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Past the peak? Trajectories of national coal fleets and coal-fired electricity generation between 1960 and 2020

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Author's declaration

No portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

Janna HOPPE

Abstract

ABSTRACT OF THESIS submitted by:

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Coal-fired electricity generation is one of the main causes of anthropogenic climate change. Nevertheless, the patterns and dynamics of coal fleet development have scarcely been investigated via quantitative, multi-country comparisons. This exploratory study integrated and analysed two datasets on electricity generating coal units worldwide to map the trajectories of 32 national coal fleets and 6 main coal consuming regions. These trajectories were evaluated through a novel framework combining theories on technology diffusion with notions of technology decline and abandonment.

The principle findings were that, generally, units built since 1970 increased in size, adopted more efficient combustion technologies, and became increasingly likely to be privately owned. Geographically, the rate of units being constructed in Asia increased dramatically while simultaneously falling in Europe and North America. Overall, countries are in different phases of the coal technology lifecycle, exemplified by varying trajectories of total installed capacity and net annual capacity growth over the last 40-60 years. Contributing to the discussion on global coal decline, this study observed that total installed coal capacity for several countries demonstrates an inverse S-curve of technology diffusion with coal fleets shrinking slowly at first, but then more rapidly. Lastly, load factors (average utilization rates) were found be lower in contracting rather than growing coal fleets.

These spatio-temporal patterns in coal capacity should be compared to trends in other coal-related sectors, such as heat provision or mining, to provide further insights into how the global phase-out of coal can be achieved.

Keywords: coal, energy transition, technology diffusion, electric capacity, phase-out

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List of Abbreviations

AFOLU	Agriculture, forestry, and other land use
BAU	Business as usual
BECCS	Bioenergy with carbon capture and storage
Btu	British thermal unit
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CDR	Carbon dioxide removal
CFI	Comparative fit index
CHP	Combined heat and power
CO_2	Carbon dioxide
COAL14	Group of countries (see section 4.2)
COP	Conference of the Parties
DEC18	Group of countries (see section 4.2)
DWLS	Diagonally weighted least squares
FOM	Fixed operations and maintenance
GCPT	Global Coal Plant Tracker (database)
GDP	Gross domestic product
GHG	Greenhouse gas
Gt	Gigaton
IEA	International Energy Agency
IED	Industrial Emissions Directive
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt hour
LCPD	Large Combustion Plants Directive
ML	Maximum likelihood
MLP	Multi-Level Perspective
MW	Megawatt
NDCs	Nationally determined contributions
NO_x	Nitrogen oxides
OECD	Organisation for Economic Co-operation and Development
PIK	Potsdam Institute for Climate Impact Research
PPCA	Powering Past Coal Alliance

R&D	Research and development
RE	Renewable energy
ROTW	Rest of the world; group of countries (see section 4.2)
SEM	Structural equation model
SO_2	Sulphur dioxide
SRMR	Standardised Root Mean Residual
TWh	Terawatt hour
UNFCCC	United Nations Framework Convention on Climate Change
VOM	Variable operations and maintenance
VRE	Variable renewable energy
WEPP	World Electric Power Plants (Platts database)

1 Introduction

As one of the most serious threats to ecosystems and human life on earth, anthropogenic climate change has become one of the most topical areas of research and contemporary discourse. In the following section, I briefly present the impacts and drivers of climate change, highlight the contribution of power supply and coal firing, and present options for deep emission reductions. The following sections thus provide a rationale for undertaking this research project in the first place and establish a broad context for all subsequent chapters.

1.1 Anthropogenic Climate Change

The accumulation of carbon dioxide (CO_2) and other greenhouse gases (GHG) in the atmosphere due to human activity has led to a global temperature rise of approximately 1°C compared to pre-industrial times (IPCC 2018). The observed warming has increased the frequency and intensity of extreme weather events, led to substantial sea level rise, ocean acidification, and a decline in sea ice extent, as well as increased precipitation in some regions of the world while others are experiencing more droughts (IPCC 2014; IPCC 2018; O'Neill *et al.* 2017). The Intergovernmental Panel on Climate Change (IPCC), among others, further expects climate change to cause an increase in the displacement of people, violent conflicts, poverty, and economic instability (IPCC 2014).

This outlook has led to the formulation of the Paris Agreement in the context of the United Nations Framework Convention on Climate Change's (UNFCCC) 21st Conference of the Parties (COP) in 2015. Its ratification constituted an important milestone in international climate negotiations and provided the cornerstone of climate protection efforts today. Its signatories pledge to limit global temperature rise to "well below" 2°C above pre-industrial levels, and to "pursue efforts to limit the temperature increase even further to 1.5°C" (United Nations 2015). However, global or country-specific pathways on how to meet this goal are scarce (Rogelj *et al.* 2018).

Due to the quasi-linear relationships between cumulative CO_2 emissions in the atmosphere and global temperature rise (Matthews *et al.* 2009), the extent of future warming depends on past and future emissions, but also to an uncertain degree on natural climate variability (IPCC 2014). The carbon budget – i.e. the allowable amount of emissions for limiting global temperature rise to 1.5°C / 2°C – is shrinking by approximately 42 $GtCO_2$ every year (IPCC 2018). Despite considerable disagreement with regards to the amount of carbon emissions compatible with a

66% chance of reaching the 1.5°C temperature goal (ranging from -200 to 800 $GtCO_2$ in 2018) as well as the 'years left' for the continuation of current emissions (ranging from -5 to 19 years) (e.g. Millar *et al.* 2017; Schurer *et al.* 2018; Lowe and Bernie 2018; Rogelj *et al.* 2018; Peters 2018), even generous estimates call for fast and far reaching emission reductions (Hausfather 2018). This would necessitate a transformation of the global economy unprecedented in scale (IPCC 2018): A 1.5°C warming may "not yet [be] a geophysical impossibility" (Millar 2017), but more and more evidence points towards requiring "Herculean efforts" (Luderer *et al.* 2018, 632).

Limiting the extent of climate change requires a range of mitigation measures, in the centre of which lie reductions in energy intensity of the global economy and in carbon intensity of energy supply (IPCC 2018). This necessarily entails the shift away from fossil fuels and the large-scale rollout of low-carbon energy technologies (Rogelj *et al.* 2018) as well as considerable and structural changes on the demand side (Creutzig *et al.* 2018). But most mitigation pathways also feature carbon dioxide removal (CDR) in the form of bioenergy with carbon capture and storage (BECCS) and the agriculture, forestry, and land use (AFOLU) sector (IPCC 2018; Rogelj *et al.* 2018). Delayed climate action increases the necessity to upscale CDR, which is associated with "considerable implementation challenges" (IPCC 2018, 18) and carries several sustainability concerns (Luderer *et al.* 2018).

Current mitigation and adaptation efforts are pursued via 'Nationally Determined Contributions' (NDCs), which are voluntary national plans to reduce emissions and adapt to the impacts of global warming under the Paris Agreement. In their current form, they are projected to result in a global temperature increase of approximately 3°C by 2100 (IPCC 2018), thereby falling short of being on track for meeting either one of the climate goals. This lack of ambition is aggravated by several barriers to mitigation, such as inertia in social and economic systems (IPCC 2014), or infrastructurally induced path dependencies (Luderer *et al.* 2018). Especially soft constraints originating from societal and political domains are perceived as key barriers to deep decarbonisation, making the 1.5 and 2°C climate targets less feasible (Jewell and Cherp 2019).

1.2 The Role of Energy and Coal

1.2.1 The Power Sector

As mentioned above, energy sector transformation lies at the heart of effective climate protection. According to Hoesly *et al.* (2018), energy supply is responsible for approximately 45% of all energy-related CO_2 emissions, of which the majority stem from the power sector (Luderer *et al.* 2018). Further, CO_2 emissions from the combustion of fossil fuels and industrial activities account for 78% of the GHG emission increase between 1970 and 2010 (IPCC 2014).

Although reaching the climate goals requires emissions reductions on both the supply and demand side (i.e. tackling the direct combustion of fossil fuels in the transport, industry, and buildings sector), mitigation potentials are greater in energy supply (Bauer *et al.* 2017; Luderer *et al.* 2018), while also being cost-efficient and providing more flexibility with regards to technology choices (Krey *et al.* 2014; Williams *et al.* 2012). Prioritising the decarbonisation of electricity supply further makes electrification measures especially in transport and heat provision powerful mitigation options.

The composition of national energy systems greatly depends on socio-economic conditions, the availability and price of energy resources, technological progress and innovation, and changes in energy end-use (Bauer *et al.* 2017). It is thus important to understand socio-economic developments to make predictions about future energy systems (Grubler 2012; Jakob *et al.* 2012). Various developments inside and outside of energy supply already exert substantial pressures that affect the degree of lock-in of incumbent companies and energy carriers as well as the diffusion of low-carbon technologies (Bauer *et al.* 2017).

1.2.2 The Coal Sector

In 2018, coal accounted for almost 40% of global power production (IEA 2019a), making it the largest source of electricity in the world. Releasing 75% more CO_2 per unit of energy than natural gas (Gabbatiss 2020), it accounts for over a third of global CO_2 emissions (Rauner *et al.* 2020). Carbon dioxide emissions from coal peaked in 2013, but recently rebound after four years of decline (Jackson *et al.* 2019). Additionally, a recent study finds that non-CO_2 GHG emissions, originating predominantly from methane leakage in coal mining, are substantially higher than initially thought (Kholod *et al.* 2020).

Davis and Socolow (2014) popularised the concept of committed emissions, which are the cumulative emissions a power plant fleet will emit over its life, assuming historic lifetimes and utilization rates. Since then, several authors have calculated committed emissions from the energy, electricity or coal sector (e.g. Pfeiffer *et al.* 2016; Pfeiffer *et al.* 2018; Edenhofer *et al.* 2018; Tong *et al.* 2019; Spencer *et al*. 2018; van Breevoort *et al.* 2015), and all concluded that committed emissions from the existing and planned coal or power sector infrastructure substantially exceed the power sector's share of the 1.5°C and even 2°C carbon budget. While all calculations are highly sensitive to underlying assumptions regarding lifetimes and load factors (Tong *et al.* 2019; Pfeiffer *et al.* 2018; Davis and Socolow 2014), these calculations effectively highlight the importance of short-term energy policy on long-term climate goals.

According to IPCC estimates, emissions from coal combustion for electricity generation must fall by 80% by 2030 for a good chance of limiting global temperature increase to below 1.5°C (Yanguas Parra *et al.* 2019). Delaying a global coal phase-out will either lead to overshooting the carbon budget, a large-scale stranding of coal infrastructure, or result in a higher need for negative emissions in the medium and long-term (van Breevoort *et al.* 2015). Since such scenarios are highly contested for the adverse effects on public health and the economy, most scholars view the accelerated phase-out of coal as one of the low-hanging fruit of climate protection (CAN Europe 2018).

While the International Energy Agency (IEA) projects coal combustion for power generation to stagnate over the next few years, they acknowledge that pressures on the coal industry have accumulated. These pressures include public opposition to coal mining and combustion, competition from renewables and natural gas, and environmental policies, such as air pollution regulations or climate targets (IEA 2019a). Further, since the formation of the Powering Past Coal Alliance (PPCA), 33 national governments and 27 subnational governments have pledged to phase out coal completely (PPCA 2020). But, since these countries only account for a small share of global coal capacity (4.4% in 2019) (Jewell *et al.* 2019), "globally phasing out coal remains one of the hardest political nuts to crack" (PIK 2020). This is despite the fact that the benefits of a global coal exit, stemming from the reduction of negative health and ecosystem impacts, by far outweigh the costs of a phase-out, which are composed of economic growth reduction and investments in energy systems (Rauner *et al.* 2020).

1.3 Research Questions and Objectives

1.3.1 Rationale

A large proportion of research in the field of energy transitions is concerned with the emergence of renewable energy technologies. Also, case study approaches dominate over large-N, multi-country comparisons (see section 2.2). Meanwhile, research on coal is led by questions of past and future emissions, its role in electricity supply, and regional transformation pathways. But the economic, social, and environmental costs of continued coal plant construction and associated combustion call for a thorough analysis of whether national coal fleets are growing or shrinking, as well as at what rate and how they change. This thesis sets out to compare several national and regional coal fleet trajectories to put respective developments into a global perspective.

The following research questions and objectives are not only informed by the research mentioned above (section 1.2.2), but by findings of several, multi-disciplinary studies, which will be reviewed in later sections (2.1 and 4.3). Finally, the rationale for looking into the historic development of coal capacity is that the past rise and decline of energy technologies can be useful to estimate future pathways (Wilson *et al.* 2013; Grubler 2012).

1.3.2 Research Questions (RQ)

The overarching research questions that this thesis sets out to answer are:

- What are the spatio-temporal dynamics of global coal capacity development? Particularly;
    a. How have national and regional coal fleets changed; where, and at what rate have they expanded or shrunk over the past decades?
    b. What is the relationship between electricity generation from coal combustion and coal capacity development?

1.3.3 Research Objectives (RO)

Following from the research questions are these specific research objectives:

1) Qualitatively investigate techno-economic characteristics of the global coal fleet in a comprehensive literature review that serves as a basis for all following analyses;
2) Explore changes in unit size, technology, ownership, location, and combinations thereof, in an exploratory, quantitative analysis using data on coal units worldwide;

3) Investigate the development of (average) retirement ages for selected countries over time and identify predictors of retirement age in a path analysis;
4) Investigate the development of annual capacity additions and retirements, as well as total installed electric and coal capacity on the country and regional level;
5) Explore the relationship between capacity development and electricity generation from coal, including a calculation of load factors.

The temporal scope of this thesis spans the years between 1960 and today but differs depending on the underlying research objective as well as the reliability and availability of data. The spatial scope is global but focuses on main coal consuming regions as well as particularly interesting national cases. This thesis is an exploratory research project that follows no other particular study in its design. It combines qualitative and quantitative elements to provide a broad overview of techno-economic aspects of coal capacity development.

1.4 Overview of Thesis

In the preceding **Chapter 1,** the motivation for studying this topic in the first place, namely anthropogenic climate change (1.1) and the role of energy supply and coal combustion (1.2), was presented. This was followed by the formulation of overarching research questions (1.3.2) and five corresponding research objectives (1.3.3).

Chapter 2 reviews relevant literature on coal (2.1) and approaches to studying energy transitions (2.2). The first half contains information on the historic development of coal use (2.1.1), its economic relevance (2.1.2), its integration into the electricity system (2.1.3), and key energy and climate policies (2.1.4). In the second half, light is shed on dynamics accompanying the rise (2.2.1), stagnation (2.2.2) and decline (2.2.3) of energy technologies as well as on empirical observations from past energy transitions (2.2.4).

In **Chapter 3**, the theoretical framework is introduced. It condenses main theories from section 2.2 with additional hypotheses regarding the decline and abandonment of energy technologies (3.2). This chapter concludes by integrating the developed theoretical framework with the research objectives (3.3).

Chapter 4 presents all methods and results. As a first step, the data and initial steps of data wrangling are described (4.1-4.2). This is followed by a qualitative analysis of techno-economic factors related to the operation of coal units (4.3), which includes sections on economic factors, technological factors, lifetimes and retirement ages, and premature retirements and stranded assets. Subsequent sections investigate the development of coal capacity characteristics (4.4), the development of lifetimes and retirement ages (4.5), and annual capacity additions, retirements, and total installed coal capacity (4.6). Finally, the relationship between coal capacity and electricity generation from coal is explored (4.7).

In **Chapter 5**, all qualitative and quantitative results are integrated using the theoretical framework. Specifically, this entails discussions on the rise (5.1), persistence (5.2), and decline (5.3) of coal, as well as general dynamics spanning all three phases (5.4 and 5.5).

Chapter 6 sums up all findings and relates them to the research objectives (6.1). Further, limitations and opportunities for further research are highlighted (6.2), alongside policy recommendations and concluding remarks (6.3).

2 Literature Review

2.1 Introduction to the Coal Complex

Before diving into more technical and capacity-related aspects of coal-fired electricity generation, a brief review of the historic development of coal as an energy source is due. Following this are sections on the economic relevance of the coal industry, coal's integration into the electricity system, as well as energy and climate policies to disincentivise the combustion of coal for electricity generation. What should be noted here is that the subsequent overview is deliberately held general, to provide a profound understanding of the use of coal worldwide. If there is an interesting case in one particular country, it will be highlighted as such.

2.1.1 Historic Development of Coal Use

The use of coal for energy purposes presumably dates back to China of 2000 BC (Dodson *et al.* 2014). Despite uncertainty as to when and by whom coal was first used, reliable artefacts corroborate the combustion of coal around the world in the Middle Ages. Until the mid-1800s however, wood remained the dominant energy resource for its low price and abundance (Igliński *et al.* 2015), and the eventual transition from wood to coal took several decades to unfold. Starting in the United Kingdom (UK), the price of coal declined and eventually sank below that of wood, as a result of which coal was substituted for wood in residential heating and cooking (Allen 2013). The increasing use of coal in households then drove investments in the transport and production of coal, which lowered costs further and led to breakthrough innovations in energy conversion technologies (ibid.). With James Watt's development of the steam engine and the extensive expansion of railroads, the industrial revolution of the 18th and 19th century kicked off. Coal not only fuelled critical improvements to steam power, but supplied energy to all end-use sectors in the UK and beyond (Littlecott 2015).

The first steam-powered station was built in London in 1882, followed by a second unit starting operation in New York City later that year (Drax 2016). These first coal-fired electric units mainly powered lamps, and coal power played a major role in the gradual electrification throughout the 20th century (Agora Energiewende 2016). The conversion of thermal energy into mechanical energy also facilitated the establishment of the metallurgical industry. Due to the low price of coal, high energy densities compared to wood, and commonly local deposits (ibid.), coal remained the dominant electricity and heat provider in many European and North

American countries up to the second half of the 20th century. In 1950, coal's share in global primary energy production was around 60% (Merrick 1984). During that time, coal consumption was dominated by direct use (60%) and coke manufacturing (20%), and to a lesser extent by power generation (15%) (ibid.).

The 1960s experienced a rapid deployment of natural gas and crude oil, which complemented coal in satisfying steadily rising energy demand (Merrick 1984). Originally perceived as the "black gold" from Montana to Poland (Chadwick 1973; Kuchler and Bridge 2018), coal lost importance in its former strongholds. With the discovery of seemingly inexhaustible natural gas and oil fields, as well as the eventual construction of nuclear reactors on a large scale, these energy sources successively replaced coal in both electricity and heat supply, as well as in direct use in the industrial, residential, and transport sector (Agora Energiewende 2016). The dissolution of the Soviet Union in 1991 and the corresponding shift to a market economy in many Eastern European countries (Pollitt 2012), as well as the Thatcher-Reagan period of market liberalisation led to increased competition among energy utilities and major efficiency gains, which substantially lowered the demand for coal. Meanwhile, many European economies shifted away from heavy manufacturing and energy-intensive industries towards service-oriented economies (Bloomberg 2016). In 1990, coal accounted for almost 40% of Europe's power supply (Alves Dias *et al.* 2018) but has since then declined by over 40% from 5,289 TWh to 3,055 TWh in 2015 (ibid.).

In China, coal was the main source of energy for power generation, railway transport, industry, and residential heating for many decades (Thomson 2003). Since 1989, China is the largest producer and consumer of coal. The stepwise introduction of oil, gas, hydro and later nuclear power was rather slow due to limited natural gas and oil resources, as well as energy security concerns. Additionally, a comprehensive fuel switch would have required substantial investments in new technologies and infrastructures, while revenues from the export of oil were heavily relied upon (ibid.). In the 1990s, China ramped up its effort in diversifying the energy mix and now deploys renewables on a considerable scale (Tianjie 2017).

While the share of coal in global energy supply was reduced by various external pressures, absolute coal use still demonstrated continuous growth in almost all world regions over the past 40 year and has only slowed down recently (Edenhofer *et al.* 2018). In 2015, the global use of coal dropped for the first time (-2.3%), which led Greenpeace (2015) to announce, "coal's terminal decline". According to their report, this decline was mainly driven by a lower than expected growth of coal use in China, brought about by economic restructuring, stringent air pollution regulations, and the rise of the renewable energy industry. Similarly, the United States (US) experienced a substantial drop in coal use as a response to public opposition, unfavourable economics, and increased environmental regulation (Greenpeace 2015). Additionally, the shale gas boom rendered many coal operations unprofitable (IEA 2019a), and climate policies in several states accelerated the long-term structural decline (Wamsted *et al.* 2019). The low profitability of the coal sector was likely "the most critical factor in coal plants' shutdown decision-making" in the US (Cui *et al.* 2020). In most PPCA countries, the transition away from coal is accompanied by the halt of governmental subsidies supporting the coal sector (Alves Dias *et al.* 2018), pollution controls (Wynn and Coghe 2017), declining efficiencies, rising operating costs (Wamsted *et al.* 2019), and either stagnating or declining electricity demand (Fleischman *et al.* 2013).

However, in 2018, Edenhofer *et al.* cautioned against Greenpeace' optimism and argued that "reports of coal's terminal decline may be exaggerated" (p. 1). And indeed, after three years of decline, coal use increased again by 1.1% from 2017 to 2018 (IEA 2019a). This "coal renaissance" (Steckel *et al.* 2015) was mainly driven by developing countries in which total electricity consumption dramatically increased as a result of growing per-capita consumption and overall population growth (Caldecott *et al.* 2017). Whilst China and India account for a substantial share in coal firing (57% of global electricity generation from coal, IEA 2020), they are representative cases rather than sole drivers (Steckel *et al.* 2015). In India, coal use grew by 8.2% annually between 2005 and 2015, while China witnessed an annual increase of 6.5% (Spencer *et al.* 2018). As extensive infrastructural projects are in the pipeline in China, India, and Southeast Asia, total electricity demand and coal consumption is expected to increase over the next years (IEA 2019a).

2.1.2 Economic Relevance

Despite vast empirical evidence, there is no consensus on whether a cause-effect relationship from coal use to gross domestic product (GDP) exists (Li and Leung 2012; Wolde-Rufael 2010; Kumar and Shahbaz 2012; Liu *et al.* 2009). Results of such analyses could be indicative of whether the decline of coal industries, or the active enforcement of phase-out measures, has negative effects on countries' economies and wealth (Wolde-Rufael 2010; Liu *et al.* 2009), but are thus far inconclusive. Such discussions, however, are somewhat misleading, as especially coal mining but also coal combustion are regionally concentrated - making respective regional economies disproportionally affected by coal sector developments (Johnstone and Hielscher 2017).

Since 2000, the production of coal has doubled, as mechanization and technological progress have improved overall productivity (Ritchie and Dowlatabadi 2017). However, available coal reserves, which are recoverable coal resources, are only a fraction of geological coal classified resources (ibid.). Due to increasing extraction costs, coal mines around the world have struggled to remain profitable since the 1980s, but fewer mines closed as rational economic decision-making would suggest (Carbon Tracker 2019).

The regional concentration of coal mining makes coal an important regional employer (Spencer *et al.* 2018). In India, for example, 1 million people are employed in the coal sector, and the income from coal mining accounts for up to 50% of total earnings for a number of states (ibid.) The majority of mining employees are unskilled or semi-skilled workers with limited alternative employment options (ibid.). This, and the century-long history of coal mining has equipped trade unions with substantial negotiating power and leverage on regional and national policymakers (Bernaciak and Lis 2017; Lis 2014). It is partly due to their influence that vertically integrated utilities cross-subsidise unprofitable mining operations, and governments support the mining industry with generous subsidies (Oei *et al.* 2019).

The coal industry has played a pivotal role in creating region's cultural identities that are inseparable from coal mining activities (Bell and York 2010). Creating such social and economic identification prevents coal regions from diversifying their economies and searching for novel ways of wealth generation and employment (Johnstone and Hielscher 2017; Oei *et al.* 2019; Andrews-Speed *et al.* 2005). Economic dependencies and job loss threats make their way down the supply chain, affecting a variety of local businesses (Johnstone and Hielscher 2017). and transport networks for domestic and international trade (Steckel *et al.* 2015): About 90% of internationally traded coal is currently transported by ship, while domestic coal trade relies on rail transport (Caldecott *et al.* 2016). Accordingly, the state and development of the coal sectors has economic and organisational impacts on shipping companies, ports, railway operators, and manufacturers of infrastructure components (ibid.). And finally, for many coal exporting countries, such as Columbia, Indonesia, Mongolia, or South Africa, the export of coal is an important foreign currency earner (Spencer *et al.* 2018).

It remains important to mention that coal mining and combustion are responsible for considerable economic loss, for example through air pollution and associated health problems

(Greenpeace 2015; Cui *et al.* 2019), acid rain that constrains agricultural production (You and Xu 2010), land degradation, and water stress (Caldecott *et al.* 2017). A recent study by the Potsdam Institute for Climate Impact Research (PIK) finds that the health and biodiversity damage reductions of a global coal phase-out considerably outweigh the economic costs in form of reduced GDP growth and energy system investments (Rauner *et al.* 2020).

2.1.3 Electricity System Integration

The majority of coal extracted today is used in power generation and to a lesser extent in iron and steel production and in the cement industry (Rocha *et al.* 2016). Unlike in industry, vast substitution opportunities exist for coal combustion in electricity generation, such as renewable energy sources, nuclear power, and as a short-term substitution option natural gas. This would not only tackle global GHG emissions efficiently and cost-effectively, but also yield a number of co-benefits in public health and environmental protection (ibid.).

Traditionally, Europe's power market predominantly consisted of national and regional markets, with vertically integrated utilities and regional monopolies (Caldecott *et al.* 2017). Since 1996, regulatory changes set out to increase competition, eradicate inefficiencies, and establish an EU-wide interconnected electricity market (ibid.). Today, in most European countries and other developed economies, electricity is dispatched according to a merit order system. In such systems, utilities offer their electricity at marginal cost, which is the cost incurred from producing one additional unit of energy, i.e. one additional kWh. Then, electricity is purchased from the lowest bidder first, then the second lowest, and so on, until demand is covered (DIW Berlin *et al.* 2019). The integration of renewables has (due to near-zero variable costs) substantially lowered wholesale electricity prices, and reduces revenues for all generators alike (Edmunds *et al.* 2015). Yet, especially the economic situation of generators with large sunk costs, such as coal plants, is dire (ibid.).

In Germany's merit order, coal generally ranks between PV, offshore and onshore wind, biomass, hydropower, and nuclear on the lower, and natural gas and oil on the higher end (DIW Berlin *et al.* 2019). The particular ordering of energy sources and technologies varies between countries, but generally demonstrates a similar pattern, where renewables are cheaper, and other fossil fuels more expensive. However, after the drastic collapse of oil prices in early 2020, coal is now the most expensive (per barrel of oil equivalent) fossil fuel in the US (Bloomberg 2020), which is likely to affect the price with which electricity from coal power stations is offered on the market. Particularly in countries with low gas prices and increasing shares of renewables, coal generation with high variable costs is gradually displaced, leading to the underutilization of coal power plants (Edmunds *et al.* 2015). A rising share of renewable energy in electricity supply raises balancing and electric capacity requirements, but the latter also depend on the size, interconnectedness, and flexibility of the electricity system (ibid.).

Many countries (including Australia, several US states, the UK, and various EU countries) have implemented capacity mechanisms (Schlandt 2015), which greatly vary in design but generally entail payments to utilities for providing secure generational capacity - rather than actual electricity delivered - to prevent supply shortages (Caldecott *et al.* 2017). Capacity reserves, a common type of capacity instruments, are perceived as alternatives to plant closures and attractive options to utilities as incurred costs can be passed onto consumers via electricity prices (DIW Berlin *et al.* 2019). There exist many disjointed national or regional initiatives, which are not only incompatible with each other, but also incentivise the prolonged use of inefficient plants (Caldecott *et al.* 2017). Additionally, capacity mechanisms are unreasonable from a technical perspective, as coal capacity reserves are particularly expensive because coal plants have long ramping up times and offer no solution to temporary shortfalls (IZES 2016 in DIW Berlin *et al.* 2019).

In many Asian countries, such as China, the electricity price is still (partly) regulated, and state-owned electric utilities shielded from considerable competition (Zhao *et al.* 2017). When the price of coal in recent years declined, this was not reflected in the electricity price and led to a distortedly high competitiveness of coal plants (Spencer *et al.* 2018). Electricity prices in China are set by provincial regulators, which artificially lowers investment risks and guarantees stable revenues for plant operators (Caldecott *et al.* 2017). Additionally, electric output is determined by guaranteed operating hours (Kahrl and Wang 2015). These provisions and the nature of a central planning system result in slow reaction times to changes in the market environment (ibid.) and have provided favourable operating conditions for coal plants. In India, the levelized costs (which are total costs; composed of capital costs, fixed costs, and variable costs) of solar energy have fallen below the variable costs of most coal plants, yet, this has not translated to an immediate substitution of coal for solar (Shrimali 2020). This has been attributed to a malfunctioning electricity market, where regulated tariff contracts dominate, and dispatch takes place at the state level (ibid.).

2.1.4 Energy and Climate Policies

Policies aiming at reducing coal combustion and limiting its environmental impact vary greatly between countries and over time. As a general rule, Edenhofer *et al.* (2018) recommend that governmental measures should reduce political uncertainty and demonstrate commitment to the long-term temperature targets. While a combination of different policies may be desirable to provide utilities with some flexibility in timing and managing their losses (Benn *et al.* 2018), restrictive policies should be evaluated carefully because they can result in significant distributional impacts (Steckel *et al.* 2015).

Specific measures include performance benchmarks, and emissions limits and standards (Pfeiffer *et al.* 2018; Cui *et al.* 2020), which have been implemented in over 20 countries as well as the entire European Union. In the EU, the Large Combustion Plants Directive (LCPD) of 2008 set limits to SO_2, NO_x, and particulate matter emissions, and was later replaced by the overarching Industrial Emissions Directive (IED), setting even stricter limits (Drax 2016). The Indian government mandated all new coal plants to use the more efficient supercritical technology (Spencer *et al.* 2018) and the majority of global coal plants are required to be equipped with pollution control technologies (Edenhofer *et al.* 2018). China has imposed national limits on consumption as well as region-specific consumption reduction targets (Spencer *et al.* 2018), while also granting plants with higher efficiencies grid priority in ten Chinese provinces (NDRC 2007 in Caldecott *et al.* 2017).

Carbon prices, imposed through carbon taxes or trading schemes, ought to render coal power production uncompetitive in comparison to low-carbon alternatives, but are by themselves often insufficient in replacing coal by natural gas (Caldecott *et al.* 2015) or incentivising a low-carbon transition (Pfeiffer *et al.* 2016). Removing alternative revenue sources such as capacity payments, or introducing governmental take-overs and write-offs have been proposed as more drastic measures of depriving coal its market base (Benn *et al.* 2018). Finally, some scholars argue that providing governmental support to renewables, for example via de-risking instruments, research and development (R&D) support, and subsidies, will enact the needed regime shift, while others claim that resulting technological improvements and declining costs are likely to be "too little, too late" to achieve the Paris goals (Edenhofer *et al.* 2018).

Coal sector policies that do not target the immediate operation of coal plants are less common. They include coal moratoriums on new coal mines (Pfeiffer *et al.* 2018; Steckel *et al.* 2015), divestment activities by development banks (Steffen and Schmidt 2019), licensing requirements for new power plants, or denying high emitters lifetime extensions (Pfeiffer *et al.* 2018). More indirectly, the liberalisation of fuel and electricity markets exerts substantial pressure on coal mining and combustion activities (Spencer *et al.* 2018). The downward trend of natural gas and renewable prices renders coal production increasingly unprofitable (Benn *et al.* 2018), which can only be cushioned by national governments to a limited extent. Additionally, energy efficiency measures in the end use sectors reduce final electricity and thus coal demand. Citizen opposition to coal mining and firing also has no immediate effect on their day-to-day operations – with a few exceptions in which the supply infrastructure was interrupted (Welt.de 2019; The Guardian 2019) – but a comprehensive shift of electricity consumers to ‘green’ competitors leads to the erosion of the consumer base and reduces the leverage on policymakers (Benn *et al.* 2018).

2.2 Energy System Change

The following sections provide a brief overview of popular concepts and theoretical frameworks for studying, conceptualising, and understanding transitions in general and energy system change in particular. Because there is no single transition theory that adequately captures the complexity and diversity of energy transitions (Cherp *et al.* 2018), insights from multiple disciplines will be integrated and structured according to the different stages of a technology’s life; namely its rise, stagnation/persistence, and decline. Finally, empirical evidence from past energy transitions mainly regarding their scope and speed will be presented.

Some theoretical contributions originate from research on energy transitions specifically, while others stem from more general observations on technological change. In all following sections, it will be assumed that these fully apply to energy systems. Further, some scholars refer to individual technologies while others base their studies on entire industries or energy systems. In order to integrate all findings, I assume that they equally apply to each other irrespective of their scope or depth. Finally, one intuitively associates the rise of energy technologies with the deployment of renewables, while relating decline to coal or nuclear. Even though many scholars also follow this distinction, there is no fundamental rule dictating this.

2.2.1 The Rise of Energy Technologies

2.2.1.1 Innovation Studies and Technology Diffusion

Energy transitions typically begin with the emergence and diffusion of a new technology (Markard 2018). The diffusion of an innovation is understood as the “process by which an innovation is communicated through certain channels over time among the members of a social system" (Rao and Kishore 2010, 1070). Innovations themselves are the manifestations of technological progress, which in turn is brought about by societal needs and pressures (Ayres 1988). The process of technology diffusion is composed of distinct phases, such as the pre-development, take-off, acceleration, and stabilisation phase (van der Brugge and van Raak 2007), or the formative, upscaling and growth phase (Wilson *et al.* 2013).

Technology diffusion is most commonly depicted in two ways: Firstly, by mapping the (annual) adoption over time in a normal, bell-shaped curve; and secondly, by mapping the cumulative number of adoptions in an S-shaped curve. The most popular model for the former is based upon Rogers (2003) adoption process, in which he categorises consumers into innovators, early adopters, early majority, late majority, and laggards (see Figure 1). Each phase of consumer adoption is associated with inherent challenges, such as mobilising sufficient financial support to set up the technology in the first phase (Rao and Kishore 2010).

Figure 1: Diffusion process and phases of consumer adoption
(source: Castro et al. 2017; adapted from Rogers 2003)

The S-curve of technology diffusion is typically represented as a logistic growth function that initially exhibits almost exponential growth, then close to linear growth around the inflection point, and finally enters a phase in which growth decelerates and the technology reaches saturation (Wilson 2012). Besides cumulative adoption, the S-curve model is also used to illustrate the development of a technology's performance (Ayres 1994; Christensen 2009; see Figure 2). Generally, S-shaped technology trajectories have multiple underlying mechanisms and drivers, and are composed of a variety of adoption processes (Grübler 1991).

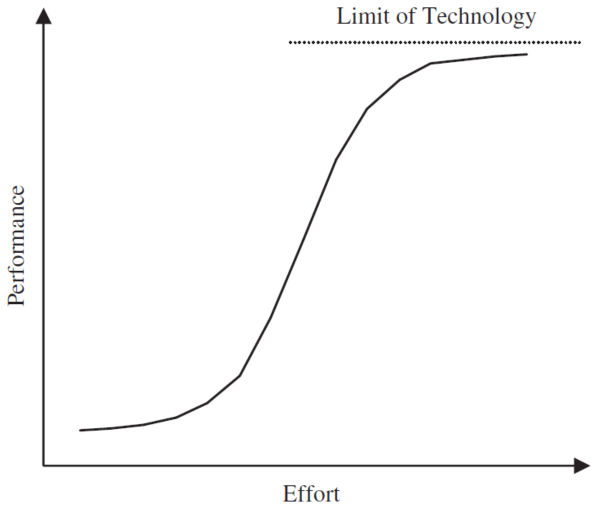


Figure 2: Technology S-curves
(source: Schilling and Esmundo 2009)

Research has shown that the rate of diffusion depends on various technical, economic, social, and institutional factors, which can each hinder or facilitate the diffusion process. According to Rogers (2003), the speed of diffusion depends on five key technology attributes: i) relative advantage, ii) compatibility, iii) complexity, iv) trialability, and v) observability. Further, a technology's success and 'survival' on the market is facilitated by an efficient management of resources, effective processes of knowledge creation, and a constant adaptation to their institutional environment (Nelson and Winter 1977; Dosi and Nelson 1994).

According to Grübler (1991), earlier stages are characterised by high levels of uncertainty and volatility. Typically, new technologies are unreliable or expensive, and only offer benefits to specific markets (Schilling and Esmundo 2009). Novel technologies are immature and cannot compete with established technologies (Markard 2018) because they lack knowledge, financial resources, and supporting technology networks (Ayres 1988). Governmental support and protection allow these innovations to mature in their 'niche' (cf. Rip and Kemp 1998).

After an initial period of turbulence and incremental improvements, learning effects, increasing production volumes, and economies of scale lower technology costs and create positive feedback loops (Neij 1997). Throughout this process, the unit size is scaled up while the entire industry grows (Wilson 2012). A dominant design eventually emerges at the end of various adaptation processes (Grübler 1991), while internal and external connections are formed and solidified. Rogers (2003) described the innovation-diffusion process as an "uncertainty reduction process" (p. 232), as technologies move from market introduction to market domination. For a long while, the emergence of a novel technology does not dramatically affect the strategic and every-day activities of incumbents, who in turn ignore or mildly oppose their emerging competitors (Markard 2018). According to the Multi-Level Perspective (MLP), one of the most popular frameworks for studying energy transitions, niche innovations break through once a 'window of opportunity' opens up (Verbong and Geels 2007) after which they replace incumbents to form a new 'regime' (Kemp *et al.* 1998).

Eventually, adverse social and environmental effects accumulate and create negative feedback mechanisms (Grübler 1991). These slow down the growth of a technology by which it reaches its inherent limit, or saturation point (Wilson 2012). While investments in early phases lead to substantial increases in performance, equivalent investments made now harvest diminishing returns (Ayres 1988; Schilling and Esmundo 2009). In this "era of incremental change" (Anderson and Tushman 1990, 606), companies focus on refining their core competencies but refrain from developing alternative ideas. This makes them vulnerable to changes in their external environment and increasingly unable to respond to pressures (Henderson and Clark 1990). They are 'locked-in' or 'too refined to innovate' (Sundstrom and Allen 2019; Fath et al. 2015) but able to delay their decline and replacement through making incremental changes.

2.2.1.2 Temporal and Spatial Diffusion

Typically, innovations originate in a 'core' market, from which they gradually spread to the 'rim' (early adopters) and eventually to the 'periphery' (late adopters) (Grubler 2012). Due to spill-over effects and the ability to build upon existing knowledge (Grubler 1991), energy technologies diffuse faster in the periphery than in the core (Grubler 2012). They do not, however, reach the same level of market penetration. The diffusion and maturation of entire energy systems, as opposed to individual technologies, generally takes longer due to the embeddedness in institutions, infrastructures, and existing knowledge (Grubler et al. 1999).

Wilson (2012), who splits the entire diffusion process into the formative, upscaling, and growth phase, argues that the formative phase in the periphery is shorter or even omitted, but the upscaling of any technology takes place over a similar timeframe in core and periphery. This is because "[l]ocal knowledge and institutions are needed to develop, manufacture (or import), adapt, install, and above all, use a new energy technology effectively" (Wilson 2012, 92). Consequently, global technology diffusion relies on knowledge, hardware, and finance, but most importantly the capacity to absorb new technologies and adapt them to suit local conditions (Nordensvard *et al.* 2018).

Studies on the diffusion of renewable energy (RE) technologies are numerous (Jacobsson and Johnson 2000; Hekkert *et al.* 2007; Bergek *et al.* 2008; Schot and Geels 2008; Loorbach and Raak 2006; Caniëls and Romijn 2008; Geels 2005). But interestingly, this kind of analysis does not exist in comparable volume in the case of fossil fuel technologies. One exception to this is Wilson et al. (2013), who find a consistent relationship between cumulative installed capacity (extent) and how long this growth takes (duration) for several fossil fuel-based technologies. The S-shaped relationship holds true for both energy supply and end-use technologies (including natural gas, nuclear, coal, cars, refineries), as well as for all world regions (including the core, rim, and periphery).

2.2.2 The Stagnation and Persistence of Energy Technologies

It is not uncommon for technologies to retain market dominance over long time periods despite being inferior to alternatives (Arthur 1989). The two main reasons behind this are the effects of lock-in and path dependency, for which research from the fields of evolutionary economics and neo-institutional theory provide key insights. Companies' activities are guided by 'technological regimes' (Nelson and Winter 1977), which are techno-economic conditions that channel a firm's everyday activities and long-term strategies into a particular direction, thereby limiting their scope of actions and introducing path dependencies. This effect is aggravated by the formation of technology clusters, which are comprised of different technologies that benefit from each other's existence and provide mutual support. This shields them from external pressures and enables them to guard their market position from competitive new clusters, effectively leading to a 'lock-in' of the dominant design (Grubler *et al.* 1999).

Firms in an industry are further influenced by shared beliefs and mindsets, as well as common norms and identities (Dutton and Dukerich 1991). This transforms former technological regimes into socio-technical ones and brings the interplay between agency and institutions into the picture (Lawrence *et al.* 2009). Socio-technical regimes are "mainstream, highly institutionalised way[s] of currently realising societal functions" (Smith *et al.* 2010, 443) and a key cause of lock-in. The presence of a uniform mission and high internal commitment to certain mental maps leads to cognitive inertia and a reluctance to reorient or restructure once external pressures arise (Turnheim and Geels 2012). As a result, the activities by firms are mainly incremental rather than architectural (Markard *et al.* 2020). Further, in this time of temporary equilibrium or plateau, systems are characterised by low overall diversity (Fath *et al.* 2015), while the concentration of power is high (ibid.; Markard *et al.* 2020).

According to Scott (2008), there are three institutional pillars: regulative institutional elements, normative elements, and cultural-cognitive elements. Cultural-cognitive elements are the most difficult to change as they are deeply embedded in societies. Giddens' (1986) structuration theory illustrates that actors are constrained by their respective socio-political structures, but that they also play a key role in shaping them (Lawrence et al. 2006). When actors relate to the existing structures, which they perceive as normality, they continuously reproduce and strengthen existing institutions (Giddens 1986).

Gregory C. Unruh (2000) applies these principles to an energy context; arguing that lock-in is brought about by interactions between a technological system and state institutions that manifest themselves in laws and regulations. Dominant energy systems are advantaged as they rely on already available infrastructures, perfectly align with legal and economic systems, and resonate with organisational structures and user-behaviour (Clausen and Fichter 2016; Smith and Stirling 2010). Energy regimes are reproduced by a variety of actions, including large investment decisions of infrastructural projects as well as routine decisions by managers or end-users (Smith and Stirling 2010). Meadowcroft (2009) further highlights that incumbent actors have established a large network of partners over time, which can include close ties to policymakers (Heyen 2017) and unlocks reinforcing mechanisms (Geels 2002).

2.2.3 The Decline of Energy Technologies

The majority of energy transition research is concerned with the emergence of (sustainable) energy technologies, while the destabilisation and decline of incumbent energy technologies such as fossil fuels and nuclear power is understudied (Markard *et al.* 2020; Heyen 2017) and often expected to happen simultaneously (Turnheim and Geels 2012). Decline has only been studied on a case study basis for specific technologies in specific regions (Markard *et al.* 2020). Critics of this ‘innovation bias’ (Hermwille 2016; Geels and Schot 2007) have highlighted that conceptually, energy transitions are ‘phase-in / phase-out’ processes (Bromley 2016) and have unfolded accordingly in the past.

2.2.3.1 Regime Destabilisation and Exnovation

Turnheim and Geels (2012) define regime destabilisation as a process in which the reproduction of key regime elements is weakened. There are several drivers behind such destabilisation, some of which are political and governed while others are not. Following preceding explanations, industry decline can be caused by limited access to resources, economic difficulties (Dosi and Nelson 1994), and eroding public legitimacy (Lounsbury and Glynn 2001; Powell 1991), but also result from weakened commitment within industry. At the same time, novel technologies pose a threat to the business model of incumbents, institutional structures change more profoundly than before, and negative externalities accumulate (Markard 2018; Markard *et al.* 2020). Industry decline is aggravated by delayed, inappropriate, or insufficient responses by industry actors (Turnheim and Geels 2012). The likelihood of such decline is higher in the case of various external pressures as industries cannot address multiple pressures simultaneously, especially when they had not been anticipated (ibid.; Geels 2018).

Destabilisation is a longitudinal process that entails elements of coordination and chaos; eventually leading to industry decline or reconfiguration (Turnheim and Geels 2012). When comparing dynamics of decline with those of the emergence of a technology, fewer rules of thumb and trends have been identified. According to Markard *et al.* (2020), processes of decline may be similar (e.g. intensification of knowledge generation), inverted (losing as opposed to gaining public legitimacy), or simply different. The decline of a technology necessarily affects networks and institutions beyond core firms, which can lead to a "vicious circle of adverse developments" (ibid., 2). If decline is inevitable, incumbent firms tend to 'milk their assets' and call for governmental compensation payments.

The concept of 'exnovation' – as the antagonist to innovation – is closely related to that of destabilisation but has a normative, intentional, and directional character. Exnovation "entails actions to disrupt institutional structures in ways that serve to unseat the ideas associated with maintaining those institutions, to allow for their replacement by new ones" (Davidson 2019, 255). Exnovation is often perceived as a process through which a certain technology is phased out completely (Heyen 2017), but this must not be the case (Antes *et al.* 2012). A prominent example is the politically intended phase-out of conventional light bulbs. There exists a large toolbox of destabilisation and exnovation instruments, such as the phase-out of governmental subsidies, divestment by public and private financing institutions, regulatory bans, withdrawals of operating permits, limits, standards, taxes, emission trading schemes, or tariffs (Heyen 2017; Rogge and Reichardt 2016; Pearson and Foxon 2012).

To counteract these, firms-in-an-industry make use of a variety of strategies that hinder or slow down their decline (Turnheim and Geels 2012). These strategies range from defensive strategies, such as incremental innovation or early diversification, to more confrontational strategies, such as framing and storytelling, discrediting opponents, indulging in symbolic action, or even bribery and unconstitutional contributions to political parties (Geels 2014; Hillman and Hitt 1999). Additional barriers to the decline of industries are the sheer number and strength of internal and external connections (Heyen 2017), the regional concentration and economic relevance of associated operations (Johnstone and Hielscher 2017; Spencer *et al.* 2018), and governmental support in the form of subsidies or exceptions from laws and regulations. Another important finding is that decline is not automatically activated once critical thresholds, such as the loss of cost-competitiveness, are reached (Grubler *et al.* 2016; Wilson *et al.* 2013). This is mainly due to institutional inertia, infrastructurally-induced path dependencies, incomplete information and high uncertainties (Metcalfe 1994, see section 2.2.2).

2.2.3.2 Temporal and Spatial Decline

Spatial decline – as opposed to spatial diffusion – is a widely neglected topic within energy transition research. An exception to this is Grubler (2012), who investigated historic energy transitions in Europe and found the decline of an energy technology to be "an inverted mirror image of the previous core-diffusion geography" (p. 13), meaning that late adopters are also the first ones to abandon the technology at hand. He bases his observations on the market share of coal in primary energy demand, which early peaked in the UK (the 'core'), and was later adopted, but also earlier abandoned in Spain, Portugal, or Italy (the 'rim').

Another example is a study by Markard *et al.* (2020), who investigate decline in nuclear power by analysing the development of annual electricity output, the number and concentration of reactor types, and decisions by nation states to ban new or restrict existing operations. Apart from several case studies of specific energy technologies in specific countries, no substantial research has – to my knowledge – been directed at the rates, timescales, and spatial patterns of energy technology decline.

2.2.4 Empirical Evidence from Past Energy Transitions

Considerable disagreement about the very definition of energy transitions as well as their scope and agenda exists (Greenpeace 1993; Fabra *et al.* 2015; Grubler 2012; Hermwille 2016; Meadowcroft 2009; Markard *et al.* 2012). For the remainder of this thesis, I draw upon Fouquet and Pearson's (2012) comparatively broad definition of energy transitions as "the switch from an economic system dependent on one or a series of energy sources and technologies to another" (p.1), as the depth and transformational character of energy system change is irrespective of its contribution towards sustainability (Cherp *et al.* 2018).

Energy transitions differ across time periods and geographies, unfold according to their specific contexts, and provide ample room for assertions regarding their respective causes and effects. However, a number of communalities, such as high complexities, multi-decadal time scales, and non-linear developments, have been identified (Wiek and Lang 2016; Fabra *et al.* 2015). Influenced by "a myriad of drivers" (Child and Breyer 2017, 11) and deeply embedded in socio-economic structures (Turnheim and Geels 2012), energy transitions have proven to be difficult to govern (Laes *et al.* 2014). Further, a global energy transition will be the result of multiple country-specific decarbonisation pathways, that spill over and influence each other (Kern and Rogge 2016).

Fouquet and Pearson (2012) argue that most energy transitions have taken place over a time period of 40 years. Grubler (2012) posits that it took 130 years for coal to replace traditional renewables in primary energy supply in Europe, and then another 80 years for coal to be replaced by oil, natural gas, and electricity. After Sovacool (2016) claimed that recent energy transitions unfolded substantially faster than in the past, a heated scholarly debate broke out (cf. Grubler *et al.* 2016; Smil 2016; Kern and Rogge 2016; Fouquet 2016; Sovacool and Geels 2016). What has been learned from this exchange, is that the speed of transitions depends on the complexity of energy systems involved, as well as the geographic area in which they occur. Generally, transitions in energy supply rather than end-use (Grubler 2012), those involving advanced technologies, as well as those requiring large capital investments and lacking adequate resources take longer to unfold (Bromley 2016).

Kern and Rogge (2016) believe that future transitions could well unfold faster than in the past, because the momentum behind ongoing low-carbon transitions is unprecedented, and energy systems are no longer dominated by just one energy carrier. Further, energy systems have become more interconnected, involve a rising number of diverse actors, and encompass multiple dynamic feedback mechanisms – all of which can potentially accelerate but also delay a transition (ibid.). With these considerations in mind, it is reasonable to assume that "[r]ates of change are slow, but not always" (Grubler 2012, 11).

3 Theoretical Framework (TF)

3.1 Research Gap and Motivation

The preceding sections have highlighted that a dominating share of energy sector research is focused on RE trajectories. Given the urgency to act upon climate change, many scholars argue that there is not enough time to wait for low-carbon technologies to successively replace the existing fossil fuel-based system (Unruh 2002; Kivimaa and Kern 2016; Smith and Kern 2009; Kemp *et al.* 2007). Understanding the decline of fossil fuel technologies is of increasingly relevance to enable decisionmakers to accelerate decline (Markard 2018). More generally, studying decline is crucial for recognizing the interactions between emerging and declining technologies, and being able to mitigate negative transition effects (ibid.).

Additionally, most studies on aspects of energy transitions are qualitative and concerned with one particular country and one particular energy technology and thus less apt to make generalisable statements about similar dynamics in other countries. Associated theoretical considerations have been criticised for lacking operationalizability and real-world applicability. At the same time, quantitative energy modelling approaches lack sensitivity to respective socio-economic and political contexts. In the absence of frameworks and theories concerned particularly with the decline of a technology or its entire life, a new theoretical framework (TF) was developed that builds upon and expands theories reviewed in 2.2.1-2.2.3. The following TF aims to combine qualitative and quantitative methods. One key underlying assumption is that national coal transition paths “connect and accumulate into global ones” (Markard 2018, 632), which is why the evolution of coal will be analysed in 32 individual countries and 6 main coal consuming regions, which are aggregates of national developments.

3.2 Theories and Hypotheses

The TF is based on the two main diffusion of innovation models, which conceptualise technology development according to cumulative adoption (S-shaped curve of diffusion of innovations) and annual adoption or phases of consumer adoption (bell-shaped curve of diffusion of innovations). Additionally, dynamics of technology decline as described in section 2.2.3 are integrated by acknowledging the eventual downfall or termination of a technology – both in a systemic sense as well as on the individual unit level. The entire life of a technology (here: coal combustion for electricity generation) is impacted by the life of its individual elements (here: coal units).

Given this additional temporal dynamic, annual abandonments of a technology (here: capacity retirements) are subtracted from annual adoptions (here: capacity additions) for every year. Given the finite nature of all fossil fuel energy carriers, annual unit retirements eventually outweigh annual additions so that the S-curve of technology diffusion is followed by a mirrored S-curve of technology decline or exnovation (Figure 3).

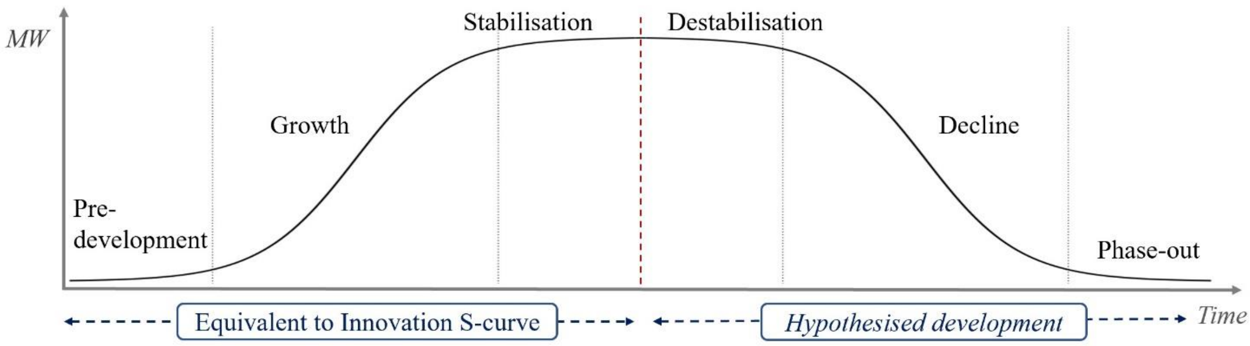


Figure 3: S-curves of Innovation and Exnovation
(author's illustration)

Similarly, this can be depicted in a bell-shaped curve, where technology abandonments display a mirrored and inverted image of adoptions (Figure 4). Both curves are based on the hypothesis that the period of decline and abandonment follows a similar trajectory (e.g. with regards to shape and speed) as the period of technology diffusion. Further, capacity retirements are assumed to take place while capacity additions are still ongoing (just like S-curves of two different technologies overlap). What matters here (and what is depicted in the model) is the net change.

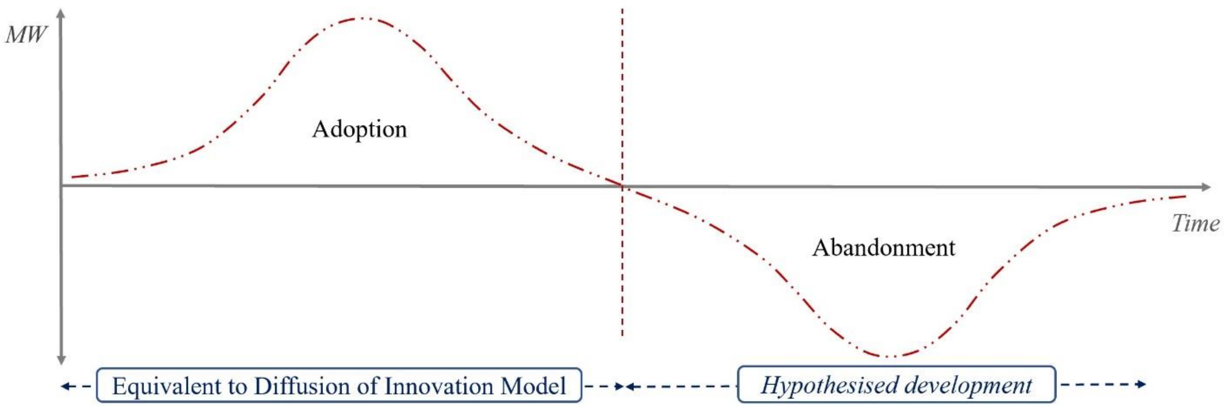


Figure 4: Phases of technology adoption and abandonment
(author's illustration)

With regards to spatial dynamics, I hypothesise that the core-to-periphery diffusion model is mirrored in decline, so that the first adopters of a technology are the last ones to abandon it (see also Grubler 2012). Further, and following Grubler (2012), I hypothesise that the saturation level in the periphery is lower than in the core.

Following section 2.2.1, it is assumed that coal capacity is undergoing constant change, and that a dominant design will emerge as the result of an ongoing adaptation process. This process presumably unfolds differently in the countries of investigation, as energy sector developments are substantially impacted by socio-economic and political contexts (sections 2.2.1-2.2.4).

Lastly, the phases rise, stagnation, and decline are not unambiguously separable. For example: is the decline of coal enacted once annual adoption levels fall or turn negative, once total installed capacity decreases, or once electricity generation from coal declines? As a result, all three trajectories will be analysed and compared.

3.3 Integration of TF and ROs

A combination of the TF and the research objectives (section 1.3.3) is depicted below (Figure 5). The TF is concerned with patterns and rates of change, over time and across countries. It provides a broad, techno-economic context (RO1); integrates qualitative aspects of coal fleet development (RO2) with quantitative change over a technology's life (RO4); shine light on the lifetime of a unit (RO3); and explores the relationship between coal capacity and coal-fired electricity generation (RO5).

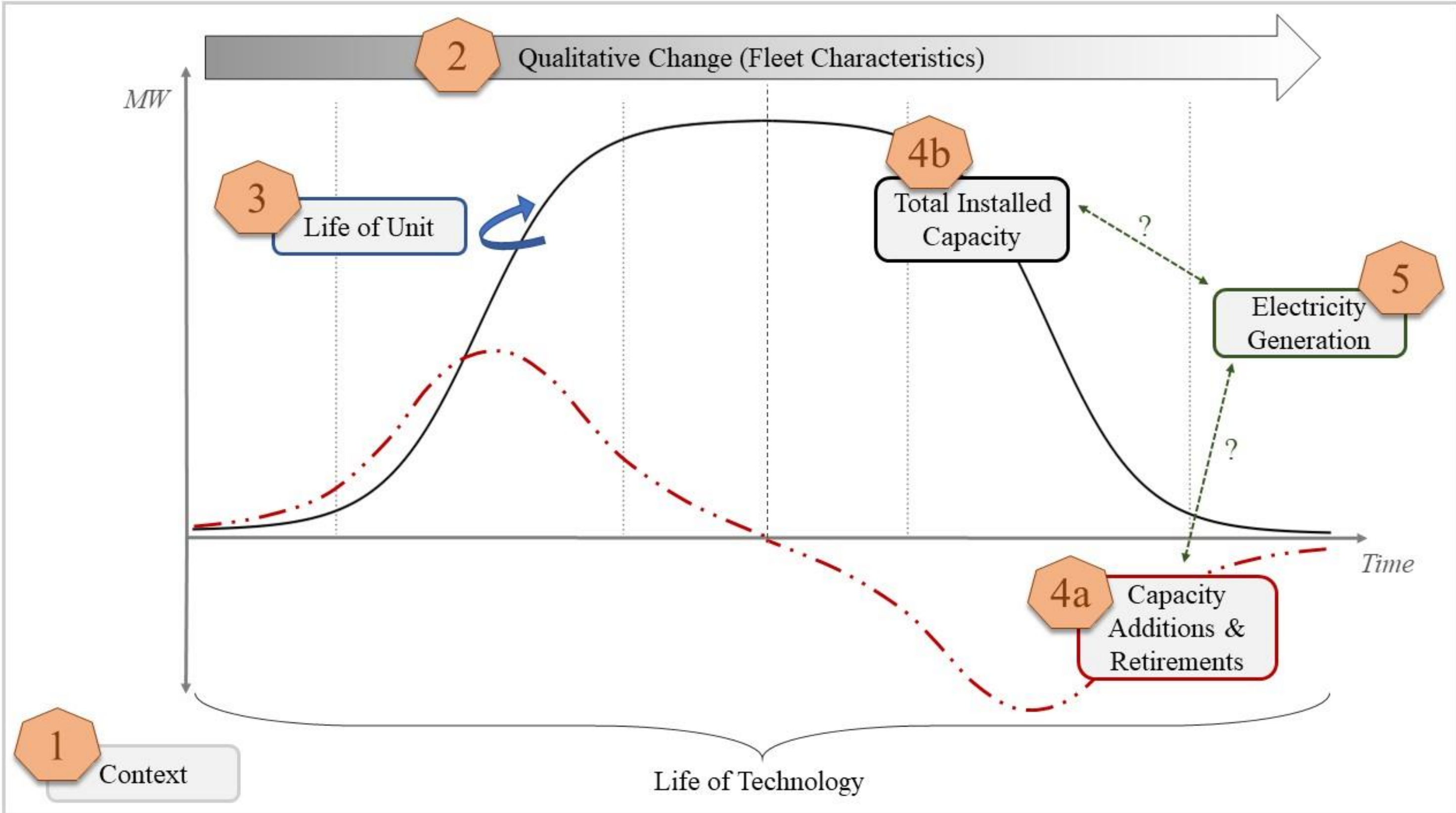


Figure 5: Integration of theoretical framework and research objectives
(author's illustration)

4 Methods and Results

4.1 Introduction and Outline

The first part of the results (section 4.3) is comprised of an analysis of literature on techno-economic aspects of coal combustion and fleet development. This section ought to provide a comprehensive overview of important factors that influence the short and long-term operating context of coal plants. Not all aspects will be revisited in later analysis, but they are deemed important to understand the internal and external factors affecting both day-to-day operations and strategic decisions to construct or retire coal plants. Specifically, economic and technological factors, lifetimes and retirement ages, as well as premature retirements and stranded assets will be discussed.

For the quantitative analyses of sections 4.4-4.7, the time frame of investigation will span the years of 1960 until today. Regarding the spatial scope, it will include all world regions but pay particular attention to the largest coal consuming countries or regions as well as particularly interesting cases. The analysis follows up with several ideas and findings from section 4.3 by testing and expanding upon previous results. All following sections will be organised according to the order of the formulated research objectives (section 1.3.3) and thus depart from the conventional structure of a comprehensive overview of methods being followed by all results. This is due to the chosen approach of exploratory data analysis, in which results from earlier steps were taken into account in later analysis and in which findings successively build upon another.

4.2 Datasets and Data Wrangling

The quantitative analyses are based on two datasets of coal power plants worldwide. One is S&P Global Market Intelligence World Electric Power Plants (WEPP) Database from October 2017, which is a comprehensive global inventory of 219,500 electric units, of which 16,913 are coal-fired stations. The other is Global Energy Monitor’s Global Coal Plant Tracker (hereafter GCPT) database of January 2020, which lists 12,875 coal-fired electric units.

Given WEPP’s greater coverage and GCPT’s more recent update, the two datasets were manually merged by maintaining WEPP as the main database, and updating information (mainly statuses and operating or retirement years) with the use of GCPT. This was done by manually matching unique unit names, and in the second instance confirming nameplate capacity, operational year, and location. The update concerned about 1,500 units that changed their status between 2016 and 2020, the majority of which can be ascribed to plants becoming operational or retiring. About 6% of the plants listed in GCPT could not be matched to respective counterparts in WEPP, which implies that they are either missing in WEPP or are listed under a different name. Given the latter, as well as their generally smaller size, these unmatched units were not included in the final dataset.

In the case of Chinese units, the matching yielded unsatisfactory results and consequently, data on Chinese coal plants was not updated. Instead, anticipated changes in 2017 (e.g. units becoming operational between 2017 and 2020) as listed in WEPP were assumed to realise accordingly. Cross-checking these assumptions with a Carbon Brief analysis of global coal plants (Evans and Pearce 2020), which is based on the GCPT database, suggests that retirements of Chines units are underrepresented for 2017-2020, as well as units becoming operational in 2019. However, values for capacity additions and retirements also deviate for the time prior to 2017, which is presumably due to the use of different main data.

All units announced to retire or start operation in 2020 were assumed to do so this year. Had units planned to become operational or retire before 2020 but were not updated accordingly, the year 2020 was assigned. While it is not uncommon for units planned or under construction to be cancelled (Shearer *et al.* 2020; Shearer *et al.* 2018), this number is presumably low for plants within one year of operation start. Finally, for all units that were listed as retired but had no explicit retirement year, a 40-year lifetime was assumed (following, for example, Farfan and Breyer 2017) and the respective retirement year added. While this can be highly inaccurate on the particular unit level, it is regarded reliable on a country or region level aggregate (Pfeiffer *et al.* 2018). For all retired plants where the retirement year would have been in the future, the retirement year was determined to be 2020. This necessarily leads to an overrepresentation of retirements in 2020, but rightly includes units that would otherwise have been excluded. Likewise, for retired units that had a known retirement but missing operational year, the latter was added assuming a 40-year operational life.

One final caveat is that the WEPP dataset is not comprehensive regarding units built in the first half of the 20th century, especially for non-OECD countries. Despite the limitations mentioned, the final dataset is deemed fairly representative and for most countries accurate, especially on the aggregate level.

Lastly, to enable a more systematic analysis, two different country classification schemes were established (see Table 1 and 2).

Table 1: Country classification scheme I: Coal use

	Countries with sustained decline in coal combustion	Countries accounting for the majority of coal combustion
Abbreviation	**DEC18**	**COAL14**
Metric	Percentage decline between peak (since 2000) and last available year, calculated as the change in power supply from coal combustion, adjusted for system size (total electricity supply). Both are averaged over 3 years. Inclusion when decline ≥ 10%.	"[T]he 18 countries that together account for over 90% of global coal-fired electricity" (Jewell *et al.* 2019) minus the countries that exhibit sustained decline in coal
Countries	Austria, Belgium, Bulgaria, Canada, Czech Republic, Denmark, Finland, UK, Greece, Hungary, Ireland, Israel, North Korea, Romania, Slovakia, Spain, Ukraine, USA *(total: 18)*	Australia, China, Germany, India, Indonesia, Japan, Kazakhstan, Malaysia, Poland, Russia, South Africa, South Korea, Turkey, Vietnam *(total: 14)* [Former Coal18: Czech Republic, Spain, Ukraine, USA]
Reference	Vinichenko and Jewell (2019)	Jewell *et al.* (2019)
Rationale	To study systemic differences between the two groups of countries	

Table 2: Country classification scheme II: Focus regions

	Focus region	Countries in focus region
Classification	China	China
	India	India
	USA	USA
	EU	Countries with coal plants: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, UK
	Non-EU OECD	Countries with coal plants: Australia, Canada, Chile, Israel, Japan, Mexico, New Zealand, Turkey, South Korea
	ROTW (rest of the world)	All other countries with coal plants
Reference	Rocha *et al.* (2016), and expanded by USA and India	
Rationale	To study systemic differences between key world regions.	
Note	The term region is here used in a broad sense. For example, China, India and the US are individual countries but highly significant given the size of their national coal fleets. Further, regions are not strictly classified according to the geographic location of countries, but also other (economic) criteria (e.g. OECD).	

4.3 RO 1: Characteristics of the Global Coal Fleet

The following literature review briefly outlines relevant areas of research on coal capacity. It serves as a qualitative basis for the following quantitative analysis. Not all topics reviewed will be quantitatively investigated in the subsequent sections but are key to understanding the operating environment of coal plants (e.g. economic factors). Other aspects will be revisited and analysed using different data (e.g. capacity development), a more comprehensive or different set of countries over a longer or different period of time (e.g. lifetimes, load factors, infrastructure age).

4.3.1 Economic Factors

4.3.1.1 Capital Costs

The capital costs of a coal plant correspond to the initial investment required. Capital costs of coal plants are substantially higher than those of natural gas plants (Hirth and Steckel 2016), and yet higher for lignite rather than hard coal plants (DIW Berlin *et al.* 2019). Similarly, capital costs for new, more efficient plants range above those of old and less efficient ones (Caldecott *et al.* 2017) but vary substantially according to specific plant characteristics and have generally increased over time. Lately, amortization periods extended beyond 20 years of operation (Umweltbundesamt 2009). Long payback periods are problematic as utilities are more likely to be legally entitled to governmental compensation payments when plants have to retire prior to making profits (Schomerus and Franßen 2018). Unlike in the case of renewable energy technologies, capital costs cannot dramatically fall as a result of mass production, and most technological improvement options have already been exploited (Ellis *et al.* 2013).

In many Asian countries, coal has been the least-cost option for over a decade (World Energy Council 2013). Nonetheless, should overall costs for renewables decline relative to coal, Edenhofer *et al.* (2018) caution against believing that this would put a halt to all new coal developments, as fossil fuel plant operators continue to access finance relatively effortlessly. At the same time, capital market constraints in many developing countries prevent the large-scale rollout of renewables (Schmidt 2014).

In most developed countries, the construction costs for coal units have "always been painfully high" (Ellis *et al.* 2013, 7) due to the large size, complexity, and safety requirements. However, investment risks were low, as electricity demand was projected to grow steadily. Additionally, excess capacity was financed by ratepayers in monopoly-dominated electricity markets (ibid.).

These two conditions have dramatically changed in recent years and now provide more favourable conditions for RE. These novel challenges could be one of the reasons why the construction of new coal plants is now dominated by large companies (Urgewald 2019), who have a greater capacity to tolerate economic losses.

4.3.1.2 Operating Costs and Revenues

The operating costs of a coal unit depend on multiple factors, such as size, location, combustion technology, ownership, and environmental regulations. Operating costs include cash costs, which are fuel costs and variable operations and maintenance (VOM) costs. Fuel costs depend on the calorific value of coal, as well as the type and distance of transport. VOM costs cover the purchase of water, chemicals, supplies, and waste disposal. But operating costs also include costs associated with keeping a unit online, maintaining its performance, and complying with environmental regulations (Gray and Watson 2018). Under normal utilization, fuel costs constitute the largest share (~70%) of total operating costs, but fixed operations and maintenance (FOM) costs per MWh of electricity rise with declining utilization rates (ibid.).

In energy-only markets, revenues are generated from electricity sales on the spot market and should be high enough to cover both operational costs in the short term and capital costs in the long term (DIW Berlin *et al.* 2019). Due to the increasing integration of renewables and the corresponding decline of electricity wholesale prices, many plants struggle to recover even their operating costs and fall back on capacity payments or revenues from heat supply (ibid.; Caldecott *et al.* 2017). Generally, capital and FOM costs are only recoverable if units are utilized at the rate they were designed for, but an increasing share of plants allocate these costs over a decreasing number of hours (Gray and Watson 2018). Higher fuel costs for hard coal plants outweigh benefits from lower capital costs so that the utilization rate of hard coal plants typically lies below that of lignite plants (DIW Berlin *et al.* 2019).

According to a Carbon Tracker report (Gray *et al.* 2018), almost half (42%) of the global coal fleet is unprofitable in 2018, and the number is expected to rise to 72% by 2040. As of now, 35% of coal capacity is presumed to have higher operating costs than renewables, which is expected to increase to 72% in 2040. Countries in which renewables are already cheaper than coal include Australia, China, India, South Africa, the United States and the EU (ibid.).

4.3.1.3 Economic and System Costs

A ‘domino effect’ (DIW Berlin *et al.* 2019) or a ‘death spiral’ (Caldecott *et al.* 2016) has been observed among various coal value chains. Mining is only profitable if a certain output quantity is reached, transport only economical under full load, and the operation of many plants only cost-effective under high utilization rates (DIW Berlin *et al.* 2019). Thus, one struggling or declining system element potentially takes up- and downstream sectors down, especially if they are vertically integrated and lack alternative suppliers, customers, or contractors.

On the other hand, energy and climate scholars agree that early action on phasing out coal lowers overall mitigation costs (Edenhofer *et al.* 2018) and reduces mitigation requirements in the second half of the century (Bertram *et al.* 2015). Early action could take the form of cancelling all coal plants currently planned or under construction, as well as discontinuing the operation of unprofitable plants – unless they are crucial for reliable electricity provision (Hughes 2016). Keeping unprofitable plants online is detrimental to regional businesses and consumers that rely on affordable electricity, because a thwarted phase-out delays the development of lower operational cost capacity (ibid.). The costs of stranded assets will be revisited in section 4.3.4.

4.3.1.4 Ownership

The majority of coal capacity in operation or under construction (90%) is situated in regulated or semi-regulated markets (Gray *et al.* 2018). This has impacts on the ownership structure, which in turn affects the operating environment and utilization of coal plants. In liberal markets, such as the US and UK, losses are suffered directly by companies and workers, whereas in political economies with high levels of coordination between governmental and non-governmental actors, more compensatory payments are made towards firms and coal sector employees (Spencer *et al.* 2018). In an overview of ownership across world regions, Caldecott *et al.* (2016) find that the majority of plants across China, India, and the EU are owned by the state or by state-owned utilities.

In China, for example, state-owned companies face a substantially different operating environment than foreign companies, which are more exposed to market forces (Caldecott *et al.* 2017). State-owned enterprises also generally have easier access to credit and are enjoying guaranteed returns on investment. This has led to the build-up of significant over-capacity in China in times of declining power production from coal (Greenpeace 2015). In many countries (e.g. China, South Africa, Germany, Spain, the Netherlands), electricity market concentration is high and only few companies own more than half of operating capacity (Cui *et al.* 2020; Wright *et al.* 2017). Lastly, it must be noted that countries might put domestic projects on halt but continue to invest in coal projects abroad (Edenhofer *et al.* 2018).

4.3.2 Technological Factors

4.3.2.1 Technology and CCS

Coal plants have multiple generation units that are each equipped with a boiler (Campbell 2013). There are three main types of steam conditions, i.e. combustion technologies (ranging from least to most efficient): subcritical, supercritical, and ultra-supercritical, which differ in boiler temperature and pressure (Caldecott *et al.* 2017). Recently, countries have built more supercritical and ultra-supercritical units, which have higher capital costs but are typically more efficient and incur lower operating costs (ibid.). Coal is usually burned in steam-cycle plants, while oil and natural gas stations rely on a broader set of technologies, including combined-cycle, and open-cycle turbines (Kefford *et al.* 2018).

Equipping coal plants with carbon capture and storage (CCS) technology is a conceivable option in the long-term future. However, no plants to date are CCS ready (Edenhofer *et al.* 2018) and such retrofits require substantial capital investments and reduce plant efficiency (Johnson *et al.* 2015). Besides technological shortcomings (Agora Energiewende 2016), CCS has a low social acceptance (Bertram *et al.* 2015) and is controversially discussed among scholars (Stephens 2015). While CCS is “unlikely to play a significant role” in power generation from coal (Caldecott *et al.* 2016, 24), CCS could be a viable option for the industry sector and other applications with limited mitigation options.

4.3.2.2 Efficiencies

When talking about plant efficiencies, scholars generally refer to thermal efficiencies. Thermal efficiencies state the amount of heat that becomes useful work, or the amount of work output for a specific amount of heat input (Energy Education 2018). Lower heat rates are indicative of more efficient combustion, because less heat input is required for the same output (Campbell 2013). European plant efficiencies range between 39% (9,186 Btu/kWh) for subcritical to 46% (7,788 Btu/kWh) for ultra-supercritical units (Caldecott *et al.* 2017). Unit efficiency also depends on the age, and maintenance efforts can only maintain initial efficiency levels over the first 25 years, after which the performance is significantly reduced (Henderson 2013). These reductions are mainly due to mechanical wear on individual components, as a result of which greater heat loss occurs (Campbell 2013). Additionally, efficiencies depend on the quality of fuel input, size of the plant, pollution control equipment (which increases electricity consumption), operating practices, cooling water technologies, ambient temperature, flexibility requirements, and plant materials (ibid.).

Inefficient plants report higher fuel consumption and higher overall operating costs, which reduces profits for asset owners (Alves Dias *et al.* 2018). Subcritical units, for example, use 60% more water on average than ultra-supercritical units (Caldecott *et al.* 2015). Additionally, inefficient plants cause higher CO_2 emissions: Carbon intensities range between 880-1,120 $kgCO_2$/MWh for new, efficient subcritical stations and over 1,340 $kgCO_2$/MWh for old, inefficient subcritical units (Caldecott *et al.* 2015). Caldecott *et al.* (2015) further find that an average subcritical unit emits 75% more CO_2 than an average ultra-supercritical one. Particularly low average efficiencies of around 30% are found in India (CEA 2016) and in Eastern European countries, while they are highest (~45%) in Germany and the Netherlands (DIW Berlin *et al.* 2019; Alves Dias *et al.* 2018).

The World Coal Association (2020) claims that a 1% improvement in the thermal efficiency of a coal plant results in a reduction of CO_2 emissions of 2-3%. Plant efficiencies can be raised by using renewables for heat or power provision, equipment refurbishments, improved maintenance and operation schedules, and plant upgrades (Campbell 2013). The combined provision of heat and power (CHP) raises the efficiency to 85-90%, but is an option mainly for hard coal plants (DIW Berlin *et al.* 2019). Governments and local authorities can provide incentives to improve efficiencies, such as setting efficiency standards or benchmarks (Campbell 2013).

4.3.2.3 Utilization and Load Factors

The utilization rate of a power plant, often also referred to as load factor or capacity factor, is the "ratio of its actual annual output to its maximum potential annual output according to its nameplate capacity" (Caldecott *et al.* 2016, 108). Load factors vary greatly across regions and over time, as they are a function of respective market conditions, fuel prices, electricity system dynamics, and electricity demand.

Load factors in India, for example, dropped by 13% between 2010 and 2015 due to coal shortages (Spencer *et al.* 2018). In China, the utilization rate of thermal plants fell below 50% in 2016, which was the lowest rate since 1969 (Greenpeace 2016). In the US, it dropped from 70% to 60% between 2009 and 2012 (EIA n.d. in Wamsted *et al.* 2019). This trend of declining load factors was not only observable on the national average, but 48 of the 50 biggest coal plants in the US had a lower capacity factor in 2017 than they did on average between 2007 and 2017 (ibid.). In the UK, on the other hand, coal plant load factors rose from 39% in 2009 to 58% in 2013, while the load factor of natural gas plants declined from 64% to 28%. Littlecott (2015) hypothesised that plant operators strategically maximised their output from the aging coal fleet before scheduled closure under environmental regulations.

Low load factors are a concern to operators as efficiencies decline and revenues shrink (Zhao *et al.* 2017). Many countries, for example China and Germany, experience an increasing mismatch between coal capacity and coal power production, partly due to the expansion of renewables which reduces operating hours of coal plants (Markewitz *et al.* 2018). At the same time, proportionally more electric capacity is required to balance fluctuating RE supply from wind and solar (ibid.). If plants are scarcely used, they are ramped up more often, which requires extra fuel and wastes heat (Campbell 2013).

4.3.2.4 Flexibility

As a general rule, plants with liquid or gaseous fuels, i.e. oil or natural gas plants, are more flexible than those with solid fuels (DIW Berlin *et al.* 2019). Lignite plants are most inflexible due to their slow start up process and high minimum loads (Öko Institut 2017). The cold start capability (which applies when plants have been shut for more than 48 hours) is 8-10 hours for old and 5-8 hours for new lignite plants, and 5-10 hours for old and 3-6 hours for new hard coal plants, which is significantly higher than that of combined-cycle gas turbines (CCGT) of under 1.5 hours, or that of open gas turbines of only a few minutes (Agora Energiewende 2017).

This disqualifies coal from providing flexible support to intermittent renewables (Kefford *et al.* 2018). While flexibility improvements are technologically possible, this would lead to heavier equipment wear (DIW Berlin *et al.* 2019) or costly investments to retrofit (Cui *et al.* 2020). In the past, the inflexibility of coal plants was not an issue, as most coal units covered the minimum power demand and provided reliable and affordable baseload power (Ellis *et al.* 2013). Today, however, low flexibility both with regards to ramping up times and minimum loads is highly undesirable due to the curtailment of renewable energy (IRENA 2019a) and reductions in coal plant profitability.

4.3.3 Lifetimes and Retirement Ages

4.3.3.1 Concepts

The concept of lifetimes of fossil fuel units is fluid and contested. Rode *et al.* (2017) criticise that many scholars make judgement-based lifetime estimates instead of conducting a historical analysis. Markewitz *et al.* (2018) similarly view lifetime assumptions as insufficiently substantiated, as well as a generally neglected topic. Differentiations between the book life, depreciable life, technical life, operational life, economic life, physical life exist but the terms are incomprehensively demarcated from each other.

The technical or physical life typically refers to the potential operational life of a plant irrespective of its economic situation, or the "period over which the plant is operating and producing power in a business-as-usual (BAU) scenario" (Kefford *et al.* 2018). But Markewitz *et al.* (2018) argue that this term is misleading. The technical lifetime is a well-established term in engineering and applies to individual, highly stressed components. Since power plants are composed of thousands of individual parts, the term technical lifetime is thus not applicable to plants in their entirety (Markewitz *et al.* 2018). Additionally, the physical lifetime depends on maintenance practices and capital investments, which in turn are influenced by regulations and broader economic conditions (Rode *et al.* 2017).

Book life or depreciable life is defined as "the period over which fixed costs are assumed to be recovered for accounting purposes" (Gitman 2009). The economic (useful) life captures both physical lifetime factors and the economic value of remaining operational (Appraisal Institute 2013 in Rode *et al.* 2017). In very general terms, a plant's lifetime is the time between the start of commercial operation and its retirement or "the overall period during which it is capable of producing electricity" (Rode *et al.* 2017). In the subsequent sections, I will use the term operational lifetime – which is dependent on economic, regulatory, and technical factors – as advised by Markewitz *et al.* (2018) and Farfan and Breyer (2017).

4.3.3.2 Lifetime and Retirement Age Estimates

The accuracy of lifetime estimates is crucial due to their frequent use in the development of future energy scenarios as well as grid planning (Markewitz *et al.* 2018). But, not only judgement-based estimates can be misleading: Cui *et al.* (2019) point out that historic lifetimes are not necessarily representative of future ones, as policies change, technologies advance, and market and economic conditions improve or deteriorate.

Rocha *et al.* (2016) calculated average (mean) lifetimes to be 41 years in Australia, 40 in Canada, 56 in Russia, 54 in the US, and 46 as a global average. Tong *et al.* (2019) claim that Chinese lifetimes have only been 24 years on average, mainly due to early retirements induced by air pollution regulations. Davis and Socolow's (2014) global analysis determined a median retirement age for coal plants of 32 years. Interestingly, Markewitz *et al.* (2018) find that average lifetimes of German coal plants have increased by 7 years for lignite and 8 years for hard coal between 1990-1999 and 2000-2014. The authors explain this with the lifetime-extending installation of flue gas cleaning facilities. Other life extending measures include the introduction of biomass for co-firing or a radical fuel switch (Alves Dias *et al.* 2018), which impede environmental regulation induced closures.

As already indicated, unit age alone inadequately predicts retirement age, as size, efficiency, pollution levels, environmental regulations (Cui *et al.* 2019), operational costs (Kefford *et al.* 2018), electricity and fuel market conditions (Markewitz *et al.* 2018), revenues, equipment failure, and replacement costs (Davis and Socolow 2014) play an important role in the strategic decision that is made for each unit individually (Markewitz *et al.* 2018).

4.3.3.3 Age Structure

Investigating the age structures of national coal fleets importantly highlights that the distribution of unit ages differs substantially between countries. Half of today's global operational capacity was commissioned after 2004. But in China, 79% of all capacity and in India, 69% of operational capacity was commissioned after 2004, which makes their national fleets significantly younger than in the EU or US (Tong *et al.* 2019). If all coal plants currently in operation were retired after a 35-year lifespan, almost 90% of US capacity would be retired by 2030, in comparison to just 12% in China or 20% in India (Cui *et al.* 2019).

4.3.4 Premature Retirements and Stranded Assets

4.3.4.1 Definition and Relevance

Stranded assets are economic losses resulting from the premature retirement of assets (Cui *et al.* 2020; Kefford *et al.* 2018) or the underutilisation of plants (Johnson *et al.* 2015). Benn *et al.* (2018) differentiate between regulatory stranding, which occurs when policymakers pass laws that impede plants from operating for their entire useful life, and economic stranding, which occurs when high operational costs and low revenues render the continuation of operations uneconomic. While stranded value (the "difference in expected and actual financial outcomes", Benn *et al.* 2018, 30) is “undesirable” (ibid., p. 69), stranding is also “a regular feature of economic systems and […] a phenomenon inherent in the ‘creative destruction’ of economic growth and technological change” (Caldecott and McDaniels 2014).

Premature retirements as a mitigation option have attracted far less attention from policymakers than the support of low-carbon technologies despite being cost-effective and not relying on technological progress (Kefford *et al.* 2018). Since premature retirements are unlikely to happen in the required volume through economic pressures alone, Miller (2013) calls for regulatory measures and incentives for coal plant closure, as well as compensation payments if necessary.

All coal projects currently under construction are likely to be retired prematurely, but more interestingly, highlight that investors do not trust climate policies to restrict future operations considerably (Edenhofer *et al.* 2018). This poses a challenge for determining the order in which plants should be retired: While operators of old plants had more time to recover their initial investment costs, the owners of newer assets should have internalised the risk of stranding before starting construction (Benn *et al.* 2018). However, the governmental responsibility for compensating plant owners for premature closure is limited after plants have recovered their capital costs (Caldecott and Mitchell n.d. in Caldecott *et al.* 2017). Further, newer plants are generally equipped with more efficient technologies and their higher capital costs suggest the prioritisation of old coal plants for retirement (ibid.).

Whether or not large-scale stranding occurs additionally depends on energy market characteristics. Stranding is less likely to occur in regulated markets where utilities can pass costs on to ratepayers, coal companies are largely state-owned, and asset owners are isolated from market forces (Benn *et al.* 2018). In liberalised markets, coal plants are exposed to fierce price competition and are typically owned by independent power producers or pure financial players, who have less stake in keeping operations running (ibid.). Consequently, uneconomic plants in regulated markets are more likely to be mothballed, idled, or underutilized, whereas uneconomic plants in liberalised markets are more likely to be retired.

Stranding assets will inevitably create winners and losers throughout society, creating the risk of stranding human capital alongside physical assets (Caldecott *et al.* 2016). Write-offs and financial losses of investors, Benn *et al.* (2018) argue, have not been sufficiently addressed, despite ongoing debates on a ‘just transition’ for all stakeholders involved.

4.3.4.2 Causes

Predictors of early retirement include SO_2 emission levels, electricity sector characteristics (Mills *et al.* 2017), regulatory changes, a shifting economic environment (Benn *et al.* 2018), present and future revenue expectations, and total installed electric capacity (Markewitz *et al.* 2018). Low prices for natural gas have been found to reduce coal-based electricity generation, but there does not yet exist evidence for any causal effect on early coal plant retirements (Linn et al. 2019). Celebi *et al.* (2010) find that merchant units (those relying on market revenues) are more likely to retire than regulated units, and that high fuel prices, low heat rates, and stringent environmental regulations act as retirement drivers. Low load factors can, but do not necessarily, lead to premature retirements. The owners view on future profitability, which is based on both anticipated electricity sales but also capacity market or other ancillary service market payments, is ultimately decisive for retirement decisions (Edmunds *et al.* 2015).

Caldecott *et al.* (2016) develop a comprehensive list of risk factors for coal plants, such as environmental change (e.g., climate change, natural capital depletion, freshwater availability), governmental regulations (e.g., carbon prices, air pollution regulations, licence conditions for operation), resources (price and availability), technological change (e.g., clean technology costs, disruption by low-carbon technologies), social norms and consumer behaviour (e.g., divestment campaigns, certification schemes). These risks are exacerbated when plants are located in densely populated areas and those with high levels of air pollution and water stress. In another study, Caldecott *et al.* (2016) conduct interviews with industry representatives, who identify falling clean technology costs, physical environmental change, market forces, and socio-political pressures as the greatest risks to asset stranding. In yet another study, Caldecott *et al.* (2017) argue that older plants are at higher risk of stranding for several financial and political reasons, such as their higher likelihood of being shut down for maintenance needs, higher repair costs, and elevated opportunity costs in the case of underperformance.

4.3.4.3 Estimates

Scholars agree that asset stranding of some degree is inevitable if climate targets are to be met. Yet, varying estimates on the economic costs of such stranding exist, which is partly due to country-specific lifetimes, regulatory conditions, and amortization periods (Cui *et al.* 2019). Pfeiffer *et al.* (2018) find that even if all outstanding fossil fuel projects were immediately cancelled, about 20% of the fossil fuel generating capacity would still need to be stranded for a good chance of remaining under 2°C of global temperature rise. These results are, again, highly sensitive to underlying assumptions: "[S]hould the share of generation-only budget be one percentage point smaller […] or bigger […], the stranding estimated for the 430-480 ppm scenario would change by 1.6 percentage points" (Pfeiffer *et al.* 2018, 8).

Spencer *et al.* (2018) found that installed electric power capacity must globally decrease by 4% annually for limiting global warming to 1.5°C. To meet the Paris targets, Gray *et al.* (2018) called for a 3-fold increase in retiring capacity, which would be a capital write-off unprecedented in volume (Bertram *et al.* 2015). Gray *et al.* (2018) estimated that coal assets of USD 267 billion are at risk in the 2°C scenario, while Kefford *et al.* (2018) found the value of stranded fossil fuel investments to be USD 591 billion across China, India, the EU and the US alone, of which 66% will occur in China and 31% in India.

4.3.4.4 Managing Losses

A number of studies developed prioritisation rules for the order of asset stranding. Cui *et al.* (2020) identify old, small, inefficient plants in regions of high air pollution and water scarcity as low hanging fruit. Pfeiffer *et al.* (2018) also suggest stranding old, inefficient plants first, and further recommend retrofitting the existing fleet to enhance efficiency or implement CCS. Other scholars make suggestions on how to minimize the negative economic and social effects of asset stranding: Johnson *et al.* (2015) favour extending the lifetimes of existing plants over the construction of new, efficient plants because it would reduce total premature retirements.

Following Cui *et al.* (2020), there is a trade-off between retirements and utilization rates: guaranteed lifetimes can lower stranded assets, but that lowers the utilization rate and thus the profits of each plant. Vice versa, high load factors of some plants would require the premature retirement of others. Avoiding stranding assets altogether is undesirable, as it will shift mitigation efforts to other sectors, which come at greater costs and greater risk to, for example, food security (Binsted *et al.* 2020).

4.4 RO 2: Development of Coal Capacity Characteristics

4.4.1 Methods

The first step of the exploratory data analysis was comprised of investigating trends in capacity-related characteristics, such as size, technology, ownership, or fuel type. All of these are variables in the WEPP and/or GCPT datasets, but do not represent a comprehensive list of aspects according to which capacity can be analysed. They do, however, provide a broad overview of the composition of historic and current coal fleets. Specifically, units entering operation were mapped over time (1970-2020) and against size (in MW), differentiated by focus region (China, India, US, EU, OECD, and ROTW), or technology (subcritical, supercritical, and ultra-supercritical). Additionally, annual capacity additions were summarised into 5-year categories (for 1981-2020), MW-weighted, and categorised according to ownership for all focus regions. Finally, annual capacity additions were analysed according to fuel types (lignite, sub-bituminous, bituminous, and anthracite) for 1980-2020.

While past developments are indicative of the composition of the current coal fleet, not all units that entered operation since 1970/80 are still operational, while some operational units of today were built prior to that time. Thus, a brief investigation into the current operational coal fleet followed, which included all units that are listed as ‘operational’ and thereby excluded units that have been retired, mothballed, or idled. Additionally, the age distribution of today’s coal fleet was analysed and differentiated by region.

4.4.2 Results

An increasing amount of coal capacity is built in China, India, and in the rest of the world, while comparatively less units are built in the EU and US (Figure 6). Another trend that emerged is that the average unit size increased over time. However, coal units with less than 250 MW continue to be built around the world. The average nameplate capacity of coal units also varies by region. Units in India, for example, tend to be smaller on average than those in other parts of the world, whereas large coal units with over 1,000 MW are predominately located in China. Finally, especially recently built units located in China and India are clustered around certain capacities, such as 200, 330, 500, 660, or 1,000 MW with few unit sizes in between.

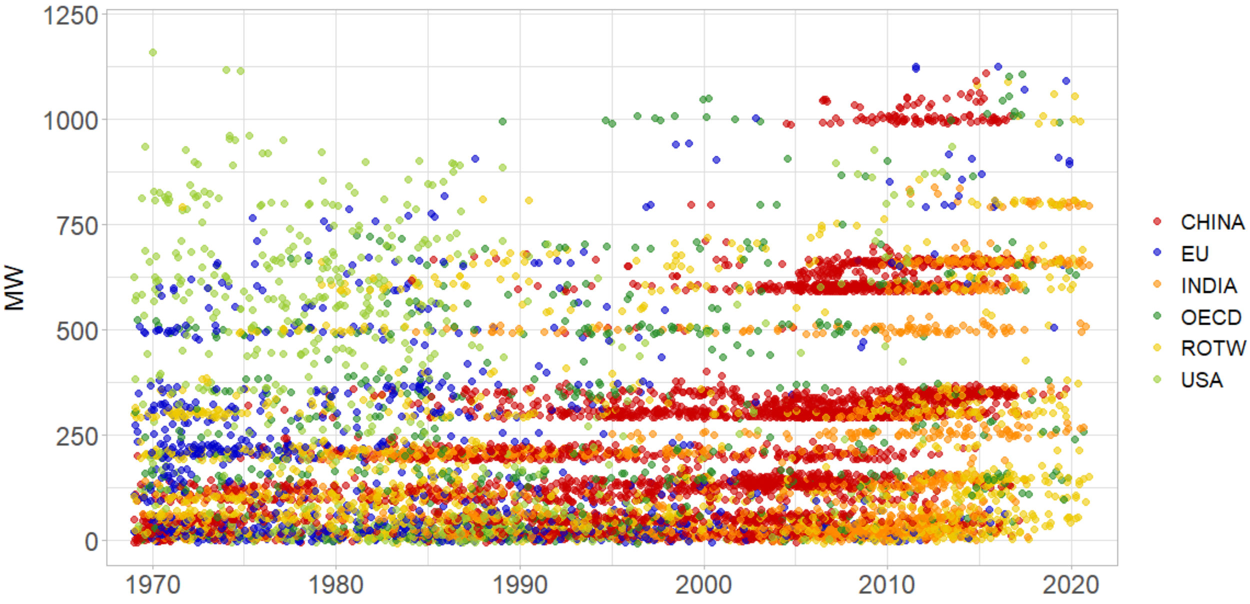


Figure 6: Capacity additions by size and region for 1970-2020

Note: Every dot represents a unit entering operation. To avoid large overlap, the jitter function was used, which adds a small amount of noise to each dot.

Figure 7 depicts the development of combustion technologies over time, for which several observations can be made. First of all, subcritical units dominate in number, both over the whole time period of investigation and within every decade. Secondly, units with subcritical technology are smaller on average than supercritical units, while supercritical units in turn are smaller on average than ultra-supercritical units. The majority of ultra-supercritical units are of ≥ 1,000 MW and have predominantly been built in the last 10 years. Subcritical units can reach up to 900 MW, but generally range under 250 MW; while supercritical units mainly range between 300 and 800 MW.

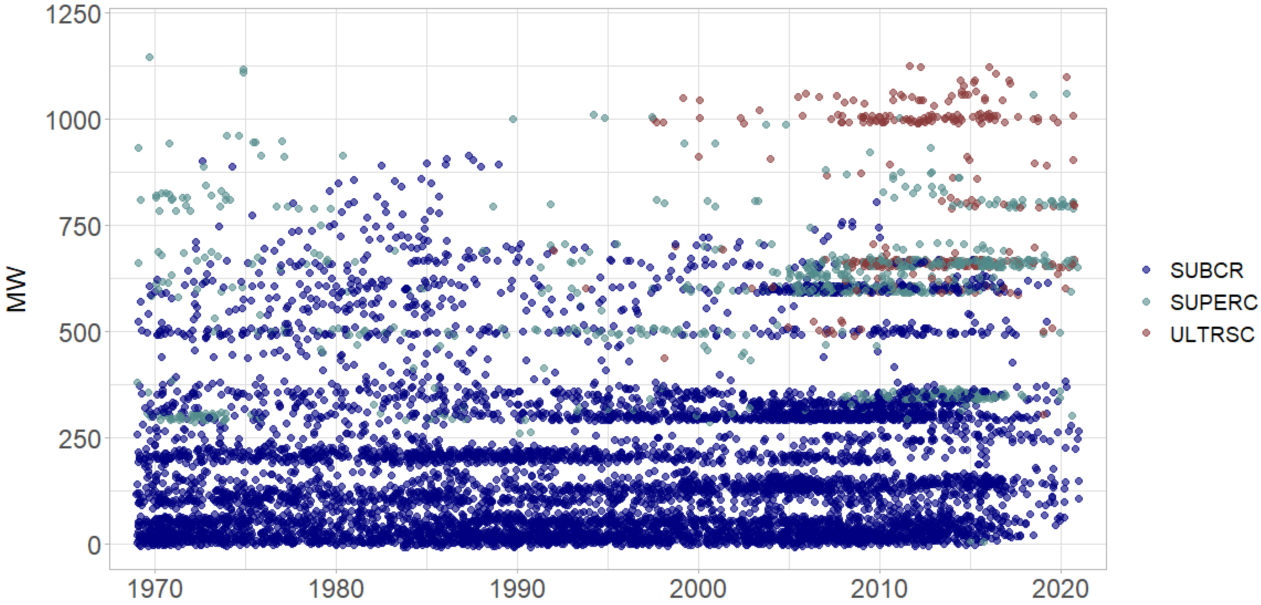


Figure 7: Capacity additions by size and combustion technology for 1970-2020

The categorisation of capacity additions according to ownership types demonstrates that the majority of new capacity since 1980 is owned by public and private utilities (see Figure 8). In the US, private utilities dominate considerably over public ones, whereas in ROTW countries and India, governmentally owned utilities account for the largest share. In these two regions, but also in the US and OECD countries, the services sector accounts for a considerable and growing share. The manufacturing and all 'other' sectors (including, for example, the commercial sector or fuel processing industries) account for only 1-18% in all regions. Interestingly, also only few units are owned directly by governments, amounting to a visible share only for 2016-2020 in the US. Overall, there is considerable movement in all regions over time.

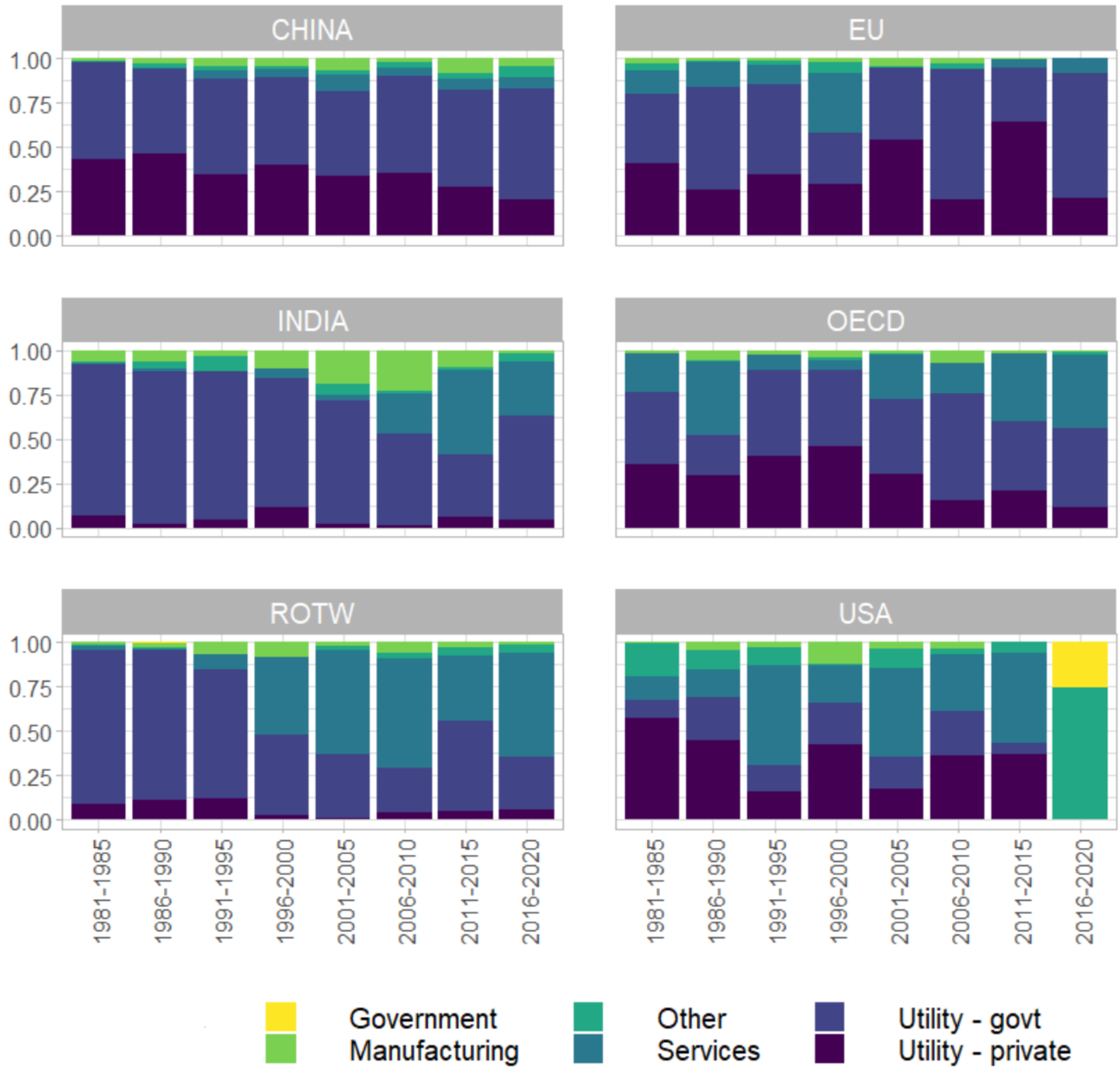


Figure 8: Capacity additions by unit ownership (MW-weighted) for 1981-2020

Note: Annual capacity additions are comparatively low in the US and EU for 2016-2020, as well as in India, China, and ROTW for the time <1990, which increases the weight of outliers. The figure is indicative of respective shares for each time period, but not of absolute numbers for each ownership category.

Figure 9 on annual global capacity additions by fuel type first of all highlights the surge in new capacity installations around 2005, more than tripling the amount of annual capacity additions between 2002 and 2010. While the respective shares of all fuel types changed over time, no definite trend can be determined. Bituminous coal is fired in more than half of all new capacity added between 1980 and 2018 and is responsible for most of the year-to-year variation. A growing share of capacity is fuelled by unidentified coal ('NA'), which is likely due to the rise in coal capacity in Asia, for which data is less complete. This further complicates making any judgement about trends in the ratio of hard coal to lignite, and the availability or preferability of one particular fuel type over others.

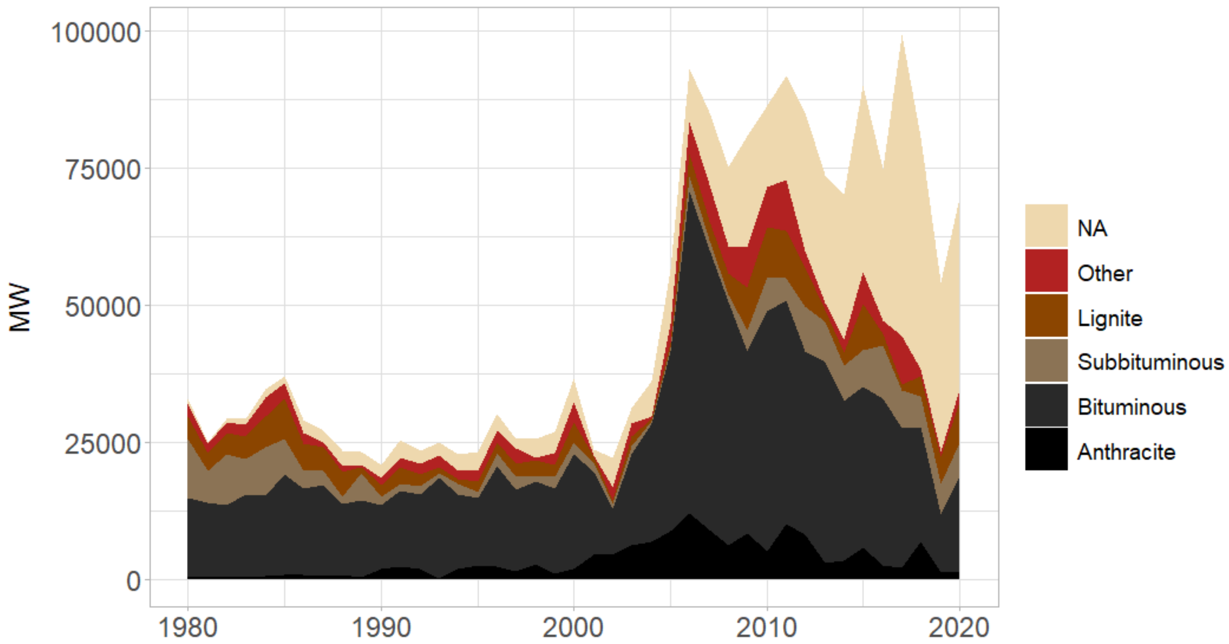


Figure 9: Capacity additions by fuel type for 1980-2020

Note: The 'Other' category is comprised of fuel mixes and waste coal; NA encompasses all units for which there was no data on fuel type.

As for the operational capacity in 2020, the majority of coal plants (weighted by capacity) are fuelled by bituminous coal (50%), while the shares of subbituminous, lignite, and anthracite coal range between 7% and 10% respectively (Appendix; Figure 30). At the same time, the majority of coal plants (again, weighted by capacity) are owned by state-owned utilities (47%), followed by private utilities (29%) and the services sector (15%). The manufacturing and all other sectors account for the remainder (9%), of which direct governmental ownership constitutes less than 0.5% (Appendix; Figure 29).

Figure 10 depicts the age distribution for all focus regions by technology. The US and EU coal fleets are substantially older on average than the coal fleets of China, India, and ROTW countries. In China and India, a negligible share of units is older than 40 years. Within the ROTW category, the majority of younger units are located in South-East Asia, while older units can be found in Russia, South Africa, or South America. The EU possess over a considerable number of both older and particularly young plants (<10 years), though the latter are predominantly equipped with the most efficient ultra-supercritical technology. At the same time, only a small share of capacity in India and the US is equipped with ultra-supercritical combustion technology.

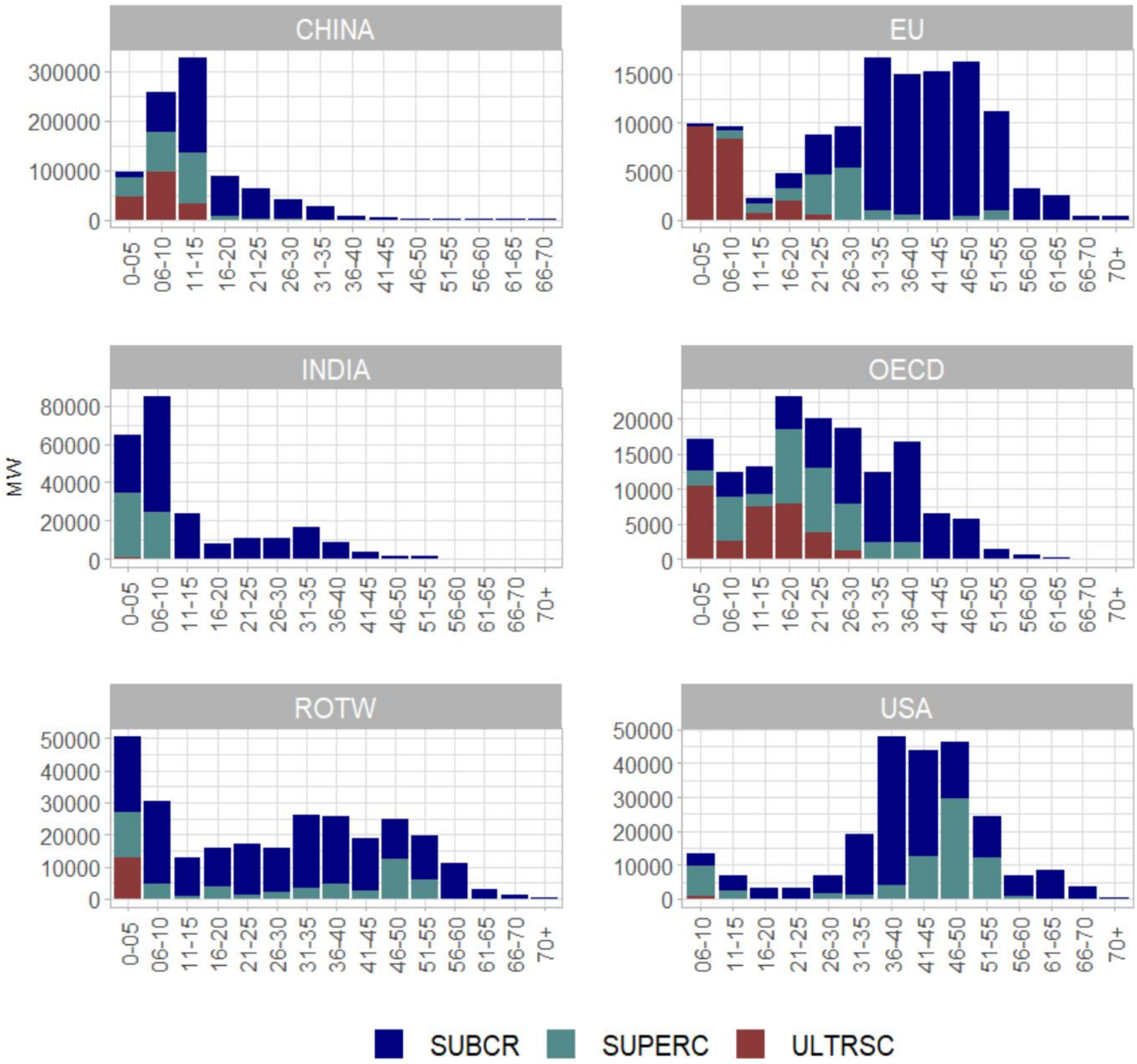


Figure 10: Age distribution and technology of the current operational fleet by region

When investigating the average age of national coal fleets (see Figure 11), it becomes apparent that these greatly vary, and a geographical pattern emerges. The six youngest coal fleets (including India and China) are all located in Asia, while the oldest coal fleets are found in Eastern Europe. The average coal fleet age ranges from 11.0 years in Indonesia, to 52.6 years in Hungary. Unsurprisingly, the EU and US have substantially older coal fleets (44.7 and 45.5

years respectively) than all other world regions. COAL14 countries also tend to have younger fleets than DEC18 countries.

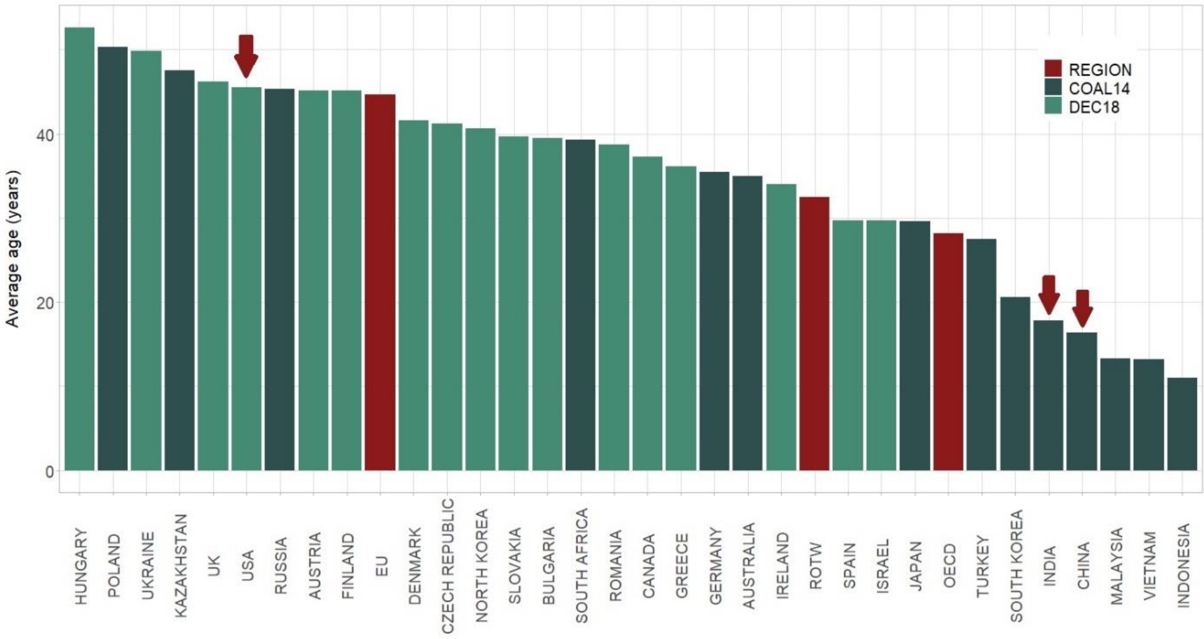


Figure 11: Average age of national and regional coal fleets in 2019

Note: Focus regions that are also countries (US, India, China) are marked with a red arrow. Belgium was excluded because the country officially phased out coal in 2016.

4.5 RO 3: Development of Lifetimes and Retirement Ages

4.5.1 Methods

To complement previous research on changes and variations in retirement ages as presented in the literature review, national average retirement ages were calculated for all DEC18 and COAL14 countries as well as for all focus regions. For this, only units that retired after 1980 were included, because more recent values are likely to be more indicative of future ones. The retirement age is conceptually congruent with a unit's lifetime, as it is calculated via the year it started and ceased operations. Secondly, the development of retirement ages over time was investigated. This was done by calculating annual capacity retirements (in MW) since 1990 for each focus region and differentiating by four retirement age categories (0-20, 21-40, 41-60, 61-80 years).

To provide possible explanations as to why retirement ages differ between countries and over time, a path analysis was conducted. While predictors of retirement age are commonly searched for on a country level and are policy-oriented (see section 4.3.3), the following analysis was deliberately limited to plant- or unit-specific characteristics as specified in the dataset.

Path analysis is a type of 'Structural Equation Modelling' (SEM), that combines a theoretical framework and a statistical technique. It is often applied to investigate complex, multi-faceted systems of relationships that demonstrate both direct and indirect causal effects. A key feature of path analysis is the diagrammatic representation of an underlying theoretical model, where each path connects two variables that are thought to be correlated or have a causal relationship. Generally, path analyses entail both exogenous and endogenous variables, the latter of which are defined or influenced by other variables inside the model. Below is the diagrammatic representation of the path analysis that was conducted on the unit level (Figure 12). Each path represents a hypothesised causal relationship.

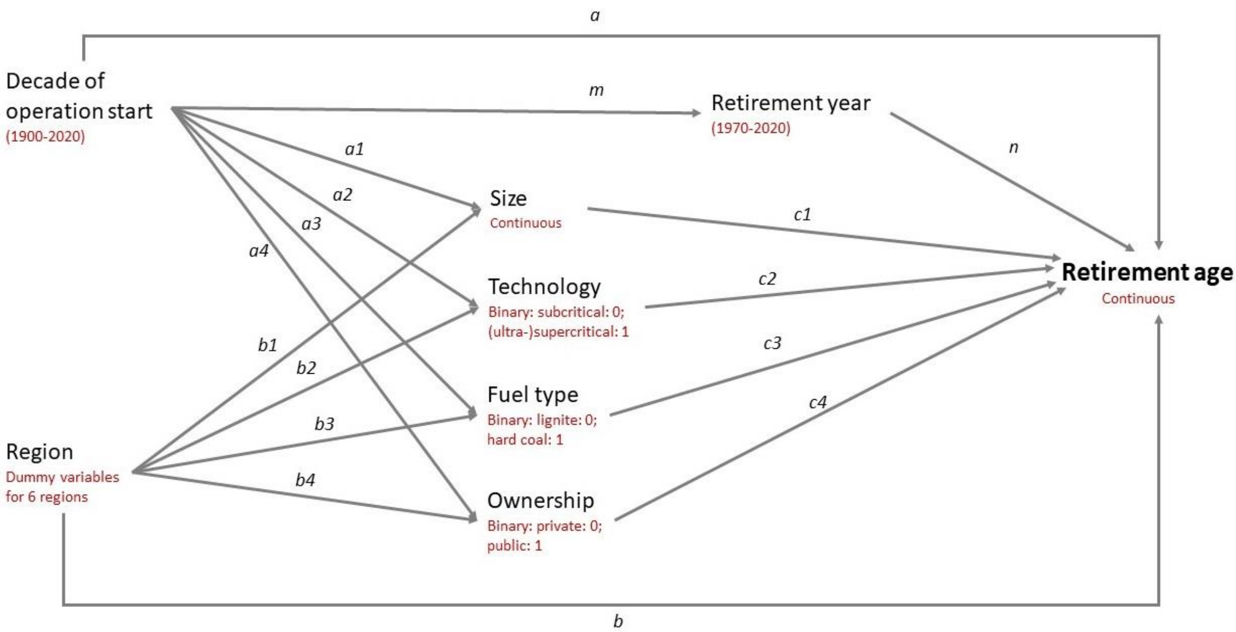


Figure 12: Theoretical model for path analysis

Note: All grey arrows signify hypothesised causal relationships between two variables; the writing in red indicates the level of a variable and its respective coding; the labels on paths are path coefficients.

For the statistical analysis, I have used the free and open-source 'lavaan'-package in R, and followed the instructions and advice of the lavaan tutorial script (Rosseel 2020) as well as its associated discussion group. The model was determined using regression operators to specify dependent and independent variables, variances and covariances; and fitted using standardised parameter values. Like most regression analyses, lavaan cannot process nominal data unless it is dichotomous. Consequently, a number of variables were reduced to two dimensions (e.g. private and public ownership; hard coal and lignite fuel; or subcritical and (ultra-)supercritical technology). This inevitably reduced the depth and detail of the data and required making several assumptions. To integrate location, dummy variables (value 0 or 1) for all six regions were created and compared to one specific reference category. In this case, the UK was excluded from the EU group and instead used as a reference point. The UK was chosen because it had the third highest unit retirements after the USA and China since 1970.

Due to the abundance of categorical variables, the WLSMV estimator was applied, which uses 'Diagonally Weighted Least Squares' (DWLS) instead of the ML (maximum likelihood) estimator in the case of continuous data. Results are standardised by rescaling the variance of the observed variables to 1, which allows inferences about the direction and magnitude of a relationship, but forbids interpretations in numeric terms. The Comparative Fit Index (CFI) is a measure of model fit, which compares the fit of a proposed theoretical model with a baseline one of poor fit (null/independence model). Ranging from 0 to 1, it is intuitively interpretable and robust in its calculation (Jackson *et al.* 2009). Another commonly used measure of model fit is the SRMR, or standardized root mean squared residual. Unlike the CFI, it measures misfit and thus identifies discrepancies between the fitted model and the data structure. It can be understood as the 'average standardized residual covariance' and is perceived as indicating good fit if the SRMR value is below 0.08 (Shi *et al.* 2018).

The path analysis is based on the WEPP dataset, which includes 4,873 retired units, 2,896 of which were retired after 1970 and had no missing values for the year of their operation start or retirement. Finally, units with missing values for other variables were excluded, which led to a final sample of 2,089 units.

4.5.2 Results

The average retirement age since 1980 ranges from 32.6 years in China to 48.2 years in the US (see Figure 13). Most operational lifetimes, however, are situated between 35 and 43 years on average. With India (41.3 years), all focus regions are widely spread across the retirement age spectrum. There appears to be no significant difference between COAL14 and COAL18 countries.

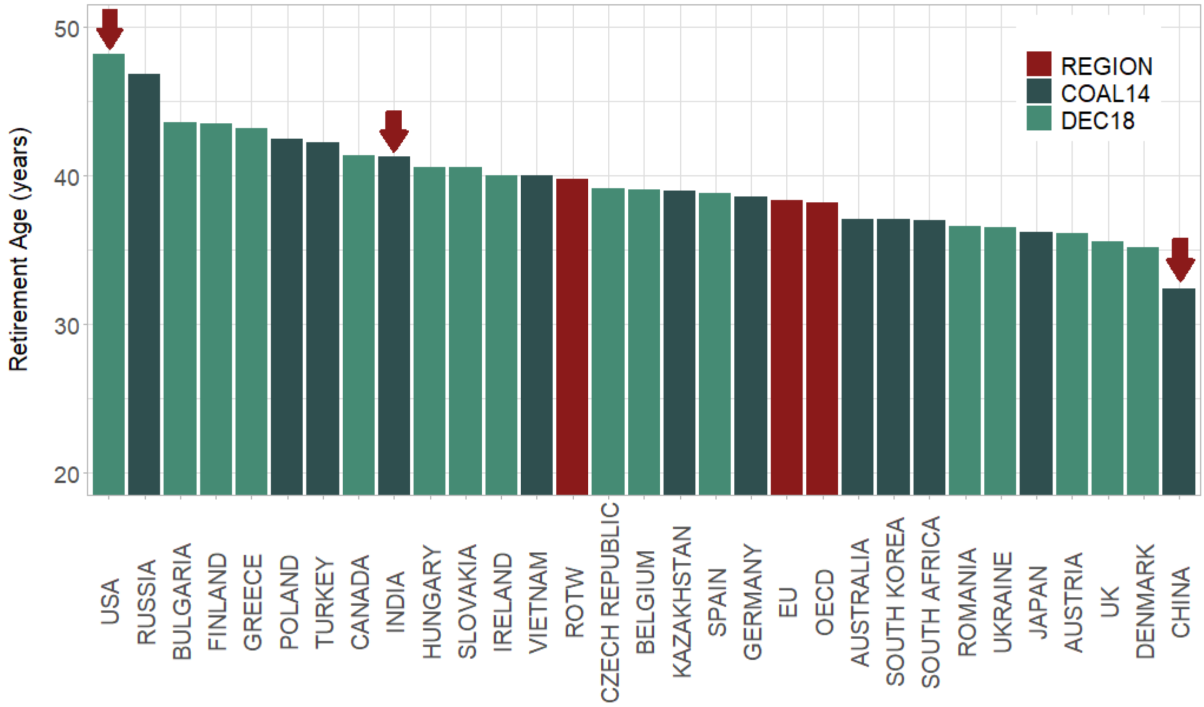


Figure 13: Average retirement age of national and regional fleets since 1980

Next, annual retirements were mapped over time for all focus regions and depicted in Figure 14. While coal units in China have almost exclusively retired prior to reaching a 40-year operational lifetime, only few units in the US have remained below the 40-year mark. Further, a considerable share of coal capacity in China retired prior to even reaching 20 years of age, while a considerable share of capacity in the US retired aged 61 and above. In the EU and ROTW countries, the share of premature retirements (<40 years) declined and mature retirements accounted for the majority of all capacity retirements in the last 15 years. What should be noted here is that not all capacity retirements are captured in the figure below, as missing data on retirement years prohibited the calculation of retirement ages for several units. This was especially the case for units located in India and the ROTW.

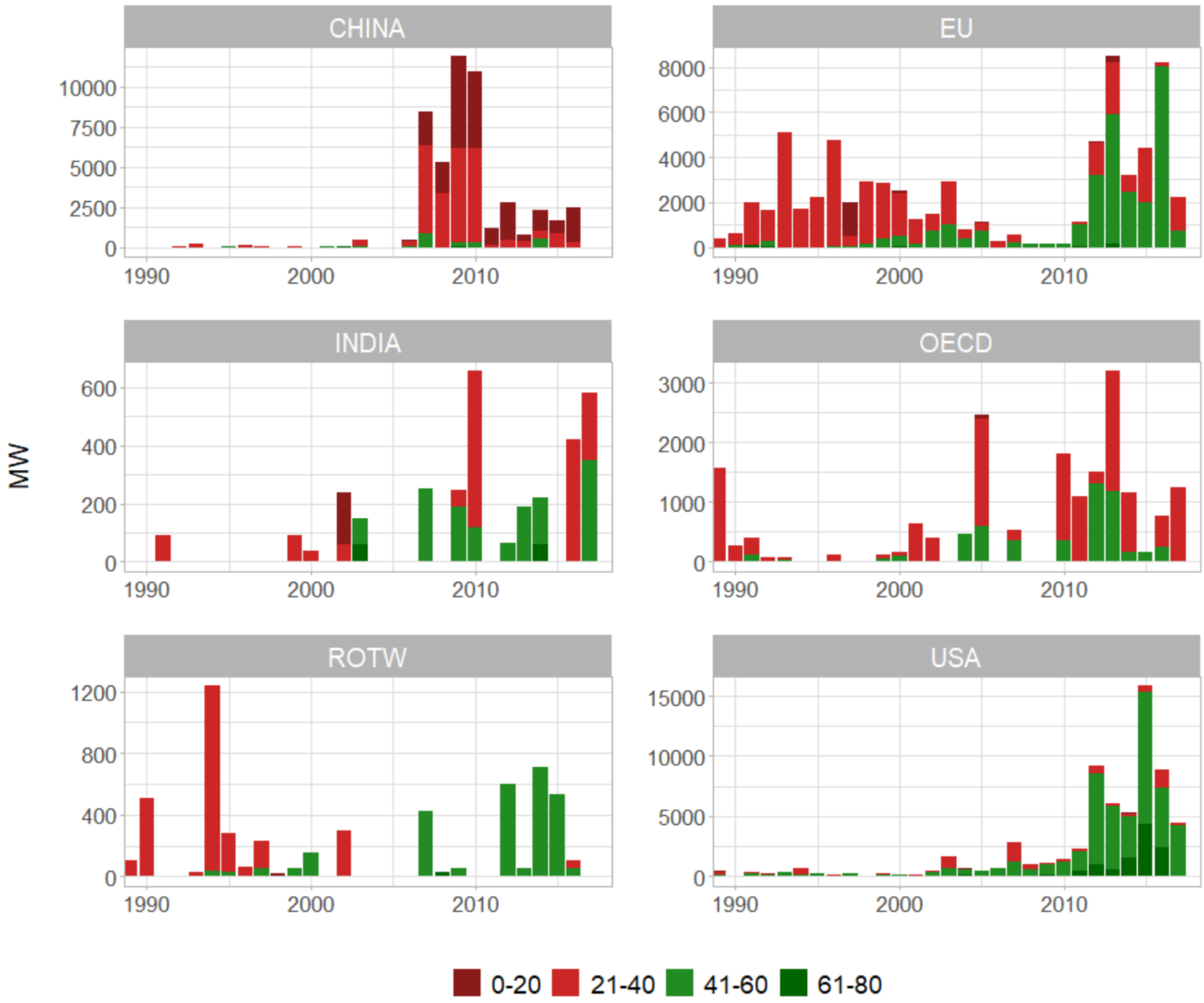


Figure 14: Annual capacity retirements by retirement age category since 1990

Lastly, Appendix Figure 31 highlights that average and median retirement ages per unit have considerably changed in most regions over the past three decades. In the EU, US, and ROTW, the average retirement age has gradually increased, whereas it has decreased in China and roughly remained the same in India and OCED countries. Variations in unit retirement ages per time period are particularly high in China for 2005 to 2014 and in the US. This is also exemplified by Figure 15, where retirement age is widely spread, and minimum and maximum values lie 80 years apart. Identified differences between regions, such as younger retirement ages in China than in the US, also emerge when investigating retirement age per unit rather than total capacity-weighted retirements. The mean retirement age lies at 38.9 years (σ 14.3), while the median age is 38 years (Figure 16). Precisely half of all units retire aged 30-50 years.

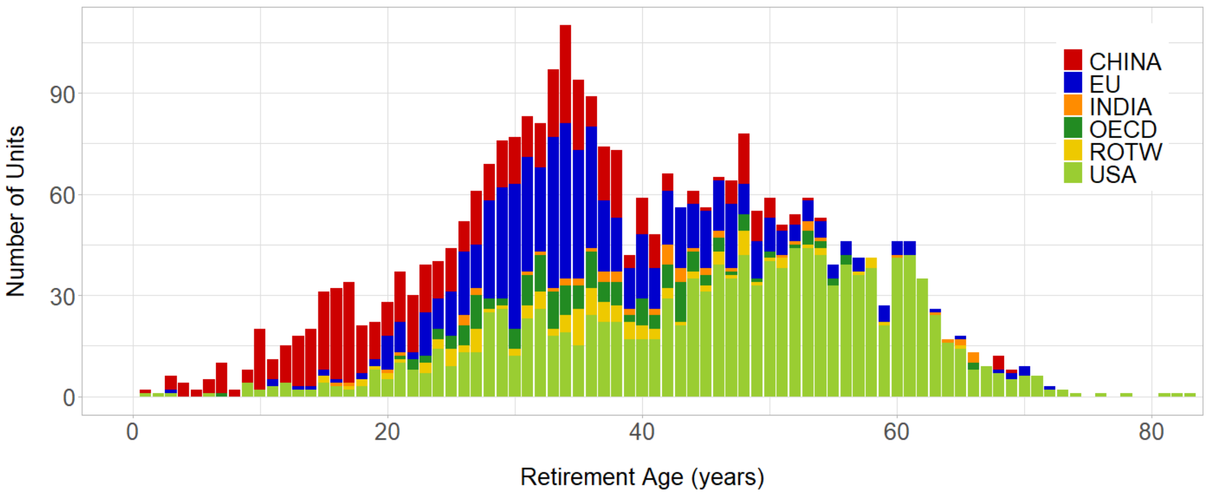


Figure 15: Distribution of retirement ages by region (since 1970)

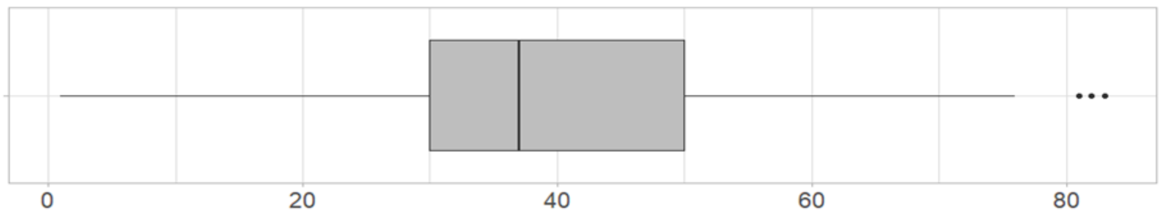


Figure 16: Median and interquartile range for retirement age (since 1970)

As for the results of the path analysis, the CFI fit index of .92 suggests that the hypothesised model is of satisfactory fit for the underlying data given the sample size (Hu and Bentler 1999). The SRMR value of the fitted model lies below the cut-off point of 0.08 (namely at 0.045), which further suggests adequate model fit. Despite substantial scholarly disagreement with regards to the interpretation of model fit measures, their arbitrary cut-off points, as well as their respective interpretation (Lai and Green 2016; Shi *et al.* 2018), the model fit results in this case provide no reason to discard the theoretical model.

As highlighted in the output diagram (see Figure 17), the majority of the hypothesised relationships between variables are statistically significant. Only statistically significant paths ($p<0.05$) are displayed below, further highlighting the standardised magnitude of the effect, as well as the direction of the effect.

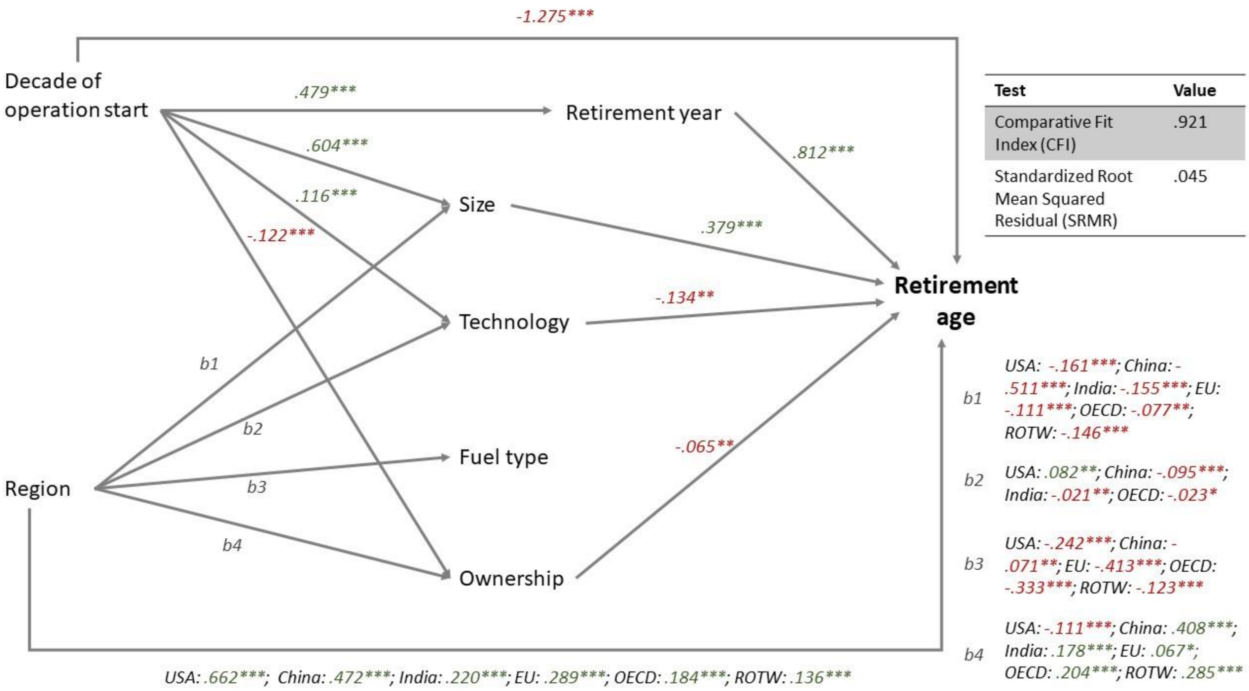


Figure 17: Results of path analysis

Note: The grey arrows signify detected and statistically significant relationships; red path coefficients indicate a negative, and green path coefficients a positive relationship.

First of all, and corroborating the results of section 4.4, the average coal unit became larger in size (MW) and more efficient in its combustion technology over time. Coal units are also increasingly likely to be privately owned. However, there exists no statistically significant relationship between when a unit started operation and the fuel type it utilizes. Unsurprisingly, a significant relationship exists between the start of operations and the year of retirement, as the latter is evidently a function of the former.

Results also show that the earlier a unit enters operation, the lower its statistically expected retirement age. Likewise, units that retire later in time are more likely to demonstrate higher retirement ages. Retirement age is further influenced by unit-level characteristics: There exists a substantial, positive relationship between the size of a unit and its retirement age. Interestingly, more efficient combustion technologies are associated with lower retirement ages, and so is the ownership by a state-owned utility or the government itself, albeit this effect is rather small. There is no statistically significant relationship between fuel type and retirement age.

On average, all six world regions have significantly smaller units than the reference category, which was specifically the case for China. While US units were significantly more efficient (used supercritical technology), units in China, India, and the OECD were significantly less efficient. However, all regional effects on technology are comparatively small. Coal in five of the regions was of lower quality, but especially so in the rest of the EU and OECD countries. Finally, only US units are more likely to be privately owned, while they are more likely to be state-owned in all other regions, especially in China. With regards to the direct effect of plant location on the retirement age, all relationships are positive and highly significant.

4.5.3 Limitations

Evidently, the model relies on explanatory variables that are present in the available dataset, but there are numerous additional variables or factors that are likely to have a significant effect on the retirement age. Thus, like any other model, it is a simplification of reality and further constrained by the number and quality of variables at hand. Additionally, the dominance of categorical variables over continuous ones notably reduces the depth of data and further complicates the interpretation of relationships between all variables. Similarly, dummy coding regions prohibited the unmediated comparison between the focus regions, and using the UK as a reference point may be problematic in some ways, as the UK possesses over a unique coal history.

While path coefficients generally range between -1 and 1, the standardised path coefficient between decade of operation start and retirement age has the value of -1.275. This is a rare, but possible occurrence in any kind of regression analysis and does not refute the significant relationship between two variables or the goodness of model fit. It could, however, point to undetected collinearity between variables. Lastly, the sample size was substantially reduced when cases with missing values were excluded, which affected the different regions to varying extents. This analysis constitutes a first exploration into the predictors of retirement age using this particular data, but could be expanded by integrating additional unit-level variables, such as annual CO_2 emissions, or economic factors.

4.6 RO 4: Annual Capacity Additions, Retirements, and Total Installed Capacity

4.6.1 Methods

In order to track the expansion or contraction of national coal fleets, annual capacity additions and retirements (in MW) were calculated. By subtracting annual retirements from annual additions, net annual capacity additions were derived, which can be positive or negative. If they are negative, a national coal fleet shrinks, while it expands when net annual capacity additions are positive. As a next step, moving averages were calculated by using the average (mean) value of year x, year x-1, and year x+1. This only marginally effects annual values for countries with large coal fleets, such as China or the US, but reduces the accuracy in the case of countries with smaller coal fleets.

Then, total installed coal capacity since 1960 was calculated. All units that were constructed after 1900 were included and total installed capacity derived via the difference between cumulative annual capacity additions and retirements. All units that are currently mothballed, deactivated, or on standby count towards the operational capacity. One important caveat is that the database is not comprehensive for the first half of the 20th century, so that total installed capacity for the time prior to 1980, and in some cases 1990, is underrepresented.

Finally, total installed electric capacity for all DEC18 and COAL14 countries for 2000 to 2018 was calculated and differentiated by source (coal, other fossil fuels and nuclear, and renewables). Since WEPP has been found to underestimate installed renewable capacity (Pfeiffer *et al.* 2018), only the data on all fossil fuel and nuclear stations was taken from WEPP, aggregated and then combined with data on RE capacity for each country from the International Renewable Energy Agency (IRENA 2019b). This number on total electric capacity was cross-checked with several sources on national electric capacity and yielded significantly better results than the reliance on WEPP alone.

4.6.2 Results

Since 1980 and until the early 2000s, between 20,000 and 30,000 MW of coal capacity were added annually but the geographical distribution throughout that time drastically changed (see Figure 18). While initially, the US, EU, and non-EU OECD countries accounted for about two-thirds of annual capacity added, this ratio shifted towards China, India, and the rest of the world. From 2003 onwards, global capacity additions substantially increased, driven primarily by accelerated growth in China. Since 2006 however, growth in China has slowed down, while an increasing share was built in the rest of the world, within which the largest growth took place in Southeast Asia. Annual growth has also slowed down in India, although less pronounced than in China. The ROTW group is still on an upwards trajectory and exhibits almost exponential growth (see also Figure 19).

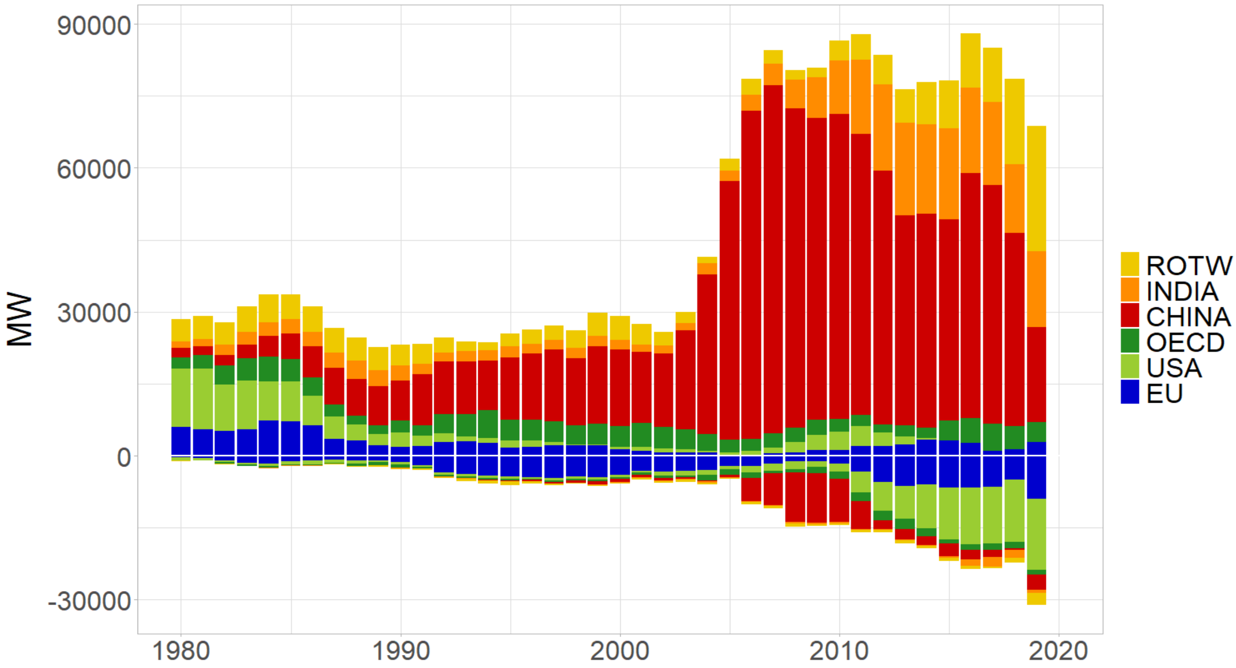


Figure 18: Global annual capacity additions and retirements by region

Note: Calculation via 3-year moving averages; retirements thus likely overrepresented for 2019 (cf. section 4.2); capacity changes in China 2017-2020 are based on announced additions and retirements as of 2017.

Between mid-2000 and 2018, worldwide capacity additions were again relatively stable at around 80,000 MW annually, whereas annual retirements have gradually increased to amount to over 20,000 MW annually in recent years. The capacity development in non-EU OECD countries is less conclusive than in all other focus regions (see Figure 19), which is unsurprising given their diverse mix of countries with regards to geographical location and economic systems. The EU and US account for the majority of retirements, but retirements do occur in all other focus regions. Interestingly, capacity additions have rebound in both the EU and US after peaking in the 1980s and a period of decline until 2005. Yet, in recent years annual retirements have outweighed annual additions, making these two regions the only two with net negative growth.

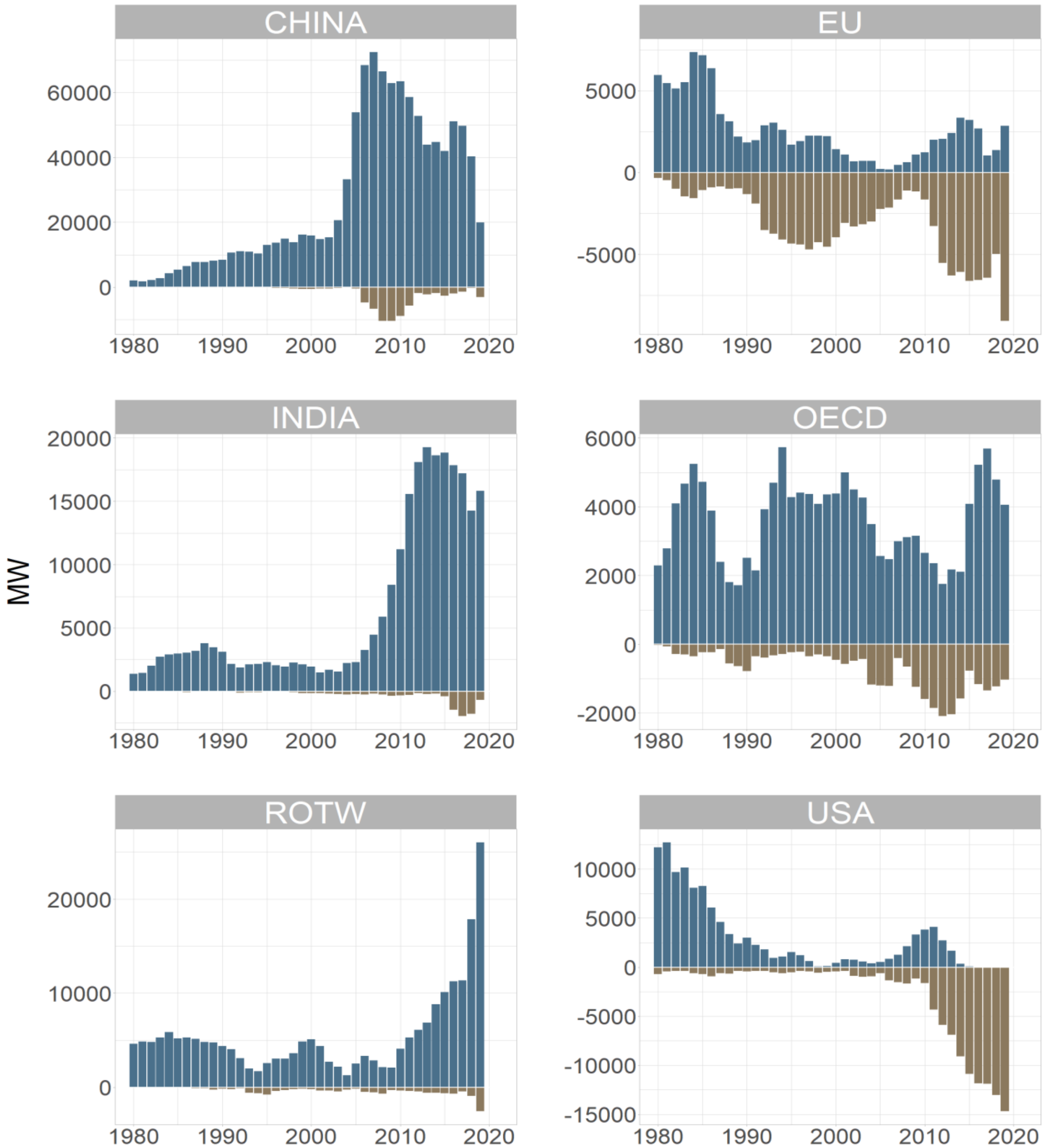


Figure 19: Annual capacity additions and retirements for each focus region

The calculation of net annual capacity additions for all DEC18 and COAL14 countries is shown in the Appendix (Figure 32), as well as in an adapted form in the next section (Figure 22). What immediately becomes apparent is that the majority of countries, especially those in the COAL14 group, have steadily growing coal fleets. In many of them (e.g. China, India, Indonesia, Japan, Malaysia, South Korea, Turkey, and Vietnam) capacity fleet growth has been strictly positive over the whole time period of 1980 to 2019. While capacity growth has slowed down in some of these countries, it has not done so in Indonesia, Malaysia, South Korea, Vietnam and Turkey.

There exist a handful of countries that exhibit a frequent change in trend and display both periods of positive and negative growth, such as Australia, Germany, the Czech Republic, or the Ukraine. In the former two countries, net capacity additions were predominantly positive in the first half, and increasingly negative in the second half of the time period of investigation, while the latter two countries exhibited growth in recent years.

In Austria, Canada, Denmark, Finland, Greece, Romania, Slovakia, and Spain (all DEC18 countries) coal fleets have been steadily and consistently shrinking for the last 20 years, while in Belgium, the UK, and Hungary (also all DEC18) net capacity change was almost exclusively negative over the last 40 years. For countries with smaller national coal fleets and fewer changes to the coal fleet over 1980-2019 (e.g. Ireland, North Korea, Bulgaria), a trend is more difficult to distinguish. Further, the effect of using 3-year moving averages becomes apparent (e.g. Israel, Ireland), and should be kept in mind when interpreting absolute values.

With regards to total installed coal capacity, 16 of the 32 countries have presumably passed their peak. In seven of them (Austria, Belgium, Canada, Denmark, Finland, Germany, and the UK), total capacity has fallen below 87.5% of peak capacity, and in Austria, Belgium, Canada, Denmark, and the UK, capacity has even fallen below 50%. While the first 25% of decline in these countries took between 15 and 26 years (19.4 years on average), the second 25% of decline took between 2 and 19 years (8.4 years on average), and the next 25% of decline even shorter (6 years on average). While the latter is only based on observations from three countries (Austria, Belgium, UK), there appears to be a general trend according to which the decline in capacity starts off slowly and then accelerates. As of now, it is too early to establish whether the decline in capacity slows down again for the last 25%, as would be suggested by an inverted S-curve trajectory.

An observation that holds true for all countries that have passed their capacity peak or are likely to do so soon is that the plateau period surrounding peak capacity lasts for a comparatively long time. Here defined as the time in which capacity is ± 12.5% of its peak, the plateau generally lasted over 20 years (25 years on average). Capacity has been particularly stable for a long time in the Czech Republic, Romania, Spain, the Ukraine, and the US.

Several countries (China, India, Indonesia, Japan, Malaysia, South Korea, Turkey, and Vietnam) exhibited an S-curve shaped increase in installed capacity over the last 20-30 years. In Vietnam, for example, installed capacity tripled in only a few years, demonstrating exponential growth as characteristic for earlier phases of the entire growth period. In Japan, on the other hand, the increase in total capacity has slowed down in recent years, indicating convergence to a saturation point. Since peak capacity has likely not been reached in these countries yet, it is difficult to establish how long total installed capacity took to increase from 25 to 50, or 50 to 75%. Assuming that China reached peak capacity in 2019, the first 25% would have taken several decades to unfold, while 25-50% took 6 years, and 50-75% 5 years. Whilst other countries have reached peak capacity, their respective speed of growth cannot be interpreted with high certainty due to underrepresented capacity prior to 1980, which is when most of their capacity growth took place. Figures 20 and Appendix Figure 33 do however suggest, that the greatest capacity increase took place in only a few years, after taking off slowly and slowing down before reaching saturation.

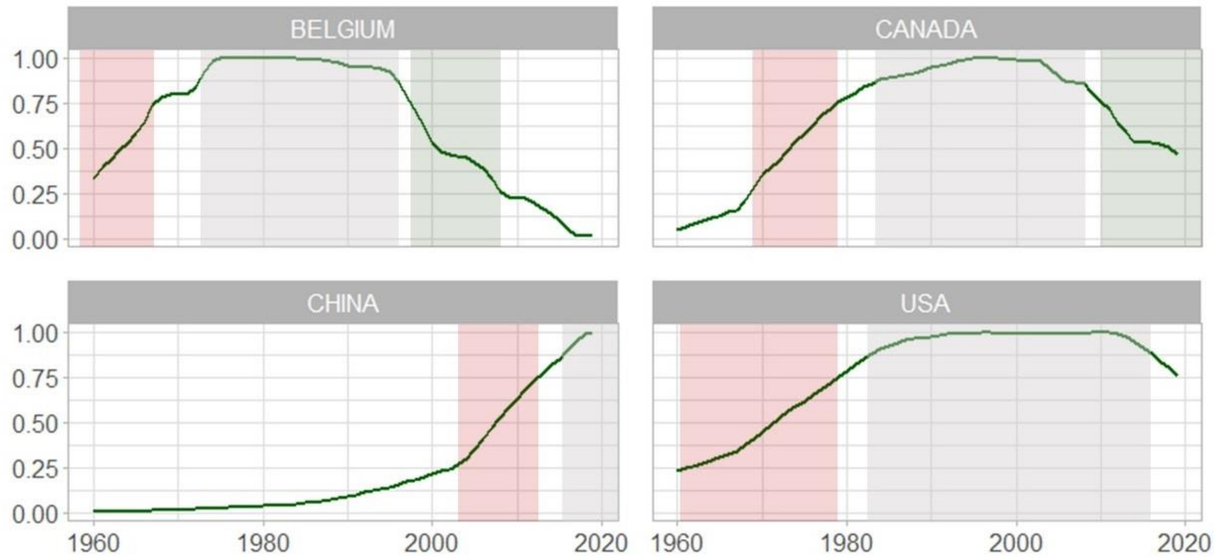


Figure 20: Total installed coal capacity 1960-2019 (example countries)

Note: Total installed capacity is normalised to maximum value (i.e. peak); total capacity is underrepresented for time <1980/90; colour coding (red = 25-75% increase, grey = max ± 12.5%, green = 75-25% decline); a figure with all countries can be found in Appendix Figure 33.

The development of coal capacity relative to total electric capacity since 2000 is also displayed in more detail in Appendix Figure 34. Generally, it can be observed that in countries where coal capacity is rapidly increasing (e.g. China, India, Indonesia, Malaysia, Vietnam), the total electric capacity is increasing at a similar or even higher rate. In China, India, and Vietnam for example, the annual rate of RE growth is substantially greater than that of coal capacity (see Figure 21 and Figure 34). Despite stagnating or declining electricity demand in many countries, total electric capacity is still steadily growing in almost all countries, which is partly due to the increasing capacity requirements caused by high levels or variable renewable energy (VRE) penetration. The share of coal in total electric capacity evidently has impacts on its significance for electricity provision as well as the ease or difficulty with which coal can be phased out.

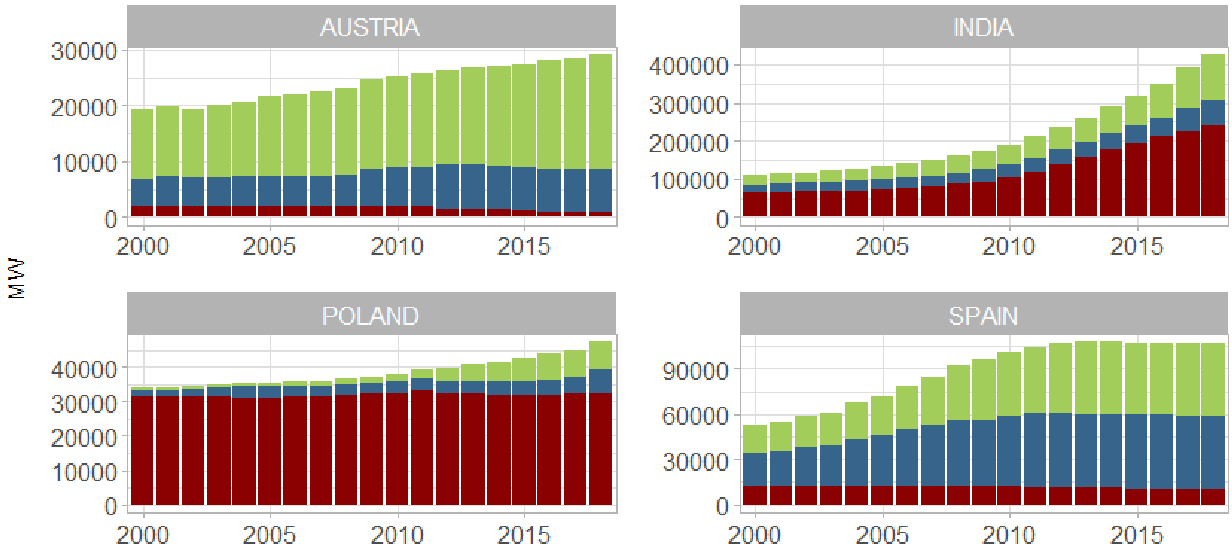


Figure 21: Total installed electric capacity since 2000 by source (example countries)
Note: colour coding (red = coal capacity, green = RE capacity, blue = all other electric capacity (mainly nuclear and natural gas)); figures for all 32 countries are depicted in Appendix Figure 34.

4.7 RO 5: Relationship between Capacity Development and Coal-fired Electricity Generation

4.7.1 Methods

Firstly, results on the development of net capacity additions were mapped against electricity generation from coal. Data on electricity generation was taken from IEA (2019) and averaged over three years as well. Both capacity additions and electricity generation were normalised to their respective peak (maximum value) for the time period of 1980 to the last available year (2019 for capacity and 2016 or 2017 for electricity generation). For mapping net capacity additions against electricity generation from coal for the whole of the EU, Croatia, La Reunion, and Slovenia were excluded because of missing electricity data for 1980-1990.

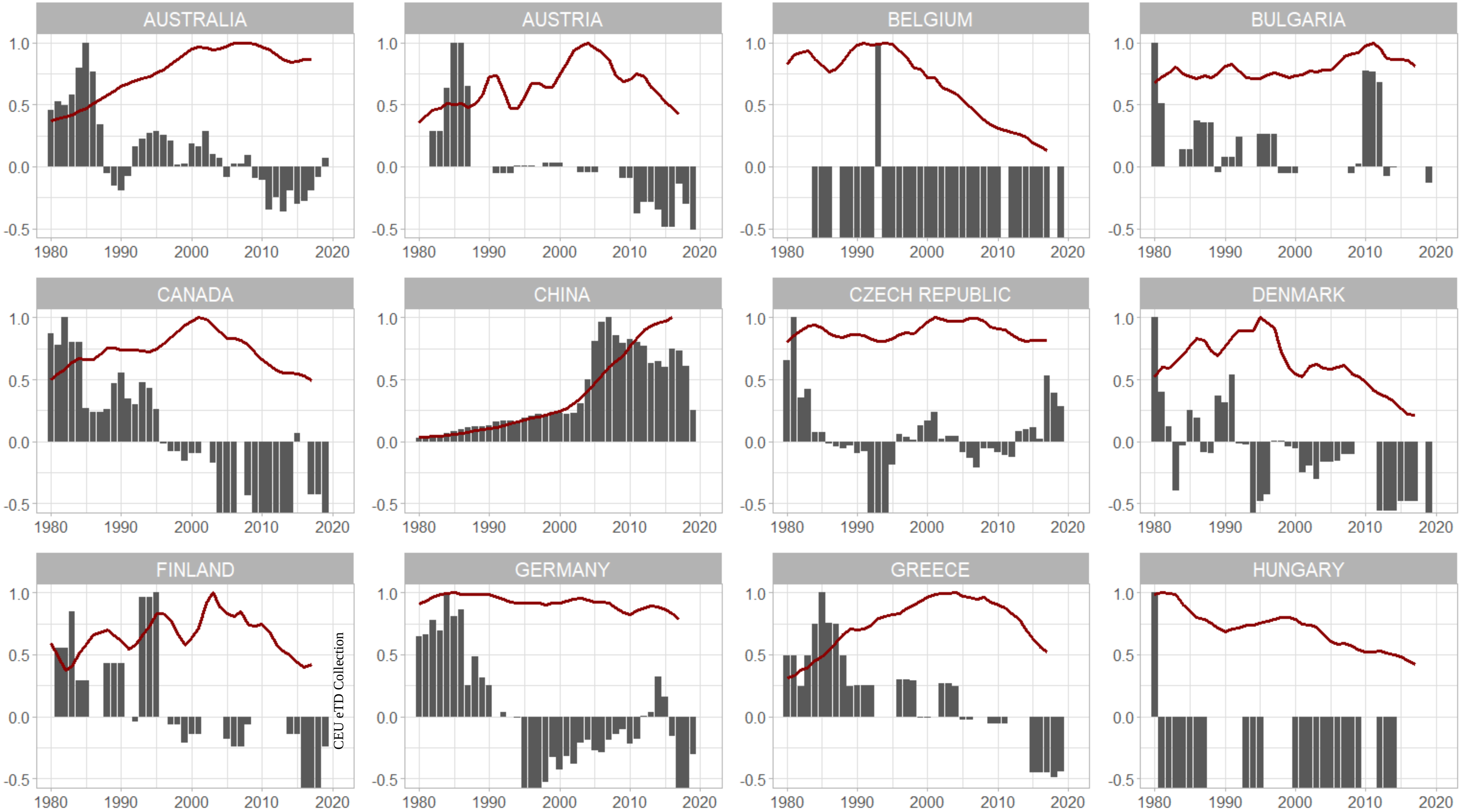
In order to derive national average load factors, the total installed coal capacity for each country and year since 1960 was calculated (see section 4.6.1). Including units that are currently mothballed, deactivated, or on standby has no substantial impact on the subsequent calculation of load factors, as those units constitute less than 1% of total capacity that has not yet retired. To account for less reliable total installed capacity prior to 1990, load factors were calculated for the years 2000 and onwards only. National and regional average load factors were calculated up to the last year for which electricity data was available (2017 or 2018) by dividing total annual electricity generation from coal combustion by the total operational capacity in the same year and multiplying it by the number of hours in a year (8,760).

For the cross-country comparison of national load factors in 2017/18 only, total installed capacity was derived via including all plants that are currently operational, and adding the capacity that was retired between 2018 and today. This excludes all units that are mothballed, deactivated, or on standby but have not yet been retired. These results were only marginally different from the other method (including units mothballed, deactivated, and on standby) in the case of China, India, the US, OECD, and ROTW countries, but made a notable difference in the case of the EU.

Finally, the role of coal in national electricity supply was further investigated by calculating coal's share in both total electricity generation and electric capacity for all DEC18 and COAL14 countries for 2000 to 2018. This was done by dividing annual electricity generation from coal by total electricity generation using the IEA (2019) data and dividing coal capacity by total capacity as derived in section 4.6.

4.7.2 Results

In the following plot (Figure 22), the normalised value of net annual capacity additions (grey bars) and electricity generation from coal (red line) is depicted. This leaves the ratio of capacity additions between years unaffected but hides their absolute annual value. Further, negative capacity additions are uniformly cut off at -0.5, because they are irrelevant for the sequence of peak capacity additions to peak electricity generation, so that a significant part of capacity development is not visible for a few countries (e.g. UK or Belgium). A similar figure but with absolute values and displaying all retirements is presented in the Appendix (Figure 32).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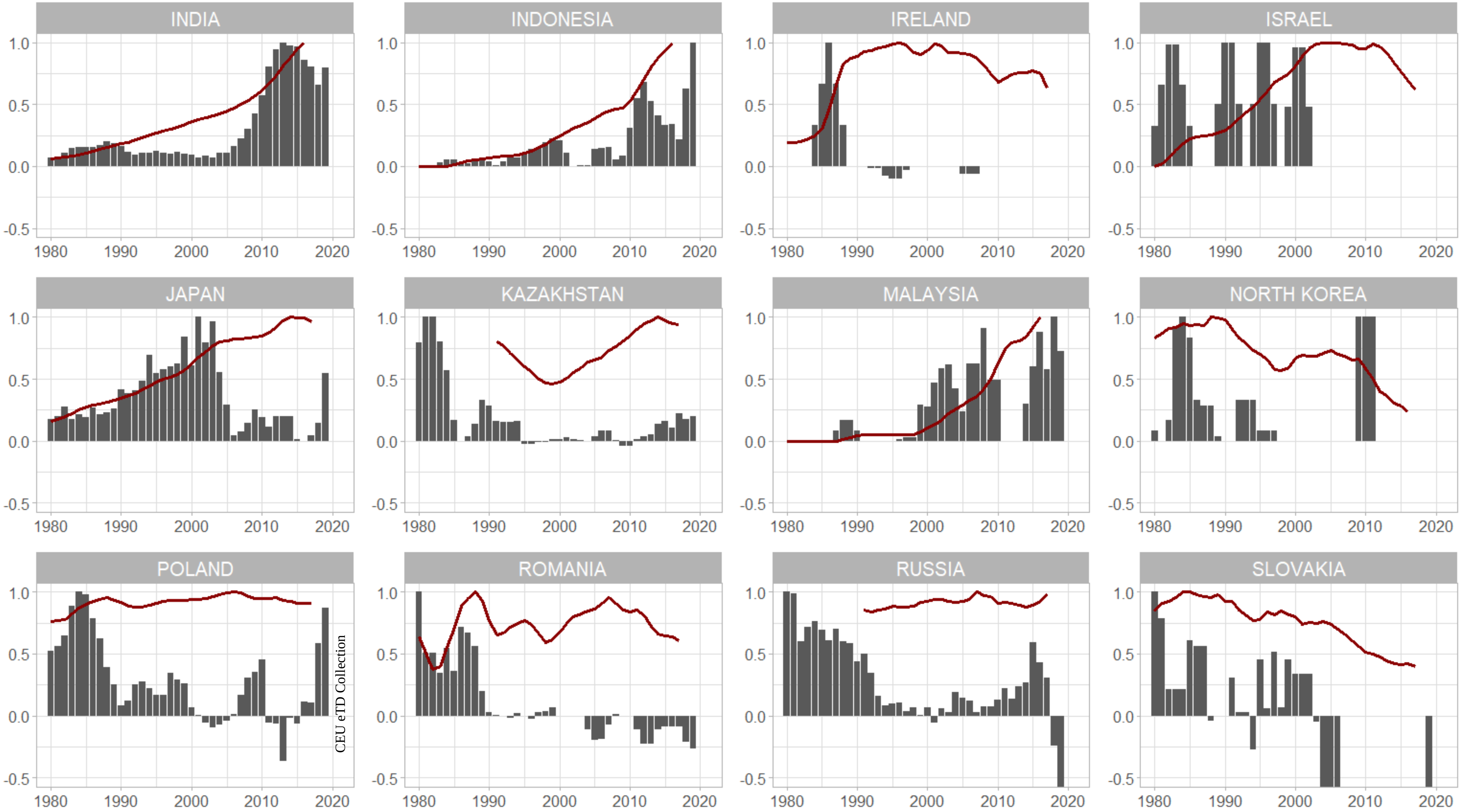

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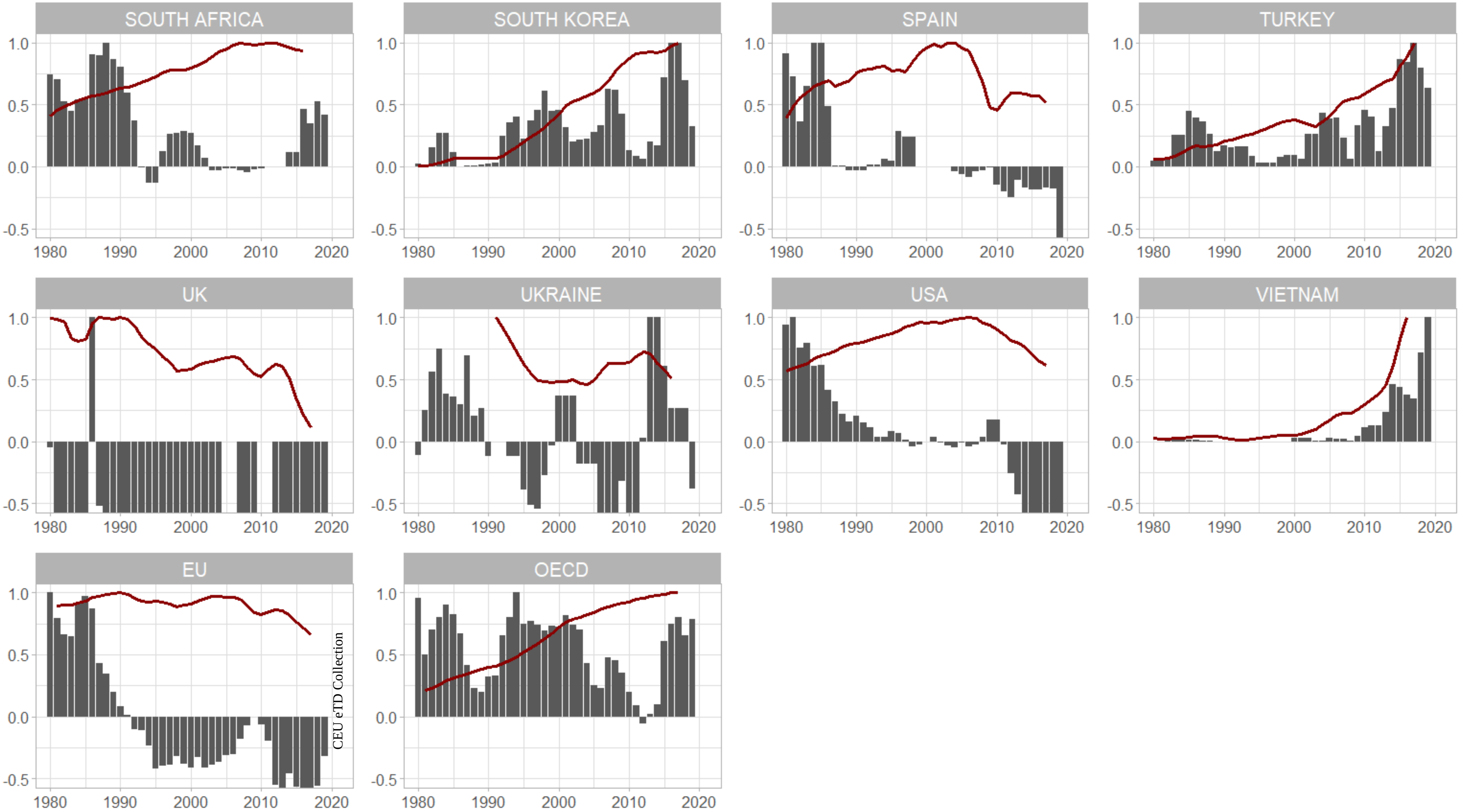
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Figure 22: Normalised net annual capacity additions and coal-fired electricity generation

Note: Both electricity generation and capacity additions were normalised to their respective peak (maximum value) for 1980-2019; both are calculated using 3-year moving averages.

In seven of the COAL14 countries (China, India, Indonesia, Malaysia, South Korea, Turkey, and Vietnam), the maximum value for electricity generation from coal lies in the most recent year for which data was available (2016 or 2017). In these countries, coal combustion from electricity was also almost negligible in the 1980s and grew significantly and almost exponentially only from 2000 onwards. In the OECD country group, electricity generation from coal shows no exponential, but an almost linear upwards trend and similarly peaks in 2017.

In some countries, electricity generation from coal fell by over 50% since peak, such as in Austria, Belgium, Canada, Denmark, Finland, UK, Hungary, North Korea, Slovakia, Spain, and the Ukraine (see Table 3). It must be noted, however, that final electricity demand has declined in many of these countries and the relative decline of coal is substantially lower than its absolute decline. In Bulgaria, the Czech Republic, Germany, Poland and Russia, coal-fired electricity generation has remained relatively stable over the last 40 years – a trend that is also apparent in the whole of the EU for 1980-2008. Since 2008, however, electricity generation from coal in the EU has dropped substantially (>30%).

When contrasting the development of net capacity additions and electricity generation, one key theme emerges, namely peak capacity additions occurring prior to peak electricity generation from coal. This, evidently, does not apply to the countries in which coal-fired electricity has not yet peaked. Also, it does not become apparent for countries where net capacity additions actually peaked prior to 1980, such as Belgium, Hungary, or Germany. In 17 of the 25 countries where peak coal-fired electricity has been reached prior to 2016, net capacity additions peak over 10 years prior to electricity generation from coal, in some cases over 20 years (e.g. Bulgaria, Canada, Czech Republic, Spain, USA, Kazakhstan, Poland, Russia, and South Africa). What is interesting here is that this seems to be a widely shared phenomenon that is not restricted to small or large coal fleets, or a particular geographical area. Excluding all countries where coal-fired electricity might not have peaked yet, the average time between peak net capacity additions and peak coal-fired electricity generation is 14 years, which would be even higher if capacity peaks prior to 1980 would be acknowledged.

Table 3: Capacity and electricity generation development for DEC18 and COAL14 countries

Country	Peak capacity additions	Peak electricity generation	Years between peaks	Capacity inflection point, ~estimate	Years of zero / negative capacity growth	Decline in electricity generation since peak (%)	Annual decline in electricity since peak (%)
Austria	1985	2004	-19	2000	18	-57.6	-4.4
Belgium	1993	1991	2	<1980	40+	-87.2	-3.4
Bulgaria	1980	2011	-31		6	-19.2	-3.2
Canada	1980	2001	-21	1996	23	-51.1	-3.2
Czech Republic	1981	2001	-20	(1986), (2006)	0	-18.5	-1.2
Denmark	1980	1995	-15	1993	21	-78.6	-3.6
Finland	1995	2003	-8	1999	24	-58.2	-4.2
UK	1986	1990	-4	<1980	40+	-88.1	-3.3
Greece	1985	2004	-19	2009	15	-47.6	-3.7
Hungary	1980	1981	-1	<1980	38	-57.7	-1.6
Ireland	1986	1996	-10	1990	31	-37	-1.8
Israel	1990	2006	-16		16	-38.6	-3.5
North Korea	1984	1988	-4		7	-76.3	-2.6
Romania	1980	1988	-8	2000	20	-39.2	-1.4
Slovakia	1980	1985	-5	2003	16	-60.2	-1.9
Spain	1980	2003	-23	2000	20	-48.4	-3.5
Ukraine	2013	1991	22	(1991), (2003)	1	-49	-1.9
USA	1981	2006	-25	2000	8	-38.6	-3.5
Australia	1985	2008	-23	(1988), (2006)	10	-13.4	-1.5
China	2007	2016	-9		0		
Germany	1984	1985	-1	(1991), 2016	4	-21.4	-0.7
India	2013	2016	-3		0		
Indonesia	2019	2016	3		0		
Japan	2001	2014	-13		0	-3.4	-1.1
Kazakhstan	1981	2014	-33		0	-5.7	-1.9
Malaysia	2018	2016	2		0		
Poland	1984	2006	-22	(2001), (2011)	0	-8.8	-0.8
Russia	1980	2007	-27	2018	2	-1.7	-0.2
South Africa	1988	2011	-23	(1993), (2003)	0	-6.2	-1.0
South Korea	2016	2017	-1		0		
Turkey	2017	2017	0		0		
Vietnam	2019	2016	3		0		

Notes: All analyses were conducted for 1980-2019, but for several countries, peak capacity additions occurs prior to 1980 (Belgium, Germany, Hungary). For the Ukraine, Russia, and Kazakhstan, electricity data has only been available since 1990 (rather than 1980). Years of zero or negative capacity growth neglects single years that do not fall under this classification. Inflection points were not calculated but represent estimates based on a visual investigation of preceding figures. Inflection points in brackets indicate temporary turning points (i.e. unsustained trends).

Results on most recent national average load factors vary greatly between countries and range between 8% in North Korea and 83% in Japan. Evidently, depicted load factors for 2017/18 (see Figure 23) only reflect one point in time and are sensitive to intra-annual changes in coal capacity or electricity production from coal in the case of smaller economies and smaller coal fleets. While electricity generation from coal is summarised in an annual sum, capacity additions and retirements take place throughout the year and sometimes de facto occur a year later or earlier than officially announced.

Generally, COAL14 countries display higher average load factors than DEC18 countries, and the respective bottom and top 6 countries are organised according to the two classifications. Interestingly, load factors in China, India, and the US are very similar and range between 55 and 57%. The load factors of the other focus regions range lower in the case of ROTW countries (48%) and the EU (47%), and higher for non-EU OECD countries (78%).

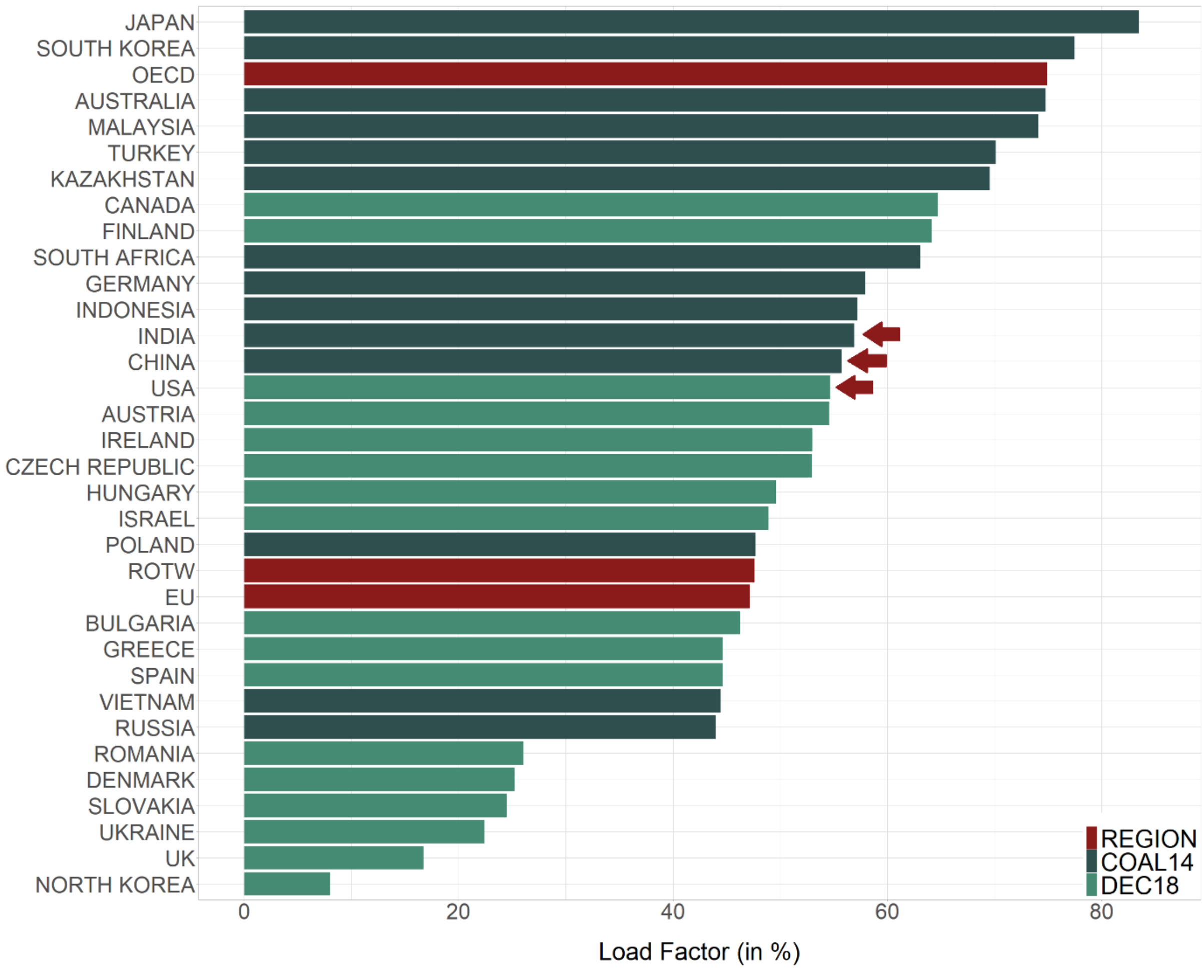

Figure 23: National and regional average load factors for 2018

Note: Calculation via operational coal capacity in 2018 and electricity generation from coal for the last available year (2017 or 2018).

When analysing the development of regional load factors since 2000 (see Figure 24), it becomes apparent that they have considerably changed over time, but do not follow a common upwards or downwards trend. The capacity factors of India, the US, and OECD countries started out particularly high (70-76%) in the early 2000s, but have remained high only for the OECD country group, while load factors in the other two regions have declined; gradually in the case of India and with greater year-to-year variation in the US. In both China and the EU, load factors ranged just under 60% in 2000, then gradually increased until 2007, after which they dropped in the late 2000s, rebound slightly again after 2010, and then dropped again. Throughout this time, the average load factors of China and the EU were never more than 5 percentage points apart. The ROTW country group possesses the lowest load factor throughout these 17 years, but it has risen from 39 to 47%.

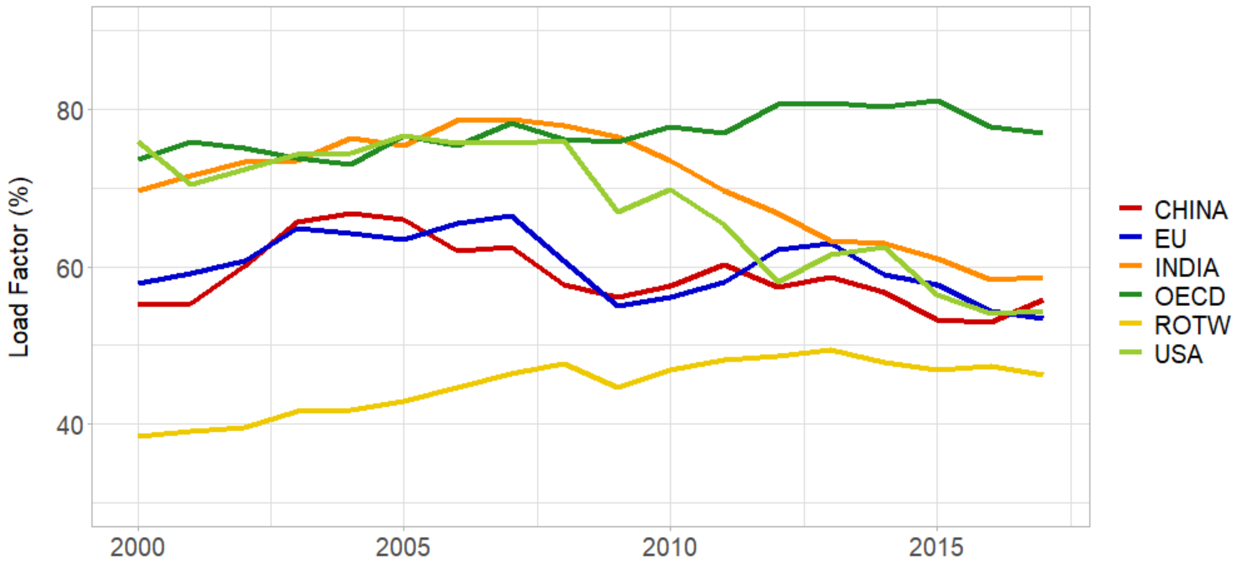

Figure 24: Regional average load factors for 2000-2017

Note: Calculation via cumulative capacity additions and retirements for all units entering operation since 1950; irrespective of operational status (includes, for example, idled and mothballed units).

Table 4 below lists national average load factors for all DEC18 and COAL14 countries, as well as the average (mean) load factor for the entire time period, and the percentage change since 2000 and 2010. It must be noted that in some cases (Ireland 2000-2006; Belgium in 2013), load factors lie above 100%, which is evidently technically impossible. This could be due to missing data on smaller coal units, as well as slight imprecisions due to the time ordering of capacity additions and retirements within one year.

Table 4: National average load factors for all DEC18 and COAL14 countries for 2000-2018

Country	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	Mean	% change (00-17)	% change (10-17)
Australia	69.5	71.8	67.3	63.7	66.5	68.6	70.5	69.9	69.3	69.3	68.7	66.6	69.7	64.4	64.1	67.4	71.3	73.7	70.5	**68.6**	**4.2**	**4.9**
Austria	37.0	44.1	42.9	52.2	51.4	47.9	47.5	45.0	39.2	28.4	40.0	43.8	45.0	44.0	35.4	49.0	44.5	43.9	40.6	**43.3**	**6.9**	**3.9**
Belgium	97.4	84.6	83.9	76.9	81.6	74.6	71.3	78.5	86.9	86.3	83.4	76.3	76.6	112.2	95.8	92.4	*NA*	*NA*	*NA*	**84.9**	**-5.0**	**9.0**
Bulgaria	35.2	40.5	35.6	39.9	39.1	38.1	39.3	46.0	47.6	43.6	46.2	50.2	42.1	35.7	39.3	41.5	35.7	38.5	34.5	**40.5**	**3.3**	**-7.6**
Canada	74.1	74.3	74.2	71.0	64.8	72.0	66.7	72.4	67.2	59.1	67.7	66.4	56.9	76.6	76.5	75.7	72.1	69.5	63.6	**69.5**	**-4.6**	**1.7**
China	55.2	55.2	60.0	65.7	66.8	65.9	61.9	62.5	57.7	56.1	57.5	60.2	57.3	58.7	56.7	53.3	53.0	52.4	*NA*	**58.7**	**-2.7**	**-5.1**
Czech Republic	65.7	65.4	62.2	63.2	62.5	61.8	63.0	68.4	63.3	59.1	60.5	61.1	57.4	54.0	53.0	53.3	54.2	53.4	49.0	**59.5**	**-12.3**	**-7.1**
Denmark	38.9	41.6	45.0	62.4	47.5	40.0	63.6	53.1	46.7	47.3	45.4	37.3	28.2	46.2	35.7	23.0	34.9	24.5	25.3	**41.4**	**-14.5**	**-21.0**
Finland	39.1	52.1	59.4	81.2	70.4	34.8	72.6	68.0	44.5	49.3	66.1	48.6	34.8	44.3	36.5	27.7	33.1	38.0	41.0	**49.5**	**-1.1**	**-28.1**
Germany	60.1	61.7	63.8	65.3	64.9	63.5	64.2	67.5	62.5	57.2	60.7	61.6	64.7	66.4	64.0	61.1	59.3	58.1	56.4	**62.3**	**-2.0**	**-2.6**
Greece	79.9	82.6	80.5	76.8	77.2	78.1	70.9	76.2	73.3	75.1	68.6	69.2	69.3	58.8	57.3	49.2	47.1	46.8	44.7	**67.4**	**-33.1**	**-21.8**
Hungary	57.0	55.0	57.2	61.8	55.7	49.5	49.1	51.8	50.3	44.8	44.3	46.1	45.3	45.1	43.2	41.7	40.7	36.0	33.9	**47.8**	**-21.0**	**-8.3**
India	69.0	70.9	72.7	72.8	75.6	74.8	78.0	78.0	77.2	75.8	72.9	69.1	66.4	62.9	62.6	60.8	58.2	57.5	*NA*	**69.7**	**-11.5**	**-15.4**
Indonesia	45.9	50.9	57.9	62.5	64.4	69.1	63.0	67.4	64.0	65.9	64.7	58.9	58.7	56.2	57.2	56.9	55.7	58.1	*NA*	**59.9**	**12.2**	**-6.5**
Ireland	100.5	108.4	104.2	96.4	90.3	103.5	100.1	95.7	98.5	82.8	71.5	75.8	93.1	81.9	80.5	92.2	87.5	72.5	53.0	**88.9**	**-28.1**	**0.9**
Israel	77.0	77.0	82.1	84.4	85.3	84.5	83.5	87.1	82.4	80.1	79.9	82.0	90.3	74.8	70.2	68.6	56.4	51.4	48.9	**76.1**	**-25.6**	**-28.5**
Japan	79.8	83.6	81.6	82.0	80.5	82.7	79.9	83.8	81.5	79.0	83.4	79.8	86.1	90.7	91.1	91.5	90.0	90.9	82.1	**84.2**	**11.2**	**7.6**
Kazakhstan	33.6	38.0	37.7	43.1	47.5	47.1	45.9	51.9	56.7	54.0	62.0	65.3	64.3	71.5	69.4	68.4	62.8	63.8	63.9	**55.1**	**30.2**	**1.7**
Malaysia	51.6	59.6	53.6	44.5	56.1	58.4	50.8	50.1	48.6	48.0	61.7	76.3	80.3	76.8	80.4	80.4	78.2	74.1	*NA*	**62.7**	**22.4**	**12.4**
North Korea	32.9	33.6	31.8	32.4	33.1	35.0	35.9	29.2	32.7	31.4	25.0	17.5	16.8	12.5	14.0	9.5	10.3	8.1	*NA*	**24.5**	**-24.8**	**-16.9**
Poland	49.7	49.5	48.9	51.8	52.2	52.3	54.1	53.2	50.5	47.6	48.7	48.5	48.4	49.5	46.8	47.2	47.4	46.9	46.7	**49.5**	**-2.8**	**-1.8**
Romania	26.3	27.3	28.1	32.2	29.7	30.9	36.0	35.9	36.7	30.9	29.4	35.2	33.4	25.3	26.6	27.2	24.4	25.7	24.1	**29.8**	**-0.6**	**-3.7**
Russia	44.6	42.7	43.4	43.5	40.6	41.4	44.6	42.4	49.0	40.6	41.1	40.5	40.9	39.5	38.1	37.5	39.7	40.4	43.8	**41.8**	**-4.2**	**-0.7**
Slovakia	46.1	46.4	41.5	47.4	45.4	51.9	49.7	45.3	44.7	37.1	35.4	35.0	33.9	30.6	29.1	28.9	28.3	30.7	24.5	**38.5**	**-15.4**	**-4.7**
South Africa	56.9	56.6	59.1	63.3	66.0	66.8	69.3	72.2	70.6	68.3	71.1	71.6	70.9	69.8	68.2	65.8	65.2	61.6	*NA*	**66.3**	**4.6**	**-9.5**
South Korea	79.3	80.8	85.2	85.4	83.3	84.8	85.0	86.0	84.5	90.3	93.9	94.6	100.4	93.5	91.1	93.7	78.9	75.9	77.5	**86.5**	**-3.4**	**-18.1**
Spain	75.3	66.8	76.8	70.8	74.8	76.1	64.5	70.6	47.7	35.3	25.2	44.9	56.8	42.5	46.6	56.3	40.8	50.5	44.4	**56.1**	**-24.8**	**25.3**
Turkey	63.5	63.9	53.5	45.0	48.0	54.7	52.7	60.0	64.8	60.9	53.2	60.8	62.4	58.5	62.0	58.8	62.8	61.0	64.5	**58.5**	**-2.5**	**7.8**
UK	45.3	49.2	48.1	57.5	54.8	56.0	61.9	56.5	52.4	43.5	45.3	45.6	60.0	67.8	56.0	42.4	24.5	18.1	16.7	**47.4**	**-27.1**	**-27.1**
Ukraine	22.9	23.4	24.0	24.0	20.0	22.1	28.7	32.0	32.3	29.8	32.2	34.8	37.6	37.4	31.9	25.3	27.7	22.1	*NA*	**28.2**	**-0.9**	**-10.1**
USA	75.8	70.4	72.2	74.1	74.3	76.5	75.6	75.6	75.9	66.8	69.6	65.2	58.0	61.4	62.4	56.4	53.9	54.2	54.6	**67.0**	**-21.6**	**-15.5**
Vietnam	39.5	24.4	37.3	55.7	51.7	87.80	81.3	87.7	88.3	80.6	82.6	63.5	63.4	61.2	47.5	49.8	59.5	50.6	*NA*	**61.8**	**11.2**	**-31.9**
Average	**57.0**	**57.9**	**58.5**	**60.9**	**60.1**	**61.0**	**61.9**	**63.1**	**60.9**	**57.0**	**58.1**	**57.9**	**58.4**	**58.5**	**55.9**	**54.8**	**51.6**	**50.0**	**48.0**	**57.7**	**-5.7**	**-6.8**

Overall, load factors differed greatly between countries and even within countries over the last 18 years. They tended to be highest on average between 2003 and 2008, while dropping substantially since then. Load factors have been highly variable in Austria, Denmark, Finland, Ireland, Malaysia, Spain and Vietnam, which all have relatively small coal fleets and experienced a sudden rise or generally high deployment of natural gas. In Australia, Canada, China, Germany, and Poland, on the other hand, load factor variability has been low. These countries possess over larger coal fleets and their natural gas use is rather stable or limited.

The final part of this RO was to investigate the role of coal capacity relative to total electric capacity and electricity generation from coal relative to total electricity generation. In nine of the analysed countries, coal accounts for more than half of total electricity generation, and is particularly high in South Africa and Poland (Figure 25). Generally, COAL14 countries tend to use coal for a greater share of their electricity generation, while in more than half of all DEC18 countries, coal contributes less than 20% of total electricity. An exception to this are the Czech Republic and Bulgaria, where coal accounts for over 50% of electricity generation.

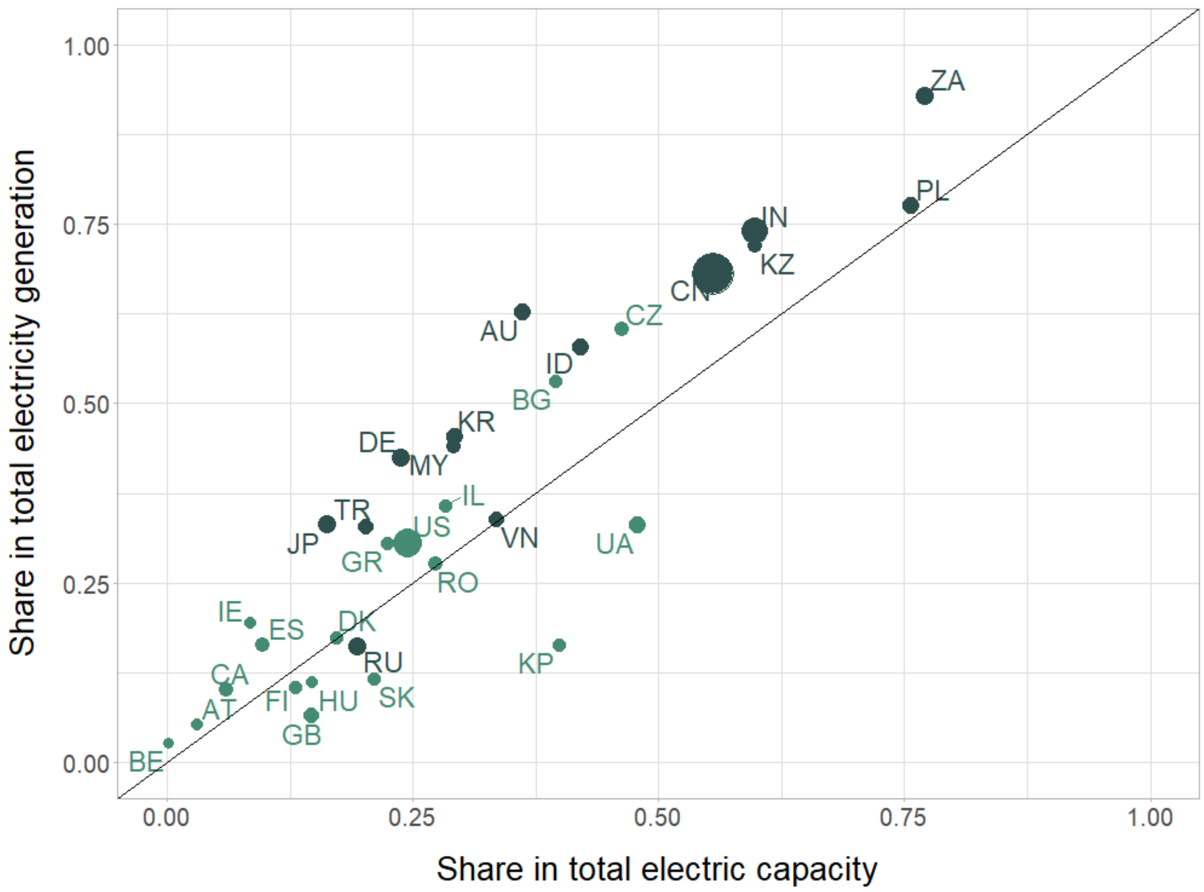

Figure 25: Share of coal in total electric capacity and total electricity generation
Note: Country codes are listed in the Appendix (Table 5).

The pattern of load factors is to some degree reflected in this figure: Countries with lower load factors tend to be situated below the diagonal line, while countries with higher load factors are more likely to be situated above it. Yet, respective shares also depend on the share of (intermittent) RE integration, the variability of final electricity demand, and the flexibility of the electricity system.

5 Discussion

The overarching goals of this research project were to investigate how coal capacity characteristics have changed on a temporal and spatial scale, to study the rate and extent of growth and contraction of national coal fleets, and to explore the relationship between coal capacity and coal-fired electricity generation. Several findings uncovered throughout sections 4.4-4.7 confirm or expand upon what previous studies (section 4.3) already established. Other results are contradictory or only moderately instructive by themselves. In order to put the various results into a broader context and provide possible explanations for their occurrence, the theoretical framework from section 3 is used to structure and interpret the results. The discussion is organised according to three phases of a technology's life (rise, persistence, and decline) and integrates findings from the literature review (sections 2.1 and 2.2), qualitative analysis of coal capacity-related factors (RO1, section 4.3) and quantitative results from RO2-5 (sections 4.4-4.7).

5.1 The Rise of Coal

First of all, drivers behind the rise of coal are numerous. They differ depending on local contexts and between early and late adopters of coal technologies. In the UK, where coal combustion as we know it today originated, positive feedbacks (cf. Neij 1997) were created in the context of the industrial revolution. Coal mining, combustion, railway expansion, the rise of the metallurgical industry and the development of the steam engine certainly formed a kind of 'technology cluster' (cf. Grubler *et al.* 1999), in which the different technologies mutually supported each other. In the whole of Europe, North America, and later the rest of the world, coal gained dominance in electricity supply as it developed a relative advantage (cf. Rogers 2003) over alternative means of electricity generation, typically over traditional renewables. These advantages included increasing cost-competitiveness, opportunities to earn foreign currency via coal exports, improvements in efficiency and performance, the provision of regional jobs in coal mining, and the reliance on local fuels (cf. section 2.1). Additionally, and particularly among late adopters (e.g. Asian economies), rapid population and economic growth and the associated surge in electricity demand were key drivers. This makes the rise of coal a result of both technological progress and societal needs (cf. Ayres 1988). Lastly, coal combustion technologies are less complex (cf. Rogers 2003) than nuclear power, and the required know-how was, as opposed to RE technologies, readily available in many countries – making coal a favourable option in developing economies.

During and after the global take-off of coal combustion for electricity generation, coal units underwent substantial changes in their design, which suggests the gradual emergence of a dominant design (cf. Grübler 1991). For example, the average unit size significantly increased between 1970 and 2020, and also became more standardized: Depending on the underlying combustion technology, a rising share of units are built with a nameplate capacity of 330, 660 or 1000 MW (section 4.4). Standardisation generally involves learning effects, through which performance increases and costs decline (cf. Markard *et al.* 2020). In the case of complex and large technologies, such as coal-firing units, costs are typically further reduced through upscaling and economies of scale (cf. Wilson 2012). However, due to increasing material costs, long planning and permitting processes as a result of public opposition, and mounting safety and environmental requirements, the capital costs of coal units have not declined with increasing production volumes or increasing unit sizes (section 4.3).

There have, however, been improvements in the performance (cf. Ayres 1994; Christensen 2009), as exemplified by the increasing share of more efficient supercritical and ultra-supercritical units (section 4.4). On one hand, these efficiency improvements can substantially lower operating costs (due to lower fuel and water consumption) and lead to lower CO_2 emissions per unit of electricity output. On the other hand, these typically large (ultra-)supercritical units require higher capital investments, which complicates cost recovery in times of accumulating external pressures. Further, their generally higher minimum loads demand conditions of rising electricity demand and high load factors (sections 4.3.2, 4.7).

Moreover, an increasing share of coal units is owned by private utilities and the services sector (section 4.4). This is not only famously the case for the US, but also applies to regions where utilities were traditionally predominantly owned by governmental utilities. A possible explanation behind this trend is that the investment environment has substantially changed, as financing institutions have been put under pressure by environmental groups and the public to divest from coal (Urgewald 2019). Additionally, entire economies and electricity markets worldwide are becoming more liberalised. The above-mentioned changes in coal capacity with regards to size, technology, and ownership (section 4.4) were confirmed in the path analysis of section 4.5.

A key feature of the spatial diffusion of technologies is the adaptation to local conditions (cf. Nordensvard *et al.* 2018). While some general trends are highlighted above, substantial differences between national coal fleets exist. In India, for example, the average unit size is smaller on average than in most other countries to suit the particular energy supply requirements. In the EU, almost all units that were built over the last decade are equipped with ultra-supercritical combustion technology, which is in line with the stringent air pollution regulations in place, but also indicates that both know-how and financial resources exist to stem these projects. Also, while there is no global trend in the use of coal types distinguishable (sections 4.4), the geographical location does have an influence on the type of fuel used nationally (section 4.5). This is unsurprising given the high costs of international coal transport and the relevance of mining operations for regional value creation and the provision of jobs.

With regards to the time scale of technology diffusion and the resemblance with an S-curve (cf. Rogers 2003), it is difficult to establish how long the upward trajectory of coal lasted on average or per country. Most countries have either not reached their respective coal capacity peak yet, or the growth period lies so far back that it is problematic to reliably determine the rate of growth due to incomplete data. It does, however, seem to be the case that years of accelerated growth account for a shorter time period that the years until a technology takes off, or years in which it slowly reaches a saturation point (section 4.6). Further, as typical for dynamics of spatio-temporal diffusion (cf. Grubler 2012), the time period of technology diffusion in the periphery is shorter than in the core due to spill-over effects and the ability to build upon existing knowledge. In the UK, for example, the rise of coal took several decades, while growth rates in Vietnam or Indonesia were exponential within less than a decade (section 4.6).

Additionally, Grubler (2012) posits that saturation levels are lower in the periphery than in the core. So far, it is too early to determine whether this holds true, and such investigation should be adjusted for electricity system size. Yet, with the exception of India, it appears unlikely that countries currently exhibiting substantial increases in coal capacity will reach a similar level of domination of coal over other sources of electricity like in South Africa or Poland (>90% of electricity supply). Theory (section 2.2.4) further suggests that saturation is reached earlier in the case of smaller economies and those in which coal accounts for a comparatively small share of total electric capacity. These two effects are reflected in the data: In Austria, for example, coal only ever supplied a small share of total electricity, and coal capacity dramatically increased in only a few years between 1980 and 1990. In Ireland, on the other hand, coal was the main source of electricity for many decades, but coal capacity still more than tripled between 1980 and 1990. Generally, increases in total installed capacity are more gradual and span a longer time period in larger economies, such as the US, Russia, or China (section 4.6).

In countries where coal is still on a steep upwards trajectory (several COAL14 countries), coal-based electricity generation and coal capacity increase at a similar rate (section 4.7), leading to relatively high average load factors that are generally associated with higher profitability. In Malaysia, Kazakhstan, India, China, and Indonesia load factors were stable or increased since 2000 and generally ranged over 50% over the last 10 years. Many of these countries are late adopters of coal but also RE electricity, so that the operation or their national coal fleets is less impacted by the intermittent nature of VREs and the overall electric capacity requirements per kWh of electricity are lower. In countries where coal is close to peak total installed capacity (e.g. Poland, South Africa, Greece) the growth in annual capacity additions came to a halt, while coal-fired electricity generation continued to rise slowly (section 4.7).

Finally, coal fleets that are rapidly growing are also typically younger on average than those that are shrinking (section 4.4). India and China are among the six countries whose national coal fleets are substantially younger than 20 years on average, which points towards continued coal combustion from the available infrastructure until 2040 and beyond. This becomes even more relevant when considering that these two countries are the world’s two largest coal consumers.

5.2 The Persistence of Coal

Throughout the rise and maturation of coal technologies, they typically demonstrate a close fit with their regulatory, economic, and institutional environment (cf. Rogers 2003; Turnheim and Geels 2012), which leads to lock-in (cf. Unruh 2000). In India and China, for example, partly regulated electricity prices, guaranteed operating hours, and favourable electricity market conditions lower investments risks and incentivise the combustion of coal (sections 2.1 and 4.3). Similarly, in Europe and the Soviet Union, coal operations were long subsidised by national governments, and environmental regulations did not considerably constrain coal combustion for many decades. Cultural-cognitive institutional elements, which are most deeply embedded in societies and most difficult to change (cf. Scott 2008), are exemplified by the emotionalised debate and continued governmental support in the case of Australia, Poland, or South Africa. This cognitive lock-in has prevented these economies from diversifying their electricity supply earlier on, as a result of which they now face an immense decarbonisation challenge.

Eventually, the adverse effects of coal combustion such as rising air pollution or climate change accumulate (cf. Markard 2018), which typically leads countries towards a saturation point and demonstrably contributed to the limited construction of new capacity (sections 4.3 and 4.6). While many countries have passed peak electricity generation from coal (section 4.7) as well as peak total installed capacity (section 4.6), their total operational capacity today still lies within ± 12.5% of peak capacity. This plateau period lasts up to several decades, with 20 years on average. Even though the construction of new coal plants becomes increasingly expensive, operators of existing coal plants continue to burn coal in hope of recovering their initial investments. Additionally, coal-firing is profitable if fuel prices are low, the impact of RE on electricity wholesale prices limited, and asset owners receive payments via capacity mechanisms. These could be possible explanations for why electricity generation from coal continues to rise for a few years after peak total installed capacity is reached (e.g. Ireland, Canada, Spain; see sections 4.6 and 4.7). On average, electricity generation from coal peaks 3 years after total installed capacity does, but then declines more rapidly.

MLP's emphasis on the 'window of opportunity' (cf. Verbong and Geels 2007) in which renewables quite rapidly replace fossil fuels thus seems somewhat optimistic. Fossil fuel industries persist, and the replacement of carbon-intensive energy carriers by low-carbon alternatives takes substantially longer than many studies suggest. Reasons behind the slow decline of coal may also include that low-carbon electricity supply provides no tangible benefits to electricity end-users (cf. Grubler 2012), and the operation of RE assets challenges the conventional business model of incumbent utilities. Further, elevated RE deployment complicates grid mechanics, balancing supply and demand, and requires investments in new, more flexible infrastructure.

Since the lifespan of coal units generally lies between 30 and 50 years (section 4.5), coal capacity built today sets countries on a path dependent trajectory, in which the premature abandonment of coal units or the underutilization of coal capacity would prohibit the recovery of investments and risk the occurrence of stranded assets. Capacity-related decisions made now thus influence energy sector development and CO_2 emissions for decades to come. If the historic trend of net annual capacity additions peaking several years prior to peak coal-fired electricity generation (section 4.7) continues in the future, many economies are nowhere near peak coal combustion.

5.3 The Decline of Coal

The two main competitors to coal are natural gas and renewable energy, which have surpassed coal in total electric capacity in various countries (section 4.6). While the operation of coal plants becomes increasingly expensive, the natural gas boom and the cost decline in the manufacturing of RE technologies make these alternatives increasingly attractive while providing the same utility, i.e. electricity supply (cf. Anderson and Tushman 1990). There exist several accelerators to the complete phase-out of coal: One is to remove the resources that coal relies upon, such as halting governmental investments in coal mining and coal plant construction, introducing capital market constraints, or removing its physical infrastructure by directly or indirectly retiring plants prematurely. Additional measures include the introduction of carbon prices and environmental fees, or the support of renewable energy technologies (section 2.1.4). The unprofitability of mining operations and public opposition to mining and combustion further drive the decline of coal, which constitute pressures that did not exist in similar volume when coal was on the rise throughout the 20th century. Large, landscape-level shocks (cf. Rip and Kemp 1998), such as the financial crisis of 2008/2009, have also contributed to a (temporary) reduction in coal combustion: Regional average load factors declined across all world regions (section 4.7) and most strongly in the US and EU. Overall, there are pressures that affect coal operations similarly around the world, while others originate from particular contexts, or have only arisen in more recent years.

Countries that exhibited a substantial decline in total installed coal capacity (-75% or more), demonstrated an inverted S-curve shaped pattern, in which coal capacity first slowly declined, but then accelerated. When, in a few years, more countries have phased out coal completely, it would be interesting to examine whether this pattern will persist, and whether the last few percent towards the complete phase out of coal are again relatively slow. While Rogers (2003) described the diffusion of a technology as an ‘uncertainty-reduction process’, the decline of a technology appears to be the opposite: National energy scenarios fail to specify coal reduction plans or set contradictory energy sector targets, and the increasing affectedness by fuel prices and climate policies complicates making predictions about the future of coal.

With regards to the spatial pattern of technology decline, results from section 4.6 are somewhat contradictory to what Grubler (2012) found. Of the countries that exhibit the greatest decline in total installed coal capacity (Austria, Belgium, Canada, Denmark, Finland, Germany, and the UK), all have been pioneers or early adopters of coal-firing for electricity generation. Whether this ‘first in – first out’ rule holds true for all countries remains to be seen, but the current membership profile of the PPCA also reflects this pattern. However, if the Paris climate goals are to be met, the overall lifetime of coal as a source of electricity will be substantially shorter among late adopters compared to early adopters. This will presumably be reflected in rapid and large-scale abandonments of coal units towards 2050.

Countries with declining electricity generation from coal (DEC18) generally exhibit lower average load factors than COAL14 countries (section 4.7). This suggests that reductions in coal capacity lag behind reductions in coal firing. While the dispatch of power plants is determined by a continuous adaptation to electricity demand and RE supply for every minute of the day, both construction and decommissioning of coal plants require several years of planning and execution. Further, DEC18 countries typically demonstrate higher levels of RE adoption, which necessitates additional electric capacity to ensure reliable electricity provision at all times.

Several countries (e.g. Czech Republic, Germany, Ukraine) have notably reduced their coal-fired electricity generation, but sections 4.6-4.7 highlight that this decline was neither linear (cf. Fabra *et al.* 2015), nor did annual capacity additions and retirements show a clear trend over the past 40 years. For example, annual capacity additions in the EU and US steadily declined but rebound around 2010. Observations like these caution against declaring 'coal's terminal decline' or basing optimistic outlooks on small, now coal-free economies like Austria and Belgium. Further, renewables can either replace coal or act as add-ons to the existing regime (cf. Geels 2018). Both effects can be observed among the studied countries: In Denmark or the UK, renewables (particularly wind power) successively replaced coal, while shares of natural gas and nuclear did not change dramatically. In Germany, on the other hand, renewables made up for the diminishing share of nuclear power, while coal combustion for electricity generation remained stable over decades.

DEC18 countries currently have older coal fleets on average than COAL14 countries (section 4.4). Having largely recovered their capital costs, retirements over the next decades are associated with no or minimal economic loss. Exceptions to this are Israel and Spain (DEC18), whose coal fleets are 30 years old on average. Given national pledges to phase out coal by 2030 (Spain) and 2025 (Israel), this will inevitably lead to premature retirements and stranded assets. Exceptions at the other end of the scale are Poland and Kazakhstan with 47 and 50 year old national coal fleets. Just like Hungary, Ukraine, and Russia, who have similarly old coal fleets, these countries carry legacies from being members of or having been influenced by the Soviet Union, where the majority of today's operational capacity was built over a short time. After the economic transition, increased efficiencies and lowered energy demand did not incentivise or require the construction of many new coal plants. This is also reflected in their comparatively low national average load factors (section 4.7). In these countries, total installed coal capacity is likely to experience a substantial and unanticipated drop over the next years, which could elevate average load factors in the absence of excess non-coal electric capacity.

The only scenario in which coal can reasonably continue to play a role in electricity supply in the medium and long-term future is through the equipment with CCS technology. Since CCS is currently not cost-effective nor widely accepted (section 4.3.2), major technological improvements will unlikely save already declining coal industries. For countries in which coal is expected to play a key role in satisfying electricity demand in 2040 and beyond, CCS could be an option of coal sector reorientation. However, in the majority of countries, the low-carbon transition will be characterised by the large-scale adoption of renewables and other low-carbon electricity sources, as well as increased reliance on storage and demand-side flexibility.

5.4 Further Considerations

The relevance of context and socio-economic embeddedness becomes apparent throughout all stages of the analyses. While it is possible to make some general observations, the results reiterate that energy transitions unfold under varying conditions and demonstrate highly different paths. Further, not all results are equally instructive, fit the TF, or support what has been stated in the literature reviewed. For example, results on the development of retirement ages over time and across regions (section 4.5) reveal no systematic patterns that offer a credible explanation as to why these differences occur. DEC18 and COAL14 countries are not notably different, nor do geographic area or size of economy seem to impact retirement ages. Further, results from the path analysis indicate that larger unit sizes are associated with higher retirement ages, but that the utilization of more efficient (ultra-)supercritical combustion technology does not protect units from being retired prematurely.

Benn *et al.* (2018) and Celebi *et al.* (2010) both established that stranding is less likely to occur in regulated markets and among state-owned utilities because coal plants are isolated from market forces and competition. Interestingly, retirement ages in China, one of the most regulated electricity markets of all countries analysed, are by far lowest (section 4.5), while they are highest in the US, where market liberalisation is high. Results from the path analysis also suggested that private ownership is associated with higher retirement ages. It would be interesting to study whether these results are influenced by other country-specific factors, such as air quality standards or amortization periods, and whether the relationship proposed by Benn *et al.* (2018) and Celebi *et al.* (2010) holds true when comparing units within one country.

All results on lifetimes and retirement ages support Markewitz *et al.* (2018) and Rode *et al.* (2017), who found the use of particular lifetimes in academic studies and energy sector scenarios to be insufficiently substantiated. The large variation between countries and substantial changes over time suggest the utilization of country- and time-specific lifetime assumptions, that should suit the particular purpose of the study.

Finally, according to Grubler (2012) energy supply technologies take longer to diffuse than end-use technologies. The decline of coal-based technologies appears to unfold accordingly: While the direct combustion of coal for transport has been phased out completely, and coal-firing for residential heating and cooking declined substantially, coal in energy supply persists.

5.5 Synthesis

Figure 26 combines several results reported in previous sections and visually integrates them into the theoretical framework. These dynamics, evidently, are based on past developments and thus not fully indicative of future trajectories. Further, they are based on average developments, and do not reflect the exact path of every (or any) country under study.

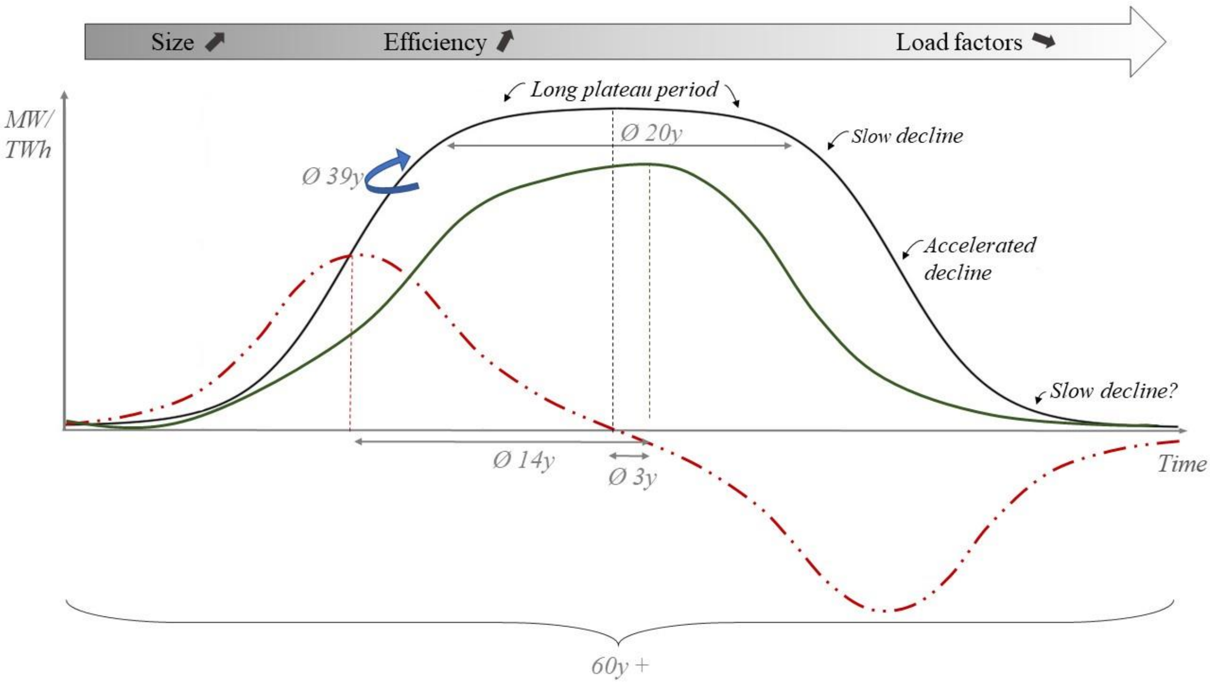

Figure 26: Synthesis of results in TF
(author's illustration)

The entire life of coal as a source of electricity spans at least 60 years, based on observations from Austria and Belgium. On one hand, coal firing presumably stretches over a significantly longer period of time elsewhere, as coal never dominated electricity supply in Austria and Belgium (nuclear and hydropower did) and the two countries are comparatively small economies. On the other hand, long time frames introduce high sensitivities to future uncertainties (e.g. changes in fuel or electricity prices or climate policies) and may shorten the life of coal substantially.

Exemplary, the TF was applied to one specific country, namely the United States (Figure 27). The US were chosen due to the considerable deployment of coal and relatively far progression through the phases of the life cycle. The development of total installed capacity (black line) demonstrates a highly similar path to that of the hypothesised development (grey dotted line). Annual net capacity additions (grey bars) also resemble the hypothesised trajectory (red dotted line) for the time period under investigation. Peak electricity generation from coal and peak total installed coal capacity fall closely together (2008-2011). Finally, the average unit retirement age increased from 38 years around 1980 to 46 years around 2000 to 55 years most recently.

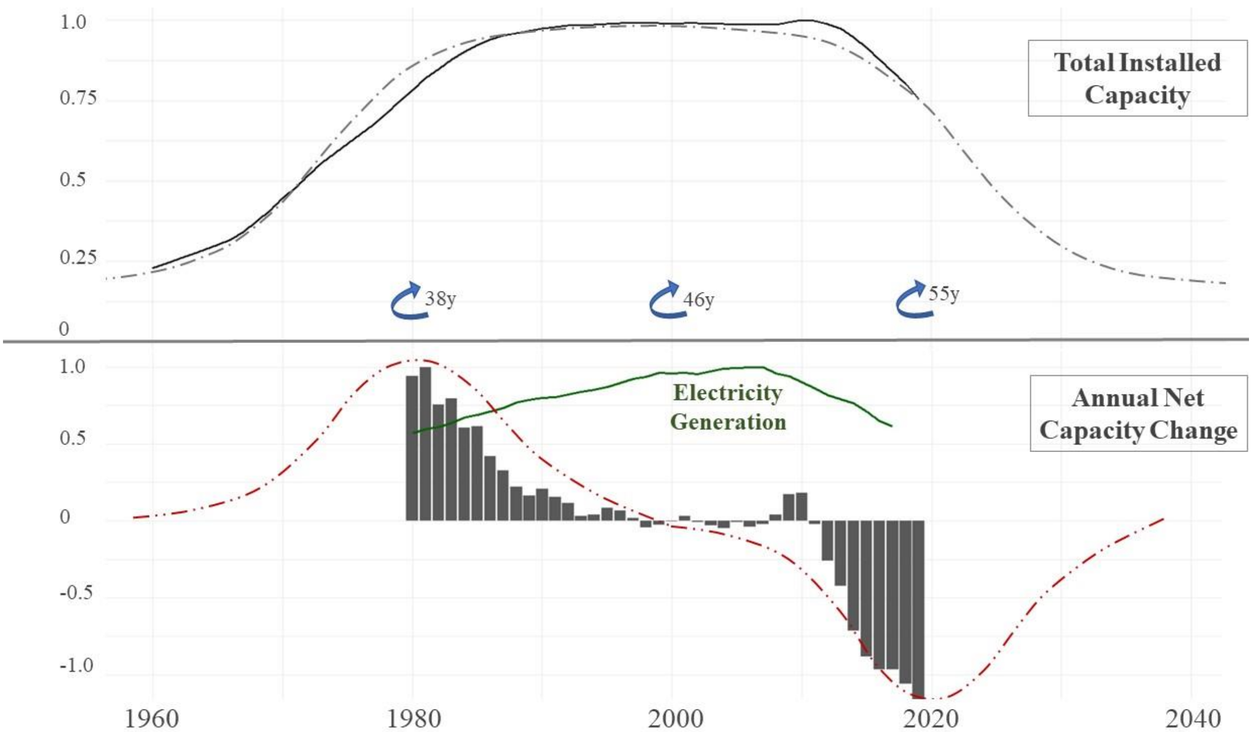

Figure 27: Comparison of TF and results (example country: USA)

Note: dotted grey and red line represent hypothesised development according to the TF; black and green line and grey bars represent observed development. Values are represented in comparison to respective peak (max) over the time period of investigation (1960-2019 for total installed capacity; 1980-2019 for annual net capacity change and electricity generation).

For many other countries, overlapping the TF with the results reveals fewer striking similarities. This is due to the fact that many countries possess over smaller coal fleets with greater year-to-year variations, or that they have not yet reached a similar phase of decline. Also, Figure 27 only represents results for the timeframes studied throughout sections 4.4-4.7. The height of annual capacity additions in the US, for example, is substantially higher prior to 1980 than this representation suggests. Nonetheless, the proposed TF appears to provide a solid basis for studying national or regional trajectories of coal development in the future.

Finally, Figure 28 reflects countries' current state with reference to peak total installed coal capacity. In cases where countries have passed their peak, their position is determined by the share of today's capacity of the initial peak, while the position of countries with growing coal fleets is based on an estimate regarding the shape of their upwards trajectories and their resemblance with the distinct phases of technology diffusion. It is thus not based on data on coal units currently planned or under construction. While Figure 28 is unlikely to exactly position countries on the upwards slope, representing planned capacity additions would also not reliably reflect future capacity development as two-thirds of all proposed projects are never implemented (Shearer *et al.* 2020).

Of all COAL14 countries, only Germany and Australia have passed peak capacity. With the exception of North Korea, all DEC18 countries, on the other hand, are in the phase of stagnation or decline. Overall, most countries are located above 75% of peak capacity, and only a few countries have presumably not reached half of their future peak capacity yet (Vietnam, Malaysia, Indonesia), while only five countries have dropped below 50% (Belgium, Austria, UK, Denmark, and Canada).

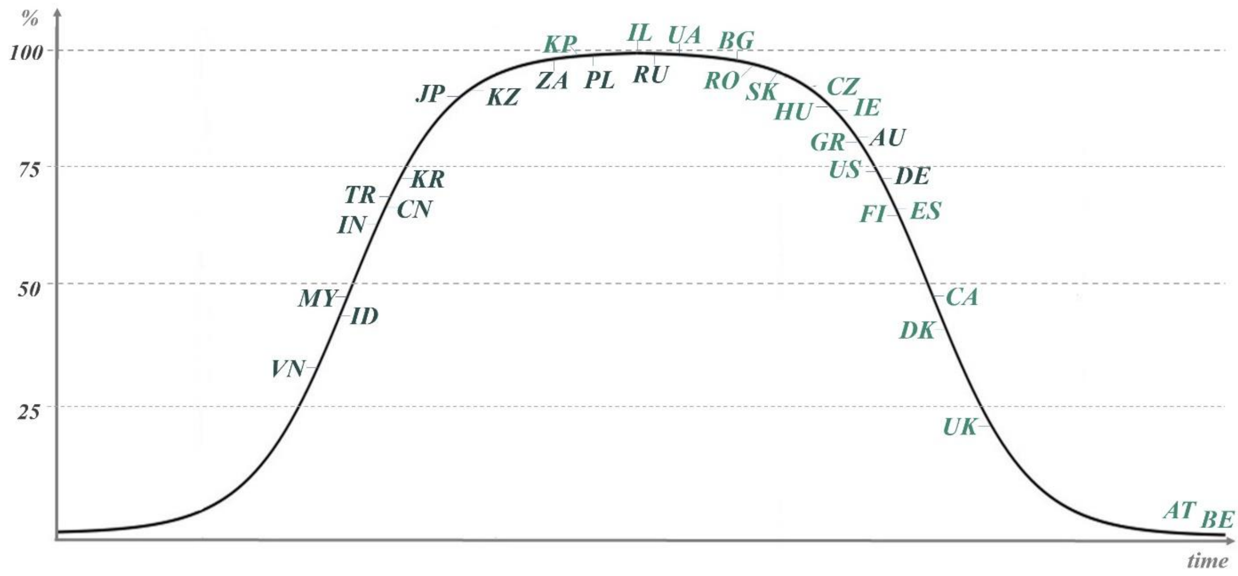

Figure 28: Total installed coal capacity in 2019 relative to peak

Note: country codes are listed in the Appendix (Table 5).

6 Conclusions

6.1 Summary of Findings and Fulfilment of ROs

The following section briefly summarises the main results and relates them to the five overarching research objectives. Most analyses relied on the integration of the two most widely used datasets on coal units worldwide (Platts World Electric Power Plant Database and Global Energy Monitor's Global Coal Plant Tracker) from 2017 and 2020 respectively. Further, data on RE capacity from IRENA (2019b) was used as well as data on total and coal-fired electricity generation (IEA 2019b). To systematically study differences between 32 countries, they were aggregated into six main coal consuming regions (EU, US, OECD, China, India, ROTW), and categorised into countries exhibiting a sustained decline in coal combustion (DEC18) and countries accounting for the majority of coal-fired electricity generation (COAL14).

1) **Qualitatively investigate characteristics of the global coal fleet in a comprehensive literature review that serves as a basis for all following analyses**

The qualitative analysis of coal fleet characteristics investigated economic factors (capital costs, operating costs and revenues, economic and system costs, ownership); technological factors (technology and CCS, efficiencies, utilization and load factors, flexibility); lifetimes and retirement ages (concept, lifetime and retirement age estimates, age structure); and premature retirements and stranded assets (definition and relevance, causes, estimates, managing losses). This section highlighted that technical and economic factors substantially influence the operation of coal plants, as well as the decision to construct new or retire existing ones. It also provided a context for all subsequent analyses and facilitated the combination of findings in the discussion.

2) **Explore changes in unit size, technology, ownership, location, and combinations thereof, in an exploratory, quantitative analysis using data on coal units worldwide**

Since 1970, the average coal unit built has increased in size and is more likely to be equipped with the more efficient (ultra-)supercritical combustion technology. There have been considerable changes in the ownership structure over time, while no trend with regards to the fuel type used could be distinguished. Overall, more units are built in China, India, and the ROTW while less units are built in the EU, US, and other OECD countries. There are significant differences in unit characteristics (size, technology, ownership, fuel type) between the analysed focus regions. Further, the EU and US coal fleets are substantially older than those in China, India and the ROTW. The oldest national coal fleets are predominantly located in Eastern Europe and the former Soviet Union, while younger coal fleets are found in Asia.

3) Investigate the development of (average) retirement ages for selected countries over time and identify predictors of retirement age in a path analysis

Average retirement ages (since 1970) range from 33 years in China (where the majority of capacity retires prior to reaching 40 years of age) to 48 years in the US (where the majority of capacity retires 40 years of age or older). Average lifetimes have risen in the EU, US, and ROTW and declined in China, while remaining relatively stable over the past 40 years in India and OECD countries. The mean retirement age is 38.9 years and the median 38 years; the interquartile range spans 30 to 50 years. Generally, smaller, more efficient, and publicly owned units are associated with a lower retirement age. Globally, coal unit lifetimes have increased over the last decades.

4) Investigate the development of annual capacity additions and retirements, as well as total installed electric and coal capacity on the country and regional level

Globally, coal capacity additions surged around 2005, mainly driven by coal unit constructions in China, and later India and the ROTW. In the EU and US, annual capacity retirements have outweighed capacity additions over the last 8 years, and capacity retirements around the world gradually increase. Most DEC18 countries have experienced 20 years or more of zero or net negative capacity change, while all but two COAL14 countries exhibit sustained growth in total installed capacity. But, countries with rapidly growing coal fleets also install more RE capacity, which increases at a similar or even higher rate. Most countries that have passed peak capacity underwent a period in which total installed capacity remained relatively stable for around 20 years. Then, coal capacity declines slowly at first, after which it accelerates. Only Belgium and Austria have thus far phased out coal completely (in 2016 and 2020 respectively).

5) Explore the relationship between capacity development and electricity generation from coal, including a calculation of load factors

Over the past two decades and among several COAL14 countries, net annual capacity additions and electricity generation from coal have increased at a similar rate. On average, electricity generation from coal peaks 14 years after peak net capacity additions and 3 years after peak total installed capacity. Globally, load factors have recently declined and are particularly low among DEC18 countries. Also, load factors differ considerable between and within countries, especially in the case of smaller economies. Regionally, load factors of the US, EU, and China have converged around 54%, while they are highest in OECD countries (77%) and lowest in ROTW countries (47%). Finally, coal still plays a key role in providing electricity worldwide, as it accounts for over 40% of electricity supply in 12 of the 32 countries.

6.2 Limitations and Further Research

First of all, most analyses were conducted irrespective of system size and development, i.e. national or regional total electricity supply or electric capacity. Acknowledging the respective share of coal could have provided a more complete picture, mediated the results, and provided some additional explanatory value. The main reasons for why this was not done lie in the accuracy and availability of data. For example, WEPP is not comprehensive for small electric stations while data on RE capacity from IRENA is only available from 2000 onwards. Additionally, the GCPT dataset is limited to coal units only, but its integration and corresponding update to the WEPP dataset to reflect recent changes (2017-2020) were thought to outweigh the benefits of addressing system size with regards to installed electric capacity. Moreover, the absolute value of coal-fired electricity generation is ultimately decisive for CO_2 emissions, and that of total coal capacity indicative of future coal fleets and stranded assets. Nonetheless, a prospective research project could incorporate these considerations and adjust calculations for system size.

By focusing the analysis on 32 national coal fleets and six main coal consuming regions, key communalities and differences could be detected and briefly discussed. At the same time, there was insufficient room to discuss the findings for each particular country in detail or to systematically compare two or more countries with regards to each research objective in great depth. Similarly, providing an explanation for every individual finding lies beyond the scope of this research project. But since it is an exploratory investigation into broader dynamics of coal fleet development, it has the potential to stimulate further research into any particular finding or aspect.

Some results, especially those concerning the temporal dynamics of the stagnation and contraction of national coal fleets, are best understood as preliminary findings based on a small number of observations. This is an inevitable caveat of studying transitions that are ongoing rather than completed. Consequently, investigating the growth and contraction of national coal fleets in a few years could confirm or challenge findings presented in this thesis, and further initiate a search for general patterns throughout the decline of energy technologies.

This thesis focused on techno-economic aspects in the operation of coal plants, but socio-economic contexts and country-specific laws and regulations are highly influential regarding future transition paths. While this is acknowledged, it has not been studied within this research project despite presumably providing explanations for the observed results. Additionally, economic aspects were only acknowledged by relying on available research, while the incorporation of data on, for example, the profitability of coal plants or the development of carbon, fuel, or electricity prices could uncover important insights.

Finally, it would be interesting to study the development of the entire coal industry with up- and downstream affiliated sectors. Also, the use of coal in the industry or buildings sector could be explored, since trends that were observed in electricity supply are not necessarily reflected in end-use sectors. Lastly, heat supply was not investigated here but constitutes an important element of any low-carbon energy transition.

6.3 Final Considerations

Globally, peak coal-firing for electricity generation has likely just been reached or lies in the near-term future. But unlike natural gas, nuclear, or renewable sources for power generation, coal combustion is in very different phases of development worldwide: While coal firing exhibits exponential growth in some countries, it has been phased out completely in others. Coal as a source of electricity has been around for over a century, but only started to play a significant role in many emerging economies over the past 15 years, which has driven the global surge in capacity additions since 2005. At the same time, only a few countries have pledged to phase out coal by 2030 and taken corresponding steps. While these countries can lead the way towards a global coal phase-out, their contribution to avoided climate change is rather limited as they only account for a small share of total coal combustion. Nonetheless, their national trajectories may provide insights regarding the speed and dynamics of declining coal industries. Further, lessons learned can help accelerate coal's decline while mitigating the negative (side-)effects of such energy transition in other countries in the future.

Despite numerous and severe adverse social and environmental effects, coal combustion for electricity generation persists. This is exemplified by several aspects and trends highlighted throughout this thesis: First of all, coal units have a long life. Historically, the majority of units operated for 30-50 years, with 39 years on average. What is more, larger units with higher combustion volumes typically retire older; and both unit sizes and retirement ages have globally increased over the last few decades. In the absence of political incentives to retire coal plants prematurely, asset owners will continue to burn coal as long as their operations remain profitable, and even beyond the point of cost-competitiveness.

As a result, national coal fleets typically remain of constant size for several years. This period of stagnation is characterised by years of incremental change, in which annual capacity additions and retirements are low or outweigh another. Finally, the destabilisation and initial decline of coal starts off rather reluctantly. This is not only due to the longevity of energy infrastructures, but also due to inertia in socio-economic systems and institutions. Understanding these barriers and temporal dynamics is crucial, as decisions regarding the operation, construction, and retirement of coal plants impact electricity systems for decades to come. Consequently, more attention should be payed to the medium- and long-term development of electric assets as opposed to day-to-day operations or yearly electricity production from coal. For example, annual power generation has very different implications in 10- versus 40-year old coal fleets, and national energy transitions will unfold at varying speeds depending on the size of the economy and electricity system.

Specific measures to accelerate the decline of coal include the cancellation of the entire coal pipeline, as well as the restriction of operating lifetimes. Further, the fuel switch to biomass or natural gas could be a viable option, as long as it prioritises the operation of existing fossil fuel plants over the construction of new ones. As external pressures accumulate, energy sector decisions should increasingly anticipate long-term rather than short-term developments of regulations, profits and energy demand. In the face of accelerating climate change, the shift towards low-carbon electricity supply worldwide must be initiated now. This will not only contribute to limiting the global temperature rise to below 1.5 or 2°C, but reduce the volume of stranded assets and further lower expenditures on problems induced by air pollution and environmental degradation. Delaying action on reducing coal firing prohibits regional economies from diversifying and utilities from development new business models.

If climate goals are to be met, the premature retirement and stranding of coal assets will be a major concern particularly to developing countries, who now possess over the world’s youngest coal fleets. At the same time, alternative means of power production will have to be developed and scaled up to satisfy growing electricity demand. International climate negotiations have thus far not addressed the required scope of premature coal plant retirements, nor the distribution of burdens of a global coal phase out. If developed countries only commit to weak near-term climate actions and delay their coal phase-outs, the decarbonisation challenge is shifted to developing countries that have fewer resources to invest in alternatives and compensate people and companies adversely affected by premature retirement decisions. This highlights that national energy paths should always be studied and pursued in a global context, and that a global coal phase-out necessitates a just distribution of burdens.

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Appendix

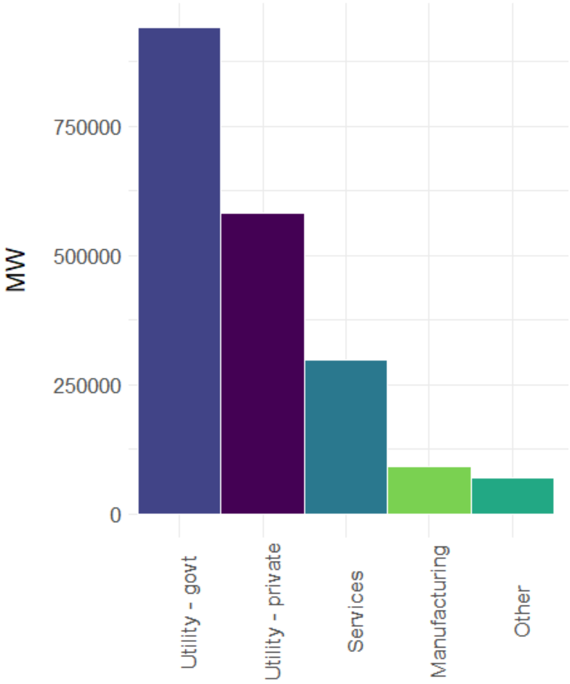


Figure 29: Current operational fleet by ownership

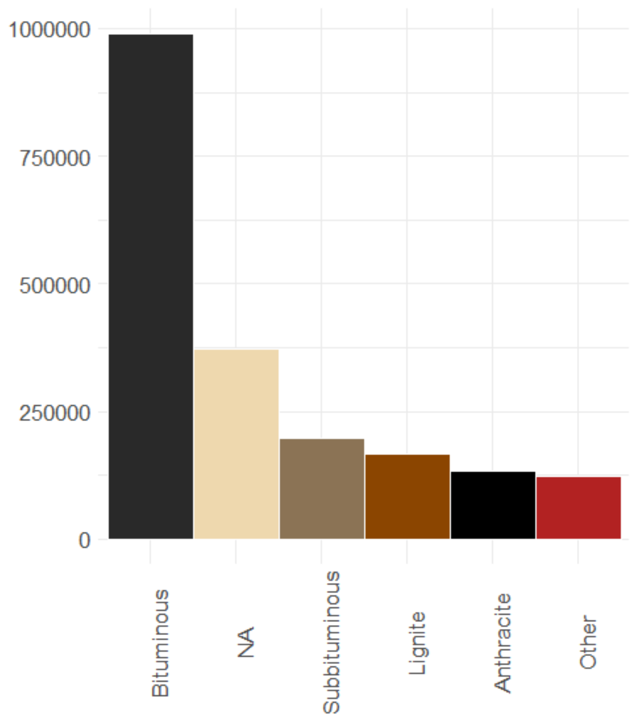


Figure 30: Current operational fleet by fuel type

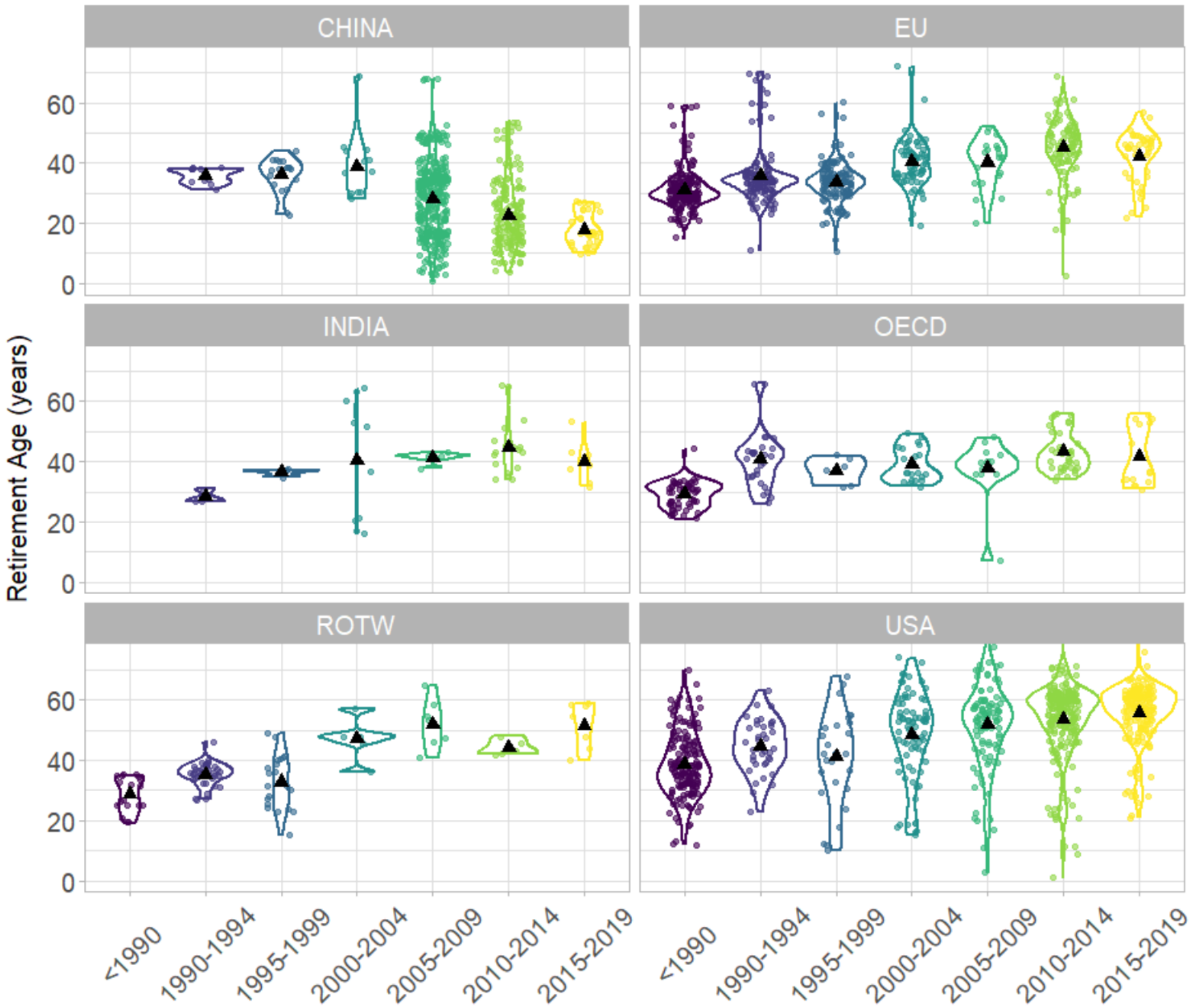
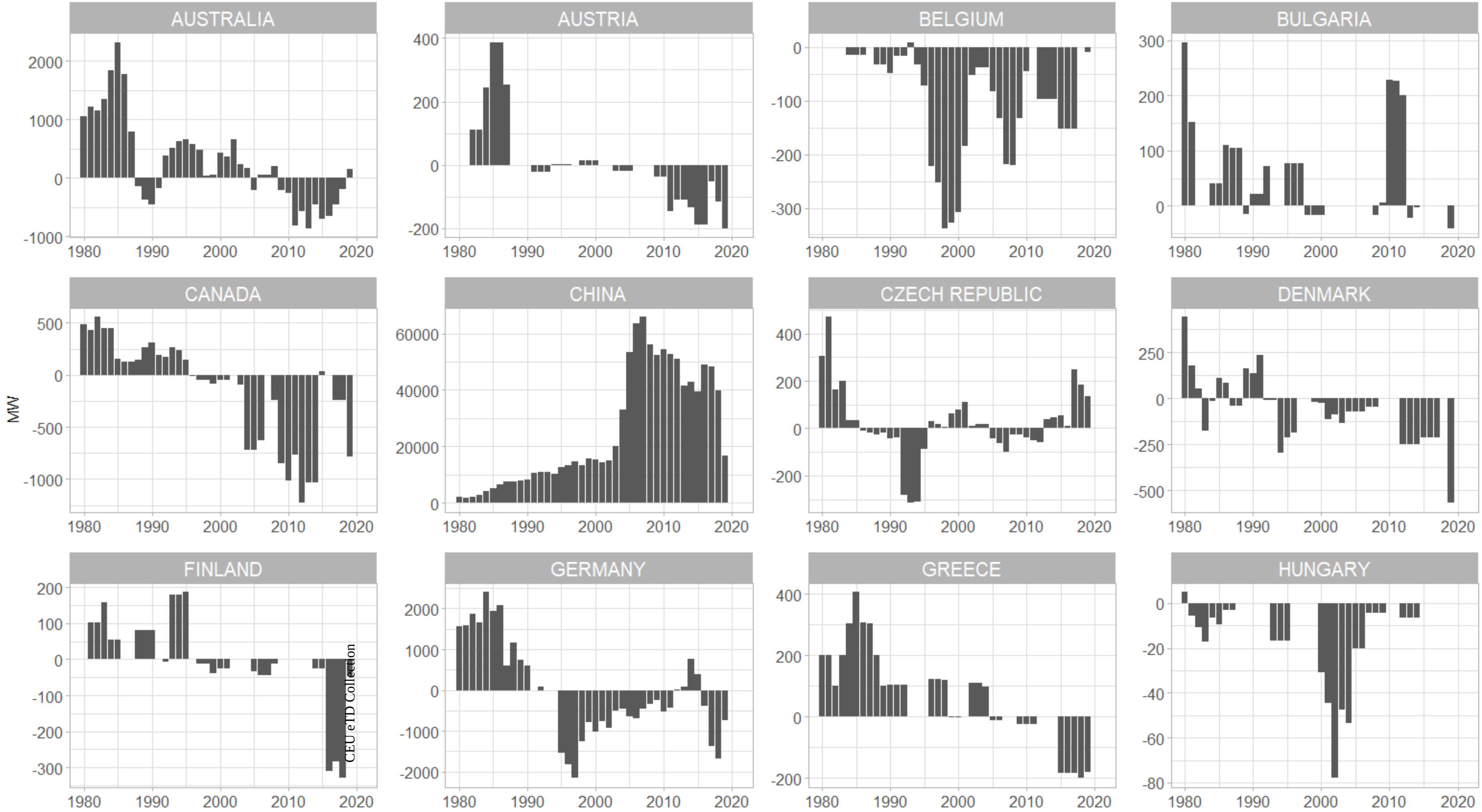
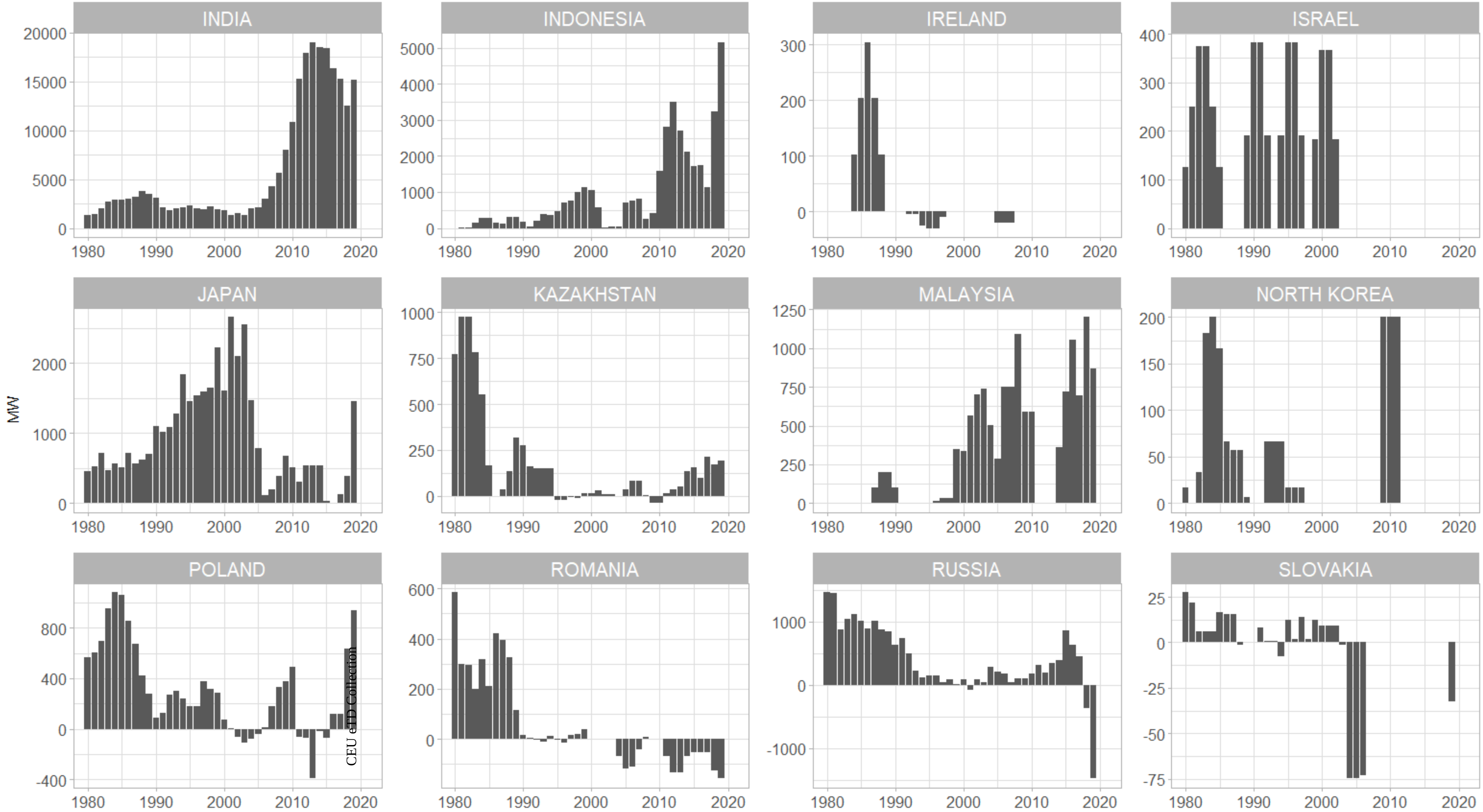


Figure 31: Development of retirement ages by focus region since 1980
Note: The black triangle represents the mean; every dot represents one retiring unit.

Table 5: List of countries and ISO country codes

Country	ISO Alpha-2 Code	Country	ISO Alpha-2 Code
Australia	AU	**Japan**	JP
Austria	AT	**Kazakhstan**	KZ
Belgium	BE	**Malaysia**	MY
Bulgaria	BG	**North Korea**	KP
Canada	CA	**Poland**	PL
China	CN	**Romania**	RO
Czech Republic	CZ	**Russia**	RU
Denmark	DK	**Slovakia**	SK
Finland	FI	**South Africa**	ZA
Germany	DE	**South Korea**	KR
Greece	GR	**Spain**	ES
Hungary	HU	**Turkey**	TR
India	IN	**UK**	GB
Indonesia	ID	**Ukraine**	UA
Ireland	IE	**USA**	US
Israel	IL	**Vietnam**	VN


AUSTRALIA
AUSTRIA
BELGIUM
BULGARIA
CANADA
CHINA
CZECH REPUBLIC
DENMARK
FINLAND
GERMANY
GREECE
HUNGARY
MW
2000
1000
0
-1000
400
200
-200
-100
-300
300
100
500
-500
60000
40000
20000
250
-250
-20
-40
-60
-80
1980
1990
2000
2010
2020


INDIA
INDONESIA
IRELAND
ISRAEL
JAPAN
KAZAKHSTAN
MALAYSIA
NORTH KOREA
POLAND
ROMANIA
RUSSIA
SLOVAKIA
MW
1980
1990
2000
2010
2020

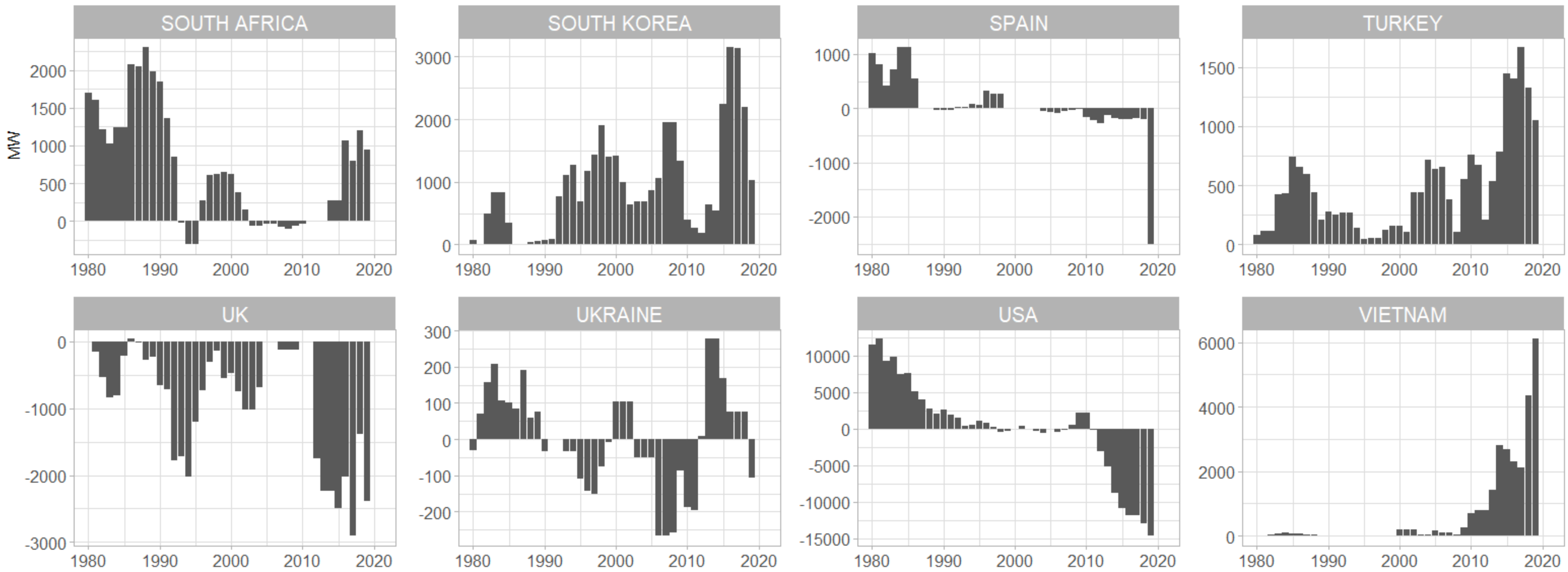
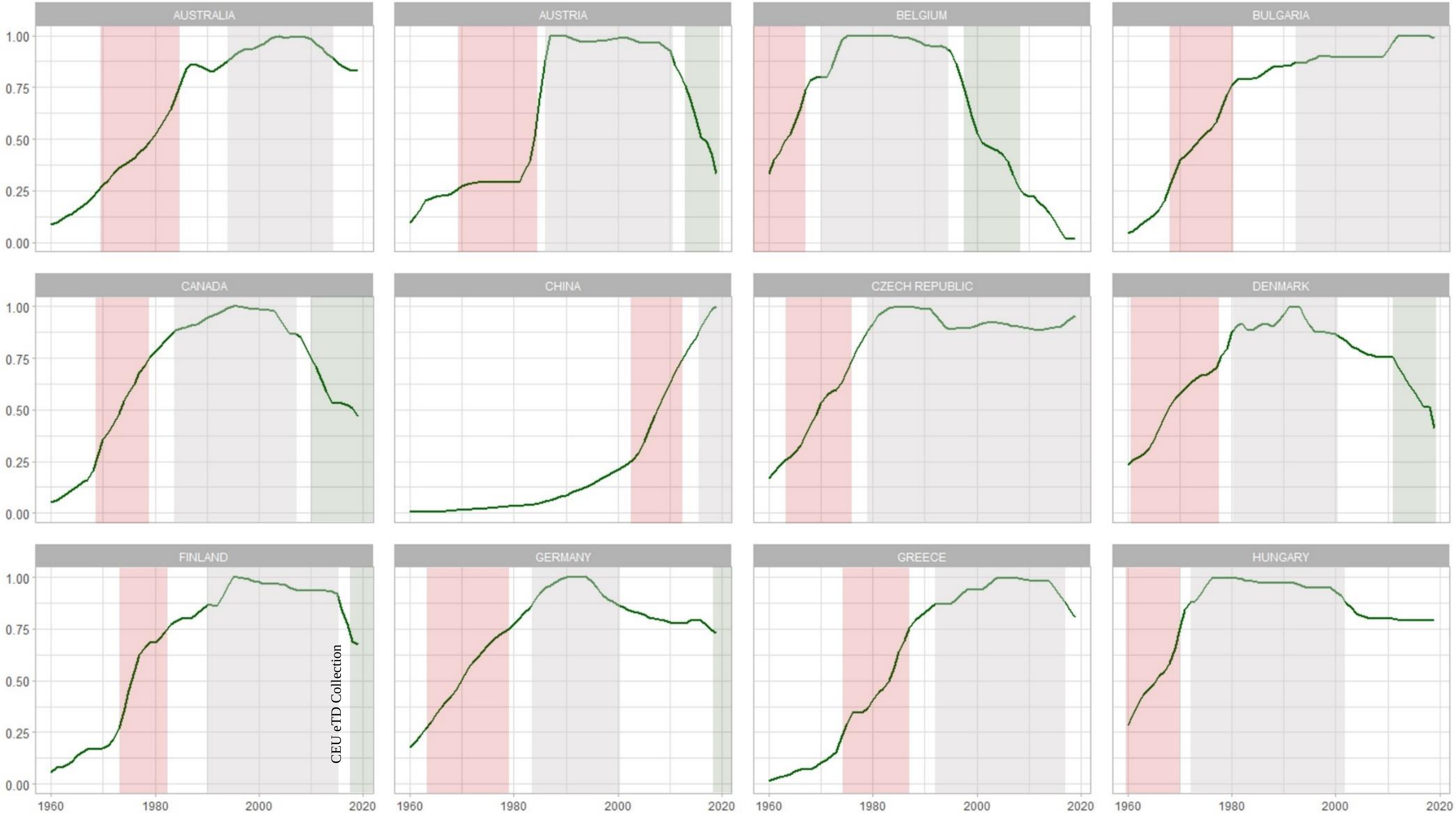
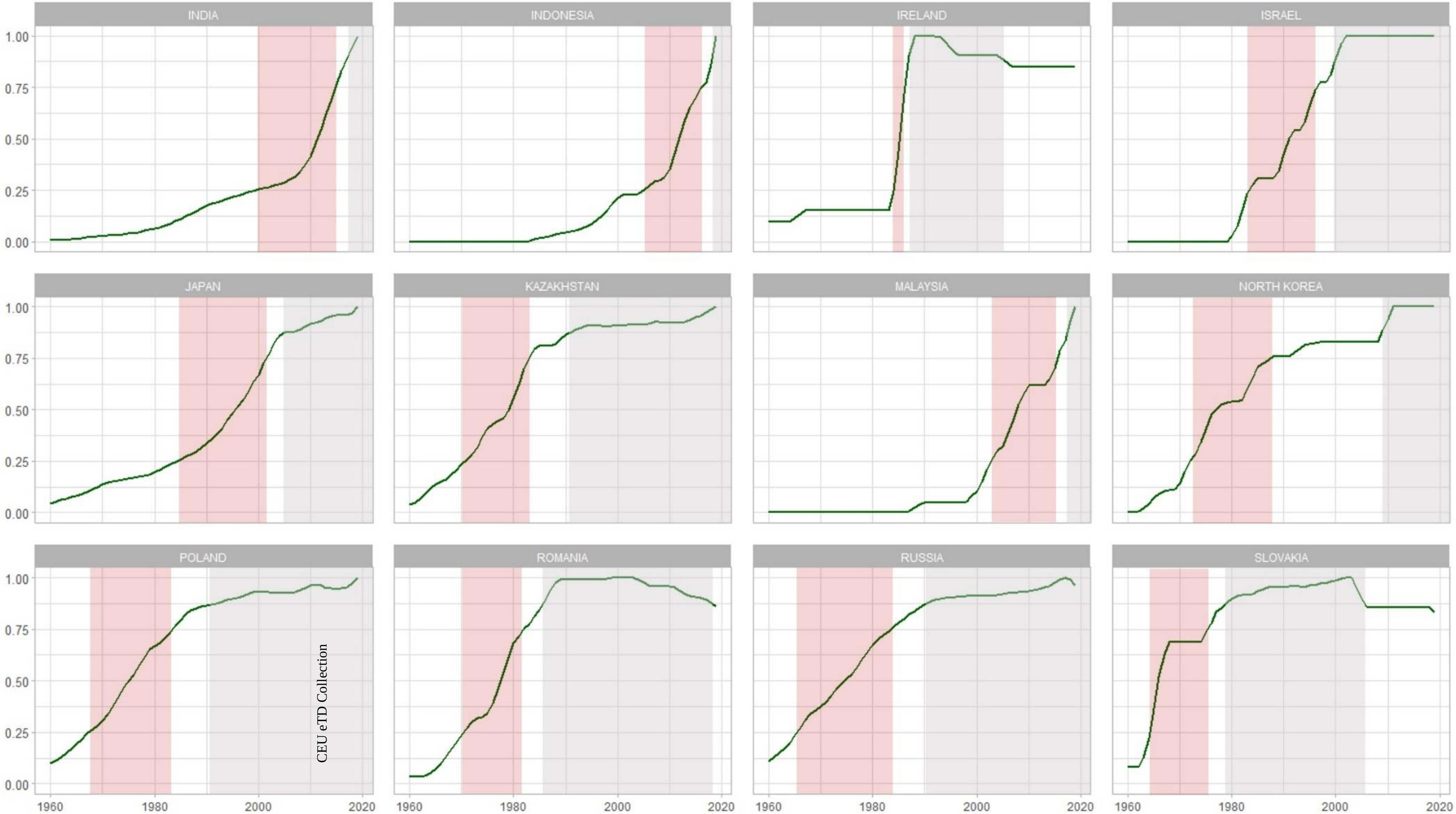


Figure 32: Net annual capacity additions by country since 1980


AUSTRALIA
AUSTRIA
BELGIUM
BULGARIA
CANADA
CHINA
CZECH REPUBLIC
DENMARK
FINLAND
GERMANY
GREECE
HUNGARY
1.00
0.75
0.50
0.25
0.00
1960
1980
2000
2020


INDIA
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KAZAKHSTAN
MALAYSIA
NORTH KOREA
POLAND
ROMANIA
RUSSIA
SLOVAKIA
0.00
0.25
0.50
0.75
1.00
1960
1980
2000
2020

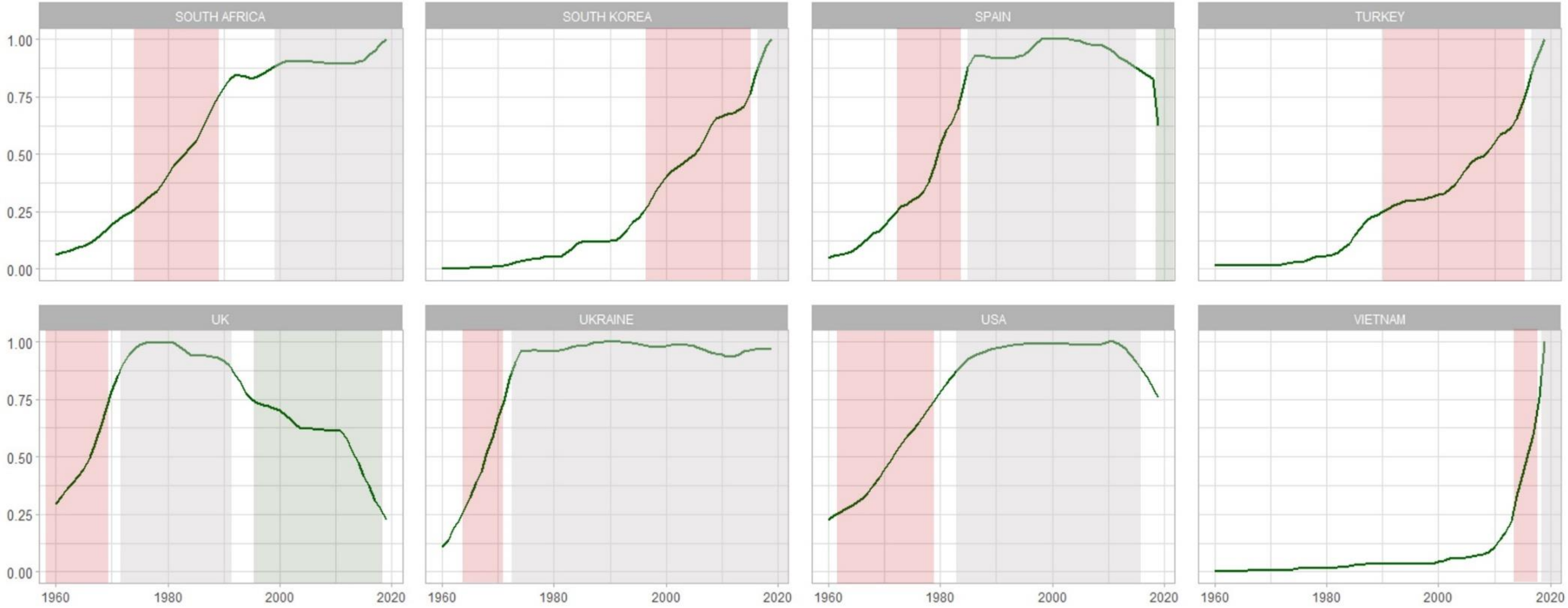
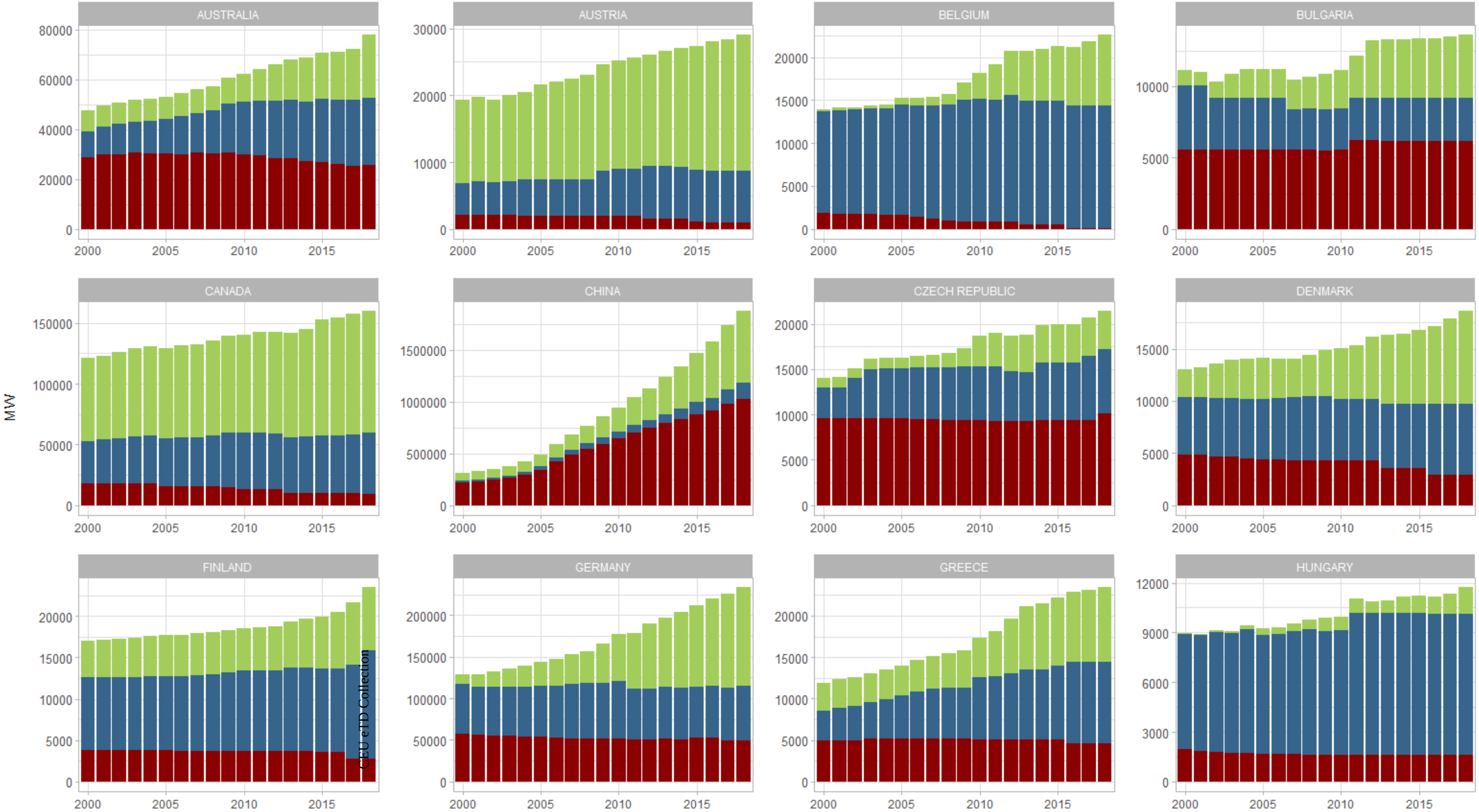


Figure 33: Total installed coal capacity since 1960

Note: Capacity prior to 1980/ 1990 is underrepresented due to incomplete data on earlier units; capacity is normalised to peak operational capacity.


MW
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2005
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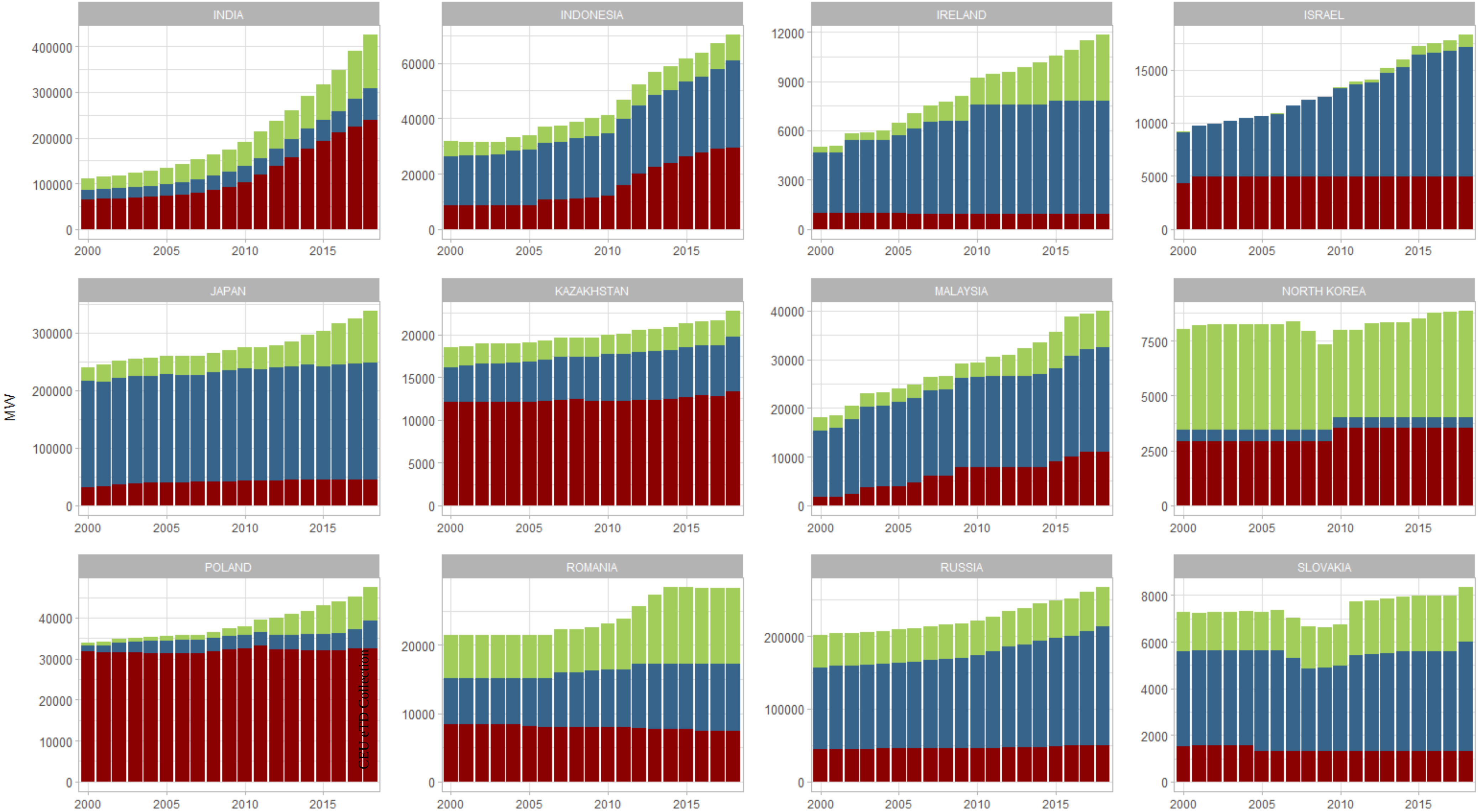
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2000
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2010
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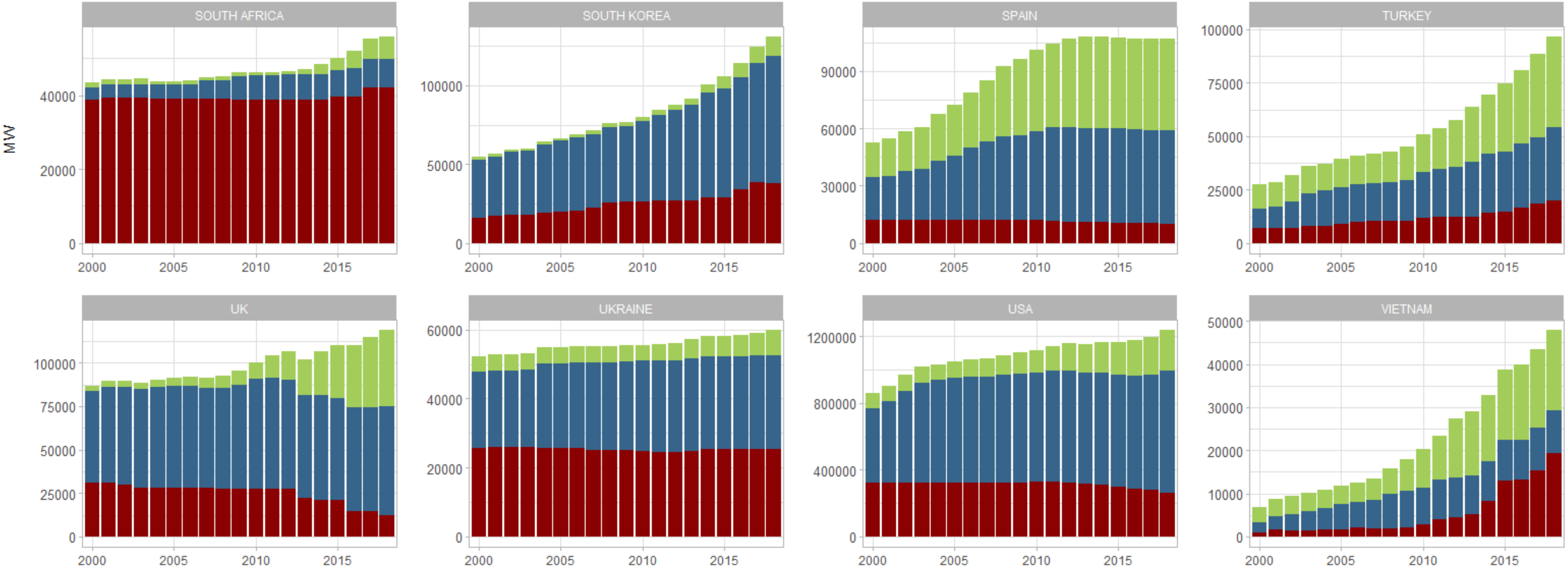

Figure 34: Total installed electric capacity since 2000

Note: red = coal capacity, green = renewable energy capacity (including hydro and waste fuels), blue = all other capacity (mainly oil, natural gas, and nuclear); sources: WEPP for all fossil fuel and nuclear capacity; IRENA for all renewable capacity.