Supporting Information

For "Retrofit Decarbonization of Coal Power Plants – A Case Study for Poland"

1. Description of a Coal Power Plant and Associated Equipment

An overview of a coal power plant site, showing the typical main components and equipment, is given in Figure S1.

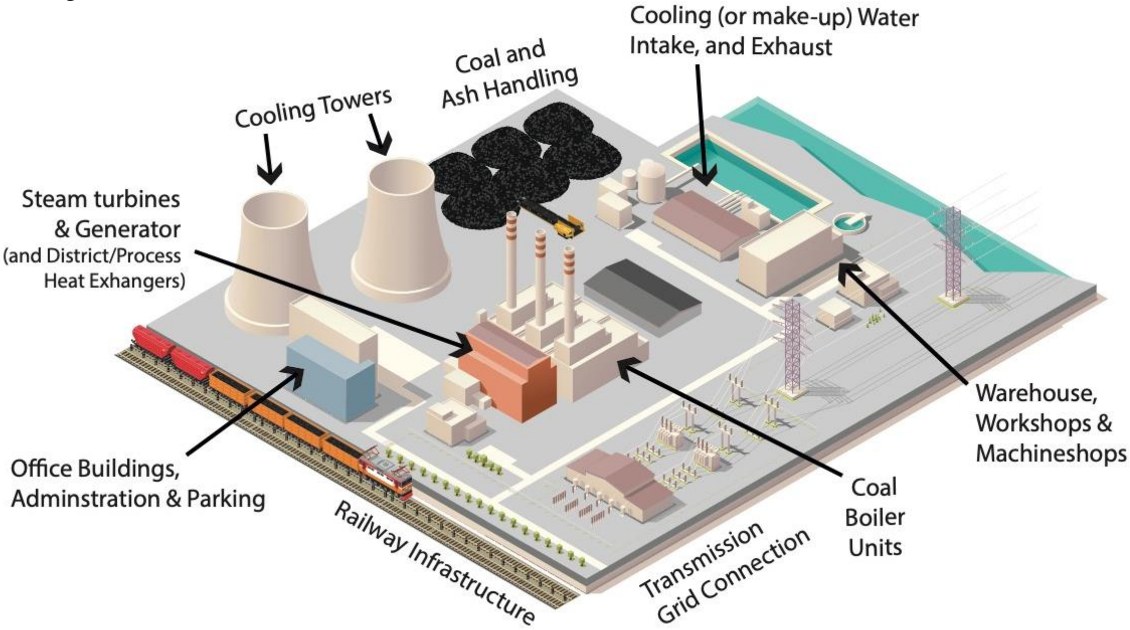

Figure S1. Coal Power Plant Site Layout and Major Components.

The equipment available at a coal power plant site will vary both with the plant power output, the type of coal it uses, and its location. A larger coal plant (above 500 MW_e) will often feature one or more individual coal units and *high-voltage* transmission grid connections, while smaller units may be connected to lower voltage distribution grids. Plants located at large bodies of water will in most cases make use of open cycle condenser cooling and will not have cooling towers, whereas plants sited away from water or by smaller rivers are equipped with cooling towers. Due to the very large throughput requirements for fuel and ash handling, most coal power plants that are fed by hard (or "black") coal have either a railway connection or port infrastructure, sometimes both. Brown (or "lignite") fired coal power plants are typically located at the mine mouth and are fed with lignite by conveyer belt directly from the mine, avoiding the need for other coal receival infrastructure. Plants typically store enough coal on site for at least a couple of months of operation. As the coal is combusted, very significant quantities of ash is produced[1]. The ash can either be stored on or near-site in large storage ponds, or transported off the site by rail or barge using only minor local storage capacity. The way that coal and ash are handled has large impact on the footprint of the plant, since the associated storage piles often dwarf the actual power units in size. The equipment at a coal power plant can for the purposes of this study be very broadly categorized in components that directly relate to the handling and combustion of coal, and everything else. The specifically coal-related equipment in Figure S1 are marked with "Coal and Ash Handling" and "Coal Boiler Units". In all retrofit decarbonization options studied except for those involving carbon capture and biomass conversion, this equipment would be decommissioned. Non-coal-specific equipment present at all coal power plants are:

- Switchyard, grid connection & associated equipment
- Steam turbines and generators

[1] Coal ash is the non-combustible solid residue of coal. In a coal-fired boiler, some of the ash remains inside the boiler and is known as bottom ash. Fly ash is the fraction that is too small to settle out in the combustion chamber; it becomes suspended in the high-velocity flue gas. Air-pollution regulations require electric utility and industrial boilers to be equipped with particulate control devices to prevent fly ash from entering the ambient air.

- Condenser cooling system (either direct open cooling or through cooling towers)
- Railway station and/or port (possible exceptions are some mine-mouth plants)
- Heavy-duty access roads
- Security fence
- Parking lots
- Ancillary buildings

Depending on the type of retrofit decarbonization option that is envisaged, large fractions of this equipment can be kept in use, leading to the potential for substantial cost savings and the avoidance of stranded assets.

2. Retrofit Decarbonization using Carbon Capture and Storage

2.1. Technology options

For carbon capture at a coal plant, there are three main approaches available in terms of capturing carbon:

- **Post-combustion capture**, which involves installing a capture plant that processes the exhaust gases of the existing power plant.
- **Pre-combustion capture**, which involves pre-treating the coal to remove the carbon before combustion. This is achieved using a modified version of coal gasification that, when carried out fully, leaves a fuel gas composed primarily of hydrogen. The gasification process also requires some form of capture technology.
- **Oxyfuel combustion**, which attempts to sidestep the problem of separating carbon dioxide from the flue gases (primarily nitrogen). Instead, oxygen is separated from air first, and then coal is burned in virtually pure oxygen. The scheme leads to an exhaust gas stream composed primarily of carbon dioxide, mixed with some water vapor and excess oxygen, from which it is much easier to isolate the carbon dioxide than when it is mixed with nitrogen.

Out of the three options, post-combustion is both the most commercially developed and the most applicable as a retrofit option. The development of pre-combustion capture in the form of Integrated Coal Gasification Combined Cycle (IGCC) plants has halted due to some high-profile failed projects[2]. Oxyfuel technology has been tried out at small scale with the 30 MW_{th} Schwarze Pumpe pilot plant in Germany between 2008 and 2014, and novel technology such as the Allam cycle developed by NetPower is now in pilot phase, with a 50 MW_e plant in operation in the United States. Oxyfuel retrofit to an existing coal plant unit has however never been carried out. Post combustion capture on the other hand is an established commercial technology, as demonstrated by a number of large industrial facilities and two power plant projects in operation. Therefore, this analysis focuses on *post-combustion capture* specifically.

2.2. CO_2 emissions

Post-combustion CO2 capture equipment is typically designed to achieve a 90% capture rate. Reference coal plant emissions can vary between 770 gCO_2/kWh for a highly efficient supercritical plant fuelled with hard coal, up to at least 1100 gCO_2/kWh for older lignite-fired units. When applying a very strict lifecycle emissions limit of <50 gCO_2/kWh, it is clear that 90% capture rates will not be sufficient, as total lifecycle emissions may still end up higher than 100 gCO_2/kWh in many cases. A 2019 study published by the International Energy Agency (IEA) concludes that 90% capture is not a technical limit,

[2] The two IGCC power plants built in the United States in the 2010s were plagued with very high capital costs: at the Edwardsport Power Station in Indiana, and at the Kemper County Energy Facility in Mississippi. The Kemper plant cost was over $7 billion (>€12000/kW), and once finished it has not run the gasifiers, instead switching to natural gas. Today there does not appear to be a market for IGCC projects, with or without carbon capture.

but “an artificial limit” that is a “historical benchmark, originally based on the economics of capture.” The study concludes that 99.7% capture increases the cost of electricity by only 7% compared to 90% capture [1]. With added-in 99.7% capture, essentially all Polish coal plants can land within the category of low-carbon energy.

2.3. Other pollutants

Ambient air pollution causes roughly 8.8 million deaths per year worldwide [2], and the emissions from the combustion of fuels such as coal for heat and electricity is a major contributor. Even if CO_2 emissions can be brought down sufficiently to qualify as “low carbon”, it is important that more stringent targets for other air pollution reductions are applied simultaneously. Since more fuel must be combusted to meet the increased energy demands of running the carbon capture equipment, but only CO_2 is captured (not any other air pollutants), adding carbon capture can in theory *increase* conventional air pollution. For example, fine particulate matter (PM2.5) and nitrogen oxide (NO_x) emissions increase roughly in proportion to fuel consumption [3]. However, SO_2, present in the flue gas from coal power plants will degrade the amine solvent in the CO_2-capture system. This contaminant *must* therefore be essentially eliminated from the flue gas before it enters the amine system. Air emissions regulations already mandate some clean-up of sulphur oxides, but the level of removal required by the amine system is even more stringent. Thus, a prerequisite (which is already priced in) of adding amine-based capture equipment is a reduction in conventional air pollution compared to a typical plant before carbon capture retrofit. From the assessment of National Energy Technology Laboratory (NETL), it appears the primary impact is a specific reduction in the emissions of SO_2, while NO_x and PM levels remain essentially unchanged. As shown in Figure S2, a combined cycle natural gas plant (NGCC) features smaller emissions of all essential pollutants (including those not shown, such as mercury), compared to coal plant even when equipped with capture equipment.

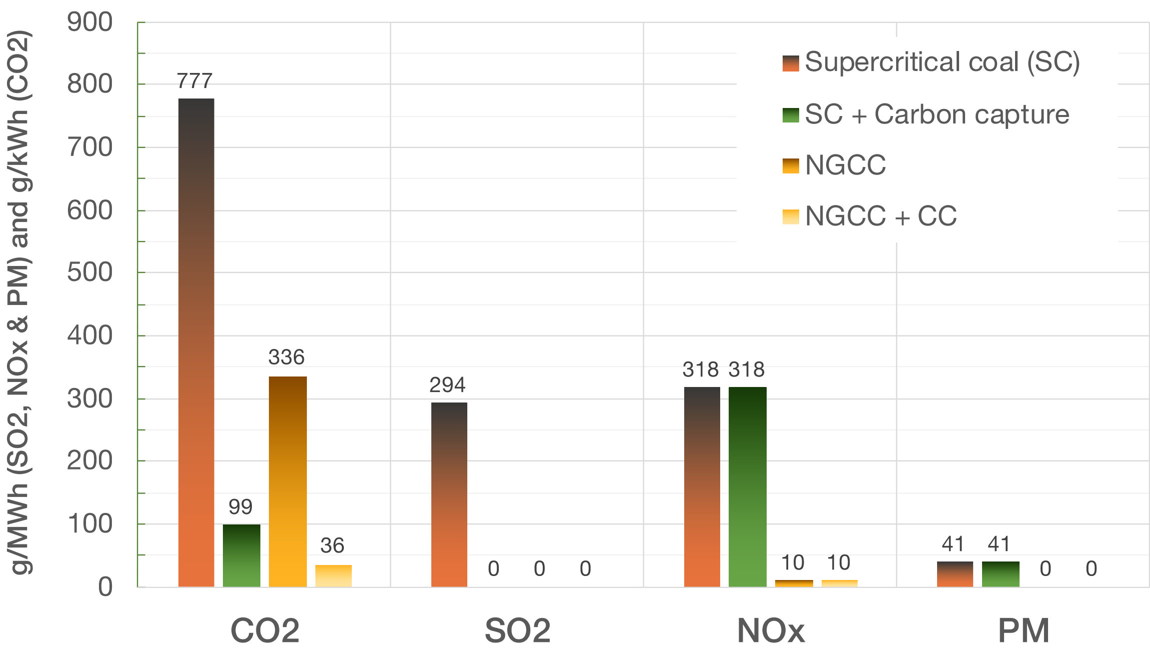

Figure S2. Air pollution impacts of adding carbon capture by NETL (developed from ref. [4])

Table S1 summarizes the results of a review study by the International Energy Agency on the impacts of air pollution from coal plants when adding post-combustion carbon capture.

Table S1. Change in conventional air pollution when adding post-combustion capture of coal plants [5]

Pollutant	Change when adding post-combustion CO_2 capture

SO_x	Eliminated
NO_x	+ 25 %
NO	+ 25 %
NO_2	– 25 %
HF/HCL	– 95 %
CO	+ 25 %
NH_3	+ 100 %
Ash	+ 25 %

To be acceptable from a health impact and environmental perspective in the long run, coal plants, even equipped with post-combustion carbon capture equipment, will need to install additional scrubbing equipment to reduce the emissions of nitrous oxides and particulate matter significantly further down.

2.4. Retrofit implications

Steam to heat the capture plant reboiler system may either be sourced from an external dedicated steam generator, such as natural gas unit the one deployed at the Petra Nova Project, or it could be extracted from the power unit's steam cycle using an integration, such as the installation at Boundary Dam. If integrated, several steam cycle modifications would typically be required to minimize output losses. Modifications to turbine and other steam equipment can in principle be completed within a 65-day outage period [6]. If a new natural gas plant is added to the site to power the capture unit, this may double the total footprint required for the capture unit. Such an option might therefore be more difficult to realize at coal sites that are densely packed.

2.5. Cost assessment

A recent review study summarized costing data from seven other reports with data for the total plant overnight capital cost for supercritical pulverized coal power plants with current (amine) post-combustion capture technology and bituminous coals [7]. The mean assessment was a cost increment of approximately €1500/kW for a plant with capture equipment compared to one without such equipment, which also agrees with an even more recent assessment by the US National Energy Technology Laboratory (NETL) [4]. This differential is a reasonable base-estimate for the cost of retrofit of the corresponding equipment. Since a >96 % effective capture rate is needed to really qualify as low-carbon in this study, the added on cost is increased further by at least 10% (inspired by analysis from IEA, ref. [1]), for an effective overnight cost of €1700/kW. The main operational expenditure for retrofitting carbon capture equipment is the energy required to run the amine process. The steam required to separate out CO_2 from the amine solvent, which is about 2 GJ/tCO_2 captured, is responsible for about two thirds of the energy requirement. Most of the remaining energy is the electricity required to run CO_2 compressors. The total energy required to run the capture plant amounts to the equivalent of ~25% of the original coal unit energy. Thus, as a first approximation, adding 90% effective CO_2 capture equipment reduces the *net* electricity (and heat) output of the plant by approximately one fourth. Additionally, for Polish conditions, the cost of CO_2 pipelines and sequestration is expected to add a further €5/MWh when developed at scale at several plants, or >€10/MWh if this cost is to be carried by a single unit [8].

2.6. Global operating experience

The first coal power plant with carbon capture and utilization (CCU) equipment was the Boundary Dam power station in Estevan, Saskatchewan, Canada, which has been operating with CCU equipment connected to one coal boiler since October 2014. The cost of the retrofit project was €1.37 billion, out of which €730 million was for the capture and storage process (€6600/kW). The captured CO_2 is sold for enhanced oil recovery (EOR). A follow-on project proposed for the Shand Power Station (also in

Saskatchewan, Canada), indicates a possible 67 % reduction in capital costs for the capture and storage equipment, meaning an effective cost around €2100/kW [6].

The W.A. Parish coal power plant near Thompsons, Texas was retrofitted with CCU equipment as part of the Petra Nova project. The capture equipment began operation in January 2017. The capture equipment at Petra Nova receives 37 % of the flue gas steam from the 654 MW unit 8 boiler at the plant, which means it is effectively a 90% CO_2-capture plant for a 240 MW boiler. A new 75 MW combined cycle natural gas (NGCC) unit was installed at the site to provide power and steam to the capture unit. The NGCC unit supplies 35-40 MW of electricity to the grid while also providing as much as 40 MW of electricity and steam to the capture unit. The total retrofit cost of the Petra Nova project was €0.9 billion (~€3600/kW) [9]. The captured CO_2 is piped to the West Ranch oil field, where it is used for EOR. Plant owner NRG Energy inc. have idled the facility since May 1, 2020, saying a collapse in the price of oil prompted by the coronavirus pandemic made it uneconomical [10].

2.7. Experience in Poland

In Poland, the utility PGE has carried out extensive carbon capture related research to assist the demonstration of the entire CCS technology chain (capture, transport, storage and monitoring) at its Bełchatów plant. In 2009, PGE initiated activities aiming at constructing a demonstration CCS plant. The plant was intended to be integrated with the new 858 MW power unit (Unit 14), which was then under construction (it entered operation in 2011). The new unit was modified to be "capture ready", which included modifications such as flue gas duct flanges (from which gas could be routed to the capture plant) and preparations were put in place for water supply to the capture plant. A solution similar to that which was later introduced at the Petra Nova plant in the US was proposed, where one third of the flue gas of the unit would be directed to the capture plant. The capture plant was to run an Advanced Amine Process (AAP) and was meant to capture approximately 1,8 million tons of CO_2 per year with 85 % capture rate from a slipstream of the flue gas extracted from a tie-in connection point located downstream one of the wet flue-gas desulfurization (FGD) absorbers. The project was cancelled in February 2013 due primarily to a lack of external funding [11].

2.8. CO_2 storage potential in Poland

The best conditions for geological CO_2 storage in aquifers occur within significant part of Polish Lowlands (Northern and Central Poland). As part of the preparatory works for carbon capture at Bełchatów, detailed work was carried out to identify formations and structures for the safe geological storage of CO_2 across eight regions of the country. The region covering the Bełchatów area, with five selected structures for storage, had a combined storage capacity of 2.2 billion tons. The estimated total potential for CO_2 storage (with a dominant, approx. 90% share in aquifers) across the country is about 10 billion tons of CO_2. This refers to a technical potential, with the actual practical and economically realizable storage potential being far lower

2.9. Carbon Capture Retrofit Decarbonization potential in Poland

Carbon capture is most effective on large units because the capture process exhibits significant economies of scale. The main motivation for carbon capture to date has been for enhanced oil recovery (EOR), which adds an income stream to compensate for the costs of capturing carbon. Even with EOR, the capture technology has not proven cost-effective to run at low oil prices. EOR applications are generally not available in Poland, and thus the carbon capture and storage costs will need to be carried covered by a carbon abatement strategy, requiring either a significant price on carbon emissions (through the EU ETS or other systems) or a regulatory cap. There are seven large, modern coal units in Poland, with a combined capacity of 5.7 GW_e, for which carbon capture was determined to be a realistic retrofit decarbonization solution. These units are listed in Table S2.

Table S2. Coal power units in Poland suggested for carbon capture retrofit.

Unit name	Power rating	Year of commissioning
Turów 11	460 MW	2020/21
Jaworzno 3	910 MW	2020
Opole 5	600 MW	2019
Opole 6	600 MW	2019
Kozienice 10	560 MW	2018
Kozienice 11	1112 MW	2017
Bełchatów 14	858 MW	2011

3. Retrofit Decarbonization from Biomass Conversion

3.1. Introduction

Coal power plants adding the possibility to combust biomass[3] by "co-firing", conversion or boiler replacement with full biomass-firing have been the main pathways for "retrofit decarbonization" of coal plants worldwide to date. These options are defined in Table S3.

Table S3. Coal-to-biomass pathways (from ref. [12])

Co-firing: the coal power plant replaces some coal with biomass in the input fuel while retaining coal as the primary fuel. Generally, but depending on the boiler technology, low percentages of the coal fuel mix can be replaced with biomass for only a modest investment. While co-firing biomass with coal has been the main driver of new biomass consumption so far, both in Poland and globally, this pathway is not applicable for retrofit decarbonization in the context of this study, as effective CO2 emissions levels even with sustainably sourced biomass remain far above the limits applied (<50 gCO_2/kWh) due to the limited fraction of biomass that can be co-fired.
Conversion: the primary fuel in a power plant unit is switched from coal to biomass. A conversion requires investments to adapt the boiler and the fuel handling facilities to use biomass rather than coal.
Replacement: a new primary fuel biomass facility is built to replace the power (and possibly heat) supply of a former coal power plant, using the same physical site and often the same steam turbines, generators and grid connection.

Under EU regulations, biomass is currently regarded as a source of renewable energy. Energy production from biomass is therefore eligible for public subsidy and exempt from CO_2 emissions charges under the EU Emissions Trading System (ETS). To meet renewable energy targets, many EU governments have promoted the use of biomass as a substitute for fossil fuels in power and heating plants. Biomass conversions are also one way for coal power plants to conform to tightening air pollution standards particularly for sulphur dioxide (SO_2) emissions, since the combustion of biomass fuels lowers SO_2 levels compared to combusting coal. Supported by both EU and national legislation, biomass (mostly wood in the form of pellets or chips) is increasingly used as a fuel to generate electricity, including in a number of large former coal power plants. Biomass accounts for 3 % of electricity generation and 19 % of heat production across the EU, one quarter of which occurs in converted coal plants.

The amount of biomass used in current or former coal power plants grew by 40% between 2010 and 2017 in the EU, reaching 90 TWh of energy input in 2017 [12]. During this period, the United Kingdom increased its biomass burning in current and converted coal plants by nearly five times, while the same figures in Denmark and Belgium nearly doubled. Poland, which by 2017 had reduced its biomass burning in coal plants to less than half of the values in 2012-2015, constitutes the only notable

[3] Biomass is a solid, organic, non-fossil material of biological origin (plants and animals) which may be used as fuel for heat production or electricity generation. The most typical example is wood, which is the largest biomass energy source [12].

exception to this upward trend (see Figure S3). This decline is primarily explained by a reduction in co-firing as the value of Polish government subsidies promoting biomass co-firing declined[4].

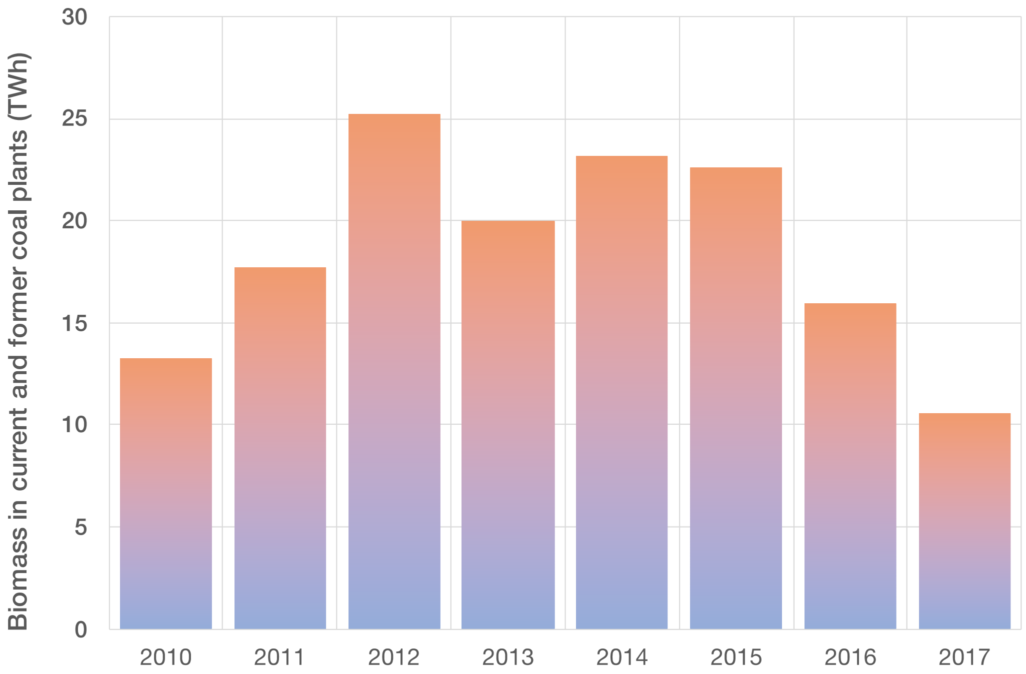

Figure S3. Biomass consumption in converted and co-firing coal plants in Poland 2010-2017 [12]

Sourcing a steady supply of the amount of biomass required to fuel a larger (>50 MW_e) power station presents serious technical, logistical and environmental challenges. For larger plants, the only viable option is typically to burn wood pellets. Wood pellets are made by drying, pulverizing and compacting biomass derived from trees. Wood pellets are more uniform and have a higher energy density than other types of biomass; these properties make it possible to transport them in the volumes required to fuel larger power stations. The global wood pellet production has risen from 15.7 MT in 2010 to ~ 36MT today [13].

3.2. Experience in Poland

The Polish power system contains 32 active units that *primarily* use solid biomass as fuel, with a combined electric capacity of 782 MW_e, producing approx. 4-5 % of annual electricity and 15 % of supplied heat. By far the largest biomass consumers are the "200-units" at Połaniec (see section 9.3), which outputs around 2.0-2.5 TWh of biomass-derived electricity annually. Significant co-firing of biomass has also been happening at the Ostrołęka, Białystok, Konin, Chorzów (see section 9.2), Jaworzno and Tychy plants. The 225 MW unit 8 at the Połaniec power plant was, at the time it was fully converted in 2012, the largest pure solid biomass-fired power unit in the world. It uses up to 0,89 MT

[4] Until 2016, the main renewable support scheme was a renewable quota obligation, which was combined with a certificate trading scheme. Biomass co-firing installations were eligible to obtain a full certificate per MWh generated from biomass. These certificates could then be traded on a specialized market. This led to a very rapid increase in biomass co-firing in Poland's coal power plants, however, over time, an oversupply of green certificates began to accumulate, by 2016 it was over 20 TWh. Prices fell precipitously from approximately 280 PLN/MWh (€65) in 2010 to sub 50 PLN/MWh (€11.5) in 2017 [90]. The Res Act of 2016 replaced the quota obligation and certificate trading scheme with a tender process as the main renewable energy incentive mechanism. However, the RES Act confirmed that generators on the certificate scheme would still be eligible to obtain a full certificate per MWh generated from biomass provided that at least 15% of the input fuel was biomass.

of wood chips and 0.22 MT of agricultural waste[5] annually [14]. Agricultural waste is collected from within 100 km radius of the plant.

3.3. Cost of replacement or conversion

Co-firing biomass at low-levels in existing coal plants typically requires additional investments of €350-€550/kW [15], but would be insufficient in terms of CO_2-reductions to qualify as low-carbon in the scope of this study. Converting the 200 MW_e Atikokan generating station in Canada from lignite to biomass cost approx. €125 million, or €625/kW_e. Since the boiler at Atikokan was built extra-large to fire high-moisture lignite coal, it could more easily be converted to biomass feedstock, something that is more difficult and costly for hard coal boilers [16] [17] [18]. The cost of a complete fuel replacement from hard coal to biomass in Poland, including replacing the boiler and upgrading the steam cycle, is assumed to cost €1250/kW_e in 2020, based on the data for Połaniec unit 8[6].

3.4. Emissions impact

Assessing the effective greenhouse gas emissions of biomass combustion for electricity and heat is a highly contentious scientific and political question. The 'payback period' of the CO_2 that would be emitted annually from switching from coal to biomass requires an integrated approach whereby carbon flows along the complete life cycle (including combustion emissions) in the bioenergy scenario are compared with carbon flows in the absence of increased harvesting for bioenergy (a reference or counterfactual scenario). No such assessment was carried out as a part of this study specifically for Polish conditions. By far the largest coal-to-biomass conversion in history is that of the four 660 MW units at Drax power plant in the UK. The experience of Drax therefore gives important guidance for the overall applicability of this pathway for large coal plant. One thing that is clear is that even though many reports state high numbers for the "theoretically available" waste & residue feedstock of biomass in many European countries, Drax sources the majority of its biomass supply from the United States. According to Drax calculations, the emissions for feedstock sourcing (not combustion) amount to 121 gCO_2-eq/kWh, already well above the limits set in this study for "low-carbon energy" (<50 gCO_2-eq/kWh). The effective lifecycle emissions that should be assigned to the combustion of biomass varies from zero to well above 1000 gCO_2-eq/kWh depending on the assumptions regarding:

- The carbon "payback time"
- What would have happened to the wood it if it had not been burnt for energy?
- What happens to the forest from which it was sourced?

An assessment of this nature was recently carried out for three wood pellet mills located in in the United States and owned by Drax Biomass, a subsidiary of Drax Power. According to the analysis [19], burning wood pellets from these mills for electricity in the UK corresponds to an effective emissions level of 468 $gCO_{2\text{-eq}}$/kWh even after a payback time of 40 years. Assigning an effective lifecycle emissions rate to the conversion of coal units to biomass in Poland is extremely difficult, feedstock-dependent, and should be carried on in detail on a case by case basis. The span of applicable values is summarized in Table S4.

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[5] A mixture of straw, sunflower, dry fruits and palm kernel [91].

[6] This conversion was reported to cost 1 billion Polish złotych in 2012, which inflation-adjusted and currency converted corresponds to €1163/kW (for 225 MW capacity) in 2020 [14]. The output capacity of Połaniec Unit 8 was downgraded from 225 to 205 MW as part of the conversion, giving a final normalized cost of €1163 * (225/205) = €1275/kW.

Table S4. Lifecycle emissions from biomass combustion for electricity.

Lifecycle step	Emissions	Source
1. Feedstock production: Extraction, chipping, drying and pelleting	78 $gCO_{2\text{-}eq}$/kWh	[20]
2. Feedstock transport (from US to Europe)	42 $gCO_{2\text{-}eq}$/kWh	[20]
3. Combustion	0-1000 $gCO_{2\text{-}eq}$/kWh	Various

3.5. Air pollution impacts

Emissions from the combustion of solid biomass such comprise both gases and particles. These include particulate matter (PM) and gases such as carbon monoxide (CO), carbon dioxide (CO_2), oxides of nitrogen (NOx), volatile organic compounds (VOCs), sulphur oxides (SOx) and a range of trace species including polyaromatic hydrocarbons. A typical biomass-fired installation will emit only small amounts of SO_2, but more nitrous oxides per unit of electricity generated than a corresponding coal unit (up to 500 gNO_x/MWh compared to 300-400 gNO_x/MWh for bituminous coal [21]. To address both particulate emissions and NOx, any future-proof biomass-converted coal unit would need to already have in place, or add in, scrubbing equipment. The minimum requirements assumed for this in this study are summarized in Table S5.

Table S5. Air pollution controls required for future-proof biomass conversion (costs from ref. [22])

Control technology	Cost, €/kW (50 MW unit)	Cost, €/kW (200 MW unit)
Selective catalytic reduction for NOx reduction	270	230
Fabric filtration for PM reduction	500	380
Summary costs	770 €/kW	610 €/kW

3.6. Biomass Conversion Retrofit Decarbonization potential in Poland

In our assessment the potential for biomass-conversion of Polish coal plant units with a capacity more than 50 MW_e and an effective age (including modernization) is limited when adhering to a lifecycle emissions limit of less than 50 gCO_2/kWh. Conversions at smaller units, such as the planned 50 MW_e conversion of Konin unit 7, are likely to continue [23]. At this small size, sourcing of sustainable local waste biomass could be possible if carefully planned and assessed. The larger 120 MW_e CHP units at plants like Siekierki (Warsaw) may also be applicable, although more challenging. In total, a potential for sustainable complete conversion or replacement of 12 units, with a combined current capacity 1100 MW_e, was found to be possible. However, no detailed analysis was carried out in regard to what sustainable and low-lifecycle-emissions feedstock could be cost-effectively supplied to these units once converted.

4. Representative Polish Coal Power Units

4.1. Introduction

In order the assess the potential and costs of retrofit decarbonization options in detail, one "representative unit" each for CHP, "200-units" and Large Power Units have been used for more detailed analysis. These representative units are introduced in the following sections. No analysis for "360-units" was performed as part of this study.

4.2. Representative Combined Heat and Power (CHP) Unit: CEZ Chórzow

The CEZ Chorzów (previously Elektrociepłownia Chorzów ELCHO) plant consists of two identical units, each with an installed coal boiler capacity of 274 MW_{th}. The units have been in operation since 2003. Each unit is equipped with a circulating fluidized bed (CFB) hard coal boiler by Foster Wheeler and an extraction-condensing steam turbine by Siemens. The capacity of each turbine is 113 MW_e electricity (in full-condensation mode) and 180 MW_{th} of heat in full-cogeneration mode. The total installed capacity at CEZ Chorzów is around 226 MW_e and up to 500 MW_{th}. The annual production is around 600 GWh_e of electricity production and 660 GWh_{th} of heat to the city of Katowice and its surrounding communities. The plant co-fires biomass with coal, and currently the share of biomass utilization in electricity production is around 16%. In 2012, the turbine island equipment (steam turbines, generators, feedwater heaters) have been thoroughly modernized, making the "effective age" of the plant equipment applicable for retrofit decarbonization options 8 years in 2020. In 2017, new Selective Catalytic Reduction (SCR) $DeNO_x$ equipment was installed to meet the IED Directive emissions levels and which allows the unit to operate after 2021 in accordance with "best available technology" (BAT) regulations.

The CEZ Chorzów units operates at an annual average electric capacity factor of 65-70 %, which is significantly above the average for the Polish coal power plant fleet. Figure S4 shows monthly-averaged electricity generation for the units during the period 2015-2018.

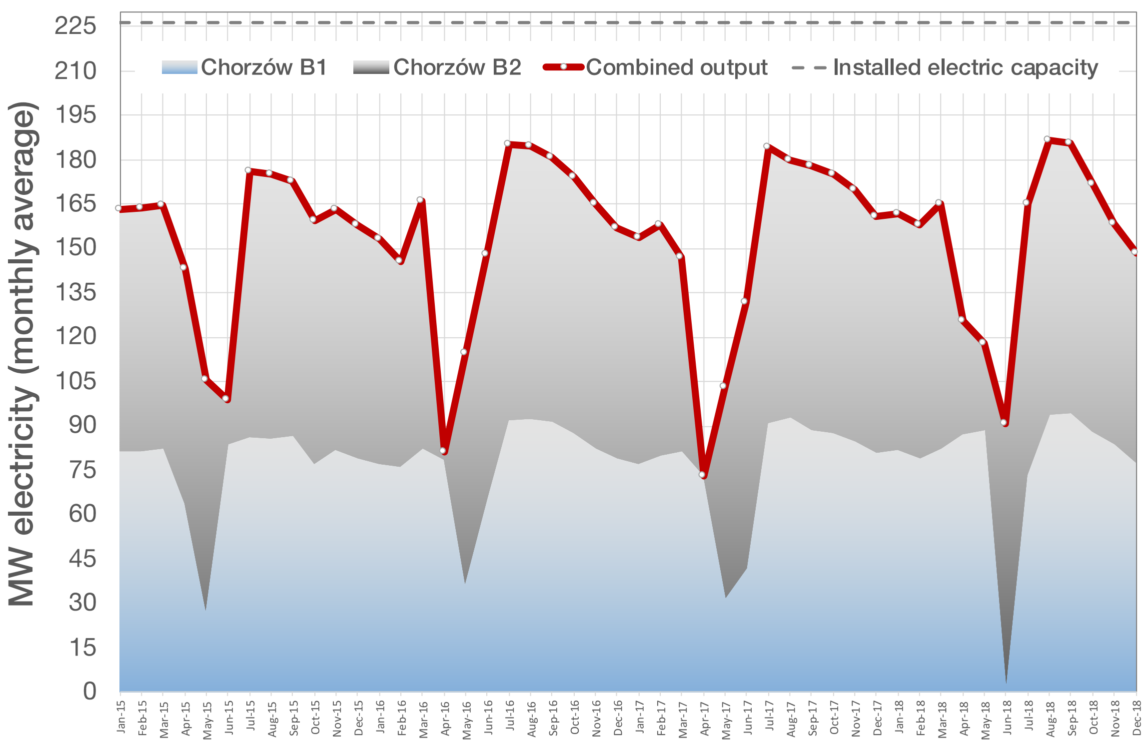

Figure S4. Monthly electricity production at CEZ, Chorzów 2015-2018.

The plant is located just north of Chorzów town, which itself is located a few kilometers northwest of the larger city of Katowice. Being a semi-urban combined heat and power plant, the site footprint is condensed. The total direct area of the site itself is about 0.13 km^2, or about 550 m^2/MW$_e$, which is close to the lower bound of the coal plant footprint range defined in section 3. Site layout is shown in Figure S5.

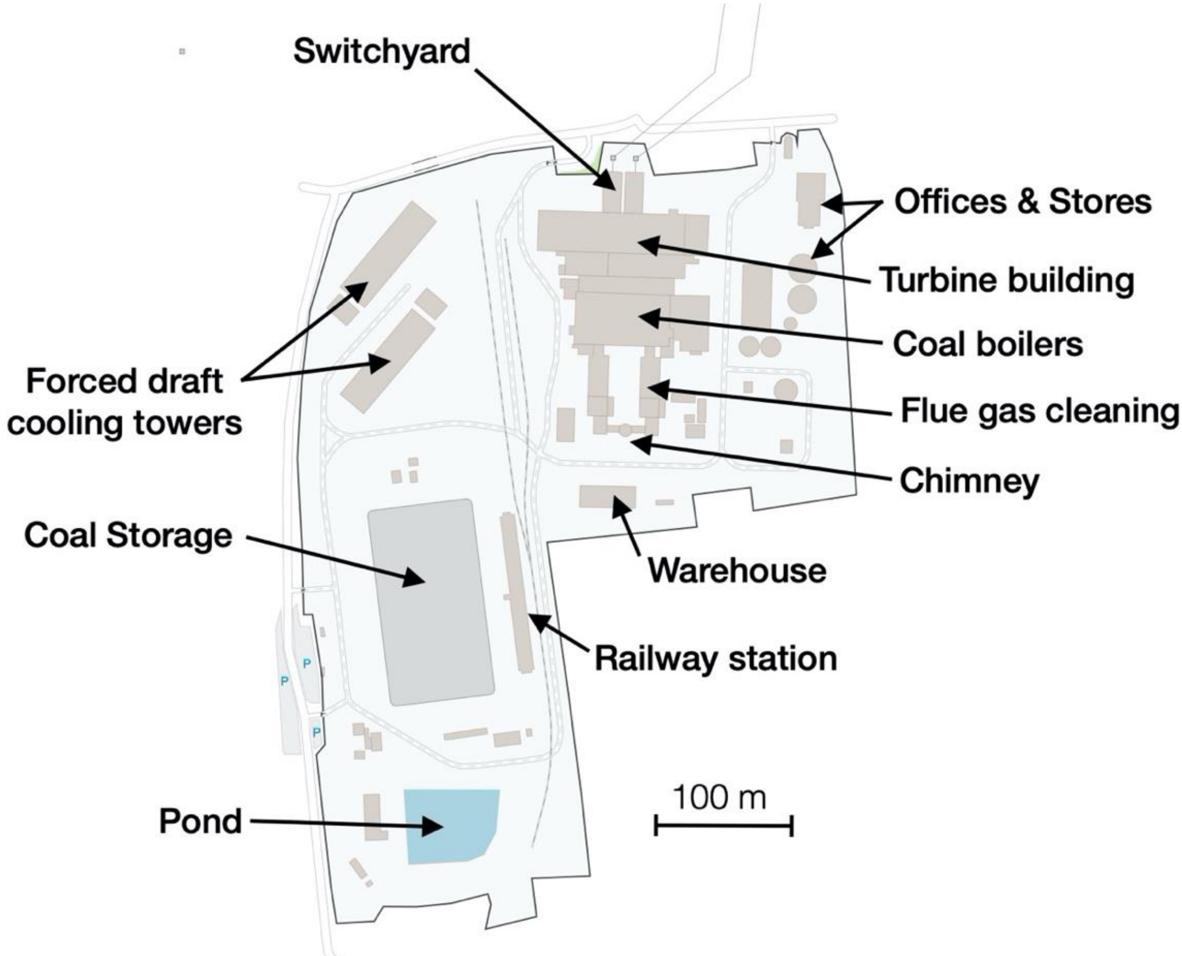

Figure S5. The Chorzów CHP plant layout (based on OpenStreetMap layers).

4.3. Representative "200-unit" model

The 200 MW-class coal-fired power units are the backbone of the Polish power system. They were primarily built in the 1970s and many units have undergone modernizations since then. From a total of 54 units (12 300 MW), 21 units with a combined installed capacity of 4940 MW have undergone recent major modernizations. The modernized 200-units are in operation at the Kozienice, Połaniec [7], Patnow, Turów and Ostrołęka B power plant sites.

The Kozienice plant has eight individual "200-units" (1821 MW), all of which were modernized in the period 2012-2016, making this the plant with the largest 200-unit capacity applicable for retrofit decarbonization analysis. The plant site also hosts unit 9 & 10, which are identical 560 MW units, as well as the largest power unit in the Polish power system, the 1112 MW unit 11. Units 1-10 utilize the Wisła river for cooling, while unit 11 was fitted with a dedicated natural draft cooling tower. The total site footprint, including ash handling, as shown in Figure S6, is about 4 km^2, giving a land usage of

[7] One unit, Połaniec unit 9, has been converted to run on biomass feedstock, and is excluded from the numbers stated here.

1500 m²/MW. All eight 200-units at Kozienice operate at an annual average electric capacity factor of 50-55 %, which is around the average for the Polish coal power plant fleet. Figure S7 shows monthly-averaged electricity generation for the units during the period 2015-2018.

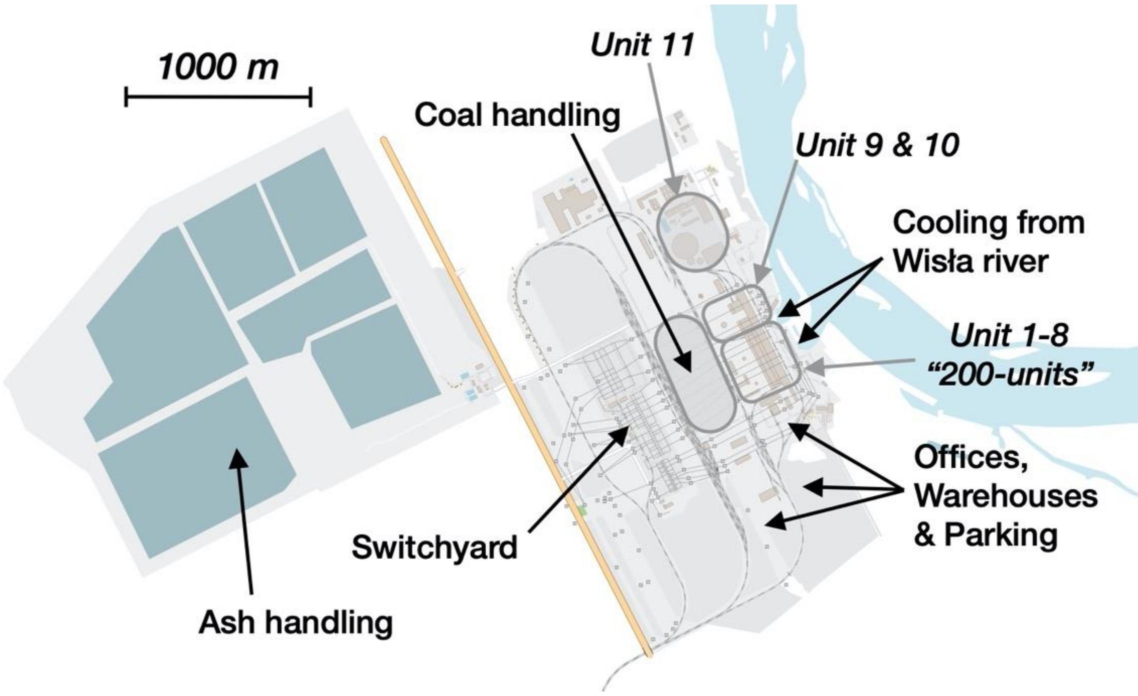

Figure S6. Kozienice Power Plant Site Layout.

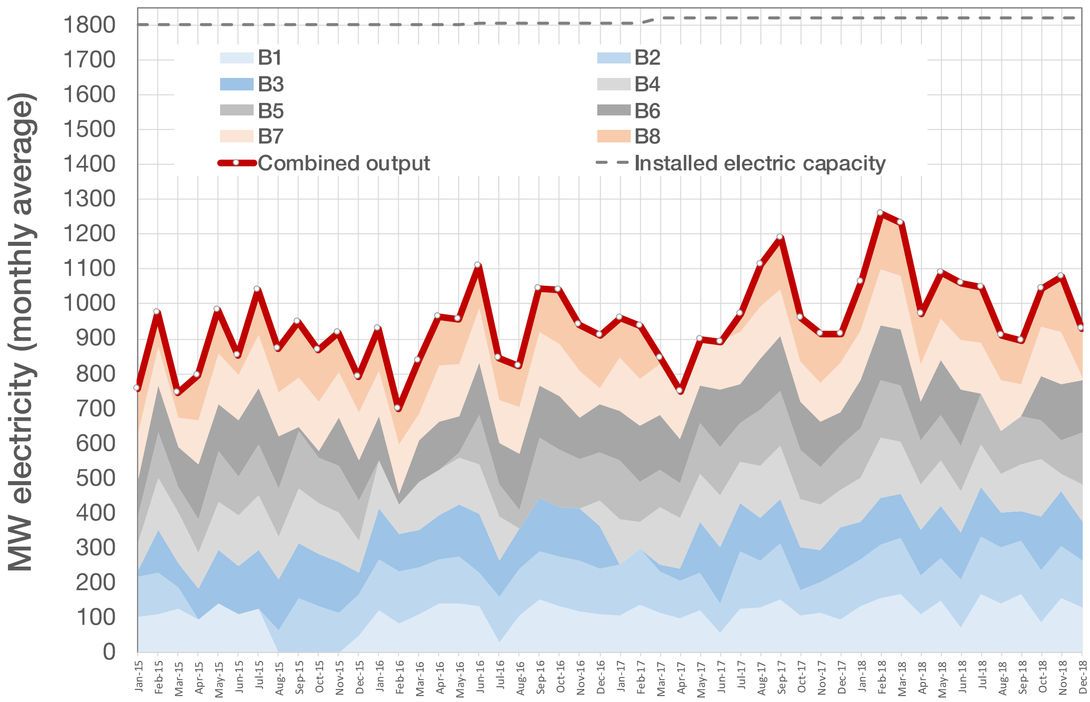

Figure S7. Monthly electricity production at the 200-units of Kozienice, 2015-2018.

The Połaniec plant also consists of eight individual "200-units" (1882 MW_e) commissioned between 1979 and 1983. The steam cycle equipment in six out of the eight units have been modernized in several waves, the first in 1992-1995 and the second in 2013-2015. The boilers can co-fire biomass, and the boiler for unit 8 has been replaced to be able to run fully on biomass feedstock. This unit can therefore already be considered as “retrofit decarbonized” (depending on the sustainability of the feedstock) and is therefore excluded from this analysis. As part of the biomass conversion for unit 8, a new boiler was installed and some of the original steam cycle equipment was replaced. The retrofits included a replacement of the high and intermediate pressure turbine stages (the low-pressure part remained unchanged), and a number of additional smaller changes to bearings and instrumentation & control. This modernization should, according to turbine manufacturer ALSTOM, add 30 more years of operational life to the existing equipment [24]. The Połaniec total site footprint is 2 km^2 for the power plant site itself, and an additional ~2 km^2 for ash handling. The land usage is therefore approximately 2000 m^2/MW, which is at the higher end of the range defined in section 3. The site layout is given in Figure S8.

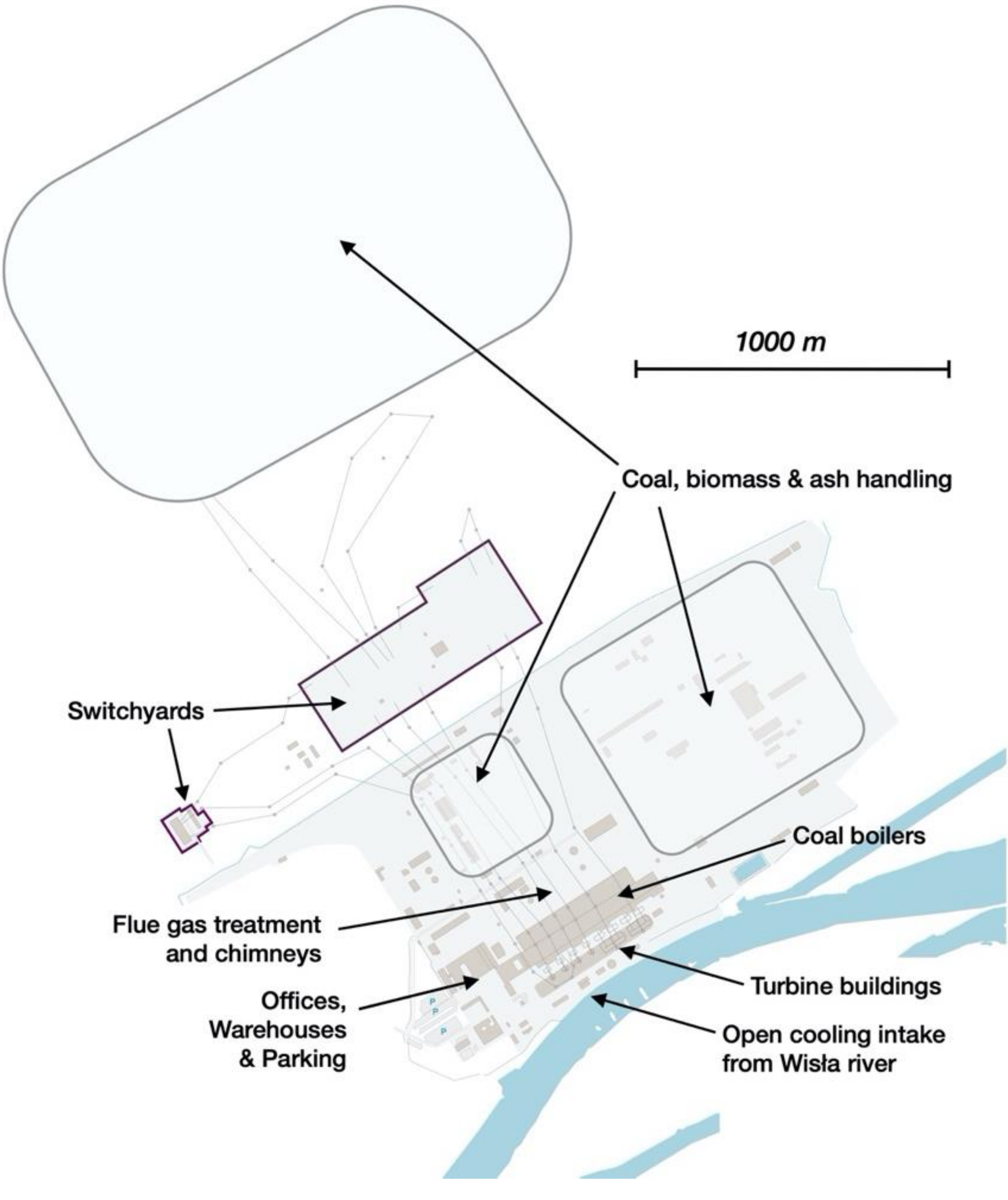

Figure S8. Połaniec Power Plant Site Layout.

The recent performance of the eight 200-units at Połaniec is highly variable. The modernized biomass-fired unit 8 operates at an annual capacity factor of above 70%, among the highest in Poland. The modernized coal burning units (2-4, 6 and 7) operate with a capacity factor of 60-65%, while the un-modernized old units 1 and 5 only manage 30-45%. This clearly shows the toll of age on this units. Figure S9 shows monthly-averaged electricity generation for the units during the period 2015-2018.

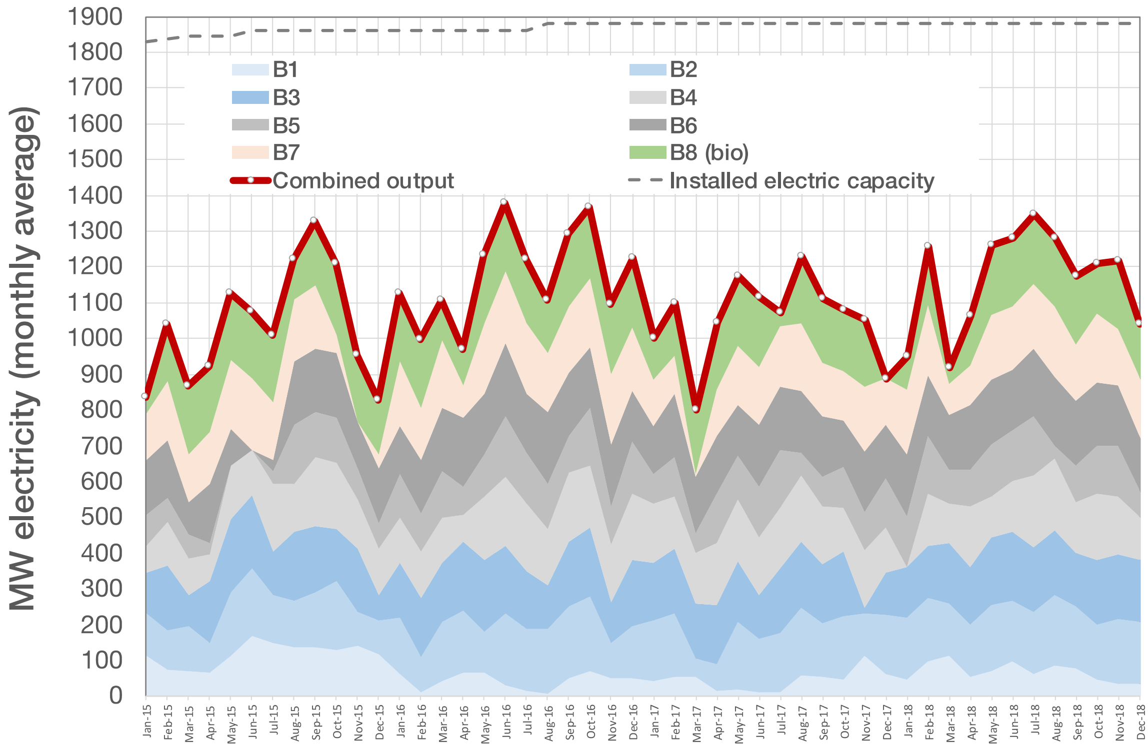

Figure S9. Monthly electricity production at the 200-units of Połaniec, 2015-2018.

4.4. Representative "Large Power Unit": Łagisza Unit 10

The large power unit category consists of a heterogeneous set of units of different designs and characteristics. As a reference plant for this category, the 460 MW unit-10 at the Łagisza power plant was chosen, located in Będzin in southern Poland. The plant began as a seven-unit coal-fired power plant of 120 MW_e each. Out of these seven original units, only two remain in operation today. In 2009, a new 460 MW_e unit was launched. When built, this unit was the world's largest supercritical block with a CFB (Circulating Fluidized Bed) boiler. The gross efficiency is 45%, while net efficiency is between 41,5 to 43,3 %, making it one of the most advanced and efficient coal units in operation in Poland. The boiler was designed and built by the Foster Wheeler and is fed with hard coal as its basic fuel, with additional fuel in the form of coal sludge. The boiler is a sensitive element and has suffered reliability problems. For its first few years of operation, production was interrupted by outages due to problems resulting from erosion of boiler components. Improvements introduced in recent years have significantly increased availability. The turbine unit consists of the turbine 28K460 and the generator 50WT23E-104 supplied by Alstom Power. According to current plans, the equipment at the unit is fit to remain in operation until at least 2046. The Łagisza total site footprint is 0.5 km^2, and the land usage is therefore approximately 700 m^2/MW with the smaller units still in operation, which will rise to 1060 m^2/MW once they are decommissioned. The site layout is given in Figure S10.

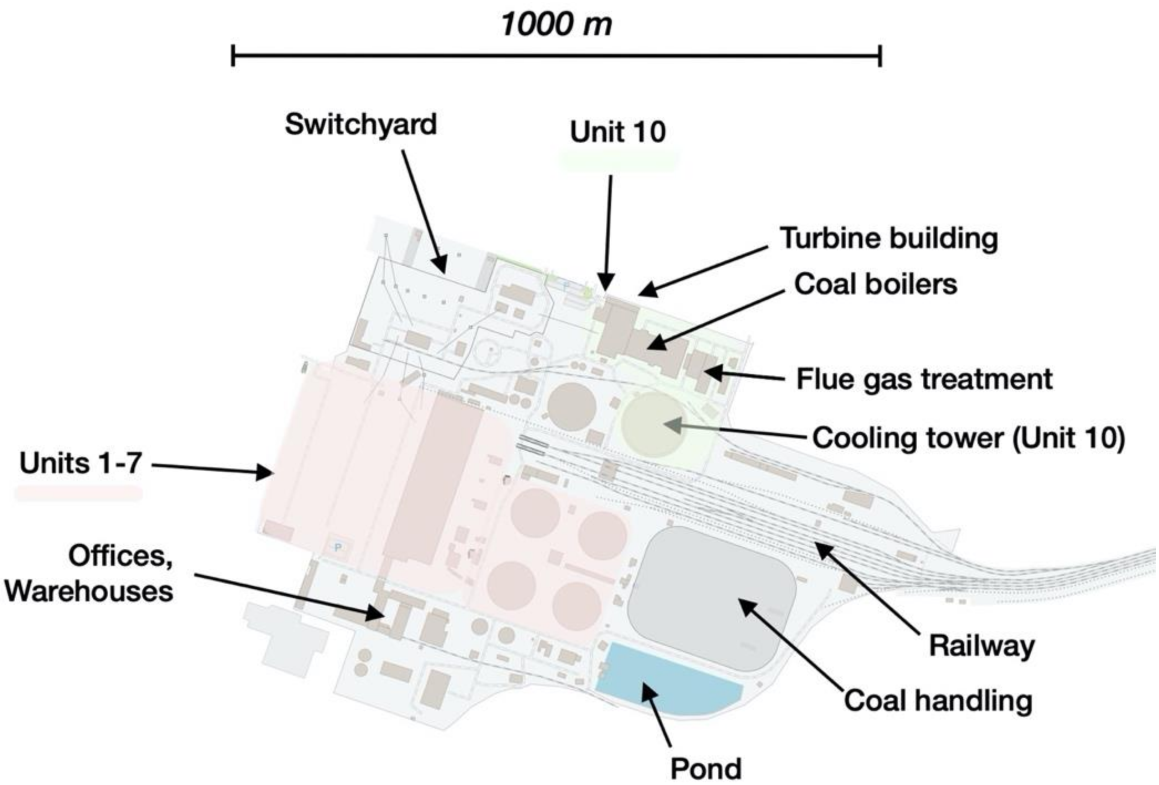

Figure S10. Łagisza Power Plant Site Layout.

The Łagisza plant also currently supplies up to 190 MW_{th} of district heating from the two smaller and older units that are equipped with extraction-condensing steam turbines. To replace the heating supplied by the older small units, the plant plans to install a new 120 MW_{th} heat exchanger that is fed from crossover between the turbine stages in the new unit. The goal of the project is to maintain and possibly increase overall heat sales, which are currently about 280 GWh_{th}/year.

5. Supporting information on geothermal energy in Poland

5.1. Current geothermal utilization in Poland

Figure S11 and Table S6 show the current utilization of geothermal power in Poland.

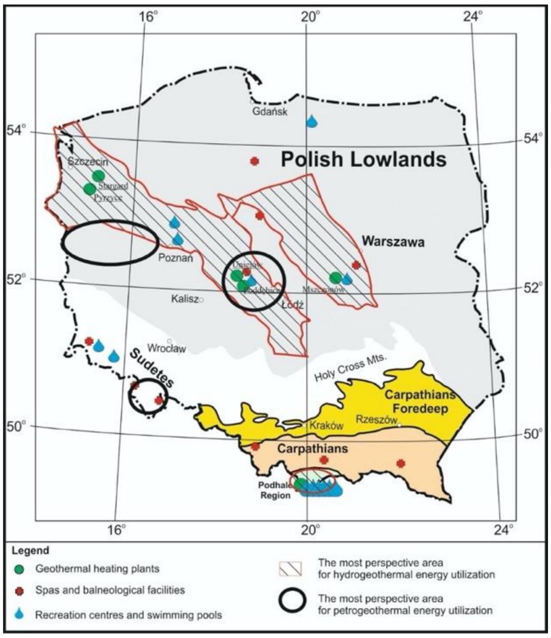

Figure S11. Current geothermal energy utilization in Poland [25].

Table S6. Characteristics of geothermal heating plants in Poland (based on ref. [26]).

Region	Water temperature [ºC]	Max. flow rate [m³/h]	TDS[8] [g/dm³]	Installed capacity [MWth]	Heat production [GWh/y]
Mszczonów	42	60	0.5	3.7	5
Poddębice	68	252	0.4	10	20
Podhale	82-86	960	2.5	40.7	140
Pyrzyce	64	360	120	6	20
Stargard	84	180	150	12,6	50
Uniejów	68	120	6–8	3.2	6
Total				76.2	240

5.2. Geographic distribution of geothermal resources in Poland

Poland is located at the contact of three main tectonic European structures: the Precambrian East European platform, the young Palaeozoic platform of the Western and Central Europe as well as the

[8] Total dissolved solids

zone of Alpine folding of Southern Europe. Each of those structures is characterized by different geological conditions. The hydrogeothermal resource parameters at a depth of 2-3 km of the most applicable regions in Poland are summarized in Table S7.

Table S7. Hydrogeothermal parameters in various regions of Poland (depths of 2-3 km) [27].

Area	**Polish Lowlands**	**Carpathian Foredeep**	**Carpathians**	**Sudets**
Geothermal reservoir	sedimentary	sedimentary	sedimentary	Crystalline, metamorphic
Temperature [°C]	30-130	20-120	20-120	max. 86.7
Discharge of wells [m3/h]	high, locally even above 300	usually less than 20, the exception is the Cenomanian aquifer - max. ca. 250	from low in Outer Carpathians to up to 550 (Inner Carpathians - Podhale)	from several to several dozen
Water mineralization [g/L]	Varied, locally high, sometimes exceeding 300	Varied, locally high, sometimes exceeding 300	from several to 120	To ca.10
Perspective areas	Mid-Polish Trough	Central part	Podhale	Cieplice and other

The highest geothermal energy potential in Poland are in the Polish Lowlands and in Podhale in the Carpathians mountain region. In the Polish Lowlands, the most interesting area is that of the Mogilno-Łódź Syncline, where there are real prospects for the use of geothermal resources for energy purposes (both heating and electricity production in binary systems) and possibly EGS installations in sedimentary rocks. In the rest of Poland, the prospects for effective use of geothermal resources is limited due to low well capacities [28].

The Polish Lowlands

One of the most prospective regions for hydrogeothermal energy development in Poland is connected with the **Polish Lowlands** [27]. Water in these areas is characterized by favorable temperatures (reaching >90°C) and favorable values of well discharges (up to several hundred m^3/h). The principal resources of geothermal waters in the Polish Lowlands are present in Mesozoic rocks. Geothermal waters have accumulated primarily in Lower Jurassic and Lower Cretaceous strata. The Polish Lowlands also is one of the most prospective areas for geothermal energy utilization in an Enhanced Geothermal System [29] [30]. Reservoirs favorable for EGSs, Carboniferous and Lower Triassic sandstones, are located in the central part of Poland (the Mogilno-Łódź Trough region and small parts of the Kujawy Swell and Fore-Sudetic regions).

Carpathian foredeep

In the **Carpathian foredeep**, geothermal aquifers only occur in small areas and at narrow depth intervals. The Cenomanian aquifer is the sole exception, since high discharges (up to 250 m^3/h) can be expected over the whole area of its occurrence in the central part of the Carpathian Foredeep. Zones with increased potential well discharges are sporadically encountered in the Upper Jurassic (tens of m^3/h) and in the Miocene aquifers (>100 m^3/h). The best hydrogeological and geothermal parameters occur in the depth interval 500-1500 meters. The remaining depth intervals have no prospects for development because of low temperatures or weak hydrogeological parameters that determine low discharges at geothermal water intakes [31] [32].

The Carpathian Mountains

In the Carpathians, the best reservoir and exploitation properties for geothermal water utilization occur in the Podhale region in the inner Carpathian. The area is represented by high yields and a low fraction of dissolved solids in the water. The most promising aquifers are located at depths of 1.0-3.7 km. In the remaining parts of the Carpathians, reservoir parameters are much less favorable. Geothermal aquifers in the Outer Carpathians are characterized by small resources and high mineralisation, which excludes their wider use for energy production [33].

Sudetic geothermal region

Quite different geothermal conditions are present in the **Sudetic Geothermal Region**. This region lies in the south west of Poland and includes the Sudete Mountains and the Fore-Sudetic Block. Geothermal waters occur in this region only within crystalline rocks. Most of the limited hydrogeothermal investigations carried out so far in the Polish part of the Sudetes were restricted to zones of occurrence of thermal waters already utilized for therapeutic purposes [34]. However, parts of the Sudetic region are characterized by favorable thermal conditions. In Cieplice, water at 86.7ºC was obtained from 2 km depth. For this reason, the Cieplice area in the Sudetic geothermal region has been studied to identify a prospective location for an EGS project in Poland [25] [35].

5.3. Polish and International Experience with High-temperature Geothermal

Based on international experience [36] [37] [38] [39], the requirements for the development and exploitation of such resources in Poland have been specified, and include:

- Temperature of the rocks: >150°C
- Thickness of the reservoir: minimum 300 m
- Suitable porosity and permeability of the reservoir rocks
- Depth of the reservoir: 3-6 km

Just 25 deep wells drilled in geothermal fields such as The Geysers, Salton Sea, and on Hawaii (USA), Kakkonda (Japan), Larderello (Italy), Krafla (Iceland), Los Humeros (Mexico), and Menengai (Kenya) have encountered temperatures in excess of 374 °C [40]. Recent, ongoing and proposed field studies related to supercritical geothermal systems include the Iceland Deep Drilling project (IDDP), the Krafla Magma Testbed project (KMT), the Japan Beyond Brittle project (JBBP), the DESCRAMBLE project (Drilling in dEep, Super-Critical AMBient of continental Europe) at Larderello, Italy, the Hotter and Deeper (HADES) project in the Taupo Volcanic Zone of New Zealand, the GEMex joint EU-Mexico project in Mexico, and the Newberry Deep Drilling project in the USA [40].

The Iceland Deep Drilling Project at Reykjanes (IDDP) passed a significant milestone in the geothermal industry when its IDDP-2 well at the Reykjanes Peninsula in Iceland reached the depth of 4,659 meters on the 25th of January 2017, after 168 days of drilling. The aim of the IDDP was examine the economic potential of supercritical geothermal systems[9]. By drilling the IDDP-2 well at Reykjanes to 4,659 m depth, which has a bottom hole temperature about 535°C, the project demonstrated for the first time that it is possible to drill into active supercritical conditions**.** The exploratory well IDDP-2 was drilled in the Reykjanes geothermal field in south-west Iceland, on the landward extension of the Mid-Atlantic Ridge [41]. If reliable electricity generation from such a resource would be proven elsewhere in the near term, this would open the door to analyze more closely the retrofit decarbonization options of tapping similar resource qualities in Poland. However, while such conditions can be found at less than 5 km in Iceland, in Poland, such temperatures are not available at depths less than 10 km. Thus,

[9] Sometimes called "superhot rock geothermal" (SHR) to distinguish from sub-critical EGS system with sub-supercritical conditions.

both technologies able to reliable withstand aggressive fluids at high temperatures, as well as cost-effective >10 km drilling technologies, will need to be developed for there this to be a real prospect in Polish conditions.

5.4. Deep drilling technologies

High-temperature geothermal resources in Poland are found in deeper and harder geologic formations than typical hydrogeothermal resources and hydrocarbon reservoirs. Present day drilling methods (developed for hydrocarbon extraction), still rely on technologies based on conventional rotary drill bits to mechanically break the rock. Drilling technologies and processes from oil and gas industry have been continuously improved to make more efficient and economic drilling processes based on this type of technology [42], but is difficult to apply to very deep and hard rock drilling that would be required to tap in to >500°C geothermal resources in Poland. New drilling methods relying on alternative rock breaking mechanisms are under development worldwide, including:

- Thermal spallation [43] [42] [44]
- Hammering [45]
- Electro-impulse [46]
- Plasma [47]
- Hydraulic jetting [48]
- Laser Jet Drilling (LJD) [42] [49] [50]

This new drilling technology has many potential advantages, but the prospects have not yet been supported by deep drilling results. These are projects in the research or laboratory phase [42]. New drilling technology was proposed among others by GA Drilling Company [51] developing the technology platform “PLASMABIT” for deep drilling. According to the company, the PLASMABIT drilling technology enables efficient drilling of production wells up to at least 10 km deep. The company has accomplished several generations of prototypes and patents, but the application of plasma drilling is still in the pre-market testing phase. Therefore, currently there is no commercially availability of this technology.

5.5 Illustration of coal plant retrofit decarbonization by deep-drill EGS

An illustration of a coal plant converted to an EGS plant can be found in Figure S12.

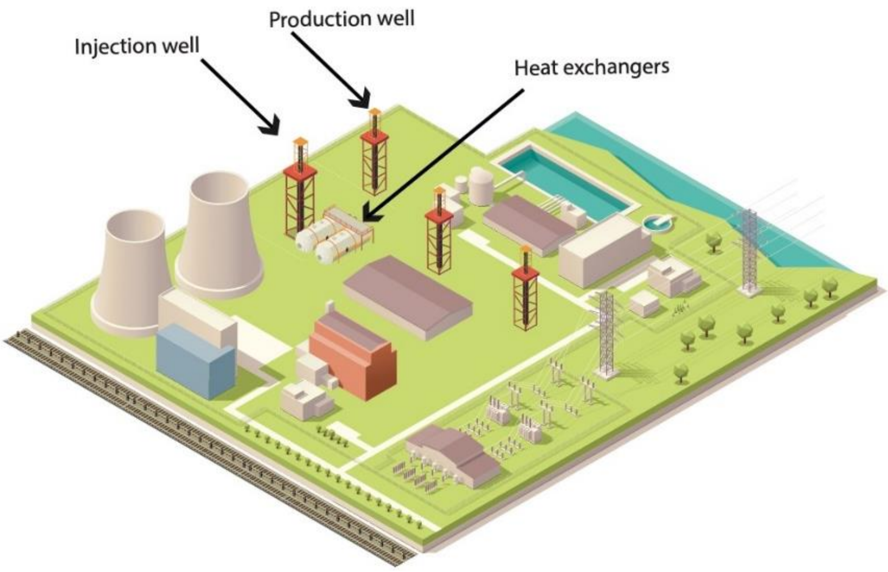

Figure S12. Coal plant converted to an enhanced geothermal system plant.

6. Supporting information on nuclear power for coal retrofit

6.1. Licensing experience with smaller emergency planning zones

No commercial power reactor has ever operated in Poland, and detailed information on planning zone sizes were not found. The current emergency planning of nuclear power plants as seen in Table S8 were developed based on the accident characteristics of early large light water reactors (LWRs) [52].

Table S8. Present-day (large LWR) evacuation zone criteria.

Country	Radius of evacuation zone or equivalent, km
France	5
Germany	10
South Africa	10
United States	16
Japan	8–10
United Kingdom	3
Canada	10–13
Russia	5
China	3–5

The development of more detailed source term analysis [53] and the general improvement of LWR safety characteristics [54] have initiated new discussions on the principles of emergency planning, even for large conventional LWRs. The 1992 Utility Requirements Document by the US-based Electric Power Research Institute (EPRI) suggested updates to LWR emergency planning [55]. Similarly, the European Utility Requirements (EUR), which was jointly developed by major European utilities, also requests the simplification of emergency planning for future LWRs [56]. There are also more specific studies on updated emergency planning for specific newer-generation large LWRs such as the AP1000 [57] and the AP1400 [58], which recommend a reduction in the size of emergency planning zones (EPZ) based on technical analysis.

More recently, utilities and developers within the membership of the Nuclear Energy Institute (NEI) worked to develop methodologies to a much support smaller EPZ for small modular reactors. Since late 2015, small modular reactor developer NuScale has submitted topical reports to the US Nuclear Regulatory Commission (NRC) detailing a proposed methodology, which aligns closely with the NEI approach, for NuScale Plant licensees to determine more appropriate, and smaller, EPZs [59]. Simultaneously, the US utility TVA (Tennessee Valley Authority) included in its 2016 early site permit application (ESPA) a request for an exemption from the current emergency planning regulations for siting of a small modular reactor at the Clinch River site. As part of the review of the TVA exemption request, a July 2018 NRC staff audit report found that a NuScale plant at the Clinch River site would meet the conditions for shrinking the EPZ down to the plant boundary [60]. In December 2019, the NRC granted TVA its exemption from a 10-mile (16 km) EPZ for future combined construction and operating license applications for SMRs. In parallel with these efforts, the NRC has developed a change to the U.S. regulation governing emergency planning that would enable a performance-based, scalable EPZ for any new SMR, which includes reduction of the EPZ to the site boundary if performance requirements are demonstrated [61]. Such a regulatory development should enable SMRs to be sited at essentially any existing coal power plant.

All published results of possible severe accidents analysis for novel reactor systems indicate that offsite consequences will not exceed the protective intervention levels at any distance outside of the plant boundary itself. For the HTR-PM, detailed analysis indicate regulatory compliance while limiting any and all emergency planning to within 500 meters of the reactor buildings: "The consequence estimation reveals that HTR-PM will not influence the area outside the site of nuclear power plant" [62]. Since the first HTR-PM demonstration plant is sharing the plant site with several large PWRs, the HTR-PM developers have not insisted on legally eliminating the off-site emergency response, but are still developing the documentation required to prove that it can be technically eliminated [63]. Given these developments, it is reasonable to assume that siting of new and inherently safe small modular nuclear reactors at existing coal sites, even at CHP plants sited fairly close to large populations centers, will not be a hindrance in terms of regulatory approvals.

6.2. Seismic analysis and activity in Europe and Poland

The geology of the proposed site and the surrounding area must be investigated to find out the local faulting pattern. Historic research is carried out in order to estimate the location and size of any earthquakes that may have occurred in the general area in the past. For some sites it may also be necessary to place sensitive detectors at various places in the locality of the site to monitor the occurrence of very small seismic events. All this information can be put together to assess the probability of earth quakes of various sizes at the site. While such surveys have already been carried out for the siting of existing coal power plants, the requirements for this with regard to the construction of nuclear facilities are far more stringent. Nuclear reactors are designed to safely withstand a certain magnitude of earthquake, and if local conditions indicate a probability for a larger earthquake or higher ground acceleration than the design basis, siting will not be possible without revising the design. Revisions may include to seismically isolate the reactor building, which would allow for a higher ground acceleration to be accepted in the safety case.

The first application of seismic isolation to a nuclear power plant was completed at Cruas, France, where 4 reactor buildings were isolated in a plant that began operation in 1983-1984. An identical implementation was also done for two reactors of the same type in Koeburg, South Africa. In both cases, the choice to add seismic isolation was done to keep the rest of the design unchanged with respect to other reactors of the same type already designed or built, in places with lower seismicity. Typically, LWRs have been designed for an expected 0.2 g peak ground acceleration, while the more active Cruas area required the units to withstand 0.3 g. The cost of adding the isolation system at Cruas was equivalent to about 2-3 % of the total civil works cost.

Poland is one of the most seismically stable countries in Europe. Only the southernmost mountainous border region with Slovakia and the Czech Republic has expected peak ground acceleration magnitude and probability of occurrence high enough to be of any real safety analysis interest to nuclear power plant siting (see Figure S13). Figure S14 shows a map of all major earthquakes in Poland over the past millennium (year 1000-2006), Figure S15 further shows the very low degree of activity in Poland compared to the rest of Europe. Compared to nearby existing nuclear-power nations such as France, Switzerland, Spain, Slovakia, Czech Republic, Bulgaria, Hungary, Slovenia, Romania, and new-comer nations such as Turkey, seismic siting considerations are not expected to be a problem of note in general in Poland at any site. One specific consideration to assess more carefully in terms of retrofit decarbonization of coal units are the risks of induced seismicity due to coal mining activities, which primarily is a potential issue at sites located adjacent to large lignite mines, such as Bełchatów [64].

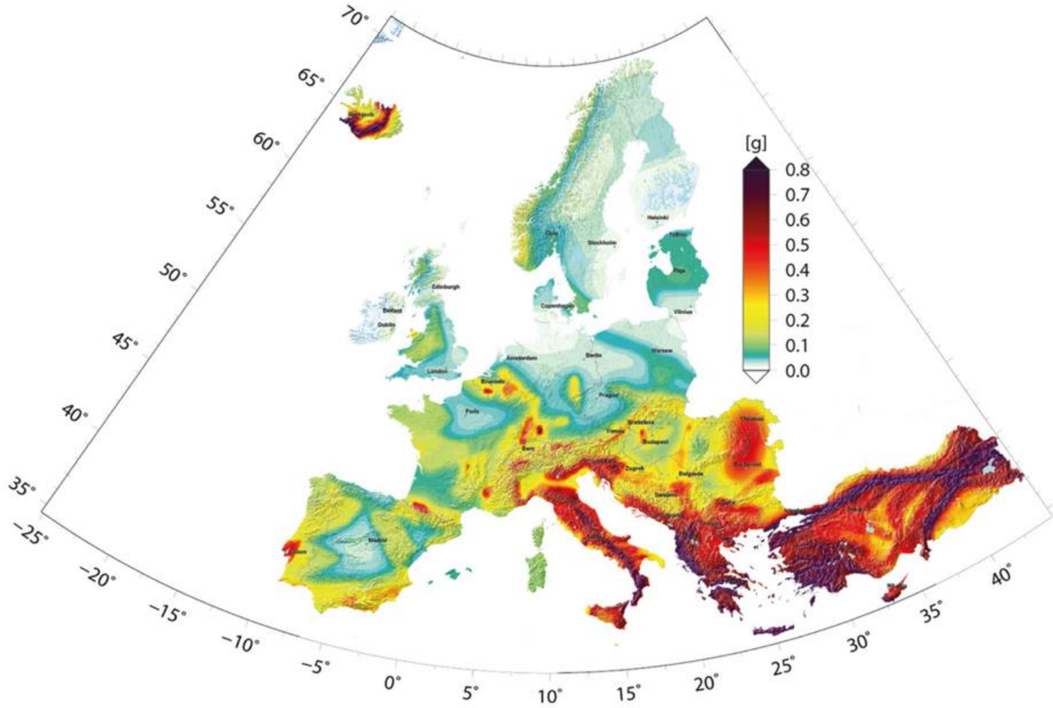

Figure S13. Peak Ground Acceleration (PGA) exceedance probabilities of 2 % in 50 years (average return period of 2475 years, reference rock velocity of vs = 800 m/s) [65].

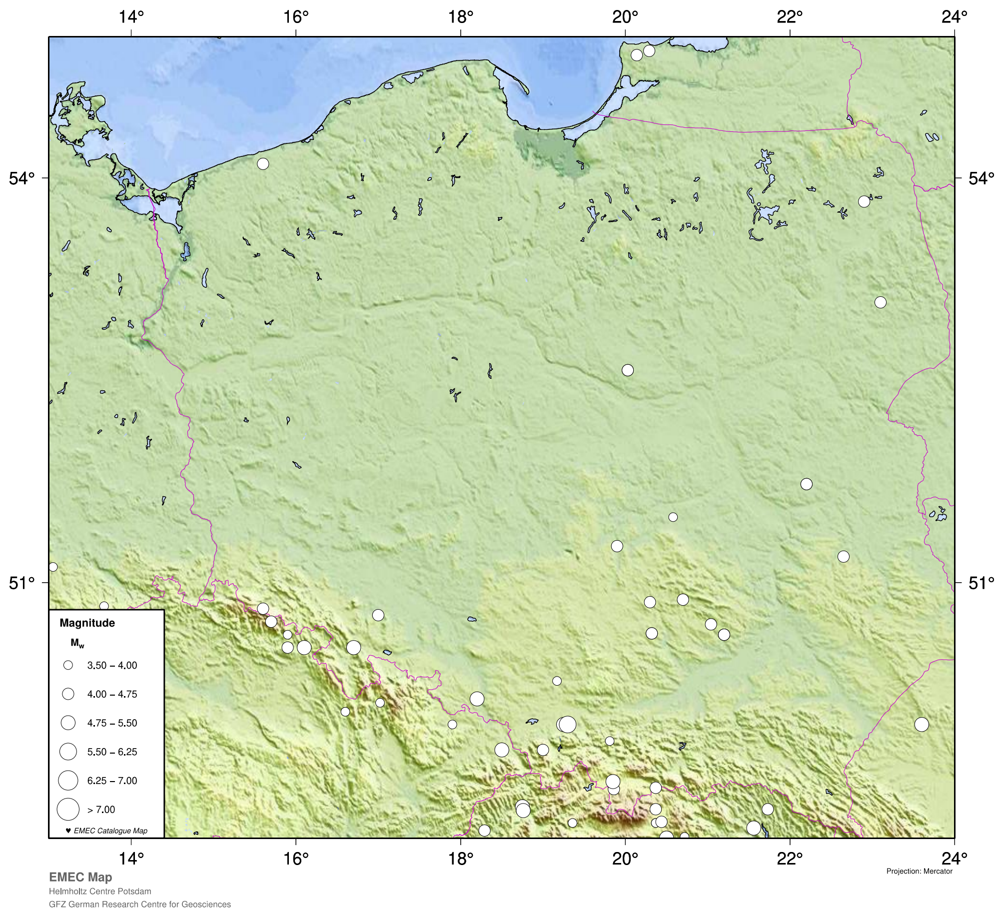

Figure S14. Earthquakes in Poland, year 1000-2006 (developed from ref. [66]).

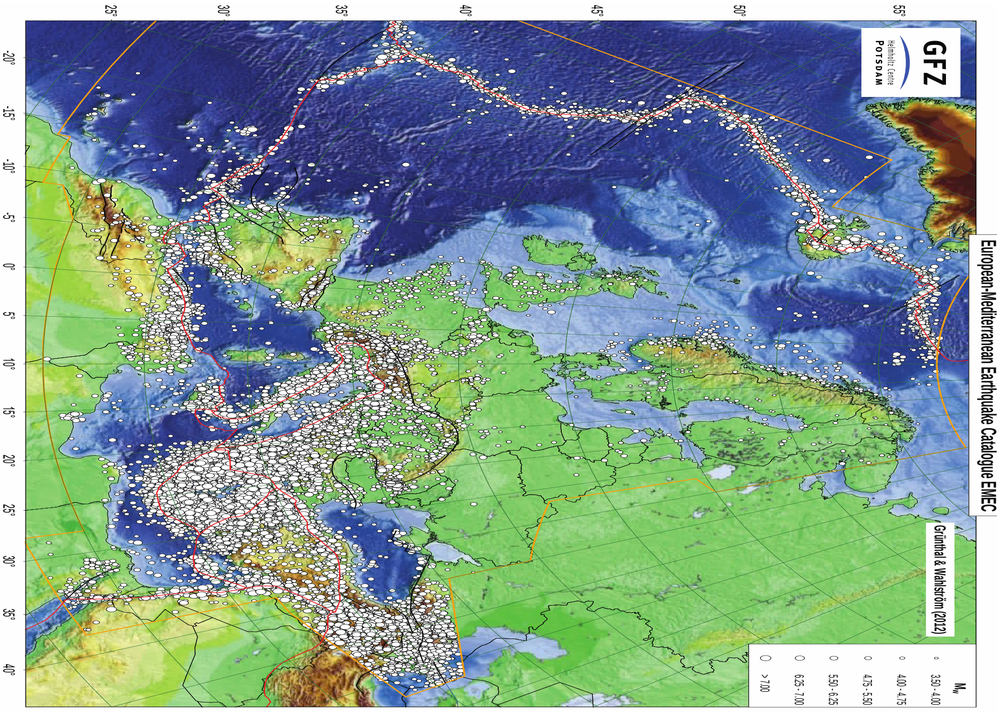

Figure S15. Earthquakes in Europe, year 1000-2006 (developed from ref. [66]).

6.3. Land footprint comparison between coal and nuclear power

The total direct land use requirements for nuclear reactors vary even more dramatically than for coal power plants in available data. The US Nuclear Regulatory commission has published the "total site area" of 67 licensed nuclear power reactor sites in the United States [67]. The footprint of these sites varies from 130 m^2/MW for the San Onofre units in California, up to a maximum of 70 000 m^2/MW for the Turkey Point site in Florida[10]. Just as for coal power plants, the power units (reactor and turbine buildings) typically take up a minor fraction of the total land, so any differences between different types or generations of nuclear reactor technology on total land use is a second order effect. Historically, nuclear power plant owners often acquired significantly more land than was needed to physically fit equipment, both to allow for future expansion but also, often primarily, to comply with explicit and implicit regulatory requirements relating to off-site radiological consequences in the case of a severe accident. The larger the plant footprint is, the smaller the difficulties in off-site emergency planning becomes. Such considerations are expected to be considerably less important with the newer, often smaller, generations of nuclear reactor technology currently being brought to market. Almost without exception, vendors are aiming to be licensed these systems with very small emergency planning zones, extending only to the site fence, which is in close proximity to the buildings and components that make up the power plant. Thus, the power capacity per area footprint for these plants are likely to be in line with the highest areal power density plants of the older generation. The required footprint of nuclear power plants ranges from roughly 130 m^2/MW for open-cooling plants, up to 500 m^2/MW for plants

[10] Turkey Point uses a unique cooling system consisting of a huge network of canals, which take up most of the total "land" area of the site. The canals were excavated to replace sea outfalls that had created a thermal plume in Biscayne Bay and was killing turtle grass. Summer sea temperatures are 30-35°C to which a 10-15°C temperature increment (ΔT) was added because of the power plants. Four units (two oil/gas; two PWRs) are now cooled by a system of 32 warm canals and eight return canals. The canals are about 60 m wide, separated by 27 m wide berms. The total length is about 270 km, giving an effective surface area of 16 km^2.

with natural draft cooling towers, as summarized ranges from roughly 130 m^2/MW for open-cooling plants, up to 500 m^2/MW for plants with natural draft cooling towers, as summarized in Table S9.

Table S9. Minimum footprint requirements for nuclear power plants.

Nuclear Plant Category	Footprint	Example plant
Open cooling (no cooling towers)	130 m^2/MW	San Onofre
Mechanical or Natural draft cooling	350-500 m^2/MW	Catawba & Limerick

6.4. Nuclear Reactor Units Evaluated

6.4.1. HTR-PM

The High Temperature Reactor – Pebble-Bed Module (HTR-PM) is 250 MW_{th} small modular reactor unit cooled by helium gas, developed in China. The R&D program for the high-temperature gas cooled reactors at Tsinghua University began in the mid-1970s, and accomplished the construction of the HTR-10 test reactor in the 1990s [68]. The HTR-PM is the next step in this development, taking the HTR-10 as a prototype and the previous research and demonstration units in Germany and the United States as references. The first power plant utilizing HTR-PM units is currently (in 2020) in the final stages of finishing construction work at Shidao Bay in Shandong province, China. The demonstration plant uses two HTR-PM modules coupled to one steam turbine cycle (500 MW_{th}, 210 MW_e), while the commercial HTR-600PM plant to follow will use six HTR-PM modules (1500 MW_{th}, 630 MW_e).

In the original design, two HTR-PM reactors are housed in one reactor building, regardless of the number of total units that are to be used. According to ref. [63], a power plant with two HTR-PM600 modules (12 HTR-PM reactor units, 6 reactor buildings) takes up a direct land footprint of 200 x 120 meters (24000 m^2), excluding the footprint of the turbine island but including fuel handling facilities and auxiliary and electrical buildings. Based on the site schematic, a single HTR-PM600 plant (six HTR-PM reactor units) likely takes a footprint of 120 x 120 meters (14400 m^2). The four-unit HTR-PM retrofit of the Łagsiza B10 unit can conservatively be assumed to take up a total direct footprint of about 100 x 100 meters. A more recently proposed redesign reduced the HTR-PM normalized building size by 50 %, by bundling six rather than two units per reactor building [69].

The reference HTR-PM modules raises the temperature of its pressurized (7 MPa) primary helium coolant from 250°C at the inlet to 750°C at the core outlet. The reactor units are coupled to single-pass (no reheat) steam generators. In the reference steam generator, water at 13.25 MPa pressure is heated from temperature of 205°C to produce an outlet steam temperature of ~570°C. On-going design work at Tsinghua University aims to redesign the reference steam generators to work at supercritical pressure with reheating, and a peak steam temperature of 600°C [70]. For most gas-cooled reactor concepts, including HTR-PM, the primary reactor coolant goes directly to the steam generator (salt and metal-cooled systems typically have intermediate loops in-between), which means the steam generator is a pressure boundary for the primary coolant forms an integral part of the reactor safety case. Because of this, no major redesign of the reference existing HTR-PM subcritical and supercritical steam generator designs was allowed out as part of this work.

6.4.2. Kairos KP-FHR

The Kairos Power Fluoride salt-cooled High temperature Reactor (KP-FHR) is a U.S.-developed reactor technology based on two decades of research and development (R&D) at universities and national laboratories, centered on the University of California Berkeley. The fundamental concept of the KP-FHR is the novel combination of solid fuel pebbles and a fluoride salt coolant. The Kairos team aims to finalize the conceptual design of the plant by the end of 2020, and to have a finalized product with full licensing documentation ready for construction of a demonstration plant in the US before 2030 [71] [72].

The combined KP-FHR reactor building, its associated fuel handling and auxiliary building, and steam generator and collection buildings, have a combined footprint of 90 x 60 m (5400 m^2) per unit, that will need to be constructed for integration with existing coal plant steam cycles. The total footprint required for the three-unit integration at the Łagisza B10 unit is approximately 100 x 50 meters for three reactors spaced 20 meters apart, and one steam generator and collection building of 30 x 60 meters.

Like most salt-cooled nuclear system concepts, the KP-FHR utilizes an intermediate heat transfer loop between the reactor coolant salt and the steam cycle. The intermediate loop heat transfer medium is "solar salt", which is a combination of Sodium and Potassium Nitrate ($NaNO_3$-KNO_3). One limitation of solar salt is a thermal decomposition temperature in the range of 600°C, which limits the upper temperature of the intermediate loop and the subsequent steam generation. The KP-FHR cycle is designed to generate 585°C steam from the solar salt using a steam generator with reheating. Since the steam generators of the KP-FHR do not perform any safety-critical function and are presently in an early-conceptual state of design maturity, we have allowed for new designs of steam generators in this study, while adhering to the constraints of using solar salt as the intermediate loop medium.

6.4.3. Generic Molten Salt Reactor (MSR)

A large number of molten salt fuelled and cooled nuclear reactor (MSR) concepts are under active development worldwide with varying degrees of financial backing, seven of which are included in the summary table of the main paper. In terms of process parameters of relevance to this study, these systems are similar to one another, with the only major difference being the thermal power output per unit. To increase the reactor unit and coal unit pairing options, a "generic" MSR option was introduced, with most of its process parameters based on one version of the ThorCon MSR design [73]. The thermal power level of the "generic MSR unit" (275 MW_{th}) corresponds to the median of the most mature MSR concepts under development.

For the 2 generic MSR units coupled to one 200-unit, the total expected footprint is 50 x 50 meters, while the footprint of a single MSR unit coupled to the CHP unit is 40 x 20 meters. Nearly all MSR concepts expect to use solar salt or similar in an intermediate loop to produce steam at a temperature of 570-585°C. While some are presently planning for subcritical steam cycle pressures and others for supercritical conditions for the reference plants, these components have no reactor safety relevance and are not part of the safety licensing case, so there is considerable flexibility in their design.

6.5. Establishing construction sites

Reactor buildings and associated auxiliary structures can easily fit on most, if not all, existing coal power plants as part of retrofit decarbonization, but it is equally important and often more challenging to find available space for the establishment of the associated construction sites. In general, temporary construction areas for a coal plant are accommodated on the (future) coal store areas, indicating that new nuclear reactor building construction sites could also be established on these existing areas [74]. For a large, 1000-1200 MW_e non-modular nuclear power plant, a minimum of ~0.3 km^2 of area is required to provide adequate working and storage areas for the contractors and for construction car and bus parks [74]. In addition, storage space will be required for topsoil removed during excavations and for excavated material required for backfill. The current full construction site at the 3200 MWe Hinkley Point C is 1.7 km^2 large [75], or about 500 m^2/MW, while the total construction site are of the 1200 MW_e Sizewell B (built in the 1990s, shown in Figure S16) is about 0.8 km^2, or 650 m^2/MW. Both of these example units are of very large, non-modular light water reactors, whose construction included not just reactor buildings but turbine buildings, auxiliary buildings, cooling systems and switchyards.

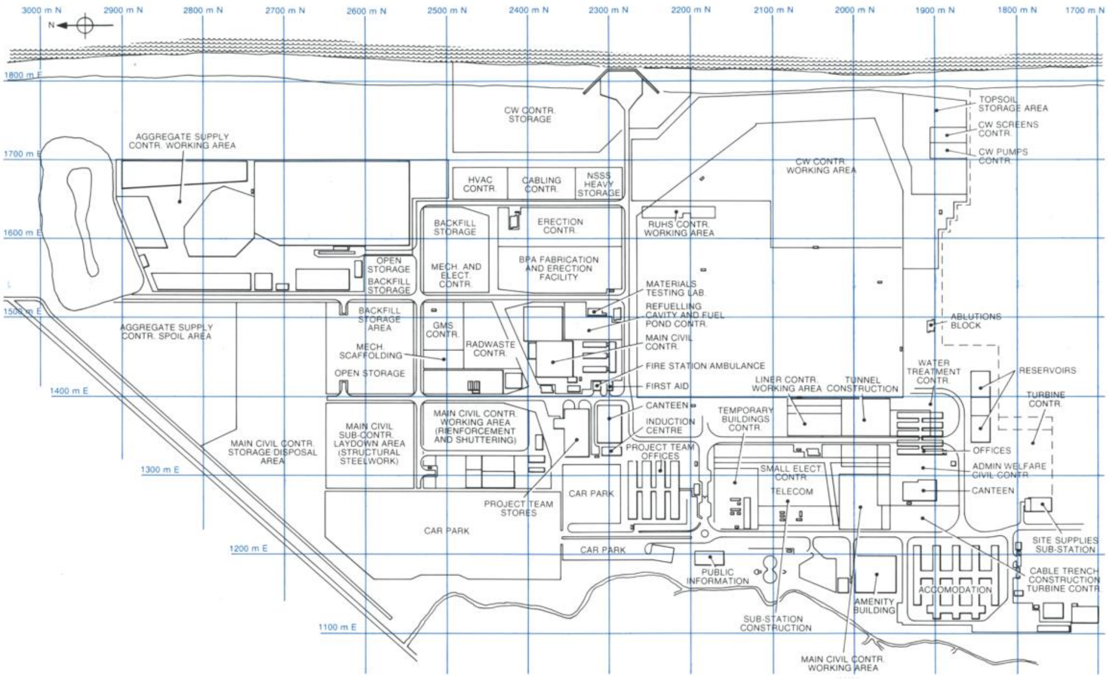

Figure S16. Sizewell B construction site layout [74].

The reduced on-site construction requirements due to the higher fraction of factory prefabricated modular components in any SMR can be assumed to reduce normalized construction site footprint requirements by at least 25 %. A further reduction of construction site size of at least 25 % is possible due to the re-utilization of existing equipment and buildings, which lead to an approximate coal-to-nuclear retrofit decarbonization construction site requirement of ~200 m^2/MWe. For the largest unit implementation analyzed here, the decarbonization of the 460 MW$_e$ Łagisza B10 unit), that would imply a total construction site size requirement of approximately 100,000 m^2 (300 x 300 meters). The full step-by-step process of converting a coal power unit to use a nuclear heat source is shown in Figure S17–Figure S19.

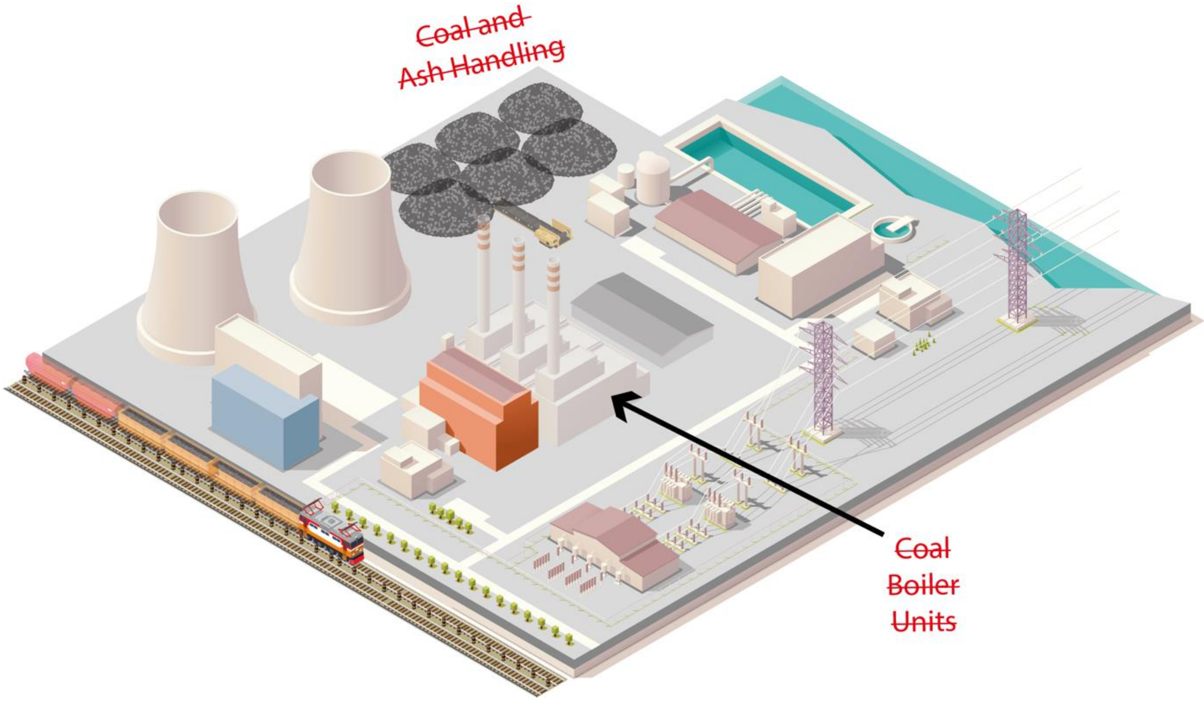

Figure S17. Step 1: Decommissioning coal-related on-site equipment.

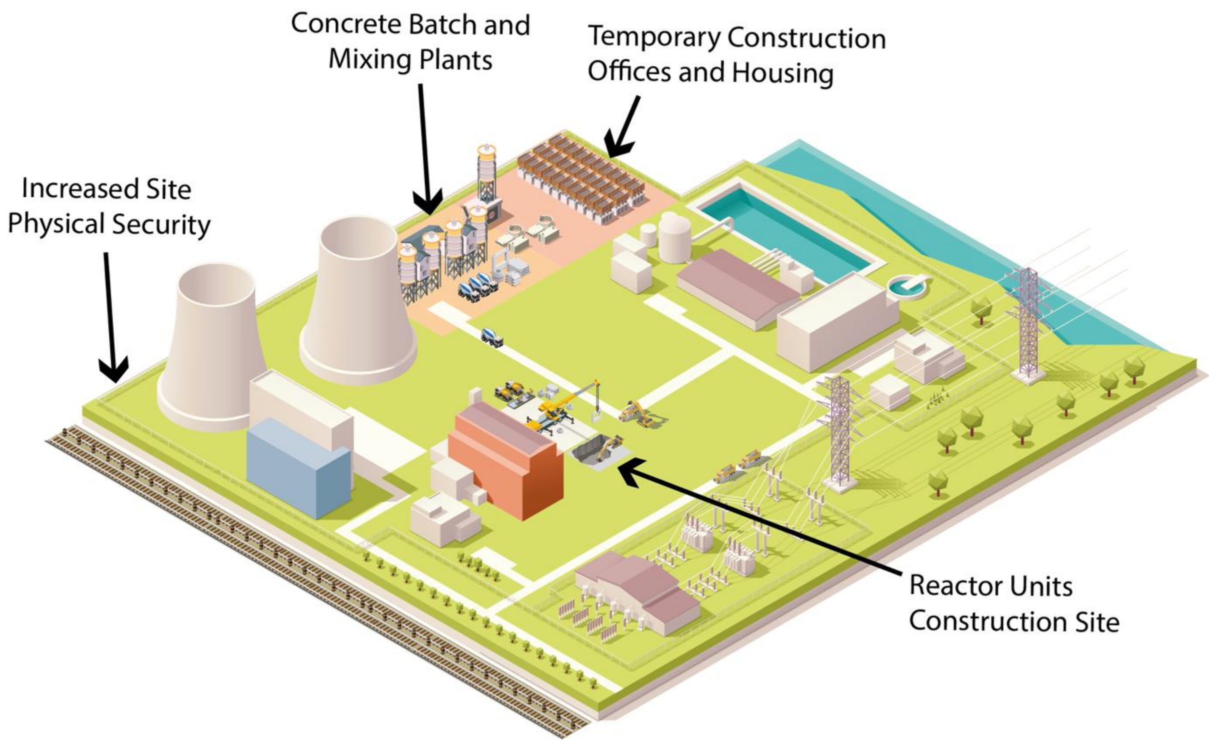

Figure S18. Step 2: Establishing nuclear reactor building construction site.

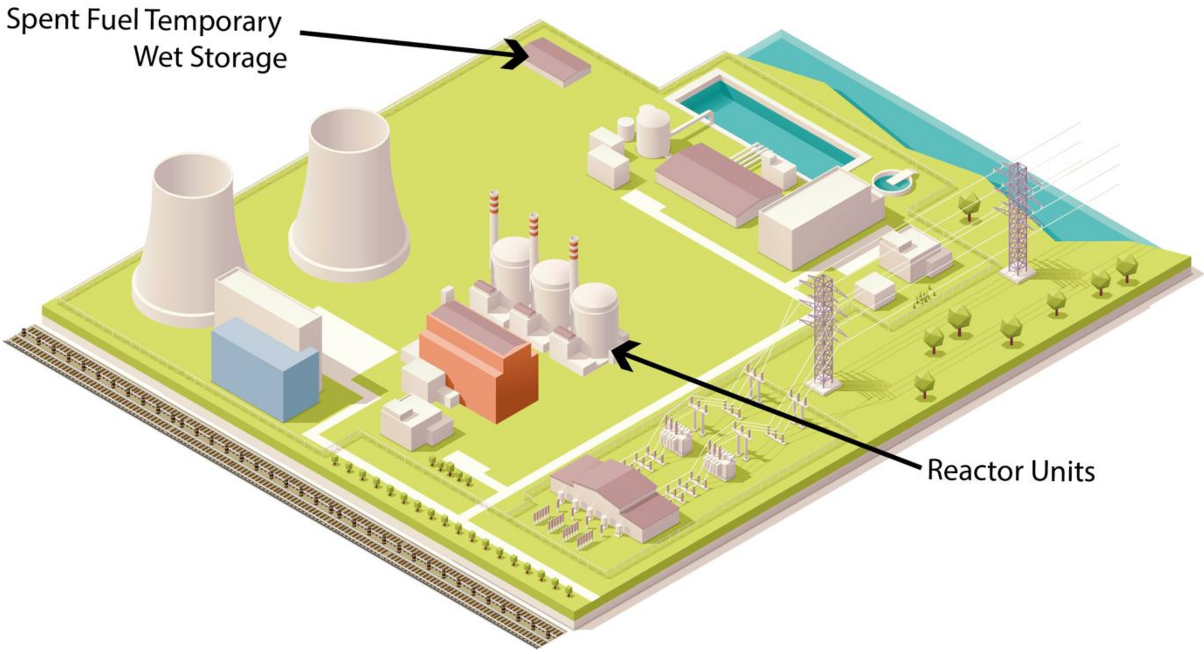

Figure S19. Step 3. Finished retrofit decarbonized coal site.

The approximate footprint of new reactor buildings, as well as the available (not required) construction area site at Łagisza, Kozienice, Połaniec and Chorzów power plants are given in Figure S20–Figure S23. Figure S20 shows the Łagisza 460 MWe unit decarbonized using three KP-FHR units, constructed in such a way the coal plant can remain in operation while the reactor buildings are being built. Figure S21 shows the Kozienice plant, where a number of smaller "200"-unit coal boilers are decarbonized by nuclear reactors, while the larger units are decarbonized through the addition of post-combustion carbon capture. Figure S22 shows the more straightforward complete decarbonization of the eight "200"-units of the Połaniec plant with nuclear reactors. Similarly, Figure S23 shows the two units at CEZ Chorzów decarbonized by two new nuclear reactors constructed on site. In each analysed case, there does not appear to be a major issue with available space to establish a construction site for nuclear reactors. However, at some sites (such as CEZ Chorzów) coal unit operation will likely not be possible during reactor building construction, since the on-site coal storage space will need to be fully utilized for construction-related equipment.

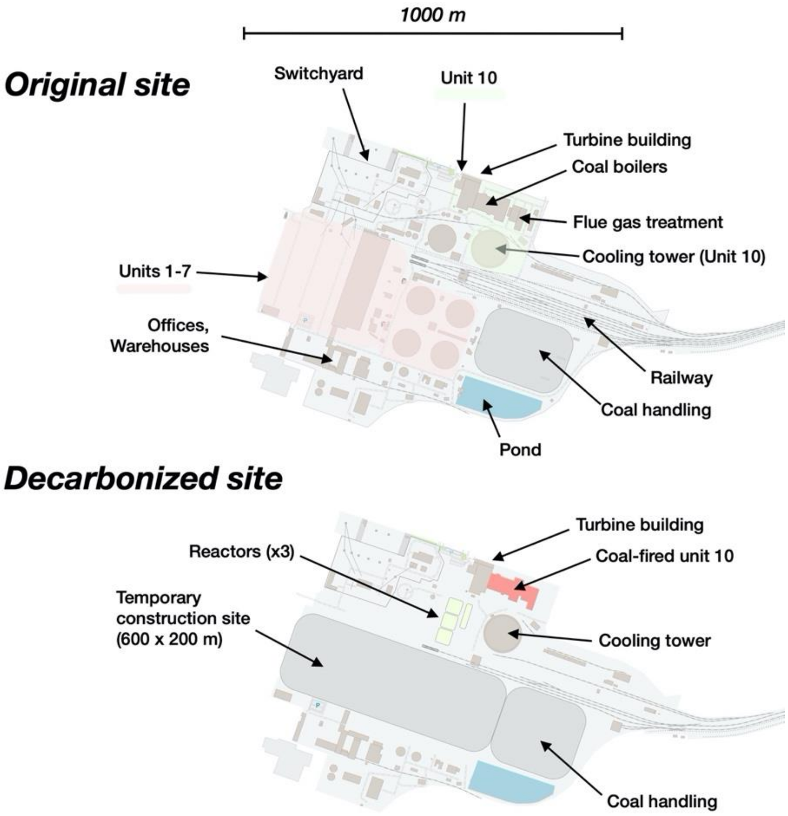

Figure S20. Retrofit decarbonization of Łagisza unit B10 with 3xKP-FHR, while unit remains in operation.

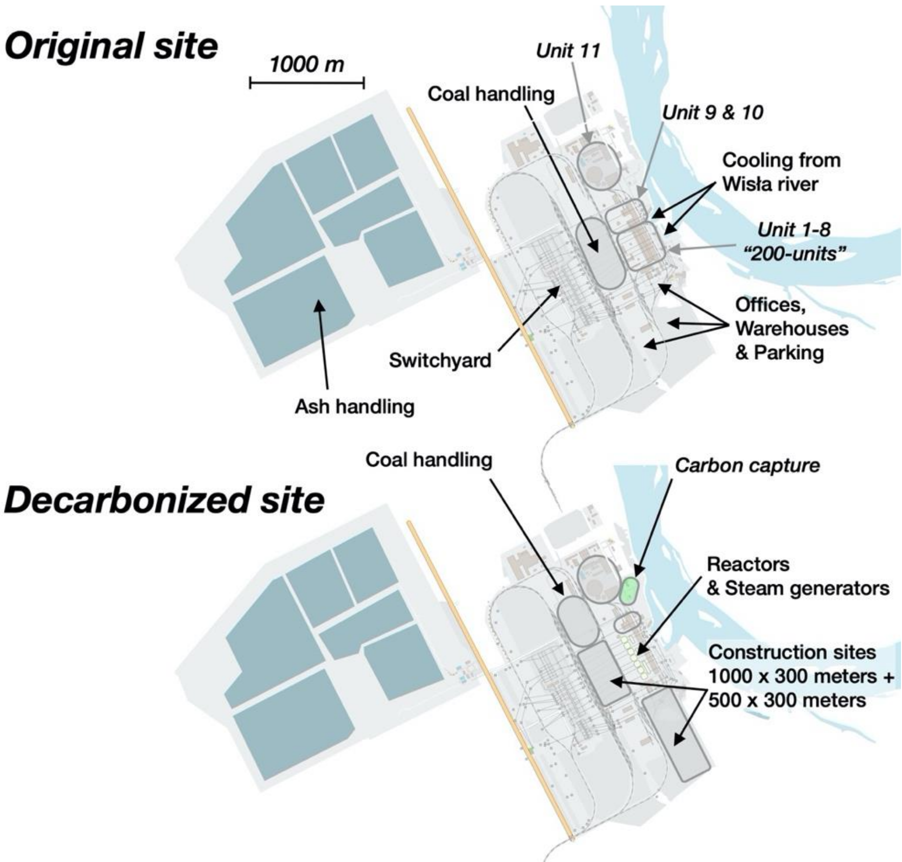

Figure S21. Retrofit decarbonization of Kozienice with nuclear reactors and carbon capture.

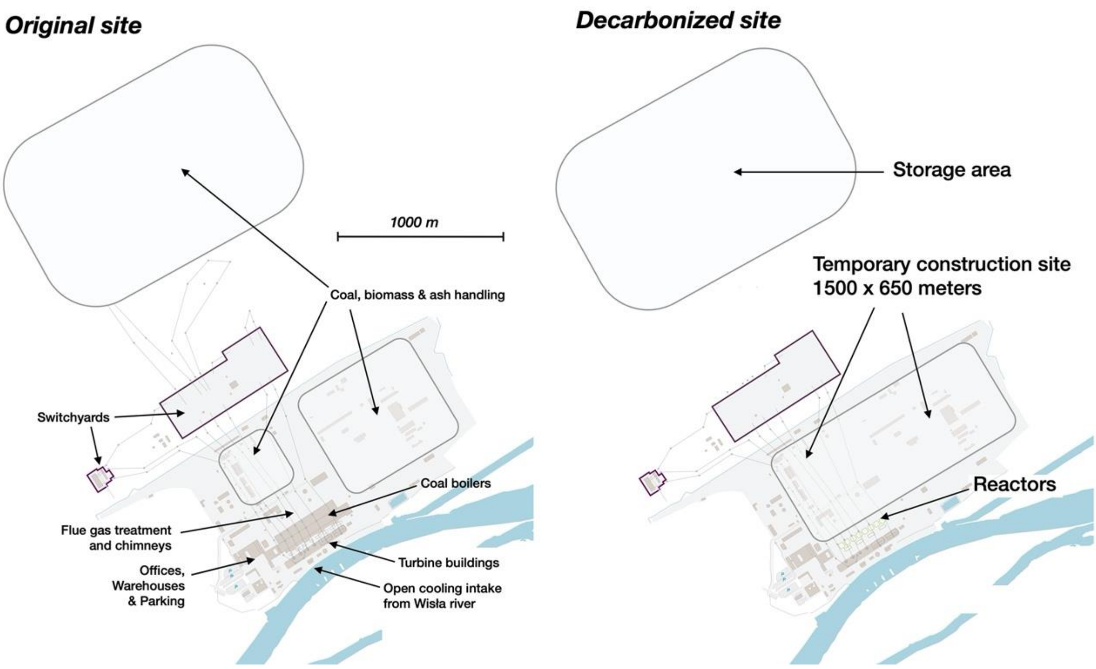

Figure S22. Retrofit decarbonization of Połaniec with nuclear reactors.

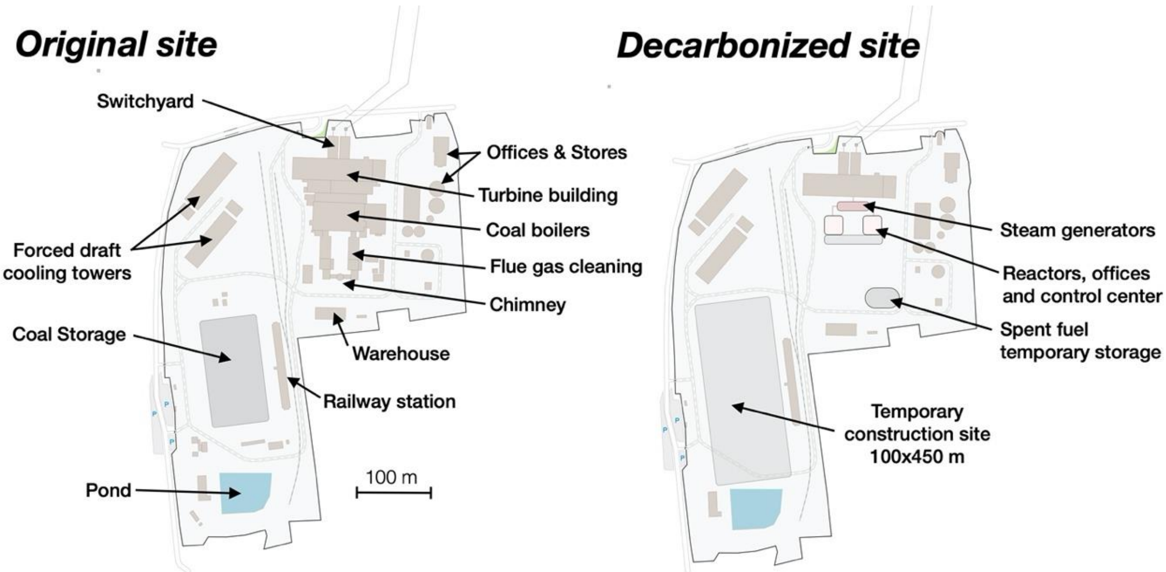

Figure S23. Retrofit decarbonization of Chorzów with nuclear reactors.

6.6. Coal plant job retention

The number of employees per unit capacity at a coal power plant varies with the total plant capacity (fewer employees/MW at larger plants) as well as with the number of individual units at the plant and the age and condition of the plant. Polish coal power as an industry, appears to have around 500-700 employees or full-time contractors per GW_e of capacity at the power units as an average, which is roughly comparable to the expected normalized staffing requirements of an advanced SMR. Only a limited number of SMR employees will require nuclear-specific expertise and experience (such as control-room and production planning staff), while most of the operational jobs are standard non-nuclear maintenance, planning and engineering jobs. With full integration, including the re-use of the existing steam cycle, job-retention could likely reach 2/3-rds of the existing plant operations and maintenance staff, assuming a comprehensive reskilling and retraining program is established while the SMR units are under construction.

7. The Current Polish Power System

7.1. Energy system summary

The Polish energy mix is unique in Europe because it is based primarily on domestic solid energy resources (hard coal and lignite) for both electricity and heating. Energy for transport, just like in all other European economies, is still primarily based on oil. The share of coal is just above half of total primary energy supply in Poland compared to less than 17 % in the European Union as a whole. The annual final energy consumption is ~3 EJ (830 TWh) and the largest energy consumers are households (30%), followed by transport (28%), industry (22%) and services (13%). In terms of final energy, heat consumption makes up about one third (1 EJ or 280 TWh) of which about one quarter is produced in the district systems [76].

7.2. Electricity generation

The power sector, responsible for around 50% of Poland's greenhouse gas emissions, is tightly coupled with domestic coal sector. Coal power makes up nearly 80% of annual electricity generation and 70% of the available generating capacity. The current generation mix, along with official Ministry of Energy forecasts until 2040, is given in Figure S24.

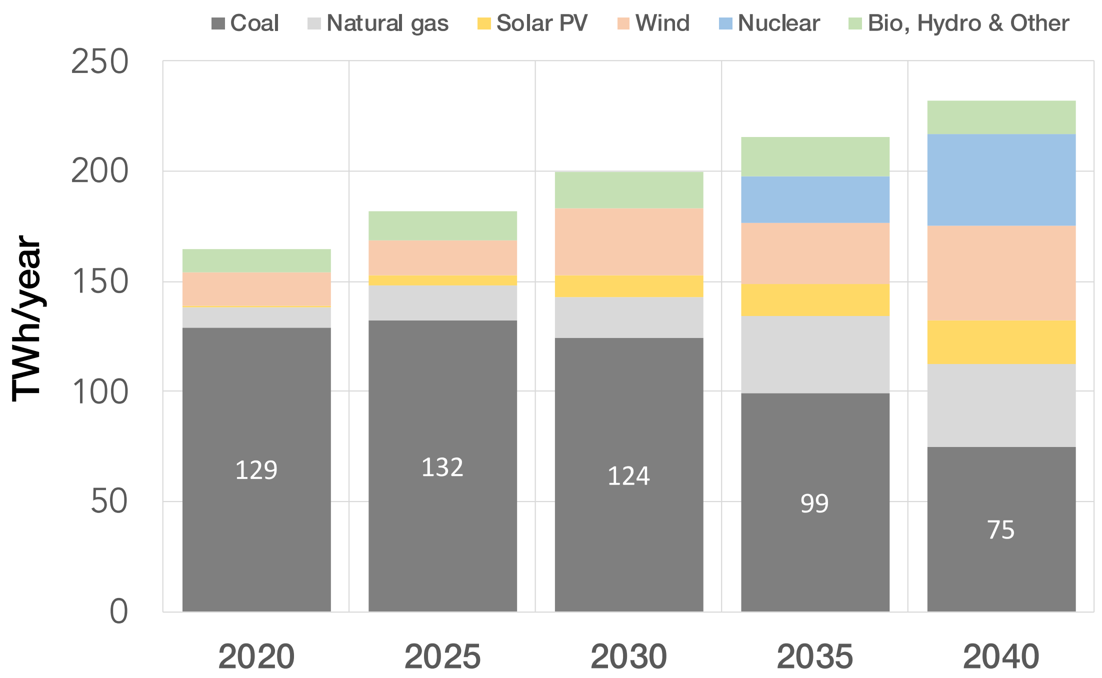

Figure S24. Polish electricity production mix and forecast until 2040 by the Ministry of Energy [77].

Coal has always been an important energy source in Poland. Ever since the fall of communism in Poland in 1989, the coal industry has been undergoing heavy restructuring and has seen a continuous reduction in employment (due to both efficiency gains and dropping demand). Poland has large coal reserves — which at the current level of production & consumption could last for up to 150 years [78].

7.3. Power prices

In 2018, the average annual price of sales of electricity on the competitive market was 45 €/MWh. The weighted-average price of a contract for baseload delivery on the day-ahead market in 2018 was 52 €/MWh, and the weighted-average price of a contract for baseload delivery in 2019 was 56 €/MWh. Due to a very mild and windy winter, well-filled north European hydro-electric reservoirs and demand reductions stemming from the economic impacts of COVID-19[11], 2020 has been characterized by extremely low wholesale electricity prices across Europe and cannot be seen as indicative of base-case underlying conditions or as a basis for future projections.

7.4. Heat

In total, 24 million tonnes of coal are used annually for heating, 12 million tonnes each in district heating systems and individually heated buildings. This represents approximately 38% of the steam hard coal mined in Poland (lignite is not used for in space heating). The total heat capacity of individually heated buildings is 139 GW_{th} (53 % coal) and in district heating plants 54 GW_{th} (81 % coal) [76]. Poland has the largest number of district heating customers among all EU countries and is second only to Germany when it comes to the amount of consumed heat produced in district heating systems. Households consume approximately one third of the national primary energy stream, mainly for heating purposes. Many buildings, especially those built before the end of the 1990s, have still not been modernized for increased energy efficiency[12]. The cost of heating represents the largest share of expenditure of less wealthy Poles, and energy poverty affects about 1.3 million (10%) households in Poland.

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[11] Coronavirus disease 2019 (COVID-19) is an infectious disease caused by severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2).

[12] Current space heating energy consumption is on average approximately 160 kWh/m^2/year per year. Technical specifications for newly constructed buildings target 95 kWh/m^2/year for single-family buildings and 85 kWh/m^2/year for multi- family buildings. From 2021 and onward, similar indicators will amount to 70 kWh/m^2/year and 65 kWh/m^2/year, respectively. Thus, with investment in to "thermo-modernization", the space heating demand of the existing housing stock could be dramatically reduced.

7.5. Ownership structure

Poland's major energy utilities are all State Treasury companies, which means that although they are all joint stock companies whose stock is traded on the exchange, the state owns a majority of their shares or is legally controlling them in some way. The ownership structure of the Polish electricity market is given in Table S10.

Table S10. The Structure of the Polish Electricity Market (various sources including ref. [79]).

Segment	Company	Market share	State ownership share
Transmission	PSE	100%	100%
Distribution	Tauron Dystrybucja	37 %	30.0 %
	PGE Dystrybucja	26 %	57.4 %
	Energa-Operator	17 %	51.5 %
	Enea Operator	14 %	51.5 %
	Innogy Stoen Operator	6 %	None
Generation	PGE	45 %	57.4 %
	TAURON	11 %	30.0 %
	Enea	9 %	51.5 %
	ZE PAK	7 %	6.0 %
	Engie	6 %	None
	Energa	3 %	51.5 %
	Small independents	19%	None
Retail	Tauron Polska Energia	29 %	30.0 %
	PGE	31 %	54.7 %
	Energa	13 %	51.5 %
	Enea	14 %	51.5 %

7.6. Employment

One of the main arguments for a continued coal-based power and heat industry is the energy security of Poland, as the coal resources (both hard coal and lignite) are domestically abundant, and the well-developed coal mining industry currently employs more than 90,000 people, the majority of which located in the southern region of Silesia (Śląskie)[13]. Adding in workers in coal power plants across Poland, the total number surpasses 110,000 workers [80]. Indirectly, adding jobs in coal-related equipment supply, logistics, services and R&D, an estimated total of 140,000 jobs depend on Poland's coal industry [80]. However, even in Silesia, mining value-add currently represents only about 5% of total value-added. In recent years the region has become a major manufacturing center, particularly for the automotive industry, which tends to require the same type of skills as mining. Moreover, the region is strategically located close to wealthier EU markets.

7.7. Domestic fuel resources

7.7.1. Introduction

The domestic production of individual energy carriers today, as well the Ministry of Energy forecast figures until 2040, are given in Figure S25. Coal in its various forms make up 82 % of domestically produced resources by energy content today, a figure which is expected to drop to 75 % by 2040.

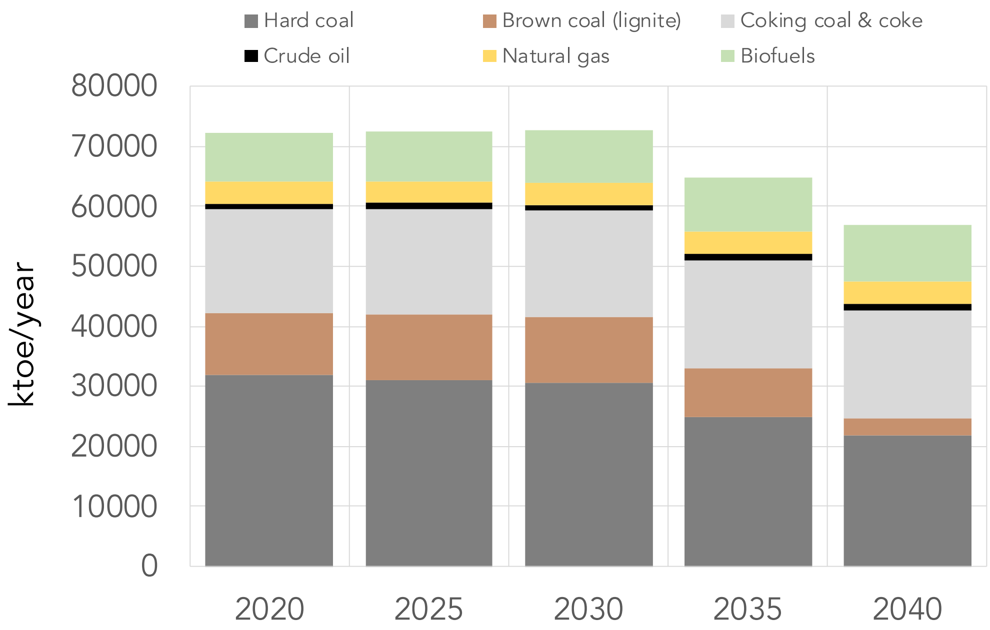

Figure S25. Domestic energy carrier (fuel) production [81].

Power-coal production (lignite and hard coal) is assumed to be maintained until 2030, after which a decline in hard coal and a near phase-out of lignite (brown coal) is expected.

7.7.2. Hard coal

The geological resources of hard coal in Poland (across 158 deposits), as of 31 December 2017, are around 60.5 billion tons. The proven reserves in the currently exploited deposits with mining licenses amounted to 1.56 billion tons [82]. At the current levels of production, these proven reserves will last for about 20 years.

[13] The Polish coal mining sector has however already lost 25,000 jobs since 2010 due to falling general demand.

7.7.3. Brown coal (Lignite)

The geological resources of brown coal across 91 deposits are estimated to be around 23.4 billion tons, including approximately 1.27 billion tons in the developed deposits. Brown coal mining is currently carried out in five mines: Bełchatów, Turów, Adamów, Konin, and Sieniawa. Brown coal mining in 2017 amounted to 63,060 thousand tons. Electricity production from brown coal sourced from a local mine is today only possible in three power plants in Poland: Bełchatów, Turów and Pàtnów.

7.7.4. Oil

In Poland, the exploitable crude oil resources, documented in 86 deposits, are estimated to be around 23.6 million tons, of which approximately 23.16 million tons are in developed fields, while approximately 14.48 million tons are proven reserves. In 2017, the production of crude oil and condensate amounted to just under 1 million tons from all deposits. There are no prospects in Poland for a significant increase in production. It is expected to remain stable at a level not exceeding 1 million tons per year.

7.7.5. Natural gas

The geological resources of natural gas in Poland are estimated at 117 billion m^3. The bulk of these natural gas resources are in the form of coal-bed methane (CBM), documented in 62 fields in the area of the Upper Silesian Coal Basin. Extraction of this resource is therefore a by-product of, and dependent upon, coal mining. Indigenous natural gas production amounts to around 5 million m^3 per year, covering 10-12% of the total consumption. The remainder is currently imported mainly from Russia. The Baltic Pipe, a natural gas pipeline connecting Faxe in southern Denmark to Niechorze-Pogorzelica in northern Poland, is expected to be in operation by October 2022.

8. Global Experience with Industrial Repurposing

Throughout history, societies have repurposed tools and infrastructure to retain value and avoid stranding assets when priorities, demand and requirements change, either temporarily or permanently. The largest-scale modern example of industrial repurposing is that of the adaptation of civilian heavy manufacturing in service of military defense in the United States during the second world war. In January 1942 — a month after the attack on Pearl Harbor, Hawaii — President Franklin D. Roosevelt ordered the establishment of the War Production Board, the task of which was to repurpose factories of peacetime industries into manufacturing plants for military equipment. For heavy manufacturing plants like those of the automobile industry, this type of repurposing became essentially all-encompassing. There were about 3 million cars manufactured in the U.S. in 1941. During the entire remaining U.S. second world war period after the formation of the War Production Board (Jan. 1942-Aug. 1945), only 139 additional civilian cars rolled off assembly lines [83]. Instead, car companies manufactured guns, trucks, tanks and aircraft engines, to a significant extent out of what was originally automobile factories. For example, tanks were manufactured in the General Motors Cadillac factory, Oldsmobile factories delivered artillery rounds and Pontiac was building anti-aircraft guns. When the war ended, a new wave of repurposing ensued, as car factories that had been repurposed for military supply quickly re-tooled for their original purpose. Additionally, many of the new military equipment factories that were built during the war, now in the hands of private industry, were converted to enable various kinds of civilian manufacturing [84]. Much more recently, smaller-scale repurposing has been employed as a response to the Coronavirus disease 2019 (COVID-19) pandemic. For example, factories of the United Kingdom's Royal Mint (which supplies the nation's coinage) started making protective visors for healthcare workers [85], vacuum-maker Dyson started manufacturing ventilators [86] and Sharp repurposed a TV-factory to manufacture surgical masks [87]. Repurposing can be temporary, as in the case of war or pandemic-time requirements, or more permanent, as in the case of converting military factories when a war ends, or the present shift from internal combustion car engine manufacturing to battery-electric vehicles as a response to both consumer demand and environmental performance objectives. The proposed repurposing of coal power plant equipment in this study will be permanent, as a return to unabated coal firing for electricity generation is untenable on both environmental and economic grounds. Throughout history, repurposing has involved retaining in operation some equipment as is, modifying some, while completely replacing some of the components. The process typically saves both time and money compared to building greenfield variants of the same capacity and function, while also retaining local economic activity and jobs.

Appendix A.

An estimate of the "committed future emissions" that *could result* from any existing power plant can be obtained from the following equation:

$$\sum CO_2[\mathrm{kg}] = P[\mathrm{MW}_e] \times 8766 \times \overline{\mathrm{CF}}[\%] \times \left(T_{\mathrm{physical}}[\mathrm{years}] - T_{\mathrm{effective}}[\mathrm{years}]\right) \times E_i\left[\frac{\mathrm{kgCO_2}}{\mathrm{MWh}}\right], \quad (1)$$

Where P is the power level in megawatts electric (MW_e), 8766 is the average number of hours in a year, $\overline{\mathrm{CF}}$ is the average capacity factor[14] from today until the end of plant operation, $T_{physical}$ is the number of years that the plant will physically endure before it deteriorates to an unusable condition from physical causes without considering the possibility of earlier retirement due to economic obsolescence or regulatory requirements. $T_{effective}$ is the apparent current age of the plant in comparison with a new asset of like kind. If a plant has undergone partial modernizations or refurbishments, the overall value of $T_{effective}$ for the plant can be calculated by summing the relative economic value (or cost) of the components, as a share of total plant value, by their individual effective age. The product of these first three terms determines the total amount of electricity generation the plant could provide (in megawatt-hours, MWh), absent any regulatory and economic factors that would drive early retirement. Finally, E_i is the emissions intensity, which defines the amount of CO_2 released for each MWh of electricity generated.

For any given power plant, the value of P is given and the value of E_i is easily determined from basic plant and fuel parameters. The likely value of $\overline{\mathrm{CF}}$ in any power market with marginal cost dispatch can only be estimated from modelling given a number of assumptions about the evolution of the merit order composition and demand in that market. Any power plant will bid to produce for a compensation that is equal to its marginal cost of production, typically determined by auction on an hour-by-hour basis. If the market price clears above this value for a given hour, the plant will run, if below this value, it will not. These factors determine the effective value of $\overline{\mathrm{CF}}$, which means its average value over a longer period of time can only be roughly approximated.

Using Equation 1, rough estimates for the committed emissions can for example be made for a single newly built 1000 MW_e coal plant, as well as for the entire current global coal fleet. The current global average capacity factor of coal power plants is ~50% [88] and is on a generally falling trend. New plants have lower marginal costs than older plants due to higher efficiencies and lower maintenance costs, and therefore operate at higher capacity factors than the fleet average. In this example, we therefore assign a maintained $\overline{\mathrm{CF}}$ of 50% for a new plant. New coal power plants entering operation today are also likely to be equipped with super or ultra-supercritical units (with high thermal efficiency) and are unlikely to be burning low-grade coal such as lignite. Therefore, an assumed value for E_i of around 850 $kgCO_2/MWh$ appears reasonable. For this example, we employ a value for $T_{physical}$ of 55 years and $T_{effective}$ for a new plant is by definition zero. The possible committed emissions from such a plant are therefore ~200 million tons of CO_2. Varying the parameters of $\overline{\mathrm{CF}}$, $T_{physical}$ and Ei in reasonable ranges (35 % < $\overline{\mathrm{CF}}$ < 50 %, 40 y < $T_{physical}$ < 65 y, 800 kgCO2/MWh < E_i < 1050 $kgCO_2/MWh$) gives a span of 100-300 million tons of CO_2.

The world has 2047 GW_e of operational coal power capacity and 190 GW_e under construction, for a total applicable near-term value of P of 2237 GW_e [89]. $T_{effective}$, the global effective age of coal power plant capacity (when including capacity currently under construction) is approximately 18 years based on calendar time, calculated with data from Global Coal Plant Tracker. Setting $\overline{\mathrm{CF}}$ to 45 %, E_i to 900 $kgCO_2/MWh$ (the global average, even counted over the next few decades, will be considerably higher

[14] The capacity factor is defined as the ratio between actual power generation and possible power generation.

than for a new plant) and $T_{physical}$ to 55 years means global committed emissions of 294 $GTCO_2$ with a span when varying input parameters of 174-414 $GTCO_2$.

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