9th International Scientific Conference ERAZ 2023 – Conference Proceedings
DOI: https://doi.org/10.31410/ERAZ.2023.463

Decarbonization Initiatives among Leading Power Utility Players

Vlado Georgievski[1]
Nevenka Kiteva Rogleva[2]

Received: August 29, 2023
Accepted: December 14, 2023
Published: March 16, 2024

Keywords:
Decarbonization;
CO_2 reduction;
Net-zero strategy;
Power utilities

Abstract: *Decarbonization of the power sector means a reduction of its CO_2 intensity, which reduces the emission of carbon dioxide per unit of electricity generated. In order to meet the emission reduction targets pledged to the Paris Agreement on climate change, power utility companies need to develop strategies on how to decarbonize their generation assets. Companies must achieve carbon neutrality by 2050, which is necessary to meet the targets of the Paris Agreement of capping global temperature rise at 1.5°C and to meet the less ambitious 2°C target. Rapid decarbonization of the power sector is needed particularly as heat and transport sectors are electrified, creating an increase in demand for electric power. Decarbonization is being achieved by increasing the share of low-carbon energy sources, particularly renewables, and a corresponding reduction in the use of fossil fuels. Worldwide, renewables now produce a third of power capacity.*

1. INTRODUCTION

Decarbonizing the power generation sector is essential for achieving the Net Zero target and carbon neutrality by 2050. However, the measures required vary by region and country. Asian utilities must focus on decarbonizing coal assets, while Europe, North America, and the Middle East should prioritize gas. Developing economies face the challenge of decarbonizing young fleets while also tackling electrification and energy independence. CO_2 prices are continuously rising, leaving utilities with no choice but to prepare for change today. There are various methods to decarbonize fossil generation assets, but none are ideal due to high costs, technology limitations, and operational changes. This paper analyzes different decarbonization levers, energy crises, and rising energy prices, and benchmarks decarbonization initiatives by selected power utilities players in specific regions. Finally, a deep dive into the techno-economic analysis of switching from natural gas to hydrogen as a decarbonization lever will be presented.

2. SECTION SNIPPETS

2.1. Literature Survey

The literature pertaining to the subject matter can be categorized based on the scope of the relevant studies. In Sections 3 and 4, we provide a review of recent studies that focus on decarbonization technologies implemented across all fossil fuel types. However, these decarbonization levers are presented in a broader sense to suit real-world scenarios. In Section 5, a benchmark research study of major power utility companies was undertaken to analyze current decarbonization initiatives and projects. Each company was scanned by checking its website

[1] Faculty of Electrical Engineering and Information Technologies, “Ss. Cyril and Methodius” University in Skopje, Rugjer Bošković bb, P.O. Box 574, 1001 Skopje, Republic of North Macedonia

[2] Faculty of Electrical Engineering and Information Technologies, “Ss. Cyril and Methodius” University in Skopje, Rugjer Bošković bb, P.O. Box 574, 1001 Skopje, Republic of North Macedonia

announcements and other relevant news portals such as Factiva, Bloomberg, and S&P Global Intelligence. In this paper, a selection of 13 power utility companies is presented and results are discussed. In Section 6, a more detailed analysis of one lever - gas to hydrogen - is undertaken, including an assessment of the technological possibilities and costs. Studies and articles from global OEMs are drawn upon in this section, providing an analysis of the current status of hydrogen gas turbines.

2.2. Methodology and Model Description

The primary objective of this study is to scrutinize the multifaceted technological methodologies for decarbonizing power generation facilities, with a focus on their distinct technological and cost-oriented characteristics. A comprehensive summary of the outcomes obtained from benchmark analyses of various companies has been compiled into a tabulated format, followed by an insightful discourse highlighting the decarbonization approaches across three major regions, namely the USA, EU, and Asia, along with the rest of the world (RoW). In addition, for the gas to hydrogen deep dive, a computational model was constructed in Microsoft Excel to assess the financial and carbon emission implications of each lever, spanning the period from 2020 to 2050. The model calculates the costs associated with investment and power generation, as well as the resulting CO_2 emissions for each fossil technology, in addition to the costs and carbon abatements achievable by implementing different decarbonization levers.

In this model, commodity prices and cost assumptions from several global sources are used but mostly rely on data by IEA and EIA. We use forecasted regional fuel price assumptions, and CO_2 emissions from the IEA WorldEnergyOutlook 2021.

3. DECARBONIZATION LEVERS IN POWER GENERATION

According to Davis et al. (2018) and Zhang et al. (2022), "there are two different approaches for decarbonizing existing fossil fuel power plants: fleet-level system and plant-level analysis." Both of them are based on the technical feasibility and economics of fossil fuel power decarbonization, but plant-level analysis usually takes in more detailed input parameters, thus resulting in more practical solutions for selected plants. Five different categories of decarbonization levers will be analyzed in this paper:

1. Operations improvement and equipment modernization,
2. Co-firing with low carbon fuels,
3. Retrofit for full fuel switch,
4. Implementation of CCUS,
5. Shutdown of fossil assets and building new plants.

3.1. Operations Improvement and Equipment Modernization

Power plants are designed to last between 25 and 35 years, but many countries extend the life of plants to 40 years or more due to economic reasons. It's not cost-effective to retire plants prematurely. Refurbishing boiler parts, upgrading turbines, and adding flue gas cleaning can help extend the life of a plant and meet new emission regulations.

"One example is drying of coal and lignite that leads to certain efficiency improvement", according to Pawlak–Kruczek et al. (2019) and Sarunac et al. (2014).

3.2. Co-firing with Low Carbon Fuels

Co-firing with low carbon fuels refers to the simultaneous combustion of a low carbon fuel and a base fuel to produce energy. Here it is analyzed co-firing coal with biomass or green ammonia, and co-firing gas with green hydrogen.

3.2.1. Co-firing Coal with Biomass

"Biomass utilization in power generation is considered carbon-neutral owing to the atmospheric CO_2 removal capability of biomass" (Zhang et al., 2022). "Biomass co-firing in coal power plants (up to 30%) has been proved possible without largely modifying the existing infrastructure" (Wang et al., 2021). Biomass co-firing involves burning biomass with coal in coal-fired power plants, which can increase the use of biomass and reduce greenhouse gas emissions. Co-firing has advantages over power plants that burn 100% biomass, such as lower capital costs, higher efficiency, and lower electricity costs. "The net electric efficiency of co-fired plants ranges from 36-44%, depending on plant technology, size, quality and share of biomass. While up to 50% co-firing is technically achievable, the usual biomass share is below 5%. Higher biomass shares result in lower emissions, and 1-10% co-firing could reduce CO_2 emissions by 45-450 million tons per year by 2035" according to (IEA, 2014), if upstream emissions are not included.

3.2.2. Co-firing Coal with Ammonia

Ammonia co-firing is the process of burning ammonia with coal in coal-fired power plants. The research of (Tamura et al., 2020) "on a 1.2 MW coal-fired furnace showed that when NH_3 and coal were mixed in the burner, the NO_x emission did not go up until the NH_3 ratio of 30%. The Japanese Chugoku Electric Power Corporation successfully demonstrated co-firing with a 1% share of ammonia in 2017". "Concerns about increased NOx emissions were addressed, and higher blending shares of up to 20% ammonia may be feasible with minor adjustments to a coal plant. In Japan, blending shares of 20% have been achieved without problems in smaller furnaces. Technical feasibility has been proven since 2017, with IHI and Chugoku Electric testing 20% ammonia co-firing in a 156 MW plant. IHI demonstrated the co-firing of ammonia and coal with a fuel mix of 20% ammonia in 2018" (IEA, 2014). "While the co-firing concept is mostly limited to Japan, it could have near-term global relevance on the supply side", according to Crolius (2019).

3.2.3. Co-firing Gas with Hydrogen

Hydrogen firing technology allows power plant owners to decarbonize their Combined Cycle Gas Turbine (CCGT) plants by converting them to hydrogen co-firing or 100% hydrogen firing in the future, playing a key role in the decarbonization of the energy sector. Natural gas with hydrogen from the chemical industry is emerging as a key fuel for burning in gas turbines. "While NOx emissions increase with higher H_2 percentages, the increase is orders of magnitude lower compared to conventional diffusion burners, and flashback risks are similar to liquid fuels. Flame speed is ten times higher than natural gas, and compact flames in DLE burners lead to a slight NOx increase. EnergyAustralia's co-firing project with GE's advanced gas turbines is set to start commercial operations in 2023/2024", according to Goldmeer (2019).

3.3. Retrofit for Full Fuel Switch

"Retrofitting is the process of modifying existing systems with new technology or features, such as improving the efficiency of power plants, increasing output, or reducing emissions. Retrofitting a significant fraction of existing coal-fired power plants is likely to be an important part of a global rollout of carbon capture and storage" (Sanchez del Rio et al., 2017). For plants suited for a retrofit, the energy penalty for post-combustion carbon capture can be minimized by effective integration of the capture system with the power cycle. This paper analyzes retrofit in the aspect of using an existing coal or gas power plant with adjustments to accommodate new fuel types. Different fuel retrofits are possible: coal to biomass, waste or natural gas, and gas to green hydrogen.

3.3.1. Retrofit Coal to Biomass and Coal to Gas

"Large coal power plants can convert to biomass through the use of new mills and burners specifically designed for biomass fuels, with wood pellets being the standard choice due to their high energy density and technical advantages", based on research by IEA-ETSAP & IRENA© Technology Brief E21 (2013) and Biofit Factsheet Coal Conversions (2020). These converted plants require huge amounts of biomass, often secured through imports, and full fuel switching to biomass can significantly reduce CO_2 emissions.

"As a consequence of an impending carbon tax, power companies might well set performance targets to be met by individual power plants" (IEA, 2014).

"Compared to coal power plants, natural gas plants are highly space-efficient, as they require less land area and leave no ash when combusted", according to (Qvist et al., 2021). They also say that retrofitting existing coal plants with natural gas boilers and carbon capture is possible, but only for plants close to natural gas pipelines.

3.3.2. Retrofit Gas to Hydrogen

On-site sorbent enhanced steam reforming of natural gas into hydrogen can reduce carbon emissions by up to 98% without expensive carbon capture systems. Siemens Energy is developing two gas turbine packages for the Leipzig Süd district heating power plant to eventually run on 100% hydrogen, while the Hydrogen-to-Magnum Project aims to convert a Vattenfall power plant gas turbine to run on 100% hydrogen by 2027 using a Mitsubishi M701F turbine. The main challenge of hydrogen combustion is flashback risk due to its rapid combustion speed.

3.4. Implementation of CCUS

CCS enables significant reductions in CO_2 emissions from fossil fuel industries like coal-fired power plants. It involves capturing and compressing CO_2, transporting it, and either storing or utilizing it. However, all CCS options have costs and reduce plant efficiency, requiring additional capital investment for equipment and infrastructure. CO_2 capture also requires more energy and fuel, making it most effective in high-efficiency plants with integrated capture processes. Retrofitting existing plants requires adequate space and nearby CO_2 storage sites. Capital costs are expected to decrease with widespread deployment.

"Carbon capture capacity poised to surge more than 10 times by 2030, but aggressive investment needed to meet mid-century targets" (Rystad Energy, 2022).

"Based on learnings from current developments and expected economies of scale, CCUS project cost is anticipated to range between \$75-\$100 per ton of CO_2 captured by 2030, meaning the total market value of the sector could reach \$55 billion annually by 2030" (Qvist et al., 2021).

3.5. Shutdown of Fossil Assets and Building New Plants

This lever has multiple sublevers capturing all the possible variations but is based on decommissioning existing coal or gas-fired plants and replacing it with a plant with less or zero CO_2 emissions. Some of the variations for coal-fired power plants are as follows: 1. Coal to Gas, 2. Coal to Gas + CCS, 3. Coal to PV, 4. Coal to PV+Wind, 5. Coal to PV+Wind+Battery. The same levers can apply to gas fired power plants: 1. Gas to PV, 2. Gas to PV + Wind, 3. Gas to PV + Wind + Battery, 4. Gas to 100% Hydrogen.

These methods typically require higher upfront CAPEX to build a new plant or invest in renewable parks. The levers are more market-competitive in countries with very high CO_2 and gas prices.

4. 2022 ENERGY PRICES ACCELERATING THE NEED FOR DECARB PATHWAY

"The European Union first proposed a cap on the price of gas and electricity in March, after energy prices took off when Russian – Ukraine conflict started. While some suppliers produce their energy, most of the price that electricity firms pay is set by financial markets, where producers, utility firms and speculators compete based on supply and demand" (Nik, 2022).

"Electricity producers are paid the same price despite having vastly different expenditures. Gas power stations are much more expensive to run than wind or solar farms and, therefore, tend to set the overall market price" (Nik, 2022).

"Current German import prices reaching above 400 EUR/MWh for natural gas and above 580 EUR/MWh for coal (July 2022)" (Statistisches Bundesamt, 2022) "were the factors for the year-ahead contract for German electricity reaching €995 (\$995) per megawatt hour at the end of August" (Nik, 2022).

Moreover, with CO_2 prices also being currently high (65 EUR/ton, Sep/2022) (Statistisches Bundesamt, 2022) and expected to double in the next decade (111 EUR/ton, Dec/2030), power utilities not only need to set a decarbonization strategy, but also rapidly accelerate it, in order to prevent and slow down the gradual elimination of fossil assets.

5. BENCHMARK RESEARCH ON COMPANY DECARBONIZATION INITIATIVES

A research study analyzed various factors and identified key strategies employed by 13 selected companies in their ongoing or planned decarbonization initiatives (Table 1). The companies were selected from different regions including the US, Europe, Asia, and the rest of the world. Utilities in Europe and the US are prioritizing the shift from coal to renewables in their immediate plans. The companies analyzed in the study include Duke Energy, Next Era, Evergy, Fortum, Uniper, Engie, Enel, RWE, Orsted, CLP, NTPC, Tepco, and Eskom.

Table 1. Decarbonization Initiatives across Major Power Utilities

Region	Company	Power Plant Actions			Diversifying from fossil fuel			Carbon Capture
		Coal to Gas	Coal to Biomass	Coal Divestment	PV and Wind	Energy Storage	Ammonia, H2	CCS
US based	Duke Energy	○	○	●	●	●	◐	◐
	NextEra	◐	○	◐	●	●	◐	○
	Evergy	○	○	●	●	○	○	○
EU based	Fortum	○	●	●	●	●	●	○
	Uniper	●	○	●	●	●	●	○
	Engie	○	◐	●	●	◐	◐	◐
	Enel	○	○	●	●	●	●	○
	RWE	○	●	●	●	●	●	○
	Orsted	○	○	●	●	●	●	●
Asia and RoW based	CLP	○	○	○	●	○	◐	○
	NTPC	○	○	◐	○	○	◐	●
	Tepco	○	○	○	●	◐	◐	○
	Eskom	○	○	○	●	◐	◐	○

Legend: ○ *No evidence of investing;* ◐ *Testing;* ● *Investing*

Source: Own research

5.1. Results and Discussion

USA: Based on this study of three major power utility companies in the US: Duke Energy, Next Era and Evergy, it was found that the shift from coal to natural gas was primarily driven by lower natural gas prices and the flexibility of gas-fired power plants to ramp up and down quickly to accommodate intermittent renewable energy sources. While the companies were also investing in renewable energy, the cheaper cost and availability of natural gas made it a more attractive option for meeting the increasing electricity demand. However, the companies recognized the need to further diversify their energy mix to reduce reliance on any single fuel source and mitigate potential future price fluctuations.

Europe: Based on our analysis of six European power utility companies - Uniper, RWE, Fortum, Engie, Enel, and Orsted - the primary driver for phasing out coal and investing in renewables, storage, and hydrogen is the strong environmental regulations in the European Union. Unlike in the United States, natural gas is not as abundant and cheap in Europe, making it less economically attractive as an alternative to coal. Additionally, the decreasing costs of renewables and energy storage technologies, along with supportive government policies and targets, have made them more competitive compared to fossil fuels. As a result, these six power utility companies are actively investing in renewable energy sources, energy storage, and green hydrogen as part of their decarbonization initiatives.

While these initiatives present opportunities, there are also risks involved, including potential project delays and cost overruns, technological limitations, and uncertain policy and regulatory environments.

Asia: Our analysis of power utilities in Asia shows that the shift towards hydrogen and ammonia as clean energy sources is driven by their potential to reduce greenhouse gas emissions, dependence on imported fossil fuels, and economic opportunities. Regulatory pressure to reduce emissions, combined with ambitious decarbonization targets in countries such as Japan, is driving investment in these technologies. TEPCO, a major power utility in Japan, is among those exploring and investing in hydrogen and ammonia as part of its decarbonization strategy. Additionally, Japan has a well-developed technology and infrastructure for hydrogen production, storage, and transportation. As of 2021, Japan is the world's largest importer of liquefied natural gas (LNG) and has already begun importing hydrogen and ammonia as part of its energy transition strategy. Furthermore, Japan has set a target to increase its use of hydrogen to 20% of its energy mix by 2050.

6. DEEP DIVE – GAS TO HYDROGEN

To power an energy ecosystem with H_2, large volumes of the fuel will need to be generated. Goldmeer (2019) and Energy et al. (2019), discuss two available methods for generating large volumes of H_2, which are steam methane reforming and electrolysis of water. While steam methane reforming is the main production method for H_2 today, it generates CO_2, making carbon capture technologies necessary to achieve a carbon-free ecosystem. “Meanwhile, using electrolysis to generate the necessary volumes of H_2 will require significant energy, potentially increasing costs. However, an alternative solution is to generate H_2 from electrolysis using excess renewable energy, or "green H_2", according to Energy et al. (2019). This approach represents a paradigm shift in power generation and could help reduce the curtailment of excess renewable power. The paper's deep dive examines the potential for using H_2 in gas turbines to support a low-carbon or carbon-free energy ecosystem.

6.1. Gas Turbine Experience with Hydrogen

“Hydrogen can be used as a fuel for power generation, and gas turbines are capable of operating on it, making it suitable for a range of industrial applications such as steel mills, refineries, and petrochemical plants”, according to Goldmeer (2019). “Several gas turbine manufacturers have developed turbines that can operate on fuels containing hydrogen, with some units accumulating over one million operating hours. In cases where there is not enough hydrogen available, a blend of hydrogen and natural gas can be generated, which can be utilized with traditional dry low NOx (DLN) combustion systems. This has already been implemented at sites such as Dow Plaquemine plant in the USA and the Gibraltar-San Roque refinery in Spain, with the latter having operated more than 9,000 hours on a blend of hydrogen and natural gas as of 2015”, says Goldmeer (2019).

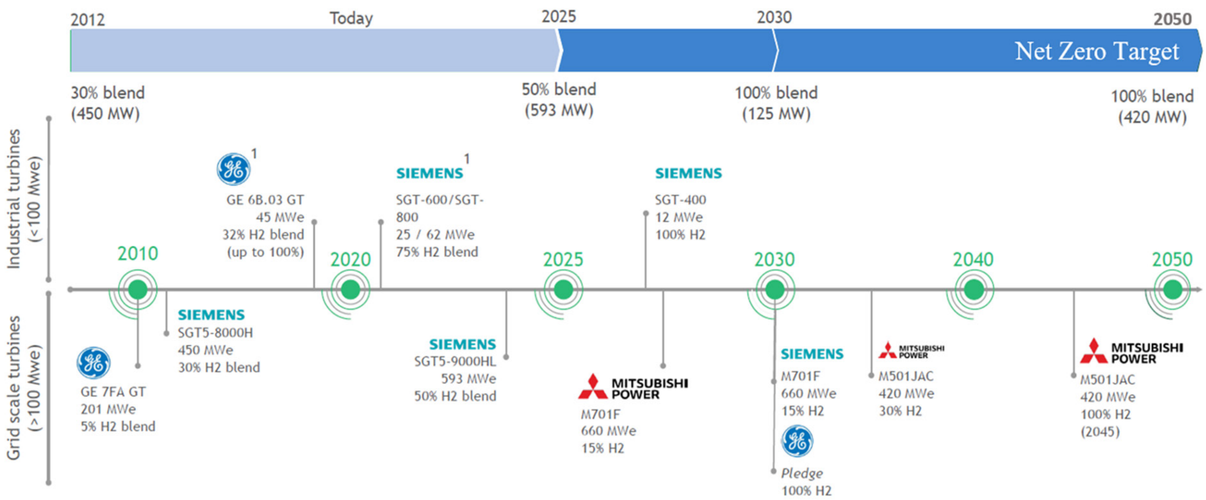
Table 2 presents the findings from the research and analysis conducted on the technological and capital expenditure (capex) requirements associated with hydrogen fuel blending.

6.2. Complete Fuel Switch from Gas to Hydrogen

Based on the available data from OEM companies and research reports, it can be concluded that the current status of CCGT turbines being able to operate on hydrogen blends or full hydrogen is promising. Major turbine manufacturers (Fig.1) such as GE, Siemens, MHPS, and Ansaldo have already pledged support to develop new H2GTs capable of burning 100% hydrogen at similar efficiencies to current CCGTs and very low NOx emissions, which would not require additional capture plants. EU Turbines, an association of the EU steam and gas turbine sector, has also committed to providing turbines capable of burning 100% hydrogen by 2030.

While the cost of building new CCGT plants that are hydrogen-ready may be slightly higher, it would enable the plants to operate on a blend of hydrogen in the future without any significant Capex investment. The availability of H2GTs is paramount for a future with hydrogen and requires continued R&D support from turbine manufacturers to overcome current technical barriers.

Overall, the potential of using hydrogen as a fuel for CCGT turbines is a promising step towards a greener future. It has the potential to significantly reduce carbon emissions while ensuring reliable and efficient power generation.



[1] Industrial Gas Turbine

Figure 1. Timeline of selected projects with hydrogen fuels

Source: Georgievski & Kiteva, 2022

However, a comprehensive approach is required that involves not only technological advancements but also supportive policies, regulations, and investments in infrastructure to fully realize the potential of hydrogen as a fuel for power generation, according to Goldmeer (2019) and Energy et al. (2019).

Table 2. Technology and Capex Requirements for Hydrogen Fuel Blend

		Hydrogen blend (% of volume)	
Requirement for add. investments/ modifications	**ca. 0-15%**	**ca. 15-30%**	**ca. 30-100%**
1. Fuel accessory system1	●	●	●
2. Gas turbine combustion system		●	●
3. Gas turbine enclosure2		●	●
4. Selective Catalytic Reduction3		●	●
5. Gas turbine controls		○	●
6. Safety system	○	●	●
7. Heat recovery system		○	●
	Minor CAPEX		**Significant CAPEX ~ 200-500 $k/MW[1]**
○ Potentially required ● Required			

[1] Assumed that CAPEX of new CCGT is ~1000k$/MW (EIA, 2020)

Source: Energy et al., 2019; own processing

6.3. Technological and CAPEX Requirements

Based on research analyses of multiple articles and studies from original equipment manufacturers, the technological and capital expenditures (CAPEX) requirements for blending hydrogen and retrofitting gas turbines vary depending on the percentage of hydrogen blended with natural gas.

Blending up to 30% hydrogen: Blending up to 30% hydrogen requires minor modifications to existing gas turbines. The main technological requirements include upgrading the fuel system to accommodate hydrogen, replacing some components with hydrogen-resistant materials, and installing additional sensors and monitoring equipment to ensure safe and efficient operation. The CAPEX investment for this process is up to 5% of the cost of a new gas turbine.

Blending up to 50% hydrogen: Blending up to 50% hydrogen requires more significant modifications than blending up to 30% hydrogen. The technological requirements include upgrading the fuel system to accommodate higher hydrogen concentrations, replacing more components with hydrogen-resistant materials, and improving the combustion system to optimize combustion efficiency and reduce emissions. The CAPEX investment for this process is between 5% and 10% of the cost of a new gas turbine.

Blending up to 100% hydrogen: Retrofitting gas turbines to run on 100% hydrogen requires significant modifications to the turbine and combustion system. The technological requirements include replacing or upgrading the entire fuel system, including storage and handling equipment, and retrofitting the combustion system to optimize hydrogen combustion efficiency and reduce emissions. The CAPEX investment for this process is between 30% and 50% of the cost of a new gas turbine.

7. CONCLUSION

The number of countries announcing pledges to achieve net zero emissions over the coming decades continues to grow. But the pledges by governments to date – even if fully achieved – fall well short of what is required to bring global energy-related carbon dioxide emissions to net zero by 2050 and give the world an even chance of limiting the global temperature rise to 1.5 °C.

Based on the companies' decarbonization initiatives, we can conclude that Europe and US are phasing out coal and investing in renewables and low-carbon technologies, Japan is focusing on green hydrogen and ammonia solutions, while India, Africa, and China still need to push the coal phase out strategy further and focus on investing into low carbon generation.

Moreover, with the impact of current energy crises and soaring energy prices, power utilities (especially EU-based), will need to accelerate the phase out of their coal and lignite assets and decommission all their fossil fueled assets by 2050 in order to meet the requirements of the Paris Agreement and save the planet from irreversible climate catastrophe. With coal phasing out in 2030 in most EU countries, and gas being a costly option, investments in renewables and low-carb technologies will be inevitable.

References

Biofit Factsheet Coal Conversions. (2020). *Coal to Biomass Conversions*. https://www.biofit-h2020.eu/publications-reports/Biofit-Factsheet_CoalConversions.pdf

Crolius, S. H. (2019, July 18). *The Evolving Context of Ammonia-Coal Co-Firing*. Https://Www.Ammoniaenergy.Org/Articles/the-Evolving-Context-of-Ammonia-Coal-Co-Firing/

Davis, S. J., Lewis, N. S., Shaner, M., Aggarwal, S., Arent, D., Azevedo, I. L., Benson, S. M., Bradley, T., Brouwer, J., Chiang, Y. M., Clack, C. T. M., Cohen, A., Doig, S., Edmonds, J., Fennell, P., Field, C. B., Hannegan, B., Hodge, B. M., Hoffert, M. I., … Caldeira, K. (2018). Net-zero emissions energy systems. In *Science* (Vol. 360, Issue 6396). American Association for the Advancement of Science. https://doi.org/10.1126/science.aas9793

EIA. (2020). *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*. https://www.eia.gov/analysis/studies/powerplants/capital-cost/pdf/capital_cost_AEO2020.pdf

Energy, E., Andersen, S. H., Sadler, D., & Sotiropoulos Michalakakos, T. (2019). *Hy-Impact Series Hydrogen in the UK, from technical to economic*. https://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Summary-Document.pdf

Georgievski, V., & Kiteva, R. N. (2022, September 23). Decarbonization initiatives among leading power utility players. *Conference Proceedings / International Conference "Energetics 2022."* https://zemak.mk/zbor-dva-za-megunarodnata-konferencija-energetika-2022/

Goldmeer, J. (2019). *Power to Gas: Hydrogen for Power Generation*. https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf

IEA. (2014). *Emissions Reduction through Upgrade of Coal-Fired Power Plants*. https://www.iea.org/reports/partner-country-series-emissions-reduction-through-upgrade-of-coal-fired-power-plants

IEA-ETSAP, & IRENA© Technology Brief E21. (2013). *Biomass Co-firing*. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2013/IRENA-ETSAP-Tech-Brief-E21-Biomass-Co-firing.pdf

Nik, M. (2022, August 30). *Energy crisis: Can the EU tame soaring prices?* https://www.dw.com/en/energy-crisis-can-the-eu-tame-soaring-prices/a-62960012

Pawlak–Kruczek, H., Czerep, M., Niedzwiecki, L., Karampinis, E., Violidakis, I., Avagianos, I., & Grammelis, P. (2019). Drying of Lignite of Various Origins in a Pilot Scale Toroidal Fluidized Bed Dryer using Low Quality Heat. *Energies*, *12*(7). https://doi.org/10.3390/en12071191

Qvist, S., Gładysz, P., Bartela, Ł., & Sowiżdżał, A. (2021). Retrofit decarbonization of coal power plants—A case study for Poland. *Energies*, *14*(1). https://doi.org/10.3390/en14010120

Rystad Energy. (2022, April 26). *Carbon capture capacity poised to surge more than 10 times by 2030, but aggressive investment needed to meet mid-century targets*. https://www.rystadenergy.com/newsevents/news/press-releases/carbon-capture-capacity-poised-to-surge-more-than-10-times-by-2030-but-aggressive-investment-needed-to-meet-mid-century-targets

Sanchez del Rio, M., Gibbins, J., & Lucquiaud, M. (2017). On the retrofitting and repowering of coal power plants with post-combustion carbon capture: An advanced integration option with a gas turbine windbox. *International Journal of Greenhouse Gas Control*, *58*, 299–311. https://doi.org/10.1016/j.ijggc.2016.09.015

Sarunac, N., Ness, M., & Bullinger, C. (2014, November 1). *Improve Plant Efficiency and Reduce CO2 Emissions When Firing High-Moisture Coals*. https://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/

Statistisches Bundesamt. (2022, September 9). *Statistisches Bundesamt (Destatis)*. https://Www.Destatis.De/

Tamura, M., Gotou, T., Ishii, H., & Riechelmann, D. (2020). Experimental investigation of ammonia combustion in a bench scale 1.2 MW-thermal pulverised coal firing furnace. *Applied Energy*, *277*, 115580. https://doi.org/10.1016/J.APENERGY.2020.115580

Wang, R., Chang, S., Cui, X., Li, J., Ma, L., Kumar, A., Nie, Y., & Cai, W. (2021). Retrofitting coal-fired power plants with biomass co-firing and carbon capture and storage for net zero carbon emission: A plant-by-plant assessment framework. *GCB Bioenergy*, *13*(1), 143–160. https://doi.org/10.1111/gcbb.12756

Zhang, C., Zhai, H., Cao, L., Li, X., Cheng, F., Peng, L., Tong, K., Meng, J., Yang, L., & Wang, X. (2022). iScience Understanding the complexity of existing fossil fuel power plant decarbonization. *ISCIENCE*, *25*, 104758. https://doi.org/10.1016/j.isci