THE ELECTRICITY MARKET, EMISSIONS AND NETWORK IMPACTS OF SIGNIFICANT INCREASES IN RENEWABLES AND GAS IN SOUTHEAST EUROPE

Elliot Roseman, Program Director, US Energy Association, 240-731-1436, eroseman@usea.org

Overview

In December 2019, the transmission system operators (TSOs) and market operators of the power systems in Southeast Europe (SEE) posed an important question to the US Energy Association (USEA): can we reliably determine and anticipate the market, grid, and emissions impacts of seeking to add and absorb substantial utility-scale renewable energy sources (RES) through 2030? Are we ready for this huge wave, if not tsunami?

The answer was far from obvious, since the tripling or quadrupling of RES anticipated could well strain individual network elements, depending on the RES project locations, and thus revamp their grid planning. Further, this change would be taking place at the same time that these companies were integrating their markets with all countries in the region (a huge shift as well), with the potential for market price fluctuations.

With regard to climate change, they were simultaneously seeking to chart a pathway to meet the EU's aggressive CO2 emissions reduction targets, such as the Clean Energy Package, while implementing carbon markets as well. This in turn could massively affect their existing generation, a large slice of which comes from lignite today. Further, new supplies of natural gas – both pipeline and LNG – could enter the market by 2030, serving as a capacity and environmental bridge, and an alternative to less secure fuel suppliers. The RES and gas integration questions are a complex undertaking, with regulatory and policy changes required to achieve its goals as well.

The USEA, through its Electricity Market Initiative (EMI), in partnership with USAID, worked closely with 15 TSOs and market operators in 11 countries for most of 2020 to analyze this nuanced set of questions. To our knowledge, this is the first systematic analysis of such significant changes for all of SEE on both the power markets and network, under conditions that could easily put stress on both. We completed this report in December 2020.

Methods

To answer the EMI members' questions required two sophisticated forecasting tools – Antares for market simulation, and PSS/E for network performance. This modeling duo enabled us to effectively organize the myriad of required inputs and data; reliably simulate the operation of both the markets and the grid in SEE in 2030; and produce granular results for each system in light of the huge scale of changes expected to take place.

With substantial support from EMI members, we gathered data and evaluated 11 market scenarios and 22 network scenarios for 2030. Key variables included alternative levels of: renewables, and their capacity factors; power demand; hydro conditions; and d) CO2 prices, as well as the net transfer capacity between countries.

Our baseline level of RES assumed values in the countries' network development plans for 2030, while for "high RES" we added a further 25%. Moreover, some countries already planned to retire old lignite plants, add natural gas facilities using new pipeline gas and LNG, and add hydro. We captured such changes as well.

We simulated major RES additions, raising wholesale wind and solar capacity from 12.2 GW in 2018 (16% of system demand) to a range of 33.2 GW (34%) to 43.9 GW (40%) in 2030. In one scenario, we further added 1,155 MW of new gas generation, as envisaged in USEA's regional gas analysis.

On the network, we simulated all 11 countries' plans to upgrade their internal and cross-border grids over the next decade, which can facilitate or limit power exchanges. To be comprehensive, we evaluated the impacts on day-ahead power markets in 2030 for all 8,760 hours, and assessed the grid impacts during the most stressful hours of the year.

The network analysis was highly granular, down to the 110 kV level, involving over 8,500 buses, 10,000 branches, 3,700 transformers, and 1,500 power plants, and included normal and stressed (n-1) operating conditions. Integrating the network models of all 11 countries into one regional grid model was a major accomplishment of this work.

Results

We divide our findings into those for power markets and CO2 emissions, and those for the grid. In the first area:

A significant finding is that day-ahead markets in 2030 can well accommodate a huge RES addition. In fact, such levels of RES will lower wholesale prices by 3-4% on average. Also, no RES generation needs to be curtailed, since inter-regional transfers, imports and exports can adjust to times when RES generation varies.

RES additions only modestly decrease CO2 emissions, as the capacity factors of wind and solar are low, compared to the coal and lignite generation they displace. CO2 emissions fall just 7-10% from this factor, in spite of the large RES additions. By contrast, the carbon market (EU ETS) has a major CO2 impact. We modeled two CO2 prices – 27 EUR/tCO_2 and 53 EUR/tCO_2. These prices would raise wholesale power prices, make coal and lignite less competitive, and reduce the capacity factor and emissions of these plants by 10-35%.

Modest amounts of new gas generation would also reduce CO2 emissions by lowering generation from older gas, coal and lignite plants, and have a neutral effect on wholesale power prices. With added gas, the green sources (hydro, wind and solar) will displace lignite and become the main power suppliers (45%) in the EMI region.

Wholesale prices converge throughout SEE by 2030, as we expect all markets in SEE to be consolidated by then, but the highest prices occur when there is low hydro, high demand, and high CO2 prices. Regional prices in 2030 may vary widely due to changes in RES, hydrology, and CO2 prices, from 47.4 to 70.5 EUR/MWh. High RES integration will reduce prices around 2 EUR/MWh or 4% in all scenarios. The impacts of hydrology and electricity demand on wholesale prices are modest: 2 EUR/MWh higher with low hydro, and 1.3 EUR/MWh with low demand.

The main driver for changes in SEE wholesale prices will be CO_2: an increase from 27 EUR/tCO_2 to 53 EUR/tCO_2 would raise wholesale prices by 18 EUR/MWh, or 35%, while substantially reducing lignite generation. The West Balkans will notice this impact most, since they are not currently part of the EU ETS.

Regarding impacts on the region's power network, the analysis of RES and gas integration was also quite positive. The regional network is robust and well prepared to absorb most of the added RES and gas generation, with attention to just a few spots. This strength is due both to the countries' prior centralized planning, and the grid additions already planned in SEE between now and 2030. Notably, we did not find a central corridor or trans-regional set of bottlenecks suggesting the need for a large coordinated regional program of high-voltage additions.

Rather, the regional need for upgrades is modest. Across thousands of elements, we found just 22 components that could raise congestion or reliability concerns due to the anticipated additions of RES and gas generation in 2030, across all the grid scenarios, including those with N-1 conditions. This is a positive finding for the integration of these new resources. These components will require selective monitoring, de-bottlenecking and upgrades.

Conclusions

While the markets and the network can accommodate these major changes, much work is required to get from here to there. From a market perspective, the combination of new RES, added gas generation and carbon prices may cause lignite plants to retire at a faster pace than in current resource plans. Utilities, their national regulators and ministries should review the economics of lignite generation as other resources limit their utilization.

Overall, adding substantial RES and gas generation would have a benign impact on SEE power markets, and reduce emissions, though prices could well rise due to CO_2 markets. Stakeholders should actively pursue the transitions required to implement these portfolio changes by 2030, and evaluate increasing the level of gas-fired generation.

Based on this study, we recommend that national regulators, policy makers and TSOs consider these added steps: a) provide the proper incentives, interconnection and queueing policies, and locations for private RES investment; b) prioritize the expansion of cross-border trade and coupling to foster clean regional projects and balancing markets; c) assure adequate grid investment with enhanced tariffs and codes and regional planning; d) strongly encourage bilateral and regional power exchanges and competitive markets for real-time, day-ahead, and longer-term markets; e) anticipate and incorporate distributed energy resources into these markets, on an equal basis with wholesale power generation; and f) proactively integrate natural gas to transition to a clean energy future through long-term generation planning, coordinated efforts with gas system operators, and robust gas planning for electricity needs.