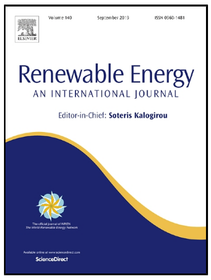
Accepted Manuscript



Assessment of future renewable energy scenarios in South Korea based on costs, emissions and weather-driven hourly simulation

Minsun Park, Mark Barrett, Tiziano Gallo Cassarino

PII: S0960-1481(19)30767-0

DOI: 10.1016/j.renene.2019.05.094

Reference: RENE 11686

To appear in: *Renewable Energy*

Received Date: 22 November 2018

Accepted Date: 22 May 2019

Assessment of future renewable energy scenarios in South Korea based on costs, emissions and weather-driven hourly simulation

Minsun Park[1], Mark Barrett[2] and Tiziano Gallo Cassarino[2,*]

[1] Institute for Environmental Design and Engineering, Bartlett School of Environment, Energy and Resources, University College London, London, UK

[2] Energy Institute, University College London, London, UK

[*] Corresponding author: t.cassarino@ucl.ac.uk

Abstract

The energy policy released by the South Korean government in 2017 aims to gradually increase renewable energy to 20% while reducing the number of nuclear and coal power plants by 2030. The constant controversy over the feasibility of this policy – which arose soon after its release – led to a number of studies focussed on the environmental, economic, political and social issues related to the current policy. However, none of these investigated the hourly dynamics of renewable energy supply, which is crucial to provide an accurate assessment of an energy policy and a technical evaluation of its feasibility. In this study, we analyse four potential renewable energy scenarios for 2030: Business as Usual, Strengthened Solar (i.e. the new energy policy), Strengthened Wind, and our Suggested Scenario. Using a bottom-up energy system modelling approach, we simulated solar and wind power generation at the hourly level, integrating weather data provided by the NASA MERRA-2 reanalysis database. In addition to the feasibility of each scenario, evaluated using annual generation and capacity factors, we also examined the environmental and cost impacts through a number of different measures. Our results show that both the Strengthened Solar and Strengthened Wind scenarios fail to meet the CO_2 emission target proposed by the government. From the economic point of view, our cost analysis demonstrates that renewable energy is sustainable for either Strengthened scenarios and cost-effective in both the short term and long term, despite the high capital cost. Instead, our suggested scenario proves to be the optimal solution by meeting the CO_2 emission target and minimising costs. Therefore, our hourly simulation provides crucial evidence to assess the new energy policy and to evaluate alternative solutions for the future energy system of South Korea.

Highlights

- Hourly solar and wind power generation in South Korea is simulated using MERRA-2.
- The South Korean government's scenario will not be able to meet the 2030 CO_2 emission target.
- Additional reduction of coal power plants, as in our suggested scenario, is essential.
- High share of renewables is cheaper on an annual basis and cost-effective in the long-term.

Keywords

Weather data, hourly simulation, solar and wind power scenarios, CO_2 emissions, economic costs, South Korea

1. Introduction

The South Korean government established its CO_2 emission reduction target as 37% of the Business as Usual (BaU) scenario by 2030 [1], as part of South Korea's emission trading scheme (KETS) [2], after its adoption of the Paris Agreement [3]. In 2017, the government established a policy aiming to transition from the current energy supply to a low-carbon energy mix, in line with what the majority of developed countries have implemented since the adoption of the Kyoto Protocol. In addition, fine dusts (PM2.5, PM10) have plagued South Korea since 2013, and public concern about fossil fuels – with coal being one of the main sources of fine dust [4,5] – has consequently become stronger [6]. Therefore, the government set the aim of reducing fine dust to at least 30% by 2022. Its mitigation action includes closing down coal power plants that are 30 or more years old, as well as cancelling both new and less-than-10%-complete construction projects of coal power plants [7]. Moreover, growing public awareness of the danger of nuclear power plants since the 2011 Fukushima Daiichi nuclear disaster and the recent earthquake near Wolsong nuclear power plant, led the government to launch a policy for phasing out all nuclear power plants by 2050.

The 8th Basic Energy Supply and Demand Plan (ESDP) was released in 2017 by the Ministry of Trade, Industry and Energy (MOTIE) to mitigate the above-mentioned social and environmental issues facing South Korea. The plan aim is to gradually expand renewable energy to 20% by 2030 while reducing coal and nuclear energy by 9.4% and 6.4%, respectively [8]. The largest reduction target has been set for the power sector, i.e. 64.5 Mt less than the emissions in the BaU scenario (333 Mt) [9]. As a mitigation action to meet the CO_2 target, the MOTIE announced the "Renewable Energy 3020" plan (RE3020) in December 2017 [1]. This plan involves a 20% increase in power generation from renewable energy sources by adding 30.8 GW of solar power and 16.5 GW of wind-generating capacity by 2030. This is, respectively, six and ten times higher than current capacity. As of 2017, the installed capacity of solar and wind power was 5.03 GW and 1.17 GW, respectively.

Recently, several studies raised concerns over different aspects of the new energy policy. Some of these adopted an evidence-based perspective on the details of the transition from the environmental and economic points of view [10]. The new energy policy has also been criticised in terms of greenhouse gas emissions reduction and energy security through South Korean power market simulations [11]. Other studies assessed the social and political aspects of the new energy policy, finding that the majority of the public is favourable to it, despite having concerns about high electricity bills [12], and that political as well as environmental preferences have a stronger influence on people judgement than scientific or economic considerations [13].

Energy system modelling is widely used [14] to give guidance towards feasible or suggested energy systems under different assumptions [15]. CO_2 emissions and financial impacts of potential renewable energy scenarios for South Korea in either 2030 or 2050 have been assessed to provide insights to policymakers on the current energy policy [11,12,16,17]. However, these studies analysed annual data, while solar and wind power generation requires spatial as well as temporal high-resolution data to be accurately simulated [18]. The Modern Era Retrospective-Analysis for Research and Applications (MERRA) reanalysis database [19] has recently become widely used to simulate solar and wind power generation. In particular, MERRA data has been used to analyse the variability of renewable power supply across Europe [20], to enhance the planning of renewable energy sources [21], and to assess cost, emissions reductions, and energy security of a wide range of energy scenarios [15].

With this study we investigate the potential power supply mix of South Korea for 2030 with an hourly simulation of the power generation driven by weather data. To provide novel insights to policymakers, emissions and economic costs are assessed for four different scenarios: Business as Usual (BaU), Strengthened Solar (SS), Strengthened Wind (SW), and our Suggested Scenario (SU). SS represents the 8th ESDP, SW switches the share of solar and wind power of SS, whereas a new SU scenario is proposed to meet the CO_2 emission reduction target and minimise the power generation costs.

2. Material and Methods

2.1. Simulation

The hourly power demand in 2030 was simulated by scaling up the national load curve of 2017, taken from the Korean Power Exchange [22], to meet the projected annual sum described in the 8th ESDP. The time series of solar power generation was calculated with the Global Solar Energy Estimator (GSEE) library [23] using the latest (2015) MERRA-2 [19] top-of-atmosphere, ground-level global irradiance, temperature at 2m, and solar time at inland grid points. Wind power generation was simulated using in-house software (Ed Sharp's unpublished results, 2016), in which wind-speed (2m, 10m, and 50m height) at grid points nearest to the actual wind farm locations, is extrapolated linearly at a turbine hub height of 80m. Then, the power output is found by using an aggregated power curve of the turbine model Nordex N80 2.5 MW [24]. Since wind and solar power were calculated for a single MW of installed capacity, these values were multiplied by the future installed capacities to estimate the actual hourly generation in each scenario. In the simulation, hourly demand is met by subtracting generation in the following order: solar, wind, coal, nuclear, liquefied natural gas (LNG), oil, hydro, biomass and waste, without any generation surplus. The simulated curves were used to: (i) assess the reliability of solar and wind power generation, (ii) estimate the CO_2 emissions, and (iii) calculate the short-term (CAPEX, annual cost) and long-term costs.

2.2. Scenarios

The scenarios for the power supply mix simulated in this study are four: Business as Usual (BaU), Strengthened Solar (SS), Strengthened Wind (SW), and our Suggested Scenario (SU). To create the BaU scenario shown in Figure 1, the fraction of power generation mix of 2017 was scaled by the power demand projection of 2030, in which coal dominates with 45%, while solar and wind reach only 1.4% of the total supply. This scenario was used as reference for the emission and economic analysis, as previously done in [25]. The SS scenario was taken from the 8th ESPD, and therefore represents the government's new policy, in which coal still provides most of the supply (36%), but solar and wind power are increased to 17%. We created the SW scenario to investigate wind power potential by taking the share of solar and wind from SS and simply swapping them. Finally, the SU scenario was created in a second stage in response to the failure of the other scenarios to meet the emission reduction target.

This scenario was found by changing iteratively, with steps of 10%, the fractions of coal, solar, and wind power taken from the SS scenario. The iteration stopped at a ratio of 7.35:2.65 between solar and wind, achieving the exact CO_2 emission target with the following shares: coal 32.5%, nuclear 23.9%, LNG 18.8%, solar 15.2% and wind 5.5%.

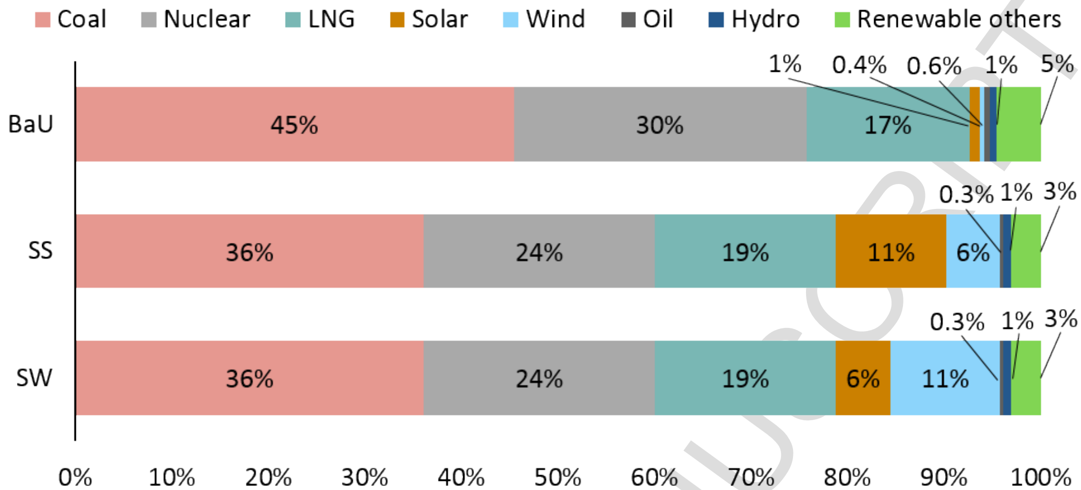


Figure 1. Supply mix for scenario Business as Usual (BaU), Strengthened Solar (SS), and Strengthened Wind (SW)

2.3. Assessment

The simulated power output under the RE3020 plan is compared with the solar and wind power generation amount in each scenario. In addition, the annual capacity factor for solar and wind power was calculated as the fraction of the simulated power output, divided by the maximum generation (or nameplate capacity) along one year:

$$CF = \frac{\sum_{h=0}^{8760} P_h}{ci * 8760} \qquad [1]$$

where P_h is the power generation in each hour h and ci is the installed capacity, which is multiplied by the number of hours in a year.

The CO_2 emission of each simulated power source are calculated using the CO_2 emission factor (Solar 48, Wind 11, Coal 820, Nuclear 490, LNG 12, and Oil 782 in g/kWh) from the Intergovernmental Panel on Climate Change (IPCC) [26]. The emission reductions in each scenario are then calculated against the emission in the BaU scenario.

CAPEX is calculated by multiplying its unit price (GBP/kW) in Table 1 to the additional capacity required in each scenario, as in Table 2, on top of the installed capacity in 2017.

	Solar	**Wind**	**Coal**	**Nuclear**	**LNG**
CAPEX (GBP/kW) [27]	1560	1820	5017	7150	1300
Fixed O&M (GBP/kW) [28]	10.1	58.5	40.3	132.6	13
Variable O&M (GBP/MWh) [16]	2.210	0	5.382	0	4.323

Fuel cost (GBP/MWh) [29]	0	0	61.78	4.75	86.49
Life cycle (years) [30]	25	25	30	40	30
Construction period (years) [27]	1	1	4	10	3

Table 1. Assumed cost and time parameters for each power source

(GW)	BaU	SS	SW	SU
Coal	6.94	0	0	0
LNG	0	0	0	0
Nuclear	4.73	0	0	0
Solar	0	45.36	19.72	61.94
Wind	0.47	24.44	50.97	23.81
Total	12.14	69.8	70.69	85.75

Table 2. New GW of installed capacity by scenario

Operation and maintenance (O&M) costs and fuel costs are annual expenditures. The capital cost is converted to the equivalent "annual CAPEX" by using the Capital Recovery Factor (CRF) and a discount rate d of 5.5% [31]:

$$Annual\ CAPEX = CAPEX * CRF = CAPEX * \left(d\frac{(1+d)^{n}}{(1+d)^{n-1}} \right) \qquad [2]$$

where n is the lifecycle. Costs in Korean Won (KRW) were converted to GBP using an exchange rate of 1156.05 KRW/USD and then of 1.2975 USD/GBP. In addition to annualized CAPEX, OPEX and fuel cost, this study considered a fixed emission trading cost of 14.67 GBP/ton CO_2e [2], even though this cost changes hourly depending on the demand and supply.

2.4. Long-term costs

A stock model was built for finding the long term cost of each scenario, as well as the year in which their cumulative costs are surpassed by the BaU scenario. The period taken into account was 25 years after 2030, i.e. the life cycle of a solar or wind farm. The required new installed capacity, without replacement, of wind and solar power for 2030 was gradually added from 2019 until 2029 using a constant rate of 10%. Replacement of the existing coal plants is 30% [32] of the scenario requirement, and 10% for nuclear power plant [33]. The construction period was set to 1 year for wind and solar farms, 4 years for the coal power plants, and 10 years for nuclear power plants [27]. To compare the capital cost with the operating expenses, the former is converted to the annuitized CAPEX as:

$$AC = \frac{(PV * d)}{1-(1+d)^{-n}} \qquad [3]$$

where PV is the present value of CAPEX, d is the discount rate and n is the payback time. The annual decrease rate for CAPEX and O&M costs is applied at 5% and 2%, respectively, due to the learning rate of technologies. The annual increase rate for fuel cost is assumed to be 3% according to the forecast that the LNG price will rise [34]. The emission trading cost is assumed to rise 1% annually, reflecting the current trend [35].

3. Results and discussions

3.1. Solar and wind power generation simulation

For solar power, the normalised hourly average along the simulated year was 7.7 MW, with a standard deviation of 10.7 MW, and the maximum peak was 39.8 MW. The highest seasonal average was 9 MW in spring, and the lowest was 6.3 MW in winter. Summer did not show the highest values because the rainy season reduces solar irradiance. For wind power, the hourly average was 20.5 MW, with a standard deviation of 22 MW, and the maximum peak was 118 MW. Winter showed the highest average of 36.2 MW, while autumn the minimum with 13 MW (Figure 2).

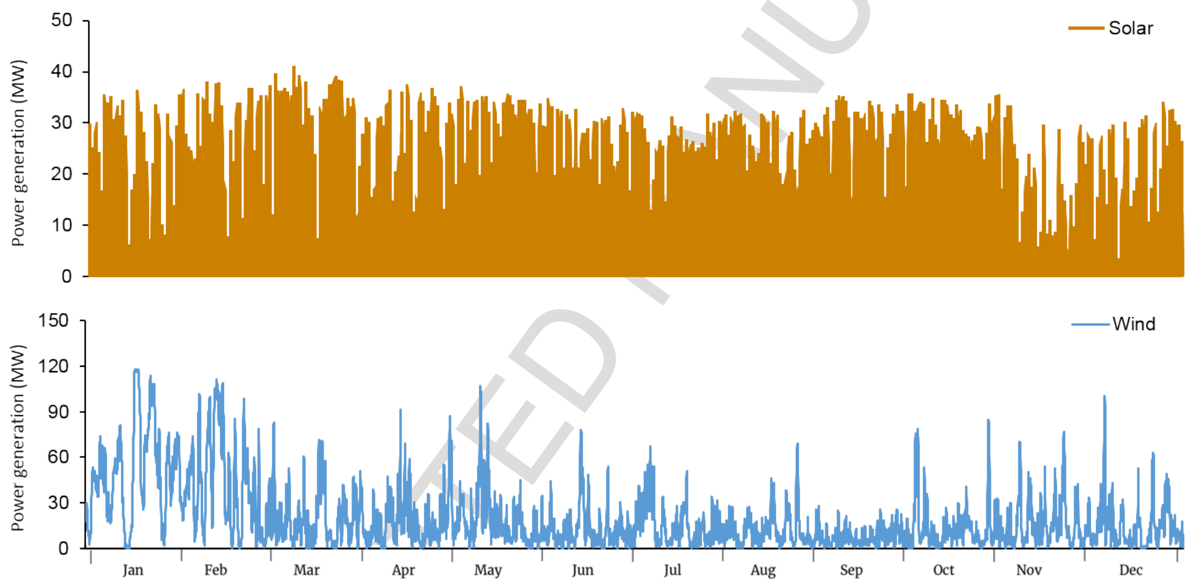


Figure 2. Simulated hourly solar (top) and wind power (bottom) output using weather data from 2017

3.2. Solar and wind power variability

The solar and wind normalised power outputs were multiplied for the installed capacity in each scenario in order to quantify expected costs and CO_2 emissions. We selected a week in May as a representative period of low power demand and high solar and wind supply (Figure 3), and a week in December with the opposite situation (Figure 4). The "low demand" week shows demand values ranging between 58 and 83 GW, with an average of 73 GW. In BaU, the supply of solar and wind power ranges from 2.5 GW to 4.9 GW (average 1.5 GW), which is around 2.5–5% of the power demand. Thus, both base and intermittent load power plants must operate at full capacity to meet demand. In SS, solar and wind supplied an average of 19 GW, with a peak of 59 GW. SW and SU reached a similar higher average production of 23 GW and 22 GW, respectively; however, only SU was able to fully meet demand (on the 14th of May). The "high demand" week shows demand values ranging between 70 and 107 GW, with an average of 90 GW. In BaU, the average wind and solar supply is 553 MW, with a peak of 3 GW, while in SS the average is 7 GW with a peak of 35 GW. In contrast to Figure 3, SW shows a lower value than SS. The average of solar and wind power is 6 GW and the peak is 24 GW. The suggested scenario still shows the highest solar and wind output, with an average of 8 GW and a peak of 46 GW. The base load unit is in full-load operation, while the intermediate load supply decreases slightly only during the peak of solar and wind supply at noon. Other periods show the same trend of the intermediate and base load supply as the BaU. Unlike the "low demand" week, solar and wind power could not meet demand alone, therefore all energy sources must be in operation at all time. Overall, the highest non-dispatchable supply is achieved during the day, and therefore an effective utilization of solar power can be useful to meet peak demand. Being only focussed on one weather year, our analysis has a limited assessment on the demand and, in particular, on wind and solar supply inter-annual fluctuations. Future improvements can either include more historical weather years to take into account climate variability, or forecasts to assess the impact of future heat waves or cold spells.

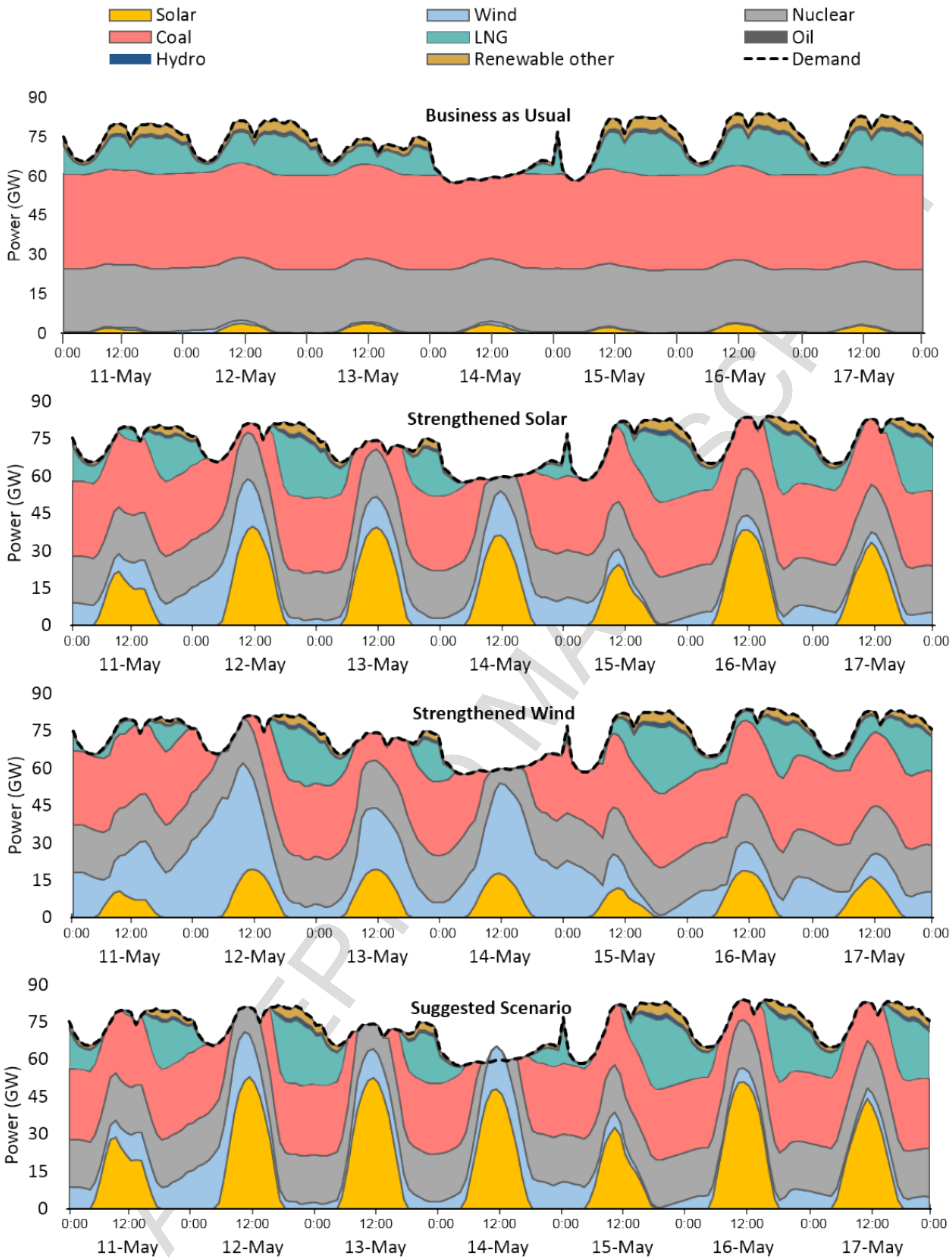


Figure 3. Week with low demand and high solar and wind supply in each scenario

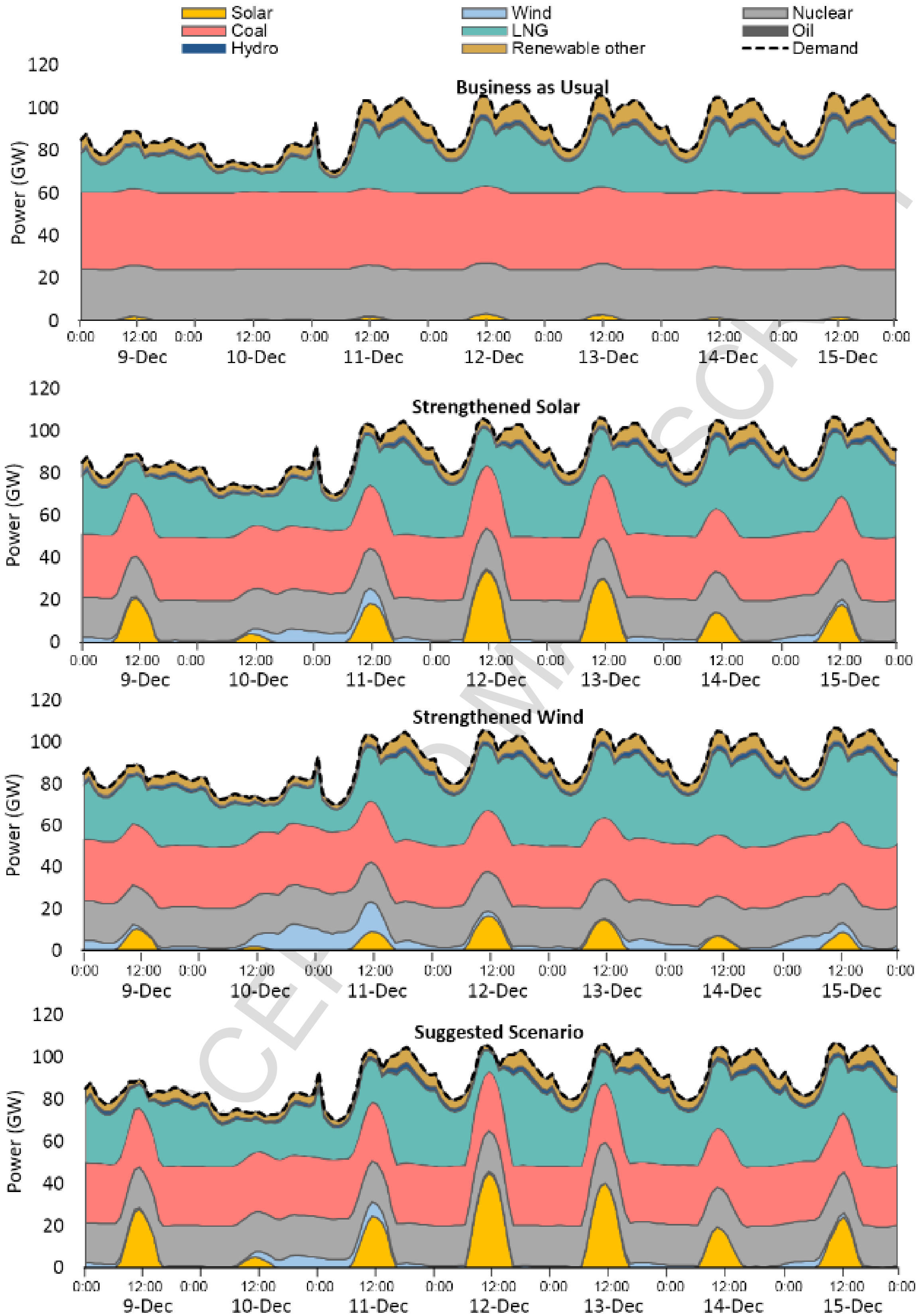


Figure 4. Week with high demand and low solar and wind supply in each scenario

3.3. Reliability of solar and wind power generation

According to the 8th ESDP, represented in our analysis by SS, the power generation from solar and wind farms is expected to reach 118 TWh annually. However, the simulated power generation in SS achieved only 79 TWh, with solar and wind reaching about 66% and 69%, respectively, of the expected generation. Similarly, SW reached 78 TWh, in which solar power is around 71% and wind 64%. The difference between the expected and the calculated power generation is due to the capacity factors (CF) calculated from our simulation (solar 18%, wind 17%), which were lower than those described in the 8th ESDP (solar 27%, wind 25%). However, the simulated CF for solar is much more similar to the one provided by NREL (18.7%) [30] than to the South Korean government's value. Wind CF, instead, is lower than the one provided by NREL (25%) because our simulation included only existing wind farm positions, the large majority of which are on-shore, where the average wind speed is around 5 m/s, that is, 2 m/s less than the average speed on off-shore areas [36]. In order to meet the generation target for SS and SW, the former requires to install further 8.06 GW of capacity for wind power and 17.04 GW for solar power, whereas the latter needs 18.79 GW of capacity for wind power and 7.2 GW for solar power. This difference implies that there is a discrepancy between the installed capacity predicted in the RE3020 plan and the power generation expected in the 8th ESDP.

3.4. CO_2 emission reduction

The CO_2 emissions calculated from our simulation for the BaU scenario is 332.34 Mt, very close to the quantity estimated by the South Korean government (333 Mt). SS and SW have almost the same emissions, that is, 278 and 276 Mt respectively (Table 3), and in both about 74% of the carbon dioxide is emitted from coal power generation; the second source is LNG, with about 23%, while the remaining sources account for just 3% (Figure 5). In all scenarios, coal power generation must be reduced to effectively limit CO_2 emissions. SS is projected to emit 1.5 million tonnes (1%) of CO_2 more than SW because the CO_2 emission factor of solar power is four times higher than that of wind power. Although the direct emission from solar power is zero, indirect emissions during the construction and supply chain are 48g/kWh [26].

(Mt)	BaU	SS	SW	SU
Coal	258.63	205.65	205.65	185.08
LNG	57.54	64	64	64
Nuclear	2.53	1.99	1.99	1.99
Solar	0.35	3.8	1.87	5.05
Wind	0.03	0.43	0.87	0.42
Oil	3.26	1.63	1.63	1.63
Total (A)	322.34	277.49	276	258.17
RE3020 Target (B)	258.17	258.17	258.17	258.17
Further reduction (A) - (B)	64.16	19.32	17.83	0

Table 3. CO_2 emissions (Mt) for each power source and scenario

Both SS and SW fail to satisfy the target set by the government in 2030, as SS would require an additional reduction of 19.32 Mt, slightly higher than for SW (17.83 Mt). These gaps are taken into account in the emission trading costs.

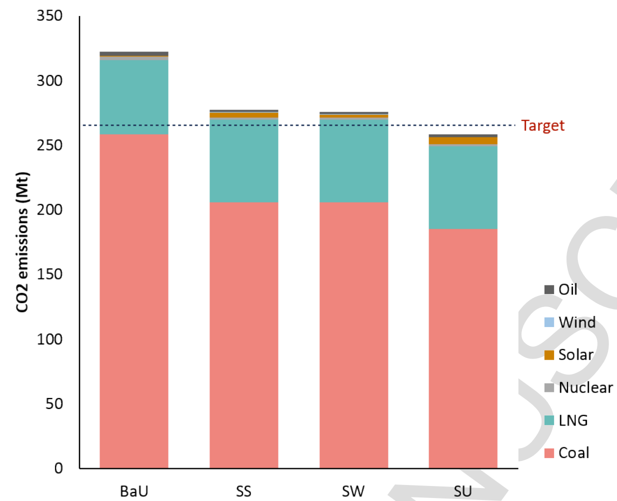


Figure 5. Annual CO_2 emissions (Mt) for each energy source and scenario

On the other hand, the suggested scenario achieves the CO_2 emission reduction target by reducing coal capacity by 10%, more than the other scenarios. Such difference reduces CO_2 emissions from 205.65 (as for SS and SW) to 185.08 Mt.

3.5. Economic costs

The total cost until 2030 for BaU is 41.18 billion GBP, split almost evenly between coal and nuclear power plants, while only 0.5% is allocated for wind power farms. SS is estimated to cost 68.34 billion GBP (60% solar, 40% wind), SW 73.24 billion GBP (20% solar, 80% wind), and SU 82.98 billion GBP (75% solar, 25% wind). Regarding the annual expenses, BaU is predicted to cost 11.34 billion GBP/a, with fuel cost rising from 19% to 51% of the total annual cost. SS is estimated to cost 10.4 billion GBP/a, whereas SW would cost about 11.5 billion GBP/a; SU, instead, is estimated to cost 9.7 billion GBP/a, saving 6.8% of the annual expenditure of SS. In all three scenarios, the annual CAPEX is the largest fraction, followed by fuel cost. In addition, BaU is estimated to incur in the highest emission trading cost, at 0.94 billion GBP/a. SS and SW are expected to cost around 27% of the BaU cost, as opposed to SU, which has no emission trading costs (Table 4).

	BaU	**SS**	**SW**	**SU**
Annual CAPEX	2.7	5.09	5.46	6.18
Fixed O&M	0.55	1.12	1.89	1.2
Variable O&M	0.29	0.22	0.16	0.17
Fuel cost	6.86	3.71	3.71	2.16
Emission trading cost	0.94	0.28	0.26	0
Total	11.34	10.42	11.48	9.71

Table 4. Annual costs (billion GBP/a) by scenario

The greatest cost-savings in SS, SW, and SU occur for fuel (in absolute numbers) and for emission trading (in percentage), however they are balanced by an increased annual CAPEX. SU has the greatest additional installation of solar and wind farms, thus the highest annual CAPEX and the lowest fuel cost, and does not incur in the emission trading cost. These results, combined with CO_2 emissions, indicate that decline of fuel consumption is essential for both environmental and economic gains. The higher fuel consumption, the more CO_2 emissions, and the higher the expenditure on fuel cost and emission trading cost.

In addition, costs for thermal power generation could be higher by taking into account intermittent operation. However, in our simulations coal-fired power generation is zero very rarely: only 0.6% of the hours in the simulated year for SS, 0.4% for SW, and 1% for SU. Therefore, as the impact of losses due to intermittent operation is very marginal, neither losses nor additional costs in coal-fired power generation are considered in this analysis. Differently from coal, LNG power generation is zero only during 14.5% of the simulation time for SS, 10.2% for SW, and 20% for SU. LNG power plants can be operated for peak load generation either through shutdown, or by keeping a minimum load. The latter method has some advantages over the former, as turning off and on again the plant can take from 30 minutes to one hour[37] and requires more fuel as well. In addition, restarting the power plant degrades the gas/steam turbines and, therefore, increases the OPEX. As the LNG power plants in South Korea are meant to be used intermittently[38], the impact from shutdowns is already considered at the design stage and in the project costs. Therefore, assuming minimum load when LNG power generation is zero does not increase CAPEX and OPEX, but only fuel costs. In order to calculate the additional fuel consumption, we can assume that the output during minimum load is 8% of total power generation, because during this operation only the gas turbine is used, at around 20% of total capacity, and it contributes to 40% of the power generation in a LNG combined cycle power plant[39]. We found that the increase of annual power generation due to minimum load operation is only 3.7% for SS, 2.6% for SW, and 5.3% for SU (calculated as the number of hours at minimum load multiplied by the minimum load). As the fuel cost accounts for 35% of the total costs, the impact of the minimum load on the total generation costs would be 1.3% for SS, 0.9 for SW, and 1.85% for SU. For this reason, we conclude that the impact of intermittent operation for LNG is negligible and can therefore be omitted from our analysis.

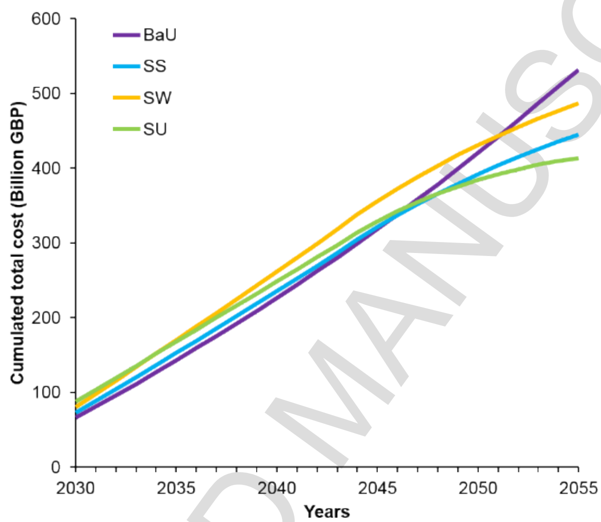


Figure 6. Annual cumulated cost projections after 2030 for each scenario.

Regarding long-term cumulative costs from 2030 to 2055 (Figure 6), BaU initial cost in 2017 starts at 5.98 Billion GPB, SS and SW at 10.2 and 11.47 billion GBP, respectively, while SU has the highest expenditure of 13 billion GBP. Based on these cumulated annuitized CAPEX during the construction period, the remaining annuitized CAPEX and the annual cost is added annually. The BaU cost rapidly increases compared to the other scenarios because of the higher portion of fuel cost, which has the highest increase rate. As a result, the total cost of BaU exceeds SS in 2046 at 337 billion GBP, SU in 2046 at 350 billion GBP, and SW in 2051 at 443 billion GBP. Moreover, the total cost of SU becomes lower than that of SS after 2048. Therefore, SS and SU are more economical than BaU after 16 years operation, and SU is the cheapest after 18, thus reversing the order compared to the starting year. BaU reaches the highest outgoing with 531.61 billion GBP, followed by SW with 486.91 billion GBP, then SS at 435.35 billion GBP, and finally SU with 413.63 billion GBP.

This analysis indicates that a high share of renewable energy, as represented by the SU scenario, is the most cost-effective in the long term, while conventional energy sources seem economical only for the initial investment in the short term. When considered as annual expenses, solar and wind energy sources are cheaper than conventional energy because they do not consume fuel. Therefore, considering CO_2 emissions as well, renewable energy is cost-effective and sustainable in both the short term and long term.

4. Conclusion

This study simulates hourly solar and wind power supply using weather data provided by MERRA-2, with the aim to investigate the solar and wind power generation potential of South Korea. The results were used to assess the environmental and economic cost of four scenarios: Business as Usual, Strengthened Solar (from the 8th ESDP), Strengthened Wind, and our Suggested Scenario, which meets the CO_2 emission target and achieves the minimum costs in the long term.

Our simulation indicates that solar power shows the highest output in spring, not summer, because the latter is affected by heavy rain periods, while wind power generates the highest output in winter. During one day of the "low demand" week in May, renewable supply was able to fully meet the power demand. December is the season with the highest demand and the lowest renewable power supply; therefore, the other sources need to be in full-load operation to meet demand. In order to maximize the utilization of solar and wind power, the design of the power mix should consider the influence of weather conditions on non-dispatchable energy sources. Hence, hourly simulations driven by climate data are essential. From our results, power generation in SS did not achieve the target generation in the 8th ESDP, therefore, additional installation of solar and wind farms should be required. The advance of technology could improve the efficiency of solar and wind power generation in 2030. However, the capacity factor of both sources depends on weather conditions. In addition, the installed capacity for on-shore wind power is limited by geographical constraints and social acceptability issues. Being characterised by a larger share of renewable energy and low fuel costs, SU is more capital intensive, but cheaper in the long term, than the other scenarios. Given the current trend of increasing fuel prices, this analysis should be considered conservative, thus our suggested renewable energy scenario could eventually become cheaper than SS and SW earlier than expected. Moreover, considering the additional emission trading cost, investing in sustainable resources, such as solar and wind, is economically beneficial both in the short and in the long term. From the environmental point of view, SW is less polluting than SS, as the CO_2 emission factor of solar power is around four times higher than wind power. However, it is more expensive than SS due to the high CAPEX and OPEX of wind power. Since the difference in CO_2 emissions between SS and SW is only 1%, SS seems to be a better solution for South Korea. Nevertheless, neither

SS nor SW could meet the CO_2 emission target in 2030. This analysis indicates that the 8th ESDP could not meet the CO_2 reduction target without an additional reduction of coal power generation, since coal is the biggest supply source. Therefore, only our suggested scenario SU achieved the national target reduction for 2030, without causing additional costs due to the emission trading scheme launched in 2015.

The current analysis has some limitations that could be improved in future work. Weather data spans only one year, thus excluding inter-annual variability. Considering climate change, which has manifested especially in a hot summer and cold winter in 2017, we can expect different solar and wind power generation, as well as a change in seasonal power demand. Wind power simulation considered only the location of existing on-shore wind farms. However, since there is high potential for off-shore farms, these could be included to improve the simulation. A possible extension of this work could include an analysis of heat demand and supply to increase the comprehensiveness of the results. Finally, different cost parameters could be applied to assess the range of expenses of each scenario. In particular, as renewable energy technologies develop and mature rapidly, the CAPEX and O&M costs will drop.

Energy system modelling plays a crucial role in providing insights to policymakers to build effective energy policies. A hourly simulation of wind and solar power dynamics, as the one presented in our study, is essential to assess the potential role of renewable energy in future scenarios and, therefore, to lead towards a transition to low-carbon and sustainable future energy system for South Korea.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

References

[1] Ministry of Trade Industry and Energy (MOTIE), 3020 Renewable Energy Plan, (2017). http://www.motie.go.kr/motiee/presse/press2/bbs/bbsView.do?bbs_seq_n=159996&bbs_cd_n=81 (accessed July 16, 2018).

[2] International Carbon Action Partnership (ICAP), Korea Emissions Trading Scheme, (2016) 1–5. https://icapcarbonaction.com/en/?option=com_etsmap&task=export&format=pdf&layout=list&systems%5B%5D=47.

[3] United Nations, Adoption of the Paris agreement, 2015. doi:FCCC/CP/2015/L.9.

[4] D. Kang, J.-E. Kim, Fine, ultrafine, and yellow dust: emerging health problems in Korea., J. Korean Med. Sci. 29 (2014) 621–2. doi:10.3346/jkms.2014.29.5.621.

[5] Greenpeace, Silent Killer: Fine Particulate Matter, 2016.

[6] Yonhap News, “Fine dust” most searched keyword by S. Korean users in H1: Google, (2018). https://en.yna.co.kr/view/AEN20180702005700320 (accessed July 22, 2018).

[7] Ministry of Environment (South Korea), Comprehensive measures for fine dust control, (2017). http://www.motie.go.kr/common/download.do?fid=bbs&bbs_cd_n=81&bbs_seq_n=159674&fil

e_seq_n=1 (accessed July 16, 2018).

[8] Ministry of Trade Industry and Energy (MOTIE), The 8th the Electricity Supply and Demand Plan (ESPD), (2017). https://www.kpx.or.kr/www/contents.do?key=92 (accessed July 16, 2018).

[9] Kansai Research Center/Institute for Global Environmental Strategies POSCO Research Institute, Domestic Carbon pricing in Korea and Companies' Response, 2017.

[10] S. Hong, B.W. Brook, A nuclear- to-gas transition in South Korea: Is it environmentally friendly or economically viable?, Energy Policy. 112 (2018) 67–73. doi:10.1016/J.ENPOL.2017.10.012.

[11] Y.H. Song, H.J. Kim, S.W. Kim, Y.G. Jin, Y.T. Yoon, How to find a reasonable energy transition strategy in Korea?: Quantitative analysis based on power market simulation, Energy Policy. 119 (2018) 396–409. doi:10.1016/J.ENPOL.2018.05.002.

[12] J. Kim, S.Y. Park, J. Lee, Do people really want renewable energy? Who wants renewable energy?: Discrete choice model of reference-dependent preference in South Korea, Energy Policy. 120 (2018) 761–770. doi:10.1016/J.ENPOL.2018.04.062.

[13] J.-B. Chung, E.-S. Kim, Public perception of energy transition in Korea: Nuclear power, climate change, and party preference, Energy Policy. 116 (2018) 137–144. doi:10.1016/J.ENPOL.2018.02.007.

[14] S. Pfenninger, A. Hawkes, J. Keirstead, Energy systems modeling for twenty-first century energy challenges, Renew. Sustain. Energy Rev. (2014). doi:10.1016/j.rser.2014.02.003.

[15] S. Pfenninger, J. Keirstead, Renewables, nuclear, or fossil fuels? Scenarios for Great Britain's power system considering costs, emissions and energy security, Appl. Energy. (2015). doi:10.1016/j.apenergy.2015.04.102.

[16] N.B. Park, S.J. Yun, E.C. Jeon, An analysis of long-term scenarios for the transition to renewable energy in the Korean electricity sector, Energy Policy. (2013). doi:10.1016/j.enpol.2012.09.021.

[17] C.Y. Lee, S.Y. Huh, Forecasting new and renewable energy supply through a bottom-up approach: The case of South Korea, Renew. Sustain. Energy Rev. (2017). doi:10.1016/j.rser.2016.11.173.

[18] J.P. Deane, A. Chiodi, M. Gargiulo, B.P. Ó Gallachóir, Soft-linking of a power systems model to an energy systems model, Energy. 42 (2012) 303–312. doi:10.1016/J.ENERGY.2012.03.052.

[19] M.M. Rienecker, M.J. Suarez, R. Gelaro, R. Todling, J. Bacmeister, E. Liu, M.G. Bosilovich, S.D. Schubert, L. Takacs, G.K. Kim, S. Bloom, J. Chen, D. Collins, A. Conaty, A. Da Silva, W. Gu, J. Joiner, R.D. Koster, R. Lucchesi, A. Molod, T. Owens, S. Pawson, P. Pegion, C.R. Redder, R. Reichle, F.R. Robertson, A.G. Ruddick, M. Sienkiewicz, J. Woollen, MERRA: NASA's modern-era retrospective analysis for research and applications, J. Clim. (2011). doi:10.1175/JCLI-D-11-00015.1.

[20] M. Huber, D. Dimkova, T. Hamacher, Integration of wind and solar power in Europe: Assessment of flexibility requirements, Energy. (2014). doi:10.1016/j.energy.2014.02.109.

[21] H. Zhang, Y. Cao, Y. Zhang, V. Terzija, Quantitative synergy assessment of regional wind-solar energy resources based on MERRA reanalysis data, Appl. Energy. (2018). doi:10.1016/j.apenergy.2018.02.094.

[22] Korea Power Exchange, Power supply and demand status, (2018). http://www.kpx.or.kr/www/contents.do?key=223 (accessed April 23, 2018).

[23] S. Pfenninger, I. Staffell, Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data, Energy. (2016). doi:10.1016/j.energy.2016.08.060.

[24] E. Sharp, P. Dodds, M. Barrett, C. Spataru, Evaluating the accuracy of CFSR reanalysis hourly wind speed forecasts for the UK, using in situ measurements and geographical information, Renew. Energy. (2015). doi:10.1016/j.renene.2014.12.025.

[25] V. Krey, Global energy-climate scenarios and models: a review, Wiley Interdiscip. Rev. Energy Environ. 3 (2014) 363–383. doi:10.1002/wene.98.

[26] B. Thomas, F. Lew, H. Edgar, M. Alan, P. Daniel, R. Joyashree, S. Roberto, S. Steffen, S. Ralph, S. Pete, W. Ryan, H. Gesine, J. David, de, N. Maarten, Annex III: Technology-specific cost and performance parameters, 2014.

[27] U.S. Energy Information Administration (EIA), Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, (2016). https://www.eia.gov/analysis/studies/powerplants/capitalcost/ (accessed July 7, 2018).

[28] R. Lacal Arantegui, A. Jaeger-Waldau, M. Vellei, B. Sigfusson, D. Magagna, M. Jakubcionis, M. del M. Perez Fortes, S. Lazarou, J. Giuntoli, E. Weidner Ronnefeld, G. De Marco, A. Spisto, C. Gutierrez Moles, ETRI 2014 - Energy Technology Reference Indicator projections for 2010-2050, 2014. doi:10.2790/057687.

[29] Korea Power Exchange, Electric Power statistics Information System - Fuel price, (2018). http://epsis.kpx.or.kr/epsisnew/selectEkmaFucUpfGrid.do?menuId=050101 (accessed July 5, 2018).

[30] National Renewable Energy Laboratory (NREL), 2017 Annual Technology Baseline, (2017). https://atb.nrel.gov/electricity/2017/index.html?t=in (accessed July 6, 2018).

[31] Korea Development Institute (KDI) - Public and Private Infrastructure Investment Management Center (PIMAC), A Study on General Guidelines for Pre-feasibility Study (5th Edition), 2008.

[32] E2 News, Older coal fired power plants, extended life by major operations, (2016). http://www.e2news.com/news/articleView.html?idxno=91465 (accessed November 17, 2018).

[33] World Nuclear Association, Nuclear Power in South Korea, (2018) 1. http://www.world-nuclear.org/information-library/country-profiles/countries-o-s/south-korea.aspx (accessed November 19, 2018).

[34] World Bank Group, Commodity Markets Outlook, 2018.

[35] Korea Exchange (KRX), Emission trading cost, Mark. Data. (2018). http://marketdata.krx.co.kr/mdi# (accessed July 20, 2018).

[36] National Institute of Meteorological Sciences (NIMS), Rate of wind speed over 5m/s, Weather Resour. Map. (2016). http://www.greenmap.go.kr/02_data/data01_5_1.do#2%231%235 (accessed July 17, 2018).

[37] Siemens, Flexibility Solutions, 2016.

[38] J. Wook, Korean LNG power plants in slump amid low unit price, high production cost, (2017).

[39] L. Balling, Flexible future for combined cycle, Erlangen, 2010.