42.5 billion and 17 import terminals valued at USD6.2 billion.

Figure 5: Status of LNG-fired power plants (left) and import terminals (right) surveyed



Source: IEEFA analysis.

The rest of this section examines these numbers for each country and provides an overview of the country-specific challenges facing projects.

The Philippines

The Philippines has experienced a high rate of project cancellations over the last five years. Since 2021, only one project has been completed, while 13 others — with an estimated value of over USD14 billion — are assumed to have been canceled or withdrawn (Appendix 1).

Over the same timeframe, the country completed its first two LNG import terminals with an estimated value of USD861 million to supply new and existing gas-fired power plants. However, four proposals for additional LNG import capacity have been canceled, withdrawn, or shown no notable progress since their announcement. IEEFA calculates that the combined value of these terminal projects is USD1.3 billion (Appendix 2).

The only LNG-fired power plant to successfully come online in the Philippines in the past five years was the 1,750 megawatt (MW) plant developed by Excellent Energy Resources Inc. (EERI).[43] The project began a public scoping study in November 2020, and the first two units of the plant were brought online in May 2025, completing the project in 4.5 years.

The country currently has five LNG-fired power projects that are reportedly still under development, with an estimated value of USD6.1 billion. However, all projects are still in early stages of development, and none has secured gas turbine orders.

Meanwhile, three remaining LNG import terminals are still being pursued by Australia's Energy World Corporation (EWC), US-based Excelerate Energy, and Quezon Power Ltd., although the country's energy minister has acknowledged that no new import terminals are needed in the near term.[44] EWC recently canceled its proposed LNG-fired power plant associated with its import terminal, noting that the company is reassessing downstream demand in the country and may also realize an impairment on the value of the terminal project.[45]

IEEFA has identified the following challenges for ongoing LNG projects in the country.

LNG-fired power projects struggle to compete in procurement processes

The Philippine power market is distinctive among emerging Asian economies because a diverse set of distribution utilities — including large private, investor-owned utilities, electric cooperatives, and local government-owned utilities — procure power supply for captive customers within their franchise areas. Rather than allocating new capacity through central state planning or direct procurement by a single state-backed offtaker, Philippine distribution utilities must demonstrate that

[43] IEEFA. Clean energy is driving coal's decline in the Philippines, not LNG. 30 July 2025.
[44] Reuters. Philippines unlikely to add new LNG terminal near-term on excess capacity. 28 October 2025.
[45] IEEFA. Gas turbine sale signals the end of another Philippine LNG project. 10 June 2026.

supply is procured on a least-cost basis through bidding procedures, or competitive selection processes (CSP).

This structure makes an LNG-to-power project's commercial prospects dependent not only on its technical and fuel-supply arrangements but also on its ability to submit a competitive bid against alternative generation technologies. High and volatile fuel prices, combined with increasing capital requirements, can render LNG plants uncompetitive compared to other participating technologies.

To date, EERI's LNG-to-power project remains the only greenfield LNG-to-power project to have secured a power purchase contract through the CSP process. Looking ahead, opportunities to bid for long-term offtake contracts will be limited by distribution utilities' procurement plans. For example, the Manila Electric Company (Meralco), the country's largest electricity distributor, only plans to procure 1.5GW of baseload capacity through 2031[46], with targeted start dates between 2028 and 2032 (Table 3). This compares with 6.5GW of proposed and ongoing LNG-fired power projects, which all face roughly four- to five-year delivery timelines for natural gas turbines. Smaller distribution utilities may have weaker credit profiles due to their financial positions, presenting counterparty risks for lenders to LNG projects.

Table 3: Meralco power supply procurement plan

Supply type	Minimum MW	CSP publication	Contract start	Contract end
Baseload	300	May-26	2028	2043
	300		2029	2044
Baseload	600	Sep-26	2031	2046
	300		2032	2047
Mid-merit	400	2Q 2028	2030	2045
Baseload	300	2Q 2031	2033	2048
Mid-merit	500	2Q 2032	2034	2049
Baseload	400	2Q 2033	2035	2050

Source: Meralco. Power Supply Procurement Plan 2026, page 21. Date accessed: 06 July 2026.

Without a PPA from a creditworthy buyer, LNG-to-power developers will be fully exposed to the country's wholesale electricity spot market (WESM), while price volatility and competition from low-marginal cost renewables could threaten the utilization rates of LNG-fired power plants. Merchant

[46] Meralco. Power Supply Procurement Plan 2026. Date accessed: 06 July 2026. Page 21.

exposure and low utilization could therefore undermine overall cost recovery and debt service for gas-to-power projects.

To improve revenue certainty for gas-fired power projects, the Philippine Department of Energy (DOE) issued guidelines in June 2026 for a mid-merit natural-gas capacity auction. The scheme may provide a useful route to market for existing, uncontracted plants that are already commercially available. However, it is unlikely to provide sufficient contracted revenue to support the financing of greenfield projects, since mid-merit plants would still depend on sales in the wholesale market for a material share of their output. This residual exposure to WESM revenues, combined with volatile fuel costs, would hinder cash-flow predictability and weaken project bankability.

Negligible demand in non-power sectors limits the need for standalone import terminals

Given that natural gas demand in the Philippines is concentrated solely in the power sector, LNG demand growth will depend entirely on the timely buildout of LNG-to-power facilities. More mature gas markets typically involve demand from various economic sectors, such as industrial and residential end-users, providing greater certainty and stability for investments in natural gas infrastructure. In the Philippines' latest energy plan, however, the government envisions negligible growth through 2050 in gas demand from non-power sectors, including transportation, households, and industry.[47]

This lack of demand in non-power sectors is particularly challenging for project sponsors of standalone regasification terminals, which are not developed with integrated LNG-fired power plants and therefore lack an immediate anchor customer. Standalone terminals typically require multiple access or sales agreements with a variety of customers to justify investment. Due to the lack of non-power demand and challenges for new LNG-fired power plants in the Philippines, the commercial basis for standalone terminals is weak.

For example, although Excelerate Energy is still reportedly pursuing a standalone floating storage and regasification unit (FSRU) in Batangas — billed as the Philippines' first open-access terminal — there is no indication that the project has secured any customers. In its 2022 initial public offering (IPO), the company stated plans to "deliver natural gas to downstream users regardless of location or size" in the Philippines. The same year, Wells Fargo provided a bullish outlook for the company, stating that the Philippines project would contribute to strong growth.[48] In 2025, the International Gas

[47] Philippines Department of Energy. Philippines Energy Plan 2023-2050. Date accessed: 7 July 2026. Page 68.
[48] Wells Fargo. Excelerate Energy: Upgrading to Overweight—Technical Weakness Creates Attractive Energy Point. 5 July 2022. Page 1.

Union (IGU) listed the project as "under construction," targeting completion in 2028.[49] However, the project was subsequently removed from IGU's list of projects under construction in 2026.

Similarly, EWC's LNG-to-power plant had been expected to come online for several years but faced numerous delays. In June 2026, the company sold its gas turbines for the power project to a US company but said it was still pursuing a standalone LNG import terminal in the Philippines.[50]

However, with existing LNG-fired plants in the country already supplied by other import terminals, and with negligible growth in demand from non-power sectors, there remains little commercial basis for either proposed terminal.

Renewables deployment reduces the need for baseload LNG-fired power plants

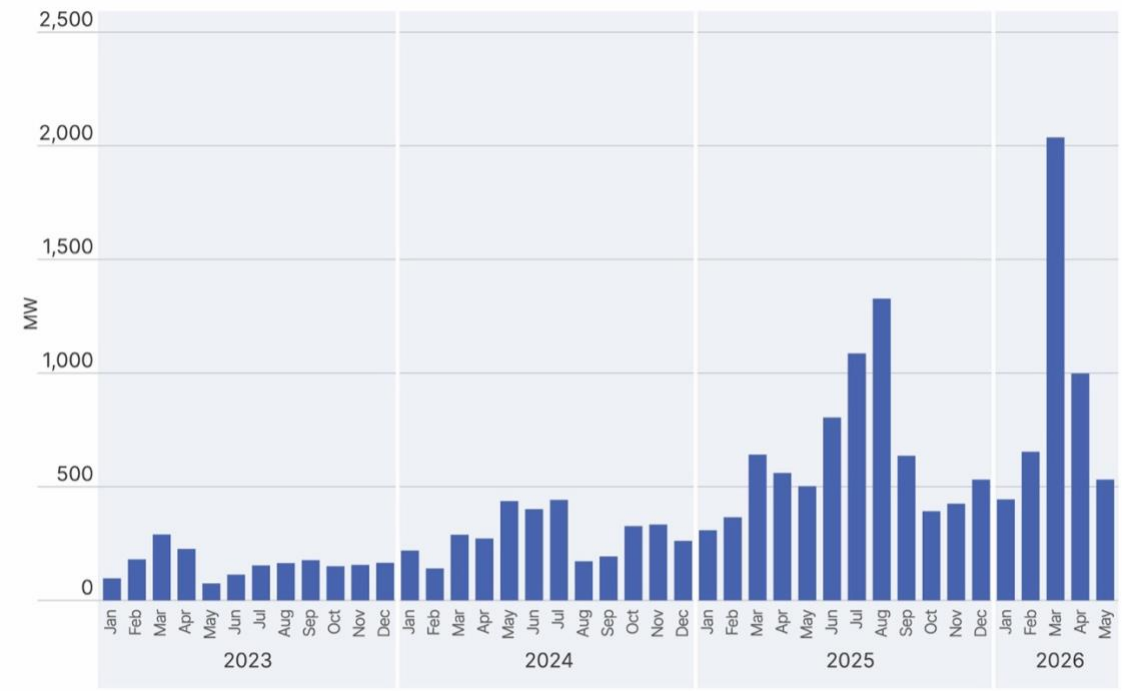
Large-scale investments in LNG infrastructure — such as import terminals, regasification facilities, pipelines, and gas-fired power plants — are capital-intensive and involve significant fixed costs. To recover these costs and remain competitive in downstream markets, these assets generally need to operate at high utilization rates. When throughput or output is low, fixed costs are spread over a smaller volume of gas or electricity, increasing per-unit costs.

For example, in the case of an LNG-fired power plant, higher dispatch levels allow capital and fixed operating costs to be amortized over a larger output base, reducing the levelized cost of electricity (LCOE). Conversely, underused plants — such as those operating in systems with high renewable penetration — face higher per-unit costs, which can undermine their economic viability and competitiveness relative to alternative generation sources.

In the Philippines, renewables growth is reducing the need for baseload LNG-fired power plants, weakening the competitiveness of LNG-related infrastructure. Since launching the Green Energy Auction Program (GEAP) in 2022, the country has awarded 22.5GW in new renewable energy contracts, including small hydro and bioenergy.[51] In March 2026, following the outbreak of the Middle East conflict, the Philippines became Asia's leading importer of Chinese solar panels and imported nearly 4.7GW of panels in the first five months of 2026 alone (Figure 6).[52] System modeling by the equipment firm Wartsila Group has shown that by 2040, solar power will account for the majority of daytime demand, reducing the role of natural gas generation to near zero during daylight hours.[53]

[49] International Gas Union. 2025 World LNG Report. 22 May 2025. Page 165.
[50] IEEFA. Gas turbine sale signals the end of another Philippine LNG project. 10 June 2026.
[51] Bloomberg New Energy Finance. Philippines Draws In New Bidders for Clean Energy Auctions. 27 May 2026.
[52] Ember. China's Solar PV Exports. Date Accessed: 8 July 2026.
[53] Power Philippines. The Philippines' mid-merit gas auction: Right policy. Now technology choice is everything. 7 July 2026.

Figure 6: Philippines monthly solar panel imports from China



Source: Ember.

As LNG-fired power plants shift toward mid-merit and peaking roles, revenue stability and operating cost predictability for new projects weaken, obscuring their financial outlook. Opportunities to secure baseload-level offtake contracts and the guaranteed revenues that come with them are likely to decline. Uncertain dispatch schedules make it difficult to commit to long-term take-or-pay LNG purchase contracts, leading to greater reliance on volatile spot markets for fuel. Renewable energy penetration makes financing new LNG import infrastructure and power plants significantly more challenging.

LNG project developers in the country have acknowledged these challenges. After selling its gas turbines to a US company and writing down the value of its proposed Pagbilao LNG project, developer EWC stated, "Increasing penetration of renewable generation is changing dispatch dynamics for thermal power assets, reducing both average WESM prices and expected operating hours. This, in turn, impacts potential revenues and asset values."[54]

[54] Energy World Corporation. Energy World Corporation to Sell its Siemens Gas and Steam Turbines for US$350 million, page 03. 2 June 2026.

Vietnam

Despite setting ambitious targets for LNG power capacity, Vietnam has faced persistent delays in advancing projects to construction. Under the country's eighth Power Development Plan (PDP8), the government aims to complete 15 LNG-fired power plants with a total capacity of 22.5GW by 2030[55], and another six plants with a combined capacity of 12.2GW by 2035.[56]

To date, however, just one project, the 1.62GW Nhon Trach 3&4 plant owned by state-owned PV Power, has been completed.[57] The project began commercial operations in January 2026 and is the only plant to operate even partially on LNG.[58] Only one other LNG project at Hiep Phuoc has signed a PPA with Vietnam Electricity (EVN).[59] The project's construction began in March 2026 and is targeting completion by 2028.[60] Every other project identified under PDP8 remains unlikely to come into service before 2030.

Global interest in Vietnam's LNG sector surged in 2021, with highly publicized projects and international commitments from countries such as the US, Japan, South Korea, and others.[61] However, excitement has noticeably dwindled amid volatility in global LNG markets and slow progress on projects.

Over the past five years, IEEFA estimates that at least 20 LNG-fired power projects with a total capacity of nearly 33GW have been canceled or withdrawn from government power priorities (Appendix 1). This does not include projects that have been significantly reduced in size from their initial announcements. Notably, the developer of the 4.8GW Hai Phong project — the largest LNG-to-power plant included in PDP8 — proposed withdrawing the project in March 2026 following the outbreak of the Middle East conflict.[62]

Given that roughly 70% of the country's natural gas is consumed in the power sector[63], canceled and stalled power projects have also resulted in numerous canceled LNG terminal projects. IEEFA estimates that 10 LNG import terminals, with a combined capacity of over 24MTPA, have been withdrawn or shown no progress over the last five years (Appendix 2).

The only LNG-fired power project brought online, Nhon Trach 3&4, was included in PDP7 in February 2017, and its first unit was expected to begin operations in 2020.[64] However, commercial operations did not begin until January 2026, nearly nine years after its inclusion in the power

[55] The Investor. Vietnam turns to LNG as power demand rises with double-digit growth ambition. 16 August 2026.
[56] Hogan Lovells Cadwalader. Vietnam considers strengthening offtake guarantees for LNG-to-power projects. 14 May 2026.
[57] VN Economy. Vietnam's first LNG power complex starts commercial operation. 9 January 2026.
[58] GE Vernova. GE Vernova powers up Vietnam with commercial operation of first 9HA gas power plant in the country. 5 January 2026.
[59] The Investor. Second LNG power purchase agreement signed in Vietnam. 29 March 2026.
[60] EnerData. Vietnam signs PPA for a 1.2 GW LNG-fired power plant. 30 March 2026.
[61] IEEFA. Beyond the Noise: Setting the Right Expectations for Vietnam's LNG Project Pipeline. January 2021. Page 1.
[62] Reuters. Vingroup proposes scrapping LNG-powered plant plan for renewables amid Iran war, document shows. 31 March 2026.
[63] IEEFA. Data Dive: A breakdown of gas and LNG demand in Asia. Date accessed: 10 July 2026.
[64] Petrovietnam Power. PV Power to take over Nhon Trach 3 and 4 thermal power plants. 26 April 2018.

development plan.[65] Instead of sovereign guarantees, its financing relied on PV Power's corporate balance sheet, substantial export credit agency (ECA) support, and a syndicate of foreign and domestic banks.[66]

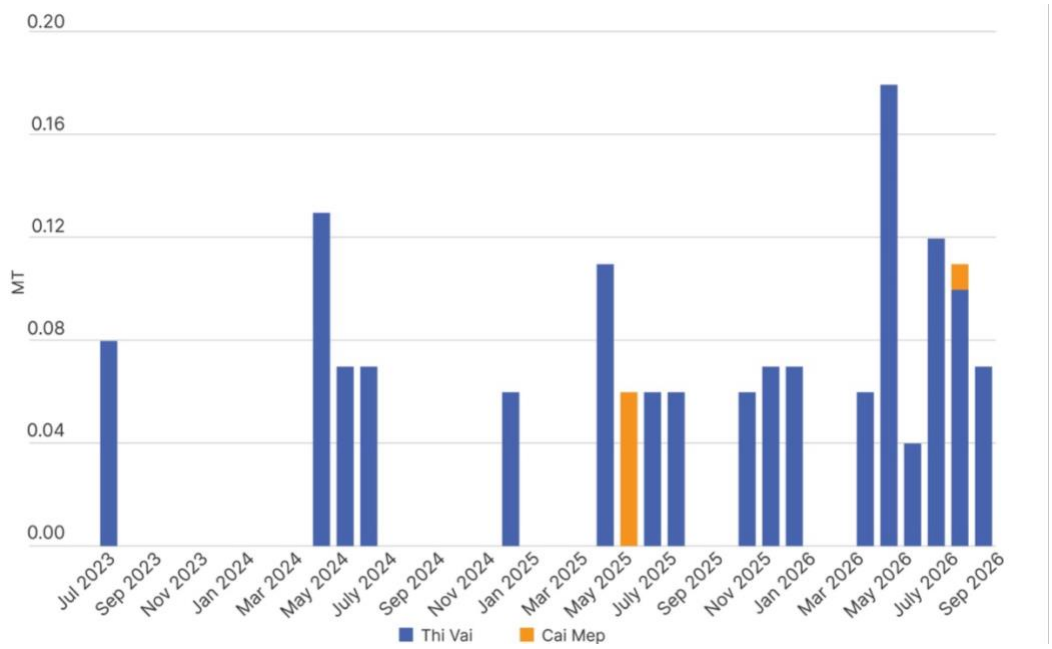
Yet, the project is unlikely to provide a straightforward model for other LNG developments in Vietnam because it benefited from a state-owned sponsor, corporate balance sheet support, and considerable ECA backing in lieu of sovereign guarantees. This is unlikely to provide a replicable template for projects led by private-sector developers, particularly given the broader sector's unresolved issues around bankability, contracting, and project readiness, as discussed below.

The country also completed two onshore LNG import terminals over the last five years. The 2.5MTPA Thi Vai terminal, owned by PV Gas, began operations in July 2023 and supplies the Nhon Trach 3&4 power plant, industrial users, and other downstream customers. Meanwhile, the nearby 3MTPA Cai Mep terminal, owned by Atlantic Gulf & Pacific (AG&P), was commissioned in April 2025 primarily to service offtakers in the Phu My industrial park.[67]

While imports to the Thi Vai terminal have increased since the start of Nhon Trach 3&4, Cai Mep has imported almost no LNG since receiving its commissioning cargo (Figure 7). The terminal reportedly has a 1MTPA offtake agreement with the planned Hiep Phuoc LNG-fired power plant, although that project has faced delays and is not expected to come online until 2028. Unless AG&P can secure new customers, cash flows for the project will remain uncertain until the Hiep Phuoc plant is completed.

[65] VnEconomy. Vietnam's first LNG power complex starts commercial operation. 9 January 2026.
[66] Citi and ING, the Korea Trade Insurance Corporation (K-SURE), and Swiss Export Risk Insurance (SERV) financed the project via a USD521.5 million, 12-year loan for PV Power. The project relied on 75% debt and 25% equity capital. The loan component of the project financing included a tied export credit of USD521.5 million, an untied export credit of USD200 million, USD300 million in foreign short-term loans and USD170 million in domestic loans. Pinsent Masons. Pinsent Masons advises on funding of Vietnam's first large-scale LNG-fueled power plants. 3 December 2024.
[67] This terminal is also referred to as the Cai Mep LNG import terminal. After taking an initial 49% stake in the project, AG&P recently acquired the remaining 51% from Hai Linh Co. Ltd.

Figure 7: LNG imports to Thi Vai and Cai Mep terminals



Source: Kpler.

IEEFA has identified the following challenges for proposed LNG projects in the country.

PPA bankability challenges limit financial viability of LNG-fired power plants

Vietnam's power sector investment requirements are too large to be met through state resources alone, therefore mobilizing private and international capital will be essential. Attracting that capital will require the government to address several persistent barriers to bankability. The most widely cited reason for LNG project delays in Vietnam is the unbankability of PPAs with EVN, the state-owned single electricity buyer. Current PPA discussions have required private investors and international lenders to bear a high degree of market and regulatory risk in several ways.

- **No government guarantees**: For many build-operate-transfer coal power projects in Vietnam, the government historically offered government guarantees and undertakings (GGUs) to enhance bankability. These commitments effectively backstopped EVN's payment obligations under the PPA and assured convertibility of revenues in Vietnamese dong to hard currency for payments to international lenders, EPC contractors, and fuel suppliers.

  More recently, however, the government has shown less willingness to provide GGUs to large-scale power projects, aiming to promote a more market-oriented and financially sustainable power sector with less reliance on state credit support and related contingent

liabilities. In their absence, project sponsors are exposed more directly to EVN's credit profile, which is currently rated below investment grade BB+ by Fitch Ratings.[68]

The Nhon Trach 3&4 project was completed without GGUs, using a financing arrangement that instead relied primarily on sizable ECA cover and access to the state-owned project sponsor's balance sheet to underpin loans. However, the Nhon Trach 3&4 project does not provide a standard model for LNG projects in the country because it was a one-off financing structure built around state-owned sponsor strength, ECA-backed debt, an existing LNG ecosystem at Thi Vai, and a project that was already sufficiently advanced despite unresolved regulatory and offtake issues.

- **Minimum contractual quantities**: Lenders to gas-fired power plants in emerging markets typically require that electricity is sold to offtakers on long-term contracts for the tenor of a loan to ensure revenue generation and reliable debt servicing. Current Vietnamese law requires EVN and subsidiaries to purchase a minimum of 65% of a project's output over 10 years, net of electricity output dispatched into the country's wholesale market. While this level can be negotiated higher, doing so would require EVN to accept higher payment obligations while limiting its ability to use cheaper power dispatched in the wholesale market.

  To date, the 65% contractual quantity has proven insufficient to satisfy lender requirements. This is largely because cheaper hydropower and renewables are more likely to be dispatched into the wholesale market, leaving gas-fired power plants reliant on contractual arrangements for revenue security. Moreover, the 65% minimum threshold applies for only 10 years after the project begins commercial operations, shorter than the typical loan tenors of 12 to 15 years for large-scale power projects in Vietnam. This leaves banks with at least a two-year tail of revenue uncertainty.

  In November 2025, the Ministry of Industry and Trade (MOIT) proposed raising minimum offtake levels to 75% and extending the application period to 15 years, though the proposal has yet to be approved.[69] Investors have demanded offtake quantities of up to 95%, with applicability periods extended to up to 25 years.[70] However, MOIT has said that increasing contractual quantities to 80% would result in system overcapacity and require EVN to pay for expensive LNG-fired power that it considers unnecessary.[71]

[68] Fitch Ratings. Fitch Affirms Vietnam Electricity at 'BB+'; Outlook Stable. 27 August 2025.
[69] The Investor. Power offtake guarantee to be expanded for LNG power investment in Vietnam. 23 May 2026.
[70] Ministry of Industry and Trade of the Socialist Republic of Vietnam. Resolving obstacles arising in the practical implementation of LNG power plant projects. 5 May 2026.
[71] Vietnam.vn. The Ministry of Industry and Trade proposes increasing the LNG power off-take ratio to 75% over 15 years. 5 May 2026.

Finally, only projects that begin commercial operations before 1 January 2031 are eligible for the 65% minimum offtake levels. Given long lead times for construction of large-scale thermal projects in Vietnam and the ongoing global gas turbine shortages discussed in Section 1, meeting this in-service target is likely to be challenging for the majority of proposed LNG-to-power projects in the country.

- **Pass-through costs and other issues**: Recent Vietnamese policy allows fuel costs of power plants using domestic gas and imported LNG to be passed through in PPAs with EVN. While this includes some fuel-related costs, such as transportation, storage, and regasification fees, it does not cover others. For example, tolling fees to use third-party regasification terminals, as well as break or termination fees, are not automatically passed through and require approval from the Prime Minister. Meanwhile, operation and maintenance (O&M) cost escalation is capped at 2.5% per year, which may be lower than annual inflation.[72, 73]

  Several other issues are hampering the bankability of LNG-to-power projects in Vietnam, including foreign currency convertibility, force majeure provisions, and dispute resolution mechanisms. These issues will have to be negotiated on a case-by-case basis before financiers can commit to new projects. This is likely to extend development timelines and could result in future cancellations as Vietnam's energy sector evolves.

High LNG costs could threaten EVN's financial recovery

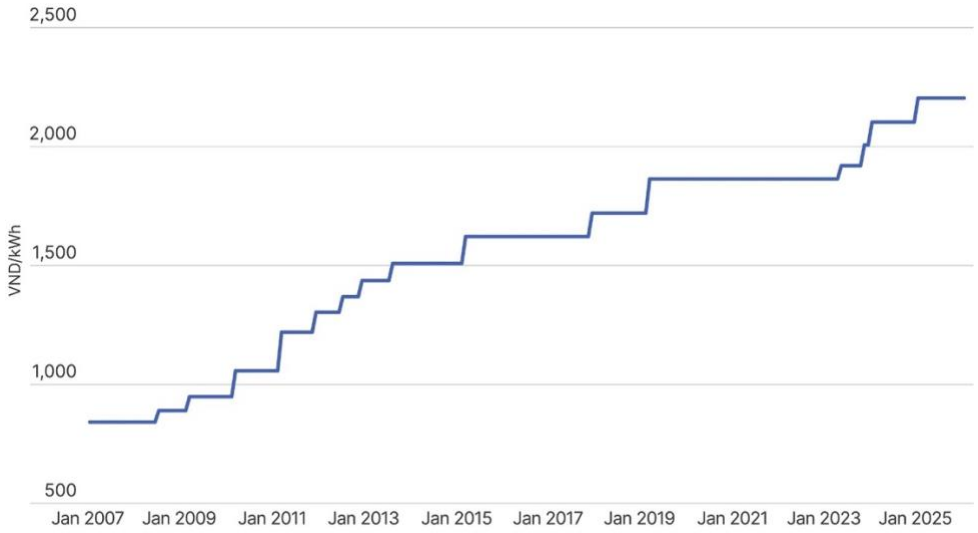
From 2022 to 2024, state-owned utility EVN was in financial distress, as higher global fuel prices caused the cost of electricity production to rise well above average regulated retail tariffs. The government did not allow retail electricity prices to adjust to pass higher input costs through to consumers, leaving EVN to absorb the resulting shortfall. In 2022 and 2023, the company amassed over VND50 trillion (USD2 billion) in losses and reported accumulated losses of VND38.7 trillion (USD1.47 billion) in 2024 despite a slight recovery during the year.[74, 75, 76] Leverage remained high, with liabilities of over VND474.6 trillion (USD18.6 billion), equivalent to 70% of total capital.[77]

In 2024, falling global fuel prices and regulated tariff increases helped the company return to a post-tax profit of VND8.24 trillion (USD314 million).[78] In 2025, the company posted a record consolidated net profit of VND51.88 trillion (USD1.97 billion).[79]

[72] Vietnam Business Law. Tariff Calculation For LNG And Coal Fired Power Projects Under Circular 57/2020. Date accessed: 30 September 2026.
[73] YKVN. Current Financing Landscape of LNG-to-Power Projects in Vietnam. 8 May 2025.
[74] Viet Nam News. Power play over EVN losses. 7 September 2025.
[75] EVN. EVN's losses mainly attributed to high input prices. 27 September 2023.
[76] Reuters. Vietnam considers rule change allowing loss-making EVN to raise power prices. 18 August 2025.
[77] EVN. Annual Report 2024-25. Date accessed: 27 August 2026. Page 19.
[78] EVN. Annual Report 2024-25. Date accessed: 27 August 2026. Page 18.
[79] VietnamNet. EVN posts huge profits but still carries losses, electricity prices may not fall. 19 June 2026.

Increases to the average regulated retail tariff were central to EVN's recovery. Between March 2019 and May 2023, end-user tariffs remained flat at VND1,864/kWh, but following the company's poor financial results, the government opted to increase tariffs four times between May 2023 and 2025 (Figure 8). Over the period, tariffs increased by a total of 18.2% to VND2,204/kWh.

Figure 8: Average regulated retail electricity tariff in Vietnam



Source: IEEFA analysis based on media reports.

However, EVN's recovery to profitability remains tenuous, due to the unpredictability of both global fuel price cycles and policy-driven tariff corrections. Greater reliance on LNG for power generation could put renewed pressure on EVN's financial position.

The Vietnamese government has set an allowable cap of VND3,410.64/kWh in PPA negotiations between EVN and project investors[80], while selling prices for Nhon Trach 3&4 are estimated to be VND3,600/kWh.[81] These levels are far above the average regulated retail tariff of VND2,204/kWh, meaning that each unit of LNG-fired power EVN is obliged to dispatch widens the gap between what it pays generators and what it recovers from customers.

This tension reflects a structural incompatibility between LNG economics and Vietnam's regulated pricing framework. Vietnam's tariff is set administratively and adjusted infrequently, with no automatic mechanism to pass through imported fuel costs. As the share of LNG in the generation mix rises, EVN would be forced to absorb the difference between dollar-denominated LNG prices and regulated retail tariffs, repeating conditions that produced the VND50 trillion losses during 2022–2023.

[80] Tuoi Tre News. Vietnam caps gas-fired power prices at $0.13 per kWh for 2026. 28 July 2026.
[81] Báo Đầu tư Chứng khoán. The power sector on the brink of a new growth cycle: Opportunities from gas and LNG. 24 August 2026.

The risk is compounded by the state of EVN's balance sheet. Despite the record consolidated profit, the group's total debt reached approximately VND341.3 trillion (USD13 billion) at the end of 2025, with debt-to-equity still more than 2.3 times, and the parent company continues to carry accumulated losses. EVN has said its roughly VND152 trillion cash position is necessary for fuel security, debt service, and the capital expenditure required for new power projects, including LNG infrastructure. The more LNG displaces cheaper domestic sources, the more EVN's cash and borrowing capacity are drawn toward financing and absorbing fuel costs that are not fully recovered through regulated tariffs. This leaves the utility exposed to renewed losses.

For LNG-to-power developers, this dynamic is central to the bankability problem. Lenders may be unwilling to underwrite long-term take-or-pay offtake from a buyer whose regulated revenues are insufficient to recover the fuel cost, and whose balance sheet is already highly leveraged. EVN's recovery has improved its credit profile, but it has not resolved the underlying cost-recovery constraint. If LNG becomes a material part of the generation mix, that alignment breaks, and the very financial fragility that made EVN's offtake unbankable in the first place would resurface. This threatens both the utility's recovery and the viability of Vietnam's LNG-to-power ambitions.

Thailand

Thailand recorded relatively strong progress in executing gas projects among the countries studied. Since 2021, four projects worth USD7.2 billion were commissioned (Table 4)[82], while projects with a combined 10GW of capacity and an estimated USD7.9 billion in investment were canceled, withdrawn, or completely inactive (Appendix 1). Four such projects were deemed canceled after the state-run utility, the Electricity Generating Authority of Thailand (EGAT), canceled EPC bidding procedures.[83]

The 650MW Burapa power plant remains in development, but its commissioning has been delayed until 2029 due to overcapacity in the power market.[84] Despite some construction progress, Burapa has not publicly announced securing EPC contracts or gas turbines.

Thailand’s latest draft power development plan (PDP) includes a target to add 9.1GW of new gas-fired power capacity by 2037 and at least 7.7GW between 2037 and 2050. Achieving this capacity expansion may entail reviving projects for which EPC bidding was previously canceled. Due to a lack

[82] This analysis excludes small power producers (SPPs).
[83] EGAT canceled EPC bidding after multiple revisions and reissuances for the proposed North Bangkok power station expansion, South Bangkok power station expansion, and Surat Thani power stations in 2025. EPC bidding for the Nam Phong replacement power project was canceled in November 2022. Bidding for these projects has not been reopened as of August 2025. While these projects may ultimately be revived according to the country’s updated Power Development Plan, IEEFA assumes that the projects remain canceled until EPC bidding is reopened. IEEFA. Thailand’s gas conundrum: Overbuilt, underutilized, and increasingly expensive, page 16. 26 February 2026.
[84] Thailand Construction News. Weak demand in Thailand results in suspension of four power plants and delay the opening of a fifth. 31 October 2025.

of publicly available details regarding project implementation, IEEFA has not included this targeted capacity in its estimates of ongoing projects in the country.

Table 4: Gas-fired power projects completed since 2021

Count	Project name	Owner	Capacity (MW)	IEEFA estimated project cost (USD million)
1	Bang Pakong Power Station	EGAT	1,386	1,033
2	Gulf Sriracha Power Project	Gulf SRC Co Ltd	2,650	2,468
3	Hin Kong Power Plant	Hin Kong Power Co Ltd	1,400	1,304
4	Rayong Gulf PD	Gulf PD Co Ltd	2,650	2,468
	TOTAL		**8,086**	**7,273**

Source: IEEFA analysis.

An analysis of Thailand's successful gas projects suggests that the country has relatively long development timelines. On average, projects took over 102 months (8.5 years) to begin commercial operations following their first public development announcement. Contributing to these longer timelines is a robust and engaging regulatory framework.[85, 86] Capital cost inflation stemming from turbine bottlenecks risks extending these timelines further.[87]

In 2021, IEEFA assessed the total value of Thailand's five proposed LNG terminals at almost USD4.7 billion. State-owned oil and gas company PTT's Map Ta Phut 2 (MTP2) terminal was commissioned in 2023, while a groundbreaking ceremony for the Gulf Map Ta Phut 3 (MTP3) terminal was held in October 2025.[88] Gulf has proposed an MTP3 expansion but has not yet greenlit the investment. Two floating terminals worth USD1.1 billion and totaling 10MTPA in capacity have been canceled or inactive since 2021 (Appendix 2).

IEEFA identifies the following challenges facing gas and LNG projects in Thailand.

Overcapacity of existing gas plants and LNG terminals

Thailand has experienced chronic overcapacity for the past decade because past PDPs were based on optimistic economic growth projections and a high reserve margin criteria for expansion, resulting in overestimated power requirements.[89] As of the first quarter of 2026, more than 11GW of plants

[85] Baird, Matthew. Environmental Impact Assessment in Southeast Asia. 12 May 2020.
[86] Schulte, William. Environmental Litigation Trends in Southeast Asia. 20 May 2022.
[87] Global Power Synergy Public Company Limited (GPSC) — a leading Thai power company — identifies growing equipment lead times as a risk to new power plant development. The company says it may now take six or seven years to secure a turbine due to turbine manufacturing constraints. GPSC. Management Discussion and Analysis 1st Quarter of 2026. Page 11.
[88] Smart Asia. Groundbreaking Ceremony – Gulf MTP Terminal Co., Ltd. 15 October 2025.
[89] IEEFA. Thailand's gas conundrum: Overbuilt, underutilized, and increasingly expensive. March 2026. Pages 10-13.

owned by independent power producers (IPPs) are operating at less than 20% capacity, with 7.2GW generating negligible electricity.[90]

Table 5: Utilization factors derived from IPP financial statements, 2023 to Q1 2026

IPP Name	Start Year	PPA Expiry	2023	2024	2025	Q1 2026
KEGCO	2016	2041	78%	64%	54%	63%
GPSC	2006	2031	8%	8%	8%	0%
RATCH	2002	2027	20%	14%	0%	0%
GLOW IPP	2003	2028	7%	5%	6%	13%
Gulf-GPG	2007	2032	1%	1%	1%	1%
RPCL	2008	2033	1%	5%	3%	0%
GNS	2014	2039	27%	18%	4%	19%
GUT	2016	2041	27%	18%	4%	19%
GSRC	2021	2046	73%	75%	53%	79%
GPD	2023	2048	80%	65%	54%	71%
HKP	2024	2049	-	95%	79%	86%

Source: Company financial reports; IEEFA calculations.

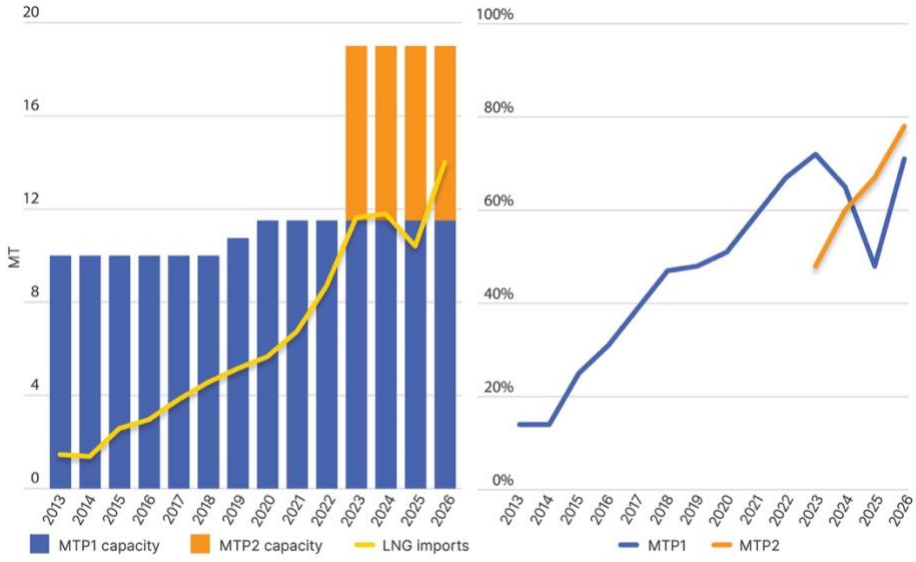
In the first phase of the latest draft PDP, Thailand is still aiming to add 9.1GW of new gas-fired capacity by 2037. However, IEEFA expects that the government will rely on recontracting existing plants with expiring PPAs in the early years of this phase. Meanwhile, the government is aiming to install 27GW of renewable capacity and 14GW of battery storage systems by 2037, rising to as much as 114GW and 55GW, respectively, by 2050.[91]

Future PPAs will likely require more flexibility to support growing renewable energy and battery capacity, which could reduce gas utilization further. This competition, together with lengthy lead times for past gas projects, means that it is unclear whether the 9.1GW gas capacity target in the first phase will be realized. If turbine shortages extend these project lead times further, Thailand may have to recontract more gas capacity or rely more heavily on faster-to-deploy renewable alternatives.

[90] This is despite warmer weather lifting gas output in 2026. IEEFA calculations based on the Energy Policy and Planning Office (EPPO) statistics. EPPO Electricity Statistics. July 2025. Retrieved on 15 July 2026.

[91] EPPO. Draft PDP 2026. 8 September 2026.

Figure 9: Thai LNG imports versus terminal capacity (left) and terminal utilization (right)



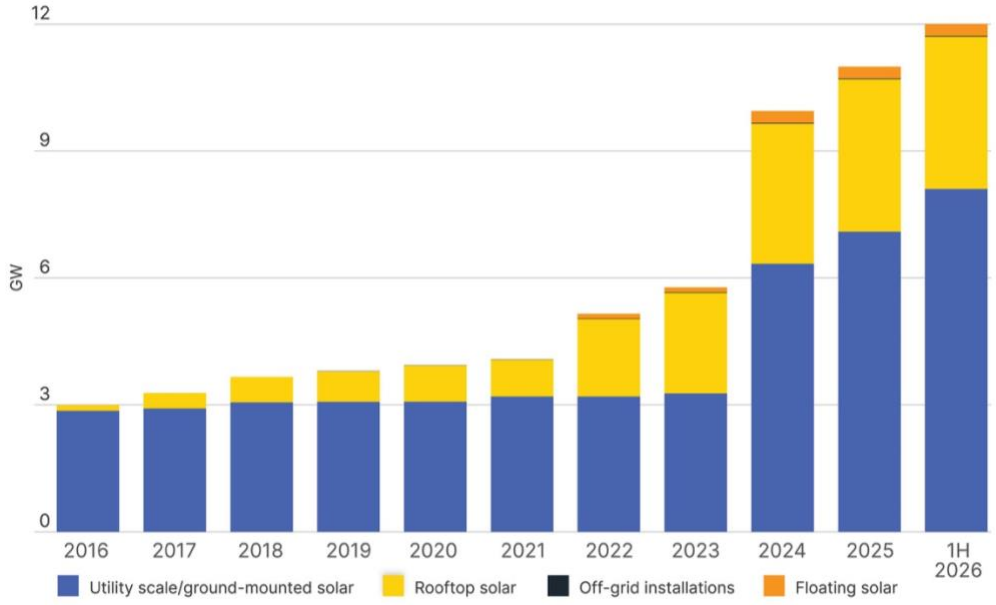
Source: Kpler; IEEFA analysis.

The need for additional import terminals in the near term also remains uncertain. In 2023 and 2024, the first two years of MTP2's operation, Thailand's total LNG imports were only slightly above Map Ta Phut 1 (MTP1) terminal capacity. Rising flows to MTP2 increased utilization in 2025, but these gains came partly at the expense of MTP1. A weather-driven increase is lifting 2026 capacity factors, but both facilities remain below full utilization. The scheduled opening of Gulf's 8MTPA terminal in 2029 is contingent on sufficient demand to support its operations.[92]

[92] Gulf Development Public Company Limited (Gulf). Management Discussion and Analysis of the Company's Performance For the quarter and year ended December 31, 2025. 2026. Page 28.

Rising renewables

Figure 10: Thailand's solar capacity by type of installation, 2016 to 1H2026



Source: Oxford Business Group; IEA; PV Magazine; ERC; DEDE; Ministry of Energy; CASE for Southeast Asia; Watson Farley & Williams; Transition Zero; IEEFA analysis.

Future gas expansion in Thailand will be competing with an increasingly cost-effective and expanding portfolio of renewable alternatives, led by solar. Since 2023, utility-scale solar additions have outpaced gas-fired capacity expansions[93], and overall solar capacity has doubled to 12GW. Solar generation grew 80% in 2025 to almost 10 terawatt-hours (TWh) and was up another 26% in the first four months of 2026, or about 6% of total power supplied.[94] With panel imports from China up 72% in the first half of the year, further solar deployment seems likely.[95]

Thailand's gas companies are also deploying solar. Gulf Development, a large-scale power producer and import terminal developer, installed almost 600MW of solar in 2025. [96] The company aims to install an additional 600MW in 2026 and deploy a further 2.75GW of capacity by 2035.[97] Sponsors of existing gas IPPs may turn to renewable alternatives to better align their portfolios with the country's next PDP, which targets 24GW of solar and 2.7GW of wind capacity by 2037.[98]

[93] Ember. IEEFA calculations based on Ember data. Ember. Electricity Data Explorer. July 2026. Retrieved on 17 July 2026.
[94] IEEFA calculations based on Ember data. Ember. Electricity Data Explorer. July 2026. Retrieved on 15 July 2026.
[95] IEEFA calculations based on Ember data. Ember. China's Solar PV Exports. July 2026. Retrieved on 15 July 2026.
[96] These include four projects with battery energy storage systems (BESS), two in 2025 and two in 2026. Gulf Development Public Company Limited. Opportunity Day Q3'2025. 17 July 2026. Pages 2, 4.
[97] IEEFA calculations based on data provided in Gulf presentation. Gulf Development Public Company Limited. Opportunity Day Q3'2025. 17 July 2026. Page 22.
[98] EPPO. Draft PDP 2026. 8 September 2026.

Recent policy developments could further support solar deployment. These include the removal of permitting barriers for businesses and tax incentives for residential and business installations. [99, 100] The Utility Green Tariff (UGT2) program makes 2.1GW of renewable capacity available for contracting by commercial and industrial users.[101] Moreover, plans expand eligibility for the direct PPA (DPPA) pilot beyond data centers will enable businesses to negotiate contracts directly with solar producers, allowing them to procure renewable electricity even if government-led capacity targets do not materialize.[102]

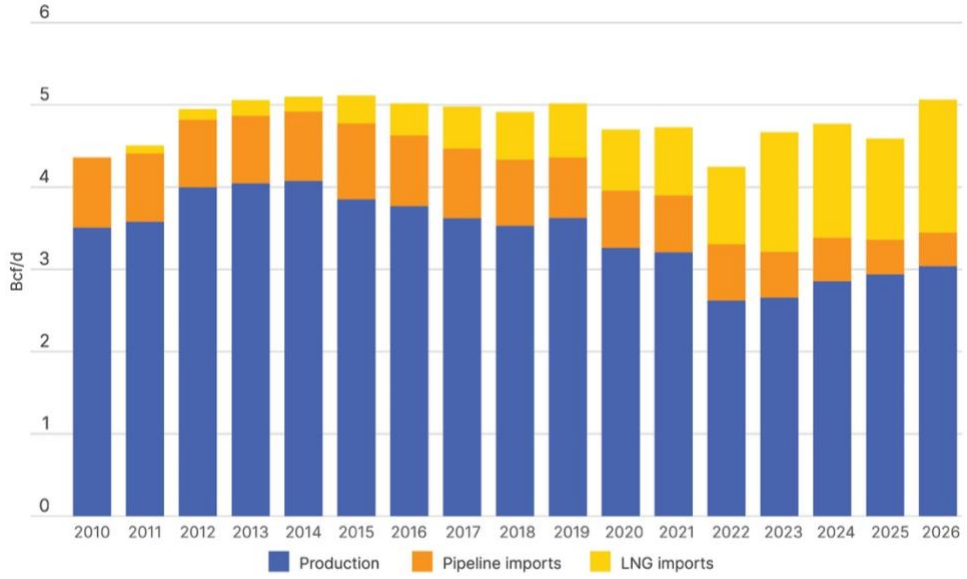
With solar firmed with battery energy storage systems (BESS) now competitive with gas-fired generation,[103] further battery deployment — up from the country's capacity of 400MW in 2024 — could reduce gas-fired generation.[104, 105] In the first five months of 2026, the value of battery imports from China increased 61% compared with the same period in 2025.[106]

Structural decline in gas resources raises gas supply costs

Structural declines in lower-cost resources are increasing Thailand's reliance on higher-cost LNG imports, which now meet more than 31% of demand. The Middle East conflict has highlighted this vulnerability. Recent force majeure declarations on low-cost Qatari supply are pushing Thailand to purchase higher-cost replacement cargoes through short-term contracts and the spot market.[107] As of July 2026, LNG procurement costs are 3.2 times those of domestic production, lifting gas supply costs to a three-year high and 31% above the 2025 average.[108]

[99] IEEFA. Iran conflict exposes Thailand's LNG vulnerability. 1 April 2026.
[100] Nation Thailand. Royal Gazette publishes up to 200,000 baht tax relief for home solar. 4 March 2026.
[101] IEEFA. Iran conflict exposes Thailand's LNG vulnerability. 1 April 2026.
[102] Reuters. Thailand approves measures to bolster clean energy markets. 15 July 2026.
[103] In 2025, the average co-located solar with battery storage facility is now cost-competitive with gas-fired generation in most markets. International Renewable Energy Agency (IRENA). 24/7 renewables: The economics of firm solar and wind. 2026.
[104] IEEFA estimates that an additional 1GW of solar plus batteries could reduce LNG import requirements by up to 0.93MTPA.
[105] Fangda Partners. Inside Thailand's Renewables Push: The 73 GW Opportunity, How to Enter and What to Watch. 04 June 2026.
[106] Battery imports through the first five months of 2026 were also up more than 2.6 times the level seen during the same period in 2024. Ember. China Cleantech Exports Data Explorer. Retrieved on 17 July 2026.
[107] IEEFA. Iran conflict exposes Thailand's LNG vulnerability. 1 April 2026.
[108] IEEFA calculations from EPPO data. EPPO. ราคา Pool gas. Retrieved on 27 August 2026.

Figure 11: Thailand's gas supply by source



Source: EPPO.

End-user electricity prices have not fully reflected rising fuel costs, resulting in a persistent subsidy burden. As of July 2026, EGAT had over THB31 billion (USD938 million) in outstanding payments stemming from past subsidies.[109] Government efforts to limit inflationary impacts of rising electricity costs mean that resolving the deferred-cost balance will require tariff recovery, fiscal support, or both.[110, 111] Global Power Synergy Public Company Limited (GPSC) — a leading Thai power company — warns that it will be difficult for EGAT to balance the subsidization of higher-cost gas supplies with the capital requirements of the next PDP.[112] If higher LNG prices are passed through to consumers, they could respond by reducing demand, further lowering the utilization of LNG infrastructure.

Bangladesh

LNG imports to Bangladesh have grown rapidly since 2022, primarily due to declining domestic gas production, limited alternative energy resources, and growth in key gas-dependent sectors of the economy. Despite fiscal and foreign exchange constraints, the country has relied heavily on foreign

[109] ERC. The Energy Regulatory Commission opens to listen to opinions on electricity bills for the period September - December 2026, offering 4 options, 3.95 - 4.73 baht per unit. 13 July 2026.
[110] ERC. The Energy Regulatory Commission opens to listen to opinions on electricity bills for the period September - December 2026, offering 4 options, 3.95 - 4.73 baht per unit. 13 July 2026.
[111] Nation Thailand. Thailand cuts September power tariff, caps first 200 units at 3 baht. 12 August 2026.
[112] GPSC. Management Discussion and Analysis 1st Quarter of 2026. 2026. Page 10.

loans to finance LNG purchases. LNG imports increased from 4.43 million tonnes (MT) in 2022 to 7.13MT in 2025.[113]

Since 2021, the country has completed three LNG-fired power plants with a combined capacity of 1.9GW and a total estimated value of USD1.8 billion, according to IEEFA analysis. However, further expansion faces challenges due to project execution risks and a growing subsidy burden as tariffs remain below LNG import costs.

Over the same period, IEEFA estimates that 10 LNG-to-power projects have been canceled, withdrawn, or shown no significant progress, with a combined capacity of 8GW and an estimated value of nearly USD7.7 billion (Appendix 1). Regulatory uncertainty has been a key driver of these project outcomes. In 2022, for example, the government withdrew from agreements to construct a 3,600MW LNG-to-power station and an associated FSRU in Payra Port.[114] Although the state-run North West Power Generation Company said that an initial 1,200MW phase may still proceed[115], the project has not progressed since.

LNG terminals have faced similar challenges. Bangladesh commissioned two FSRUs between 2018 and 2019. Despite recurring technical problems and weather-related outages, both have operated at near-full utilization when available in recent years. The country has yet to complete a third terminal despite numerous proposals. In 2024, Bangladesh's interim government canceled contracts with Summit Group and Excelerate Energy to build two FSRUs with capacities of 4.6MTPA and 3.75MTPA, respectively.[116] A tender process for a 7.5MTPA terminal was canceled the same year.[117]

In total, IEEFA tracked six LNG terminal projects that were canceled, withdrawn, or inactive between 2021 and 2025, with a combined capacity of more than 38MTPA and a total estimated value of USD5.6 billion (Appendix 2).

In July 2026, Bangladesh launched another tender for a third FSRU terminal at Kutubjom, amid recurring technical outages at existing FSRUs and a growing gap between demand and supply. The terminal has an estimated capacity of 4.5MTPA. The tender was awarded to China National Energy Engineering and Construction Co., but no timeline has been released for the project's completion. Following contract cancellations in 2024, the government is also reportedly reviving plans for a 7.5MTPA onshore import terminal in Matarbari.[118] However, it had not released a tender as of August 2026, and the former projects are still considered shelved.

Similar to other emerging markets covered in this report, development timelines for the three LNG-fired power projects completed in Bangladesh over the last five years were significantly longer than the timelines announced by project developers and global averages. IEEFA analysis suggests that

[113] IEEFA analysis of Kpler data.
[114] Prothomalo. Govt backtracks from LNG-fired power plant. 13 August 2022.
[115] Prothomalo. Govt backtracks from LNG-fired power plant. 13 August 2022.
[116] Gas Outlook. Bangladeshi state-run Petrobangla scraps LNG deals. 28 November 2024.
[117] Gas Outlook. Bangladeshi state-run Petrobangla scraps LNG deals. 28 November 2024.
[118] Financial Express. Tokyo Gas completes feasibility study for Bangladesh's first land-based LNG terminal. 3 October 2025.

these three projects took nearly 7.5 years to begin commercial operations from the start of pre-construction activities.

For example, the 718MW Reliance Meghnaghat combined-cycle plant was originally proposed in 2015 and began pre-construction activities in March 2016, targeting completion in April 2019.[119] As of 2022, however, the project remained less than 70% complete, with delays attributed to COVID-19-related disruptions and the late delivery of project equipment.[120] Loan repayments reportedly began in June 2023, requiring Japanese power investor JERA — which acquired 49% of the project in 2019 — to inject additional equity to avoid default.[121]

Although the facility was completed by March 2024, it remained offline due to PPA renegotiations and a shortage of available natural gas supplies required for commissioning. It was not until mid-2025 that the project received a sufficient and continuous gas supply to complete commissioning and begin operations. The plant was reportedly shut down just two weeks later due to gas supply constraints and continued to face recurring fuel shortages as of July 2026.[122, 123]

IEEFA identified several challenges for the expansion of LNG terminals and power plants in Bangladesh:

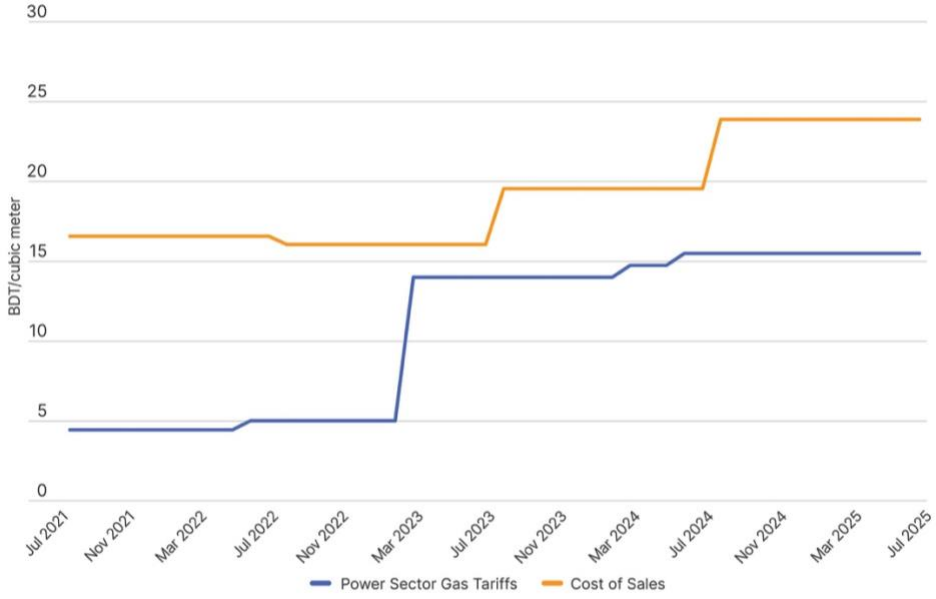
Growing gas subsidy burden increases payment-security risks

End-user gas and electricity tariffs in Bangladesh have historically remained below the cost of supply, resulting in a growing subsidy burden for state-owned utilities Petrobangla and the Bangladesh Power Development Board (BPDB). This artificially inflates end-user LNG demand and leaves Petrobangla and BPDB reliant on timely fiscal transfers to meet obligations to LNG suppliers and power producers. This could weaken the credit quality of offtake commitments for new LNG terminals and power projects.

Figure 12 below compares Petrobangla's gas supply costs with gas tariffs for the power sector. Based on the company's annual reports, IEEFA estimates that supply costs in 2025 remained more than 50% higher than the rates charged to large electricity generators, despite a 248% increase in tariffs for power generators over the past five years. Meanwhile, gas prices for industries increased 180%, according to Petrobangla's annual reports.

[119] Reliance Bangladesh LNG and Power Limited. Environmental and Social Impact Assessment Report of Reliance Meghnaghat 750 MW Combined Cycle Power Plant. October 2017. Page 55.
[120] Financial Express. Meghnaghat plant may miss deadline. 5 June 2022.
[121] Energy Transition Bangladesh. Govt clears JERA Meghnaghat Plant for operation by June 15. 6 June 2025.
[122] The Business Standard. How flawed policy keeps shutting gas-fired power plants amid fuel shortage. 23 August 2025.
[123] BDnews24. LNG terminal shutdown squeezes gas supplies, power generation and households alike. 28 July 2026.

Figure 12: Petrobangla gas sales costs vs. power sector gas tariffs



Source: IEEFA calculations based on Petrobangla's annual reports.

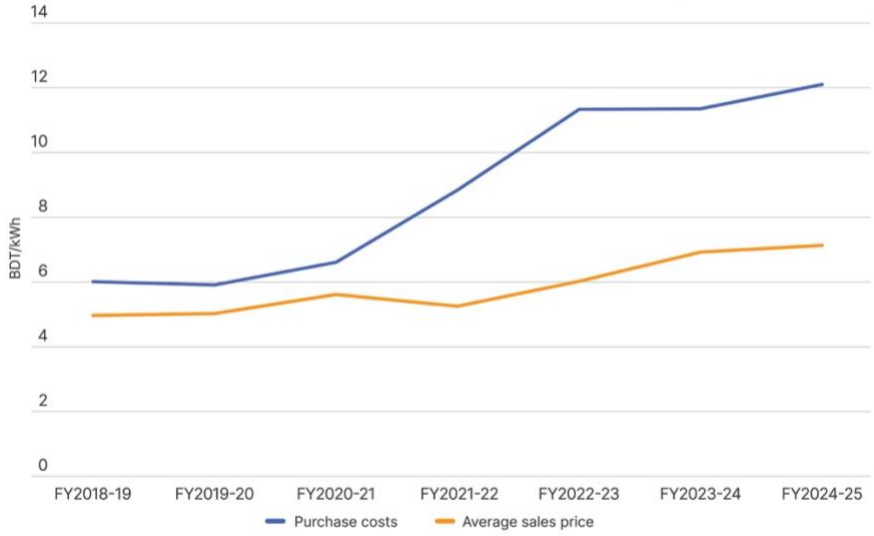
Gas tariffs have increased for end-users in Bangladesh to cover rising LNG import costs. Petrobangla's total costs for LNG imports and regasification increased 33% between 2021 and 2025, compared with 8% for domestically produced gas.[124] While wellhead costs for onshore domestic gas production in Bangladesh have typically ranged from USD2–4/MMBtu under previous production-sharing contracts, LNG from the global market has been volatile, reaching USD27.5/MMBtu in September 2026.

However, with domestic production falling at an average annual rate of 4.64% since 2019[125], the government has increased subsidy allocations for Petrobangla. In its 2025-26 budget, the government allocated BDT90 billion (USD740 million) to cover LNG import costs, up from BDT25 billion (USD296 million) in 2019.[126]

Given gas's central role in Bangladesh's power mix — accounting for 44.1% of generation in 2025–2026[127,] — the increase in gas tariffs for the power sector from BDT4.45 per cubic meter (m^3) in July 2019 to BDT15.5/m^3 in May 2024 has contributed to rising generation costs for BPDB. Between 2019 and 2025, BPDB's average purchase cost for electricity doubled, from BDT6/kWh to BDT12.1/kWh. However, the single buyer's average sales price increased from BDT5/kWh to BDT7.1/kWh, leaving a gap of BDT5/kWh (Figure 13).

[124] Based on Petrobangla annual reports.
[125] IEEFA. Bangladesh's LNG dependence raises concerns about energy resilience. 29 December 2025.
[126] IEEFA. Bangladesh's LNG dependence raises concerns about energy resilience. 29 December 2025.
[127] IEEFA. Fostering Bangladesh's Energy Transition. 6 May 2026. Page 17.

Figure 13: BPDB electricity procurement costs vs. sales prices



Source: IEEFA calculations based on BPDB's annual reports.

The gap between procurement costs and sales prices has seen power subsidies increase nearly 5-fold since 2019. Annual subsidies allocated to BPDB increased from BDT80 billion (USD948 million) in 2019 to BDT370 billion (USD3.03 billion) in 2025. As of January 2026, Petrobangla's receivables reportedly totaled more than BDT280 billion (USD2.3 billion), of which BPDB owed BDT160 billion (USD1.3 billion).[128]

This growing burden has prompted the Bangladesh Energy Regulatory Commission to increase end-user tariffs to improve BPDB's liquidity and strengthen its ability to meet payment obligations to generators and fuel suppliers. Compared with December 2022, electricity tariffs for industries with a sanctioned load of 5MW have increased 50%.[129]

Continued increases in government-allocated power subsidies put pressure on the state-owned enterprise's creditworthiness and raise the risk of government default on payments to electricity generators. Meanwhile, rising power tariffs will continue to increase operational costs and threaten the competitiveness of key economic sectors.

Dependence on loans for LNG procurement

While subsidies can insulate end-users from global commodity volatility, they increase pressure on government finances needed to pay for imports.

[128] Business Standard. Petrobangla steps up dues recovery to tackle mounting LNG import costs. 3 April 2026.
[129] IEEFA. Higher electricity tariffs should accelerate Bangladesh's clean energy transition. 31 July 2026.

Since 2022, Bangladesh has relied on external financing to pay for its rising energy import bill and avoid depleting its currency reserves.[130] This included a USD5.5 billion program from the IMF, which began in 2023 and stipulated energy price increases and a phase-out of subsidies.[131] The country also transformed an existing arrangement with the International Islamic Trade Finance Corporation (ITFC) to use USD500 million to finance gas imports.[132] However, credit rating downgrades in 2024 challenged its ability to access foreign currency to finance LNG imports.[133]

In 2026, the ITFC agreed to increase its LNG funding in FY2027 to USD600 million.[134] Renegotiations with the IMF are resulting in a replacement program, but the details on subsidy reform and the implications for energy tariffs remain unclear.[135] Regardless, any increase in energy costs will be hard for end-users to absorb and could reduce demand as consumers shift away from grid-supplied electricity.[136] The crisis is accelerating a private consumer-led rooftop solar buildout[137], which, together with investments in domestic gas exploration and energy efficiency improvements, could reduce the need for further LNG imports.

In early 2026, the World Bank created a six-year, USD350 million annual credit facility for Bangladesh that is acceptable to LNG suppliers.[138] This was doubled in May 2026.[139] Since then, LNG procurement has increased, with Petrobangla signing a dual-benchmark long-term contract with commodity trader Gunvor.[140] However, the deal includes pricing premiums that could increase if an LNG glut causes the JKM-Henry Hub differential to narrow sharply later this decade. Amid this uncertainty, it is not clear whether the contract will improve the profitability and liquidity of Petrobangla enough to reduce its subsidy reliance.[141]

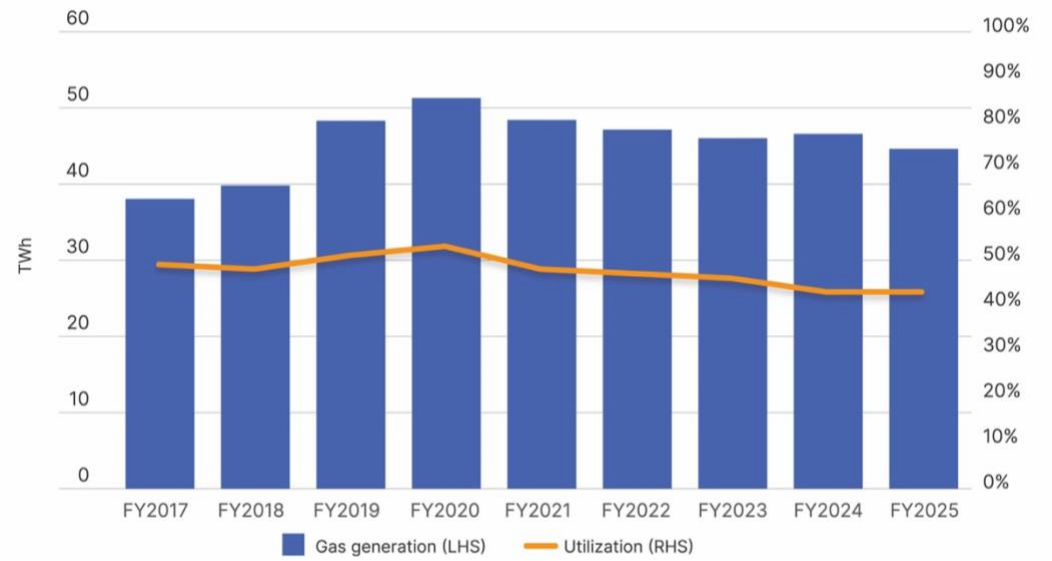
Bangladesh's currency reserves have increased during the six months of the current crisis.[142] Access to new credit facilities from the IMF, ITFC, and World Bank will help alleviate these financial pressures. However, increasing reliance on LNG could put renewed pressure on currency reserves. With Fitch's outlook for Bangladesh revised to negative in May 2026, further stress could lead to credit rating downgrades[143], impairing the country's access to credit facilities to fund future LNG import increases.

[130] IEEFA. Cambodia at a Crossroads - An Economic Assessment of LNG-to-Power Plans. November 2024. Page 19.
[131] Reuters. Bangladesh says IMF agrees phased approach to reforms under new programme. 13 July 2026.
[132] Reuters. ITFC signs deal to fund $2.1 bln of Bangladesh oil, gas imports. 7 February 2024.
[133] World Bank. Bangladesh - Energy Sector Security Enhancement Project (English). 27 May 2025. Page 5.
[134] The Financial Express. ITFC confirms $3.3b fertiliser, fuel import financing. 1 July 2026.
[135] Reuters. Bangladesh says IMF agrees phased approach to reforms under new programme. 13 July 2026.
[136] IEEFA. Higher electricity tariffs should accelerate Bangladesh's clean energy transition. 31 July 2026.
[137] IEEFA. Role of distributed resources in energy transition: A multi-country perspective. 4 August 2026.
[138] The purpose is to provide payment security in the form of standby letter of credit (SBLC) facilities with high-quality lenders for one-sixth (2 months) of the projected annual value of imports from long-term contracts and the whole value of spot cargoes. World Bank. Bangladesh - Energy Sector Security Enhancement Project (English). 27 May 2025. Page 8.
[139] World Bank. Bangladesh - Energy Sector Security Enhancement Project: Additional Financing (English). 15 May 2026.
[140] The government approved 14 short-term cargo deliveries for this year. TBSNews. Govt secures 90% LNG premium cut from US firm Gunvor, approves 117 cargoes. 12 August 2026.
[141] World Bank. Bangladesh - Energy Sector Security Enhancement Project (English). 27 May 2025. Page 5.
[142] Bangladesh Bank. Foreign Exchange Reserve (Monthly). Date Accessed: 13 August 2026.
[143] Fitch Ratings. Fitch Revises Outlook on Bangladesh to Negative; Affirms at 'B+'. 13 May 2026.

Unreliability of gas supplies

Despite the commissioning of two FSRUs in the late 2010s, Bangladesh's gas availability has declined since 2021. These constraints are a significant challenge for gas-dependent end-users, including independent power projects, which may be unable to generate electricity or achieve expected project cash flows during periods of gas rationing.

Figure 14: Output and utilization of Bangladesh's gas-fired capacity, FY2017 to FY2025



Source: BPDP; IEEFA calculations.

Exacerbating this issue is an increase in latent demand from gas-fired power plants. While the capacity of gas-fired power plants grew almost 34% from 2017 to 2025, gas generation grew only 17%, peaking in 2020 and falling 13% since then. Competing for rationed gas molecules, the gas fleet's utilization fell from 53% in 2020 to 43% in 2025.[144]

Frequent disruptions at Bangladesh's floating import terminals often reduce utilization. BPDB statistics suggest that utilization of the gas-fired power fleet averaged 31% for three weeks after a fire at an FSRU reduced gas supply by 450 million cubic feet per day.[145, 146] However, Bangladesh's gas constraints remain evident even when terminals are fully operational. In late June 2026, Petrobangla could allocate enough gas to meet only 39% of gas-fired power demand, even when both FSRUs were operating at full capacity.[147]

[144] BPDB. Annual Report 2024-25. 9 October 2025. Page 13-14.
[145] Dhaka Tribune. Bangladesh approves LNG procurement from Saudi Aramco subsidiary. 7 August 2026.
[146] IEEFA calculations from BPDP daily statistics. BPDB. Daily Generation. Retrieved on 31 August 2026.
[147] Taken from Petrobangla's 26 June 2026 daily gas report. Petrobangla. Daily-Gas-Intake-Offtake-Reports. 27 June 2026.

Figure 15: Utilization of select gas-fired plants, 26 June to 9 August 2026



Source: BPDP; IEEFA calculations.
Note: Utilization here is calculated by subtracting the gas shortfall of each power plant from its evening peak availability.

Generating sufficient cash flow to meet return expectations without reliable gas supplies is a serious challenge to the bankability of large-scale gas power projects. Constraints can delay the commercial operation of projects, but they do not delay debt repayments. In 2023, JERA expressed difficulty in servicing loans for the 718MW Reliance Meghnaghat power plant, which saw its commissioning delayed due to gas rationing.[148] Meanwhile, the 584MW Unique Meghnaghat LNG power plant, designed to operate at an 84.6% load factor[149], generated zero electricity for several weeks due to gas rationing (Figure 15). While investors can recoup availability payments after commissioning[150], a lack of dispatch could impair the project's profitability.

Efforts to alleviate supply constraints currently focus on fast-tracking a third FSRU. However, even if all three terminals were at full capacity, there is no guarantee that power plants would be sufficiently utilized.[151] Historically, Bangladesh has been unable to complete pipeline infrastructure in time to meet the supply requirements of successfully completed power projects.[152] While a prospective onshore terminal could provide more reliable supply, it will require investments in additional pipeline capacity to move the gas to end-users.[153]

A further constraint is Bangladesh's ability to finance LNG procurement. Additional regasification capacity does not in itself assure greater gas availability: it must be matched by sufficient foreign-exchange liquidity and working capital to purchase LNG cargoes and pay suppliers on time. Petrobangla's constrained foreign-currency position has already hindered timely LNG payments. Expanding terminal capacity without a credible and sustainable funding mechanism could therefore

[148] Bonik Barta. Gas crisis stalls JERA's power plant despite readiness. 5 December 2024.
[149] AIIB. ESIA Report for Proposed 600MW Combined Cycle Power Plant at Sonargaon, Narayanganj, Bangladesh. 2022 December. Page 43 (85 of pdf).
[150] AIIB. ESIA Report for Proposed 600MW Combined Cycle Power Plant at Sonargaon, Narayanganj, Bangladesh. 2022 December. Page 43 (85 of pdf).
[151] Asia News Network. Bangladesh government braces for costly LNG future. 30 July 2026.
[152] Bonik Barta. Gas crisis stalls JERA's power plant despite readiness. 5 December 2024.
[153] Global Flow Control. Bangladesh Expands LNG Capacity with New FSRU Terminal. 30 July 2026.

raise the country's contingent import bill and financing needs without reliably increasing gas deliveries to power plants.

Taken together, overcapacity in gas-fired generation, declining domestic gas production, frequent FSRU disruptions, and insufficient import and transmission infrastructure are likely to require Petrobangla to ration gas supply. With the state-owned gas supplier projecting no growth in gas-fired generation through FY2030[154], existing gas projects are likely to experience extended periods of underutilization. Such conditions are unlikely to provide the level of bankability required to attract significant interest from gas project investors.

[154] Between FY2025 to FY2030, Petrobangla expects gas demand to stay around 1.4Bcf/d. Petrobangla. Annual Report 2024-25. 17 February 2026. Page 59.

Conclusion

Between 2021 and 2026, more than half of LNG-fired power projects and LNG import terminals in the Philippines, Vietnam, Thailand, and Bangladesh have been canceled, withdrawn, or shown no significant progress. The value of canceled or inactive LNG-fired power plants and import terminals in the four markets surveyed was nearly 4.5 times the value of completed projects over the same period.

LNG-to-power development has also proceeded far more slowly than commonly assumed. Average completion timelines for LNG-fired power projects exceeded seven years across the four markets, surpassing widely cited estimates of three-to four-year lead times.

The high proportion of LNG-to-power projects that have been canceled, withdrawn, or shown no significant progress, together with long development timelines, raises questions about forecasts for rapid LNG demand growth in the region. IEEFA finds that regulatory and policy instability, foreign exchange exposure associated with US dollar-denominated obligations, the weak credit profiles among state-backed offtakers, and sensitivity to volatile fuel prices remain fundamental obstacles to the financing and completion of LNG-related infrastructure projects.

These barriers have only intensified since 2021, as two major geopolitical crises, a shortage of gas turbines, and the depreciation of local currencies against the US dollar have compounded financing costs and lengthened development timelines for LNG projects.

At the same time, rapidly falling renewable energy costs have increased the competitive pressure on gas-fired generation, while helping to mitigate exposure to recurring US dollar-denominated fuel purchases and geopolitical disruptions in global fuel supply. As these structural constraints persist, expectations of rapid, large-scale LNG demand growth in emerging Asian markets warrant closer scrutiny.

Appendix I: LNG-fired power projects canceled or inactive since 2021

Count	Project name	Owner	Capacity (MW)	IEEFA estimated project cost (USD million)
		The Philippines		
1	EWC CCGT Power Plant	Energy World Corporation	650	607
2	Lloyds Energy Philippines Floating Power Plant	Lloyds Energy Philippines	1,200	1,121
3	Lucidem LNG Power Plant	Lucidum Energy	300	280
4	Natural Gas-Fired Power Plant	Batangas Clean Energy	1,100	1,028
5	Saint Joseph Batangas Power Plant	First Gen	600	560
6	SMC Ilijan LNG Power Plant I	SMC Global Power Holdings	1,200	1,121
7	SMC Ilijan LNG Power Plant II	SMC Global Power Holdings	1,200	897
8	SMC Ilijan LNG Power Plant III	SMC Global Power Holdings	1,200	897
9	Vires LNG-Fired Power Barge Project	VIRES Energy	500	467
10	Navotas LNG-fired Power Plant	SMC Global Power Holdings	6,491	6,063
11	Sangali LNG-fired Power Plant	SMC Global Power Holdings	300	280
12	San Carlos CCGT	SMC Global Power Holdings	300	280
13	Leyte CCGT	SMC Global Power Holdings	600	560
		TOTAL	15,641	14,162
		Vietnam		
1	Hai Phong II (Phase 1)	VinGroup	800	759
2	Hai Phong II (Phase 2)	VinGroup	800	608
3	Hai Phong II (Phase 3)	VinGroup	3,200	2,430
4	Ke Ga Integrated Project (Phase 1)	Energy Capital Vietnam, KOGAS, Excelerate, B. Grimm	1,200	1,139
5	Ke Ga Integrated Project (Phase 2)	Energy Capital Vietnam, KOGAS, Excelerate, B. Grimm	2,400	1,823
6	Long Son II	EVN, Mitsubishi	1,200	911
7	Long Son III	EVN, Mitsubishi	1,200	911
8	Quang Ninh 2	N/A	1,500	1,139
9	Khanh Hoa I	Millennium Group	1,500	1,424
10	Khanh Hoa II	Millennium Group	1,500	1,139
11	Khanh Hoa III	Millennium Group	1,500	1,139
12	Phu My 3.1	Phu My 3 BOT Power Co. (Semcorp, Kyushu Electric, Sojitz)	850	807
13	Ca Mau 3	PetroVietnam	1,500	1,424
14	Vung Ang 3 Phase II	PV Power	1,500	1,139
15	Tien Lang Phase 1	ExxonMobil, JERA	2,250	2,136
16	Tien Lang Phase 2	ExxonMobil, JERA	2,250	1,709
17	Ca Na (Phase 2)	N/A	1,500	1,139
18	Ca Na (Phase 3)	N/A	1,500	1,139
19	Ca Na (Phase 4)	N/A	1,500	1,139
20	Cong Thanh II	N/A	3,000	2,278
		TOTAL	32,650	26,332
		Thailand		
1	Songkhla Chana Power Station	Korea Western Power Co Ltd	1,700	1,583
2	Wang Noi Power Plant Replacement	EGAT	2,600	1,937
3	Nam Phong Replacement	EGAT	650	484
4	North Bangkok Power Plant Extension	EGAT	1,400	1,043
5	South Bangkok Power Plant Extension	EGAT	2,100	1,565
6	Surat Thani Power Station	EGAT	1,400	1,304
		TOTAL	9,850	7,917
		Bangladesh		
1	Matarbari RLNG Power Station	CPGCBL, Mitsui	600	570
2	Payra LNG Power Plant	North-West Power Generation Company	3,600	3,417
3	Gazaria LNG Power Plant	Edra Power Holdings Sendirian Berhad (80%), Winnievision Power Limited (20%)	660	626
4	Meghnaghat Unlima LNG Power Plant	Anlima Group (75%), General Electric (25%)	450	427
5	Mirsarai LNG Power Plant	Confidence Power Holdings Limited (62%), General Electric (20%), Confidence Power Limited (9%), Electrapack Industries Limited (9%)	660	626
6	Raozan LNG Power Plant	BPDB	400	380
7	Haripur LNG Power Plant	BPDB	250	237
8	Ghorashal LNG Power Plant	BPDB	225	214
9	Siddhirganj LNG Power Plant	BPDB	600	570
10	Bheramara LNG Power Plant	BPDB	610	579
		TOTAL	8,055	7,646

Source: IEEFA analysis based on various public reports; IJ Global; Global Energy Monitor; Philippines Department of Energy; EGAT; BPDB; Baker Mackenzie; Frasers; ACB Securities Co. Ltd.; MB Securities.

Note: All project valuations in this report are estimated by IEEFA using a standardized methodology. These valuations may differ from publicly reported investment figures.

Appendix II: LNG import terminal projects canceled or inactive since 2021

Count	Project name	Owner	Capacity (MTPA)	IEEFA estimated project cost (USD million)
The Philippines				
1	Batangas LNG Terminal	Batangas Clean Energy Inc.	3	558
2	Shell Energy Tabangao LNG Import Terminal	Shell Energy Philippines	3	558
3	Vires LNG Terminal	VIRES Energy	3	558
4	Mariveles LNG Terminal	Samat LNG Corp.	0.4	100
		TOTAL	9.4	1,775
Vietnam				
1	Tien Lang FSRU	ExxonMobil, JERA	3	328
2	Khanh Hoa LNG Terminal	Petrolimex	3	567
3	South West LNG Terminal Phase 1	N/A	1	109
4	Tien Giang LNG Terminal I	N/A	2	378
5	Tien Giang LNG Terminal II	N/A	4	643
6	Chan May LNG Terminal	Chan May LNG JSC	2.87	543
7	Hai Phong LNG Terminal	Vingroup	5	547
8	Mui Ke Ga LNG Terminal	Energy Capital Vietnam, KOGAS, Excelerate, B. Grimm	1.5	164
9	Nam Dinh LNG Terminal	JAPEX, ITECO JSC	0.65	166
10	Northern Vietnam LNG Terminal	Excelerate, ITECO JSC	1.2	227
		TOTAL	24.22	3,673
Thailand				
1	Gulf of Thailand FSRU	EGAT	5	537
2	Surat Thani FSRU	EGAT, PTT PCL	5	537
		TOTAL	10	1,073
Bangladesh				
1	Matarbari LNG Terminal	Rupantarita Prakritik Gas Company	7.5	1,206
2	Maheshkhali ACWA Onshore Terminal	ACWA Power, Aramco	7.5	1,206
3	Matarbari Summit FSRU	Summit	4.6	428
4	Payra FSRU (Excelerate)	Excelerate Energy	3.75	349
5	Payra LNG Onshore Terminal	Government of Bangladesh	7.5	1,206
6	Kutubdia (Petronet) LNG Terminal	Petronet	7.5	1,206
		TOTAL	38.35	5,600

Source: IEEFA analysis based on various public reports; IJ Global; Global Energy Monitor.

Note: All project valuations in this report are estimated by IEEFA using a standardized methodology. These valuations may differ from publicly reported investment figures.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends, and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable, and profitable energy economy. www.ieefa.org

About the authors

Sam Reynolds

Sam Reynolds, Research Lead, LNG/Gas, Asia, focuses on the economic, financial, and climate risks associated with natural gas and liquefied natural gas (LNG) infrastructure developments in Asia. He is the author of several studies concerning the region's transition to renewable energy, stranded asset risk in the natural gas sector, and the macroeconomic risks associated with a greater regional dependence on imported LNG. sreynolds@ieefa.org

Christopher Doleman

Christopher Doleman, LNG/Gas Specialist, Asia, focuses on the economic, financial, and climate implications of developing the natural gas value chain throughout Asia. In previous roles, he has analyzed how developments in policy, energy markets, and technology shape energy systems and affect energy security. cdoleman@ieefa.org

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