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Reforming Korea's Electricity Market for Net Zero

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Abstract

This report was commissioned by Korea's Ministry of Trade, Industry and Energy and carried out jointly by the International Energy Agency (IEA) and the Korea Energy Economics Institute. The objective of the study was to analyse market design improvements to enable achieving net zero in Korea's power sector, in accordance with the country's long-term decarbonisation objectives. For this the IEA devised a Korea Regional Power System Model to evaluate the emissions implications of the plans laid out in Korea's 9th Basic Plan for Long-Term Electricity Supply and Demand and the Carbon Neutral Strategy published in 2021. The analysis includes a scenario elaborated by the IEA, based on the *World Energy Outlook*'s Announced Pledges Scenario, to analyse potential for further market improvements. This analysis covers market improvements in areas such as carbon pricing, market price enhancements that better reward low-emissions technologies and security of supply, and market access reforms to ensure the participation of a wider range of new technologies and distributed energy resources.

Acknowledgements, contributors and credits

The report was jointly prepared by the International Energy Agency and the Korea Energy Economics Institute at the request of Korea's Ministry of Trade Industry and Energy, with the objective of analysing electricity market design improvements to attain the country's net zero objectives.

The report was conducted under the guidance of Dr. César Alejandro Hernández Alva, Head of the IEA Renewables Integration and Secure Electricity (RISE) Unit and Dr. Tae Eui Lee, Research Fellow of the Korea Energy Economics Institute (KEEI). Keisuke Sadamodi, Director of Energy Markets and Security at the IEA and Dr. Yongduk Pak provided expert comments and senior guidance. The report was led and co-ordinated by Enrique Gutierrez, with Zoe Hungerford as the lead modeller and with contributions from Keith Everhart, Craig Hart, Luis Lopez, Julia Guyon, Danhak Gu and Heejin Kim (RISE). Doyob Kim and Brendan Reidenbach from the Energy Efficiency Division (EEFD) provided valuable input and advice for the analysis on distributed energy resource integration.

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Executive summary

Korean objectives to reach economy-wide net zero by 2050 will require significant changes in the power sector

In October 2020, Korea announced its pledge to achieve net zero emissions by 2050. With 586 million tonnes of CO_2-equivalent in 2019, Korea accounts for 2% of global annual emissions. Its power and industrial sectors are major contributors to annual national emissions at 37% and 36% respectively.

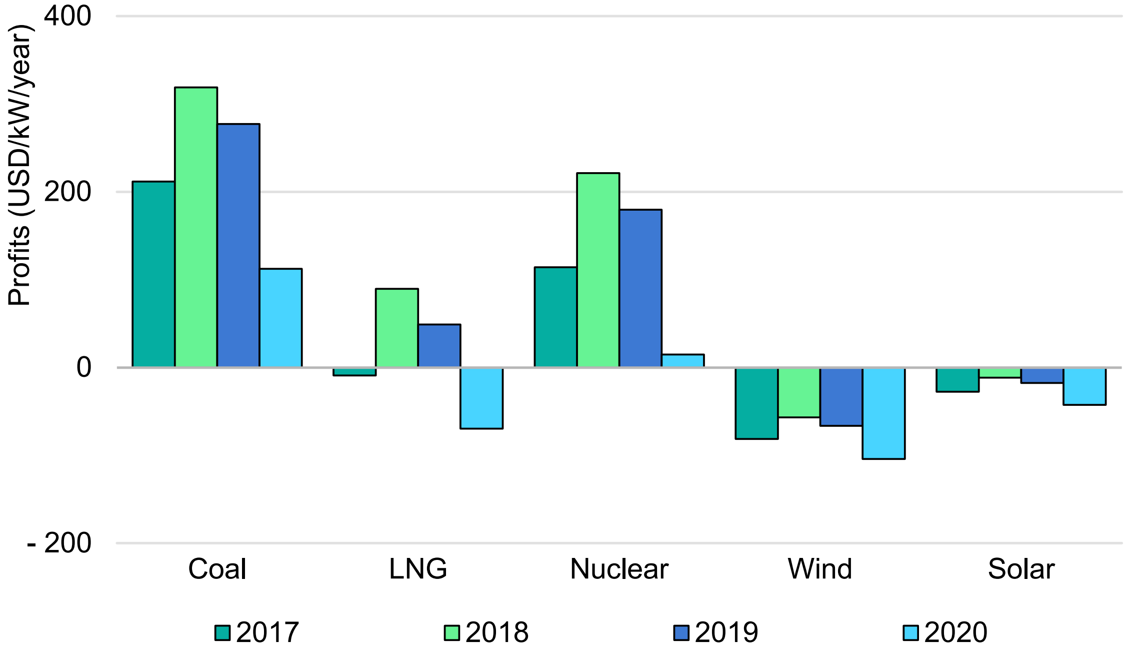
Net zero emissions by 2050 would require very strong support measures and incentives that introduce renewable and other low-carbon energy sources and interventions to rein in emissions of greenhouse gases in all sectors of the Korean economy. The power sector is the largest source of emissions in many countries, including Korea, and should be the first sector to decarbonise as shown in the Net Zero by 2050 roadmap by the International Energy Agency (IEA).

The purpose of this report is to examine how electricity market design in Korea must change to facilitate national decarbonisation without undermining electricity security. The IEA and the Korean Energy Economics Institute (KEEI) have developed the Korea Regional Power System Model, which includes six power system regions. This model simulates what would happen to the Korean power sector after implementation of the 9th Basic Plan for Long-Term Electricity (BPLE) in 2034, and under the Announced Pledges Scenario (APS) in the *World Energy Outlook* (WEO) 2021 by the IEA in 2035. The latter is aligned with Korea's pledge to achieve net zero emissions by 2050.

Korea's current electricity market design does not help achieve the objectives of decarbonisation and security

Korea aims to reduce emissions from the power sector in a cost-effective way, without compromising electricity security. In liberalised power markets, like Korea's, the wholesale market should be the key enabler to reach policy objectives and to ensure the efficient dispatch of all resources. However, Korea's current cost-based system does not account for factors such as emissions and system security. In recent years, this has resulted in higher profits for technologies with lower fuel costs and higher emissions, like coal-fired generation.

Estimate of profitability* for new plant by type, 2017-2020



* Energy rents, less fixed operation and maintenance (O&M) and annualised capital cost; Weighted average cost of capital (WACC) = 7%.

Source: IEA (2020) *Projected Costs of Generating Electricity 2020*; Korea Power Exchange (KPX).

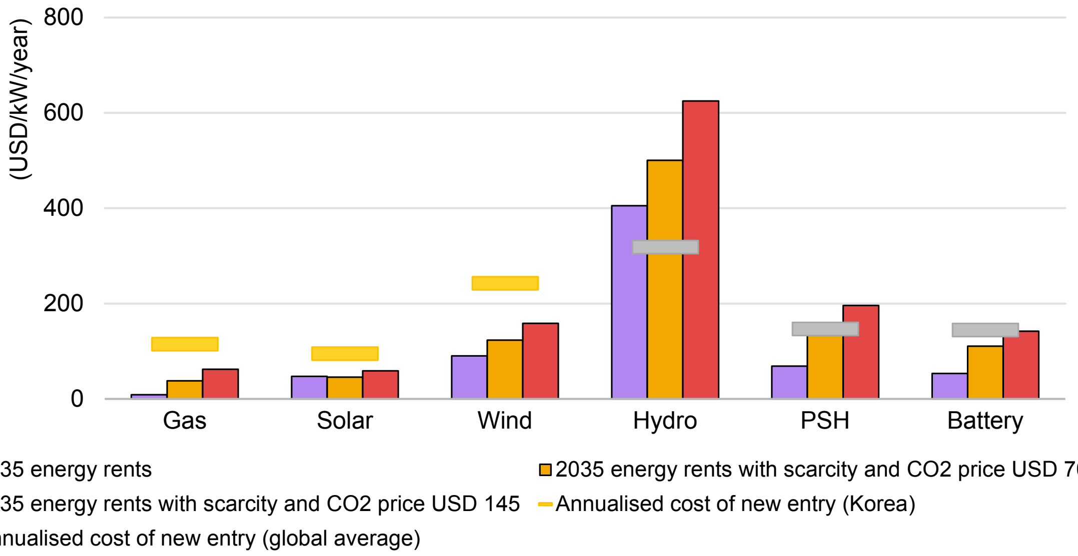
Maintaining this pricing regime would not enhance the power system's ability to secure sufficient low-carbon energy and dispatchable capacity by 2035. Considering the recent introduction of policies to phase out coal-fired generation and limit nuclear electricity, it will be important to secure enough investment in alternative low-carbon dispatchable resources such as hydro, pumped storage hydropower (PSH) and battery storage.

Two enhancements to price formation in the electricity market can significantly contribute to Korea's decarbonisation objectives. First, incorporate the cost of carbon into wholesale prices, either by allowing the emissions trading scheme to impact wholesale prices, or through taxation. Even low levels of CO_2 prices (USD 60-70/tonne), far below those considered in the WEO by the IEA for developed economies with net zero pledges, would improve the profitability of low-carbon assets such as wind, solar, hydropower and PSH. This would also give the right signals to demand-side resources and flexible assets regarding when to consume energy and discharge to minimise emissions.

Second, allow the shortages of operating reserves to be reflected in wholesale pricing during hours of scarcity, which increases the prospects for flexible technologies such as PSH, batteries, hydro and gas plants.

Including both price enhancements would correct the existing biases in the wholesale market design and align the incentives given to market participants with Korea's decarbonisation objectives. This would foster a gradual substitution process where low-carbon energy replaces highly polluting sources and provides incentives to invest in assets that can provide the services needed to keep security of supply.

Estimate of profitability* by unit type, Announced Pledges Scenario 2035



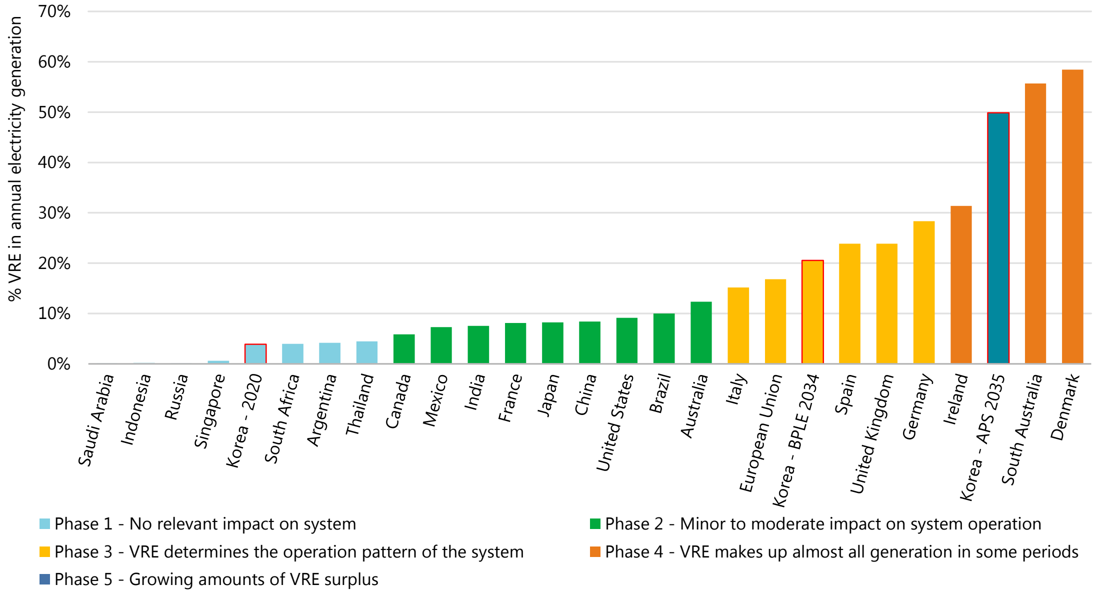
* Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using system reference marginal price (short-run marginal cost [SRMC]) and scarcity pricing with carbon price.

Source: IEA Korea Regional Power System Model.

Decarbonising Korea's power system will increase its flexibility requirements and require new technologies

Korea's annual variable renewable energy (VRE) share of electricity supply was 4% in 2020, and the country is in Phase I in the Phases of VRE integration framework developed by the IEA. Following the 9th BPLE would bring their VRE share to around 21% in 2034 and place the country in Phase III. This would require coping with maximum hourly VRE penetrations of 60% relative to load and coping with three-hour ramp-down requirements equivalent to 51% of the daily peak already by 2030.

Annual VRE share in selected countries for 2019 and Korea in 2020, and the Basic Plan for Long-Term Electricity 2034 and Announced Pledges 2035 scenarios



The APS 2035 scenario would bring their VRE share to around 50% and place Korea in Phase V of renewables integration. This phase implies many hours where available VRE generation exceeds electricity demand as well as longer periods of VRE surplus or deficit, which are more challenging to accommodate in an isolated system such as Korea's. In this scenario, balancing electricity supply and maintaining grid stability would require increased flexibility coming from all sources – dispatchable power plants, the national grid, energy storage and demand response.

Increased time and locational granularity will allow for better VRE integration and reduce grid expansion costs

For Korea, the current plan to reduce dispatch intervals from hourly blocks to 15 and 5 minutes provides a first good step to facilitate power system decarbonisation. Countries like Australia, which have introduced 5 minute dispatch intervals to cope with a high penetration of solar PV may offer useful experiences for Korea. This, along with intraday and real-time markets, would greatly complement the existing day-ahead market and provide participants with incentives to balance the system and properly forecast their output and demand, ensuring smooth operation of the system.

Korea's current system has a single bidding zone power market with uniform pricing, which in practice does not recognise any physical constraints in the transmission and distribution networks. The market, therefore, lacks the proper signals for timely investment in transmission and optimal choice of locations for generation assets. This problem will grow larger with higher shares of VRE.

Introducing zonal pricing as a first step would help the Korean market identify and solve critical transmission bottlenecks. Results from the APS in 2035 show that the short-run marginal cost in each region will begin to diverge during many periods of the year. As a dynamic measure, zonal or nodal pricing can help capture these changes as they happen and provide better information for generation and transmission planning.

Technology neutral capacity payments based on performance are a tool to meet critical power system needs

Even with enhancements in pricing and market design, achieving Korea's policy objectives of electricity security and decarbonisation may still require additional incentives for investments in certain technologies. Regulatory or revenue uncertainty and the lack of visibility over decarbonisation paths can be significant barriers to securing investment at the scale or pace required.

Capacity payments can thus help to complement market revenues and ensure enough investment. They should be technology neutral and remunerate new technologies, such as battery storage, VRE and demand response, which have typically been excluded from such schemes.

Moreover, the remuneration to these assets should reflect their contribution to the system's most critical conditions, such as net load peaks or reserve shortfall hours, which may evolve over time. It is also important to remember that capacity payments are not meant to pay twice for the investment, so they need to be designed in such a way that they reflect only the "missing money" required by generators to break even, subtracting net revenues received in the wholesale electricity market.

Market-based renewable support schemes can accelerate VRE deployment while improving the efficiency of Korea's wholesale market

Even with wholesale market reforms, market revenues alone may not be enough to bring about sufficient levels of low-carbon energy, which would still require dedicated support mechanisms to accelerate investment. Currently, Korea's main instrument for this is a Renewable Portfolio System with incremental requirements for generators, and varying support levels depending on the maturity of individual technologies. The effectiveness of Korea's support mechanisms could be improved using mechanisms that link the level of support directly to potential revenues from the wholesale market.

Feed-in premiums and competitive auctions that provide additional revenues to generators on top of wholesale market revenues are an option to minimise costs of decarbonisation. These mechanisms can be designed to reward technologies based on the time and locational value of their generation to the system, encouraging system-friendly deployment. Moreover, being benchmarked around wholesale market revenues, these approaches are compatible with the market enhancements listed above.

Since Korean regions have different levels of VRE resource availability and demand, each region will have a different profitability/cost profile. The introduction of feed-in premiums with long-term auctions could help locate new VRE capacity where it adds the most value to the Korean power system. The United Kingdom's Contract for Differences scheme, the Mexican Long-Term Auction and the German Feed-In Premium Scheme are all support mechanisms that provide more revenues to resources generating energy at times and locations where it is most valuable to the system, providing incentives to properly choose location and technologies.

Certificate mechanisms are compatible with carbon pricing and scarcity revenues, since these price enhancements would reduce the cost of certificates for technologies producing in hours of scarcity and where the marginal source of energy is carbon-intensive.

Effective deployment of distributed energy resources in Korea will require accelerating digitalisation

At present, large industrial consumers constitute the largest share of participants in the country's demand response programmes. However, recent advances in digitalisation technologies for the power sector are already driving the deployment of distributed assets, such as electric vehicles (EVs), battery storage, and cogeneration for active participation in balancing markets. This, however, will require a greater deployment of advanced metering and control technology and, potentially, the entry of new service providers.

Improving market access is necessary to ensure the participation of distributed energy resources in Korea's electricity markets

As the share of VRE generation and distributed assets increase in the Korean power system, it may be helpful to review how the costs of keeping the system in balance are managed.

Utilising the full array of distributed resources potentially available in the Korean Power system – including EVs, behind-the-meter batteries, solar panels and diesel emergency backup generators – is likely going to require major changes to the rules for market access. Other system operators in the world delegate the task of handling large numbers of small demand-side assets to retailers and other market participants. Korea needs to create its own schemes for these assets to be represented in the market.

The increase in renewables will drive an increase in balancing requirements, and in a system where balancing costs are passed directly to consumers, system operators may not see a need to innovate or look for cheaper providers. In this case, introducing incentive-based regulation for network costs or allowing the entry of new participants in the retail market can be a driver for innovation in the management of balancing requirements.

As the share of VRE increases, retail pricing structures in Korea will need to adapt

In the 2035 Korea APS scenario, optimising the charging pattern of 30% of EVs could lead to significant savings in average energy costs (19%) and peak capacity costs (30%) for the EV fleet. Emissions from EV charging would be reduced by 20%. However, the current retail tariff structure would not encourage such optimisation of EV charging patterns, as Korea's current schedule for time-of-day tariffs sets the peak load period during the middle of the day in summer. In the future, this would end up discouraging the use of electricity from solar PV for charging EVs, thus increasing costs and emissions.

Moreover, the participation of behind-the-meter battery energy storage systems for flexibility and system services could be encouraged by providing new revenue opportunities, beyond the existing potential for savings through avoided network charges. In other jurisdictions, the shift from so-called critical pricing of network costs to active participation in ancillary services and balancing markets has contributed to reducing system costs and improving the dispatch of battery storage as the system decarbonises.

Chapter 1 – The role of the power sector for Net Zero

Pathways to global Net Zero

The Intergovernmental Panel on Climate Change (IPCC) Special Report on Global Warming of 1.5ºC reports that achieving net zero CO_2 emissions by mid-century helps to keep global temperature increase to 1.5ºC by 2100, thereby reducing the climate-related risks to natural and human systems (IPCC, 2018). An increasing number of countries including Korea have announced targets to achieve net zero emissions by 2050.

In October 2020, Korea announced its pledge to achieve net zero emissions by 2050. Korea is a significant emitter at 586 million tonnes of CO_2-equivalent in 2019 (2% of global annual emissions). Its power and industrial sectors are major contributors to annual national emissions at 37% and 36% respectively. The Korean economy accounts for 2% of global GDP and its industrial output is crucial to the global economy. A carefully designed path to reduce emissions would help maintain Korea's competitive edge during its energy transition.

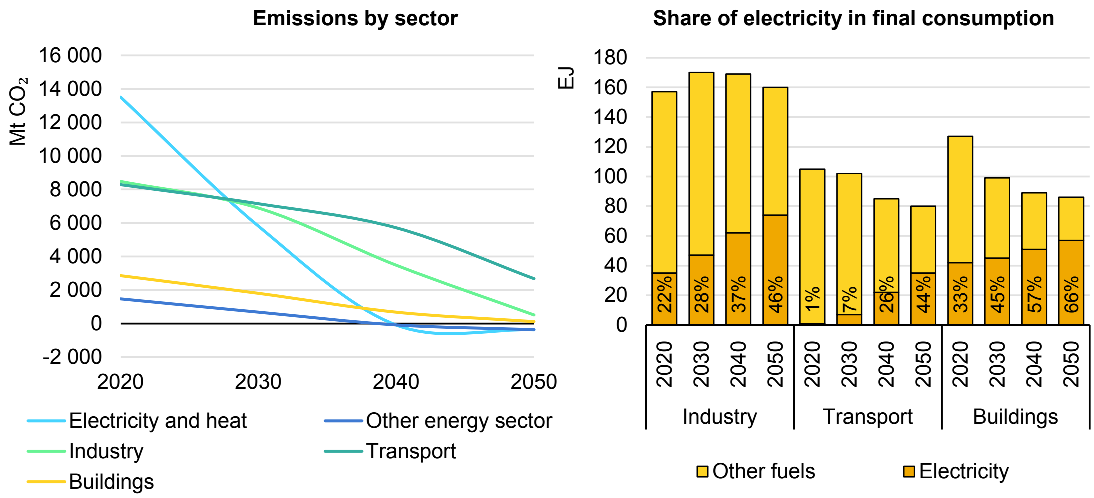
Achieving net zero emissions by 2050 requires a massive transformation of the greenhouse gas-emitting sectors. Among them, the global power sector, responsible for 40% of annual emissions in 2020, requires the most rapid accommodation of existing technologies and an introduction of new ones necessary for decarbonisation. Significant changes to regulation and market design are also needed to make this process cost-effective.

The power sector is critical to decarbonisation of the global economy

The IEA published a roadmap to achieve net zero by 2050, outlining policy and technology milestones to achieve decarbonisation for each sector (IEA, 2021a). In the roadmap, the Net Zero Scenario (NZE) is presented, which describes how energy demand and the energy mix will need to evolve if the world is to achieve net zero emissions by 2050. The power sector is expected to play a key role in achieving net zero emissions between 2030 and 2040 – the earliest among the sectors. This is achieved through increasing the share of low-carbon power generation from 29% to 88% and through the deployment of net-negative emissions technologies.

At the same time, the power sector's scope increases as electricity forms a larger share of final energy consumption from 20% today (81 EJ) to 49% in 2050 (169 EJ). This increased electrification allows a number of end-uses to be decarbonised within an early timeframe.

Emissions by sector (left) and share of electricity in final consumption by sector (right) in the Net Zero Emissions scenario



Source: IEA (2021a), *Net Zero by 2050 - A Roadmap for the Global Energy Sector*.

Power system transformation will require significant changes to system operations, network infrastructure and market design

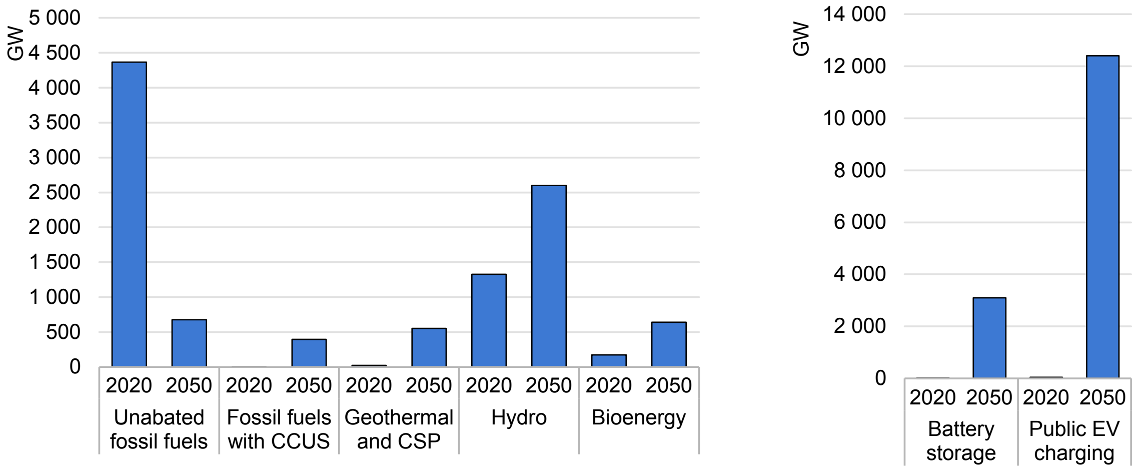
The low-carbon technologies required to attain a net zero power sector are built and operated differently compared to the existing system, which is predominantly based on fossil fuels. This has implications for systems operations as well as infrastructure investments that require revisiting the regulatory frameworks governing their remuneration.

Variable renewable energies (VRE), such as wind and solar PV, are expected to play a significant role in achieving net zero. In the NZE, solar PV and wind energy global generation increase from 2 413 TWh in 2020 (9% of total generation) to 48 254 TWh in 2050 (68%). To maintain stability and reliability, technologies that help match demand and supply, such as battery storage, are scaled up from 18 GW today to around 3100 GW by 2050.

In addition, low-carbon flexible and dispatchable generating technologies that can ramp up and down in different time frames also need to scale up. For example, current global installed capacity of bioenergy (171 GW in 2020) and hydrogen-based generation (0 GW) increase significantly to 640 GW and 1870 GW respectively by 2050 in the NZE. In many cases the contribution of these technologies to capacity requirements will be more important than the quantity of energy they produce.

Competitive power generation markets would see larger price variations in the NZE due to the share of zero-cost variable solar PV and wind. Measures to assign value to the flexibility of dispatchable generation are important to provide the necessary signal for investment.

Installed capacity for flexible supply (left) and storage (right) in 2020 and in the Net Zero Emissions scenario, 2050



Source: IEA (2021a), *Net Zero by 2050 - A Roadmap for the Global Energy Sector*.

Expanding and strengthening transmission and distribution infrastructure are needed both to meet increasing electricity demand and to address the mismatch in the locations of supply and demand. Increased electrification of end-use sectors, such as transport, will require the deployment of public electric vehicle (EV) charging infrastructure that can exceed the existing capacities of distribution grids. Moreover, solar and wind generators are often further away from load centres than conventional thermal power plants, and hence require new transmission routes. Taking these into consideration, total annual investment in network infrastructure would increase from USD 260 billion in 2020 to approximately USD 800 billion in 2050 in the NZE scenario.

Korea's objectives for Net Zero by 2050

Korea's net zero pledge is the country's most ambitious climate-related commitment thus far. In 2010, Korea enacted the Framework Act on Low Carbon Green Growth, aiming to voluntarily reduce greenhouse gas (GHG) emissions in 2020 to 543 Mt CO_2-eq. However, by 2017 it was not on track in reducing emissions and modified its target to 2030 (IEA, 2020).

For the 2015 Paris Agreement, Korea targeted a reduction in emissions to 536 Mt CO_2-eq by 2030. This was revised in 2021 with a new target of 437 Mt CO_2-eq by 2030 to support the announced net zero goals.

In September 2021, the Korean parliament approved the bill on carbon neutrality and set aside KRW 12 trillion (USD 10 billion[1]) for the state budget in 2022 to address GHG emissions reductions (S&P Global, 2021). Korea's Carbon Neutral Strategy (CNS) also elaborates details of the country's net zero target in 2050 with two main scenarios that have varying implications for the power supply and transport sectors:

- **Scenario A**: total cessation of fossil unabated generation or conversion into zero-emissions fuel; targeting a 71% share of new and renewable energy (NRE)[2]; targeting an 80% share of electric vehicles in the transport fleet and 17% from alternative fuels such as hydrogen.
- **Scenario B**: partial maintenance of thermal generation while gas remains the primary flexible power source; high carbon capture, utilisation and storage (CCUS) deployment; 61% share of NRE; targeting more than 85% of cars with no internal combustion engines (non-ICE cars).

Common measures in the industrial sector include hydrogen reduction in steelmaking, fuel conversion in cement, the usage of electric heating furnaces in petrochemicals and increasing energy efficiency in semiconductors. In the building sector, measures include the construction of zero energy buildings, roll-out of smart energy management solutions and increasing the share of district heating from renewable energy and waste.

In the power sector, scenario B achieves net zero with greater reliance on carbon capture, abating 84.6 Mt CO_2 per year. The two scenarios project different power mixes, with scenario B relying on grid imports from the Northeast Asia supergrid[3] along with an expanded use of fuel cells, whereas scenario A relies more on an

[1] 1 USD = 1174 KRW.

[2] New and renewable energy is a group of technologies comprising solar PV, solar thermal, wind, geothermal, bioenergy, hydro, marine, bioenergy, waste, fuel cell and coal gasification or liquefaction.

[3] The Northeast Asian Super Grid cross-border transmission line project initially proposed in 2011, involving the People's Republic of China (hereafter, 'China'), Korea, Mongolia, Russian Federation (hereafter 'Russia'), and Japan. Construction has not yet started as political and legal frameworks are yet to be decided.

expanded use of NRE such as solar PV and wind. Both scenarios rely significantly on generation – between 14% and 22% – from low-carbon fuels.

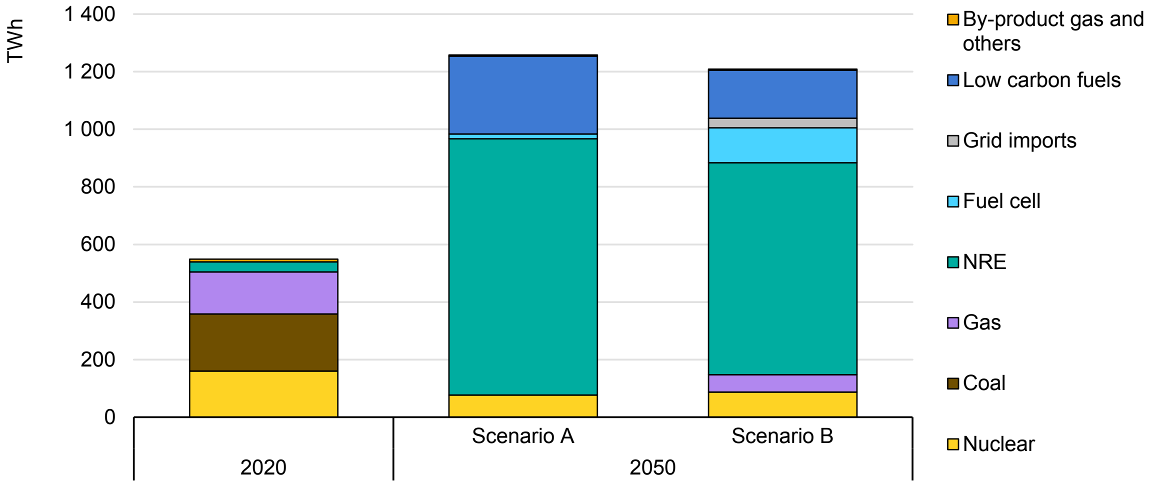
Emission targets for Korea's Carbon Neutral Strategy

	2018 emissions ($MtCO_2$-eq)	**2050 emissions** ($MtCO_2$-eq)	
		Scenario A	**Scenario B**
Power	269.6	0	20.7
Industry	260.5	51.1	51.1
Building	52.1	6.2	6.2
Transport	98.1	2.8	9.2
Agriculture	24.7	15.4	15.4
Waste	17.1	4.4	4.4
Hydrogen	0	0	9
Fugitive	5.6	0.5	1.3
SUBTOTAL	**727.7**	**80.4**	**117.3**
Sink*	-41.3	-25.3	-25.3
CCUS	0	-55.1	-84.6
Direct Air Capture**	0	0	-7.4
TOTAL	**686.4**	**0**	**0**

* Sinks involve measures to reinforce absorption capacity such as: forest cultivation, ecological restoration, reforestation of idle land, cultivation of urban forests, expansion of long-life wood production, expansion of carbon sinks using marine ecology and expansion of grassland area.
** Carbon offsetting using direct air capture (DAC) is used to cover the remaining emissions from the transport sectors

Sources: Government of Korea (2021a), 2050 Carbon Neutral Strategy of the Republic of Korea.

Power sector generation in Korea's Carbon Neutral Strategy, 2050



Notes: Low-carbon fuels include hydrogen and ammonia used as combustion fuel in steam and gas turbines. Grid imports are based on the proposed Northeast Asian supergrid.

Sources: Government of Korea (2021a), 2050 Carbon Neutral Strategy of the Republic of Korea.

Use of nuclear power still follows the principles of the 3rd Energy Master Plan (EMP) of stopping new construction of nuclear power plants and retiring existing nuclear plants according to their technical lifetime. On this basis, the last retirement of nuclear capacity is anticipated in the 2080s (IEA, 2020).

In its Carbon Neutral Strategy, Korea laid out principles to achieve decarbonisation of its power system, including instruments to achieve the following:

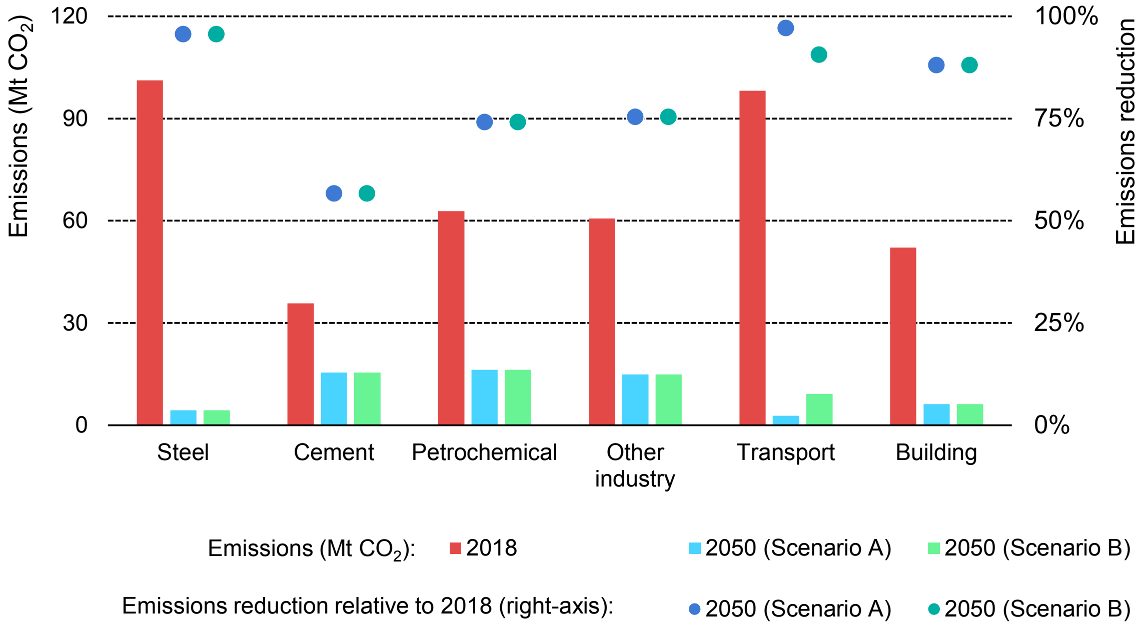
- Facilitate carbon pricing through the emissions trading system by increasing the portion of paid carbon allowances and reflecting carbon costs in electricity rate.
- Speed up variable renewable energy (VRE) uptake through easier permitting and the creation of regulatory mechanisms for distributed renewable energy.
- Ensure system stability through expanding flexible resources and electricity storage, as well as the introduction of real-time market and ancillary services market in the electricity market.
- Gradual phase-out of fossil fuel generation in consultation with affected communities and preparation of retrofits for low-carbon fuels such as hydrogen and ammonia.
- Support commercialisation of R&D technologies, such as floating solar with hydro, hydrogen turbines and marine energy.

The details of how these policies are implemented are critical to achieve the desired results. The right investment and regulatory environments could help usher in the required energy infrastructure and manage their future costs.

End-use electrification as a vector for emissions reductions

In 2018, industry, transportation and buildings accounted for the majority of emissions in Korea (54%), therefore decarbonising these sectors is a major component of Korea's Carbon Neutral Strategy (Government of Korea, 2021a). To reduce emissions, there are a number of potential pathways available that should be explored, such as fuel replacement, energy efficiency, materials efficiency and behavioural changes that lead to avoided demand.

Emissions reduction per sector according to the Korean Carbon Neutral Strategy

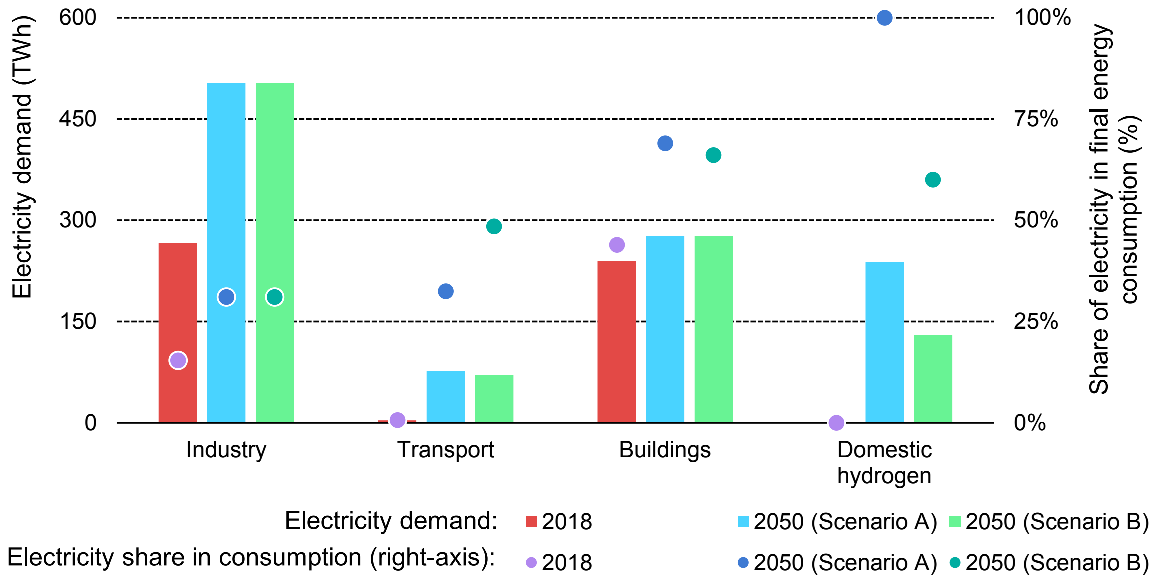


Note: Emissions for industrial subsectors emissions are based on the proportion of total industrial emissions attributed to each subsector in the August 2021 draft of the Korean Carbon Neutral Strategy.

Source: Government of Korea (2021), 2050 Carbon Neutral Strategy of the Republic of Korea.

With the decarbonisation of the power sector, electrification can become a key vector for decarbonisation in industry, transport and buildings. This will involve not only the direct replacement of fossil fuels with electricity, but also increased energy efficiency, enabled by electrification. As a result, it is estimated that the share of electricity in final energy consumption in the aforementioned sectors will increase significantly according to the Korean Carbon Neutral Strategy, although the absolute increase in electricity demand will be offset by efficiency gains across the sectors, which is especially evident in the buildings sector.

Growth in electricity demand and share of final energy consumption per sector in Korea according to its Carbon Neutral Strategy



Note: Size of electricity demand and share in final energy consumption is based on provisional data in the in the August 2021 draft of the Korean Carbon Neutral Strategy, aligning the old scenarios to the Scenarios A and B based on relevant information such as emissions

Source: Government of Korea (2021a), 2050 Carbon Neutral Strategy of the Republic of Korea

Despite the overall increase in the share of electricity in these sectors, there remain some limitations for direct electrification. For example, certain industrial processes currently require very high heat input that electricity cannot provide through existing technologies and that only low-carbon fuels, including biofuels and hydrogen, can provide without direct emissions. Similarly, constraints in energy density for battery storage technologies and the applicability for certain transport modes, specifically transoceanic maritime transport and aviation, also limit the extent to which transport can be directly electrified. Additionally, decarbonisation of industry will require more than just the replacement of direct energy inputs but will also rely on reducing process emissions through the substitution of fossil fuels for chemical reactions, as well as other raw materials in the manufacturing process, which result in downstream emissions.

While electrification can replace heat input in industry, its cost competitiveness with current technologies remains limited. As a result, the Korean Carbon Neutral Strategy has limited room for electrification in heavy industry (steel, chemicals and cement). Electrification will play the largest role in steelmaking, where all furnaces will be replaced with electric-arc furnaces to produce steel, while Korea also aims to replace a portion of furnaces (53%) in chemical production with either electric furnaces or biomass boilers.

As a key component of Korea's export economy, the decarbonisation of industry will be a delicate process as it will potentially affect the cost competitiveness of Korean products in the global market. These include products with small margins in competitive markets such as semiconductors, batteries and automobiles that form a core component of the 2050 economy. The challenge is therefore to decarbonise industry while remaining competitive, which may require global co-operation as well as frameworks that enable a level playing field for new technologies. For example, the newly proposed Carbon Border Adjustment Mechanism (CBAM) in the European Union put forward plans to add a carbon border tax on certain products to avoid carbon leakage, i.e. the relocation of certain companies or imports from countries with less stringent carbon emission standards (European Commission, 2021).

Transport was the second largest sector for emissions in Korea in 2018, with the majority of these coming from road transport (94%). EVs therefore should be central to decarbonising the transport sector, especially considering the strong battery and automotive industries in Korea. In the road transport sector, the share of battery electric vehicles (BEVs), hydrogen-powered fuel cell electric vehicles (FCEVs) and vehicles with internal combustion engine (ICE) vehicles (including hybrids) differs across the different net zero scenarios (Table 1). Apart from different proportions of BEVs and FCEVs, the main point of difference between the two scenarios is the share of ICE vehicles (3 or 15%) that remain on Korean roads, with a sizeable portion of the fuels for these consisting of e-fuels produced by direct air capture (DAC). Apart from road transport, electrification would also significantly impact the decarbonisation of rail, with all railways being either electrified or hydrogenised.

Share of road transport in Korea in 2050

Vehicle type	Share in Scenario A (%)	Share in Scenario B (%)
BEVs/FCEVs	97	85
ICE vehicles (including hybrids)	3	15

Source: Government of Korea (2021a), 2050 Carbon Neutral Strategy of the Republic of Korea.

In Korea, the government announced a series of targets and ambitions between 2019 and 2020 to accelerate EV deployment, notably that by 2030, 33% of new cars should be either electric or fuel cell powered and a target of 1.13 million battery EVs and 200,000 passenger fuel cell electric vehicle (FCEV) stock by 2025

(ICCT, 2020). To accompany the EV transition and minimise range anxiety, the government further aims to raise the charger-to-EV ratio to at least 50% nationwide (Electrek, 2021) and has revised its subsidy scheme in 2021 to further support EVs and FCEVs (Hyundai MG 2021). The EV sales share is increasing steadily in Korea (reaching 3% of total car sales in 2020); two new models of light-commercial vehicles (LCVs) were introduced to the market in 2020, and the country has taken the lead in FCEV deployment, with 29% of the worldwide FCEV stock, surpassing the United States and China.

While electricity demand for buildings in Korea in the CNS scenarios will increase by 16-24% in 2050 relative to 2018, TFEC will decrease by 21-23%, where energy efficiency and electrification are the two key drivers in the decarbonisation of buildings. This is not only through an increased in the stock of high-efficiency devices but also through better and smarter management of energy use through energy management systems. Although Korea aims to replace the majority of gas in cities with electricity, its Carbon Neutral Strategy sees 50% of the current gas demand in cities remaining in 2050.

Ensuring competitiveness in the energy transition

Korea's role as one of the main exporters

Korea was the 10th largest economy in the world in 2020 and is highly integrated into the global economy, being 6th in total exports and 9th in total imports (OEC, 2021). Exports of goods and services have contributed between 36% and 54% of the country's GDP over the last decade (World Bank, 2020a). The country's export-oriented industrial development has shifted from labour-intensive low value-added activities, such as textiles and footwear, to more capital-intensive high value-added ones, such as cars and electronics.

Currently, its most valuable exports are in integrated circuits (USD 82 billion), cars and vehicle parts (USD 59 billion), refined petroleum (USD 39 billion) and ships (USD 19 billion), and these are tightly integrated with the remaining domestic subsectors (OEC, 2021). For example, 27% of the domestic output of basic and fabricated metals went as input to machinery and transport manufacturing in 2018 (Bank of Korea, 2020).

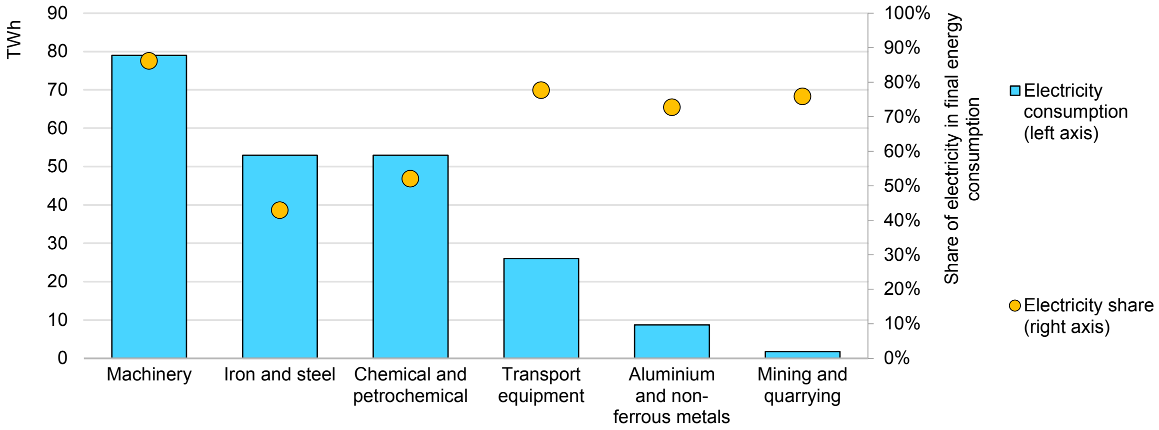
Given the role that exports play, Korean policy makers focus on the global competitiveness of its industries and services. Innovation is one of the key priorities, with R&D spending among the highest in the world at 4.8% of GDP compared to Japan or the United States at 3.3% and 2.8% respectively (World Bank, 2020b). Korea's Green New Deal aims to decarbonise the industry sector, decouple energy consumption from its economic activity and enable energy transition through digitalisation (IEA, 2020).

The economic importance of Korea's industrial sector, its competitiveness and its development are major factors to consider during Korea's transition to a carbon-neutral scenario.

Dependency of Korea's exports on power sector

Korea's industry is highly reliant on the power sector, with 50% of its final energy consumption coming from electricity. Sectors such as machinery and transport equipment cover the main export industries of automobiles and shipbuilding. The manufacturing of such relies on high amounts of electricity use and is aided by secure supply and relatively low industrial electricity prices.

Electricity consumption and its share in total energy consumption in selected industrial sectors in Korea, 2019



Source: IEA (2021b), *World Energy Statistics and Balances* [database].

Industrial electricity prices in Korea are among the lowest in OECD countries at USD 95/MWh in 2019, compared with countries like Japan at USD 164/MWh and Germany at USD 146/MWh. Tariffs vary depending on voltage, time-of-use, season and rate, and cross-subsidies between industrial and residential tariffs persist (IEA, 2020).

The cost of materials is also a crucial factor in the competitiveness of the country's exports. Aluminium and steel are key components of automobiles and ships, for example. As energy-intensive processes, their prices are significantly influenced by the cost of energy input. For instance, approximately 33% of Korea's steel sector uses electric-arc furnaces (World Steel Association, 2020).

Given the role of electricity in Korea's economy, it is therefore important to consider the competitiveness of these key industries when transitioning to zero carbon electricity.

Korea's current pathway

Korea satisfies 90% of its primary energy demand through imports. Its electricity system is heavily reliant on coal (43% of total generation in 2019), natural gas (25%) and nuclear (25%), whose fuels are entirely imported. While the country is in a continental peninsula, its electricity system is an isolated system with no cross-border interconnections. As such, security of supply is an important driver for its energy policy. Diversification of resources and increasing domestic supply through increasing installed renewable energy are some of the directions chosen.

Korea's national energy policy is based on its Energy Master Plan (EMP), renewed every five years. The most recent plan is the 3rd EMP drafted in 2019 with the vision to achieve sustainable growth and improve quality of life through energy transition. Among its objectives for 2040 are:

- A reduction of 39.2 Mtoe of final energy consumption.
- A 30% to 35% share of renewable energy generation.
- 8.3 million electric vehicles and 2.9 million hydrogen vehicles, up from 55 thousand and 1 thousand respectively in 2018.
- A 30% share of distributed generation, up from 12% in 2017.
- Increasing hydrogen supply to 5.26 million tonnes, up from 130 000 tonnes in 2018.
- Promotion of the Northeast Asia Super Grid.

The new nationally determined contribution (NDC) aligned with the announced Carbon Neutral Strategy sees some of these 2040 targets being achieved by 2030, indicating Korea's commitment to pursue a sustainable energy transition. For example, Korea plans to achieve 30% renewable energy generation, 4.5 million electric or hydrogen vehicles and 7.6 million tonnes of hydrogen production as early as 2030.

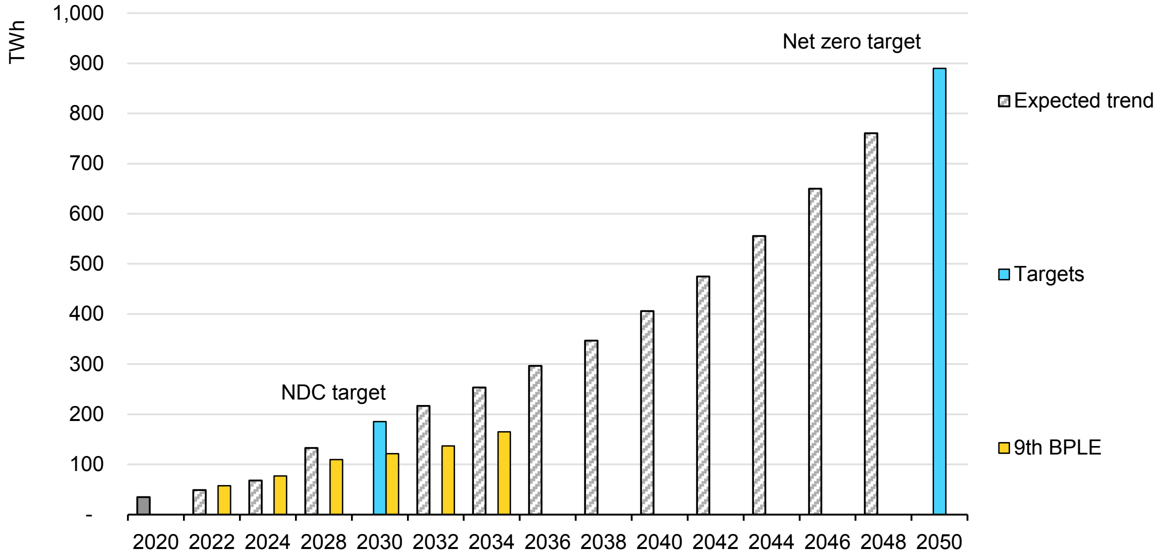
Within the power sector, the Basic Plan for Long-Term Electricity Supply (BPLE) is the main planning blueprint, which is revised every two years. The 9th BPLE was announced at the end of 2020 prior to the finalisation of the Net Zero strategies.

Consequently, several measures and power plant commitments need to be revisited during the next scheduled BPLE revision to account for the new net zero and NDC targets.

Increasing renewable energy generation

While generation from new and renewable energy is expected to grow 41 TWh in 2020, 122 TWh in 2030 and 158 TWh in 2034, according to the 9th BPLE, the new NDC already targets increased generation from NRE at 185.2 TWh by 2030, or 18% annual average growth starting today. In the CNS, the share of new and renewable energy would be 736 TWh to 890 TWh by 2050, equivalent to 11% annual average growth from the 2030 NDC targets.

Historical and projected renewable energy generation based on 9th Basic Plan for Long-Term Electricity, Nationally Determined Contribution and Carbon Neutral Strategy targets



Notes: NDC = Nationally Determine Contribution. The net zero target considers the higher renewable generation in Scenario A. Scenario B targets a renewable generation.

Source: IEA Analysis of Government of Korea (2021), 2050 Carbon Neutral Strategy of the Republic of Korea; MOTIE (2020), 9th Basic Plan for Long-term Electricity.

Growth of NRE is driven primarily by solar PV and wind generation in the BPLE, contributing 83% to the overall generation growth. The share of variable renewables in total generation would increase from 4% in 2020 to 20% in 2034.

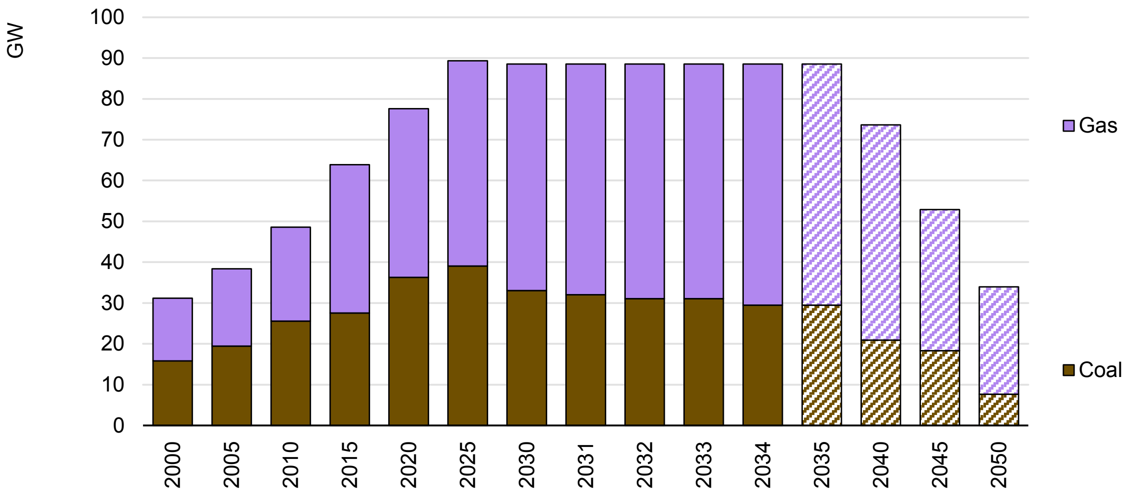
While the share of variable renewable energy in the CNS has not yet been defined, its share within the overall NRE generation (61% to 71% of total generation) is likely to remain significant. Integrating higher levels of VRE should thus be a primary focus to help achieve the medium-term target of renewable energy by 2030 and to pave the way towards the 2050 targets.

Early retrofitting supports the net zero targets of low-carbon fuels

Dispatchable and flexible power source would remain valuable to support the integration of higher levels of VRE. The 9th BPLE foresees that coal- and gas-fired capacity – the conventional power plants providing such service – will stand at 29.5 GW and 59 GW respectively by the end of the planning period in 2034. With expected technical lifetimes and no additional power plants, the remaining capacities would be 7.7 GW and 26.3 GW respectively by 2050.

These remaining capacities alone do not entail emissions. If they operate for only a few hours of the year during peak periods, the resulting emissions could remain low while providing peaking capacity. Moreover, if the plants are equipped with CCUS or if the fuels are replaced with biomass or other low-carbon fuels like ammonia or hydrogen, the emissions from these dispatchable plants could be mitigated while keeping the value of flexible and dispatchable technologies within the fleet.

Remaining installed capacities of coal and gas plants by 2050 based on technical lifetimes



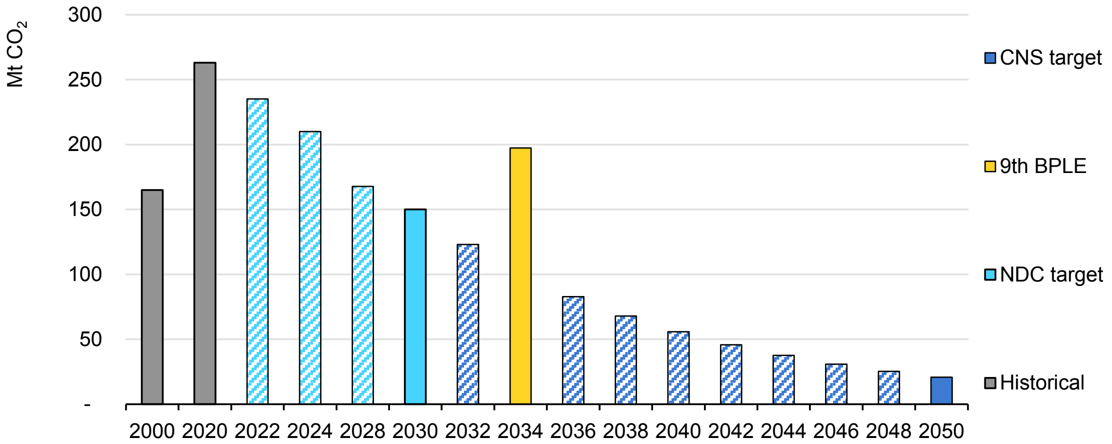
Source: IEA Analysis of MOTIE (2020), 9th Basic Plan for Long-term Electricity; Platts (2020), *Global Power Plant* [Database]

Korea's new NDC targets include around 22 TWh of generation from ammonia by 2030. In the KNZS scenarios, low-carbon fuels generation is expected to be 167 to 270 TWh by 2050. These generation levels imply around 38 to 61 GW of installed capacity operating at mid-merit level, primarily flexibility services to the system. By 2040, around 72 GW of coal- and gas-fired generation are still operational and retrofitting these to use low-carbon fuels could justify an extension of the physical assets' lifetimes.

Policies to reduce the emissions of the power sector need to be assessed

Based on the expected thermal and renewable capacities in the BPLE, the absence of carbon capture technologies within the 2020 to 2034 period and the effect of the current emissions trading scheme, the expected emissions will remain high through 2034.

Historical and projected carbon emissions from power generation based on the 9th Basic Plan for Long-Term Electricity, Nationally Determined Contribution and Carbon Neutral Strategy targets



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Notes: CNS = Carbon Neutral Strategy; BPLE = Basic Plan for Long-Term Electricity. CNS target in this figure considers the higher emissions from Scenario B. Scenario A would require a more aggressive reduction. Emissions by 2034 from the 9th BPLE assumes current configuration of ETS where carbon costs are not reflected in the dispatch.

Source : IEA Analysis of MOTIE (2020), 9th Basic Plan for Long-term Electricity; Government of Korea (2021a), 2050 Carbon Neutral Strategy of the Republic of Korea; Government of Korea (2021b), Planned Update of Nationally Determined Contributions.

The current GHG emissions trading scheme in Korea – introduced in 2015 – covers over 70% of emissions, including heat, power, industry, buildings, domestic aviation, waste and public services. Since the beginning of 2021, the Emissions Trading System (ETS) entered its third phase (2021 to 2025), whereby the power sector is allocated 90% of its allowances free of charge.

Allowances, including price and volume limits, in the power sector are determined by technology-specific benchmarks for fuel type. Currently the cost of allowances is not reflected in the wholesale market, but instead passed through to customer tariffs, which allows the Korea Power Exchange (KPX) to compensate generators for any emissions that exceed their allowance (IEA, 2021c). In addition, dispatch does not reflect the carbon cost, so the current scheme does not offer any real incentive for the power sector to reduce emissions.

These policy details should be revisited to ensure that the progress towards Korea’s Carbon Neutral Strategy is improved.

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Chapter 2 – Matching Korea's emission pathways with its policy objectives

Modelling Korea's power system in 2034 and 2035

Electricity generation in Korea today relies heavily on fossil fuels, which composed 65% of total electricity generation in 2020, consisting primarily of coal (38%) and gas (27%); nuclear power accounted for 29%. Korea has no electricity interconnections with other countries and relies entirely on domestic electricity production to meet demand. The government is committed to strongly increase the share of energy from renewable sources in the next decade and to gradually phase out nuclear and coal-fired power generation (IEA, 2020).

Korea's 9th BPLE was released on 28 December 2020, and is currently the most up-to-date official, detailed plan for the Korean power sector (MOTIE, 2020). However, the plan was released only months after the Korean government announced its pledge to reach net zero emissions by 2050. As a result, the net zero ambition was not reflected in the 9th BPLE. In addition, in October 2021 Korea announced a new set of Nationally Determined Contributions under the Paris agreement, which also outline a more ambitious clean energy pathway than the 9th BPLE.

To illustrate the market design considerations to achieve Korea's net zero pledge, the analysis in this report is supported by a net zero compatible power sector scenario for the medium term (2035). As there is currently no official detailed plan available for the Korean power sector in 2035 under Korea's Carbon Neutral Strategy, we use the IEA's Announced Pledges Scenario (APS) (IEA, 2021a). The APS is one possible pathway consistent with the Korean economy achieving net zero by 2050 (IEA, 2021b). The main purpose of the scenario in this context is to help illustrate market design considerations for the Korean government as part of their net zero pathway. The APS should not be viewed as a reflection on the specific development pathway that the Korean power system should take to meet its net zero objectives.

The IEA has developed a detailed power system model, the IEA Korea Regional Power System Model, for this report. In addition to the APS, this modelling includes one scenario that aligns with the 9th BPLE capacity plan in 2034 and uses 2020 as the base year.

These scenarios were used to develop recommendations for the Korean power sector to achieve a net zero pathway by 2050, including policy support, market design and power system flexibility needs.

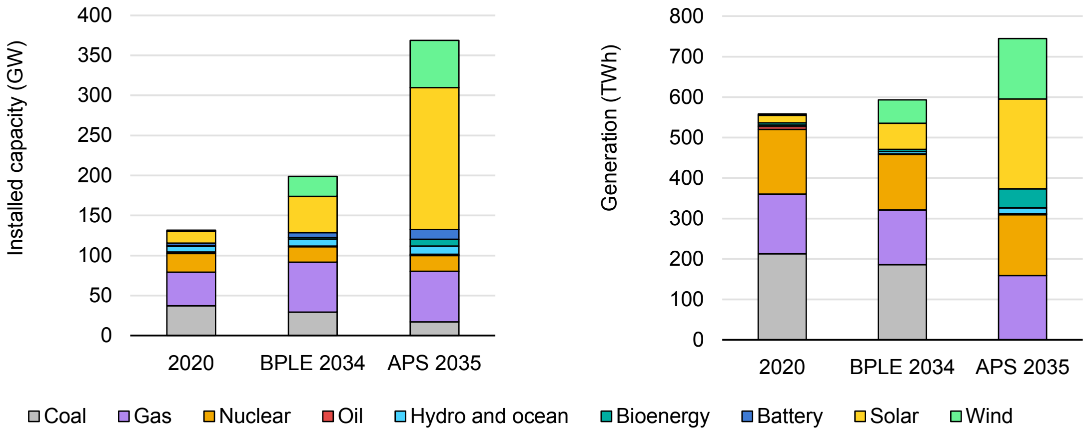
The IEA Korea Regional Power System Model is a 6-region model, developed in collaboration with the Korean Energy Economics Institute. The model represents the hourly dispatch of the Korean power system and includes sensitivities to illustrate the impacts of different levels of emissions pricing and flexibility options on power system operation and market outcomes. The model structure and the full set of cases analysed are described in the Annex of this report.

IEA Korea Regional Power System Model main scenarios and sensitivities

Scenario	VRE share	Sensitivities
Validation 2020	4%	-
BPLE 2034	21%	CO_2 price
APS 2035	50%	CO_2 price, demand response, battery storage, flexible cogeneration

Under the 9th BPLE, the Korean power system in 2034 will shift from coal generation towards increased, gas-fired generation based on conversion of a substantial amount of coal-fired capacity to combined cycle gas power plants. At the same time, the variable renewables share will rise from today's 4% to around 21% by 2034. These measures see a reduction in emissions intensity from around 485 t CO_2/MWh today to 365 t CO_2/MWh in 2034, and absolute emissions from the power sector falling 17% despite growing demand. However, this reduction still falls short of the reductions expected for the net zero pathway envisaged in the APS. In that scenario, Korea sees an emissions intensity around 75 t CO_2/MWh by 2035 and a 79% fall in power sector emissions relative to today, despite strongly growing demand.

Installed capacity (left) and generation (right) by technology in 2020, and in the Basic Plan for Long-Term Electricity 2034 and Announced Pledges Scenario 2035



Notes: BPLE = Basic Plan for Long-Term Electricity; APS = Announced Pledges Scenario.

Sources: KPX 2021 (2020); IEA Korea Regional Power System Model (BPLE 2034); IEA World Energy Model (APS 2035).

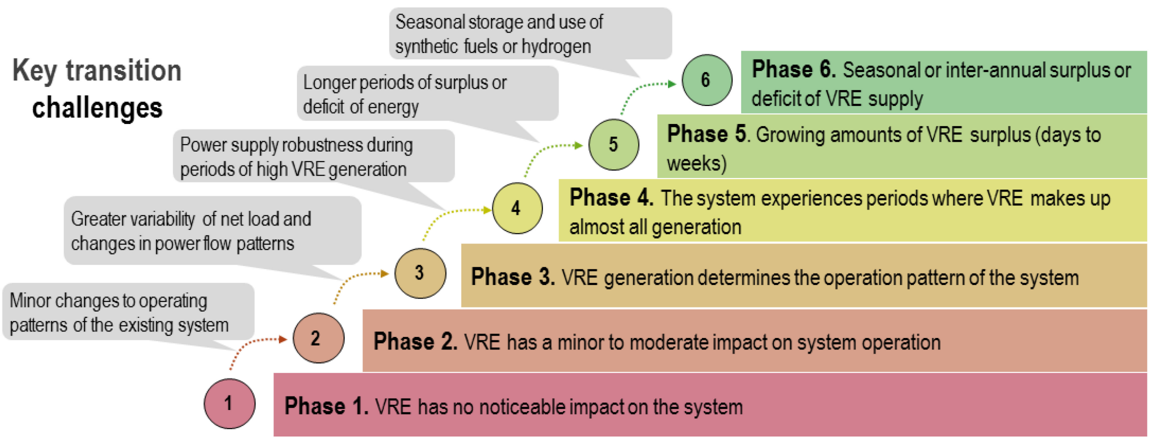
The steep emissions cuts achieved in the APS come from a range of complementary measures, to be discussed in more detail in the following sections: deep restructuring of the generation mix with rapid build-out of renewables generators supported by low-emissions dispatchable technologies; a strong carbon pricing signal ensuring that the cost of carbon emissions is accounted for in system dispatch; and the expansion of multiple sources of power system flexibility including demand response, allowing the integration of variable renewables to be maximised while maintaining system security. Policy and market design approaches to enable this rapid acceleration of renewables deployment are discussed in detail in Chapter 3, while this chapter focuses on the more technical aspects. While national grid strengthening is an important aspect of power system flexibility for Korea's net zero pathway, the technical details of grid strengthening are not explored in this report. Market design aspects relevant to grid development are, however, addressed in Chapter 3.

Deployment of VRE plays a vital role in emissions reduction

Korea's power system pathway laid out in the 9th BPLE would bring Korea to around a 21% share of VRE in generation by 2034. This is in tandem with a series of changes required to power system operations. In addition, experience from a number of other countries shows that there are a wide array of well-understood solutions that provide safe and cost-effective ways to integrate these amounts of VRE generation.

The IEA has developed a framework where renewables integration is conceptualised in a series of six phases which group and explain the typical transition challenges as VRE shares increase, as well as the different potential integration measures that can be implemented. While power systems will not transition sharply between phases, aspects such as size of the power system, degree of interconnectedness, and match between the load profile and VRE resource endowment can be useful to understand the dynamics of transitions from one phase to the next within a specific power system (IEA, 2019a).

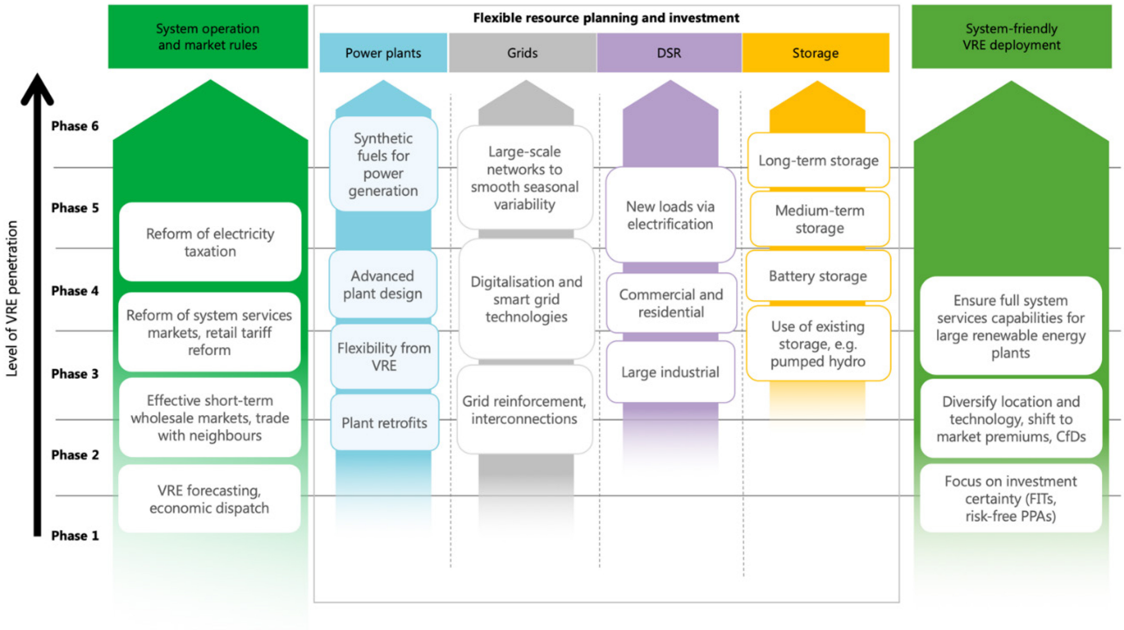
VRE integration phase assessment



Source: IEA (2019a), *Status of Power System Transformation: Power System Flexibility*.

As countries advance through the phases, different flexibility measures allow increasing amounts of renewables to be smoothly integrated into the system while maintaining secure power system operation. In the earliest phases, upgrades to operating practices and making better use of existing system resources are usually sufficient. From phase 3, the need for flexibility increases and requires increased flexibility sources. While all sources of flexibility can potentially assist in all phases, the earliest priorities include options such as plant retrofits for more flexible operations, internal grid reinforcement and interconnections. Moving into higher phases, increased demand response and energy storage become more important. At the highest phases of integration, options such as synthetic fuels and longer-term storage become critical to balance load and variable renewables across seasons and years.

The main pillars of power system transformation



Notes: CfD = contract for difference; DSR = demand-side response; FIT = feed-in tariff; PPA = power purchase agreement.

Source: IEA (2019), *China Power System Transformation*.

While VRE deployment greater than the levels foreseen in the 9th BPLE is needed to achieve the country's net zero pledge, even reaching the BPLE's targets will require Korea to deal with integration challenges from Phase 3 of VRE integration; particularly as an isolated power system that cannot rely on imports and exports during periods of low or high renewables generation. These challenges include dealing with maximum hourly VRE penetrations upwards of 60% relative to load and coping with steeper daily ramps, with a highest hourly ramp of 16 500 MW – 18% of daily peak demand – and three-hour ramp-down requirements equivalent to 51% of the daily peak already by 2030 (IEA, 2021c). A more detailed picture of the specific flexibility challenges is found in the IEA's 2021 Korea Electricity Security Review. Korea is already planning to implement a number of measures to improve renewables integration, which are laid out in the 9th BPLE:

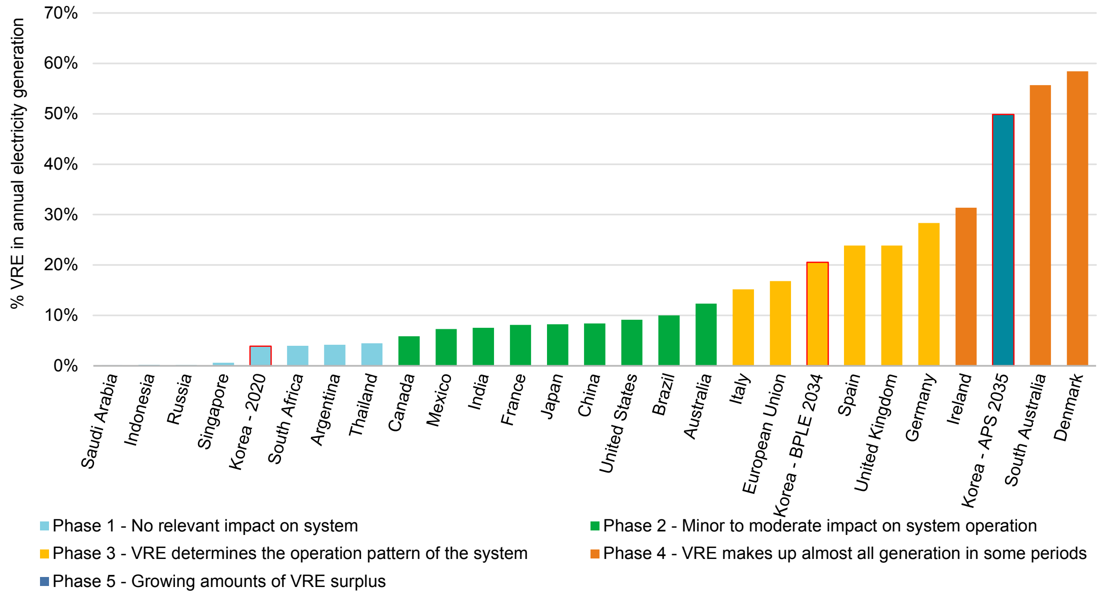
- Introduce a new bidding system for VRE, increase forecast capabilities, diversify RE resources and use Virtual Power Plants.
- Renewables generators greater than 20 MW will be able to bid to receive capacity payments. Compensation for curtailment is also under consideration.
- Reduce the bidding period from 1hr to 15 to 5 minutes to bring the market closer to real time.

- Create an ancillary services market where storage and distributed energy resources (DER)[4] can participate.

Increased deployment of VRE requires greater power system flexibility

Most countries today are in Phases 1-3 of renewables integration, with many having just begun their energy transition. A small number of regions and countries have reached Phase 4, such as Denmark and Ireland. This Phase describes systems where wind and solar PV compose almost all generation in certain periods, presenting challenges related to system stability. This can begin to occur in systems with about 30 to 40% annual share of VRE generation and may occur at first in only certain isolated or weakly interconnected subsystems or regions, such as in Texas and South Australia. However, as systems rapidly decarbonise to achieve net zero emissions, systems will transition to Phases 5 and 6, which are broadly categorised by more frequent and continuous periods of structural imbalance between VRE generation and demand (i.e. VRE surplus).

Annual VRE share in selected countries for 2019 and Korea in 2020, Basic Plan for Long-Term Electricity 2034 and Announced Pledges Scenario 2035



[4] Distributed energy resources correspond to small scale solar PV, wind energy, and combined heat and power limited to 40MW that can be connected to a 22.9kV distribution line.

The annual share of VRE provides a general picture of the contribution that VRE sources make to the power system. VRE-leading regions have accumulated a substantial body of knowledge for how to cope with the uncertainty and variability of solar PV and wind. It is also worth highlighting that high instantaneous VRE penetration levels can be an indicator of electricity security challenges. This can be of critical concern to system operators. When VRE production reaches an extremely high share or even exceeds total system demand in certain periods, as has occurred in regions such as Denmark and South Australia, system stability becomes an electricity security concern as the power system's ability to operate smoothly through unexpected events may change.

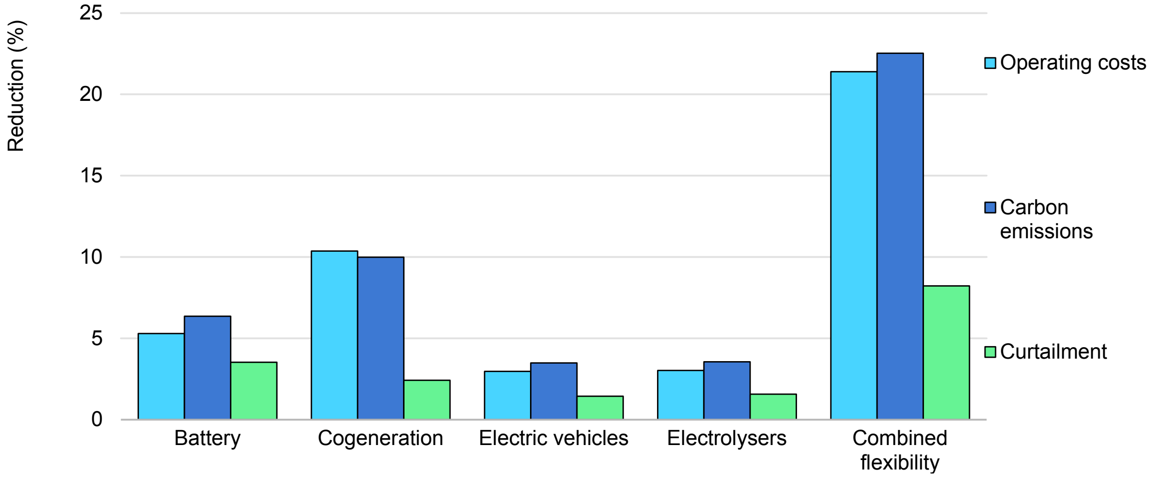
These concerns require more attention for regions with little or no interconnection to other grids like Korea. Ireland, for example, is pursuing a diverse set of measures to continuously increase the maximum amount of renewables that can be accommodated in the system through the Delivering a Secure Sustainable Electricity System programme (DS3) (IEA & RTE, 2021). The Irish system operators are also undertaking ongoing analysis to identify and solve the challenges of accommodating ever increasing variable renewables in their system (EIRGRID & SONI 2021). Korea is less vulnerable to these challenges than Ireland due to the larger size of the Korean power system but will nonetheless need to pay attention to stability as its VRE share increases.

Integrating VRE shares in Korea in the APS 2035

With the substantial increase in VRE shares from around 4% today to 50% in the APS in 2035, the Korean power system will move into phase 5 of renewables integration. This will require increased flexibility to balance electricity supply and maintain grid stability, coming from all sources – dispatchable power plants, the national grid, energy storage and demand response. These resources help to adapt both electricity demand and supply to better align with renewables output.

The value that flexibility resources can bring to the Korean power system is illustrated by comparing an inflexible case for the APS, where needed flexibility does not materialise, with the base APS scenario, where multiple flexibility sources are included. The combination of flexible cogeneration, batteries and flexible demand can reduce operating costs by around 21%, and also reduce emissions and curtailment. In addition, in the presence of a carbon price of USD 145/t CO_2, emissions savings from increased flexibility almost double from 12% to 23%. This level carbon price for 2035 aligns with the WEO APS in advanced economies with net zero pledges, which sees a carbon price of USD 120/t CO_2 in 2030 and USD 170/t CO_2 in 2050.

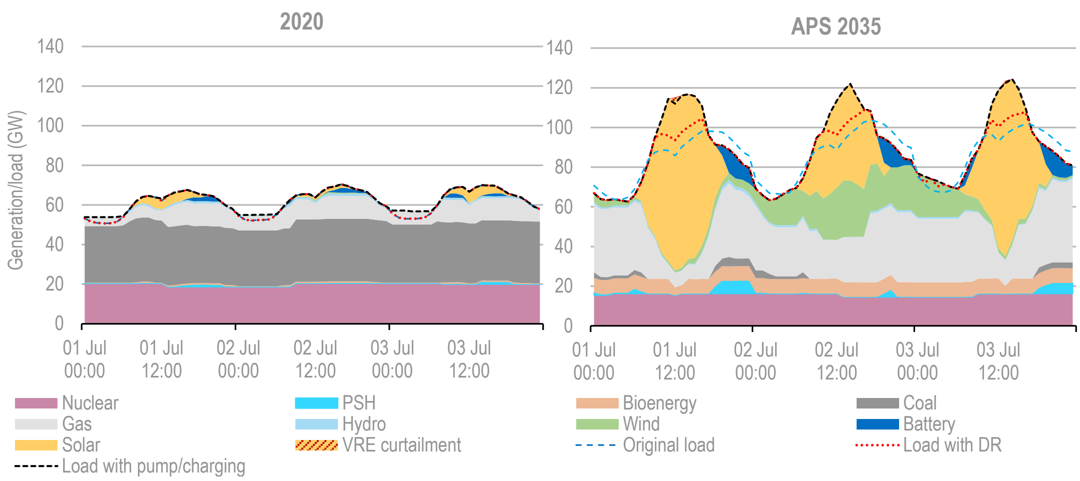
Impact of individual and combined flexibility measures on reducing curtailment, emissions and operating costs in Korea in the Announced Pledges Scenario 2035



Note: Combined flexibility case includes battery storage, and flexible EV charging, electrolyser load and cogeneration.
Source: IEA Korea Regional Power System Model.

Power system operation in the APS changes substantially from today due to factors on both the demand and supply side. In 2020, the ratio of peak to average demand is around 1.45; and nuclear, coal and gas make up the vast majority of supply. Through 2035, peak demand is expected to grow faster than average demand, and development of new demand, such as EVs and electrolysers, will affect the load shape. In the IEA Korea Regional Power System Model APS 2035, 30% of EV load is assumed to be flexible as well as all grid-connected electrolyser demand, allowing a proportion of demand to be shifted into the middle of the day to accommodate high solar output.

Power system dispatch by technology in 2020 and the Announced Pledges Scenario 2035



Notes: APS = Announced Pledges Scenario; DR = demand response; PSH = pumped storage hydropower; VRE = variable renewable energy.
Source: IEA Korea Regional Power System Model.

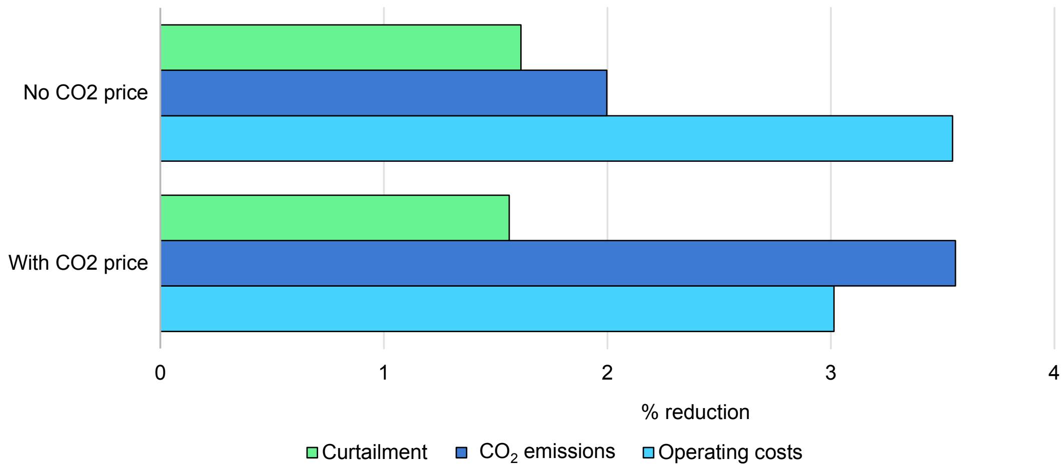
Increased battery and pumped storage hydropower capacity also help to absorb solar output during the day, while gas power plants ramp more extensively to accommodate variations in renewables supply across the day. More flexible dispatch of cogeneration plants also allows more variable renewables to be used. The role of coal becomes primarily as a flexibility and peak capacity provider, while its energy contribution is minimised. Flexibility helps to reduce variable renewables curtailment; however some amount of curtailment may be economically efficient in high renewables scenarios – this is discussed in Chapter 3 of this report.

New technologies, such as electrolysers, are key for providing flexibility and will contribute to decarbonising the rest of the economy

Hydrogen production through electrolysis accounts for an increasing share in power sector demand in the APS. This is consistent with Korea's Carbon Neutral Strategy, which estimates its total hydrogen demand in 2050 to be 27.4 to 27.9 Mt H_2, of which 80 to 82% comes from overseas imports and the rest through domestic production – mainly using electrolysis.

The use of electrolysers is expected to add 130 to 238 TWh (10 to 20%) of electricity demand in 2050 in the CNS; IEA analysis shows that deployment of electrolysers in 2035 with flexible operations can contribute to better integration of variable renewables as well as emissions reductions. As with other flexibility options, the effect on emissions reductions in the APS is larger when considering the integration of carbon pricing in electricity markets.

Reduction in curtailment, emissions and operating costs due to flexible electrolyser demand in the Announced Pledges Scenario 2035



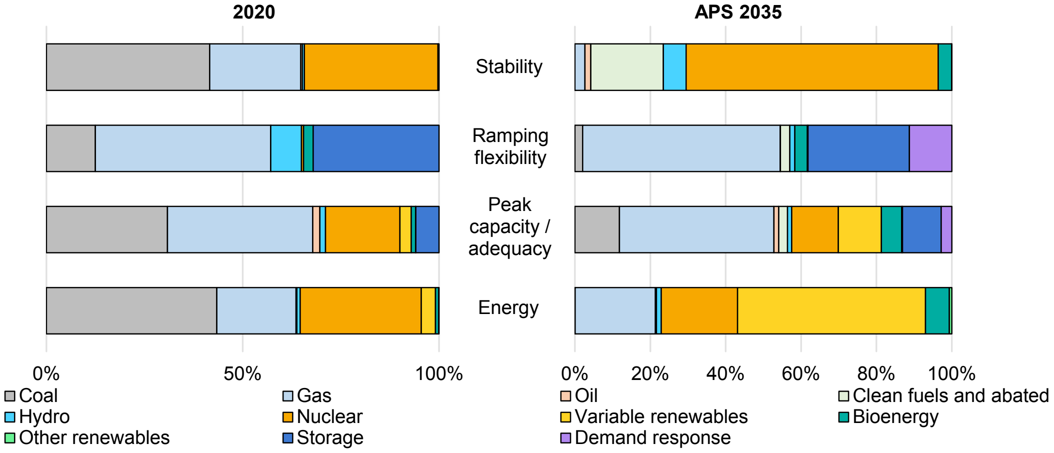
Source: IEA Korea Regional Power System Model.

Electrolyser deployment improves hydrogen supply security, reducing the planned reliance on overseas imports. This should be a consideration for policy makers, as Korea's estimated hydrogen demand in 2050 according to the Carbon Neutral Strategy could represent more than 5% of the global hydrogen demand, as presented in the IEA NZE scenario.

Deployment of new technologies is needed to deliver all system services at the lowest cost

In order to operate securely, power systems rely on multiple services, including bulk energy supply, adequate capacity to cover peak periods, the flexibility to follow load and supply variations and stability that allows the system to operate smoothly during and after disturbances. Power systems have traditionally relied on conventional dispatchable plants, particularly fossil fuel generators, as well as nuclear and hydropower to provide a range of services alongside energy. This means that most of the services required for secure power system operation have come from the same technologies that supply energy. This applies to Korea's power system today, which is currently dominated by thermal power plants providing dispatchable, flexible capacity that also provides inertia for stability in addition to energy.

The energy and service contributions of different technologies to maintain electricity security, 2020 and the Announced Pledges Scenario 2035



Notes: APS = Announced Pledges Scenario. For calculated contributions, stability is based on contribution to inertia in the 100 lowest-inertia hours, although inertia is only one aspect relevant to stability; detailed technical studies are required to capture all components. Ramping is calculated from the contribution to the top 100 hourly ramps. Peak capacity / adequacy is based on the contribution to capacity needs in the modelled year. Full system adequacy assessment requires further study, for example, based on a stochastic adequacy model accounting for interannual variability in demand and supply as well as generator and transmission outages. Energy is the share in annual generation. These measures aim to give an illustration of the diverse aspects of electricity security, but do not encompass all relevant components or potential technology contributions.

Sources: Energy generation comes from the IEA's World Energy Model and estimates for stability, ramping flexibility and peak contribution use the Korea Regional Power System Model.

As Korea transitions to higher shares of renewable energy, the picture changes – variable renewables become the most cost-effective source of decarbonised energy but cannot supply all the services needed for security. Other new technologies are also specialised to provide specific services. For example, batteries are becoming an increasingly cost-effective source of flexibility but do not provide primary energy supply.

As a result, the most cost-effective power mix for Korea on a net zero pathway will require a diverse set of technologies providing different services. The role of markets is to bring forward the most efficient combination of these technologies to meet system needs, and to achieve this, markets will need to provide signals that incentivise all services. This means that services will need to be unbundled, or compensated separately, to attract the right level of investment – as discussed in detail in Chapter 3.

It is important to note that the set of technologies seen in 2035 will also continue to evolve through 2050. Nuclear power, for example, continues to play a strong role in maintaining stability in the lowest-inertia hours in 2035 as a result of its favourable position in the merit order for low-carbon dispatch, but other low-carbon dispatchable technologies, discussed in the next section, will meet this need as nuclear is phased out in accordance with Korean government policy. In addition to dispatchable, synchronous generators, multiple options exist to maintain stability with increasing penetrations of variable renewables, explored in detail in a report by the IEA and the French utility, Réseau de Transport d'Electricité (IEA & RTE, 2021).

New technologies for low-carbon dispatchable generation can contribute to a secure low-carbon power system in Korea beyond 2035

A key question for Korea on its net zero pathway is: which are the dispatchable low-carbon sources that will complement renewable resources and can balance the system? Unfortunately, traditional low-carbon workhorses: hydro, nuclear, geothermal and biomass are subject to important constraints, either from social acceptance, or due to their dependence on natural resource availability. For example, IEA analysis shows that in 2034 flexible operation of nuclear plants is an option for the days with the lowest net load, but at present there are no established security guidelines for this kind of flexible operation of Korea's nuclear generators (IEA, 2021c).

Deployment of scalable, low-carbon dispatchable technologies will be one of the key steps that the Korean power system will need to take to meet its net zero objectives in the coming decades. This section provides an overview of low-carbon dispatchable technology options, including deployment status in Korea today, international examples and the main considerations for Korea in the coming years. Biomass, CCUS and co-firing with low-carbon fuels can all contribute to maintaining security in the Korean power system on its net zero pathway.

Use of biomass for fuel switching

Biomass is a widely used renewable fuel that can provide dispatchable power using existing plants but is limited in supply and availability and can be subject to local conditions. In 2019, Korea generated 9.3 TWh from biomass (IEA 2021d), the majority of which comes from imported wood pellets, raising questions about its sustainability (IEA, 2021c).

The most common combustion method uses pulverised coal (PC) boilers that are already widely deployed in Korea and are proven to manage co-firing with biomass. Dangjin Bio-1, a 105 MW plant using a circulating fluidised bed boiler, was originally designed to use coal as its primary fuel but was progressively changed to fire an average of 80% biomass in 2015 (Todd, 2019). Such technologies, however, are limited by the quality of feedstock. Higher ash content found in cheap feedstock limits its combustion efficiency, and thereby limits the co-firing ratio.

Higher co-firing ratios require higher quality and costlier wood. The most well-known example is Drax biomass plant in the United Kingdom, which has progressively increased its co-firing ratio and is now running on 100% biomass. Originally built as a 3960 MW coal plant in 1974, the units have been converted to burn wood pellets sourced from forests in the United States, Canada, Europe and Brazil (Drax, 2020). This conversion was possible through a contract-for-differences (CfD) at GBP 100/MWh (USD 159 in 2012 prices), until 2027 (EU, 2016).

The limitations of domestic biomass supply could be addressed if low-quality feedstocks are considered. However, higher co-firing ratios with low-quality feedstocks are only achievable with increased retrofit costs. Retrofits could involve feedstock pre-treatment (e.g. drying, sorting, gasification and pyrolysis), combustion modification or post-combustion treatment of effluent gases. Commercial examples of such modifications include: the Vaasa plant, a 140 MW bio-gasification plant in Finland that uses forest residues as feedstock for electricity and district heating (Power Technology, 2013); and the Energy Works plant, a 28 MW gasification plan in the United Kingdom that uses wood and municipal waste as feedstock (Energy Works, 2021).

In Korea, biomass is costly. At an average unit settlement price of KRW 113.4/kWh (USD 94/MWh) in 2020, it comes second only to oil-based generation at KRW 200/kWh (USD 170/MWh) for the highest unit price (EPSIS, 2021). It is supported primarily through the Renewable Portfolio Standards (RPS) where generating companies are required to ensure that a certain percentage of their generation comes from new and renewable energy sources, or to purchase equivalent renewable energy certificates (REC). RECs are given varying weights to encourage diversity in the RE technologies developed. The weights assigned to biomass ranges from 0.25 for bio-solid recovery fuels (bio-SRF), to 2.0 for unused forest biomass. Given the concerns outlined above, Korea could take advantage of this existing mechanism by assigning higher weights to domestically sourced biomass and low-quality feedstock to generate investment in biomass supply or pre-treatment retrofits in power plants. Likewise, it could also lower the weights for imported biomass supply to reduce reliance on imported feedstock.

Technology readiness in Korea for utilising biomass is quite advanced, however, the challenge to scale up deployment depends upon establishing a sustainable domestic supply chain.

Decarbonising the fossil fuel fleet using CCUS

Using CCUS can help mitigate the carbon emissions associated with existing fossil fuel plants. By retrofitting these plants with carbon capture capacity, Korea could still maintain the benefits of dispatchable generation and flexibility in the power system without contributing to greenhouse gas emissions. However, CCUS is still limited globally due to the costs associated with the capture technology as well as transport and storage of the captured CO_2.

To date only two utility-scale CCUS plants have entered operation, both of which obtain additional revenue through selling the captured CO_2 for enhanced oil recovery. Petra Nova, in the United States, can capture 1.4 Mt CO_2 per year at a rate of USD 65/t CO_2 and Boundary Dam, also in the United States, can capture 1.0 Mt CO_2 per year (IEEFA, 2021). The success of these projects has been mixed, however, with Petra Nova being temporarily idled as of May 2021 as a result of a pandemic-driven drop in demand, and Boundary Dam's operators announcing that the CCUS system would not be replicated at other facilities.

In its 3rd EMP, Korea aims to develop facilities that capture and store 3 Mt CO_2 per year by 2023. Currently, it only has several pilot-scale carbon capture projects, including two 10 MW pilot units at the Boryeong and Hadong power stations, each capable of capturing 200 tonnes per day (IEA, 2020). Captured CO_2 from these projects are currently sold to industrial users for additional revenue.

Storage of captured carbon remains the most significant challenge, both globally and for Korea. Gaseous CO_2 needs to be stored in stable geological formations, such as depleted oil and gas fields that do not allow CO_2 to escape back into the atmosphere. The government conducted its first storage demonstration in 2013 in the Pohang Basin, with an estimated capacity of 0.27 Mt CO_2 (IEA, 2020), but a series of earthquakes resulted in a postponement of activities. Such events make storage more challenging to accomplish.

More recently, the country announced its plans to use the depleting Donghae gas field to store 0.4 Mt CO_2 annually for 30 years from 2025 (Lee, 2021). Technologies are being developed to convert gaseous CO_2 to solid material and offer a more stable storage product not subject to the same geographical and geological constraints. Supporting their early demonstration would be advantageous given the limited geological sites in the country.

The CNS targets between 55 Mt CO_2 and 85 Mt CO_2 of carbon capture by 2050. About 60 Mt CO_2 is reserved for domestic and international storage, with the remaining 25 reserved for conversion to be utilised for other purposes. Such large volumes of carbon capture would require significant remuneration from the generators or industries through continued operation in a carbon-priced market or through new revenue streams for the captured or converted carbon.

Using low-carbon fuels for co-firing

Fuels such as hydrogen and ammonia can be suitable candidates for co-firing in gas and steam turbines to provide flexible supply. The CNS targets generation of 160 to 270 TWh from low-carbon fuels by 2050, while the NDC targets 22 TWh of generation from ammonia as early as 2030.

Co-firing with hydrogen has already been technologically proven in gas turbines. Original equipment manufacturers have achieved up to 90-95% co-firing of hydrogen and indicate that 100% co-firing is technically attainable. Korea currently plans to conduct a demonstration by 2027 at the 1.8 GW Ulsan combined cycle power plant (Patel, 2021).

Co-firing with ammonia is at pilot-scale for steam turbines currently using coal. JERA, a Japanese power company, achieved 20% co-firing with shipped low-carbon ammonia from Saudi Arabia, resulting in an electricity cost of USD 150/MWh. It plans to implement 20% co-firing for its whole coal fleet by 2030, and 100% firing by 2040 (JERA, 2021). In Korea, Hyundai Heavy Industries signed an agreement with Saudi Aramco to import ammonia for power generation by 2024 (HHI, 2021).

Production costs represent the largest challenge for the use of low-carbon fuels, especially when the fuels are produced via electrolysis from renewable energy or from fossil fuels with carbon capture. This cost is compounded by transport and storage considerations.

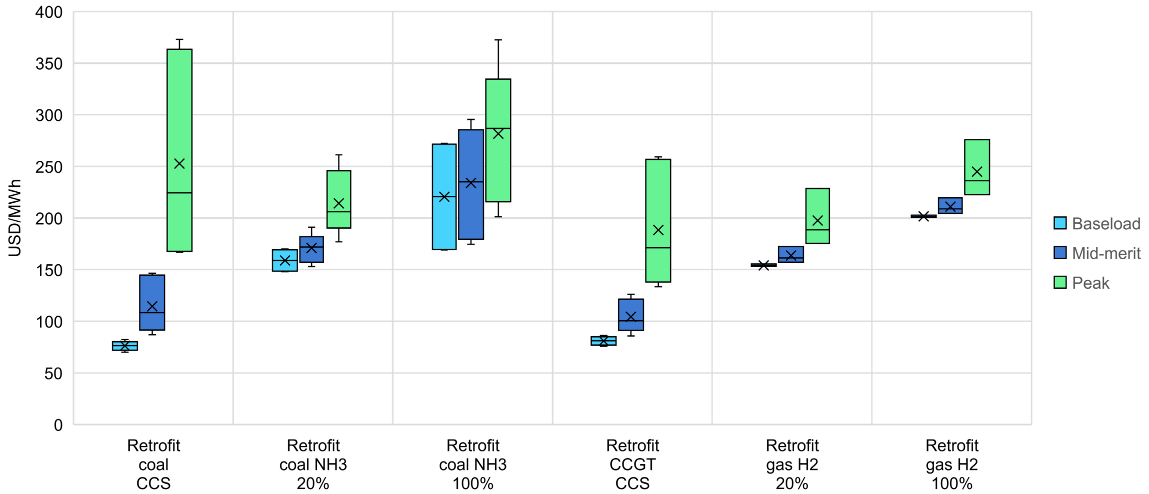
In its Hydrogen Economy Roadmap, Korea outlines its intent to leverage economies of scale and diversify sources of production to help lower the supply. It aims to increase domestic production from 50% of a total 1.94 million tonnes/year by 2030 to 70% of a total 5.26 million tonnes/year. By doing so, Korea intends to achieve supply costs of KRW 4 000/kg (USD 3.4/kg[5]) by 2030 and KRW 3 000/kg (USD 2.6/kg) by 2040 (Government of Korea, 2019). Given the prevailing gas turbine efficiencies, this would lead to a generation cost of around USD 190/MWh by 2030 and around USD 145/MWh by 2040.[6] Commercialisation for this application is likely to be achieved only by 2045 (Korea Hydrogen Study Team, 2018).

While there are no parallel strategies specifically targeting ammonia for power generation, the potential for their deployment is still promising. By 2034, about 29 GW of coal capacity and about 13 GW of gas capacity using steam turbines remain that can be utilised for ammonia co-firing.

The roles of different low-carbon dispatchable generation technologies in the power system eventually depend on the relative costs of supply and carbon price, as well as the costs of retrofitting them. Levelised cost of electricity (LCOE) estimates show that it would be more cost-effective to run power plants retrofitted with carbon capture at higher capacity factors due to higher retrofit costs, while peak periods are more appropriate for retrofitted plants using hydrogen and ammonia due to their fuel costs in relation to carbon prices.

[5] 1 USD = 1174 KRW in 2021.
[6] Assuming 55% CCGT efficiency and 120MJ/kg heat content.

LCOE estimation for retrofits in existing plants for CCUS and low-carbon fuel in 2030 in Korea



Notes: CCS = carbon capture and storage; CCGT = combined cycle gas turbine. WACC = 5%; Retrofits consider initial construction costs as sunk; Grouping is based on capacity factors: baseload = 75% to 85%, mid-merit = 30% to 60%; peak = 10% to 25%; 2030 baseline prices based on Announced Pledges Scenario (APS) in IEA (2021f): carbon = USD 130/t CO_2, coal = USD 73/tonne, gas = USD 7.20/GJ; 2030 low-carbon fuel prices based on case studies in IEA (2021e): hydrogen = USD 1.7/kg, ammonia = USD 270/tonne to USD 470/tonne.

Source: Analysis based on IEA (2020), *Projected Costs of Generating Electricity in 2020*; IEA (2021e), *The role of low-carbon fuels in the clean energy transitions of the power sector*; IEA (2021f), *World Energy Outlook 2021*.

While there are identified challenges in commercialising carbon capture as described in the previous section, baseload and mid-merit applications with partial co-firing (e.g. 20%) could still provide reasonable emissions reduction by the 2030s while maintaining flexible and dispatchable services for the higher variable generation share. Doing so also helps to increase the country's learning and experience rate to optimise the production, use and delivery of these fuels.

Further development of low-carbon fuels must consider life-cycle emissions. Importing hydrogen and ammonia would need to consider the production type (i.e. from biomass, renewable electricity or fossil fuel with carbon capture) to avoid dependence upon supply chains that further increase GHG emissions, and which could create future security concerns.

Negative emissions could be achieved through bioenergy combined with carbon capture and storage

Due to the lack of technical certainty of viable alternatives to decarbonise some end-uses, such as aviation, the deployment of negative emissions technologies in other sectors may be required to achieve net zero objectives economy-wide. The power sector is often regarded as one in which not only zero emissions could be reached, but also one that could become a carbon sink in the 2050 timeframe, helping the world stay within the 1.5ºC limit set by the 2015 Paris Agreement with limited or no overshoot. Deployment of negative emissions technologies can help address the uncertainties associated with future emissions reduction. Combining bioenergy and carbon capture (BECCS) is one of the more mature technologies for reducing atmospheric CO_2 aside from land use options. It has a global potential of up to 5 Gt CO_2 per year limited by the supply of sustainable bioenergy and with a range of USD 100-200 per t CO_2 captured (IPCC, 2019).

Currently, commercial deployment of BECCS are in the form of bioethanol production plants utilising captured carbon for enhanced oil recovery (EOR), of which five are operating in North America. There are three ongoing developments of BECCS projects in the power generation sector (Consoli, 2019):

- Mikawa in Japan captures 500 t CO_2 per day or 50% of daily emissions from the 50 MW power plant. It originally co-fired biomass and coal, but it has been retrofitted with a new boiler capable of burning 100% biomass (Kitamura, 2019).
- Drax in the United Kingdom has started piloting carbon capture in their retrofitted biomass plant, and the UK projects 50 Mt CO_2 could be captured by 2050 via BECCS, or half of United Kingdom's emission targets (Drax, 2019).
- Klemestrud in Norway is a waste-to-energy plant capturing 0.4 Mt CO_2 to a storage site in the North Sea.

Developing BECCS in these countries aside from Japan has been aided by prevailing emissions trading systems that cover the power sector. Prospective income from carbon credits could help pay for retrofitting costs and more expensive feedstock.

Studies of in-situ BECCS in Korea suggest a potential to capture 0.13 to 0.23 Mt CO_2 per year. This number is limited by the location of storage facilities in the south-eastern areas of the peninsula relative to the location of generation in the western areas (Kraxner, 2014). While the potential is promising, the challenge of biomass supply and carbon storage as identified in earlier sections would need to be addressed before any meaningful BECCS deployment could be achieved.

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Chapter 3 – Policy and design improvements in Korea's wholesale electricity market

Korea aims to reduce emissions from the power sector in a cost-effective way, without compromising electricity security. Variable renewable sources will become the largest source of electricity supply, making it necessary to both introduce policies and regulations that support this development as well as update system operation practices and market design. Reflecting the costs of carbon-emitting generation in the wholesale market price signals will help to reduce the costs of this transition. The variability of VRE will require key services – like flexibility and dispatchability – to be properly compensated in order to procure the necessary amount to maintain electricity security at the lowest possible cost. Unfortunately, the current electricity market design in Korea works against its policy objectives. Maintaining the current misalignment between price signals in the market and the value provided by the technologies compatible with the country's policy objectives will require significant and increasing out-of-market payments to deliver a secure and decarbonised power system. The market reforms needed to bring about these changes at the lowest possible cost are the focus of this chapter.

Well-designed electricity markets promote fast and affordable decarbonisation of the power sector

Electricity systems are shaped by regulation and competitive markets. While all systems rely to some extent on regulation, the extent to which a system relies on competitive markets marks its degree of liberalisation. Within liberalised markets, the investment and regulatory framework should create incentives for private behaviour to support efficient investment and operation. Sound policies can achieve electricity security and decarbonisation objectives at the lowest possible cost, but improper or conflicting measures will lead to unfulfilled ambitions and/or excessive costs.

Traditional power systems have relied heavily on centralised planning, with key decisions about generation, transmission, distribution and rates made by regulators with input from policy makers. In the past, this structure was arguably necessary because the natural monopoly aspects of the grid make a single, regulated entity the most efficient method for providing electricity. But technological improvements, particularly with respect to telemetry, or measurement, of all actors on the grid and their supporting communications networks and computer systems, opened opportunities for liberalisation and competition. Liberalisation has allowed the risk to shift from end users to investors and created incentives to operate the grid more efficiently, building a constant pressure to drive down costs while increasing fairness by limiting the cross-subsidisation that can occur when system actors do not pay the full price of their consumption.

The wholesale electricity market is the central feature of a liberalised power system – and as such, it must send the correct price signals while also respecting the physical constraints of the system. This requires co-ordinating each participant's actions in real time through an auction. Spot market prices, including their distribution over location and time, provide important signals to investment and operational decisions. For generators, spot market prices determine utilisation rates in the short term and retirement decisions in the long term. This includes the relative merit of peaking or baseload or battery technology, which is determined by the amount of price volatility seen in the system. For electricity retailers, prices help form the basis for tariff offers to customers, including parameters like periods and rates of peak and off-peak pricing schedules. It is therefore imperative that spot market prices accurately reflect both the cost of providing the service and the actual economic value of electricity.

Marginal pricing, where the costliest action taken to balance the system sets the price, encourages efficient outcomes because it reflects the aggregate supply and demand of all system actors. Each generator produces until the point at which its cost is equal to the price received in the market, while customers consume electricity only when its cost is less than the value of their consumption. At market price, no system actor is enriched by changing their level of supply or demand. This efficient dispatch also supports investment decisions through rents received in the wholesale market – generators with lower operating costs earn sales revenue above their short-run costs to help recover their investment costs and earn a rate of return.

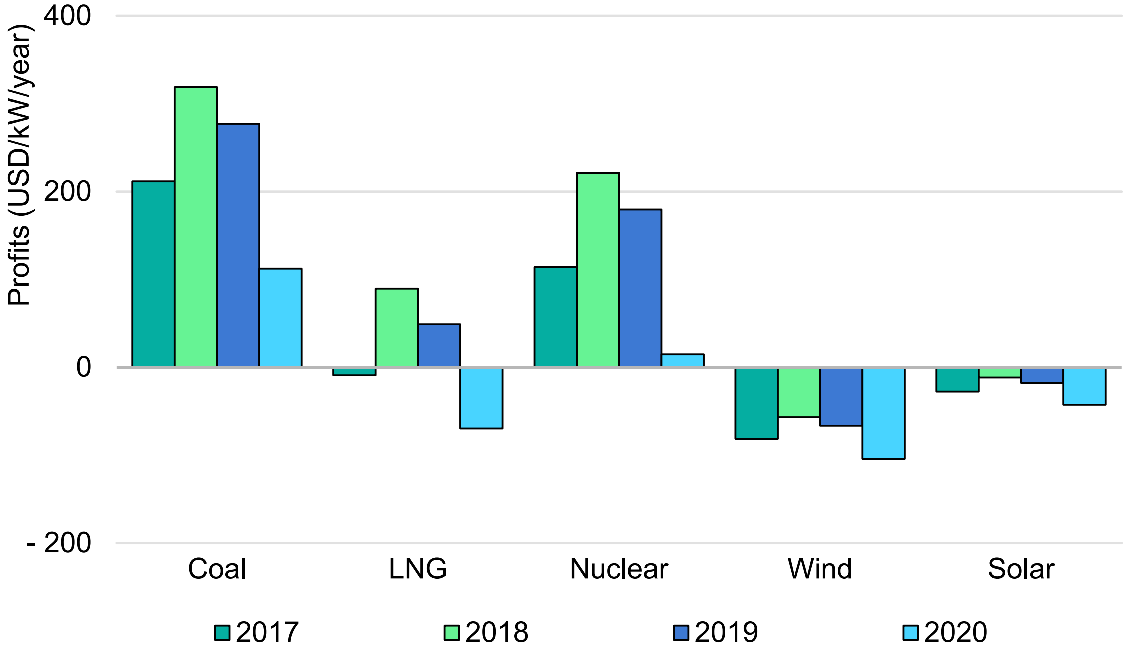
Korea’s current electricity market design works against its long-term climate ambitions

Korea’s energy market currently uses a cost-based system to set a marginal price at the whole system level. Variable costs for all generators are set monthly and then for each hour, on a day-ahead basis; the level of system demand determines the marginal unit and thus the system price. A dispatch including system and generator constraints, such as ramp rates, minimum start times and minimum operating levels, is then conducted to determine whether these price-setting schedules should be adjusted to ensure secure operation.

While this structure results in efficiently dispatching and compensating units based upon their operating costs, the outcomes do not necessarily reflect the optimal social outcome nor support Korean policy objectives. This is particularly true of the resulting level of emissions, as emissions cost is not included in the price of fuel.

We can observe this by calculating the energy rents received by different technologies in Korea and comparing those rents with the annualised cost of new entry, which includes annualised capital costs (with a 7% WACC) and fixed operating and maintenance costs. If the rents received by a technology, per unit of capacity, are consistently greater than the annualised cost of new entry, this indicates that the technology is profitable. From 2017 to 2020, Korean coal plants, despite emitting higher levels of CO_2 and other pollutants than other technologies, have seen higher profits than plants with moderate emissions and high fuel costs (like liquefied natural gas [LNG]), or zero emissions and high capital costs (like nuclear, wind and solar).

Estimate of profitability* for new plant by type, 2017-2020



* Energy rents, less fixed O&M and annualised capital cost; WACC = 7%.

Source: IEA (2020b), *Projected Costs of Generating Electricity 2020*; KPX.

By providing more profitable conditions to more polluting technologies, the price signals embedded in Korea's current market work against the country's long-term objectives. Current incentives encourage market participants to continue using and constructing higher emissions technologies, raising emissions above their desired level and increasing the need for significant out-of-market payments to attract investment in less polluting technologies.

Moreover, even if investment in low-carbon energy, such as VRE, materialises, it is not clear that the current market design will provide market participants with enough incentives to generate the flexibility and dispatchable resources required to operate a highly decarbonised system with large shares of renewables. The paths considered in the Korean BPLE include a significant increase in variable renewables. Without further reforms in the market design, these new investments are likely to have impacts that will make fast and affordable decarbonisation more challenging:

- Less polluting but more expensive fuels, like biomass or LNG will be outcompeted, while low-carbon sources, like wind and solar, will see their value eroded.
- Revenues from the energy market may be reduced for dispatchable technologies, increasing reliance on capacity payments that do not necessarily recognise performance or their real contribution to security of supply.

- Increased output variability from VRE may not be accompanied by the system flexibility that is needed.

All these trends can move the market away from an efficient mix of resources that allow a low-cost and affordable decarbonisation. Without good market design, government will need to rely on out-of-market revenues, such as administratively defined payments, to make these investments happen, often with less powerful or precise outcomes than those provided by market signals.

Nonetheless, changes to market design can be implemented in order to correct these trends and realign the incentives of both market participants and consumers towards a low-cost and affordable low-carbon power system.

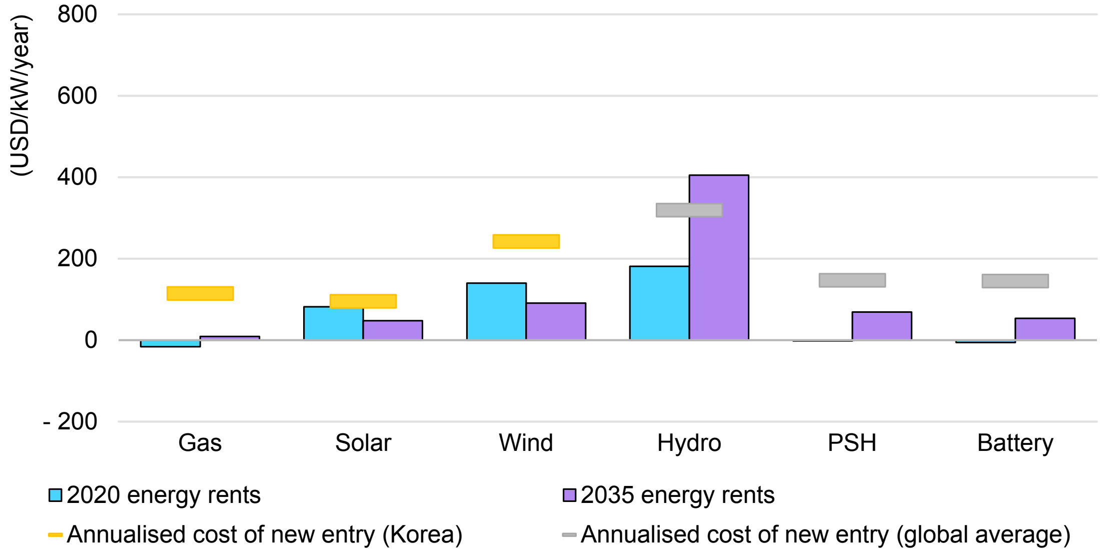
While it is true that such a system can occasionally produce volatile (and sometimes very high) market prices, those prices will reflect actual system conditions faced by producers and consumers, including the marginal cost of emissions. Consumers will have a strong incentive to curtail their demand during high-priced periods, and producers who can bring more supplies to the market will receive a price that reflects the value they are providing to the system. Such pricing mechanisms can be implemented using specific measures to minimise the impact to consumers, without eliminating the incentives created on both the supply- and demand-side.

To ensure compatibility with Korea's long-term policy objectives, it is important to improve the wholesale market design, effectively rewarding system value rather than only system costs in order to remunerate low-carbon and dispatchable technologies.

Energy market rents alone in the current Korean market design are unlikely to support sufficient levels of generation

Taking the same approach applied to the historical data, we can also compare the annualised cost of new entry with energy market rents per unit of capacity in the modelled data to observe the expected profitability of different technologies under each scenario. We see that, despite significant penetration of variable renewables by 2035, rents are expected to remain relatively stable in the APS under the current market design. The figure below shows a comparison of the expected profitability of generating technologies in 2020 and 2035. Units running on natural gas are expected to receive the lowest margin per unit of installed capacity, because in most cases gas will be the marginal fuel at any given hour. When comparing rents to the annualised cost of new entry for each technology, we see that the business case improves for battery storage and PSH, but not enough to bring about sufficient levels of investment when added to the existing locational constraints for additional PSH. Moreover, the analysis shows a decrease in 2035 energy rents for both solar PV and wind.

Estimate of profitability* for new plant by type, 2020 and Announced Pledges Scenario 2035



*Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using system reference marginal price (SRMC) with no carbon price.

Source: IEA Korea Regional Power System Model.

As a result, the pressure from current market incentives lead to insufficient investment in dispatchable sources. These incentives run counter to both the long-term objectives and the type of low-carbon energy mix represented in the Announced Pledges Scenario described in Chapter 2.

Integrating carbon pricing in market design supports emissions reduction

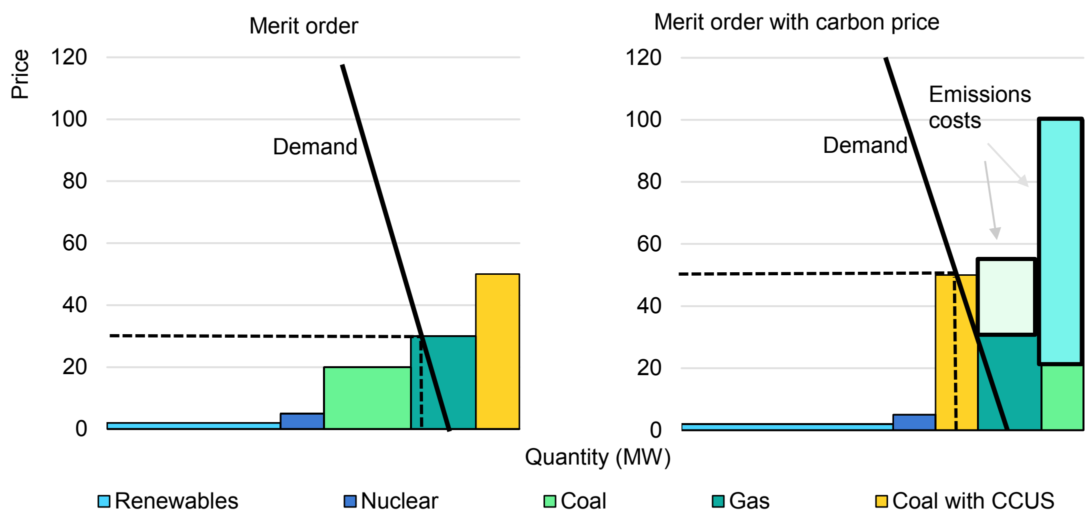
A strong carbon price would be the first option to rebalance Korea's energy market to a more decarbonised outcome at the lowest cost. Including a carbon price within the wholesale market price has significant advantages over other forms of decarbonisation incentives – mainly because it targets carbon directly and without regard to emissions-producing technology. Furthermore, carbon pricing treats all forms of carbon reductions equally, including whether the reductions occur on the supply side or through energy efficiency. Carbon pricing also follows the principles of marginal pricing discussed earlier. It affects the merit order of generation, which would encourage emissions-saving behaviour at the right time and location through fuel switching and storage of renewables for later use.

Carbon pricing for fuel switching

The current emissions scheme in Korea covers over 70% of emissions, including heat, power, industry, buildings, domestic aviation waste and public services. Since the beginning of 2021, the Korean Emissions Trading System (KETS) entered its third phase (2021-2025), where the power sector is allocated 90% of its allowances free of charge with the remainder allocated by auction. Emission allowances, including price and volume limits, in the power sector are determined by technology-specific benchmarks for each fuel type.

The cost of emissions that exceed the allocated allowances in the power sector should increase generator costs. However, these costs are currently compensated by KPX through customer tariffs. In the 8th BPLE, the government of Korea stated its objective to introduce “environmental dispatch”, which aims to incorporate the cost of allowances into the electricity market to strengthen the competitiveness of LNG plants and facilitate fuel switching to less polluting sources of electricity (IEA, 2021). KPX has proposed amending its rules on the operation of the electricity market by 2021, with the Cost Evaluation Committee under KPX tasked with integrating the cost of allowances into each generator’s variable cost, which is then used to determine merit order and wholesale market prices. Inclusion of a sufficiently high carbon cost can shift the merit order for dispatch, resulting in a reduction of emissions as lower emissions technologies are dispatched more.

Illustrative effect of carbon price on merit order for dispatch with representative operational costs of different generation technologies

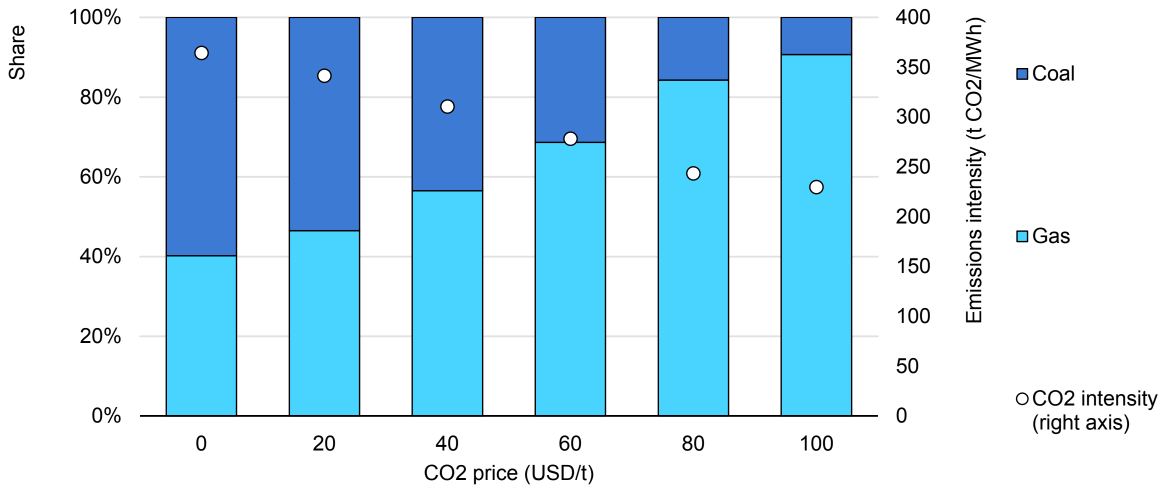


Source: IEA (2021), *Korea Electricity Security Review*.

The role of carbon pricing for emission reduction in Korea

A sensitivity where different CO_2 prices are included in the BPLE 2034 scenario in the IEA Korea Regional Power Sector Model illustrates the potential for carbon pricing to reduce emissions in Korea. A series of CO_2 prices from USD 0 to USD 100/t CO_2 in increments of 20 are tested, while keeping the underlying capacity mix constant. This results in a drop in emissions intensity from over 360 t CO_2/MWh with no CO_2 price to approximately 230 t CO_2/MWh with a price of USD 100/t CO_2, or a 37% reduction. Most of this reduction is achieved by a price of USD 80/t CO_2, with minimal further improvement seen once most coal-fired generation has been displaced by gas-fired generation. While Korea's current plans include the introduction of a cap on gas generation, this will only be effective to a certain extent in terms of reducing emissions. As will be shown later in this chapter, the introduction of a carbon price that adapts to the country's emissions targets will contribute to continue reducing emissions by encouraging deployment of other low-carbon sources and will remain effective even after the phase-out of coal generation.

Shift in shares of coal and gas in generation with increasing CO_2 price for the Basic Plan for Long-Term Electricity scenario in 2034

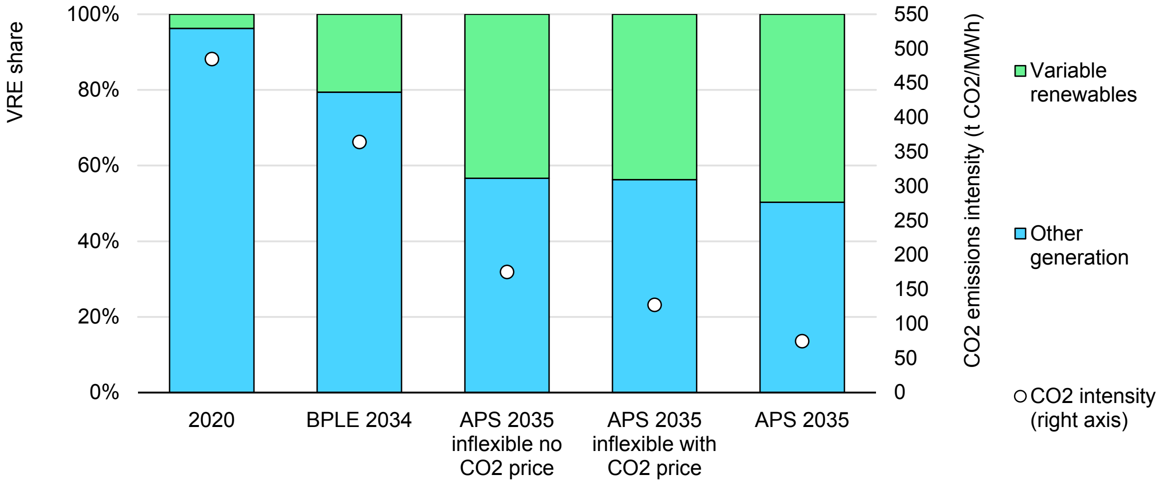


Source: IEA Korea Regional Power System Model.

Carbon pricing can strengthen the emissions reduction potential of VRE

To reach net zero, the power sector needs a strong foundation of low-cost, very low or zero-emissions generation to supply energy needs. Due to the rapid cost decline of solar photovoltaic and wind generation in recent years, variable renewables are expected to play a central role in allowing power systems to achieve net zero emissions globally. A series of scenarios for Korea illustrate how increased renewables should be accompanied by a set of complementary changes in the power sector. In the BPLE 2034 scenario, a combination of reduced coal capacity and increased gas and renewables capacity drives a 25% reduction in emissions intensity relative to 2020.

Reducing emissions intensity in the Korean power sector with increased renewables, carbon pricing and system flexibility



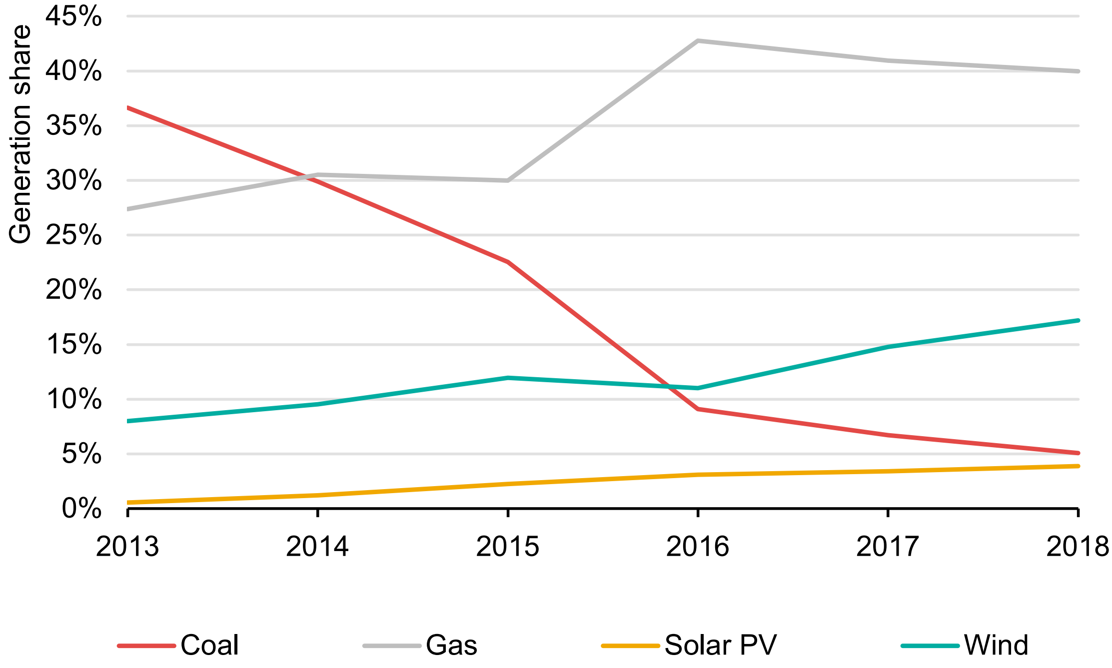
Notes: BPLE = Basic Plan for Long-Term Electricity; APS = Announced Pledges Scenario.

Sources: APS 2035 results with full flexibility and CO_2 price are based on the IEA's World Energy Model while APS sensitivities and all other scenarios come from the Korea Regional Power System Model.

The IEA APS scenario sees a large increase in variable renewables capacity as well as a substantial reduction in coal-fired generation capacity and initial deployment of CCUS technologies relative to the BPLE 2034 scenario. This fundamental shift in the capacity mix alone is enough to drive a 52% reduction in emissions intensity relative to the BPLE in 2034, compared to a situation where the needed flexibility in the system does not materialise and no CO_2 price is implemented. Adding a CO_2 price alone to an inflexible APS scenario reduces emissions intensity by another 27% through ensuring that high-emitting generation is used only during a very small number of hours to meet capacity needs. Finally, the introduction of multiple flexibility measures – which include flexible cogeneration, battery storage, flexible EV charging, and flexible electrolyser load – allows variable renewables to be more fully utilised and brings overall emissions intensity to around 75 t CO_2/MWh, an 85% reduction.

This was the viewpoint of the UK government when it implemented carbon price support, whereby a UK-specific tax is added onto the price of carbon in the EU ETS (Howard, 2016). First introduced in 2013, this tax has helped to provide stronger market signals for clean energy investment and dispatch than the EU ETS alone and has facilitated both growth in renewable generation and a dramatic reduction of coal-fired generation, with its share of generation declining from 37% in 2013 to 5% in 2018. The share of VRE generation grew from 9% to 21% over the same period.

Decline in the share of coal generation in the United Kingdom after the introduction of the carbon price support

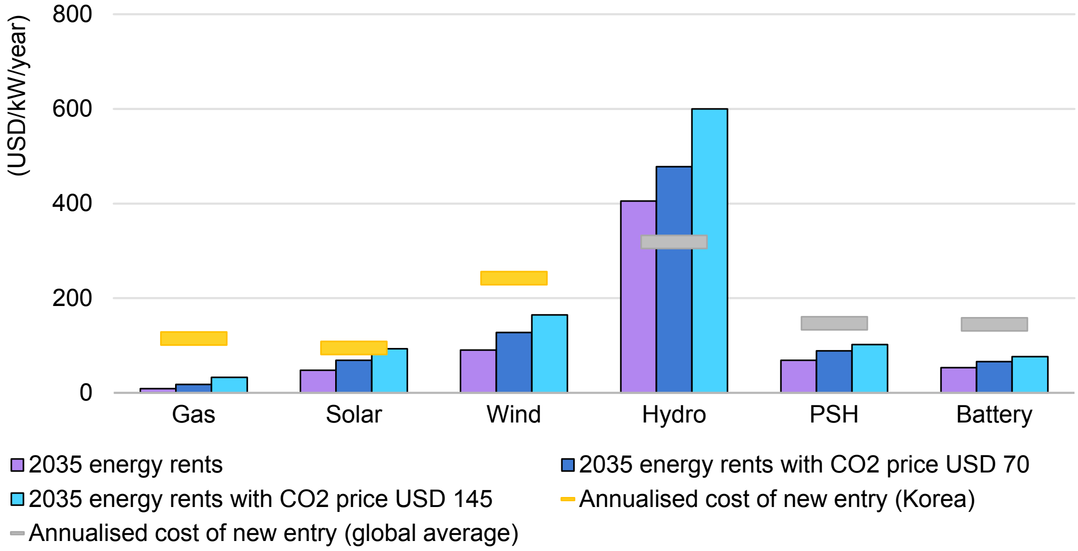


Source: IEA (2021), *Korea Electricity Security Review*.

Pricing carbon within the wholesale market improves remuneration of low-carbon generation

Emissions pricing has a significant effect on the financial viability of each generation technology in 2035 in the APS. As expected, CO_2 price has a highly positive effect on energy rents received by hydropower, wind and solar plants. Gas plants also receive a small increase in rents, as the increase in the cost of fuel for gas is smaller than the comparative increase in the cost of fuel for coal, leading to significant fuel switching. This analysis does not include coal due to the policy to phase out coal and ban new coal assets after 2035 as well as to the plan to introduce a cap on coal-fired generation. However, as a means of illustration, the introduction of a carbon price would have a significant effect on reducing energy market rents for coal-fired generation.

Effect of carbon pricing on profitability* for new plant by type, Announced Pledges Scenario 2035



*Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using system reference marginal price (SRMC) with two carbon price scenarios: USD 0 and USD 145 per tonne of CO_2.

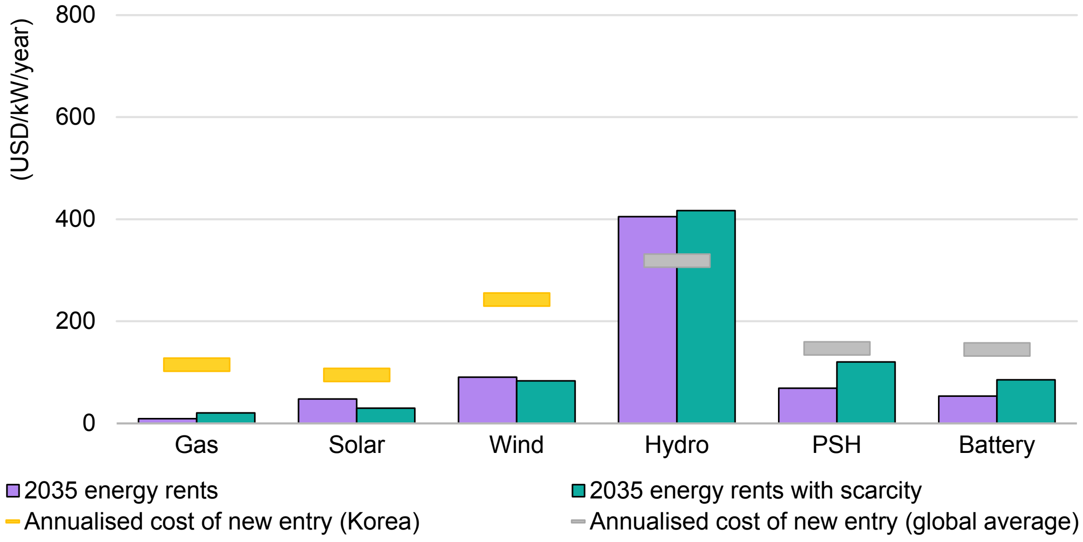
Source: IEA Korea Regional Power System Model.

Pricing that reflects the value of security of supply allows for a more diversified portfolio of dispatchable resources

The price signal in Korea can also be strengthened by embedding the cost of services (energy and ancillary) required for secure operation into the wholesale market.

As ancillary services are developed in Korea, they should be harmonised with the energy market and embedded in the marginal cost of electricity, allowing for price increases in periods of stress, such as reserve shortages. This will reward actions taken by market participants to relieve stress in the system. The figure below shows how such a mechanism compares to the current (short-run marginal cost (SRMC) pricing mechanism, with higher payments received by flexible and dispatchable resources and with much of the revenue coming from periods with reserves shortages.

Estimate of profitability* by unit type, without carbon pricing, Announced Pledges Scenario 2035



* Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using system reference marginal price (SRMC) and scarcity pricing.

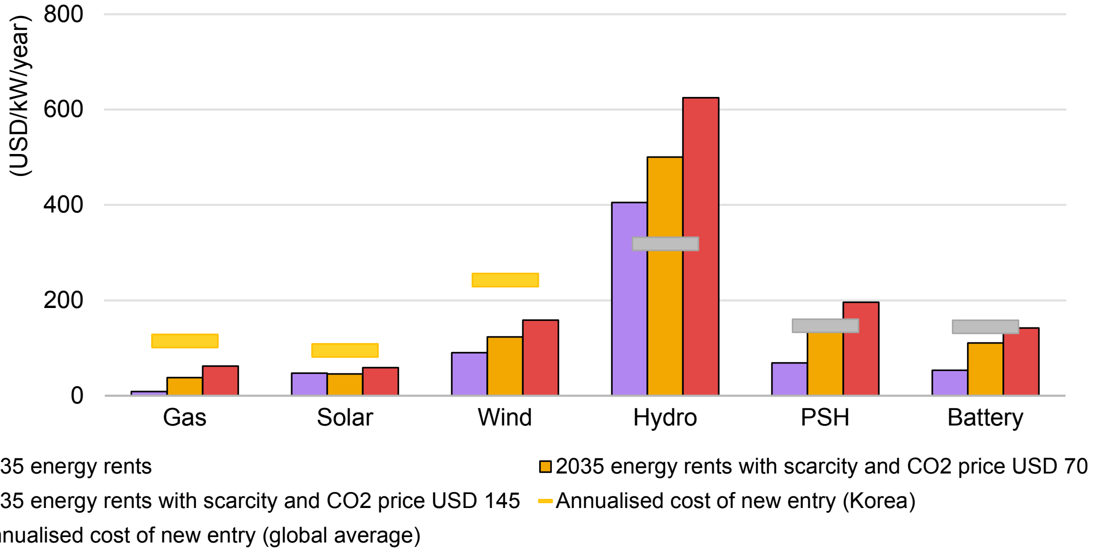
Source: IEA Korea Regional Power System Model.

It is important to highlight that this additional revenue coming from the electricity market does not mean increased prices for consumers, as the increase in electricity revenue reduces the "missing money" problem for plants and should be reflected in reduced capacity payments. Despite this revenue neutrality, the effect on incentives is both large and beneficial to the system, since market participants are heavily rewarded by their availability in times of stress. It is important to note that while nuclear power still plays a role in the APS in 2035, the figure above does not include the change in energy rents given current plans to reward nuclear generation through vesting contracts.

Wholesale market price enhancements align markets and emissions goals

Combining the effects of the two wholesale market price enhancements discussed above – reflecting the cost of emissions and reserves shortages in wholesale prices – reveals a significant improvement to the financial viability of many generating technologies with attributes required to support a fast and affordable decarbonisation. As a reminder, without pricing enhancements, of the eight major technologies modelled, only nuclear could be expected to recover the cost of new entry using the current pricing structure. These enhancements would improve the outlook for all the other technologies: gas, wind, hydro, pumped storage and batteries. Altogether, these pricing enhancements would change the direction that the energy mix could take in the future, effectively rewarding low-carbon technologies, the provision of flexibility and the contribution to security of supply.

Estimate of profitability* by unit type, Announced Pledges Scenario 2035



* Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using system reference marginal price (SRMC) and scarcity pricing with carbon price.

Source: IEA Korea Regional Power System Model.

While reforms to the wholesale energy market can significantly improve the financial viability of resources that support the policy objectives of secure operation and decarbonisation, additional out-of-market payments may still be needed for a variety of reasons. In particular, regulatory risks, a lack of certainty about the level of carbon prices and a lack of clear vision about the speed and depth of the economy's decarbonisation can create an environment that market participants find unsuitable for investment.

Capacity payments should remunerate assets based on their actual contribution to adequacy

The need for additional revenues in the form of adequacy payments will depend upon the wholesale energy market design enhancements, as detailed in the modelling results. The necessary price to ensure that these resources are built or maintained can be estimated from these results. For our estimation, we took the difference between energy rents and fixed O&M for the least profitable generation technology in each case. In 2035, for the base case with the SRMC price, the needed capacity payment is USD 37 per kW for a gas plant with energy rents of USD 11 and Fixed O&M of USD 48. Adding the carbon price alone raises the payment to USD 48 per kW for a coal plant with energy rents of USD 1 and Fixed O&M of USD 49. But adding the scarcity price to the carbon price eliminates the need for the capacity payment, as each technology can at a minimum recover its fixed operating and maintenance costs.

In order to understand the joint effect of a carbon price and scarcity pricing, our estimates show that – if it were participating in the wholesale market – an existing typical coal plant could almost recover its annual fixed operating and maintenance costs of USD 49 per kW, given the energy and ancillary service rents received of USD 74 per kW. With energy rents of USD 118, a new entrant gas plant would just be able to recover the USD 115 per kW of capital cost and annual fixed operating and maintenance cost. Thus building new gas plants would be an economically efficient decision, particularly to support system security while the share of VRE increases.

A capacity payment might thus still be required to provide this "missing money" to either maintain the existing supply of dispatchable power generation or to induce new investments.

Nonetheless, even if capacity remunerations are needed, they should not be interpreted as a fixed payment. A well-designed capacity market should reward actual resource contribution towards system adequacy by linking the payment to resource availability during periods of system stress instead of just year-round availability, as is currently the case in Korea. In Mexico, for example, the capacity payment is based on the 100 hours – calculated ex post – during which the system was shortest of reserves. In this way, payment relates more directly to the value the resource provided to the system by avoiding reserve shortages and load-shedding events, and the economic damage that these incur.

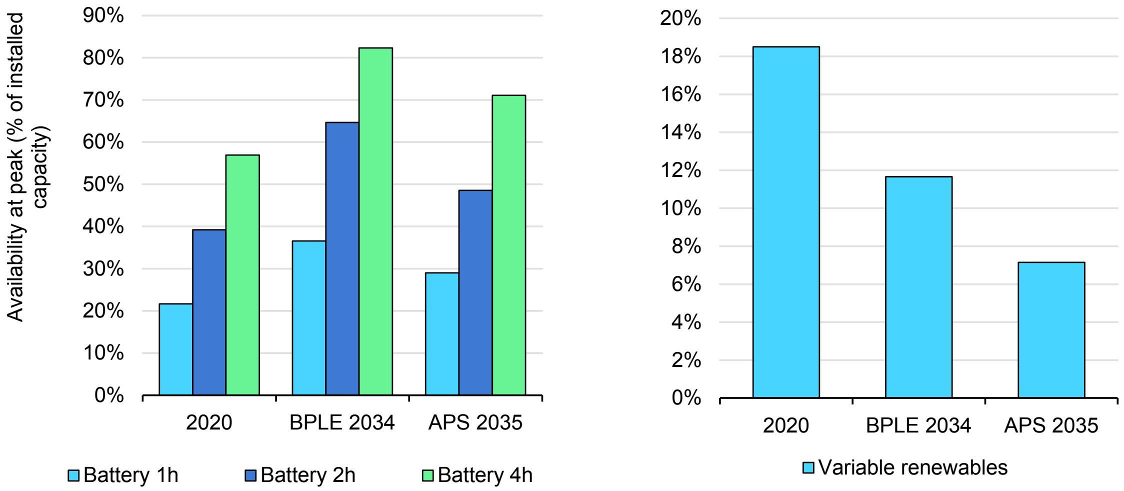
PJM introduced a capacity performance mechanism in 2016 as a response to a severe cold snap called the "polar vortex" in January 2014, which drove outage rates up to 22% among capacity-cleared resources due to fuel supply issues, ambient temperature effects on unit performance and boiler system failures. As a result, energy prices reached nearly USD 2 000/MWh and PJM had to take extraordinary measures, including voltage reduction and emergency demand response, to avoid load-shedding.

The capacity performance mechanism introduced penalties to generating units that had received a capacity payment but did not perform during specified "performance intervals", which include emergency conditions when the system is stressed. These penalties can reach up to 150% of the yearly capacity payment received by a generating unit. In response, generating facility owners invested to strengthen the resilience of their fleets, including procurement of spare parts, weatherproofing of components and firming of gas supplies. The relative performance of the generating fleet in the 2014 polar vortex and the early 2018 cold snap that brought similar weather conditions to the PJM region demonstrates the effectiveness of these penalties. Unit outages in 2018 were less than half than in the 2014 event and, particularly, resources common to both years performed even better, lowering their outages rate from 12.4% to 5.5%.

Technology neutrality, or recognising the capability of all resources, including VRE, demand response, storage and energy efficiency to compete for adequacy payments on a non-discriminatory basis, complements capacity performance measures. Where possible, capacity performance measures should account for factors such as duration of storage, the overall share of VRE in the system and the duration, frequency and magnitude of critical periods. Adapting to the evolving interplay between these factors is an advantage of technology neutrality, as it allows for appropriate remuneration of assets according to their actual performance.

The figure below shows the capacity contribution of various technologies in different scenarios. For instance, in 2020, a battery energy storage system (BESS) facility of 1 MW had a different contribution to security of supply depending on its duration, although the increase is not proportional, as it depends upon the length of episodes of stress. In the case of a 1-hour duration battery in 2020, the capacity contribution is around 22% of rated capacity, while a four-hour duration BESS is 57%.

Average availability/capacity contribution during 100 most critical hours for different battery durations and variable renewables in 2020, Basic Plan for Long-Term Electricity 2034 and Announced Pledges Scenario 2035



Notes: BPLE = Basic Plan for Long-Term Electricity; APS = Announced Pledges Scenario.

Source: IEA Korea Regional Power System Model.

Another relevant point is acknowledging VRE's capacity contribution for planning purposes and understanding how that will evolve as the system evolves. With larger shares of VRE, this contribution will erode as the stress periods become those periods with low VRE generation. This effect can be measured by comparing the capacity contribution of VRE in 2020, about 18%, with that in 2034 of BPLE, at just below 12%, and dropping to 7% in APS. Even if their capacity value is low, it is relevant to consider that – given the large size of the VRE fleet – this is a significant contribution to peak capacity in total terms.

A number of power markets like California, Belgium or Great Britain have introduced variants of capacity payments, either to allow assets to bridge years of insufficient rents to keep them online for mid-term reliability requirements, or to bring about new investments in capacity to cover the peaks in the system. Capacity auctions in Great Britain's electricity market have specifically included different contract durations to differentiate between existing and new assets. However, aspects like benchmark considerations for derating different technologies as well as setting the reference around a specific technology rather than the system's needs indicate that these have not necessarily been technology neutral systems. Going forward, the introduction of technology neutral, performance-based capacity payments in Korea can contribute to increasing the security of supply while effectively rewarding technologies that actually perform when they are needed. The introduction of such flexible payment designs can help particularly as technology evolves beyond 2035 and new technologies are able to serve the system's needs.

Renewable support schemes can top up market revenues to ensure low-carbon generation deployment is in line with Korea's targets

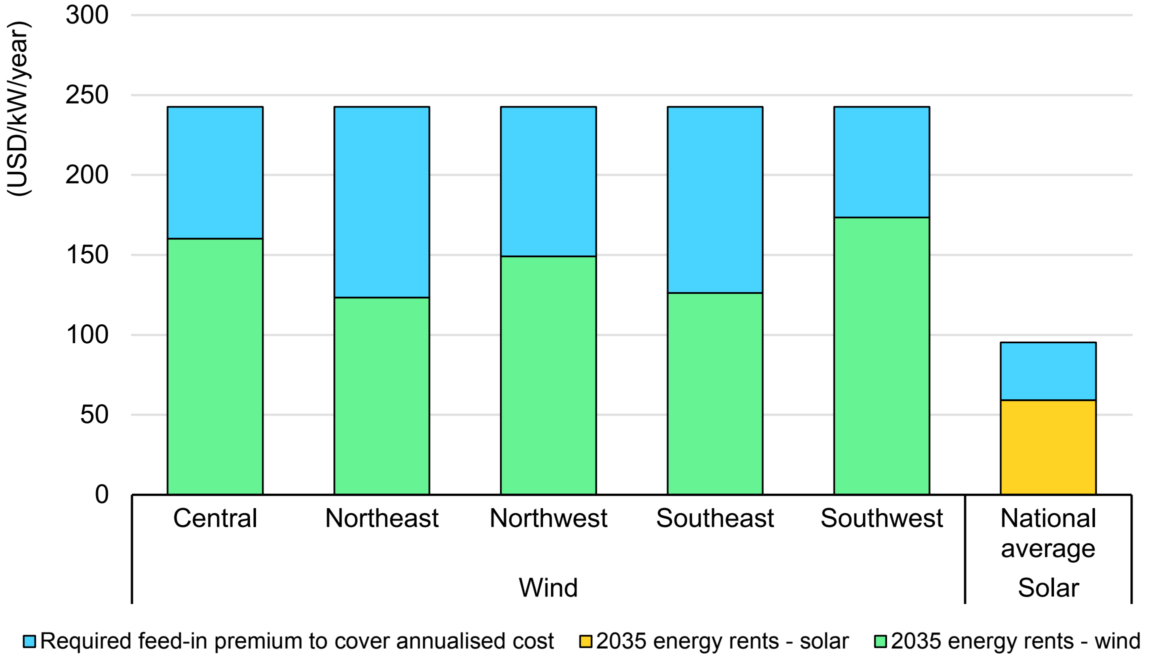
Currently, the primary policy that Korea uses to increase its share of renewables is the Renewable Portfolio Standards (RPS), where power generators with at least 500 MW of installed capacity need to increase their share of renewable energy generation. This obligation is progressive, starting from 2% in 2012 to 10% by 2023 (KNREC, 2018). Generators can either install renewable generation on their own or purchase renewable energy certificates (REC) from the market operated by Korea Power Exchange (KPX). To support different RE technologies based on their current competitiveness, Korea differentiated the weight of certificates ranging from 0.25 for bio-solid recovery fuels (bio-SRF), to

1.0 for solar PV installation at a regular site, to 4.5 for an energy storage system connected with wind (KNREC, 2018).

Other jurisdictions use a variety of tools to support renewables investment with guaranteed payments, including auctions for renewable energy, renewable energy credits, net metering and tax credits. Auctions for feed-in premiums, which provide low-carbon generators additional revenue on top of average wholesale market value, have been used as one of the most promising instruments to foster fast and cost-effective deployment of low-carbon resources for various reasons:

- Feed-in premiums push the task of finding the most valuable VRE resources to market participants, rewarding those that generate during hours of scarcity and high prices, and discouraging investments in VRE resources that produce at peak times of the day or in locations with oversupply.
- If awarded by auctions, they can provide contracts of long enough duration to facilitate project financing, without completely removing risks for the life of the project and keeping proper incentives for developers.
- Feed-in premiums complement revenues from the wholesale market and are thus compatible with the price enhancements described elsewhere in this chapter.
- If carbon pricing is too low to significantly increase the value of low-carbon electricity in the wholesale market, feed-in premiums provide an essential source of revenue to trigger the development of new projects.
- More importantly, carbon revenues and feed-in premiums (FIPs) can counterbalance each other, thus limiting the impact to consumer prices. For example, as the carbon price rises and drives increases in the wholesale market price, supported generators will derive more income from wholesale markets than from FIPs, thus limiting the total amount that is socialised to end-consumers.
- As an illustration, the figure below shows the different level of premiums that would be required by wind and solar developers in different regions in Korea in 2035 in a case where carbon prices are USD 70/t CO_2 and thus lower than in the APS. In comparing wind and solar, we see that although wind revenues per unit of installed capacity in each region are higher than for solar, the required feed-in premium is lower for solar due to its lower investment cost.

Estimated feed-in premium required for wind and solar in various regions – Announced Pledges Scenario 2035*



*Comparison of energy rents to fixed O&M and annualised capital cost; WACC = 7%.
Notes: Using scarcity pricing with 70 USD per ton carbon price.

Source: IEA Korea Regional Power System Model.

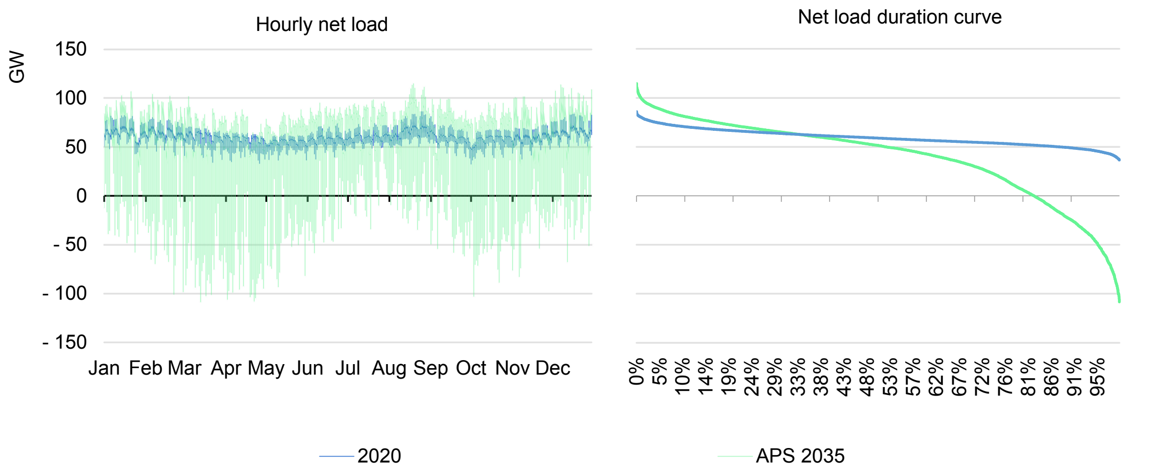
Since Korean regions have different levels of VRE resource availability and demand, each region has a different profitability/cost profile. When considering VRE capacity auctions, within the peninsula, developers' projects proposed in the south-west region are more likely to be awarded in auctions, as they require the lowest premiums and provide the most value to the system. This, in turn, promotes system-friendly deployment of VRE, since it will reduce the additional flexibility and firm capacity needs and will minimise the cost of transmission expansion. Depending on the government's policy, these auctions could be designed to be technology neutral – letting developers choose the technology – or be designed for a specific technology.

It is important that any complementary support systems take advantage of and are compatible with the market design, and account for both the time value and the location value of energy, as well as encouraging VRE producers to take on the responsibility and risk for self-bidding and forecasting. While aspects of bidding and balancing are already included in KPX's plans for 2025, these could be complemented by ensuring that VRE has access to additional participation in ancillary services as the system evolves.

Enhancing wholesale market operations is key for better renewables integration

Balance between supply and demand needs to occur instantaneously across all locations on the power system to maintain frequency stability and thus secure operation, but competitive markets make simplifications of this complexity necessary for operational reasons. In Korea, the dispatch is segmented into one-hour blocks. If, during the hour of operation, the system conditions change from projected expectations, reserves need to be activated to cover the difference. An integration of higher shares of variable renewable energy will increase volatility in net load over all timescales – from minutes to hours, days and weeks and seasons – and will lead to significant changes in net load profiles in 2035 (see figure below).

Hourly net load and load duration curve, 2020 and Announced Pledges Scenario 2035



Note: Net load is based on available variable renewables generation subtracted from the demand curve, prior to the impacts of demand response and energy storage.

Source: IEA Korea Regional Power System Model.

By 2035, hourly net demand ranges from a low of -108 GW (more VRE generation than demand, resulting in potential VRE curtailment) to 115 GW, a difference of 223 GW. This difference is more than four times higher than that observed in 2020, when net load was between 32 and 86 GW, a range of 54 GW. The system will experience higher hourly and sub-hourly ramps, and larger differences between minimum and maximum daily demand, which will create incentives for flexible loads and generation to participate, if given the correct price signal. Smart demand-side response, Smart charging, PHS and Batteries are all key resources to shift energy from low to high priced periods. The additional periods of low or even zero-price hours can be an opportunity for resource-intensive, yet flexible, industries to shape their demand to reduce costs while providing system benefits.

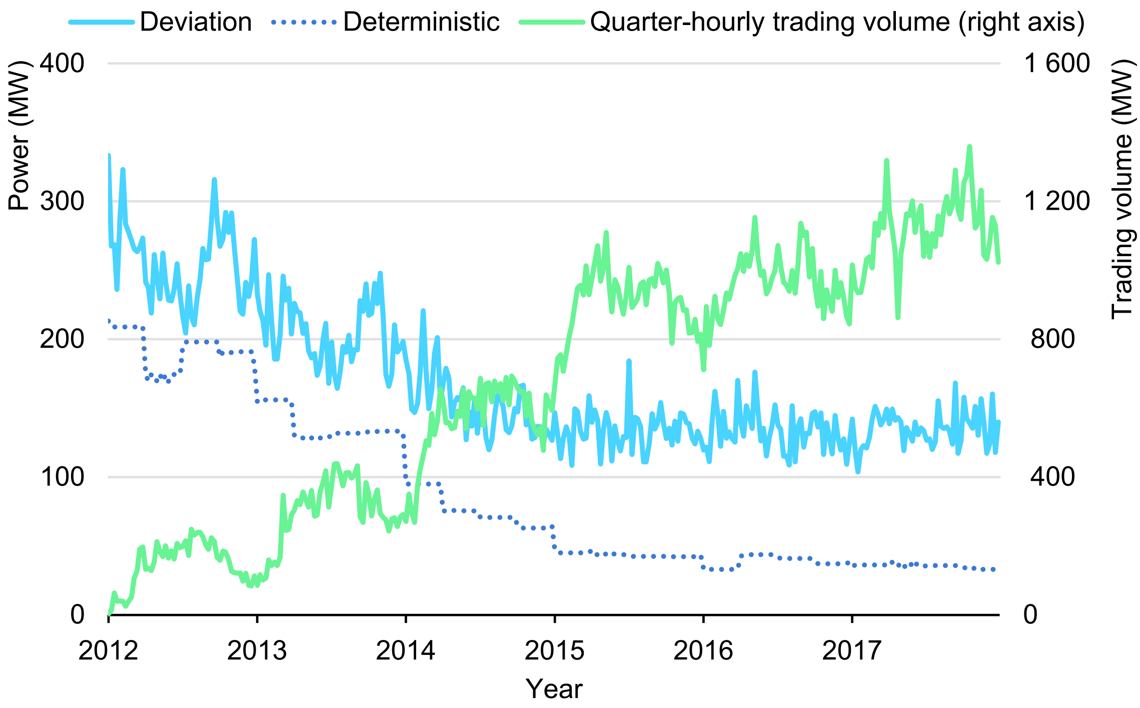
An important element of ensuring effective integration of VRE generation within the system is to provide the appropriate incentives for operators to not only locate where it is best for the system but to generate when it is best for the system. In particular, when reviewing higher incidence of zero-price or negative-price hours, Denmark's support for renewables provides some valuable lessons for the Korean power market. In Denmark, the payment of market premiums for large-scale VRE generators is not fixed on a set year period, for example every 25 years, but rather on a budget of effective hours of generation. On top of the locational incentives provided by the FIP system, this provides operators with an incentive to only inject power into the system during hours when electricity is needed, maximising the limited number of hours they will be rewarded in. Such a design could be considered in Korea, building upon the current plan for self-bidding of VRE generators and enhancing it in the future to ensure that much higher shares or VRE are achievable while supporting the power system.

Higher granularity of pricing and closer to real-time procurement can improve cost efficiency

Shortening the interval between price schedules, as is currently in discussion in Korea, is one reform that can provide multiple benefits to power systems that are dealing with increasing short-term variability. The increase in granularity can more accurately reveal when energy is needed to provide system balance. Resources focused on arbitraging price differences can target more frequent intervals and thus offer their services more efficiently. Shorter intervals also decrease the amount of reserves required to be held for smoothing out changes in dispatch schedules, or ramping. This service becomes more valuable as VRE penetration increases. For example, in Germany the increase in shorter interval trading (15 minutes) led to a decrease in the amount of reserves required to balance the system. In particular, the need for reserves due to scheduling changes, represented by the dotted blue line in the figure below, was lessened significantly.

Most recently, countries like Australia have been pioneers in introducing five-minute dispatch intervals, seen as particularly beneficial to better integrate the country's high share of solar PV. When considering the current proposals to enhance the dispatch horizons in Korea's power system, the design should enable gradually increasing the time granularity of dispatch periods. This will be particularly relevant to Korea, as solar PV is expected to contribute significantly to the decarbonisation of the country's power system. Additional improvements, such as consideration of future constraints in dispatch and price formation, may be an option as computational capabilities improve.

Reserves requirement and quarter-hour trading in Germany, 2012-2017



Source: Koch and Hirth (2019).

Higher regional granularity promotes system-friendly deployment

The Korean power system is a nationwide physical system of generators and loads interconnected by a complex grid, comprised of the transmission and distribution networks. The transmission and distribution systems have physical constraints for their operation, limited due to factors such as the thermal limits of equipment (lines, transformers and so forth), security constraints related to the loss of key components and stability limits in the case of faults. Additionally, the spread of generation and demand is not homogenous, with load centres occurring in places with high industrial development or large population centres. Similarly, generation, and especially renewables, may be more concentrated in certain areas of the grid due to the strength of resource or fuel supply.

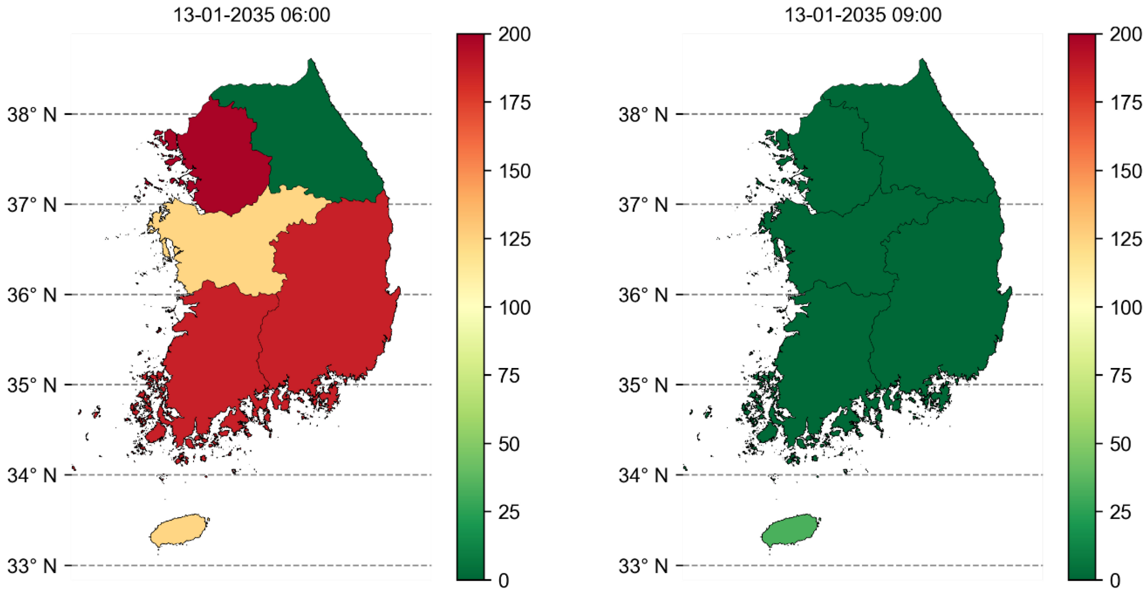
However, this complexity is not represented in the current implementation of the Korean electricity market. Instead, the market only considers a single bidding zone with uniform pricing across the system, which in practice treats transmission and distribution networks as if there were no physical constraints (known as a "copper plate").

This divergence from the system's actual physical constraints using a copper plate can lead to market distortion in terms of valuing generation based on where it is produced and where it is needed. In the short term, this can lead to inefficient system operation as market-cleared dispatch is required to be re-dispatched based on physical system constraints, bringing with it economic and environmental consequences. In the longer term, the market also lacks the proper signals for timely investment in transmission and building generation assets where they are most needed. This latter point can also lead to even more market distortion if generation capacity is built on the wrong side of a congested line.

To better reflect the system's physical constraints and reduce this distortion, markets can increase their geographical granularity, through two main approaches. The first, nodal pricing, or locational marginal pricing (LMP), implements pricing at each transmission node in the power system. In this approach, the divergence of prices between nodes reflects both congestion in the transmission network as well as transmission losses. Nodal pricing has been implemented in several systems in the United States to good effect, increasing the efficiency of operation, planning and investment (IRENA, 2019b). As more distributed energy resources (DERs) are added to the grid, it will be equally important to implement this higher granularity into retail markets to ensure that resources are properly valued and incentivised based on both the timing and location of production (IEA, 2017).

The second approach is zonal pricing, whereby multiple bidding zones are defined in a single system or country. This approach lies between nodal pricing and the single bidding zone approach currently employed in Korea. For zonal pricing, bidding zones are defined around those parts of the grid where congestion is generally not an issue and the zonal price is uniform.

Short-run marginal cost across regions during a period of peak (left) and minimum (right) net load, Announced Pledges Scenario 2035

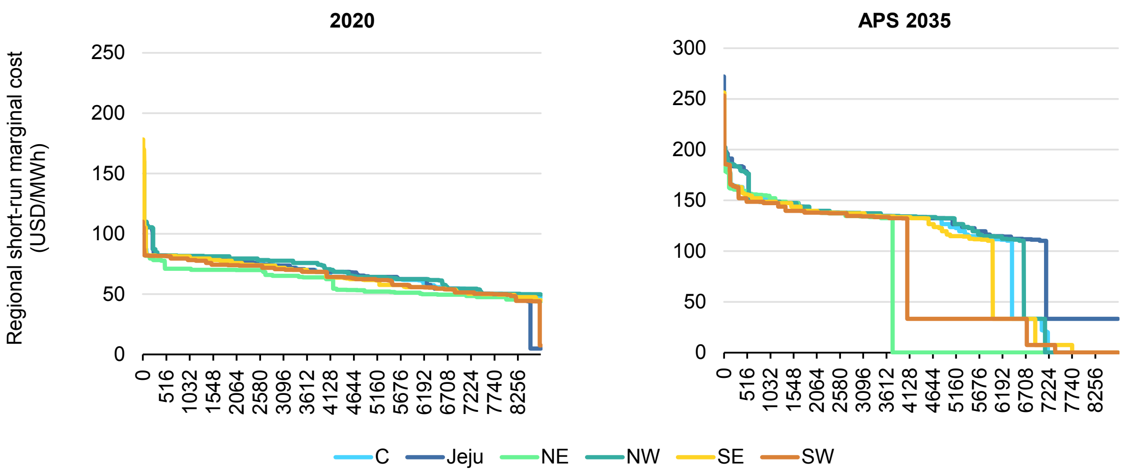


Source: IEA Korea Regional Power System Model.

While zonal pricing does not capture all the physical constraints in the system, it can be implemented in a way that captures the most critical bottlenecks in the transmission system, thereby offering a simpler alternative to nodal pricing. This approach has been employed in the European system, where each country represents at least a single bidding zone, is responsible for its own dispatch and for calculating the available transfer capacities (ATCs) for trade between zones (IRENA, 2019b). However, many European countries (e.g. Italy, Sweden and Denmark) have split their systems even further into multiple bidding zones to operate more efficiently and to reflect key bottlenecks within their transmission systems.

However, as more renewables are deployed, the location of these bottlenecks may begin to shift or multiply. Without nodal or zonal pricing to reflect the regional diversity of demand and resources, the market may lack the proper signals to deploy these renewables where they are most needed or to invest in a timely fashion in those parts of the grid where it is most urgently required. This is also the case for storage facilities and load shifting assets. Results from the modelling in 2035 indicate that this will have begun to occur in Korea under the APS scenario, where the SRMC in each region will begin to diverge during many periods of the year (see figure below), driven by changes on both the supply side, with an evolving generation mix and higher shares of VRE, and the demand side, with newly electrified loads, higher energy efficiency and shifting or expanding demand centres.

Short-run marginal cost by region, sorted from highest to lowest, 2020 and Announced Pledges Scenario 2035



Notes: APS = Announced Pledges Scenario.

Source: Korea Regional Power System Model.

Two settlement systems contribute to security by updating information between day-ahead scheduling and real-time operations

Day-ahead markets minimise operating costs taking into account factors such as start-up costs and minimum run times, on top of the cost of fuel, when committing thermal generation units. This lowers overall costs compared to pricing that considers fuel costs only. However, because day-ahead clearing generally occurs on the morning of the day before the day of operation, this results in a lag that can be between 14 and 38 hours from the moment when clearing is done to the hour of operation. Supply and demand conditions cannot be perfectly forecast in this timeframe, and deviations between the day-ahead schedules and real-time operations can be significant. This is why the implementation of Korea's real-time market is a welcome step, as it gives market signals reflecting scarcity and abundance as they happen.

Linking the real-time market to the day-ahead market will improve security of supply and enhance market competitiveness. The day-ahead market serves as the forward market and then adjustments to the day-ahead schedule occur in the real-time market. This process, known as a two or double settlement structure, disciplines generators to place realistic offers for their supply and load-serving entities to accurately forecast demand since a large mismatch between their bids in day-ahead and real-time expose the entity to large fluctuations in price and, potentially, to financial losses. This in turns helps create a more secure operation of the system, as all actors have incentives to minimise unforeseen imbalances between their supply and demand.

However, with the introduction of significant amounts of VRE, there is a growing need to adjust dispatch schedules to reflect new information about supply and demand conditions closer to operation. Intraday markets are a relatively recent development in some markets, and are desirable because significant changes in the forecasted load, generator and transmission outages, and variable renewable generation availability can occur between day-ahead scheduling and real-time operation. As a third market existing between these time frames, intraday markets allow adjustment of commitment decisions to optimise the use of system resources. Intraday markets are increasingly important in Europe, particularly as shares of VRE increase.

The analysis presented in Chapter 2 shows that integrating increasing shares of VRE will lead to a significant incremental increase in intraday flexibility needs. This will require, on the one hand, the development of very refined forecasting methods for variable renewable energy as well as increasing the resolution and precision of intraday markets. IEA analysis shows that for countries like France, where solar PV will be the driver of power system decarbonisation, improving reserve methods for reserve sizing and distributed resource management will be key to reducing the need for additional operational reserves. This is likely to be the case in Korea's power system as well. To address this, experiences like those in Great Britain's power system's may be helpful by introducing real-time balancing mechanisms, which are linked to the wholesale market's scarcity signals and allow all resources, including VRE, to balance the power system in real time.

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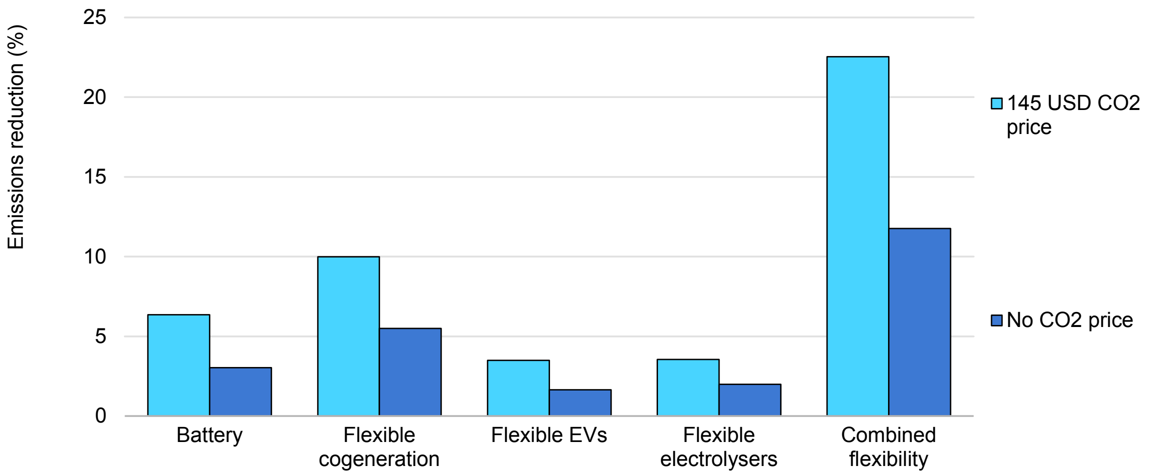
Chapter 4 – Distribution-level markets and the link with markets beyond the power sector

The analysis presented in the previous chapters shows that achieving Korea's decarbonisation objectives will require significant shares of variable renewable energy generation and increase the system's flexibility requirements. Distributed energy resources (DER) such as distributed generation, battery storage, demand response and EVs can contribute to balance the system, but their contribution both to emissions reduction and flexibility needs to be maximised through effective co-ordination and by linking their operation to power systems conditions. The deployment of these resources is not enough to achieve the objective of a low-carbon and secure power sector, it is equally important that these resources interact with the rest of the system in order to both contribute to security of supply and to take advantage of large amounts of low-carbon energy.

Emissions reductions by flexibility measure with and without CO_2 price, Announced Pledges Scenario 2035



Source: IEA Korea Regional Power System Model.

Effectively enabling the participation of DERs in Korea will require a number of measures, ranging from opening wholesale and ancillary service markets to the participation of smaller, distribution-connected resources, to developing appropriate standards for aggregation and interoperability and reforming price signals faced by end-consumers. Around the world, the majority of electrical loads – such as water, space heating and, increasingly, transport – are charged without optimising for system conditions. Thus, developing tariff offers that link end-consumer electricity prices with system conditions or participation rewards can be a useful avenue to improve the alignment between new emerging electrical loads and the changing demand for services such as ramping, peak-shaving and system balancing.

Moreover, rolling out DERs along with a robust digitalisation strategy will be necessary due to the complexity of co-ordinating thousands of smaller, distributed devices to ensure that these can reliably and cost-effectively contribute to system services.

Market opportunities to tap into Korea's demand response potential

Korea currently has two broad categories of demand response (DR) programmes: reliability DR and economic DR (KPX, 2021a). Reliability programme participants register their DR capacities at the Korea Power Exchange (KPX) in advance and activate them according to KPX instructions, foreseeing a system emergency. KPX compensates the activated resources with availability and activation payments. Economic DR participants conversely bid in the day-ahead market, and successful bidders are remunerated with activation payments. The availability payment is set at the generator's capacity payment, while the activation payment is based on system marginal prices. In June 2021, 83% of registered DR capacity came from large customers (KPX, 2021b). Korea has recently made some improvements, including launching a dedicated DR programme for small resources and allowing fixed payments to an economic DR participant in proportion to activated capacity.

As Korea's power system decarbonises with rapid penetration of variable renewables and phasing out of the traditional flexibility providers – large fossil fuel generators – the need for alternative flexibility options increases. DERs such as EV, behind-the-meter, and commercial batteries are small, agile resources located close to consumers and fit for providing temporal and locational flexibility. However, their participation can only be realised when the markets are properly designed. Regulators can improve markets to enable fair compensation for the values that DERs can provide. Therefore, regulators in Korea can aim to improve overall market mechanisms as recommended in Chapter 3, rather than making incremental improvements under the current cost-based pool regime. At the same time, they can prepare in advance to open the improved markets to DERs.

Some jurisdictions, such as the United States and Europe, are undertaking diverse experimentation to unlock the potential of DERs. Their experiences can provide lessons for Korea. The value of flexibility is typically captured in the market prices as, for example, increased price volatility in the day-ahead markets. Regulators can add more time and locational granularity to market prices so that they can reflect the ever-changing system conditions. This, in turn, can improve both DER economics and system reliability. For example, the Australian Energy Market Operator (AEMO) recently transitioned towards a 5-minute settlement for its energy markets (AEMO, 2021). Some countries have capacity markets in place to ensure long-term resource adequacy. Regulators can design the mechanism to reflect flexible ramping capacity needs rather than static peak capacity. The flexible resource adequacy requirements introduced by the California Public Utility Commission (CPUC) to address its duck curve issue is a good example. In addition, DERs are connected to distribution grids close to consumers, meaning that they can benefit wholesale markets, distribution systems and consumers alike. Regulators can establish clear rules and procedures that allow DERs to stack multiple revenue streams (CPUC, 2021). New York Independent System Operator (NYISO) developed a dual participation model whereby DERs can provide dual services simultaneously, for example, energy service to the ISO's real-time market and grid congestion management service to distribution utilities (FERC, 2020a).

The centralised dispatch power system that Korea adopted needs to develop a new market participation model for new types of resources, such as batteries and aggregation of small resources. The US Federal Regulatory Energy Commission (FERC) ordered in 2018 that all ISOs establish a market participation model for electric storage resources (FERC, 2018). ISOs thus far have had only two types of resources: generation and consumption. However, batteries can both generate and consume and thus require a tailored bidding format, without which batteries should make two separate offers as generators and consumers. Batteries also have a unique technical constraint: limited storage capacity, and thus their state-of-charge needs to be incorporated into the bidding format.

Furthermore, in 2020 the US FERC also ordered to open all wholesale markets to the aggregation of DERs, raising a variety of new questions about market participation models to the US ISOs (FERC, 2020b). A large number of small-sized, aggregated resources may be scattered across large regions impacting and facing different distribution grid conditions to which each resource is connected.

Therefore, close co-ordination between an ISO and distribution utilities is a prerequisite to the new model's success. Distribution utilities also need to modernise their grids and take over new roles as active network managers, called distribution system operators (DSOs). Regulators in Korea can develop market participation models for new resource types in parallel with improving markets as recommended in Chapter 3. It is especially important to note that low-voltage grid modernisation and the transition towards DSO require significant financial resources and well-planned preparation. The caveat is that the market integration of DERs is not a matter of merely adding new resources to the current power system. Instead, every aspect of the system needs transformation. The IEA plans to publish a new report soon to identify future services of DERs, highlight current best practice and provide practical recommendations to help policy makers unlock the full potential of DERs

Optimising cogeneration use offers opportunities for both emissions reduction and increased flexibility

Combined heating and power (CHP) production is one of the most efficient ways to consume fossil fuel due to its ability to fulfil heating and electricity demands. It is not commonly thought of as a flexible asset, however, due to the inflexibilities associated with the connected heating demand. However, with the right market configuration, CHP services can be unlocked to provide system flexibility.

In technical terms, increasing the flexibility of CHPs is simple. Operators could first begin with controls that bypass the turbine and sustain heating production, or install heat storage tanks. As higher low-cost variable renewables enter the system, CHP operators may encounter situations where it would be cheaper to use electric boilers to satisfy heating demand, rather than burning fuel. These measures make business sense if CHPs are allowed to participate in the electricity market, and be remunerated for the stability, flexibility and demand response that they can provide.

Activating low-carbon distributed flexible resources in Denmark

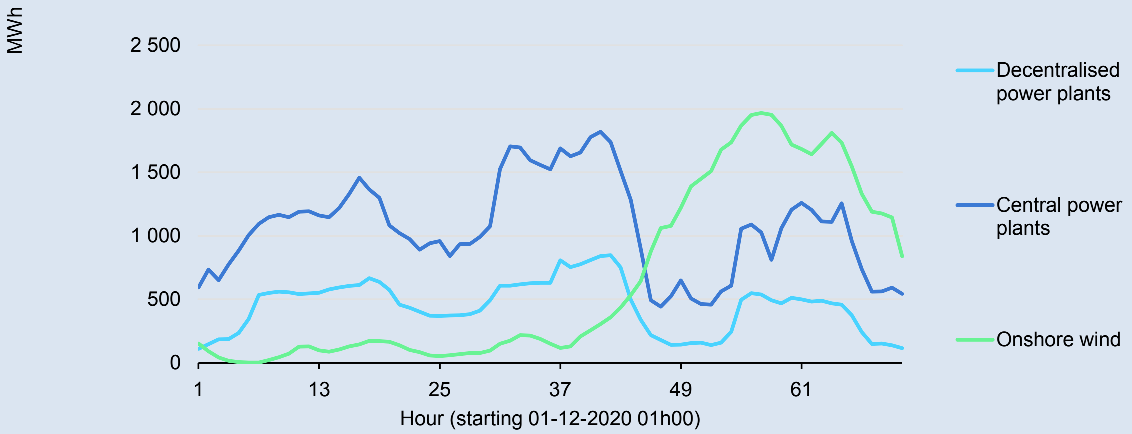
Denmark has a significant amount of district heating (65% of dwellings), of which 70% to 80% is provided by CHPs (Euroheat, 2019). They are primarily installed in urban areas with high population density where several dwellings could be heated by a small network with relatively small losses.

As part of the country's goals to increase integration of wind energy, CHPs have started participating in providing flexibility to the electricity market. By lowering their output during levels of high wind generation, curtailment is avoided. To achieve this while servicing the heating demand, certain technical measures have been made (DEA, 2017):

- Adding or using the existing heat storages more frequently
- Installing electric boilers
- Bypassing electric generation turbines to service only the heating output

Due to the abundance of wind power in Denmark, certain bidding zones of the electricity market experience negative prices. Due to this, a number of CHPs have installed electric heat boilers to avoid additional fuel combustion and act as a net electricity consumer. As a result, the higher levels of wind energy integration lead to further decarbonisation of the heating sector.

Generation in DK1 bidding zone from Dec 1 to Dec 3 in 2020

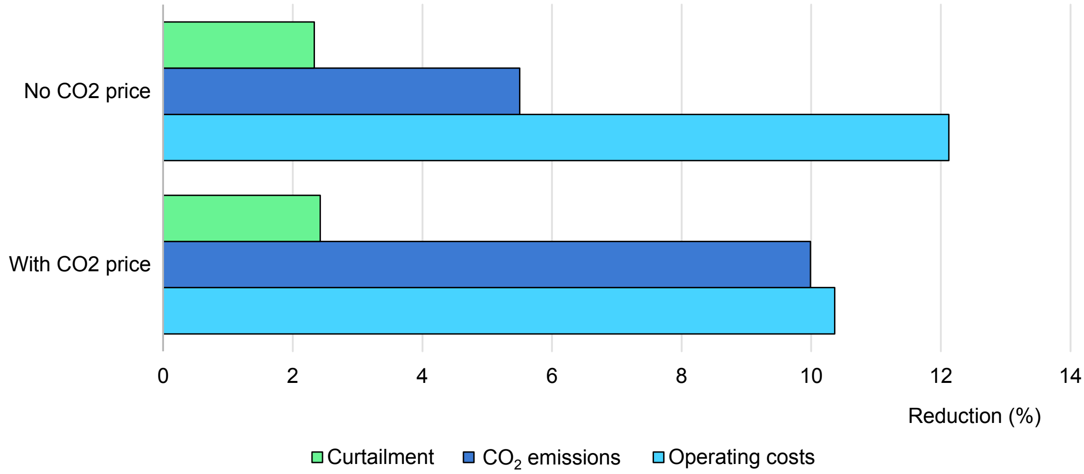


Denmark has also taken steps to incentivise fuel switching in CHPs to reduce carbon emissions. The 2012 Energy Law reduced tax duties for heat and electricity revenues for coal CHPs switching to biomass, leading to an increase in biomass use from 39 EJ in 1990 to 83 EJ in 2019. The incentive is also extended to biogas for CHPs running on gas, leading to an increase from 0.8 EJ to 17 EJ between 1990 and 2019 (Energistyrelsen, 2019). In addition, as part of renewable electricity incentives, CHPs using bioenergy obtain a 20 EUR/MWh premium on the electricity market price (DEA, 2017). The combination of efficient district heating planning, market design and renewable energy incentives allowed Denmark to rapidly achieve lower carbon emissions in the electricity and heat sectors.

Source: IEA Analysis of Energinet (2021), *Production and Consumption - Settlement*

Today, a substantial amount of cogeneration operates on a must-run basis following heating requirements. In the APS 2035, relaxing these must-run constraints leads to a reduction in curtailment of around 2% as well as reduced operating costs. Emissions are also decreased by 5.5% with no carbon price, and around 10% when a carbon price is included.

Reduction in curtailment, emissions and operating costs due to flexible dispatch of cogeneration in the Announced Pledges Scenario 2035



Source: IEA Korea Regional Power System Model.

In addition to the benefits of flexible CHPs, there is an additional benefit of increasing the baseline capacities of CHPs. Aside from fuel use efficiency, CHPs could have the scale necessary to use alternative fuels, such as biomass and waste compared to individual household boilers, thereby contributing to even higher decarbonisation rates.

Despite these advantages, their deployment in Korea is still limited. The current installed capacity of is 2.6 GW with additional 2.8 GW planned in the 9th BPLE. They produce about 67% of the district heating needs (Euroheat, 2017), while district heating itself supplies only 15% of the population's heating needs compared to approximately 50% in Denmark (Epp, 2019). A study by KEEI (2017) provides recommendations to amend aspects of the gas market and ETS to help increase the uptake of CHP.

Increasing the total capacity of CHPs can help provide additional sources of flexibility for Korea, as well as contribute to decarbonisation through a more efficient fuel use.

Smart charging of EVs in Korea can contribute to significant emissions reductions in both the power and transport sectors

Transport electrification is both a challenge and an opportunity from a system integration perspective. With increasing EV numbers and growing penetration of variable renewable energy sources in the system, it will become increasingly important that EV users charge in times of high VRE availability. Indeed, if the additional electricity demand from EVs is not controlled, a significant rise in peak demand can occur, and current mobility patterns show that it would not necessarily coincide with high VRE availability times. While the typical EV charging patterns are influenced by the type of vehicle and the activity profile, passenger light duty vehicles (PLDV), which are expected to account for more than 60% of global EV electricity consumption by 2030 according to the IEA Sustainable Development Scenario, typically charge upon their return home from work. Without smart charging, they are expected to have the largest contribution among EVs to evening peaks as shown below.

Analysing the impact of charging patterns in the 2035 Korea APS scenario shows that optimising 30% of the expected EV fleet's charging pattern can lead to significant savings with average operating and peak costs for the EV fleet reduced by 21% and 30%, respectively, and EV emissions reduced by 21% as summarised in the table below.

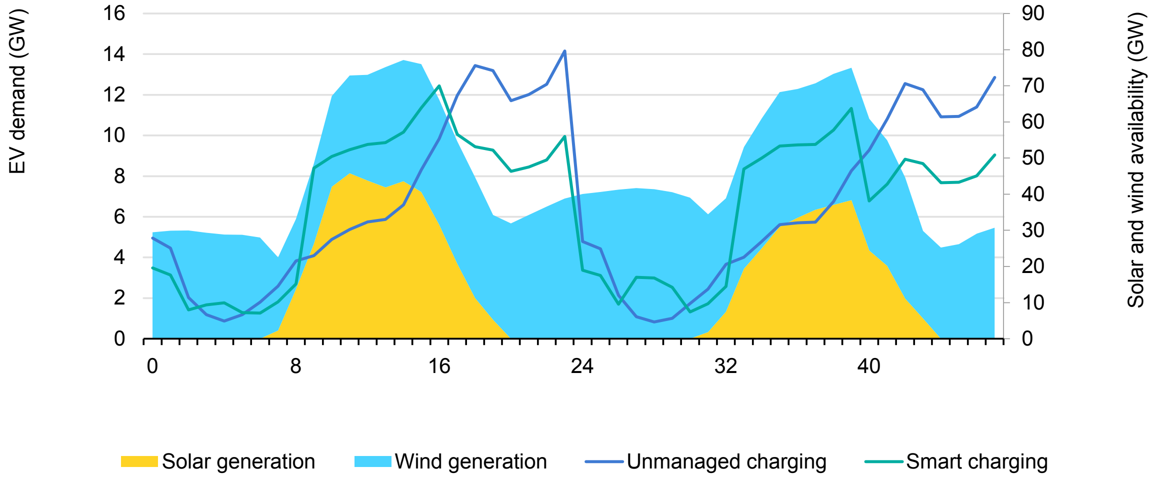
Cost savings for the EV fleet when charging is optimised

	Peak costs	Operating costs	Emissions
USD/MWh avoided	18	21	/
% Reduction	30%	21%	21%

Source: IEA analysis using the IEA Korea Regional Power System Model APS 2035.

With respect to the total system, smart charging allowed 1% curtailment reduction and up to 3% reduction of the total operating costs. The displacement of demand from peak times to times of higher generation availability also generates CO_2 emissions reductions. The aim should be to maximise those reductions that correlate with incentivising charging in times of high VRE availability. In the APS 2035, smart charging of 30% of the EV fleet shifts the EV load to times of high solar availability, as seen in the figure below. This is crucial to ensure that the electrification of road transport is decarbonised.

Electric vehicle load profiles for unmanaged and smart charging relative to solar and wind availability, Announced Pledges Scenario 2035



Source: IEA Korea Regional Power System Model.

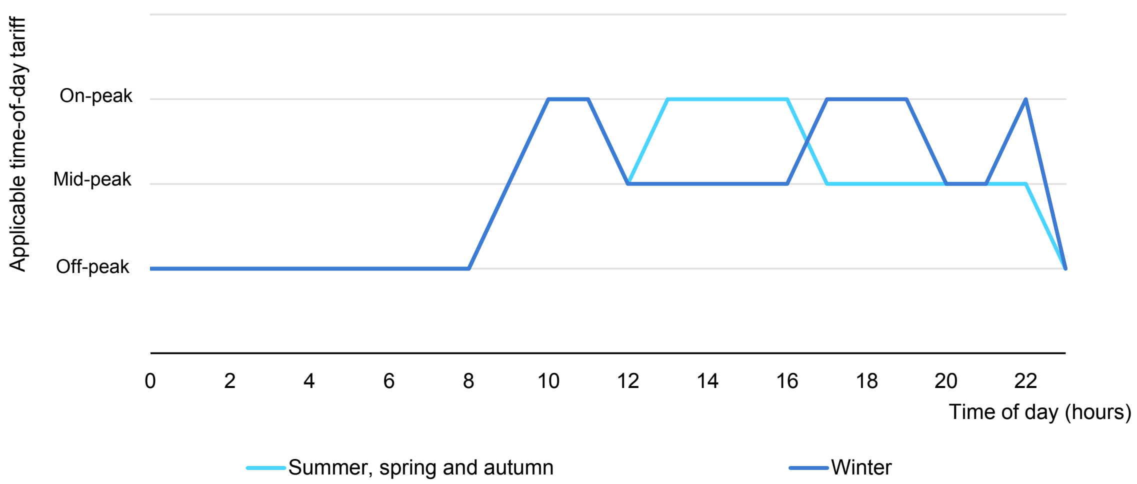
Moreover, replacing ICE's by EVs in the APS 2035 comes with the benefit of emissions reductions outside the power sector, delivering the same level of service demand in transport but with a reduction of 53% in emissions relative to ICEs, even with unmanaged charging. Indeed further optimisation of charging leads to greater emissions reductions by displacing charging at times of greater solar availability and away from peak load times. For example, in the model, deploying 30% of the fleet's capacity to be flexibly charged across the day leads to a 63% emissions reduction when compared to a full ICE fleet. This increases to 84% with the full EV fleet using smart charging.

Furthermore, analysing EV smart charging in the APS 2035 with and without CO_2 price showed that CO_2 price strongly contributes to maximising CO_2 emissions reductions. While the case without CO_2 price already provides an emissions reduction compared to no smart charging, that reduction is doubled with a CO_2 price. Indeed, in a price environment in which the CO_2 price is linked to the generation costs, the electricity generation from low-carbon technologies will be favoured as the least costly option for EV charging. As such, the optimisation will incentivise charging in times with high VRE availability, for example during mid-day peak of solar PV production.

Korean retail tariff design needs to evolve to realise the benefits of smart EV charging as the power system evolves

Time-of-use tariffs are one of the main measures used to ensure smart charging of EVs to materialise the peak load and emissions savings obtained in the above scenarios. At present, Korea has a set of diversified retail tariff structures for different customer types that vary in complexity, ranging from rising block tariffs for low-income residential customers in two seasonal schedules, to fully diversified tariffs which account for seasonal differences as well as three time-of-day segments: off-peak, mid-peak and on-peak. As can be seen below, Korea's current schedule for time-of-day tariffs sets the peak load during mid-day in summer to counter the effect of cooling loads such as AC.

Distribution of time-of-use tariffs across the day in by season in Korea



Korea's current EV tariff is in line with the rest of its time-of-use (TOU) tariffs, which are consistently higher in summer than in winter and the spring/fall seasons. At present the summer on-peak tariff for EV's covers the early afternoon and is set at KRW 227.5/kWh, which is slightly more than three times the off-peak tariff of KRW 52.6/kWh (KEPCO, 2021). In the coming years, as the share of EVs increases and solar PV's share in generation increases, it will be important to update the tariff as the current design would encourage EV charging during the evening peaks, thus reducing the potential benefits in terms of emissions and system cost reductions.

Understanding the implications of different charging patterns – depending on whether for personal-use vehicles, commercial fleets or public transport – will be key in designing future tariff offerings that facilitate the integration of EVs in the power system. Indeed, there are already a number of studies in Korea to this end. In June 2020, KEPCO launched a full-scale demonstration of EV smart charging and recruited EV owners to participate, aiming to demonstrate the direct control effect of V1G charging. By June 2021, when the demonstration project started, KEPCO had installed 130 smart chargers for electric vehicle customers from four regions participating in the project. The project will last until July 2022 and aims to validate the technology, test peak demand load reduction and optimise VRE integration (EPJ, 2021).

Further improvements in managing the EV fleet and ensuring their active participation in system balancing and emissions reduction can be achieved through vehicle-to-grid (V2G) approaches. A step further in smart charging, V2G allows for both managed charging and discharging of EVs and, with the right tariff structure, can contribute to both balancing the power system as well as reducing EV owners charging bills.

To estimate global V2G potential, IEA analysis excluded 50-60% of commercial vehicles, 80-95% of PLDVs, considered only 5% of the two/three-wheelers and buses, and accounted for all additional limitations linked with battery lifetime and discharge rate. Despite these limitations, the technically available potential for V2G in the SDS for 2030 exceeded the additional generation capacity required to meet peak demand in most EV markets (IEA, 2020a). The flexible capacity provided by V2G could further be used to compensate variability in renewable-based generation. EVs would charge in times of high renewable penetration in a low-price environment, and discharge when demand is strong and prices high. Access to dynamic pricing with even greater time resolution for three daily pricing blocks could lead to a better alignment between charging behaviour and system conditions to both avoid charging during peak demand periods as well as favouring charging in times of lower emissions intensity.

In addition to its targets and ambitions for EV and electric vehicle supply equipment deployment, the Korean government has started implementing measures to promote smart charging and V2G technologies, notably with its Smart Energy Strategy and the second basic plan for a smart grid. It plans to ensure open access to all charging stations, regardless of the charging point operator, with one single membership card and mandate charger installation in new apartments (Maeng et.al 2020). The government's Smart Energy Strategy also foresees further pilots as well as a revision of electricity market access rules to allow for V2G participation in the wholesale market. These are welcome steps that should be combined with revised, eased market participation rules, as well as an adequate flexibility remuneration.

Reforming retail tariff structures and improving the link with wholesale market design is key to ensuring active participation of distributed energy resources

As a result of electrification of industrial, transport and building sectors, total electricity demand is expected to more than double from 526 TWh in 2018 to between 1165-1215 TWh (Government of Korea, 2021), placing a larger emphasis on timely investment in and secure operation of the electricity system. Electricity markets will therefore play an important role in ensuring that sufficient signals are present for investment in a suite of tools, including supply from low-carbon resources, electricity networks and flexibility.

Active participation of electrified demand resources in Korea's electricity markets will require action within the Korean power sector to ensure investment in shared infrastructure (e.g., at-work charging for EVs), and market design and regulation that enables and incentivises participation from a greater pool of demand-side actors that allows access to this flexibility.

The current range of tariff structures in Korea already includes a few incentives for both implicit and explicit participation in balancing the system. These include the seasonal and time-of-use elements in tariff structures for commercial, industrial and large consumers, but also dedicated programmes for load management as mentioned earlier. Notably, the market-based demand response programme introduced in 2014, allows participation in the wholesale market through an aggregator (Kang, T., 2020). This allows aggregators to offer demand response in daily bids of at least 10MW upon previous registration with KPX. Currently, aggregators' resources are mostly bigger industrial customers (Chae, J. and Joo, S.-K. 2017).

One particular flexibility resource that could be better deployed by improving the retail tariff design and linking it more closely to conditions in wholesale and ancillary services markets is storage. This includes both the current stock of BESS deployed in hybrid combinations with VRE installations which is managed by KEPCO and, more importantly, the 2-3 GWh of behind-the-meter BESS capacity that has been installed at industrial sites.

First, further analysis could investigate optimised operations of KEPCO's transmission connected batteries, which are currently dispatched to reduce ramping requirements at the beginning and the end of the day, on a fixed schedule. While this use-case is compatible with existing intraday variability patterns, increased incidence of network constraints and increased net load volatility may become more attractive sources of revenue at higher shares of VRE generation.

Second, studying the deployment of behind-the-meter BESS units at large industrial facilities for system services may reveal additional benefits in terms of emissions reductions and VRE integration, while limiting the need for additional investments in new BESS assets. While the current tariff offering for industrial users based on Critical Peak Pricing may present an incentive to individual large consumers to install a battery to reduce energy bills, this may also lead to inadequately shifting network costs to regulated consumers while not necessarily reducing peak load requirements on the system as a whole. This has been seen in power markets like Great Britain and Quebec, and most recently lead to the retirement of the Triad programme for Critical Peak Pricing in Great Britain's power market. By contrast, allowing the aggregation and co-ordinated deployment of behind-the-meter (BTM) storage for system services, such as balancing or ramping, can lead to significant reductions in system costs and improved dispatch. To ensure effective participation, however, retailers and regulators need to work together to improve the tariff structure and ensure that the correct monitoring and control infrastructure is in place.

Increasing competitiveness in retail service provision can accelerate DER participation in system services and reduce the cost of lowering emissions

Increased competitiveness in the Korean electricity market can be a driver of increased diversification of services for the provision of flexibility and emissions reduction. This can range from setting regulatory targets for cost reduction in balancing and ancillary services to allowing the entry of new participants in the retail market.

The increase in renewables will drive an increase in balancing within a pure pass-through system, and system operators may not see a need to innovate or look for cheaper providers. In countries like Germany and the United Kingdom, network management costs, which include the cost of balancing and reserve provision, make around a third of the costs faced by end-consumers. While there are multiple forms of regulating the remuneration of network costs, there is increasing evidence that moving from pure cost-of-service models to well calibrated, incentive-based regulation can help to reduce the end costs for consumers while facilitating the integration of low-carbon and distributed technologies. Within the European Union, the electricity regulation package of 2018 allows for national regulatory authorities to introduce performance targets to incentivise distribution system operators to raise efficiencies, including through energy efficiency, flexibility, smart grids and smart metering (Pató, Baker, Rosenow, 2019). While the restructuring model present in European and North American power markets is not directly comparable to Korea's structure, they may offer some insight into the management of network costs. As the share of VRE generation and distributed assets increase in the Korean power system, it may be helpful to review the way in which costs of balancing and network management are recovered in order to incentivise greater competitiveness and avoid increasing energy costs – particularly when consumers are not able to switch suppliers.

Another option to accelerate decarbonisation while meeting the system's increased flexibility requirements and maintaining affordability may be to allow the entrance of new retail and ancillary service providers. Experience from European markets shows that allowing new entrants, who initially specialise in specific industries or models for flexibility provision, can contribute to improve the participation of distributed energy resources in particular system services and eventually in the wholesale market.

The contribution of distributed energy resources to decarbonisation will hinge on accelerating the digitalisation of Korea's power system

At present, large industrial consumers represent the largest share of participants in the country's demand response programmes, owing largely to the relative ease of co-ordinating fewer large resources as opposed to thousands of smaller distributed assets. However, recent advances in digitalisation technologies for the power sector are already driving the active deployment of distributed assets, such as EVs, battery storage and cogeneration for active participation in balancing markets. This, however, will require greater deployment of advanced metering and control technology, and potentially the entry of new service providers.

With regards to the deployment of advanced metering technology, which would accelerate the development of more granular tariff structures for end-consumers, as of 2019, KEPCO counted with about 8.8 million smart meters installed, but this is far from the original target of 22.5 million smart meters by 2020 (IEA, 2020c). While this has delayed the widespread introduction of more disaggregated tariffs, it need not stop the development of more innovative retail structures. In fact, in power markets like Great Britain's and in some US markets, targeting consumer groups like EV owners and commercial users that already have smart meters can be a first good step.

However, other benefits of digitalisation can be realised through the deployment of a more top-down infrastructure. The introduction of real time markets along with the revamping of the KPX dispatch platform is already an example of how power system operation can be improved through digitalisation. Further operational improvements, such as the introduction of renewable energy control centres in India or Spain, or the introduction of a distributed resources desk in the United Kingdom, are examples of how digitalisation can help accelerate decarbonisation. Moreover, KEPCO's recent introduction of tools that enable users to carry out real-time metering and power quality, provide further evidence of how digitalisation can contribute to ensure security of supply (Korea Times, 2021).

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Annex: Power system modelling and methodology

Korea Regional Power System Model

To evaluate the market design requirements of a net zero pathway for the Korean electricity market, the IEA has developed a detailed power system model: the Korea Regional Power System Model. The model undertakes a techno-economic analysis using a production cost modelling approach, with a focus on operational aspects for three one-year "snapshots": 2034 for a capacity mix based on the 9th BPLE, 2035 based on the IEA Announced Pledges Scenario, and 2020 as the reference year. The model separates Korea into six regions so that differences in electricity supply can be accounted for, without maximum constraints on transmission but with a cost applied to transfers between regions.

Emissions have been calculated according to estimated fuel characteristics and plant efficiencies. Production profiles for renewables were represented, along with operating costs and with detailed operating characteristics for thermal technologies represented such as plant technical minimum operating levels, minimum up and down times, start-up times and ramp rates. The hourly simulations were based on unit commitment and economic dispatch. Hourly load profiles are based on historical demand from 2020, projections for the growth in total and peak demand in the 9th BPLE, and projections in the growth of EV and electrolyser demand. Underlying EV charging patterns are based on KEPCO charging station data. Pumped storage hydropower in both the BPLE and APS scenarios are based on the 9th BPLE.

The three main modelling horizons represented are 2020, 2034 under the BPLE, and 2035 under the IEA Announced Pledges Scenario. A number of different cases are modelled in order to investigate the impact of market and flexibility options.

IEA Korea Regional Power System Model scenarios and cases summary

Scenario	Case(s)	Description
2020	Validation	Generation capacity and demand based on 2020 historical values
BPLE 2034	Base	Generation capacity and demand based on 9th BPLE, no CO_2 price
BPLE 2034	CO_2 price sensitivities	Five cases with the BPLE base scenario including CO_2 prices of 20, 40, 60, 80 and USD 100/t CO_2
APS 2035	Base	Capacity and demand based on IEA's Announced Pledges Scenario, CO_2 price of USD 145/t CO_2 , and flexibility from cogeneration, EV charging, electrolyser demand and batteries
APS 2035	Inflexible	APS base case but without flexibility from cogeneration, demand response and batteries
APS 2035	Flexibility sensitivities	Four cases based on the inflexible APS, with flexibility only from cogeneration, EV charging, electrolyser demand, or batteries
APS 2035	CO_2 price sensitivities	Six cases covering the APS base, inflexible, and flexibility sensitivity cases but with no CO_2 price

Abbreviations and acronyms

AEMO	Australian Energy Market Operator
ATC	available transfer capacities
BECCS	bioenergy with carbon capture and storage
BESS	battery energy storage system
BEV	battery electric vehicles
BPLE	Basic Plan for Long-Term Electricity
BTM	behind-the-meter
CBAM	Carbon Border Adjustment Mechanism
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CfD	contract-for-differences
CHP	combined heating and power
CNS	Korea's Carbon Neutral Strategy
CPUC	California Public Utility Commission
DAC	direct air capture
DER	distributed energy resources
DR	demand response
DSO	distribution system operators
EMP	Energy Master Plan
EOR	enhanced oil recovery
ETS	emissions trading system
EV	electric vehicle
FCEV	fuel cell electric vehicle
FERC	Federal Energy Regulatory Commission of the United States
FIP	feed-in premiums
GDP	gross domestic product
GHG	greenhouse gas
ICE	internal combustion engine

IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
KEEI	Korea Energy Economics Institute
KEPCO	Korea Electric Power Corporation
KETS	Korean Emissions Trading System
KPX	Korea Power Exchange
LCOE	levelised cost of electricity
LCV	light-commercial vehicles
LMP	locational marginal pricing
LNG	liquid natural gas
NDC	Nationally Determined Contribution
NRE	new and renewable energy
NYISO	New York Independent System Operator
NZE	IEA's Net Zero Emissions scenario
O&M	Operation and maintenance
PC	pulverised coal
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PLDV	passenger light duty vehicles
PSH	pumped storage hydropower
PV	photovoltaic
RE	renewable energy
REC	renewable energy certificates
RPS	Renewable Portfolio Standards
SDS	Sustainable Development Scenario
SRMC	short-run marginal cost
TOU	time-of-use
US	United States
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook

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