WHACK-A-MOLE

Will South Korea's coal power transition be undermined by overcompensated gas?

April 2020

Carbon Tracker Initiative

SFOC
Solutions for Our Climate

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

About Solutions for Our Climate

Solutions for Our Climate (SFOC) is a Korea-based group that seeks to advocates for stronger climate policies and reforms in power regulations. SFOC is led by legal, economic, financial, and environmental experts with experience in energy and climate policy and works closely with policymakers.

www.forourclimate.org | solutions@forourclimate.org

About the authors

Matt Gray – Managing Director, Carbon Tracker

Matt joined Carbon Tracker in 2016 to start the Power & Utilities workstream. Matt has worked as a sell-side analyst and consultant for over 10 years and has experience in Europe, Australasia and Asia. At Jefferies, Matt was named the most accurate EUA price forecaster in 2012 and 2013 by Bloomberg News. More recently, Matt was a consultant analyst at the IEA and has also worked on carbon trading and origination at Credit Suisse and energy efficiency at the UK's DECC. Matt has a BAppSci from the University of Otago and an MSc from the University of Manchester.

Valeria Ehrenheim – Analyst, Carbon Tracker

Valeria works in the Power and Utilities team as Junior Gas Analyst. Before joining, she has been developing financial models for renewables and infrastructure investments through project financing. Passionate about financial valuation and climate change solutions, she finds a great fit in Carbon Tracker. Valeria has a BSc in Physics and a MSc in Green Management and Energy from Bocconi University.

Joojin Kim – Managing Director, Solutions for Our Climate

Joojin founded Solutions for Our Climate (SFOC) in 2016, after working at Kim & Chang, Korea's largest law firm. His work as a lawyer was mainly in the power sector and environmental regulations. He has several years of experience with the international climate change regime, including working with the Korean delegation to United Nations climate conferences. Most recently, he participated in government committees relating to the development of South Korea's Third Energy Framework Plan and 2050 low emission development strategy (LEDS). Joojin received his LL.M. from Georgetown University Law Center and master's degree and bachelor's degree from Seoul National University.

Gahee Han – Research Associate, Solutions for Our Climate

Gahee is a researcher at Solutions for Our Climate working on coal power and renewable energy policy. She started her climate career in 2016 while working on Climate Technology Centre & Network projects at the United Nations Industrial Development Organization. Gahee then went on to conduct greenhouse gas reduction research in a lab environment, further deepening her interest in emissions policy. Gahee has a BSc in environmental science and engineering from Ewha Womans University.


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Executive Summary

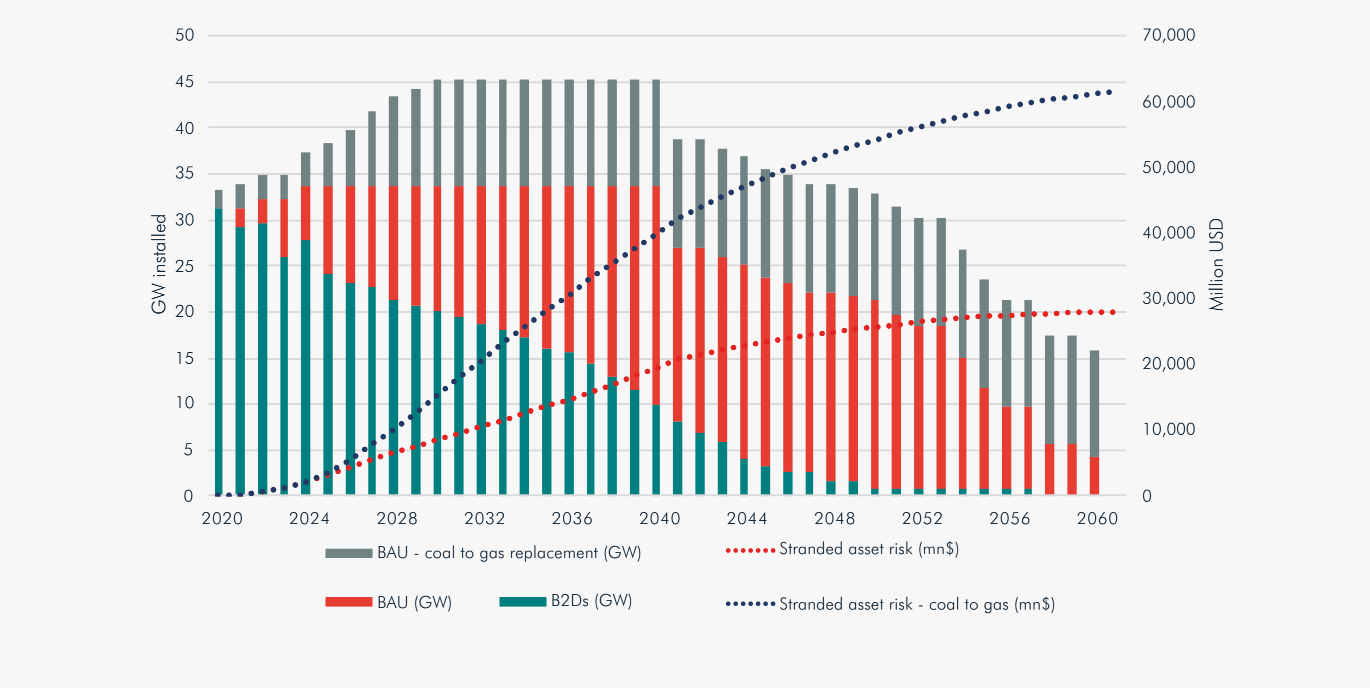
In this report, we analyse the financial and economic viability of new and existing gas power investments in Korea. In doing so, we find that the Korean government risks playing a game of whack-a-mole by shutting coal capacity only to have it replaced with gas.

1.1 Net zero or unabated gas: Korea needs to phase-out unabated gas by 2050 in Paris-aligned scenario or potentially risk $60 bn in stranded assets

Based on the 8th Power Plan as well as board decisions and letters of intent by Korea Electric Power Corporation (KEPCO)'s generation companies, up to 13.7 GW of coal capacity may be retired between now and 2034 and replaced with gas power. These replacement plans will likely be confirmed in the 9th Power Plan, which will be released later this year. If these replacements take place as proposed, there is a risk the Korea government will compromise its ability to meet the temperature goal in the Paris Agreement. In Carbon Tracker's below 2°C scenario, where planned, under-construction and operating gas capacity is forced to shut down in a manner consistent with the temperature goal in the Paris Agreement, unabated gas (i.e. not equipped with carbon, capture and storage (CCS) technologies) is phased-out by 2050. In this scenario stranded asset risk from wasted capital investments and reduced operating cashflows could amount to $60 bn by 2060 if the aforementioned coal capacity is replaced with gas. Even without considering coal-to-gas replacement, the existing pipeline of under construction or planned gas capacity could result in wasted capital and decreased cashflows of $30 bn by 2060. In the business as usual (BAU) and BAU coal to gas replacement scenarios, where gas units are operated for their useful lifetimes, Korea will still have unabated gas units online beyond 2060. This reality conflicts with Korea's ruling Democratic Party plan to achieve net-zero carbon dioxide emissions by 2050.[1]

[1] https://news.bloombergtax.com/daily-tax-report/s-korea-plans-new-green-act-to-reach-net-zero-emissions-by-2050

Figure 1. Cost-optimised below 2°C scenario retirement schedule for Korea's unabated gas units and potential stranded asset risk



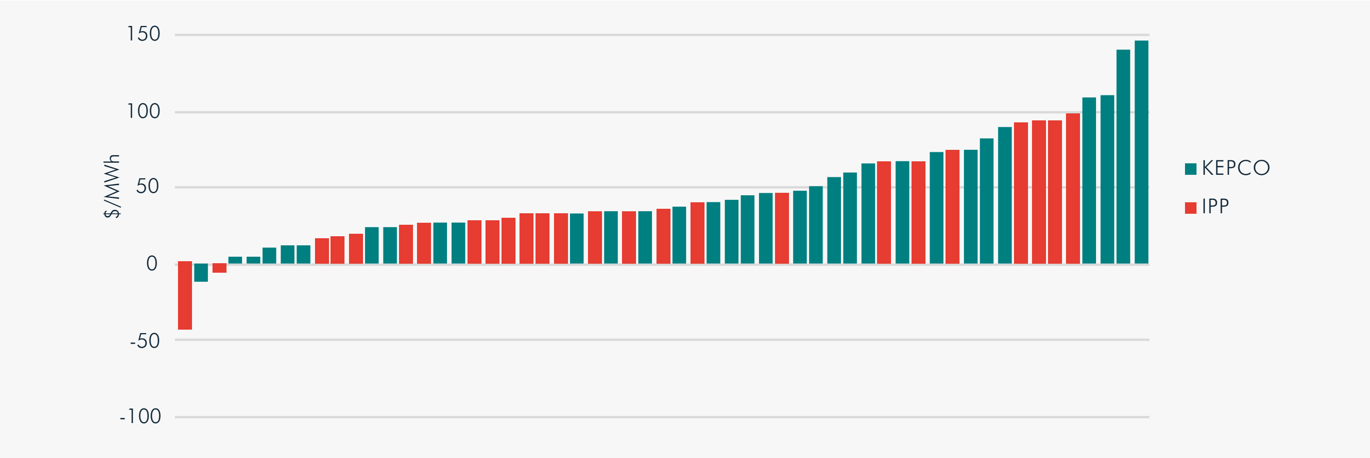
Source: Carbon Tracker analysis

Notes: The stranded asset risk here represents the cumulative sum of the present value of the cash flows difference between B2DS and BAU scenarios. BAU coal to gas replacement assumes 13.7 GW of coal capacity be retired and replaced with gas capacity.

1.2 KEPCO's generation companies are overcompensated relative to Independent Power Producers (IPPs)

Gas units in Korea receive approximately $8-9/MWh to be made available for dispatch. This market structure disproportionally benefits KEPCO's generation companies as their gas units are older and thus more inefficient and therefore have lower capacity factors than privately-owned IPPs. For this reason, KEPCO's gas units have higher operating cashflows than IPP units. As detailed in Figure 2, the average operating cashflows of KEPCO's gas units is $154/MWh. This compares to $69/MWh for IPP units. In addition, KEPCO's generation companies are subject to a cost guarantee scheme, which means if cashflows are lower than the operating cost plus a regulated rate of return, they are entitled to recoup these losses. These out-of-market revenues disincentivise KEPCO's generation companies to reduce their capital and operating costs to ensure consumers get access to the cheapest power possible.

Figure 2. Operating cashflows of KEPCO and IPP gas units



Source: Carbon Tracker analysis

Notes: excludes four KEPCO units and one IPP who have revenues in excess of $250/MWh.

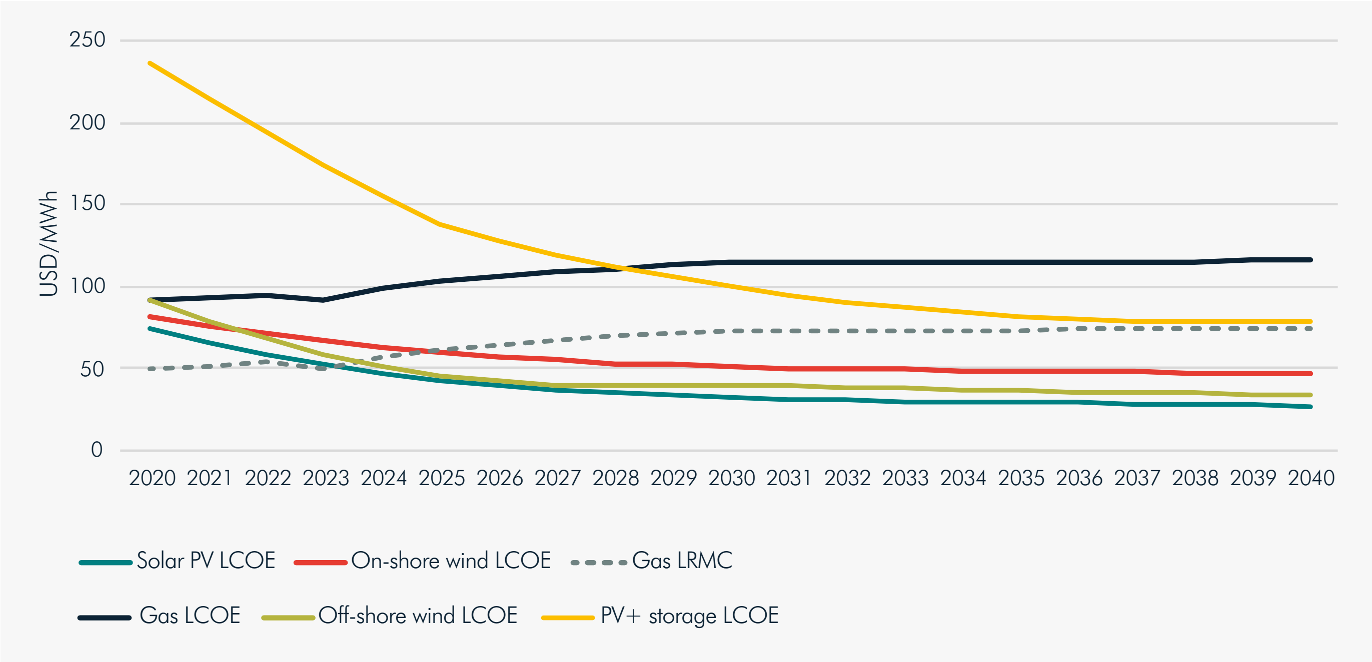
1.3 Peak not baseload: New gas power uncompetitive with new renewables today and existing gas as early as 2023

There are three economic inflections points which will make gas uncompetitive relative to renewable energy:

1. When new renewable energy outcompetes new or under-construction gas.
2. When new renewable energy outcompetes existing gas.
3. When new firm (or dispatchable) renewable energy outcompetes existing gas.

Independent of an additional carbon price or more stringent air pollution regulations, the LCOE of renewable energy in Korea could be lower than the LCOE of gas today. Specifically, the LCOE of offshore wind, utility-scale solar PV and onshore wind are already cheaper than the LCOE of gas, while solar PV with storage LCOE could be in 2028. Crucially, the LCOE of offshore wind, utility-scale solar PV and onshore wind could be cheaper than the long-run marginal cost (LRMC) of existing gas units by 2024, 2023 and 2025. These findings underscore an important investment signal: gas should not be built for baseload supply, but rather periods when variable renewable energy is unavailable.

Figure 3. Year when new renewables outcompetes new and existing gas



Source: BNEF (2019), Carbon Tracker analysis

Notes: storage costs are from Bloomberg NEF and include 4 hours of storage.

1.4 High level policy recommendations

1.4.1 Reform market regulations to avoid overcompensating KEPCO's generation companies

This analysis highlights how gas units owned by KEPCO's generation companies have been overcompensated due to market regulations. Capacity payments and the cost guarantee scheme made available to KEPCO's generation companies has made new gas investments lucrative and largely risk-free. These policy perversities will ultimately be paid for by the energy consumer through higher power prices. Policymakers need to address this economic inefficiency by abolishing the cost guarantee scheme for KEPCO generation companies, as well as reforming the capacity procurement system by allowing more direct competition between renewables and conventional power units. This will ultimately involve KEPCO unbundling its transmission and distribution business to allow new entrants, especially renewable energy generators, to directly sell power to consumers through a simplified, robust and transparent power market regulation.

1.4.2 Avoid the temptation to replace existing coal with new gas or risk stranded assets

New investments in baseload gas capacity will unlikely be a least-cost solution over the capital recovery period. This report highlights how gas power is losing its economic footing, independent of additional climate change and air pollution policies. As such, Korean policymakers should develop a retirement schedule based on the LRMC of individual unabated gas units. Once policymakers have developed a cost-optimised retirement schedule at the asset level, they should then undertake systems planning analysis to take into consideration the system value of individual assets. Understanding system value is outside the scope of this analysis.

2. Background

This report follows previous analysis by Carbon Tracker on the financial risks and relative competitiveness of coal power in South Korea titled Brown is the new green – Will South Korea's commitment to coal power undermine its low carbon strategy? which found the following:

1. South Korea has the highest stranded asset risk in the world due to market structures.
2. South Korea risks losing the low carbon technology race by remaining committed to coal.
3. Planned retrofits to cost $3.6 bn which will accelerate the competitiveness of renewables and could impact KEPCO's finances.

We use reasonable assumptions to analyse the financial risks associated with new and existing gas-fired capacity, as well as the significant economic opportunities related to the pursuit of low carbon alternatives. Consequently, this note highlights how South Korea's long-term commitment to gas power could burden the state with either higher tax rates, greater debt levels or increased power prices, as well as hinder the development of least cost and low carbon technologies.

2.1 Market overview

The Korean government started implementing a privatisation of its power market in 1999. This resulted in the introduction of the Korea Power Exchange (KPX) for wholesale power price trading, and the unbundling of KEPCO's generation business into six generation companies in the early 2000s. Privatisation was suspended in 2004 due to controversies in Korea, and power generation came to be characterised by a mix of market and non-market forces.[2] Although the government has initiated several market reforms to restructure the power sector, the state owns 68% of operating capacity through the auspices of KEPCO's six generation companies. KEPCO has some competition from IPPs in power generation, but controls transmission and distribution. KEPCO is practically the only entity in Korea that is allowed to sell power. Figure 4 below illustrates Korea's power market structure.

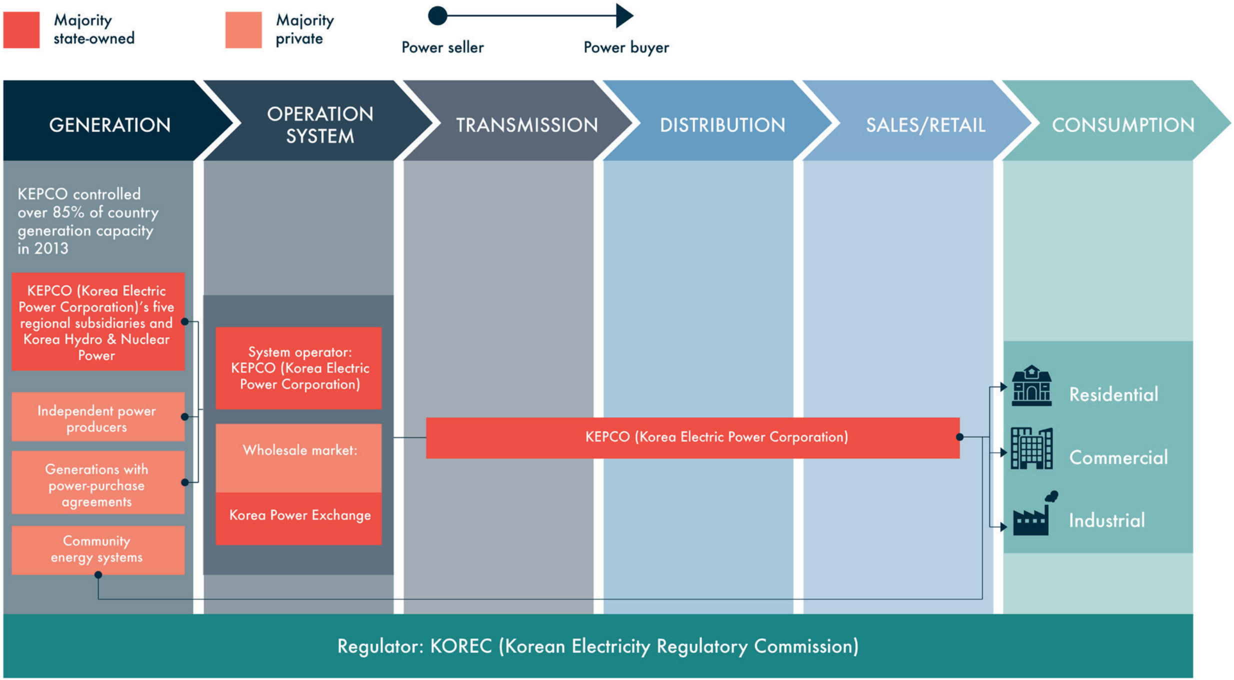
Korea's power market structure is far from straightforward and in an important respect bifurcated. KEPCO's power generation companies are subject to a cost guarantee scheme, while the privately-owned IPPs, except for one coal power IPP, are not. The cost-plus mark-up factor was initially the same per generation source (i.e. one adjustment factor for coal, nuclear, gas, respectively) among KEPCO's generation companies. This has since changed whereby MOTIE (Ministry of Trade, Industry and Energy) started to apply a coal adjustment factor for each generation company, meaning the operating cashflows of each generation company is guaranteed through a cost-plus mark-up policy. This cost guarantee scheme combined with the fact that KEPCO has no competitor in power sales, has made

[2] For example, KPX forecasts electricity demand for each trading day and receives bids from generation companies for available capacity one day in advance. Based on this, the wholesale market price is determined by KPX in accordance with a pricing mechanism under its Electricity Market Operation Rules, rather than the short-run marginal cost like Western European markets.

capital investment decisions, such as building new coal or gas units easy and financially attractive. The IPPs are not part of this policy and receive the spot price plus additional out of market revenues, such as capacity charges.[3]

An important feature of KEPCO is that its management has little control over influencing future cashflow. Tariffs are regulated and KEPCO has limited ability choosing the sources it purchases power from. It also cannot appoint heads of generation companies it owns outright, as these decisions are made by the Korean government.

Figure 4. Korea's power market structure

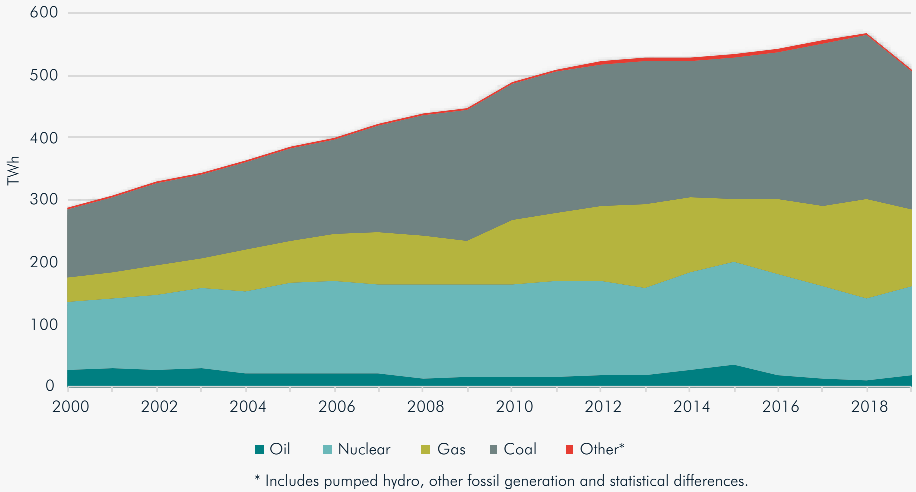


Source: Carbon Tracker analysis adapted from Bloomberg NEF

[3] See Table 1 below for more information.

Gas generation in Korea has grown significantly since the start of the 21st Century. From 2001 to 2019, gas generation increased 370% and now represents around a quarter of total generation. There is currently 6.2 GW of gas generation planned. All of this planned capacity is owned by KEPCO's generation companies.[4] The South Korean government aims to reduce its reliance on coal and phase-out nuclear by increasing its share of renewables to 20% of total generation by 2030. Currently there is no policy to reduce emissions from gas generation, other than the emissions trading system, which has limited effect on the power mix as fossil generators are mostly compensated for these costs. Solar and wind power continue to grow but retained a fractional 2.6% share of total generation in 2019.

Figure 5. Korea's power generation mix from 2000 to present day



Source: BP Statistical Review of World Energy June 2019

Notes: Other includes pumped hydro, wind, solar, other fossil generation and statistical differences.

[4] These companies include: Korean Southern Power, Korean East-West Power and Korean Western Power) as well as IPPs (GS Power, Tongyeong Ecopower, Ulsan GPS, Naepo Green Energy, Korea District Heating Corporation, and Seoul Energy Corporation.

3. Data sources, key assumptions and modelling methodology

1.3 Data sources and assumptions

The asset-level model outputs in this analysis are based on a number of assumptions about commodity prices (fuel, power and carbon), variable and fixed operations and maintenance costs (O&M) and policy outcomes (out-of-market revenues and control technologies costs, for example). For metric definitions see Box 1. For data sources and assumptions see Table 1.

Box 1. Metrics used in this report

LCOE = Capital cost + LRMC

The 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 simply the sum of all costs divided by the total amount of generation. The LCOE is based on a discounted cash flow model where costs of developing and running power generation assets are discounted using a real weighted average cost of capital.

LRMC = Fuel + Carbon + VOM + FOM

The LRMC is the cost of operating a gas unit. Fuel costs include the cost of buying, transporting, and preparing the gas. Carbon costs are based on existing and ratified policies. Variable O&M costs vary with the use of the unit. Fixed O&M costs do not vary with the use of the unit and include capital additions to maintain performance and comply with environmental regulations.

Operating cashflows = Revenues – LRMC

KEPCO and IPPs units benefit from revenues from in-market, capacity, carbon price exposure, renewable portfolio standards, scheduled energy payments, constraint-off, constrained-on, capacity payments, renewable portfolio standards, total emission trading system and other payments.

Table 1. Assumptions and sources for gas modelling and renewable energy analysis

Parameter	Details	Source
Assumptions for gas		
Inventory data on unit-level characteristics	Unit name, plant name, plant location, unit installed capacity, unit status, unit cycle type, operation start year, planned retire year and the parent company.	Global Energy Monitor (2019)
Capital cost	Overnight capital cost of combined cycle gas turbines.	IEA (2015)
Fixed O&M	Fixed O&M for combined cycle gas turbines was estimated from data provided by Leigh Fisher. Costs are inflation adjusted.	Leigh Fisher (2016)
Variable O&M	Variable O&M for combined cycle gas turbines was estimated from data provided by Leigh Fisher. Costs are inflation adjusted.	Leigh Fisher (2016)
Fuel quality	Gas quality, expressed in terms of energy content (MJ/m3), was from data provided by KEPCO.	KEPCO (2019)
Capacity factor	Capacity factor data are provided by SFOC, at the unit-level, and cross validated with KEPCO generation data.	KEPCO (2019) and SFOC
Cooling type control technologies by plant	From the World Electric Power Plants Database and data provided by the National Assembly through SFOC. Polluting emissions of natural gas power plants concern only NOx, hence the types of control technologies reported are: low-NOx burner and selective catalytic reduction (SCR).	S&P Global Platts (2019) and SFOC

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Parameter	Details	Source
Fuel cost	Provided by the National Assembly through SFOC. Fuel costs are provided at the unit level.	Multiple legislator offices of National Assembly, including the office of Assemblyman Sunghwan Kim (2019)
Carbon price	Carbon price was taken from International Carbon Action Partnership and assumed unchanged from 2019 onwards.	ICAP (2018)
Combustion efficiency	Gross, low heating value (LHV) adjusted for unit age. Combustion baseline efficiency data, for different types of cycle, were taken from RICARDO.	RICARDO (2015)
Efficiency adjustments from cooling and pollution controls	Adjustments made to the overall combustion efficiency of the plant depending on the technology installed were taken from the EPA.	EPA (2018)
Environmental control technology capital and operational costs	SCR costs assumed for all NOx control technologies for gas plants. Different capex for capacity ranges obtained applying a scaling factor defined (pages 5-8). The cost obtained for a 500 MW unit applies for units larger than 500 MW.	EPA (2018)
Unabated gas-fired power generation pathway for below 2°C scenario	We use OECD decline rates from the IEA's Beyond 2°C scenario (B2DS).	IEA (2017)

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Parameter	Details	Source
Pollution limit regulations and associated capital and operational costs	We assumed no additional capital costs for the installation of environmental control technologies across the fleet because the regulated limits don't cover gas production.	Carbon Tracker estimates
Plant revenues	SFOC obtained revenue data from multiple legislator offices of the National Assembly. We were not able to reconstruct the KPX power market algorithm and hence, for the purpose of this study, assumed that recent three-year average revenue of each unit will continue during the period reviewed. Revenue data for all KEPCO's and a few IPPs' generators were provided in a complete set at the unit level, whereas those for 13 private generators were shuffled and provided in a random order. SFOC matched the given random data for 13 private generators based on the publicly available unit specifications such as the start year, whether the plant is a PPA unit or a merchant plant, and the amount of annual power generation. For the remaining four IPPs of which data were missing, we obtained the revenue data from publicized company reports or assumed a market spot price for electricity. The market spot price was estimated from the revenues in USD/MWh earned by IPPs with a similar unit capacity and capacity factor.	Provided by SFOC who sourced the data from multiple legislator offices of the National Assembly, including the office of Assemblyman Sunghwan Kim.
Discount rate for the net present value (NPV)	Loan 80%, Equity 20%. Cost of debt 7.99%. Discount rate for the NPV assumed to be the weighted average cost of capital, which is the rate that a company is expected to pay to finance its assets, weighted over the different sources of capital (debt and/or equity).	EY (2018)
Projects lifetime	40 years	EY (2018)

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Parameter	Details	Source
Loan term (years)	20 years	EY (2018)
Capital tax rate	27%	EY (2018)
Assumptions for onshore wind		
Capital Expenditure (CAPEX)	CAPEX for onshore wind in South Korea in 2019 was estimated from data on a 43.2 MW wind farm completed in 2018 from which 8% was subtracted to account for cost declines going to 2019. The cost breakdown structure was assumed to be the same as in the case of Japan as South Korea appears to be having at least one domestic turbine manufacturer that is given some market share. A lower bound CAPEX was calculated using 15% assumption and a higher bound using a 20% assumption, the standard assumption for OECD countries.	MK (2018)
Operation & Maintenance Costs	O&M costs were estimated by Carbon Tracker. From this estimate, a 15% less expensive lower band was calculated and a 20% more expensive upper bound.	Carbon Tracker estimate
Capacity factor	Capacity factor was estimated by Carbon Tracker, taking as reference a study on Japan, due to the share of the market given to local turbine manufacturers.	Carbon Tracker estimate
Capacity (MW)	Data for capacity projections was sourced from the REMAP team at IRENA while data for 2019 was projected using historical deployment data from IRENA.	IRENA (2019) IRENA (2019a)
Return on Equity (ROE)	Data on return on equity was taken from NYU Stern. There was no specific data for South Korea and instead the value for emerging markets was used (12.83) to which 2% was added as 12.83 is too low for South Korea given that Japan has an ROE for renewables of 15%.	NYU Stern (2019)

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Parameter	Details	Source
Cost of Debt	Data on cost of debt was sourced from the World Bank. The interest rate, 3.6%, found was for loans on short and medium term to which another 1 percentage point was added to account for the riskier long term loan. Finally, inflation data was sourced from IMF. The debt equity split was assumed to be 80% debt and 20% equity, a common assumption for OECD countries.	World Bank (2019) IMF (2019)
Capacity deployment and learning rate	A learning curve of 19%, assumed from global cost declines, was used to project LCOE declines going forward based on global results published in 2018. The low, mid and high LCOE and the highest capacity projections were used to compute the LCOE of onshore wind going to 2040.	IRENA (2018)
Assumptions for solar PV		
Capital Expenditure	CAPEX for solar PV in South Korea in 2019 was estimated using data from IRENA 2018 cost report declined by 8% to account for cost reductions to 2019, together with the cost breakdown. A lower bound CAPEX was calculated using 15% assumption and a higher bound using a 20% assumption.	IRENA (2018)
O&M Costs	O&M costs data were estimated by Carbon Tracker. From this estimate, a lower bound O&M was calculated using 15% assumption and a higher bound using a 20% assumption.	Carbon Tracker estimate
Capacity factor	Capacity factor was estimated by Carbon Tracker.	Carbon Tracker estimate

Table continued overleaf

Parameter	Details	Source
Capacity (MW)	Data for capacity projections was sourced from the REMAP team at IRENA while data for 2019 was projected using historical deployment data from IRENA.	IRENA (2019) IRENA (2019a)
Cost of Debt	Data on cost of debt was sourced from the World Bank. The interest rate, 3.6%, found was for loans on short and medium term to which another 2 percentage points was added to account for the riskier long-term loan and for the more riskier offshore wind technology. Finally, inflation data was sourced from IMF. The debt equity split was assumed to be 75% debt and 25% equity to account for more equity being asked for in offshore wind projects as they are generally riskier investments.	World Bank (2019) IMF (2019)
Capacity deployment and learning rate	A learning rate of 30% was used for solar PV LCOE as this is more in line with global learning curves for solar PV and South Korea has a much lower cost base than Japan.	IRENA (2018), Carbon Tracker estimate
Assumptions for offshore wind		
Capital Expenditure	CAPEX for offshore wind in South Korea in 2019 was estimated using global weighed average CAPEX data from IRENA report in 2019 from which 10% was subtracted to account for cost declines over the year, 2018 to 2019 and generally lower CAPEX structures observed in Asia. A lower bound using 15% decline was calculated and a higher band using 20% increase was calculated. The cost breakdown structure was assumed to be the same as in the case of Japan as South Korea appears to be having at least one domestic turbine manufacturer that is likely to be given market share in the offshore wind market as well.	IRENA (2019)

Table continued overleaf

Parameter	Details	Source
O&M Costs	O&M costs data were estimated by Carbon Tracker, sourced from IRENA and IEA data.	Carbon Tracker estimate
Capacity factor	Capacity factor was assumed to be 13% higher than the one observed at global level in IRENA 2019 study to account for annual increases and better technology. A lower band, -15%, and a higher band +20% was calculated.	IRENA (2018)
Capacity (MW)	Data for capacity (MW) projections was sourced from the REMAP team at IRENA while data for 2019 was projected using historical deployment data from IRENA.	IRENA (2019) IRENA (2019a)
Return on Equity	Data on return on equity was taken from NYU Stern. There was no specific data for South Korea and instead the value for emerging markets was used 12.83% to which 2% was added as 12.83 is too low for South Korea given that Japan has an ROE for renewables of 15%.	NYU Stern (2019)
Cost of Debt	Data on cost of debt was sourced from the World Bank. The interest rate, 3.6%, found was for loans on short and medium term to which another 2 percentage points was added to account for the more riskier long term loan and for the more riskier offshore wind technology. Finally, inflation data was sourced from IMF. The debt equity split was assumed to be 75% debt and 25% equity to account for more equity being asked for in offshore wind projects as they are generally riskier investments.	World Bank (2019) IMF (2019)
Capacity deployment and learning rate	A learning curve of 19%, assumed from global cost declines, was used to project LCOE declines going forward based on global results published in 2018.	IRENA (2018)

Source: see table.

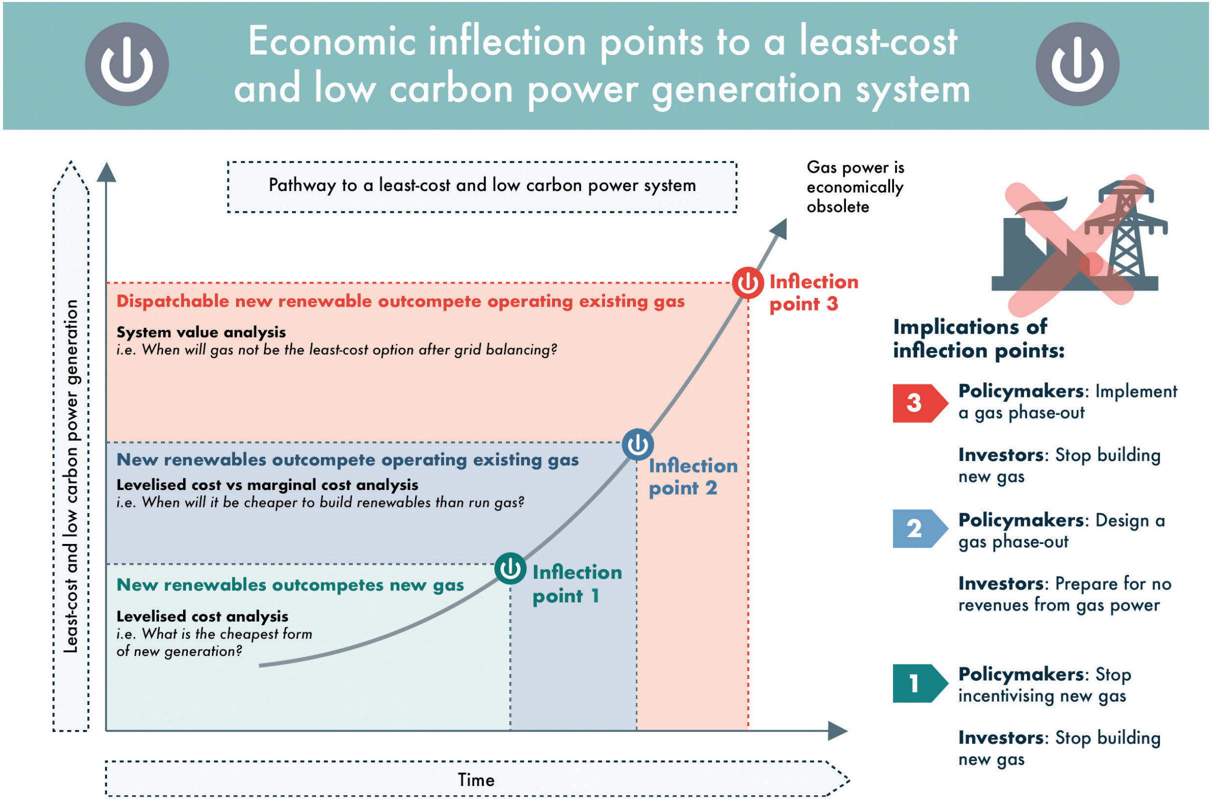
3.2 Modelling methodology

3.2.1 Stranded cost risk model

Our stranded cost risk model compares both the LCOE of new gas power investments and the LRMC of existing unabated (i.e. CCS-unequipped) gas power capacity with the LCOE of onshore wind, offshore wind and utility-scale solar PV. While the limitations of using generic LCOE analysis for understanding the economics of power generation have been well documented, it does provide a simple proxy for when new investments in unabated gas power no longer make economic sense and when investors and policymakers should plan and implement an unabated gas power phaseout.[5] The assumptions for the LRMC and LCOE estimates are detailed in Table 1. There are three economic inflection points that policymakers and investors need to track to provide the least-cost power and avoid stranded cost risk: when new renewables and abated gas outcompete unabated gas; when new renewables and abated gas outcompete operating existing unabated gas; and when dispatchable renewables and abated gas outcompete operating existing unabated gas. These inflection points are illustrated in Figure 6.

[5] We acknowledge that LCOE analysis is a limited metric as it does not consider revenues from generation and the system value of wind and solar. According to the IEA, the best way to integrate variable renewable energy (VRE) is to transform the overall power system through system-friendly deployment, improved operating strategies and investment in additional flexible resources. Flexible resources include better located generation, grid infrastructure, storage and demand side integration. See: IEA (2016), Next-generation wind and solar power: From cost to value. Available: https://www.iea.org/publications/freepublications/publication/NextGenerationWindandSolarPower.pdf

Figure 6. The intersection between the economic inflection points and the policymaking process for a least-cost power system



Source: Carbon Tracker analysis

3.2.2 Below 2°C stranded asset risk model

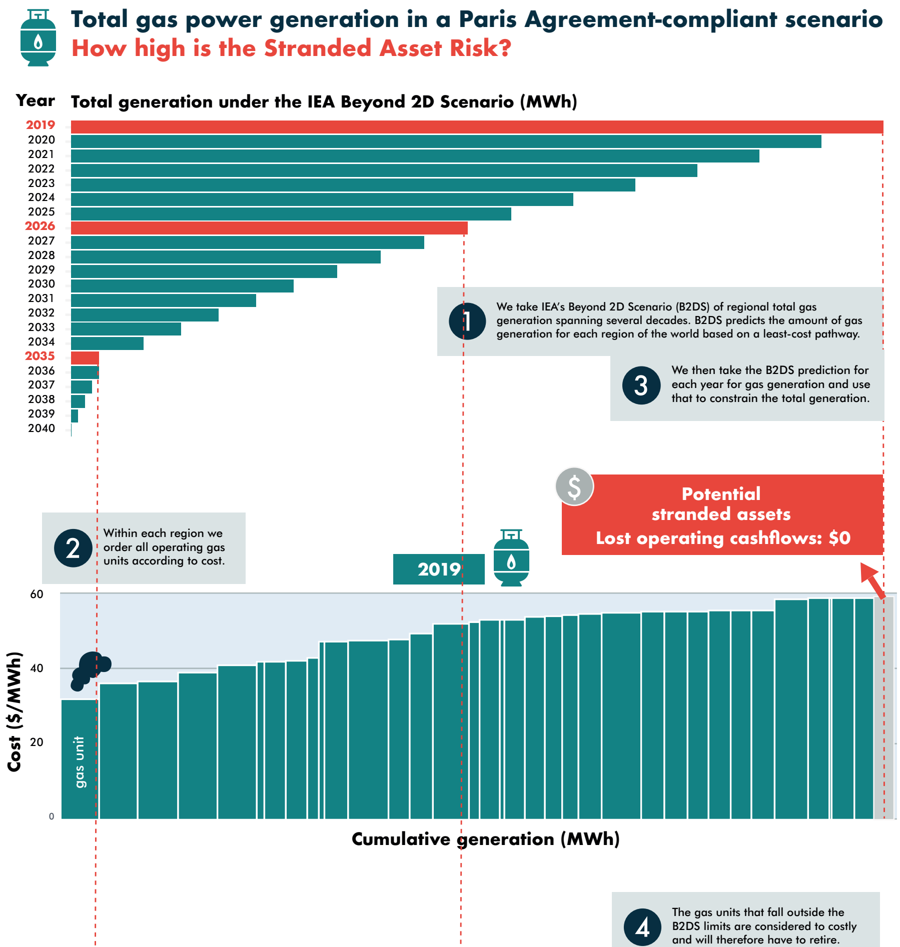
The stranded asset risk in Carbon Tracker's 2°C scenario is defined as the difference between the NPV of revenues in a BAU scenario and a scenario consistent with the temperature goal in the Paris Agreement. The retirement schedules are developed based on the LRMC. Underlying this analysis is the logic that in the context of efforts to reduce carbon emissions and demand for unabated gas power, the least economically efficient will be retired first. The modelling approach involves three steps.

Firstly, we identify the amount of capacity that is required to fill the generation requirement in the IEA's beyond 2°C scenario (B2DS). Under the B2DS, gas generation without carbon capture and storage (CCS) is phased-out globally by 2050. This analysis assumes CCS will not be available to extend the lifetimes of gas capacity, as the costs will likely be prohibitively expensive. Regions have different phase-out dates. For Korea, we assume a phase-out date of 2050 which is broadly consistent with other OECD countries.

Secondly, we rank the gas units to develop a retirement schedule, based on the authority, region or grid responsible for maintaining security of supply. The units are ranked based on the LRMC. The gas units with the highest LRMC are phased-out until the aggregated asset level generation reaches the limits set out in the B2DS.

Thirdly, we calculate the cash flow of every operating and under-construction gas unit in both the B2DS and BAU outcomes to understand stranded asset risk. Stranded asset risk under the B2DS is defined as the difference between the NPV of cash flows in the B2DS (which phases-out all gas power by 2050) and the NPV of cash flows in the BAU scenario (which includes announced retirements in company reports or otherwise assumes a minimum lifetime of 40 years). Figure 7 provides a schematic illustration of the below 2°C stranded asset modelling methodology.

Figure 7. Schematic illustration of the modelling methodology



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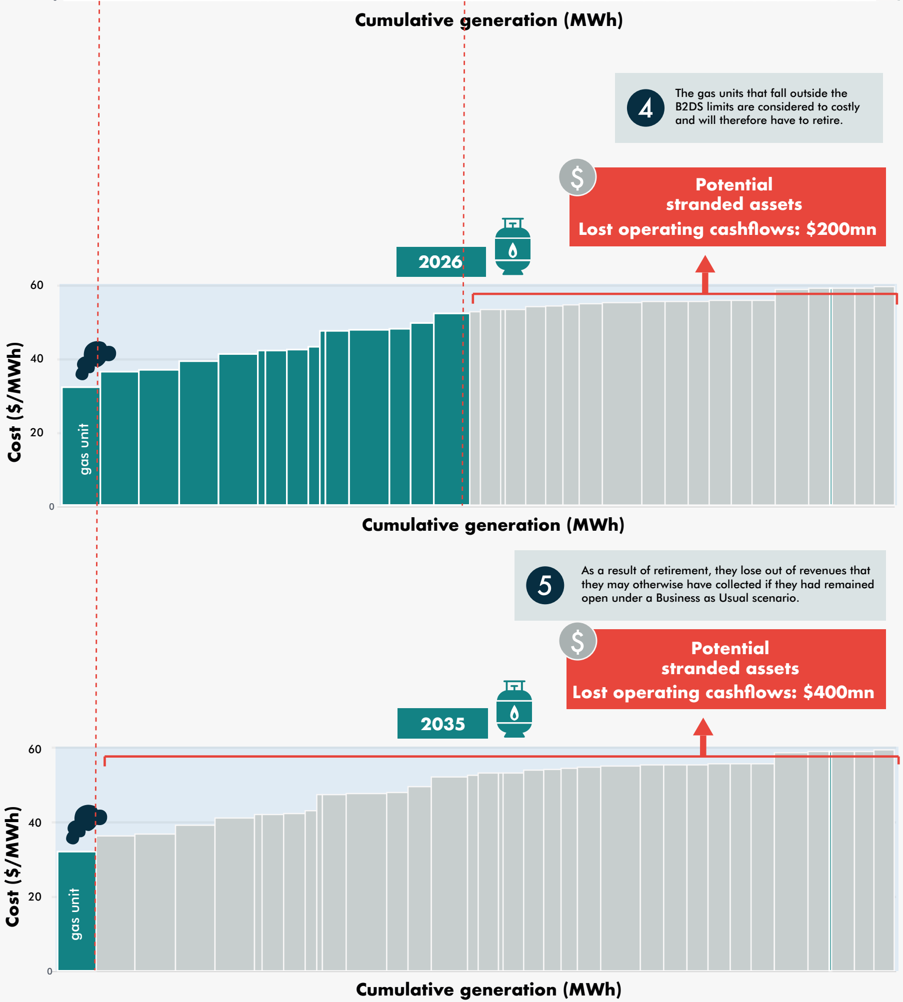


6 The difference between the total revenues collected under a Business as Usual scenario and a Beyond 2D scenario is known as **Stranded Asset Risk**.

Source: Carbon Tracker

4. Results and discussion

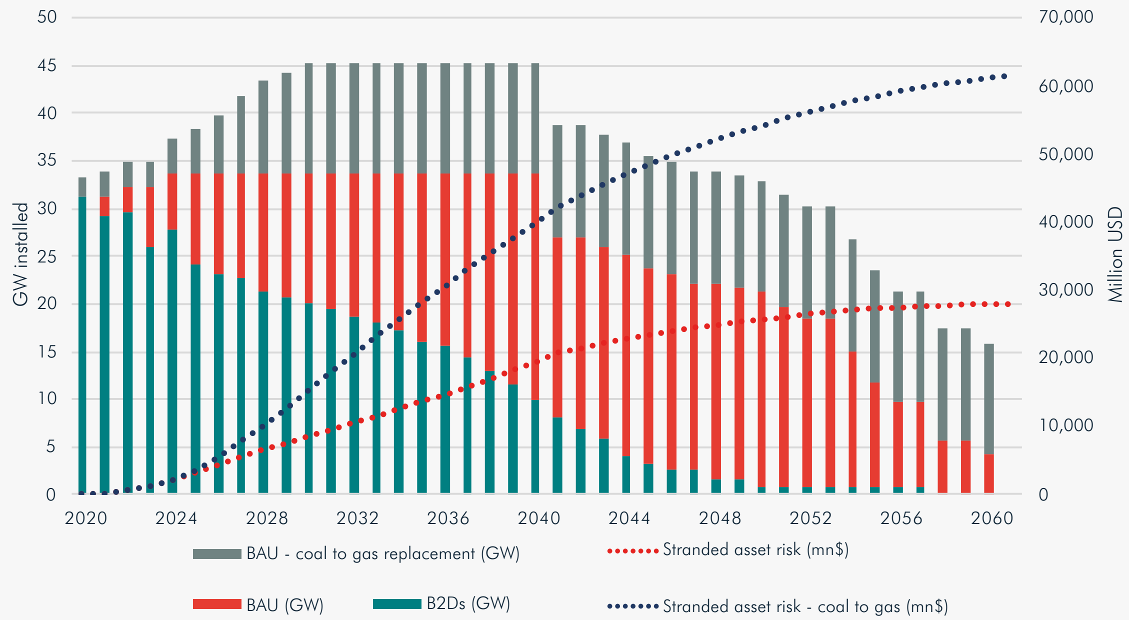
4.1 Korea needs to phase-out unabated gas by 2050 or risk billions in wasted capex and reduced cashflows

In 2017, the Korean government introduced the 8th Power Plan, which includes a forecast for power demand until 2031.[6] The plan aims for installed renewable capacity of 59 GW by 2030, representing 20% of total power generation. Despite these positive policy signals from the Korean government, there is a significant risk gas capacity will be built out in a manner inconsistent with the temperature goal in the Paris Agreement. Based on the 8th Power Plan and several announcements by KEPCO's generation companies, up to 13.7 GW of coal capacity commissioned before 2005 may be retired between now and 2034 – and replaced with unabated gas capacity. These replacement plans are likely to be detailed in the 9th Power Plan, which is due to be published later this year. If these coal units are replaced with gas capacity, it will undermine the ruling Democratic Party's ability to meet the temperature goal in the Paris Agreement, as well as their plan to achieve net-zero carbon dioxide emissions by 2050.[7]

Our below 2°C scenario constrains gas capacity based on the amount of unabated generation required under the IEA's B2DS. In this scenario, planned, under-construction and operating gas capacity is forced to close by 2050 to meet the temperature goal in the Paris Agreement. If this scenario is realised capital investments and reduced operating cashflows could amount to as much as $60 bn by 2060. This assumes the government allows KEPCO's generation companies to build and operate all planned gas capacity, as well as replace all coal capacity planned to close one-for-one with gas. The risk of wasted capital costs and reduced cashflows could be reduced to $30 bn if the government decides to replace the aforementioned coal retirements with renewable energy. Nonetheless, even this more conservative scenario would mean the Korean government would unlikely meet the temperature goal of the Paris Agreement and their own net-zero ambitions, as there will still be gas capacity in operation post-2050.

[6] http://english.motie.go.kr/en/tp/energy/bbs/bbsView.do?bbs_seq_n=605&bbs_cd_n=2&view_type_v=TOPIC&&currentPage=1&search_key_n=&search_val_v=&cate_n=3
[7] https://news.bloombergtax.com/daily-tax-report/s-korea-plans-new-green-act-to-reach-net-zero-emissions-by-2050

Figure 8. Cost-optimised below 2°C scenario retirement schedule for Korea's unabated gas units and potential stranded asset risk



Source: Carbon Tracker analysis

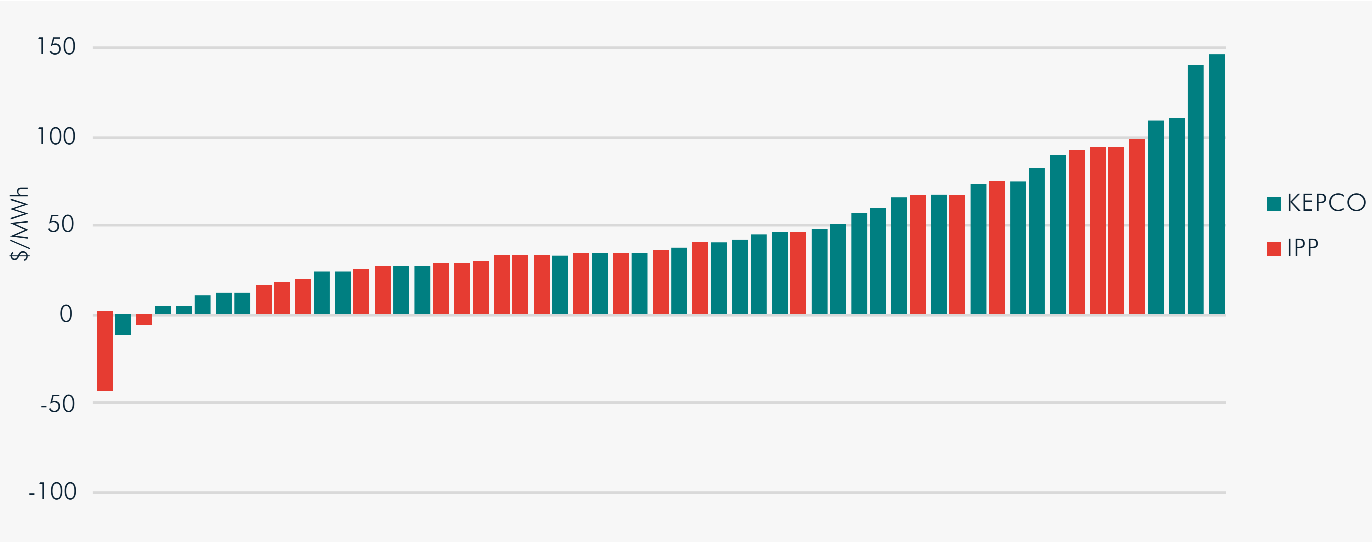
Notes: The stranded asset risk here represents the cumulative sum of the present value of the cash flows difference between B2DS and BAU scenarios.

BAU coal to gas replacement assumes 13.7 GW of coal capacity be retired and replaced with gas capacity.

4.2 KEPCO's generation companies are overcompensated relative to IPPs

The economics of gas generation in Korea is not straightforward and in an important respect bifurcated. While all Korean gas units receive around $8-9/MWh to be made available, KEPCO's generation companies also benefit from cost-plus mark-up policy. Since KEPCO's gas units are older they typically have lower capacity factors and therefore benefit relatively more on a MWh basis than IPP units who have to cover their remaining costs in the spot market. The MOTIE apply an adjustment factor for KEPCO's power generation companies, meaning the operating cashflows of each company are effectively guaranteed through a cost-plus mark-up policy. If the cashflow from gas units owned by KEPCO's power generation companies are lower than cost-plus mark-up, these companies may recoup their deficits by adjusting in-market revenues from their coal units. This is reflected in the operating cashflows of KEPCO-owned gas units. The average operating cashflows of KEPCO's gas units is $154/MWh. This compares to $69/MWh for IPPs. This discriminatory regulation reduces the incentivise for KEPCO's generation companies to optimise their capital and operating costs.

Figure 9. Operating cashflows of KEPCO and IPP gas units



Source: Carbon Tracker analysis

Notes: excludes four KEPCO units and one IPP who have revenues in excess of $250/MWh.

4.3 Peak not baseload: New gas power uncompetitive with new renewables today and existing gas as early as 2023

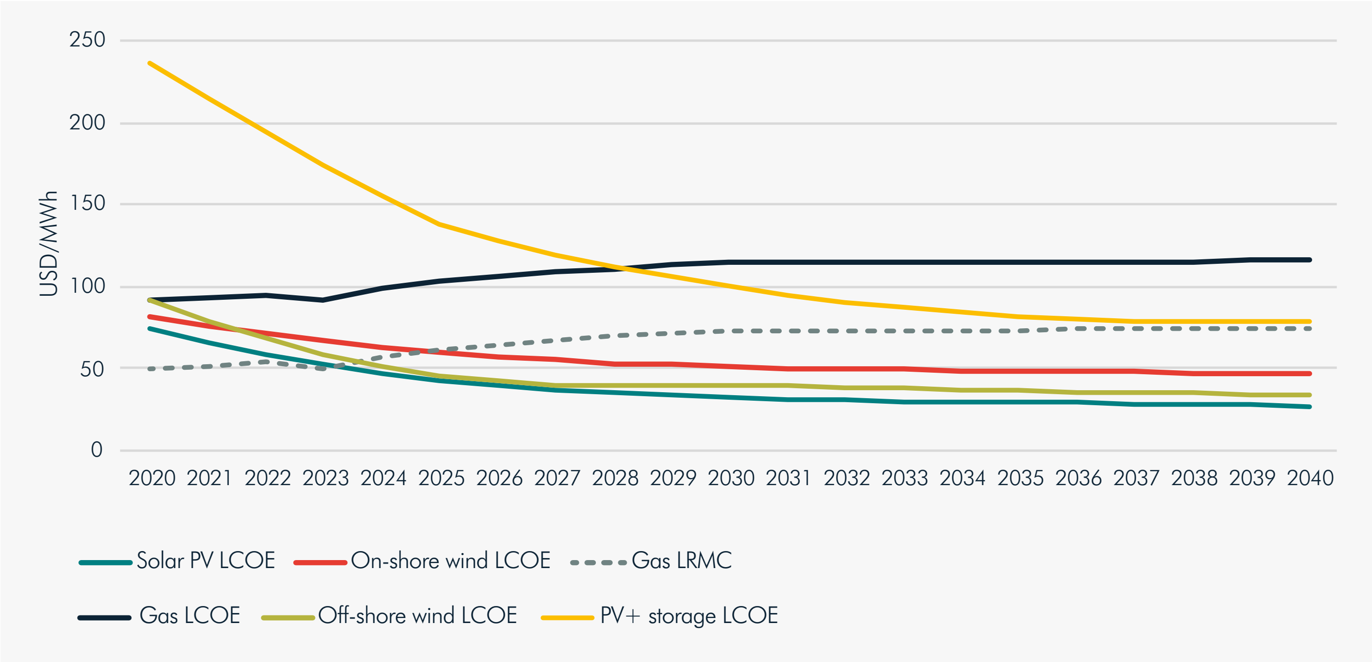
There are three economic inflections points which will make gas uncompetitive relative to renewable energy:

1. When new renewable energy outcompetes new or under-construction gas.
2. When new renewable energy outcompetes existing gas.
3. When new firm (or dispatchable) renewable energy outcompetes existing gas.

Renewable energy is subject to significant deflationary pressure from economies of scale. Since 2010, utility scale solar PV and onshore wind LCOE has declined 84% and 53%, respectively.[8] While wind and solar has a fractional share of the market now, within one decade, these technologies may have such a share of the market that it becomes a trigger for energy price deflation, with significant consequences for gas generators that rely on continued growth. Independent of an additional carbon price or more stringent air pollution regulations, our analysis shows the LCOE of renewable energy in Korea could be lower than the LCOE of gas today. Specifically, the LCOE of offshore wind, utility-scale solar PV and onshore wind are already cheaper than the LCOE of gas, while solar PV with storage LCOE could be in 2028. Crucially, the LCOE of offshore wind, utility-scale solar PV and onshore wind could be cheaper than the long-run marginal cost (LRMC) of existing gas units by 2024, 2023 and 2025. These findings underscore an important investment signal: gas should not be built for baseload supply, but rather periods when variable renewable energy is unavailable and thus running a progressively lower capacity factors are wind and solar incrementally increases.

[8] BNEF, 2019 LCOE Update.

Figure 10. Year when new renewables outcompetes new and existing gas



Source: BNEF (2019), Carbon Tracker analysis

Notes: Storage costs are from Bloomberg NEF and include 4 hours of storage.

5. High-level policy recommendations

5.1.1 Reform market regulations to avoid overcompensating KEPCO's generation companies

Our research reveals that KEPCO's gas generators are overcompensated related to IPPs. This outcome could result in higher energy costs for consumers and undermine Korea's transition to a low carbon economy, as KEPCO's generation companies have little economic incentive to build new renewables. KEPCO and Korean policymakers must address this inefficiency by abolishing the cost-plus mark-up policy, significantly reforming its capacity procurement system and allowing more direct competition between renewables and conventional power units, such as coal, gas and nuclear generators. The cost-plus mark-up policy made available to KEPCO's generation companies has made capital investments in new gas capacity highly profitable and disincentivised investments in wind and solar.

Moreover, KEPCO has been inefficiently managing available capacity as well by paying a flat capacity rate to all conventional power units. As of 2018, KEPCO paid $2.1 bn to gas plants, $1.6 bn to coal power plants and $0.9 bn to nuclear power plants as capacity payments.[9] These payments could potentially be reduced with by introducing a capacity market system and procuring only required capacity from least-cost sources, including demand response and battery storage. KEPCO urgently needs to unbundle its transmission business and allow new entrants to sell power directly to customers. Failure to do so will likely stifle the transition to a low carbon economy and could result in higher power bills for households and businesses.

5.1.2 Avoid the temptation to replace existing coal with new gas or risk stranded assets

New investments in gas capacity will unlikely be a least-cost solution over the capital recovery period. This period is typically 15-20 years for new gas capacity and 5-10 years for retrofits relating to performance enhancements or control technology installations. This analysis highlights how gas power is losing its economic footing, independent of additional climate change and air pollution policies. As such, Korea should stop investing in and building new baseload gas immediately. Korean policymakers should develop a retirement schedule based on the LRMC of individual gas units. This analysis will allow policymakers to close the higher cost units first and lower cost units last, which should help ensure that the end consumer receives the lowest cost electricity possible, maximising economic growth. Once policymakers have

[9] KPX, Power Market Statistics (2018)

developed a cost-optimised retirement schedule at the asset level, they should then undertake systems planning analysis to take into consideration the system value of individual assets. Understanding system value is outside the scope of this analysis. Carbon Tracker intends to conduct this analysis with local partners and make this research publicly available.

6. Conclusion

As the economic risks of continuing to build and operate coal-fired capacity become more obvious and widespread, the Korean government needs to ensure it does not shut coal and replace it with gas. The Korean government needs to reform their power market to ensure a coal to gas switch is avoided and any additional gas capacity is used for peaking capacity only.

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8. Appendix

In-market revenues: KPX forecasts the demand for the trading day and receives offers for hourly available capacity from generation companies one day ahead. It then determines the market price (system marginal price, SMP) by producing a Price Setting Schedule. It is a CBP where generators are not allowed price bidding but quantity and variable-cost (mainly consist of fuel cost) of each generator is solely considered. In-market revenues are settled for the energy actually generated on the given trading day in accordance with the quota allotted in the Price Setting Schedule.

Balancing revenues: constraint-on/off payments, revenues assigned when a plant/unit is forced to turn on or shut down to cover demand against the scheduled order. Within the model, they are treated as in-market revenues.

Capacity revenues: revenues related to capacity market rules. Capacity payment is the price paid to a generating unit that has declared its availability in the day-ahead bidding. In South Korea, CP reflects the capital cost of a generator and its fixed O&M cost. The concept of CP was introduced in the Korean power market to ensure the recovery of capital costs of generators and to offer an inducement to attract new capacities.

Emission Trading Scheme Payment: South Korea's ETS is a cap-and-trade system: a market open to the transaction of trade permits, which allow participating businesses to emit a given amount of greenhouse gases. A cap is set by the government which defines the maximum level of total emissions permitted during a certain time period. From 2018 to 2020, 97% of allowances are allocated for free and 3% for auction whereby companies can purchase a share of emissions from government. The share of auctioned emissions will increase to over 10% from 2021. Some of the expenses spent by power generation companies for purchasing a share of emissions is compensated in the market.

Renewable Portfolio Standards Payment: revenues that gas plants get if they guarantee that a percentage of energy is produced from renewable sources. Under the Renewable Portfolio System (RPS), power generation companies generating 500MW or more are mandated to have a certain percentage of total power generation come from new and renewable energy. In order to meet the annual RPS ratio (6.0%, in 2019) supply obligators must either build new renewable energy generation facilities or purchase Renewable Energy Certificates (REC) in the marketplace to meet the mandatory quota. Some of the expenses spent by power generation companies (suppliers) for purchasing RECs is compensated.

Other revenues: they include other minor sources of revenues, such as Start Up Payment Adjustment, Marginal Generation Set Adjustment, Additional Adjustment SCON, Automatic Generation Control Payment, Local Plant Tax, etc.

8.1.2 Coal units that may be replaced by gas in 9th Power Plan

KEPCO's generation company	Unit	Start year	30th anniversary	Reference
Korea Midland Power	Boryeong Unit 1	1983	2013	8th Power Plan
	Boryeong Unit 2	1984	2014	8th Power Plan
Korea Southeast Power	Samchonpo Unit 3	1993	2014	8th Power Plan
	Samchonpo Unit 4	1994	2024	8th Power Plan
Korea Western Power	Taean Unit 1	1995	2025	8th Power Plan
	Taean Unit 2	1995	2025	8th Power Plan
Korea Midland Power	Boryeong Unit 5	1993	2023	Letter of intent to government
	Boryeong Unit 6	1994	2024	Letter of intent to government
Korea Western Power	Taean Unit 3	1997	2027	Letter of intent to government
	Taean Unit 4	1997	2027	Letter of intent to government
Korea Southeast Power	Samchonpo Unit 5	1997	2027	Letter of intent to government
	Samchonpo Unit 6	1998	2028	Letter of intent to government

Table continued overleaf

KEPCO's generation company	Unit	Start year	30th anniversary	Reference
Korea Southern Power	Hadong Unit 1	1997	2027	Letter of intent to government
	Hadong Unit 2	1997	2027	Letter of intent to government
	Hadong Unit 3	1997	2027	Letter of intent to government
	Hadong Unit 4	1998	2028	Letter of intent to government
Korea East West Power	Dangjin Unit 1	1999	2029	Letter of intent to government
	Dangjin Unit 2	1999	2029	Letter of intent to government
	Dangjin Unit 3	2000	2030	Letter of intent to government
	Dangjin Unit 4	2001	2031	Letter of intent to government
Korea Southern Power	Hadong Unit 5	2000	2030	Letter of intent to government
	Hadong Unit 6	2001	2031	Letter of intent to government
Korea Western Power	Taean Unit 5	2001	2031	Letter of intent to government
	Taean Unit 6	2001	2031	Letter of intent to government
Korea Southeast Power	Yeongheung Unit 1	2004	2034	Board decision
	Yeongheung Unit 2	2004	2034	Board decision

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