Carbon Tracker Initiative

April 2022

Stop Fuelling Uncertainty
Why Asia should avoid the LNG trap

About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

www.carbontracker.org | hello@carbontracker.org

Acknowledgements

The authors would like to thank the following individuals and organisations for offering their insights and perspectives on the report. Their comments and suggestions were of great value.

Makiko Arima; Gyuri Cho and Gahee Han – SFOC; Sam Reynolds – IEEFA; Yugo Tanaka – IGES; Ayumi Goto – GSCC.

All errors and omissions are solely the responsibility of the Carbon Tracker power & utilities team.

Authors

Jonathan Sims – Senior Analyst

Lee Ray – Senior Analyst

Durand D'souza – Data Scientist

Nicolás González-Jiménez – Consultant Data Scientist

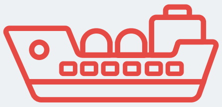
Lorenzo Sani – Associate Analyst

Kofi Mbuk – Clean Tech Analyst

Table of Contents

01

Key Findings

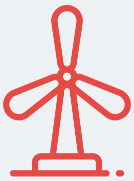


Increased exposure to the highly volatile global LNG market would be unwise.

The Russia-Ukraine conflict has demonstrated that gas supplies can be weaponised or face international sanctions at any time, and shown clearer than ever that now is not the time for nations to be increasing their dependence on volatile gas markets for energy sector needs. Planning a power system centred around renewables with battery storage will minimise exposure to commodity price risk, can be developed at lower cost than new gas, and will prevent billions of dollars of LNG infrastructure investment from stranding.

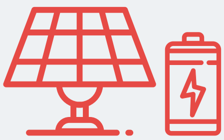
New large-scale gas units in Japan, South Korea and Vietnam appear totally incompatible with a net zero emissions by 2050 pathway and any that are built may be forced to close well in advance of the end of planned lifetimes.

Up to $70 billion could be lost if planned new gas units are developed under this more stringent climate scenario. The vast majority of projects would require extensive government backing to be made viable. The provision of which makes no sense when cheaper renewable alternatives are available.



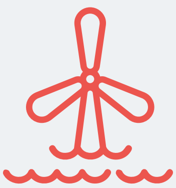
Opportunities for renewables in Japan, South Korea and Vietnam are vast and more cost competitive than gas.

New solar and onshore wind power developments in Japan, South Korea and Vietnam are either already cheaper, or will become cheaper overall investments than new gas units by 2025. Given typical planning and construction timeframes of at least four years for new gas, any units that move ahead to development could face constrained running hours from day one amid strong competition from lower cost renewables.



Even new solar units with battery storage capacity will become cost competitive with existing gas plant capacity in Japan and South Korea during the early 2030s.

This means that these nations will have a low carbon energy source able to provide comparable flexibility services to a gas unit available at lower cost to the system within a decade, allowing policy makers to plan their phase out of power sector gas use in line with their net zero emissions by 2050 targets. This inflection point could come even earlier in the event of upward swings in LNG prices.



Offshore wind sector growth potential in Asia is huge.

Large coastlines and territorial water areas mean that all three countries analysed here are extremely well-positioned to become world leaders in offshore wind development. Offshore wind capacity in South Korea and Vietnam will become cost competitive with new gas this decade.

02

Executive Summary

Introduction

This report continues our series exploring the long-term risks associated with investment in power sector gas infrastructure globally. It follows on from our Put Gas on Standby report from last year which focused on the outlook for gas power plants in Europe and the US, with attention turning here to Asia and the extreme risks associated with nations in this region increasing their exposure to the highly volatile market for liquefied natural gas (LNG).

We have focused this research on Japan, South Korea and Vietnam – three nations that have all declared national intentions to achieve net zero emissions by 2050[1], yet continue to plan for a future in which unabated gas-fired power has a central role within their power systems.

As shown in Table 1 below, these countries stand at differing stages in maturity in their power sector gas development. All three are however now reaching a point where policy makers must decide whether to commit to long-term power sector gas dependency, or to instead focus efforts on lower cost and lower risk renewables.

The risks associated with gas infrastructure investment have never been higher. The Russia-Ukraine conflict has demonstrated that gas supplies can be weaponised or face international sanctions at any time and nations should now be urgently prioritising ways to reduce exposure to this highly volatile market.

Table 1: Gas plant capacities included in Carbon Tracker model by stage of development

Country	Gas power capacity in operation (GW)	Gas power capacity planned or under construction (GW)
Vietnam	8.2	56.3
Japan	76.4	10.1
South Korea	41.3	18.3
TOTAL	125.9	84.7

Source: Global Energy Monitor

1 Japan and South Korea net zero 2050 targets written into national law; Vietnam has pledged to aim for this goal.

Increased dependency on volatile LNG market would be unwise

The geographical landscape in Asia has meant that most nations in the region have had little choice as to the form their gas imports are delivered. Without producing sufficient supplies domestically or being able to build extensive pipeline networks to nations that do, gas-fired power stations are predominantly fuelled by freight-delivered liquefied natural gas (LNG).

Extreme volatility and sharp price spikes in recent years have shown that it would be unwise for nations to intentionally increase their energy system exposure to this global market, however, even before considering the environmental impact of further gas expansion.

Both Japan and South Korea's over-dependence upon gas for power sector needs has seen consumer energy bills driven to long-term highs over the past year, with an extremely cold winter and depleted gas storage facilities having forced some Japanese gas system operators to purchase supplies on the spot market. Decreasing LNG market exposure should consequently be a priority for policy makers to protect the public from any future price spikes.

The difficulties that these two nations are experiencing in shifting away from gas dependency in pursuit of net zero emissions should be viewed as a warning to Vietnam to avoid a similar path, as it begins its own transition towards mid-century climate neutrality and coal phase out.

A power system centred around the use of renewables with battery storage will minimise Vietnam's exposure to international commodity price volatility, can be developed at much lower overall cost than the extensive pipeline of gas infrastructure required for the coal-to-gas transition currently in planning, whilst putting the country firmly on track to deliver its net zero emissions by 2050 pledge.

Infrastructure stranding

Vietnam requires significant investment in its grid infrastructure for whatever future path it chooses for its energy supplies. The country's rallying demand for energy requires improvements to be made for new capacity to be given grid access and for rising generation to be transmitted. Investment in new gas-fired power stations dependent on LNG for their fuel supplies means that most planned projects rely on LNG terminals being developed alongside. In other words, many proposed gas plants are only viable if additional capex is spent on related LNG infrastructure.

Vietnam has a current pipeline of 13 planned LNG terminals, although only two have begun construction. Of these two, the first phase alone of the Thi Vai terminal is estimated to cost around $285 million to build[3]. Assuming that the second phase of this project goes ahead, this will likely take total spending above the $500 million mark.

Vietnam's plan to build a whole pipeline of terminals consequently has the potential for several billion dollars of infrastructure to strand, even before calculating the amount of value at risk of destruction at the power plant level.

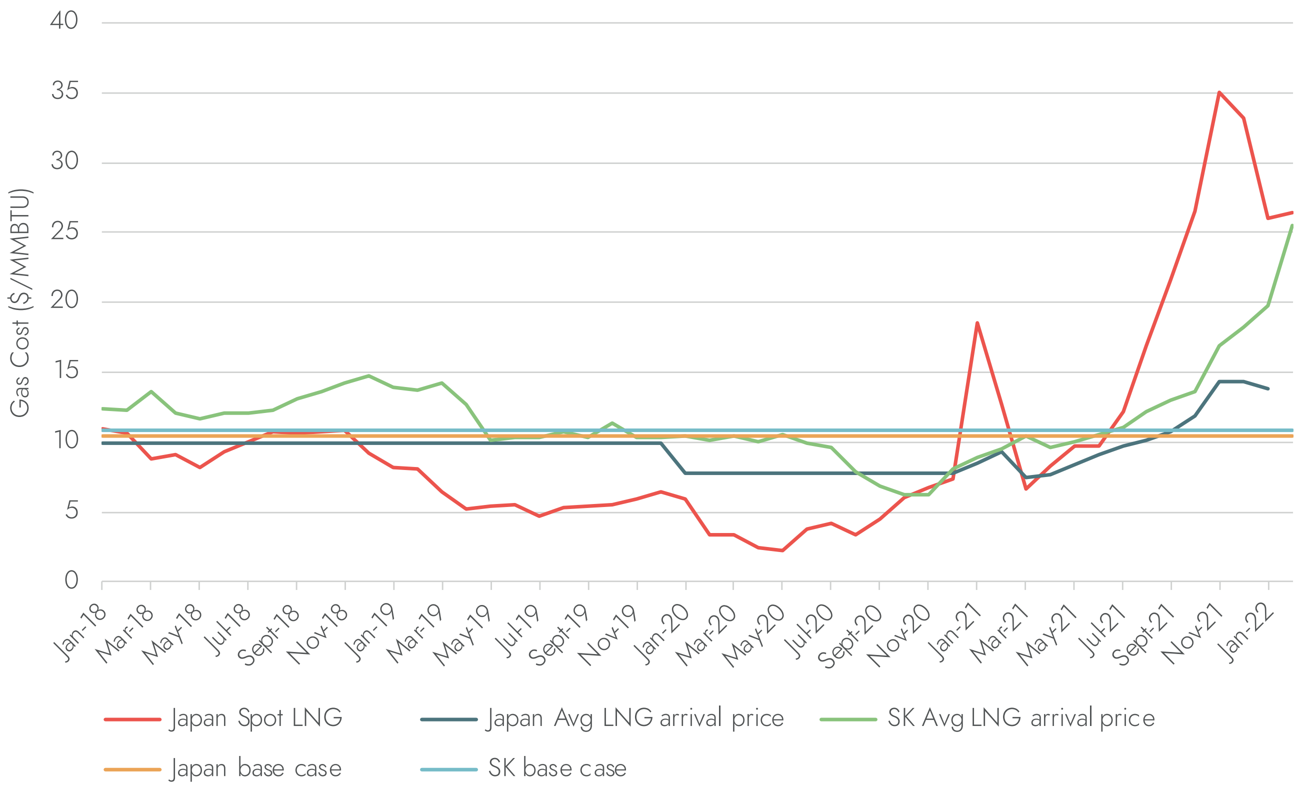
Centring grid improvements around planned gas plant investments, rather than lower cost renewables in Vietnam, also means that grid infrastructure and connections will be left at risk of stranding when gas units are outcompeted by renewables. Vietnamese policy makers need to mitigate this risk by future-proofing the grid now and building infrastructure that can accommodate the rapid build-out of renewable technologies.

Small increases in LNG prices bring forward crunch points for gas plants

Given expectations for much greater competition from European buyers for LNG cargoes in the near-term, as nations try to reduce their dependence on pipeline gas supplies from Russia in the wake of the country's invasion of Ukraine, we believe that our base case assumptions[4] represent a conservative outlook for how LNG market prices will turn out in Asia over the coming years. As shown in Figure 1 below, actual market values have turned out up to three times above these base case figures in recent months.

2 Global Gas Infrastructure Tracker – Global Energy Monitor
3 Thi Vai LNG Terminal – Global Energy Monitor Wiki
4 Based on market values recorded over 2019-2021 period. Full details of the price assumptions used in our model are provided in the report methodology, a link to which can be found in the appendix.

Figure 1: Carbon Tracker base case LNG prices versus actual spot prices



Source: Japan Oil, Gas and Metals National Corporation; Japan Ministry of Economy, Trade and Industry; Electric Power Statistics Information System (South Korea)

We find that in both Japan and South Korea, a 50% increase in average LNG price above our base case figures is enough to lift the long-run marginal cost (LRMC) of running these nations' existing gas plant fleets to levels leaving them struggling to compete with even solar with battery storage costs from 2025. While in Vietnam, this same price adjustment in fuel price would also leave running costs for the country's planned new build gas units around the same cost level that new solar with battery storage capacity is projected to be available at by 2025.

We consequently use sensitivity analyses to demonstrate the impact that price volatility in the LNG market could have on operating costs for gas plant capacity and show that key crunch points for plant owners could arrive sooner than anticipated.

Majority of new gas will be value destructive

We find almost 86% (73 GW) of planned gas projects will be economically unviable in Japan, South Korea and Vietnam even under generous business-as-usual (BAU) timeframes. This is especially pertinent for Vietnam which has a very large project pipeline relative to the other two countries and its small existing base of gas plants in the country.

Not surprisingly, under our climate-constrained alternative scenario, NZE2050, 94% (80 GW) of planned projects in these three countries are uneconomical, equivalent to almost $70bn. As the world moves to limit carbon emissions and avoid the worst effects of climate change, continuing to invest in assets that do not fit within NZE2050 is a financial risk.

Given the fragility of new gas economics, projects are very sensitive to key inputs. Fuel costs are the single largest cost item for a gas plant, meaning plant costs and profitability are highly sensitive to changes in fuel prices. Project economics deteriorate quickly even with modest rises in the cost of fuel. For example, all else being equal under BAU, we estimate that a 50% increase in the price of gas versus our base case assumption would swing Japanese gas projects into negative territory with an aggregate NPV of $-5.3bn. For Vietnam, the equivalent price hike renders project economics almost three times as bad and for South Korea almost two and a half times as poor.

Wedding the grid to volatile and high gas prices locks users into a worst-case outcome when compared to lower cost, lower risk and cleaner renewables.

Lower cost renewables will leave only minimal grid role for gas

We present a cost comparison analysis between the projected lifetime operating costs of new renewables capacity in the three countries with the associated costs of investing in and running a gas-fired power station. We find that the economics steer overwhelmingly in the direction of new renewables capacity, with both new solar and onshore wind power projected to be cheaper to build and operate than new gas units in each of the three nations.

In the case of Vietnam, a country with few operating gas plants but a big pipeline, avoiding any long-term dependence on a supposed bridge fuel and planning for a coal-to-clean transition should be prioritised.

For Japan and South Korea, while standalone solar and onshore wind farm costs already compete favourably with the costs associated with building and operating new gas-fired power stations, we project that even solar with battery storage capacity installed will become cheaper to construct and operate than continuing to operate the countries' existing gas plant fleets during the early 2030s.

This still leaves a role for the most flexible gas units to provide backup grid supplies for the years until this inflection point is reached and for the handful of winter hours when cold snaps drive demand spikes beyond it, but with alternative sources of grid flexibility continuously arising and the urgent need for rapid power sector decarbonisation, this should be the limit to such facilities' future role.

> **"We find that the economics steer overwhelmingly in the direction of new renewables capacity"**

Offshore wind

We also find that all three nations assessed in this report hold enviable potential for significant offshore wind power sector development.

While we project that new offshore wind capacity in South Korea and Vietnam will become cost competitive with gas this decade, operating and construction costs for the technology are expected to fall at a slower pace in Japan owing to deep seabed conditions. Given Japan's high degree of maritime expertise and standard of port facilities however, we believe that there is every chance that the costs associated with offshore wind development there could come down quicker than our conservative estimates once the first initial projects planned are launched.

High level recommendations

POLICY MAKERS

- **Spur private sector investment in renewables through subsidies.**

  The provision of CfD or feed-in tariff subsidies for new renewables capacity, particularly in the offshore wind sector, will offer developers certainty over project revenues for the initial years of operation and can serve to drive down long-term costs at a quicker pace than they otherwise would fall. Such subsidies should be issued through competitive, transparent auction allocation processes.

- **Ensure policy alignment with NZE2050 by ending support for new gas.**

  Net zero emissions now not only represents the best option for nations' climate ambitions, but also energy security, in bringing reduced exposure to and dependency on volatile fossil fuels. This should increase the sense of urgency in delivering the transition to low carbon technologies and mean that policy makers no longer look to provide financial support to new gas plant projects through power purchase agreements that risk hiking consumer energy bills.

INVESTORS

- **Ensure that project assumptions are aligned with NZE2050 to avoid significant value destruction.**

  New large-scale gas units appear totally incompatible with a net zero emissions by 2050 pathway and any that are built may be forced to close well in advance of the end of planned lifetimes. Failing to consider the implications of net zero targets in place in Japan, South Korea and Vietnam and pressing ahead with developments could lead to sizeable losses for investors, with up to $70 billion at risk if projects are developed under this more stringent climate scenario.

- **Grasp the investment opportunities that are arising in Asian renewables.**

  Japan, South Korea and Vietnam are all ideally placed to significantly expand their renewables capacity over the coming years and appear particularly primed for investment in the offshore wind sector. Investment costs for renewables already compete favourably with new gas in this region, while involvement in this sector is clearly free from the increasing volatility associated with investment in the gas sector.

CARBON TRACKER MODEL ASSUMPTIONS AND SOURCES

Our base case projections for fuel and electricity values are based on an average of market values recorded over the 2019-21 period, to capture price movements from both before and during the Covid-19 pandemic.

Our base case fuel price assumptions are listed in the following table:

Country	Japan (LNG)	South Korea (LNG)	Vietnam (LNG)	Vietnam (domestic gas)
Price $/ MMBTU	10.5	10.8	10.5	5.33 in 2021, rising to 6.59 in 2050

Full details of the fuel price assumptions included in our model are outlined in the methodology document, a link to which is included in the appendix.

Data for under construction and planned projects was obtained from Global Energy Monitor.

Although we have not carried out a full systems analysis for this research and have instead performed a cost comparison assessment of technologies, we accept that battery storage will likely be a vital component of future low carbon energy portfolios to ensure security of power supply. The four-hour lithium-ion battery technology type that we have selected for this analysis is sufficient to mean that excess renewable energy produced earlier in the day can be shifted to and supplied to the grid during the peak demand evening hours and therefore provide flexibility services comparable with a peaking gas plant.

03

Increased dependency on volatile LNG market would be unwise

Fuel costs are inevitably often the largest single cost item for gas-fired power stations. Gas prices are subject to international commodity market movement however, which can result in significant variations for cost from year to year.

Such price moves can be the difference between gas-fired power generation capacity being profitable to operate or not and volatile fuel prices should make the continued investment case for such assets even less attractive when compared with renewables which require near-zero marginal costs for operation.

The high level of risk that the LNG market poses to gas plant economics in Asia compared with lower cost and lower risk renewables should discourage nations from increasing their dependency on the commodity for future years, even before considering how misaligned any investment in new gas infrastructure is with net zero emissions by 2050 pathways.

Accelerating the transition to lower risk and lower cost renewables not only clearly aligns with the actions that Japanese, South Korean and Vietnamese policy makers should now be taking in their pursuit of net zero, but can also provide the benefit of triggering a gradual shift away from LNG market exposure.

Not the time to increase dependence on LNG market

Our base case assumptions for LNG pricing are based on an average of values recorded over 2019-2021[5], during which period the market recorded extreme levels of volatility. Record price lows were seen during the first half of 2020, before spiking back to record highs a year later, as global supply struggled to keep pace with large swings in demand during the Covid-19 pandemic[6].

Given expectations for much greater competition from European buyers for LNG cargoes in the near-term, as nations try to reduce their dependence on pipeline gas supplies from Russia in the wake of the country's invasion of Ukraine, we believe that our base case assumptions represent a conservative outlook for how LNG market prices will turn out in Asia over the coming years.

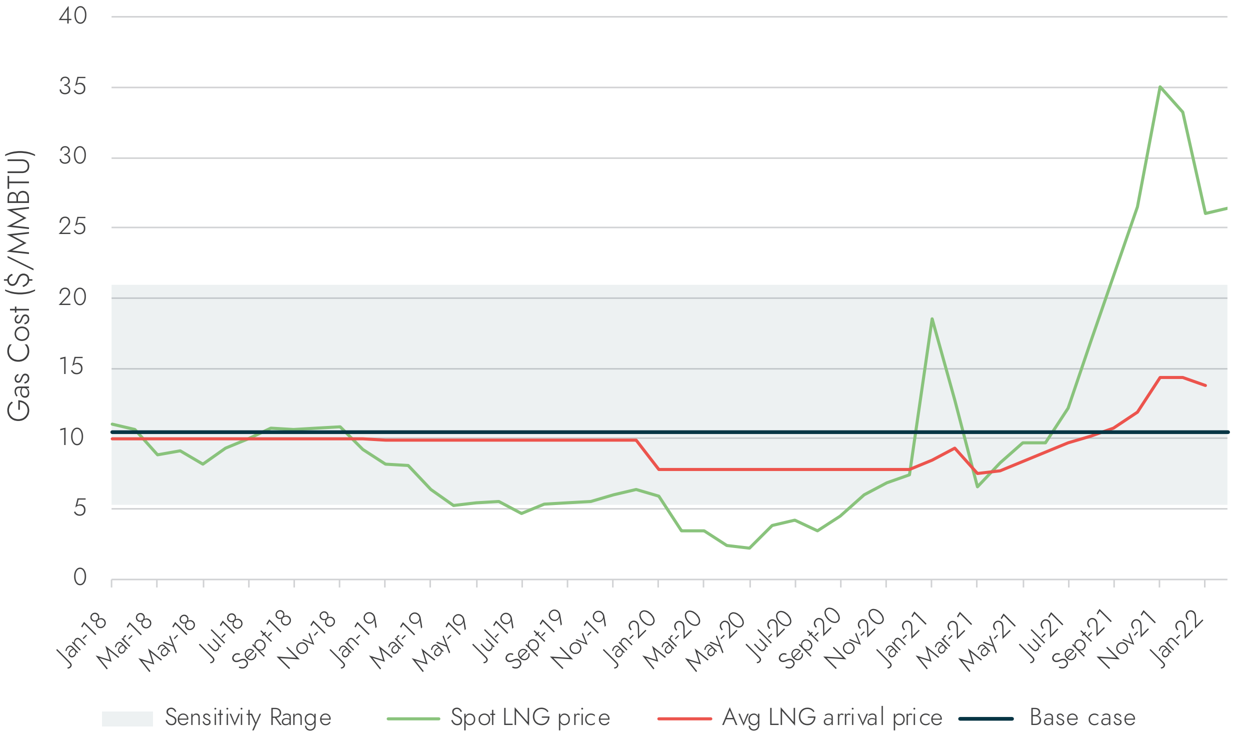
Such unanticipated geopolitical events demonstrate how quickly the global supply picture for gas and LNG markets can change, creating price spikes which policy makers should be aiming to free their nation's energy sector from exposure to.

As shown in Figures 2 and 3 below, actual market values have spiked to levels more than 300% above our base case figures within recent months. We also show in the blue shaded areas on these charts the actual price range for which we run sensitivity analyses on percentage changes in LNG price later in this chapter, with the bottom of the area representing a 50% decrease in price level from our base case numbers, and the top a 200% increase. Given that recent LNG prices have surpassed even the top end of this shaded area, we are demonstrating that none of the potential price moves presented in our sensitivities are inconceivable.

5 Full details of the fuel price assumptions included in our model are outlined in the methodology document, a link to which is included in the appendix.

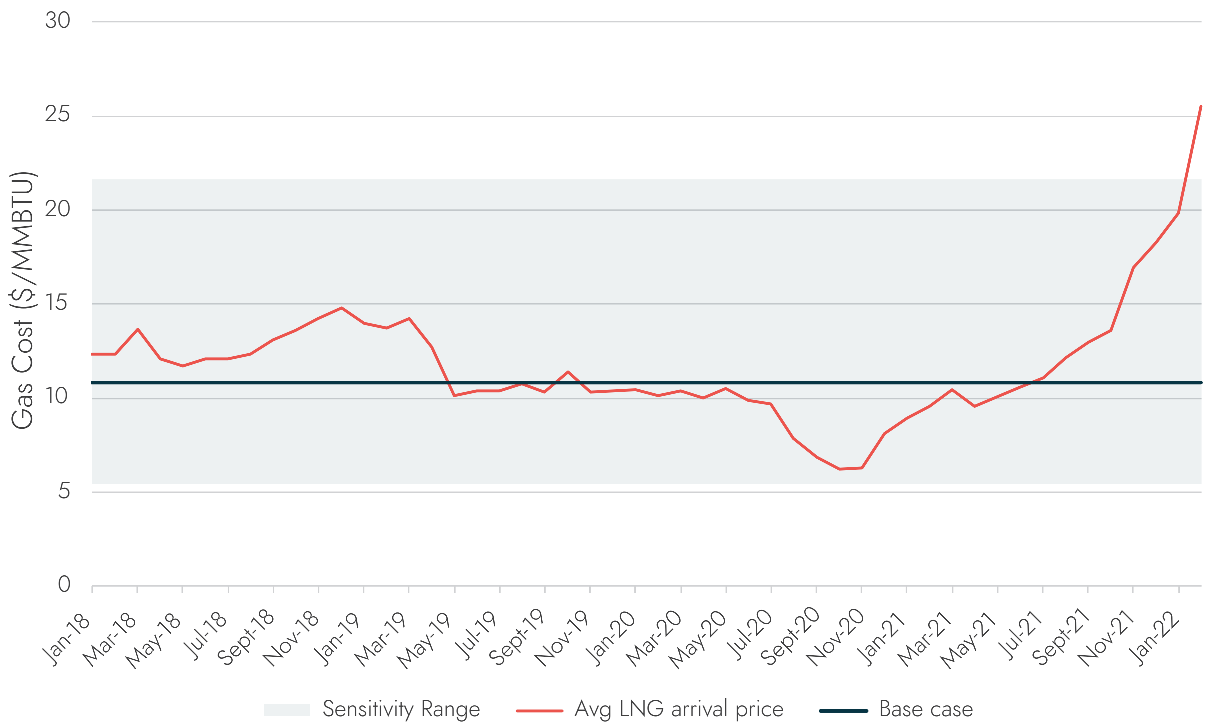
6 Explainer: What's behind the wild surges in global LNG prices and the risks ahead (Reuters.com)

Figure 2: LNG prices in Japan: base case figures versus average LNG arrival prices and spot prices

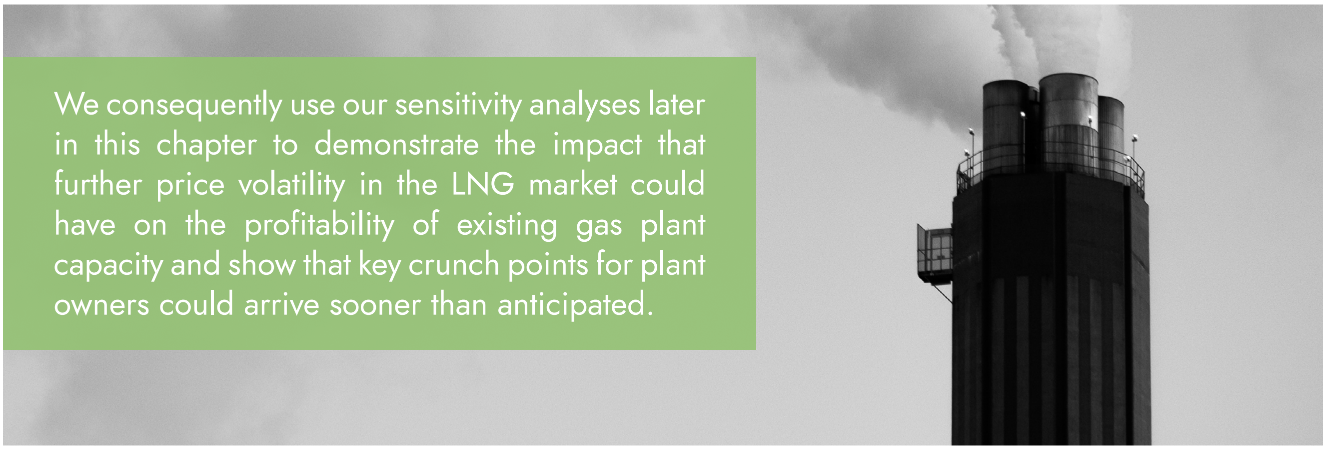


Source: Japan Oil, Gas and Metals National Corporation; Japan Ministry of Economy, Trade and Industry

Figure 3: LNG prices in South Korea: base case figures versus average LNG arrival prices



Source: Electric Power Statistics Information System



We consequently use our sensitivity analyses later in this chapter to demonstrate the impact that further price volatility in the LNG market could have on the profitability of existing gas plant capacity and show that key crunch points for plant owners could arrive sooner than anticipated.

Asia driving LNG demand, but nations must aim to decrease exposure to highly volatile market

The global LNG market more-than-tripled in size over the 20 years to 2020, with total trade estimated at around 380 million tonnes by 2021[7]. Much of this demand growth has been driven by activity in Asia, which is projected to account for as much as 95% of the total increase expected over 2020-2022[8].

The geographical landscape in Asia has meant that most nations in the region have had little choice as to the form their gas imports are delivered. Without producing domestically or being able to build sufficient pipeline networks to nations that do, gas-fired power stations are predominantly fuelled by freight-delivered LNG.

These logistics have left Japan and South Korea particularly dependent on LNG imports for their gas supplies, with these two nations alone accounting for around a third of global imports in 2021. Plans to build a further 10.1 GW and 18.3 GW of gas power plant capacity in Japan and South Korea respectively over the coming years will only serve to increase these countries' exposure to the LNG market.

Meanwhile Vietnam risks following a similar course to LNG dependency with its current plans to build just over 56 GW of new gas-fired power plant capacity. The Vietnamese government plans to start LNG imports this year and has indicated expectations for shipments to rise quickly to around 10 million tonnes annually by the end of the current decade[9].

This will require significant expansion of Vietnam's LNG terminal infrastructure to receive cargoes, and there are current plans to build up to 13 such facilities across the country over the coming years[10]. This adds further to the amount of infrastructure and capital investment that will become at risk of stranding over the long-term when lower cost renewables outcompete gas plant units or limit their operating hours.

In this section, we profile each country's level of LNG infrastructure development and exposure before highlighting the potential impacts that price changes in the global market could have on the economics of their power sector gas plant fleets.

7 Global LNG trade growth expected to slow to 4% in 2022: IEA (SPGlobal.com)
8 How Asia changed the global LNG market in the space of a year (WoodMac.com)
9 Vietnam to start LNG imports in 2022 as key step in lowering emissions, energy security: minister (SPGlobal.com)
10 Global Gas Infrastructure Tracker – Global Energy Monitor

3.1 Japan

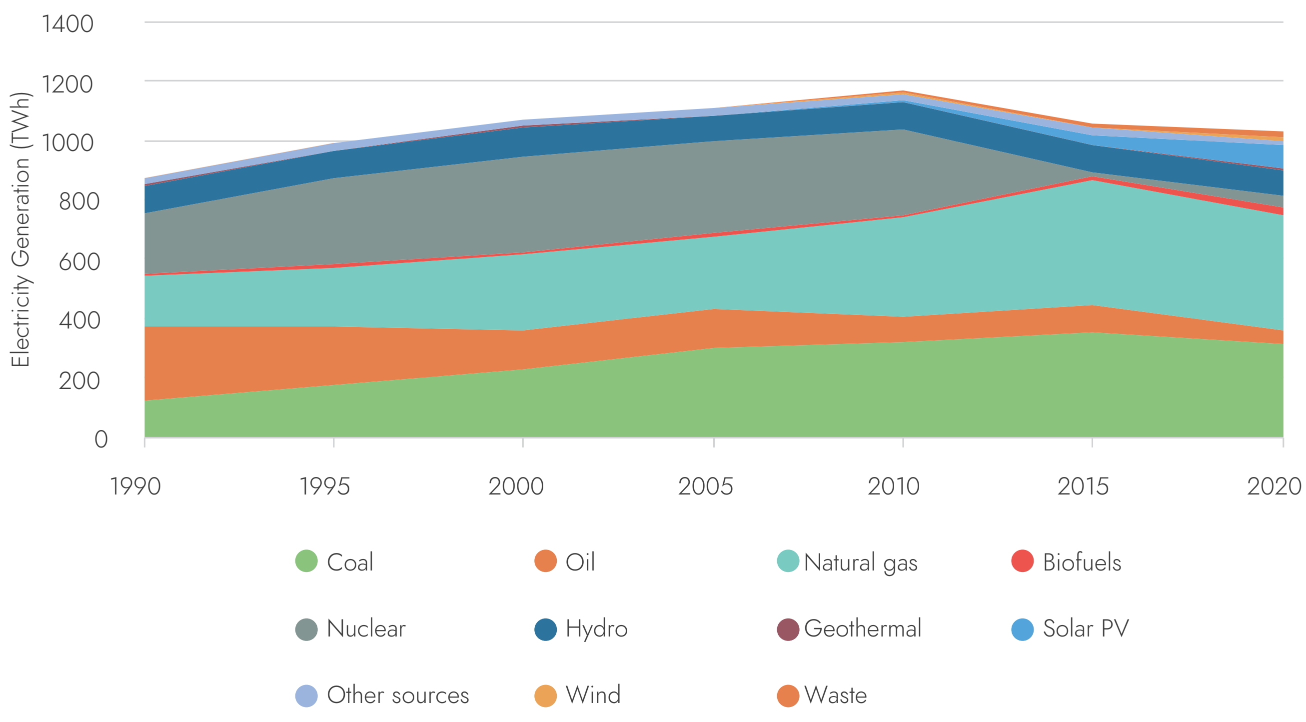
Japan has historically been the world's largest importer of LNG – a position the country held since the 1970s – although lost this spot to China in 2021[11]. This displacement was driven more by rapid demand growth from China rather than any reduction from Japan, delivered imports to which remained unchanged from 2020 in 2021, at around 75 million tonnes.

Japan's LNG demand has been well supported over the past decade by a strong increase in power sector gas use, to cover a steep reduction in supply from the nation's nuclear plant fleet following the Fukushima nuclear disaster in the country in 2011.

The Japanese government has however set an ambitious 2030 target of cutting LNG-fuelled gas plants' share of the country's power generation mix to only around 20%, as part of its long-term emissions reduction strategy[12] and aims for having an electricity system predominantly supplied by clean energy sources by the end of the decade.

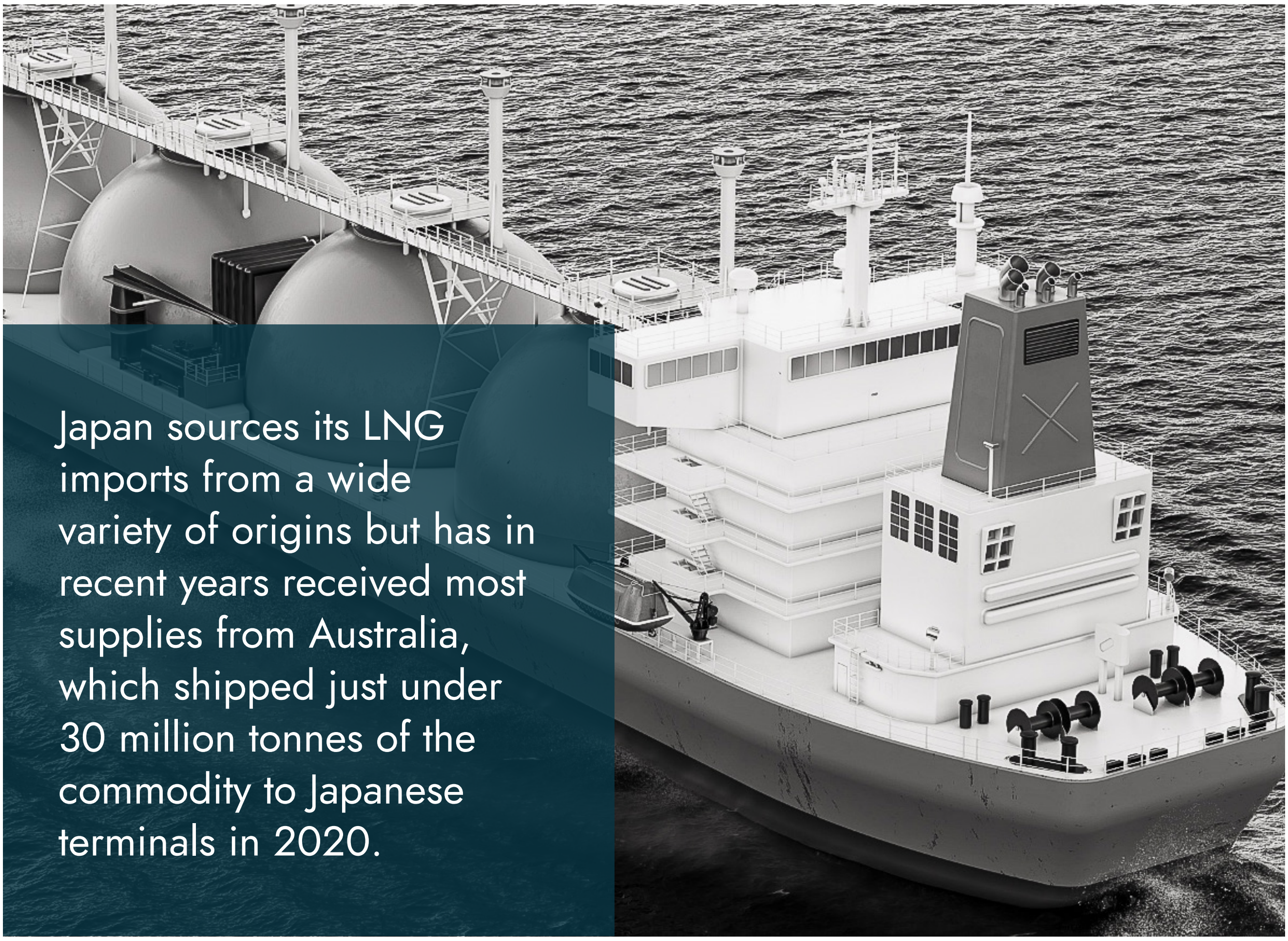
As shown in Figure 4 below, power sector gas burn almost doubled over the 10 years from 2005-2015, peaking at around 453.7 TWh in 2014. Greater adoption of solar and wind power capacity in recent years, as well as early signs of a nuclear sector recovery have seen output from gas-fired facilities begin to decrease, however. This rate of decline will need to accelerate significantly however[13] if the country's net zero emissions by 2050 target is to be achievable.

Figure 4: Japanese electricity generation by source



Source: IEA

11 United States poised to be world's largest LNG exporter in 2022 as China becomes top LNG importer (IHSMarkit.com)
12 Japan set for 60% non-fossil fuel power supply in 2030 in GHG slash drive – SPGlobal.com
13 Japan – Countries & Regions (IEA.org)



Japan sources its LNG imports from a wide variety of origins but has in recent years received most supplies from Australia, which shipped just under 30 million tonnes of the commodity to Japanese terminals in 2020.

Japan's vast 76.4 GW of operational gas plant capacity has required significant investment in LNG infrastructure to ensure fuel supplies are received. The country has just over 40 operational LNG terminals built, with a further three in planning or under construction[14].

Japan sources its LNG imports from a wide variety of origins but has in recent years received most supplies from Australia, which shipped just under 30 million tonnes of the commodity to Japanese terminals in 2020. With this representing around 40% of Japan's total LNG receipts in that year, there appears to be a risk that the country could face supply issues in the event of any significant increase in competition for Australian cargoes from European buyers.

Japan's dependence on gas means that domestic consumers have been confronted themselves with the effects of global LNG price volatility. Recent highs in the market, caused by an extremely cold winter and depleted gas storage facilities having forced some Japanese gas system operators to purchase supplies on the spot market, have driven retail energy prices in Japan to their highest levels in at least five years[15]. Decreasing the country's level of exposure to the LNG market should consequently be a priority for policy makers to protect the public from any future price spikes.

While Japan has a small pipeline of new gas plant projects relative to Vietnam and South Korea, it is primarily investors in the country's existing operational units that must assess the risks that growing LNG price volatility will have for their assets.

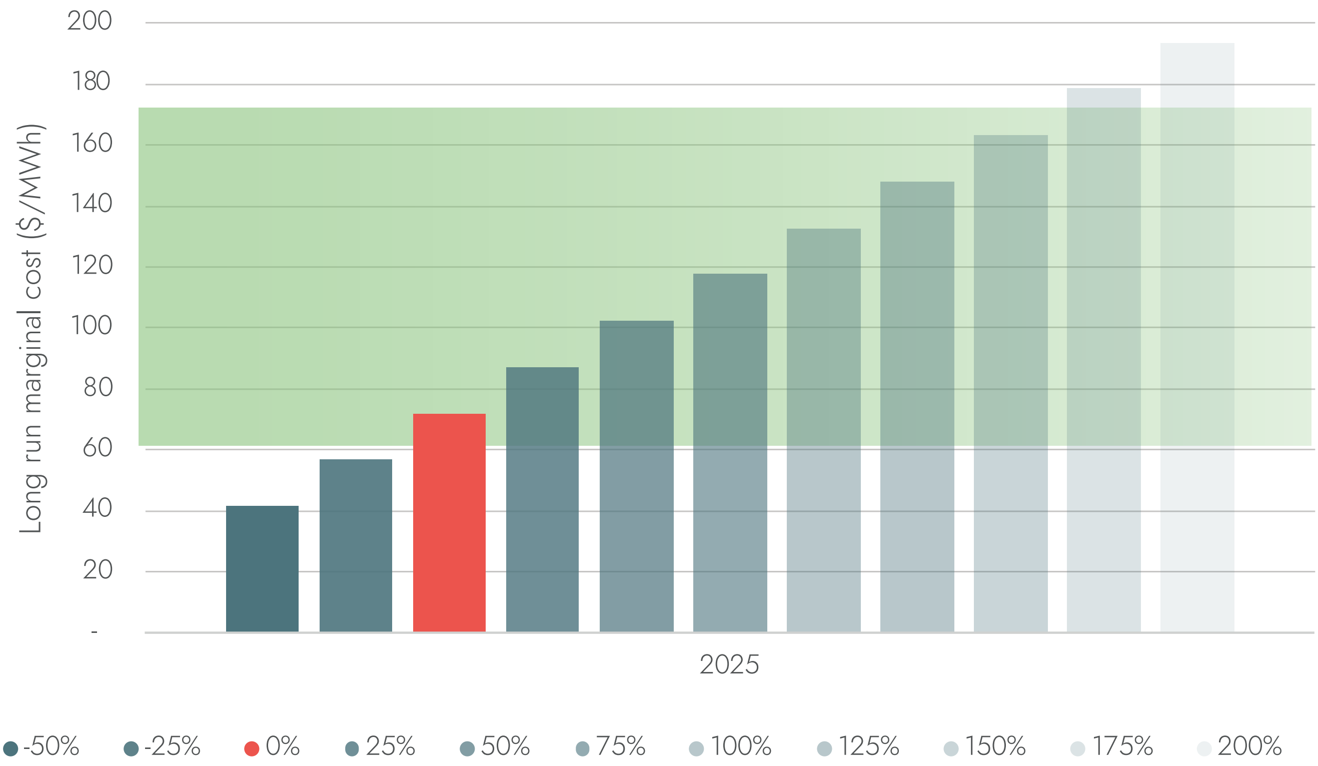
14 Global Fossil Infrastructure Tracker (GlobalEnergyMonitor.org)
15 Energy bills in Japan set to hit highest level in at least five years (JapanTimes.co.jp)

As shown in Figure 5 below, our sensitivity analysis on the impact of higher LNG prices on the operating costs of Japan's existing gas plants found that a 50% increase in average LNG price above our base case figures is enough to lift the average long-run marginal cost (LRMC) of running Japan's existing gas plant fleet to just over $100/MWh, leaving such units struggling to compete with even solar with battery storage costs from 2025 (see section 5.1 for renewables cost comparison).

This could leave significant levels of capital investment at risk of stranding if Japanese plant owners continue to fund assets which will likely have to face up to declining capacity factors amid increased competition from lower cost renewables over time.

The light green shaded area on Figure 5 represents the projected levelised cost of energy (LCOE) range for new renewables, rising from standalone solar at the bottom, through solar with storage, standalone onshore wind, to our highest range scenario estimates for onshore wind plus storage at the top.

Figure 5: Impact of changes in LNG price on operating costs of existing Japanese gas plants



Source: Carbon Tracker analysis

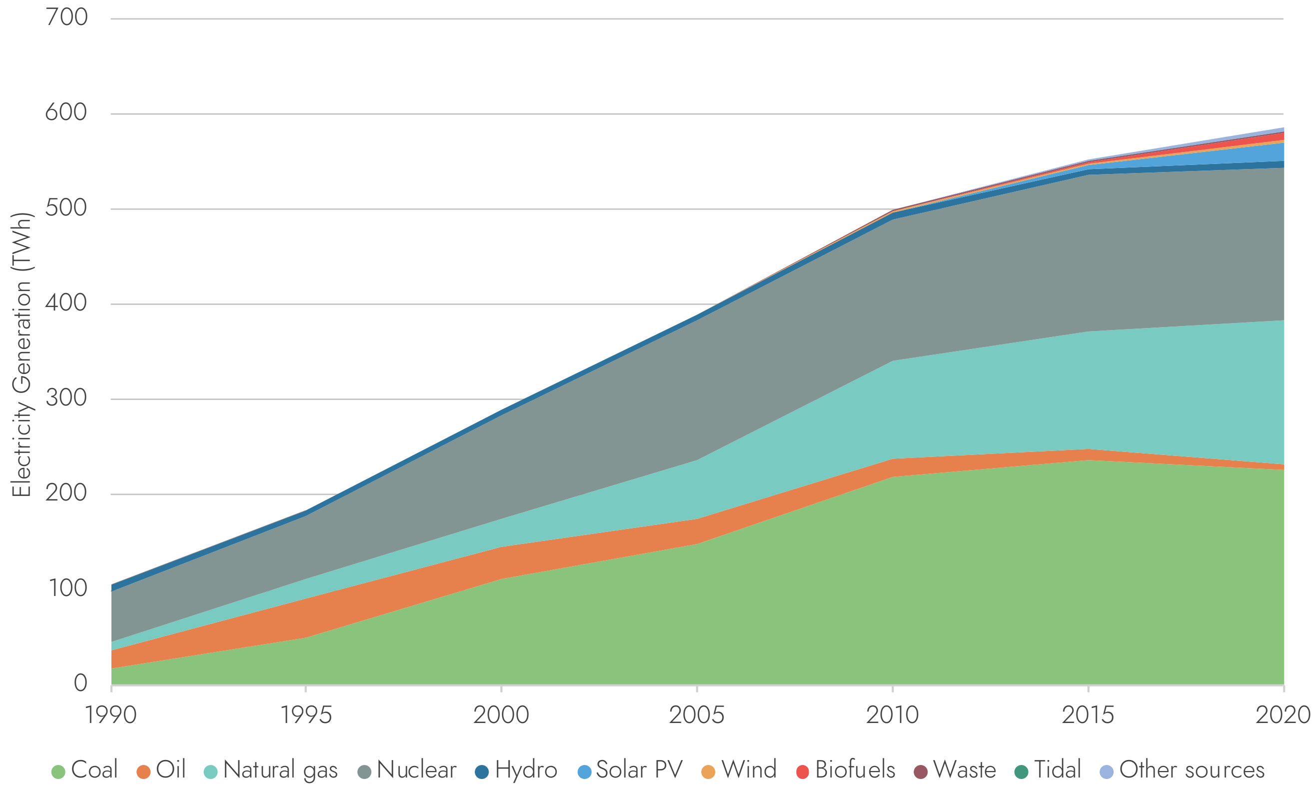
3.2 South Korea

South Korea's imports of LNG have risen steadily over the past two decades, with shipments to the country reaching around 46 million tonnes in 2021[16]. The nation sources the bulk of its LNG supplies from Qatar, the US and Australia, but has bought cargoes from a wide variety of origins in the recent past.

Minimal renewables sector deployment within South Korea has seen both gas and coal-fired power generation rise sharply over the past decade to meet demand. Gas-fired power generation in the country reached a record of just over 150TWh in 2020 — the last year for which the IEA has provided generation data — although remained the third largest source of output, behind coal and nuclear facilities[17].

As shown in Figure 6 below, South Korea's gas-fired power production rose by close to a third over the 2010-2020 period, with early signs of decline in the country's coal-fired output likely to drive further increases, unless the government stimulates deployment growth in the low carbon technologies that are urgently required to deliver the nation's net zero emissions by 2050 target.

Figure 6: South Korea electricity generation by source



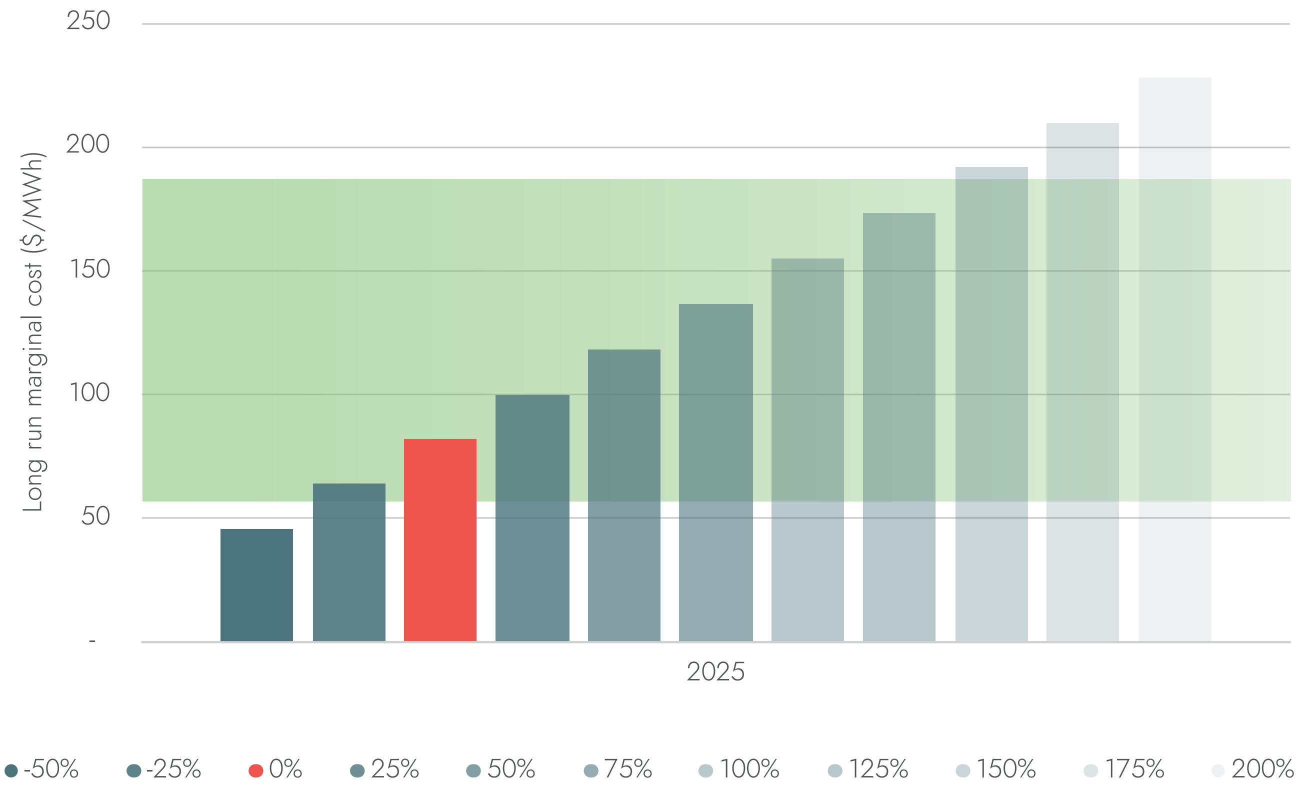
Source: IEA

16 United States poised to be world's largest LNG exporter in 2022 as China becomes top LNG importer (IHSMarkit.com)
17 Korea – Countries & Regions (IEA.org)

South Korea's position on power sector gas plant investment fits in-between the two other nations we analyse in this report. The country already has an extensive network of gas-fired power units running, with total operational capacity of 41.3 GW, but also has a relatively large pipeline of new projects planned, equal to 18.3 GW of potential capacity.

We analysed the impact that further increases in LNG market prices would have on the profitability of Korea's existing gas plant fleet and found that a 50% rise above our base case numbers would lift the average LRMC of running South Korea's existing gas fleet to around $118/MWh which would be uncompetitive with even solar with battery storage technology from 2025.

Figure 7: Impact of changes in LNG price on operating costs of existing South Korean gas plants



Source: Carbon Tracker analysis

3.3 Vietnam

Vietnam stands at a much earlier stage of gas plant development to Japan and South Korea and its current level of exposure to the global LNG market is minimal with just 8.2 GW of operating gas plant capacity, none of which is fuelled by LNG.

As highlighted in the chapter's introduction, Vietnam's lack of LNG infrastructure means that its plans to build a new generation of gas plants will require significant investment in LNG terminals being built alongside[18].

Only two of 13 planned Vietnamese LNG terminal projects are currently under construction, with the first phase alone of the Thi Vai terminal estimated to cost around $285 million to build[19]. Assuming that the second phase of this project goes ahead, this will likely take total spending above the $500 million mark. Vietnam's plan to build a whole pipeline of terminals consequently has the potential for several billion dollars of infrastructure to strand, even before calculating the amount of value at risk of destruction at the power plant level.

The difficulties that the other two nations analysed in this report are experiencing in shifting away from gas dependency in pursuit of net zero emissions should be viewed as a warning to Vietnam to avoid a similar path, as it begins its own transition towards mid-century climate neutrality and coal phase-out.

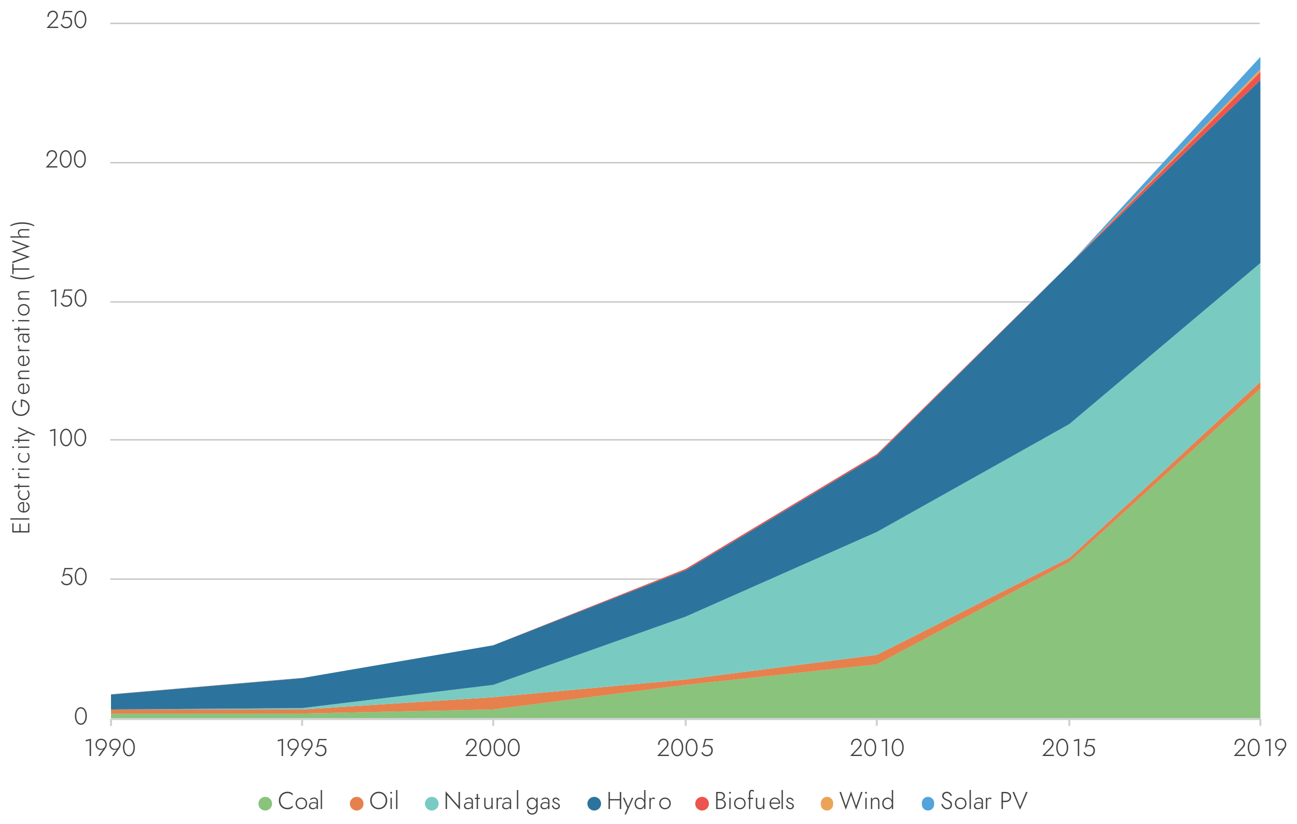
The high levels of price volatility that other Asian nations are currently faced with when fuelling their gas units and the effect that this has had on domestic consumer energy bills should also discourage Vietnamese policy makers from increasing the country's exposure to and dependence upon the LNG market.

This does not mean however that the country should seek instead to invest heavily in domestic gas infrastructure as an alternative means to source its fuel supplies. Investment costs for new renewables are projected to compete favourably with new build gas developments in Vietnam, even when associated costs for battery storage are added (see section 5.3).

18 Vietnam – Countries & Regions (IEA.org)
19 Thi Vai LNG Terminal – Global Energy Monitor Wiki

Renewables' share of total output in Vietnam has risen considerably in recent years however, with combined hydro, wind and solar power generation having turned out above the country's gas-fired power output since at least 2015, as shown in Figure 8 below.

Figure 8: Vietnam electricity generation by source



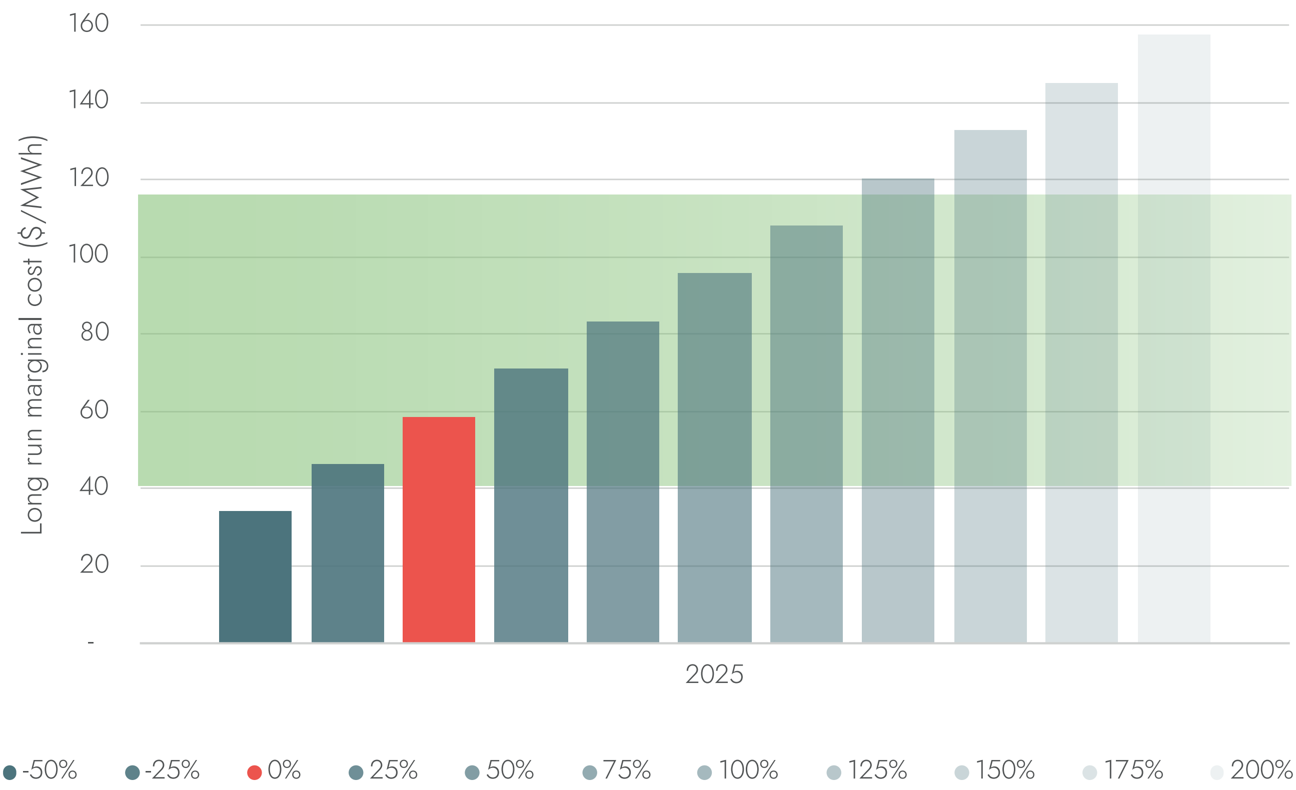
Source: IEA

As we show in Chapter 5, renewable technologies are increasingly cost competitive with planned gas plant developments. Renewables should consequently be the priority sector for the Vietnamese government when seeking to develop the country's energy system infrastructure.

The cost comparison for new gas units in Vietnam against new renewables appears even worse when considering the implications that feasible swings in fuel price could have on projected operating costs for new Vietnamese gas plants.

As shown in Figure 9 below, we project that a 50% increase in fuel price above our base case figures for Vietnam would take the projected average LRMC for the country's planned new build gas units to around $83/MWh in 2025 and to roughly the same cost level that new solar with battery storage capacity is available at (see section 5.3).

Figure 9: Impact of changes in fuel prices on operating costs of planned Vietnamese gas plants



Source: Carbon Tracker analysis

Vietnam requires significant investment in its grid infrastructure for whatever future path it chooses for its energy supplies. The country's rallying demand for energy requires improvements to be made for new capacity to be given grid access and for rising generation to be transmitted.

Centring these improvements around planned gas plant investments, rather than lower cost renewables risks meaning that it will not only be gas power stations left at risk of stranding over the long-term by the cheaper availability of low carbon capacity, but also grid infrastructure and connections.

Vietnamese policy makers need to prevent this risk by future-proofing the grid now and building infrastructure that can accommodate the rapid build-out of renewable technologies. A power system centred around the use of renewables with battery storage will minimise Vietnam's exposure to international commodity price volatility, can be developed at much lower overall cost than the extensive pipeline of gas infrastructure required for the coal-to-gas transition currently in planning, whilst putting the country firmly on track to deliver its net zero emissions by 2050 pledge.

PROJECT FINANCE MODELLING

To determine a project's viability, we estimate overnight investment costs and forecast operating profits, debt financing obligations, and tax expenses.

Investment costs are dependent on the power plant technology (CCGT or OCGT) and are based on in-house estimates.

For our cost estimates, we consider the effect of economy of scale, applying a scale factor of 0.5. The scale factor has been determined to represent the distribution of costs found in our costs database.

$$\text{Investment costs} = \text{Reference cost} \times \left(\frac{\text{Reference capacity}}{\text{Installed capacity}} \right) \times \text{scale factor}$$

Construction periods are assumed to be three years for CCGTs, and two years for OCGTs and steam turbine units.

We also assume a debt financing term of 20 years and a linear depreciation of 30 years.

We did not calculate a project specific WACC because in many cases such granular data was not available or was extremely limited. We assumed the same interest rate during construction and operation of the project. We assumed that the investment is split equally during the years of construction. Financial parameters such as WACC, interest rate and debt-to-equity ratios have been estimated at a country level based on company and country data extracted from Bloomberg.

Operating profit forecasts are based on the modelling assumptions used in our global gas power economics model.

Variable	Japan	South Korea	Vietnam
Project lifetime (years)	30	30	30
Loan (%)	74%	78%	45%
Equity (%)	26%	22%	55%
WACC	2.6%	7.8%	6.0%
Loan term (years)	20	20	20
Interest rate (%)	0.2%	2.1%	1.2%
Capital tax rate (%)	30.6%	25.0%	20.0%

04

Majority of new gas will be value destructive

We complement the data and analysis from Carbon Tracker's global gas power economics model with our project finance model for under-construction and planned gas units in Japan, Vietnam and South Korea.

Our modelling assesses the viability of a gas plant over its lifetime by calculating each project's net present value (NPV). The NPV is the sum of future cash flows, considering investment costs, operating profits, financial costs and taxes of a project, discounted by the weighted average cost of capital (WACC). All else being equal a negative NPV indicates that developers/companies will not recoup their investment and should be taken as an economic signal to developers/companies to cancel the project. We also show sensitivity of project economics to changes in key variables including fuel and debt costs. For simplicity, we aggregate project level data by country to reveal the big picture.

Over 90% of projects in South Korea and Vietnam are value destructive

We use BAU as a reference scenario and NZE2050 as the climate-constrained alternative. Under a BAU scenario we assume that each gas plant will run for 30 years. The NZE2050 achieves net zero emissions by 2050, which corresponds to limiting temperature rises to 1.5 degrees based on emissions to this point. In this scenario, emissions will decline rapidly prior to 2040 meaning almost all unabated gas plants will need to be phased out by 2040, and many much earlier.

We calculate NPV for each project under BAU and NZE2050, which would see a sharp curtailment of the gas plant's operating life. In many instances, the comparison between the two scenarios is superfluous given the vast majority of projects in Vietnam and South Korea are NPV negative even under BAU.

> **"The vast majority of projects in Vietnam and South Korea are NPV negative even under BAU"**

As can be seen in Table 2, 86% of all projects (73 GW) under a BAU scenario are expected to generate a negative NPV, most of which relate to projects in South Korea and Vietnam. This offers a clear conclusion: project developers will likely not recover their initial investment even if the plant runs for its planned lifetime.

In practice, in Vietnam this realisation highlights the likelihood that electricity tariffs will need to rise significantly in order to build new gas plants. Given that any power purchase agreements (PPA) agreed would need to at least equal the LCOE of the project, either consumer prices of electricity would need to significantly rise or, as we believe, the number of PPAs issued will be limited when considering that the LCOE of new renewable technologies is either already lower or will fall below that of new gas over the next few years (see section 5.3). It would be difficult for the Vietnamese government to justify the resulting hike in consumer electricity bills to support new gas when lower cost renewables are already available.

It may also seem counterintuitive that there is less value destruction under NZE2050 compared with BAU in Vietnam but this reflects the extent to which we project Vietnamese units' profitability will come under pressure during latter years of operation owing to the potentially steeper carbon taxes faced over time. Those plants forced to end operations earlier will avoid these higher payments.

Table 2: Economics of new gas projects under BAU and NZE2050

Country	Total NPV of Projects under BAU ($m)	Total NPV of Projects under NZE2050 ($m)	Total GW planned	% of Projects NPV negative BAU	% of Projects NPV negative NZE2050
Japan	10,968	-1,759	10.1	1%	60%
South Korea	-10,043	-11,163	18.3	95%	95%
Vietnam	-61,203	-55,716	56.3	98%	100%
Total	**-60,278**	**-68,638**	**84.7**	**86%**	**94%**

Source: Carbon Tracker analysis

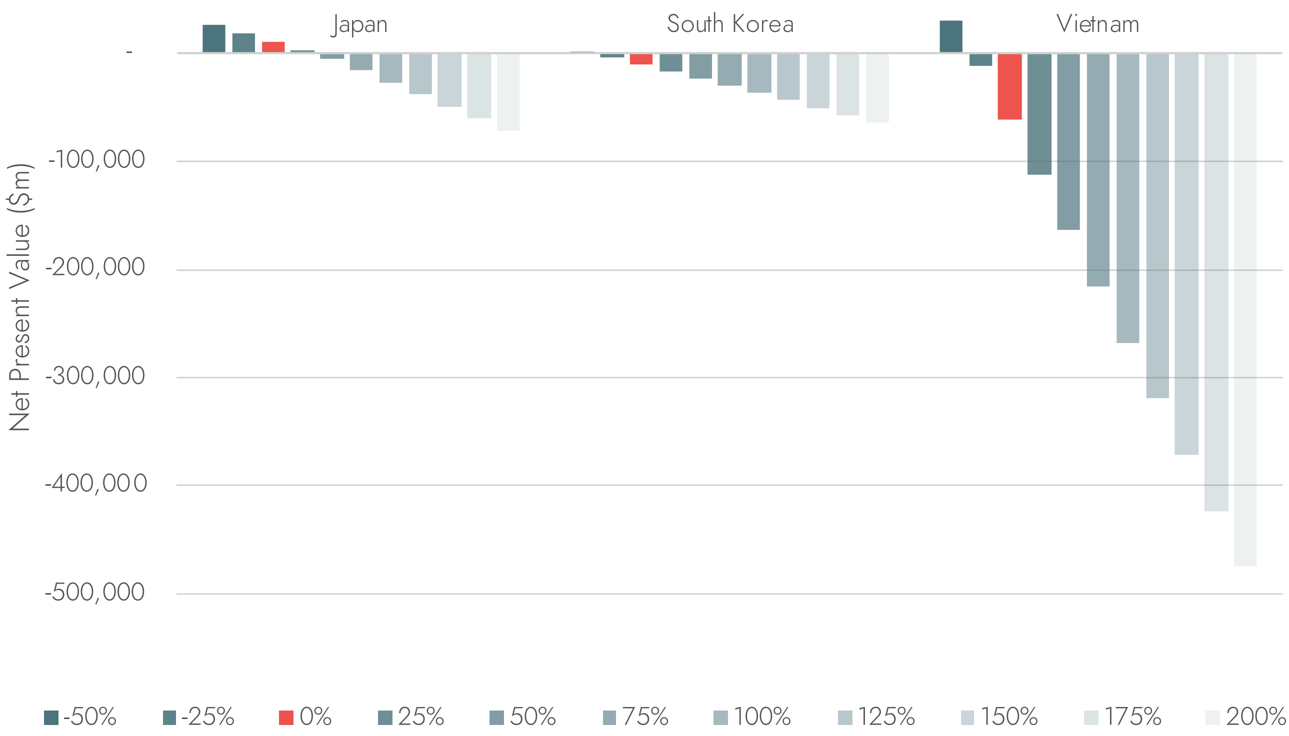
Not surprisingly, under NZE2050 the NPV of projects overall becomes more negative (94%/80 GW), largely owing to a deterioration in economics of Japanese projects as operating profits are foregone on early closure of gas plants even when debt repayments still fall due and capital costs have not been fully recovered.

Even ignoring the longer term impacts of NZE2050, building new gas plants carries with it many shorter-term risks which should not be ignored including fuel price volatility, supply insecurity and, in many cases, higher electricity prices for end users or a higher subsidy burden ultimately borne by taxpayers.

For ease of reference, we aggregate the findings at a country level. This should enable readers to assess the relative risk and rank countries accordingly. However, each project within a country will have its own dynamics (location, efficiency, utilisation rate, etc) and any conclusion should be drawn with reference to the specific project in mind.

Not surprisingly fuel costs are the single largest cost item for a gas plant, meaning plant costs and profitability are highly sensitive to changes in fuel prices. As can be seen in Figure 10, project economics deteriorate quickly even with modest rises in the cost of fuel. For example, all else being equal under BAU, we estimate that a 50% increase in the price of gas versus our base case assumption would swing Japanese gas projects into negative territory with an aggregate NPV of $-5.3bn. For Vietnam, the equivalent price hike renders project economics almost three times as bad and for South Korea almost two and a half times as poor.

Figure 10: Impact of changes in fuel prices on aggregate Net Present Value of new gas plants



Source: Carbon Tracker analysis

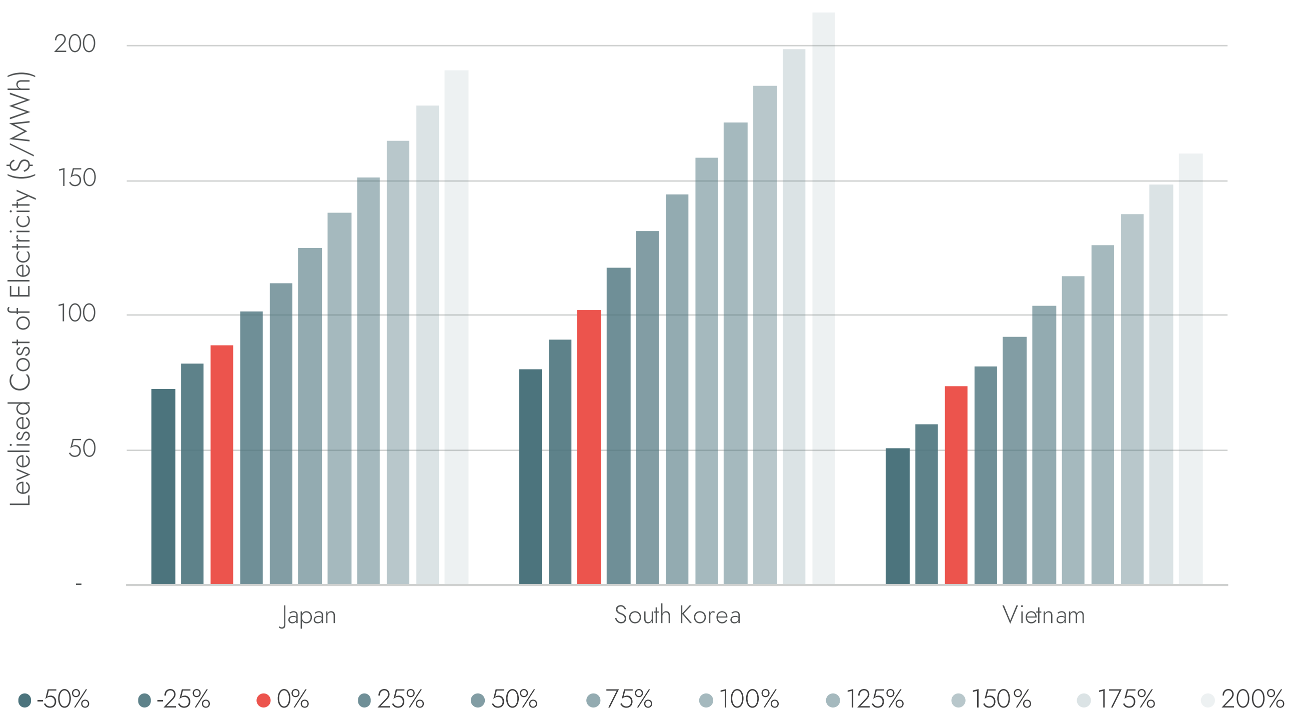
Another way to consider the effect of fuel price rises is on the impact of the LCOE of a project. As shown in Figure 11, all else equal a 50% rise in fuel costs would see the average LCOE rise to $92/MWh from $73/MWh under our base. This would essentially bring forward the competitiveness of solar PV plus storage with a new build gas plant by three years, to 2026, when comparing the LCOE of each.

For Japan, a 50% rise in fuel costs would see the average LCOE rise to $112/MWh compared to $90/MWh in our base case. This would bring forward the competitiveness of solar PV plus storage with a new build gas plant by three years, to 2025, when comparing the LCOE of each.

For South Korea, a 50% rise in fuel costs would see the average LCOE rise to $131/MWh compared to $102/MWh in our base case. This would bring forward the competitiveness of solar PV plus storage with a new build gas plant by three years, to 2024, when comparing the LCOE of each.

In other words, higher LCOEs imply significantly higher electricity prices or a higher subsidy burden. Either way this would leave limited time for new gas to outcompete new renewables on cost.

Figure 11: Impact of changes in fuel prices on LCOE of new gas plant projects



Source: Carbon Tracker analysis

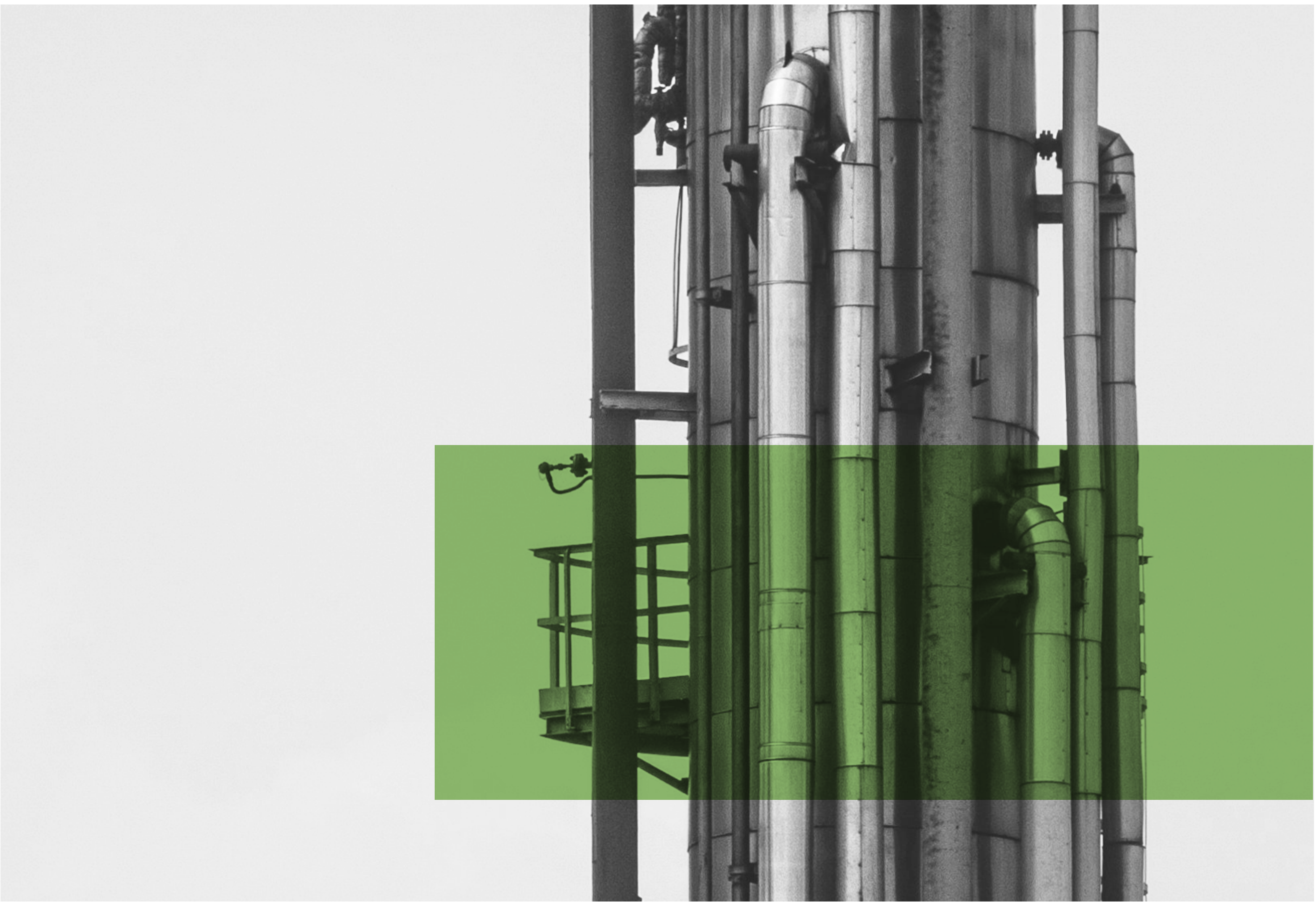
Higher LCOEs imply significantly higher electricity prices or a higher subsidy burden.

In reality, in a regulated market like Vietnam, the cost would primarily be borne by the state utility, Vietnam Electricity (EVN), as consumer tariffs are set by the government and are frequently below the cost of supply. In a liberalised market like Japan, power prices would rise, as was the case in November 2021[21], to reflect the higher input costs, something which would primarily be borne by end users. In South Korea, both KEPCO, the state utility, and end users have been shouldering the burden of higher fuel costs, although until recently the major burden fell on KEPCO[22].

Either way higher costs are typically borne directly or indirectly either by the government (and taxpayers) or end users. Wedding the grid to volatile and high gas prices locks users into a worst-case outcome when compared to lower cost, lower risk and cleaner renewables.

The war in Ukraine is leading to a narrative of more fossil fuel dependence and diversity of suppliers in a bid for energy security. This is misguided as fossil fuel reliance is synonymous with energy insecurity and price volatility. Low-cost renewable sources are a cheap, abundant and clean hedge to this and should be the focus. It is all but impossible to forecast fossil fuel prices, but renewable technologies provide long-term visibility of electricity prices and offer financial stability.

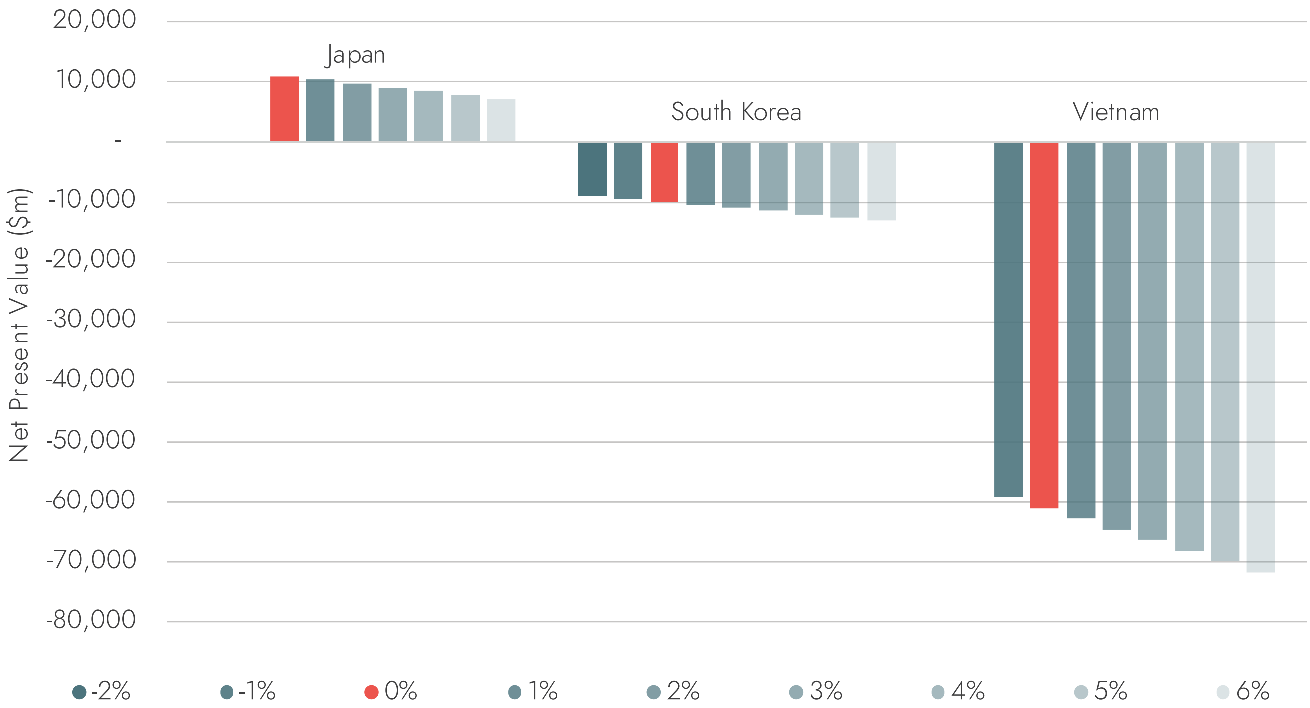
Given we use conservative assumptions for interest costs, we also analyse how increases in debt costs could impact project economics. This is especially pertinent for projects with a longer dated start-up, such as in South Korea, and in countries where financing conditions may be tighter because of less deep capital markets, such as Vietnam (see below).



21 Japan power prices hit near 10-month high | Reuters
22 [Newsmaker] Korea raises electricity price for first time in 8 years (koreaherald.com)

As shown in Figure 12, every 1 percentage point (ppt) increase in the cost of debt over the base case would on average render an additional $1.8 bn in negative NPV for Vietnam, $500m for South Korea and $600m for Japan. We highlight that we are already considering comparatively low costs of debt across the five countries ranging from just 0.2% in the case of Japan to 1.2% for Vietnam and 2.1% for projects in South Korea.

Figure 12: Impact of changes in debt costs on aggregate Net Present Value of new gas plants



Source: Carbon Tracker analysis

We believe there is a risk for funding costs of unabated gas plants to increase over the course of this decade as more lenders restrict financing for fossil fuel investments as has already been the case with coal[23]. Specific gas projects could follow a similar pathway given ever-increasing commitments by institutions and countries to restrict fossil fuel financing and shift to green financing to achieve net zero goals, as evinced at COP26[24]. This is especially relevant for projects in Vietnam and South Korea, many of which are not expected to start either until later this decade or early in the 2030s.

Below, we highlight the key findings at a country level from our project finance analysis. The combined country level totals below are the sum of the outputs of our individual project figures.

23 Coal financing costs surge as investors opt for renewable energy | Coal | The Guardian
24 Finance - UN Climate Change Conference (COP26) at the SEC – Glasgow 2021 (ukcop26.org)

4.1 Japan

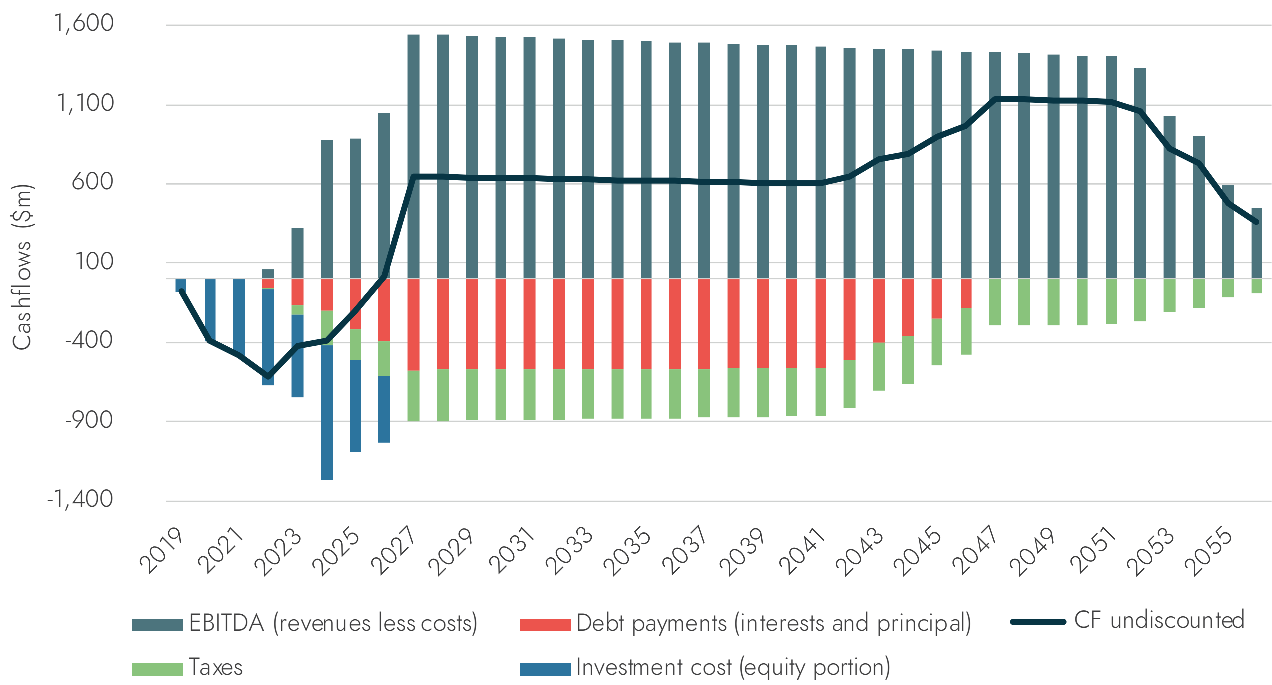
We analysed a planned pipeline of 16 new build gas units equal to a total 10.1 GW of potential generation capacity. With the exception of one unit of 150 MW all planned units are Combined Cycle Gas Turbines (CCGTs) with an average size of 630 MW.

We find that almost all new gas projects in Japan (99%) are expected to generate a positive NPV of $11bn over their lifetime under BAU. This is driven by high power tariffs and capacity payments. The retirement of older, less efficient plants, which are being replaced with newer and more efficient ones, also helps explain the profitability outlook. This is compounded by the fact that there is a lack of viable alternatives for power generation given hitherto limited renewables deployment, no grid interconnection with other countries and slow re-commissioning of nuclear plants.

Profitability is also boosted owing to a minimal impact from carbon taxes (we assume a flat carbon tax of around $3/t which is the current level). We find that carbon taxes are too low to be effective as an emissions rationing mechanism given the large majority of new gas units are forecast to be highly profitable. All else equal, we estimate that a carbon tax of approximately $60/t would render the aggregate project value of new build gas in Japan negative and an average LCOE of $107/MWh. It is worth noting that $60/t is approximately 30% below the current EU carbon price of €78/t[25] ($86/t)[26]. Assuming an equivalent carbon price to the EU would see a rise in average LCOE to US$116/MWh from a base case of $90/MWh.

Project economics are also supported by extremely low assumed debt costs, which, as we discuss above, may not turn out to be the case.

Figure 13: Aggregate undiscounted project cash flows for new build gas in Japan BAU



Source: Carbon Tracker analysis

25 Pricing data taken from Ember as of 1 April 2022
26 Pricing data taken from Bloomberg as of 1 April 2022

Under NZE2050 we find that 60% of new gas projects in Japan would be unviable generating an aggregate NPV of -$1.8bn. On average we find that under NZE2050 gas units would only be operational for 10 years before being shuttered thus depriving the owner of two thirds of the project's anticipated cash flows even while debt principal and interest remain outstanding.

The parent companies of the majority of projects being developed in Japan are publicly traded TEPCO and Chubu Electric Power (4.6 GW attributable), and Kyushu Electric Power and Tokyo Gas (2 GW). Under a NZE2050 pathway it is these companies, and ultimately the shareholders, that would bear the risk of losses from the early closure of plants.

We acknowledge that some developers may be anticipating full lifetimes for gas units based on their intention to install Carbon Capture and Storage (CCS) technology. However, we caution this remains a nascent technology with limited success to date and, current, prohibitively high capital costs. The uncertainties regarding retrofitting costs for CCS may mean that installation is unfeasible even in the medium-term.

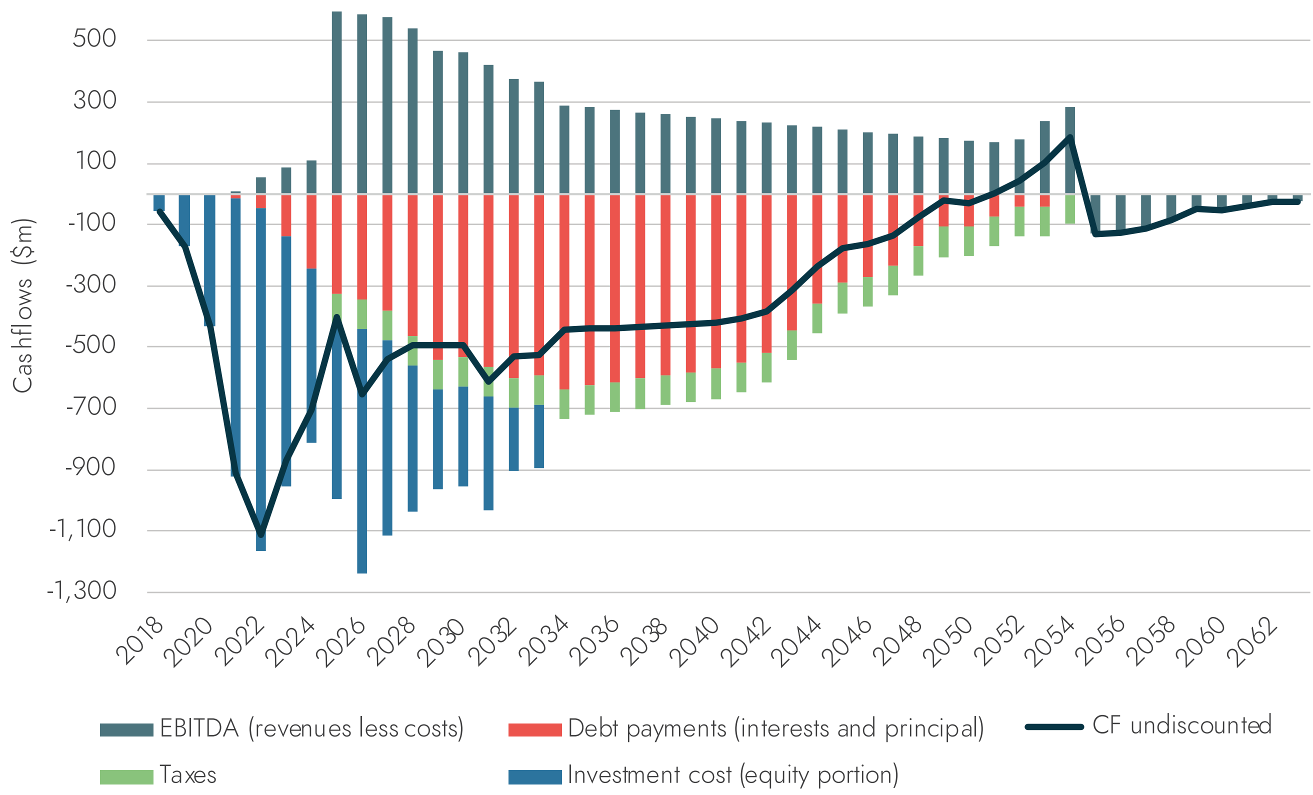
4.2 South Korea

We analysed a planned pipeline of 30 new build gas units equal to a total 18.3 GW of potential generation capacity. With the exception of one unit of 500 MW all planned units are CCGTs with an average size of 610 MW.

We find that almost all (95%) new gas projects in South Korea are expected to generate a negative NPV of -$10bn over their lifetime under BAU. Although revenues are sufficient to offset operating costs, overall unit profitability is comparatively low owing to assumed low capacity factors and, once debt, taxes and interest repayments are considered, project economics appear weak with cash flows insufficient to service these obligations. It is worth pointing out that current low capacity factors for gas units are attributable to excess supply. The oversupply situation is likely to be exacerbated with new builds coming onstream even accounting for coal plant retirements and incremental demand.

We highlight that all else equal even if capacity factors were 50% higher than our base case assumption for South Korea, many projects would still be value destructive with an aggregate NPV of -$4bn.

Figure 14: Aggregate undiscounted project cash flows for new build gas in South Korea BAU



Source: Carbon Tracker analysis

Under NZE2050, we find that 95% of new gas projects in South Korea would be unviable generating an aggregate NPV of -$11.2bn. On average, we find that under NZE2050 gas units would only be operational for 9 years before being shuttered thus depriving the owner of over two thirds of the project's anticipated cash flows.

Publicly traded KEPCO is the parent company of the majority of projects being developed in South Korea. KEPCO is majority-owned by the state and has 12 GW of projects attributable to it. Under a NZE2050 pathway it is ultimately the taxpayers that would bear most of the risk of early closure of plants assuming the government stepped in with compensation for losses suffered by the company.

Our analysis also shows that South Korea's long-dated project pipeline is particularly risky. We estimate that all gas projects from 2027 onwards will have a higher LCOE than solar plus storage, which equates to 15 projects (9.1 GW), or 50% of all projects by capacity. In other words, within just five years firm renewables will outcompete all future gas plant projects on cost in South Korea.

It is worth highlighting that around half of new gas projects in South Korea are coal-to-gas switching projects. This may mean that the impetus to approve projects could outweigh the simple economics of an individual project and projects may go ahead regardless of whether or not they are value accretive. Regardless of this our analysis shows under a NZE2050 scenario there will be limited time to operate the gas units before they are retired implying the opportunity for gas as a transition fuel will be very short-lived.

"South Korea's long-dated project pipeline is particularly risky"

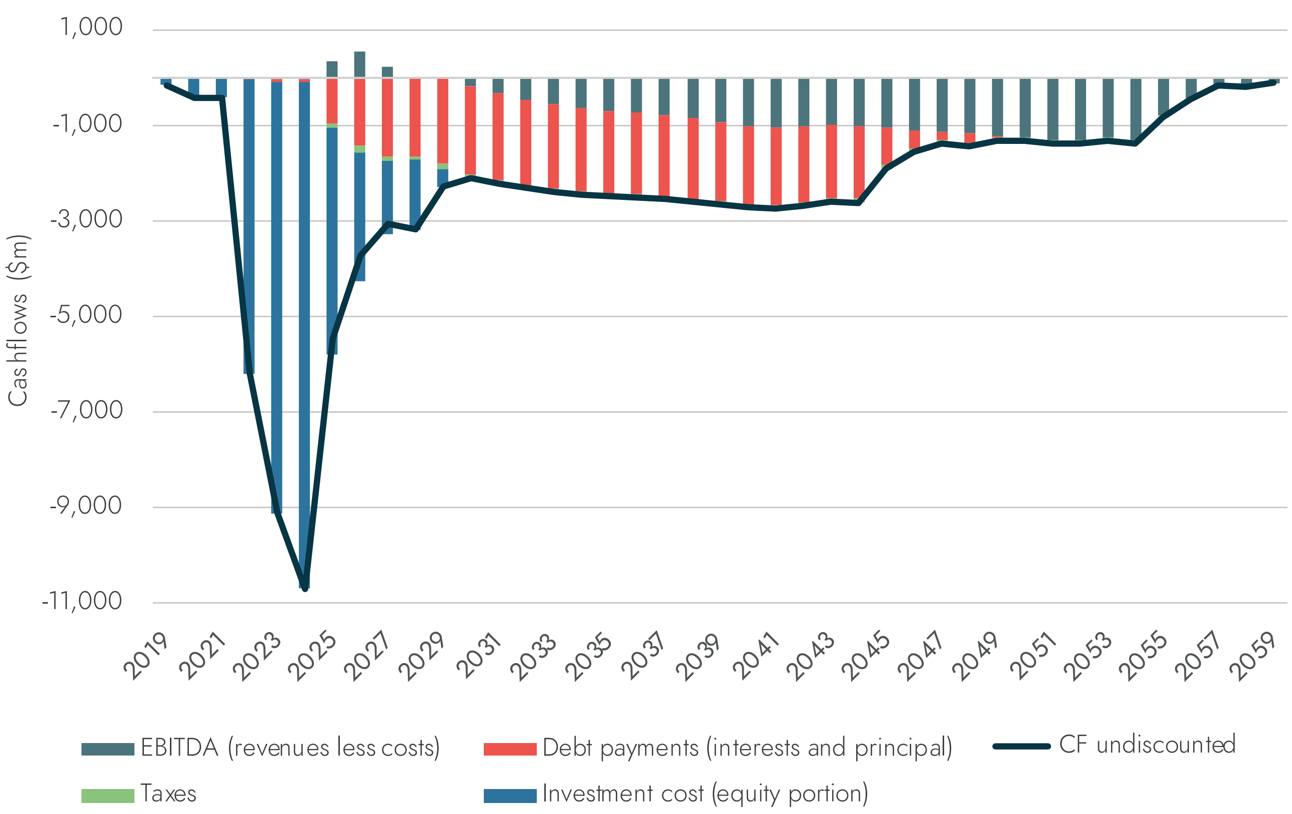
4.3 Vietnam

We analysed a planned pipeline of 37 new build gas units equal to a total 56.3 GW of potential generation capacity. All planned units are CCGTs with an average size of 1,500 MW. However, we caution that some of the larger projects are significantly bigger than anything that has yet been developed in the country and, as such, because of factor constraints such as scale complexity and/or financing availability, these projects may only be part-developed, implying that average project size will likely come in well below 1,500 MW.

Of the 37 new units, many will rely on LNG as their input fuel with only 15 units (12.5 GW) planning to use domestic gas. In our analysis, we assume around a 100% price premium for imported LNG compared to domestic gas. This premium in itself should be a red flag for policymakers. Not only is Vietnam potentially locking the grid into more expensive fossil fuel power compared to low cost, low risk renewables, the choice to rely on LNG imports hikes costs even more.

We find that all new gas projects in Vietnam are expected to generate a negative NPV of -$61.2bn over their lifetime under BAU. Revenues are generally insufficient to offset operating costs, especially in later years and once debt, taxes and interest repayments are considered, project economics appear even worse.

Figure 15: Aggregate undiscounted project cash flows for new build gas in Vietnam BAU



Source: Carbon Tracker analysis

Under NZE2050, we find all new gas projects in Vietnam would be unviable generating an aggregate NPV of -$55.7bn. On average, we find that under NZE2050 gas units would only be operational for 4 years before being retired thus depriving the owner of the vast majority of the project's anticipated cash flows. The extremely short operating life is a clear signal that such units should not be built as they are not compatible with a net zero scenario.

As discussed, the improved NPV under NZE2050 compared with BAU in Vietnam reflects the extent to which we project Vietnamese units' profitability will come under pressure during latter years of operation owing to the steeper carbon taxes faced over time. Those plants forced to end operations earlier will avoid these higher payments.

Vietnam's regulated market structure and availability of PPAs for new gas plants does raise the possibility that projects in receipt of these support contracts may potentially generate a positive NPV. Assuming that for a project to break even the PPA agreed would need to at least equal the plant's estimated LCOE, however, we estimate that electricity prices in the country would need to increase by around 30% for aggregate NPV to turn positive, implying a 30% hike in end user tariffs.

Given that the LCOE of new renewable technologies is either already lower or will fall below that of new gas over the next few years (see section 5.3), it would be difficult for the Vietnamese government to justify this hike in consumer electricity bills to support new gas when lower cost renewables are already available.

Connected to the above point, is the potential lack of financing availability for projects in Vietnam. Not only does the existing market structure (no country-wide gas market, opaque bilateral power agreements, etc) make it difficult to develop projects on a large scale, which is what Vietnam is trying to do, but also the non-investment credit rating of Vietnam may make financial conditions much tighter than in Japan or South Korea.

As highlighted in a recent report by IEEFA[27], many proposed projects in Vietnam aim to achieve financial close during a narrow window this decade (2025-2027) with potential constraints on financing availability a risk, especially in sub-investment credit grade sovereign countries like Vietnam, where lenders often require additional assurances and guarantees from the government, but which, owing to recent law changes, are unlikely to be forthcoming. This means that there simply might not be the available financing to accommodate 56 GW of new gas plant projects.

Even if the above challenges are overcome, we would also be very cautious about the number of projects that could feasibly go ahead from a practical standpoint. Vietnam has a huge pipeline of new gas projects relative to its existing base of gas plants with the draft Power Development Plan (PDP8) targeting just over 20 GW of gas capacity this decade alone[28]. There is a lack of proven track record in developing gas projects at scale in Vietnam with limited gas-fired power capacity having been developed over the last decade.

In addition, the majority of planned LNG power plants rely on LNG terminals being developed alongside. In other words, many of the proposed gas plants are only viable if additional capex is spent on the related LNG infrastructure. Given the inherent uncertainties of mutually contingent projects, a large number of planned LNG units may never get out of the starting blocks. We highlight that Vietnam has significant domestic gas reserves, which are cheaper and less volatile than imported LNG. Should upstream development happen at scale it could potentially change the economics of the gas dependent plants, but it would almost certainly render many of the investments in LNG import infrastructure as stranded. This in itself should be a stark warning to developers in Vietnam. Nevertheless, the cost arguments fall heavily on the side of renewable technologies and development of any gas reserves would be incompatible with climate targets.

27 Examining-Cracks-in-Emerging-Asias-LNG-to-Power-Value-Chain_December-2021.pdf (ieefa.org) pp43,47
28 The Proposed Vietnam PDP8 Update and the Risks From the Coal Pivot (energytracker.asia)

The mix of parent companies for projects to be developed in Vietnam is more fragmented than that of Japan or South Korea and include international, domestic, state-owned and publicly traded companies. Millenium Petroleum Group (9.6 GW attributable), PetroVietnam (6 GW), EVN (5.1 GW), AES Corporation (2.3 GW), Exxon Mobil and J-Power (each with 1.5 GW) are the most relevant project developers. In this instance, under a NZE2050 pathway it is likely to be a combination of shareholders and taxpayers who bear the risk for early closure of projects.

Aside from the fact that developing new unabated gas plants is incompatible with achieving net zero targets, it is also worth highlighting that Japan, South Korea and Vietnam are signatories to the Global Methane Pledge, which aims to reduce methane emissions by 30% by 2030. The current planned gas projects in these countries appear at odds with the objectives of the pledge.

05

Lower cost renewables will leave only minimal grid role for gas

The rationale behind continuing to invest in gas capacity appears highly questionable when the comparative economics to cheaper and lower risk renewables are laid out, especially when the wider context of nations planning to align their power system emissions trajectories with net zero pathways are considered.

In this chapter, we present a cost comparison analysis between the projected lifetime operating costs of new renewables capacity in the three countries assessed in this report with the associated costs of investing in and running a gas-fired power station.

We find that the economics steer overwhelmingly in the direction of new renewables capacity, with both new solar and onshore wind power projected to be cheaper to build and operate than new gas units in each of the three nations. Even offshore wind developments will be lower-cost investments than the extensive pipeline of new-build gas plants that Vietnam has in planning within three years.

Given typical planning and construction timeframes of at least four years for new gas, any units that move ahead to development could face constrained running hours from day one amid strong competition from lower cost renewables.

We compare the levelised cost of energy (LCOE) for new renewables capacity with both the LCOE and long-run marginal cost (LRMC) of running a new gas-fired power unit. We have provided full details of the calculations for each of these metrics in the appendix.

For Japan and South Korea, we also compare the costs of investing in new renewables with the projected costs of continuing to run existing gas plant units. We find that even new renewables with storage will become cost-competitive with current facilities within 10 years, leaving such assets at high risk of stranding this decade.

Here we profile each of the three countries we have assessed and present a detailed cost comparison for both their existing and planned gas plants against estimated costs for building and running new renewables capacity.

5.1 Japan

Japan's renewable power generation capacity has ramped up sharply in recent years, with the country ending 2020 with approximately 103.5 GW installed[29]. However, these installations still represent less than a third of Japan's total generation capacity, however.

The Japanese government pledged in late-2020 to steer the country towards a net zero position for its greenhouse gas emissions by mid-century, this goal was then enshrined into national law in 2021[30]. As part of this, the country is planning for a 36-38% share for renewables within the electricity sector by 2030, but local environmental campaigners have called for the ambition of this interim goal to be raised to 50%[31].

Solar

Solar power capacity comfortably makes up the bulk of Japan's total renewable capacity, with just under 69 GW installed by the end of 2020, having more-than-doubled over the 2015-20 period.

This rapid deployment rate has pulled down associated investment costs for new capacity to the point at which we project it will be cheaper to build and operate new solar in Japan than a new gas-fired power station by just 2024 when directly comparing the LCOE of each[32]. This inflection point would have come sooner, but challenging terrain heightening land build costs and frequent natural disasters lifting insurance premiums mean that renewable construction costs in Japan are higher than they would be under similar market conditions elsewhere[33].

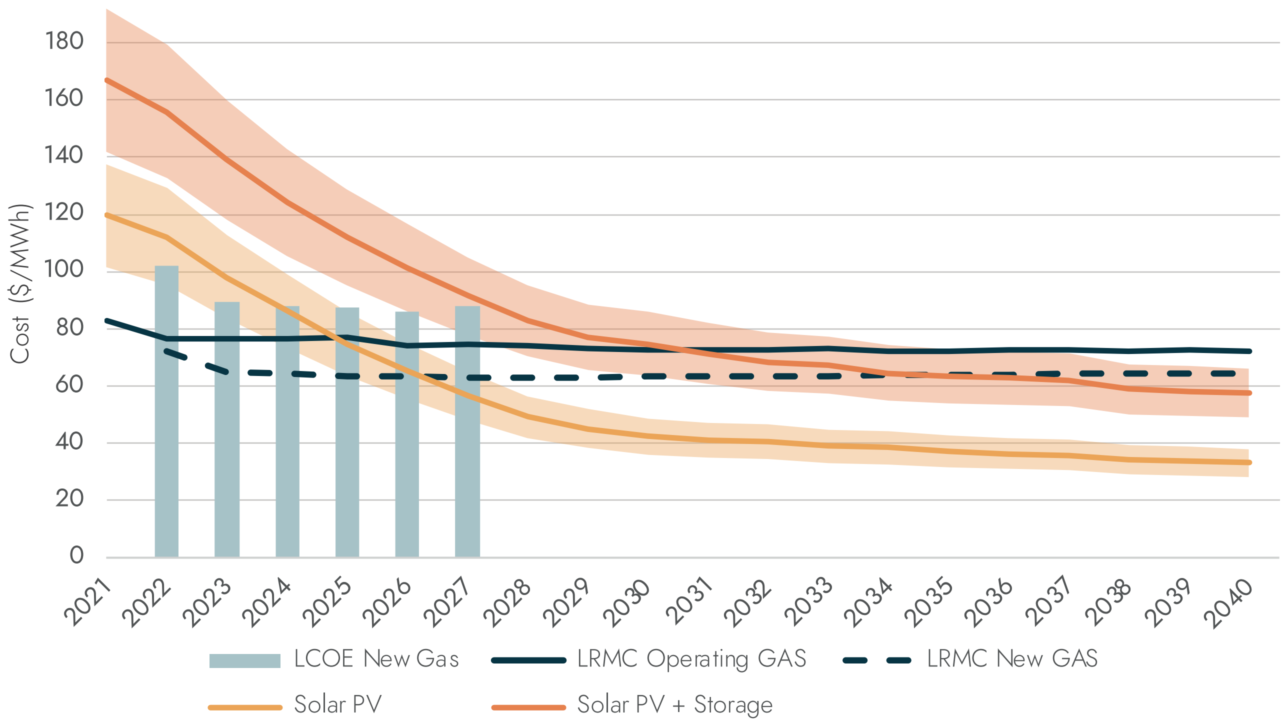
We also project that new solar will become cost competitive with Japan's existing gas plant power capacity by 2025, while even solar farms with battery storage capacity included in the project are expected to become cheaper overall investments by 2031, as shown in Figure 16 below. This means that Japan will have a low carbon energy source able to provide comparable flexibility services to a gas unit available at lower cost to the system within a decade and should allow the country to plan its phase-out of power sector gas use in line with its net zero emissions by 2050 target.

Although we have not carried out a full systems analysis for this research and have instead performed a cost comparison assessment of technologies, we accept that battery storage will likely be a vital component of future low carbon energy portfolios to ensure security of power supply. The four-hour lithium-ion battery technology type is sufficient to mean that excess renewable energy produced earlier in the day can be shifted to and supplied to the grid during the peak demand evening hours and therefore provide flexibility services comparable with a peaking gas plant.

This may leave some flexible small-scale gas units to provide backup grid supplies for the handful of winter hours when cold snaps drive demand spikes, but with alternative sources of grid flexibility continuously arising and the urgent need for rapid power sector decarbonisation, this should be the limit to such facilities' future role.

29 Energy Profile – Japan (IRENA.org)
30 Japan's legal commitment to carbon-neutral 2050 must be catalyst for change (Mainichi.jp)
31 Japan will become carbon neutral by 2050, PM pledges (TheGuardian.com)
32 Based on mid-range scenario cost estimates. Low- and high-range scenario cost estimates shown at lower and upper ends of shading on charts. Full details of each scenario are available in the report methodology.
33 What are the high cost factors for renewable energy in Japan? – Research Project on Renewable Energy Economics, Kyoto University

Figure 16: Cost estimates for new solar + battery storage versus gas plants in Japan



Source: Carbon Tracker analysis

Onshore wind

Challenging geographical conditions characterised by mountainous terrain and multiple islands creating difficulties for the construction of required grid connections have held back the deployment of onshore wind capacity in Japan, which stood at just under 4.5 GW in 2020[34].

Nonetheless, despite these challenges, the Asia Wind Energy Association has assessed Japan as having the potential for up to 144 GW of installed onshore wind capacity[35].

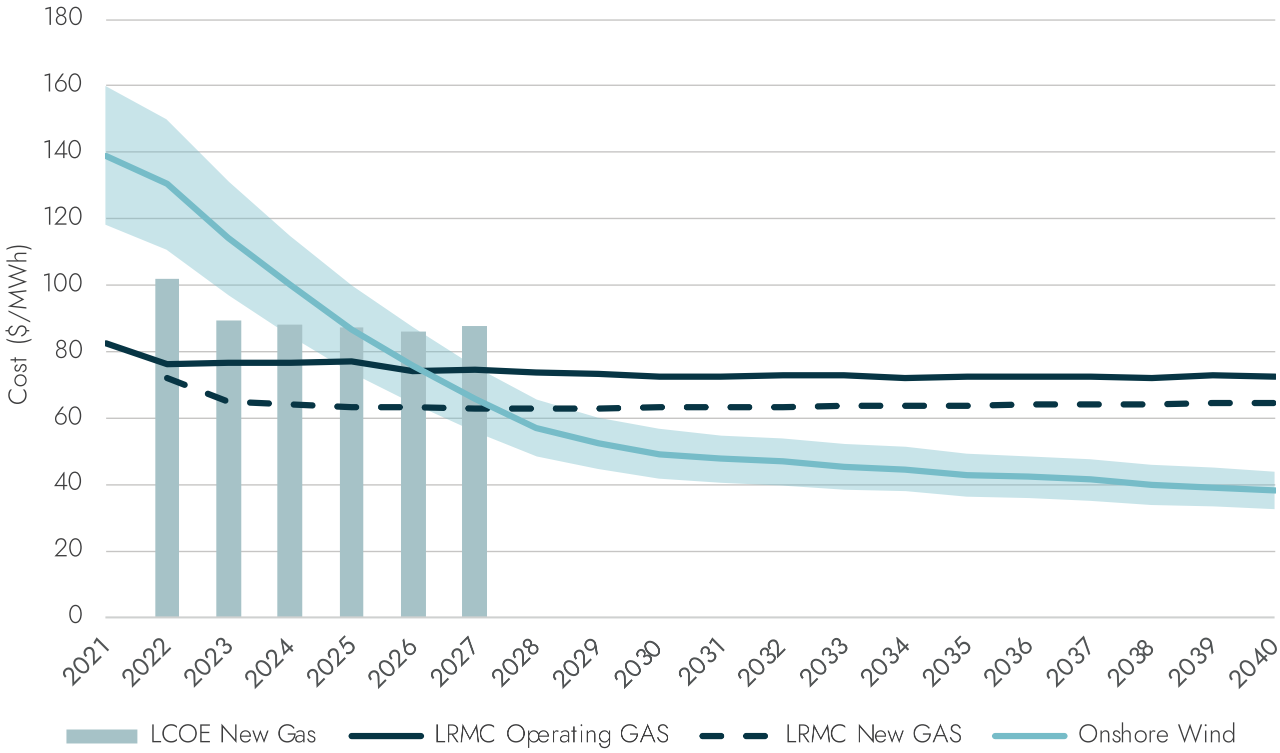
The rate of deployment has shown signs of improvement, with capacity growing by more than 50% over the 2015-20 period but will need to accelerate further if the country's long-term climate targets are to be achievable.

Our analysis show that on an economic basis, there appears little reason for construction of such projects not to quicken, with new onshore wind farms projected to be cheaper overall investments than new gas plants in Japan from 2025 under our mid-range scenario estimates when comparing the LCOE of both.

The timeframe for when new onshore wind farms in Japan become cost competitive with the country's existing gas plant capacity comes slightly later, but still by 2027, it will be cheaper to build and operate new onshore wind power capacity in the country than continuing to operate a gas unit. This inflection point is brought forward by two years to 2025 under our low-range scenario, which is characterised by lower upfront capital costs, lower interest and tax rates, and lower operational and maintenance costs.

34 Energy Profile – Japan (IRENA.org)
35 Market Overview – Japan (AsiaWind.org)

Figure 17: Cost estimates for new onshore wind versus gas plants in Japan



Source: Carbon Tracker analysis

Offshore wind

With Japan having one of the largest sea territories in the world, the country has regularly been flagged as having huge potential for offshore wind sector development.

The country only had an estimated 65 MW of operational capacity of this technology type installed at the end of 2020[36], but the Japanese government has targeted rapid development in the sector over the remainder of the decade, with a goal of 10 GW of capacity by 2030, rising to 30-45 GW by 2040[37].

The Asia Wind Energy Association estimates that the country ultimately has potential for more than 600 GW of capacity, given the enormity of its sea territory[38].

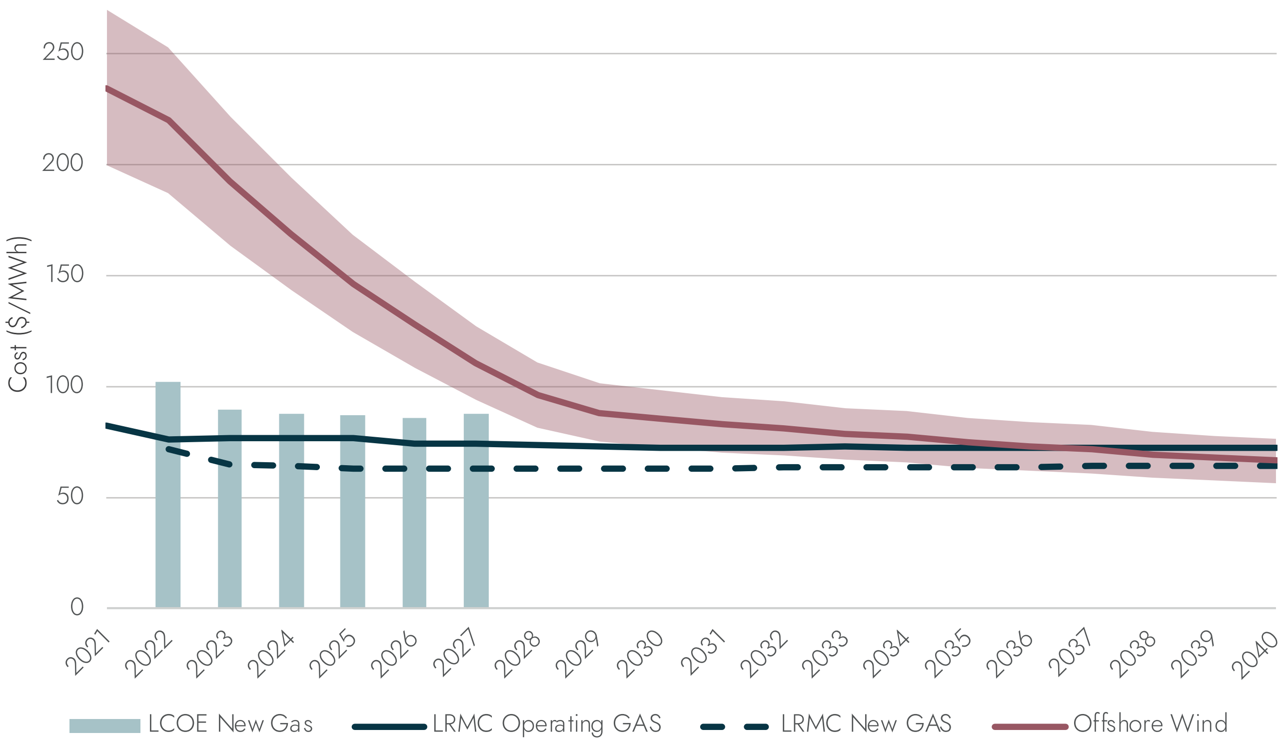
Offshore wind farms can deliver capacity factors of more than 40%, with this figure projected to reach levels well above 50% by the end of this decade as turbine infrastructure continues to improve[39], meaning reliability and production levels are comparable to that of gas plant facilities even without storage capacity installed.

36 Japan Inc. ups its game in offshore wind power (IHSMarkit.com)
37 Japan launches third offshore wind auction (Offshorewind.biz)
38 Market Overview – Japan (AsiaWind.org)
39 Future of Wind – Deployment, investment, technology, grid integration and socio-economic aspects – International Renewable Energy Agency

High construction costs, driven largely by deep seabed conditions, have previously deterred developers and policy makers from investing more in the Japanese offshore wind sector, and while costs do remain high compared with other Asian nations, we still project that new offshore wind farms are still on track to become cheaper overall investments than continuing to run existing gas units in Japan during the mid-2030s under our mid-range scenario estimates. These account for the Japanese government delivering its specified target of driving down offshore wind investment costs to around $85/MWh and $75/MWh by 2030 and 2035, respectively.

As shown in Figure 18 below, this inflection point could be brought forward by several years to the early part of the 2030s under our most ambitious, low-range cost projections.

Figure 18: Cost estimates for new offshore wind versus gas plants in Japan



Source: Carbon Tracker analysis

Given Japan's high degree of maritime expertise and standard of port facilities, we believe that there is every chance that the costs associated with offshore wind development could come down quicker than our conservative mid-range estimates once the first initial projects planned are launched and so the low-range scenario should not be considered unrealistic by any means. Offshore wind farm developments are already being delivered in Europe at cost levels of only around $80/MWh, while globally the average LCOE for the technology has already fallen below $95/MWh[40], with one Japanese project developer already last year accepting a power purchase agreement at a price only just above $100/MWh[41].

40 Offshore Wind Market Report: 2021 Edition – US Department of Energy
41 Mitsubishi Corporation wins a bid for the shocking "11.99 yen" in 3 offshore wind power areas – Nikkeibp.com

5.2 South Korea

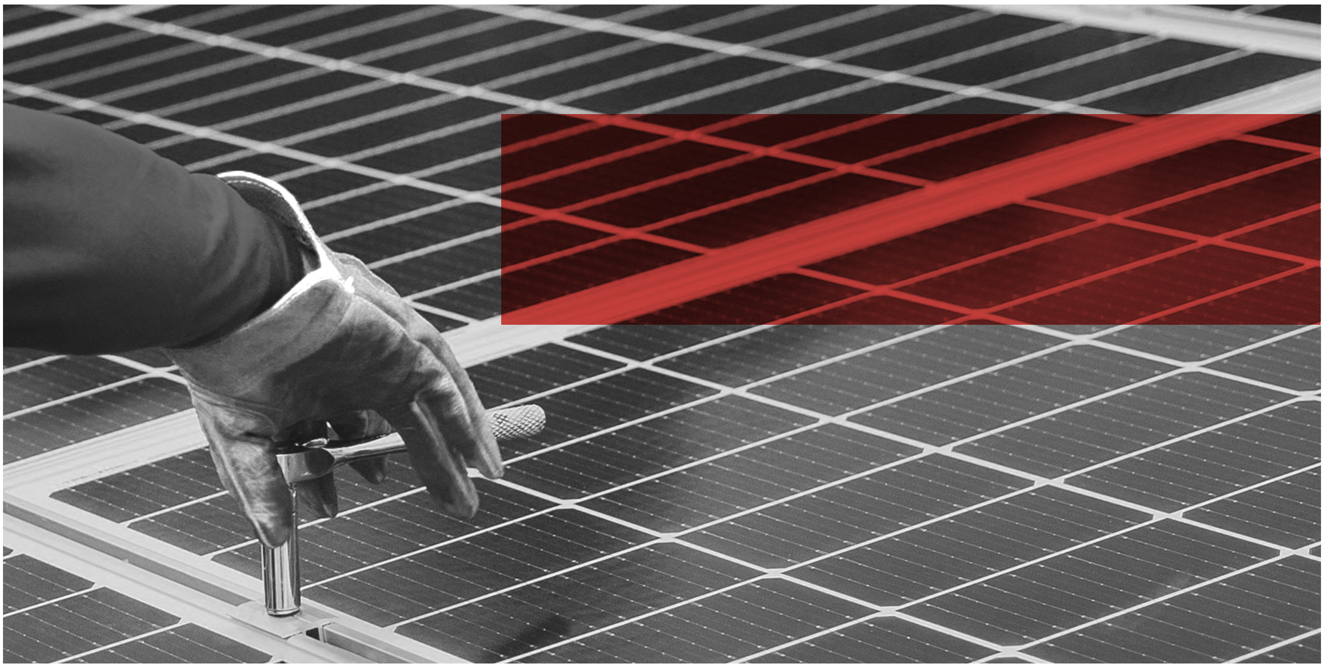
South Korea's renewable capacity is alarmingly low given the country's ambition to reach climate neutrality by mid-century and size of its economy.

The nation was estimated to have only around 21 GW of renewables installed by the end of the 2020 calendar year[42], with output produced from this capacity accounting for just 6.5% of South Korea's total power generation in that year, even when including supplies from biofuel units. This is the lowest share for renewables in the power mix of any of the 38 OECD member countries[43].

South Korea has a goal of raising renewables' share of the electricity mix to around 40% by 2034[44], although this has faced criticism from environmental organisations for a lack of ambition[45].

Research carried out by Carbon Tracker in 2021 in partnership with South Korea-based non-governmental organisation Solutions for Our Climate and Chungnam National University showed that this 40% share target for renewables could be delivered as early as 2028 if the government is ambitious enough, however. This projection was based on year-over-year growth rates of 32% for solar and 27% for wind being achievable following the results of a least-cost optimisation analysis of renewables investment in the country.

Despite South Korea's much lower level of renewables deployment, more favourable geographical conditions for installation are expected to mean that project costs for build in Korea turn out comparatively lower than in Japan. Costs for new renewables build in South Korea also compete very favourably with gas in the country.



42 Energy Profile – South Korea (IRENA.org)
43 The Main Barriers to the Renewable Energy Transition in South Korea (EnergyTracker.asia)
44 Energy Profile – South Korea (IRENA.org)
45 South Korea's climate roadmap fails to impress businesses, environmentalists (IHSMarkit.com)

Solar

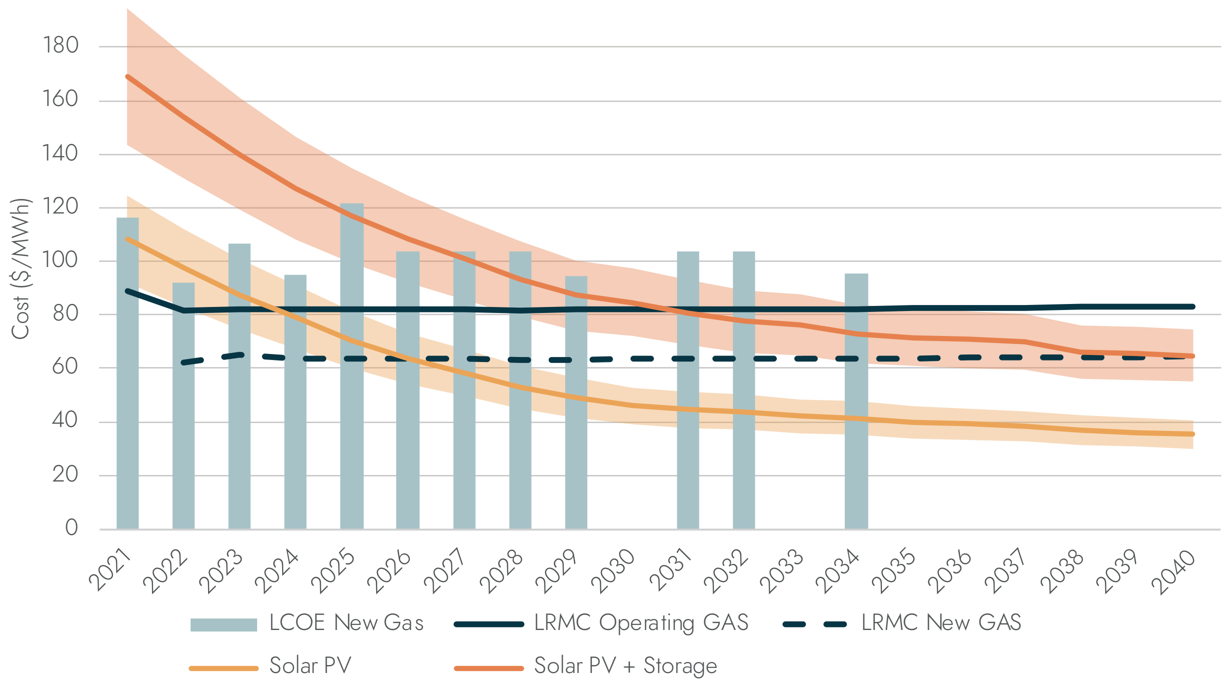
Solar farms make up comfortably the largest share of South Korea's current renewables capacity. The country had around 14.6 GW of solar power installed by the end of 2020, with this having risen more than threefold over the 2015-20 period[46].

This rapid deployment rate has helped to significantly pull-down costs for the technology, and we project that it is already cheaper to invest and run a new solar farm in the country than to build and operate a new gas-fired power station, when directly comparing the LCOEs of both technologies.

In fact, as shown on Figure 19 below, by just 2025, it will be cheaper to build and operate a new solar farm with battery storage capacity installed than it will be to invest in new gas in the country, leaving any new build units planning for extensive operating lifetimes of beyond this length of time at risk of stranding.

Even when comparing against existing gas capacity in South Korea, we find that solar farms become cost competitive by only 2024, while solar with battery storage is then projected to become a cheaper overall investment than continuing to run existing gas units during the early-2030s.

Figure 19: Cost estimates for new solar + battery storage versus gas plants in South Korea



Source: Carbon Tracker analysis

46 Energy Profile – South Korea (IRENA.org)

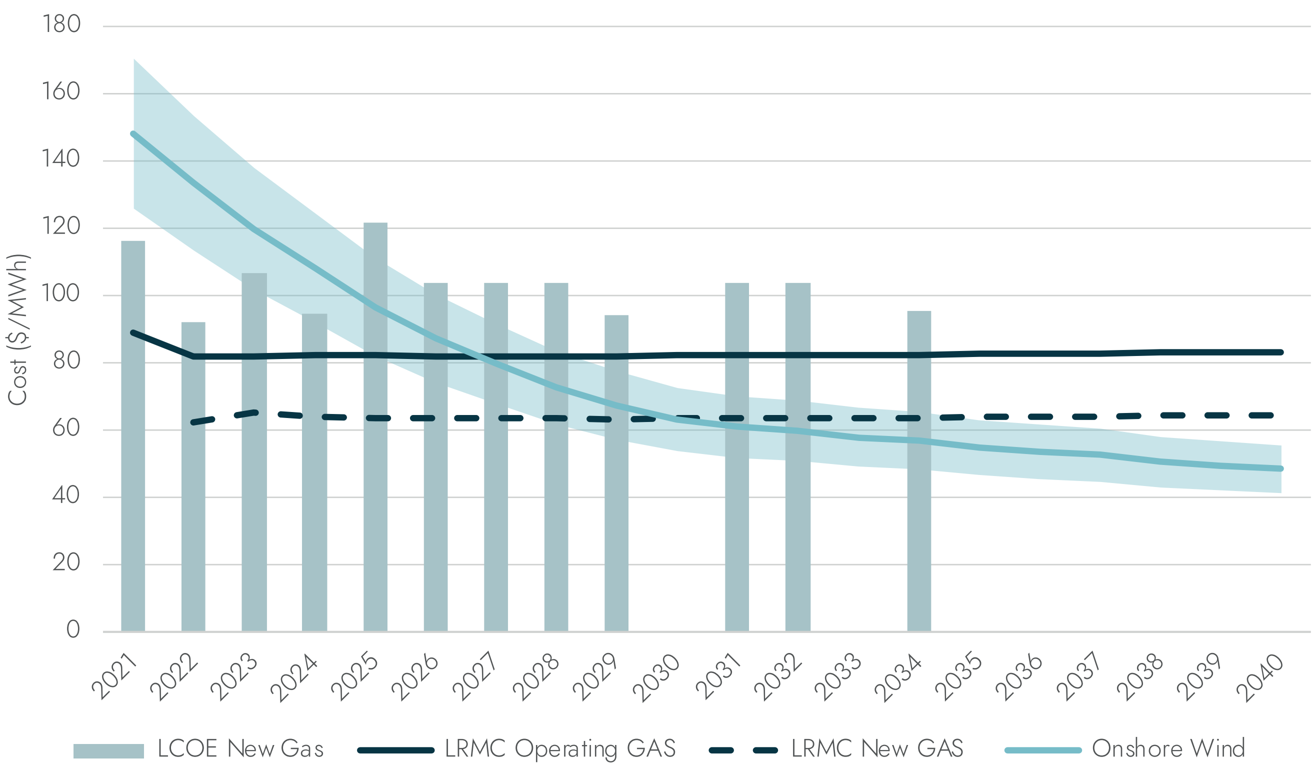
Onshore wind

Given South Korea's low starting point for wind power, having ended 2020 with only around 1.6 GW of capacity[47], the rate at which operating, and installation costs come down are slower than we project for solar in the country. Nonetheless, we project that onshore wind farms in the country will still quickly become cost competitive with gas units if deployment is ramped up over the coming years.

Our analysis projects that by just 2025, a new onshore wind farm in South Korea will become a cheaper overall investment than a new gas-fired power station in the country, when comparing the LCOEs of both. This inflection point could be reached earlier, however, with new onshore wind beating new gas projects from as early as 2023 under our low-range scenario estimates.

As shown in Figure 20 below, we also project that by 2027, it will be cheaper for South Korea to build and operate new onshore wind capacity than continuing to run existing gas units. This could be achieved as early as 2025 under our low-range scenario estimates, however. Continuing to pile long-term capital into existing gas units appears to consequently be becoming a highly risky strategy given the strong competition that renewables appear likely to pose over the coming years, when considering the knock-on effects that these developments will have for gas plant usage and revenues.

Figure 20: Cost estimates for new onshore wind versus gas plants in South Korea



Source: Carbon Tracker analysis

47 Energy Profile – South Korea (IRENA.org)

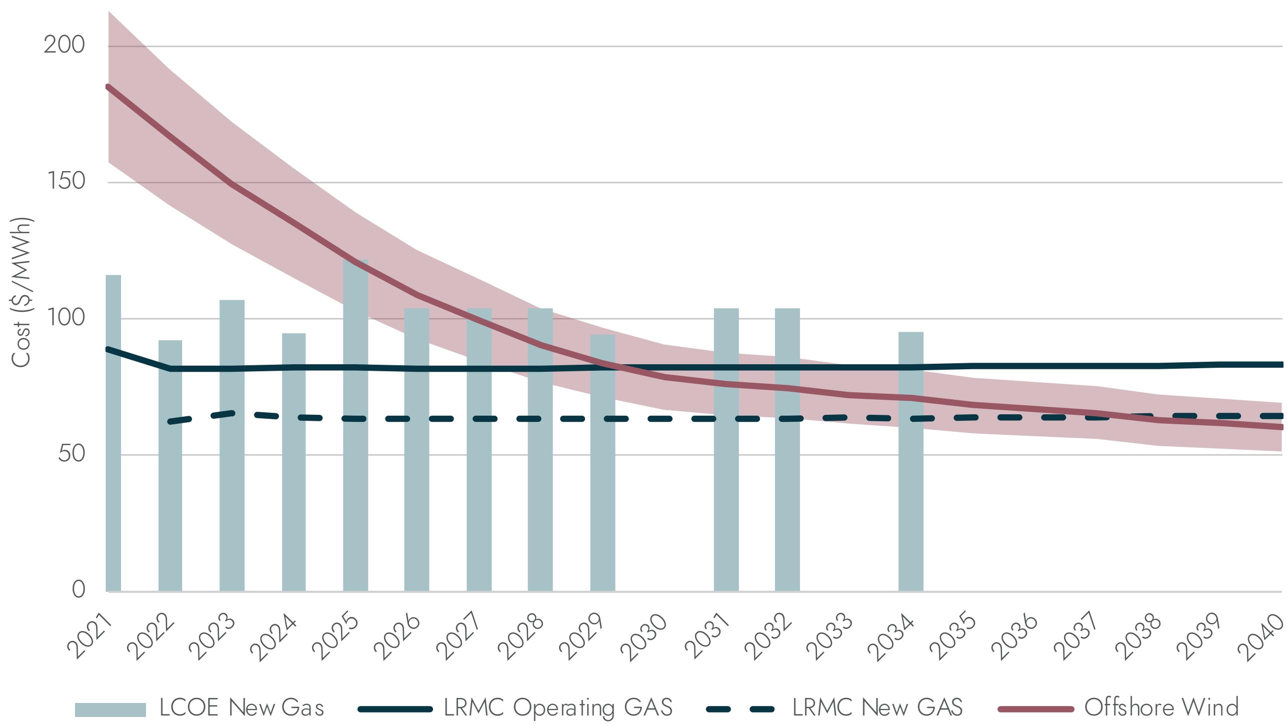
Offshore wind

This South Korean government is targeting at least 12 GW of offshore wind capacity being installed in Korean waters by the end of the current decade, up from less than 150 MW currently[48].

We project that South Korea's ambitions in this sector, coupled with its existing expertise and port facilities within the maritime sector, could pull down investment costs for offshore wind sharply over the coming years. As shown in Figure 21 below, our model estimates that by just 2025, new offshore wind farms could outcompete new gas plant projects when directly comparing LCOEs for each.

Even when comparing with South Korea's existing gas plant fleet, the LCOE of new offshore wind farms still fall below the LRMC of running gas this decade, as shown below. Given the capacity factors that offshore wind technology can deliver comparing favourably to those of a gas unit, this cost outlook would suggest that South Korea can press ahead with the phase out of its existing gas plant fleet in line with its net zero emissions by 2050 target and replace the retiring capacity with lower cost low carbon forms of supply.

Figure 21: Cost estimates for new offshore wind versus gas in South Korea



Source: Carbon Tracker analysis

5.3 Vietnam

Vietnam has experienced rapid growth in its renewable energy sector in recent years, although still has plenty of potential for further development. The country ended the 2020 calendar year with 35.6 GW of renewable capacity, having posted a growth rate of around 120% over the 2015-20 period[49].

The government plans to support continued growth in the sector over the remainder of the decade and identified ambition to kick-start the country's wind power sector in a recent draft of its Power Development Plan VIII (PDP8), although urgent investment in improving the country's grid infrastructure to accommodate new capacity is also required alongside this.

These plans are also currently accompanied by stagnated coal power phase out and plans to invest significantly in gas-fired power generation, which may not be necessary. The rapid deployment rate of renewable capacity that has been seen in Vietnam influenced conclusions from previous Carbon Tracker research which identified the country as one of the global emerging markets that could feasibly look to "leapfrog" fossil fuels by replacing outgoing coal with renewables capacity rather than gas.

Our Reach for the Sun: the emerging market electricity leapfrog report from July 2021 concluded that India and Vietnam particularly "have been able to build substantial renewable energy capacity even under policy and market conditions that might not match the standards of advanced economies" meaning that if policy frameworks are improved and deployment rates consequently accelerated further, there is minimal reason why Vietnam should rely on any supposed transition fossil fuel for its electricity needs.

Solar

Solar farms comfortably make up the bulk of Vietnam's current renewable power capacity, with a total of 16.5 GW installed at the end of 2020. Much of this development has been achieved within the past few years, with capacity growing by an estimated 237% over the 2019-20 period alone, with this growth rate scoring among the highest for solar power anywhere in the world[50].

The amount of ambition shown by the Vietnamese government for solar in its PDP8 document was relatively limited however, with a goal for solar to reach only around 18.6 GW by 2030[51].

We believe that capacity levels can be far higher by that year given recent rates of deployment and the falling investment costs projected for the technology.

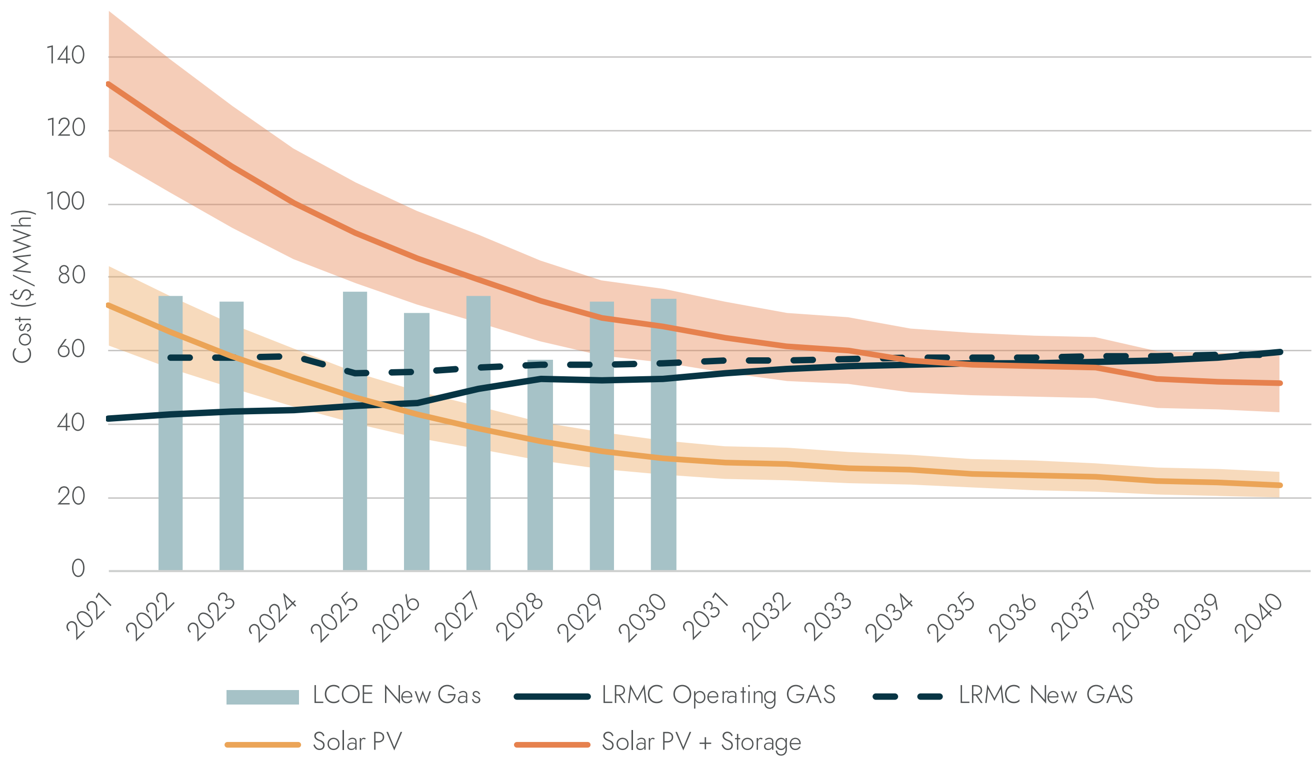
Investment and operating costs for new solar in the country are notably cheaper than in both Japan and South Korea and compare very favourably against projected costs for new gas plant projects in the country.

As shown in Figure 22 below, we find that it is already cheaper to build a new solar farm in Vietnam than it is to build and operate a new gas-fired power station, when comparing the LCOE of each.

Even costs for new solar capacity with battery storage installed are also then projected to fall below those associated with a new gas plant development by 2030. This would give any new gas plant developer an extremely limited period of time in which to get their unit built and operating before finding the asset is either stranded or has its operating hours severely constrained due to the increased competition from renewables and battery storage flexibility services.

49 Energy Profile – Vietnam (IRENA.org)
50 Energy Profile – Vietnam (IRENA.org)
51 The proposed Vietnam PDP8 update and the risks from the coal pivot (EnergyTracker.Asia)

Figure 22: Cost estimates for new solar + battery storage versus gas plants in Vietnam



Source: Carbon Tracker analysis

Onshore wind

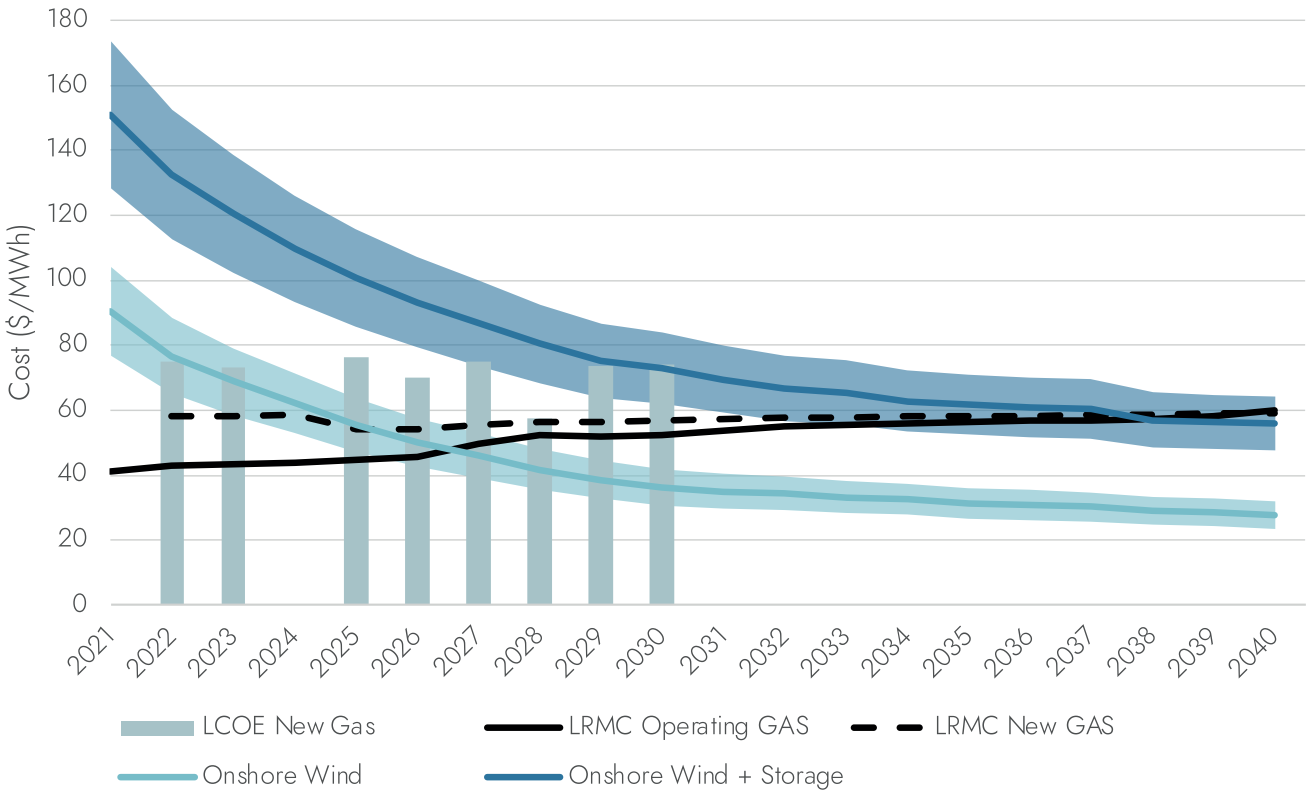
Vietnam's onshore wind capacity jumped sharply in 2021 as developers rushed to complete projects ahead of the end of a government feed-in tariff subsidy regime for the technology. Around 3.6 GW of new capacity was installed, from a starting base of just 600 MW at the end of 2020.

Uncertainty over the future of subsidy availability for onshore wind developments and requirements for grid infrastructure improvements to accommodate greater renewables penetration threaten to slow the deployment rate, but from an economic perspective, there is little reason why Vietnam cannot continue to build-out its low carbon capacity over the coming years.

Investment costs for onshore wind developments in Vietnam already compare favourably with those associated with new gas in Vietnam and are expected to fall sharply over the remainder of the decade. Building and operating a new onshore wind farm will be cheaper than investing in a new gas unit by just 2023 when comparing the LCOE of both technologies, as shown in Figure 23 below.

We also project that even a new onshore wind farm development with battery storage capacity will become cost competitive with a new gas unit in Vietnam by just 2030, leaving the investment case for new gas in the country highly questionable given the limited number of years such an asset would have before facing competition from low carbon forms of supply able to provide comparable flexibility services.

Figure 23: Cost estimates for onshore wind + battery storage versus gas plants in Vietnam



Source: Carbon Tracker analysis

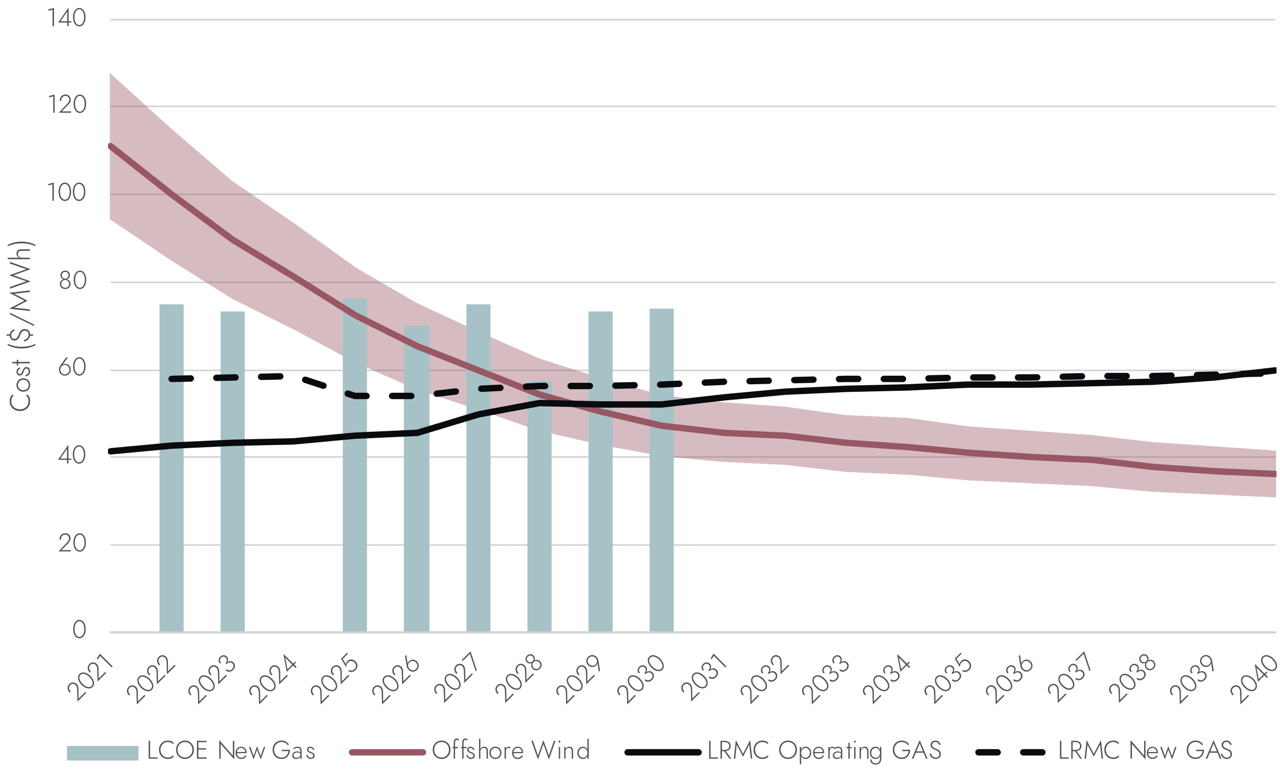
Offshore wind

Vietnam's estimated 3,000 kilometres of coastline and strong wind speeds mean the country has plentiful potential for investment in the offshore wind sector.

This has been acknowledged globally, with the World Bank having estimated Vietnam's potential for offshore wind capacity at nearly 600 GW. Given the high-capacity factors that offshore wind can provide and these comparing favourably with those of a gas-fired power station, the investment case for choosing to press ahead with Vietnam's extensive pipeline of gas projects appears highly questionable.

This is especially true when we examine the projected lifetime investment costs for each of these technologies. As shown in Figure 24 below, we find that by just 2025, a new offshore wind farm will be a cheaper overall investment than a new gas-fired project when comparing the LCOE of each.

Figure 24: Cost estimates for new offshore wind versus gas plants in Vietnam



Source: Carbon Tracker analysis

Vietnam is starting from a very favourable position compared with other nations in its prospects of delivering net zero, having delivered strong deployment rates for renewables in recent years and having minimal gas plant capacity to phase out. The Vietnamese government must ensure that the country does not steer off-track from the required pathway to this goal however and provide sufficient incentives to investors to ensure that its vast potential in the renewables sector is delivered.

06

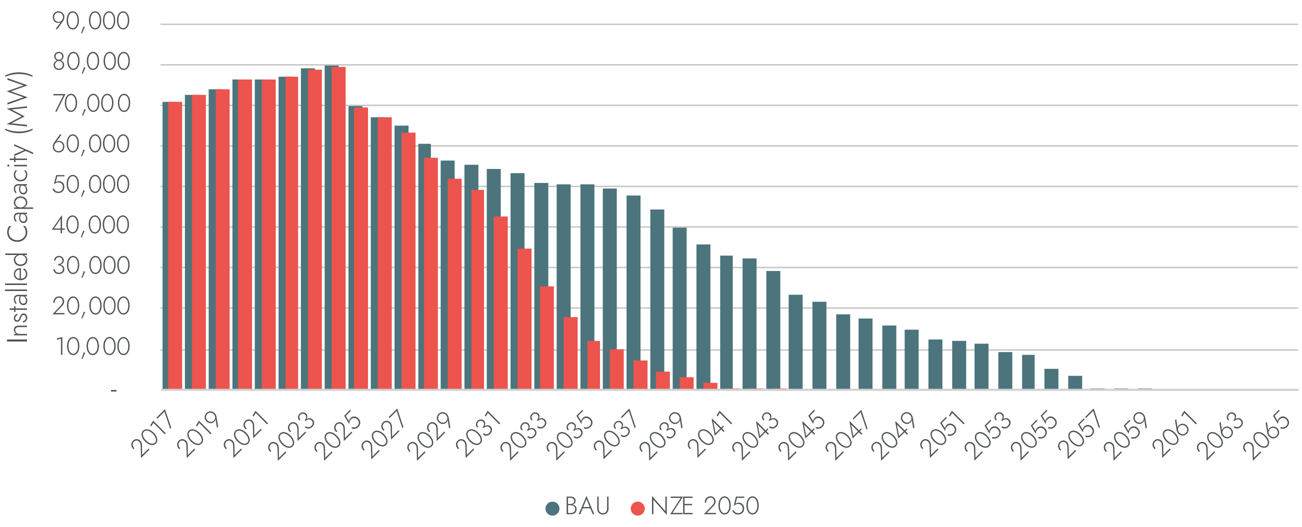
Appendices

6.1 Link to methodology document

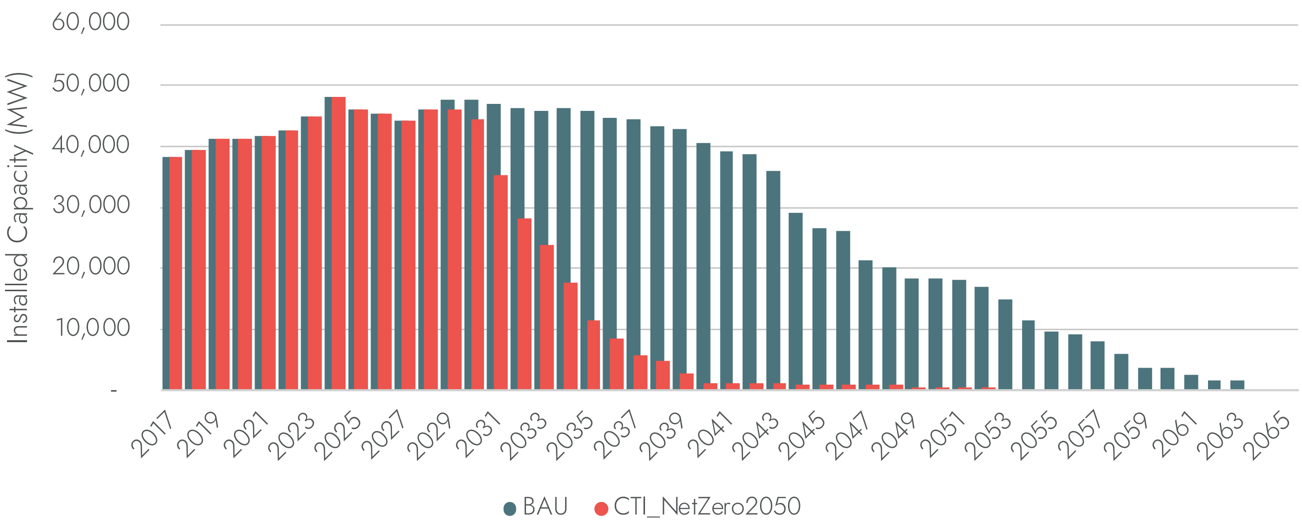
The methodology document containing a detailed description of the model and of assumptions used for the analysis of this report is available at: *https://carbontracker.org/wp-content/uploads/2022/04/PDG-Asia-Methodology_Final.pdf*

6.2 Phaseout Pathways gas-fired capacity by country

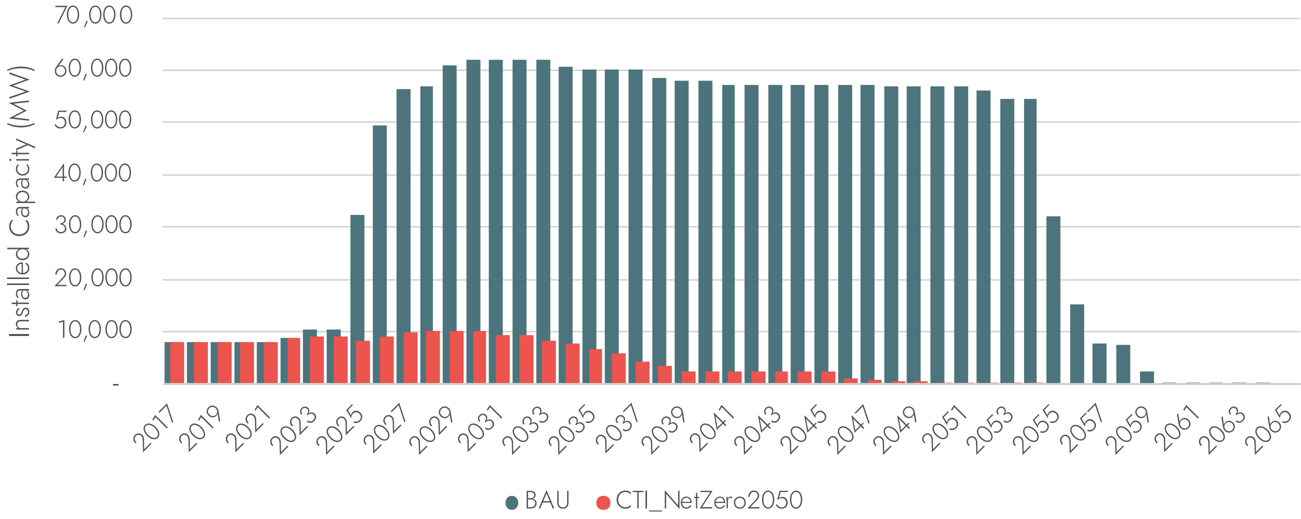
Installed Gas-Fired capacity in Japan under BAU and NZE2050



Installed Gas-Fired capacity in South Korea under BAU and NZE2050



Installed Gas-Fired capacity in Vietnam under BAU and NZE2050



6.3 Short-run marginal cost, long-run marginal cost and levelised cost of energy

Short-Run Marginal Cost

We define the short-run marginal cost (SRMC) as the sum of fuel, carbon and variable operating & maintenance (VOM) costs. The SRMC cost is a good indicator to understand the dispatch decisions of a plant owner in liberalised markets where units compete for the right to sell power to consumers. Typically, a power plant will sell electricity on the wholesale market when the clearing price is above its SRMC. The SRMC for a given year is calculated as follows:

$$SRMC_y = \frac{\text{Fuel cost}_y + \text{Carbon cost}_y + \text{VOM costs}_y}{\text{Electricity Generation}_y} \quad [\$/MWh]$$

Long-Run Marginal Cost

The long-run marginal cost (LRMC) includes SRMC plus fixed operating and maintenance (FOM) costs and any capital additions from meeting environmental regulations. The LRMC represents the total costs of producing electricity each year, thus determining the overall profitability of a power plant. The LRMC for a given year is calculated as follows:

$$LRMC\_y = SRMC\_y + \frac{\text{FOM cost}_y + \text{Pollution control cost}_y}{\text{Electricity Generation}_y} \quad [\$/MWh]$$

Levelised Cost of Energy

The levelised cost of electricity (LCOE) is a standard analytical tool used to compare power generation technologies and is widely used in power market analysis and modelling. The LCOE is the discounted sum of all the costs incurred during the lifetime of the assets divided by the discounted total of the estimated electricity generation. While the limitations of using LCOE analysis for understanding the economics of power generation have been well documented, this provides a simple proxy for comparing the overall cost of generating electricity with different energy technologies, in this case gas and variable renewables. Additionally, by including the coupling of variable renewables with storage, we can better reflect in the comparison the flexibility services provided by gas plants with clean alternatives. We calculate the LCOE as follows:

$$LCOE = \frac{\sum_y \frac{LMRC_y * \text{Electricity Generation}_y + \text{Interest}_y + \text{Taxes}_y + \text{Loan installemnts}_y}{(1 + WACC)^y}}{\sum_y \frac{\text{Electricity Generation}_y}{(1 + WACC)^y}}$$

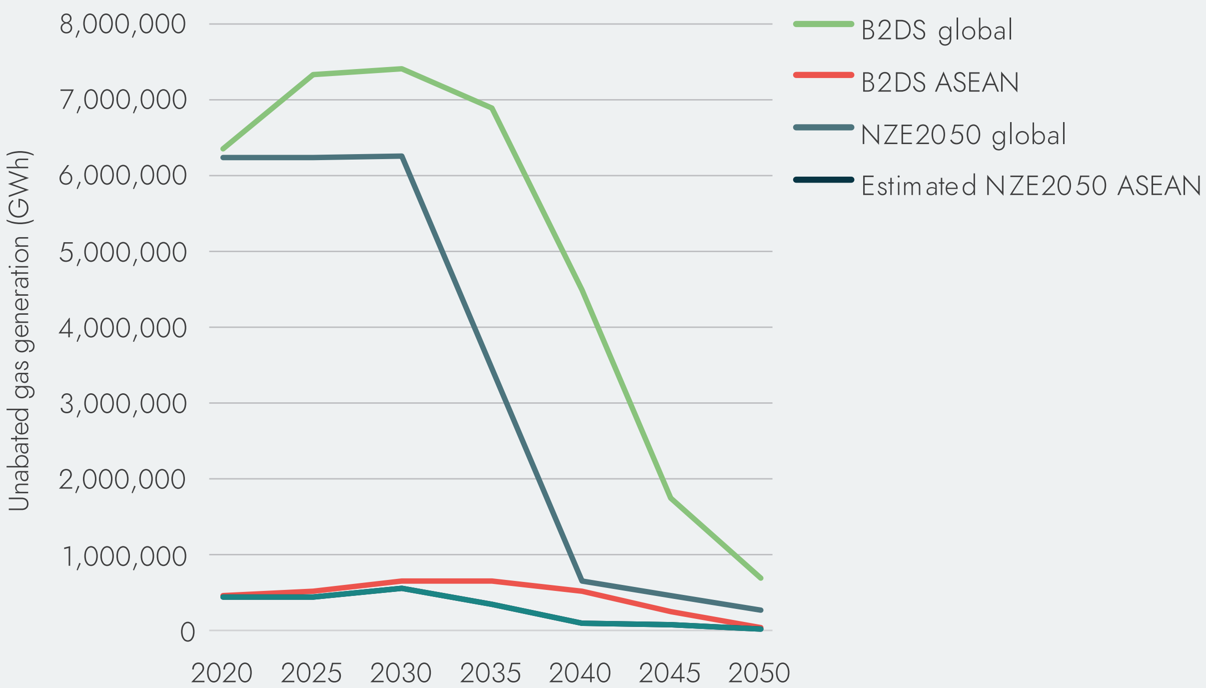
6.4 Net Zero 2050 scenario details

CARBON TRACKER'S NET ZERO 2050 SCENARIO

Carbon Tracker's net zero 2050 scenario is a regional interpolation of the IEA's global NZE2050 scenario and the Beyond 2 Degrees Scenario (B2DS). This is an interim scenario to model a net zero 2050 phaseout of coal and gas while we await the release of a more granular scenario by the IEA.

To estimate how gas generation would decline under the more restrictive criteria of net zero emissions by 2050, we scale each regional trajectory in the B2DS according to the ratio of the global NZE2050 to the global B2DS unabated gas generation trajectories.

This is illustrated by the chart below:



Regional NZE2050 unabated gas generation (year) = Global NZE2050 unabated gas generation (year)/Global B2DS unabated gas generation (year) x Regional B2DS unabated gas generation (year).

We acknowledge that this interim scenario is not as rigorous as a regional integrated assessment model. However, this is beyond the scope of our report and we will adopt regional NZE2050 data when it becomes available.

Disclaimer

To know more please visit:

www.carbontracker.org

@carbonbubble