Pathways to Net Zero for Power and Industry in the United Kingdom

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Declaration of Originality

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Abstract

Climate change mitigation is amongst the key challenges of the Anthropocene. The United Kingdom has declared its interest in leading the way to net zero CO_2 emissions by 2050. The debate around technologically feasible, economically viable, and socially optimal pathways to a carbon neutral energy system and economy is ongoing. This thesis aims to contribute to questions concerning the decarbonisation of power and industry in the UK. To this end, the technological viewpoint, the system viewpoint, and public viewpoint are assumed. First, electrification of heat and transport is quantified, and the role and value of power-to-gas storage as novel technology is analysed. Second, the industrial sector is modelled, and pathways for the combined decarbonisation of power and industry are investigated. Third, trajectories to net zero are connected to economic growth and employment, bridging the gap between technology-focused energy systems modelling and the macroeconomic layer.

It is found that seasonal effects are significant in the energy system under electrification and increasing deployment levels of intermittent renewable energy. Inter-seasonal storage and/or low-carbon dispatchable power generation are required to ensure a reliable supply of electricity. Cost-optimal abatement technologies in industry are identified. The emissions balance between the power and industrial sectors is evaluated, with power reaching carbon negativity in the 2040s, and offsetting residual emissions in industry in 2050. Carbon capture and sequestration emerges as key technology in trajectories to net zero. The effects of policy instruments, including a carbon price and negative emissions credit, are quantified, and the importance of a compromise between private and public sector is highlighted. Further, a net zero target is estimated to increase value added and employment. Importing industrial goods and offshoring emissions *vs.* expanding domestic production and exporting low-carbon products, as well as locally sourcing *vs.* importing technology components and raw materials are shown to greatly impact value and job creation.

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We can only see a short distance ahead,
but we can see plenty there that needs to be done.

Alan Turing

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Chapter 1

Introduction, Background, and Motivation

1.1 Climate change mitigation and the UK context

The Intergovernmental Panel on Climate Change (IPCC) concludes with high confidence that anthropogenic climate change is advancing and representing a danger to human lives, livelihoods, and nature. Negative impacts of climate change, some of which can already be observed, include an increasing frequency of extreme weather phenomena such as floods, droughts, and wildfires, the destruction of ecosystems, both marine and terrestrial, as well as rising sea levels and reduction of crop yields [1, 2, 3, 4, 5]. It also acts as a threat multiplier, exacerbating existing conflicts [6]. Limiting the global temperature increase to less than 2°C, preferably 1.5°C, has been determined as crucial by the IPCC [1, 2]. A global effort is required to reduce emissions of greenhouse gases (GHG) – CO_2, CH_4, N_2O and others – to contain the consequences of a warming planet. Since the severity of climate change impacts is determined by the amount of GHG in the atmosphere, *i.e.*, cumulative emissions, the speed of the transition to climate neutrality directly influences its effectiveness [2].

With the Paris Agreement in 2015/16 almost all countries signed an international treaty aiming to limit the global temperature increase [7]. Many countries, including the European Union, the United Kingdom, the United States, and China have since committed to net zero CO_2 emissions by the middle of the century [8]. Private companies have joined the effort by pledging to reduce emissions to zero [9]. However, net zero commitments by both countries and companies exhibit large variations with regard to the emissions covered by the target, the existence of a plan how the target might be reached and the presence of a reporting mechanism [9, 10].

In the United Kingdom, the intent to mitigate climate change is legislated in the Climate Change Act, which in 2008 set a target of 80% reduction of GHG emissions relative to the 1990 baseline by 2050, and created the Climate Change Committee (CCC) as advisory body. The CCC sets carbon budgets as limits on UK GHG emissions relative to 1990, the 1st of which covered the years 2008-2012 [11]. Based on the CCC's recommendation, the Climate Change Act was updated in 2019 to a net zero GHG emissions target by 2050 – establishing the UK as the first country with a net zero commitment [12]. With its announcement, the UK aimed at "leading the world yet again in becoming the first major economy to pass new laws to reduce emissions to net zero by 2050 while remaining committed to growing the economy" (Energy and Clean Growth Minister Chris Skidmore) [13]. The assertion that climate change mitigation goes hand in hand with economic growth also appears in the UK's Clean Growth Strategy in 2017 [14]: "Protecting our environment for the next generation also benefits our wider economic prosperity." (Former Prime Minister Theresa May). The UK has publicly declared its interest in globally leading the way to a decarbonised economy while creating jobs, announcing with the 6th carbon budget for 2033-2037 in 2021: "The UK will be home to pioneering businesses, new technologies and green innovation as we make progress to net zero emissions, laying the foundations for decades of economic growth in a way that creates thousands of jobs" (Former Prime Minister Boris Johnson) and "If we are to tackle the climate crisis and safeguard lives, livelihoods and nature for future generations, others must follow the UK's example." (COP26 President-Designate Alok Sharma) [15].

The results of the IPCC are presented for the global energy system. Solutions to reaching climate targets, however, need to be specific for individual countries, necessitating country level modelling. There is significant existing work from the UK public sector regarding pathways to net zero for the UK economy. BEIS's Clean Growth Strategy [14], using the BEIS Industry Pathway Models, the Usable Energy Database, and UK MARKAL, sets targets for decarbonising power, industry, transport, buildings, and other sectors, and details the government funding for the transition. Carbon capture and sequestration / utilisation (CCUS) is mentioned as potential key technology, recognising that energy efficiency improvements will not suffice. The report further suggests that greenhouse gas removal (GGR) technologies may be needed in order to offset residual emissions, yet it lacks specific pathways for the power sector and the individual industrial sectors. It remains unclear when which abatement technologies might be deployed, the expected emissions reduction per sector, and how abatement scenarios might compare against each other. The modelling by the CCC in its net zero technical report [16] offers more detailed pathways for the transition. For the power sector, the report outlines the need for firm and/or flexible low-carbon power and bioenergy with CCS in addition to renewable and nuclear power, projecting the power sector to reach near zero emissions in 2050. In case of the industrial sector, their core scenario involves efficiency improvements, a reduction in methane leakage and venting, electrification, bioenergy, and CCS. Its ambitious scenario, reaching 10 $MtCO_2$/yr in industrial emissions in 2050, represents a "challenging scenario that required a fast pace of deployment of low-carbon technology in comparison to the natural turnover rate of industrial assets". The potential loss of domestic industry and associated carbon leakage are noted as to be avoided, but not quantified. The analysis appears to view the sectors in isolation, neglecting the influence of the sectors on each other, and again lacking pathways for the industrial sub-sectors. Recently, the Industrial Decarbonisation Strategy outlines the UK's plan for reducing industrial emissions and the policies which support the transition in industry [17].

Sector integration is at present being discussed as a means of reducing the transition cost and utilising synergies between sectors of the economy. The demand for shared resources, the emissions balance, technology learning, common energy vectors, and shared infrastructure, *etc.*, connect individual sectors.

Integrated modelling of emission intensive sectors is required to determine effective decarbonisation pathways. Furthermore, feedback loops exist in between the sectors, such as large-scale deployment of technologies in the power sector raising demands for commodities (steel, cement, *etc.*) in the industrial sector.

The transition of the economy to net zero emissions involves a variety of stakeholders – the private sector, the public sector, the general public – and consequently differing sets of motivations and priorities. Companies tend to focus on maximising the utilisation of existing assets, maintaining competitiveness, and minimising the transition cost, comprised of the cost of building new production facilities, operating existing capacity, and the balance between taxes and incentives. Meeting climate targets, minimising the cost of policy incentives, and optimising the impact of the transition on economic growth, are amongst the priorities of the public sector. When taking the perspective of the general public, rising energy prices associated with decarbonisation and even fuel poverty and energy debt have to be considered [18, 19, 20]. Retaining jobs, and creating new jobs are further on the agenda of government and the general public. The presence of different stakeholders necessitates viewing pathways to net zero from distinct perspectives. Optimal strategies for the transition to carbon neutrality require compromises between these individual viewpoints.

1.2 Energy systems modelling

The transition to net zero emissions is frequently analysed with models, tools, frameworks, and methods in the field of energy systems modelling. A great many energy systems models exist in the literature, developed by various universities, research institutes, and public organisations. Exhaustive lists, comparisons, and categorisations are provided in Connolly *et al.* [21], Bazmi *et al.* [22], Hall *et al.* [23], and Lopion *et al.* [24]. The following summarises the variety of modelling approaches and dimensions.

One common set of categories for energy systems models is top-down, bottom-up, and hybrid models [25]. Top-down models excel at describing economic growth, employment, welfare, but lack technological detail, whereas bottom-up models depict the technological layer – energy generation, storage, transmission, and consumption technologies – in detail yet lack macroeconomic parameters. Top-down models include input-output models (such as Mayer [26]), econometric models, computational general equilibrium (CGE) models (such as Bernard *et al.* [27]), and system dynamics. Bottom-up models can be further differentiated into partial equilibrium models, optimisation models (such as Bazmi *et al.* [22]), simulation models, and multi-agent models. Hybrid models attempt to bridge the gap between the two model classes and combine features of both. In this context, soft linking is understood as executing two models separately and manually transferring data in between them. Hard linking involves combining the formulations and running the models together, or otherwise automating their communication. Herbst *et al.* identify "scarcely any hard links between process-oriented energy models and macroeconomic models" and suggest the disciplinary gap between the developers and users of bottom-up models (engineers, natural scientists, energy companies) and top-down models (economists, public administrators) as a reason [25]. Pfenninger *et al.* group models on national and international level into optimisation models, simulation models, power systems and electricity market models, qualitative and mixed methods scenarios [28]. Patrizio *et al.* distinguish models by techno-economic detail – technology portfolios, demand and supply constraints –, pathway dynamics – representation of different scenarios and policies over time –, and heterogeneity – inclusion of distinct agents [29]. In this framework, the majority of energy systems models combine techno-economic detail with pathway dynamics. Table 1.1, partly adapted from Hall *et al.* [23], presents an overview of modelling choices.

Models exist along all these dimensions, developed for specific purposes, to answer various questions regarding cost-optimal system design and operation, decarbonisation, energy security, *etc.* For instance, the TIMES/MARKAL modelling family has dominated the academic literature and has a long history of being utilised in the UK public sector, including in modelling by the CCC [23, 31, 32, 33]. Recently, the MUSE model has been developed as agent-based, multi-sector, partial equilibrium, simulation energy systems model [34, 35, 36].

Several current challenges and areas of improvement are identified by the literature. Herbst *et al.* emphasise the development of models which hard link the

Table 1.1: Dimensions of energy systems models [23].

dimensions	examples
supply and demand description	endogenous *vs.* exogenous, inelastic *vs.* elastic
geographical coverage	global, regional, country, local
sectoral coverage	power, heat, transport, energy in general, overall economy
time horizon	single point in time (static), short/medium/long-term
spatial resolution	spatially aggregated, country-level zones, transmission, distribution
temporal resolution	sub-hourly, hourly, monthly, yearly
analytical approach	top-down, bottom-up, hybrid, other
mathematical problem type	simulation *vs.* optimisation, system planner *vs.* agent-based, linear, non-linear, mixed integer
technology portfolio	conventional, low-carbon, renewable; storage; transmission
treatment of uncertainty	deterministic, scenario approach, robust optimisation, stochastic programming, Monte Carlo analysis [30]
licensing/availability	open source, commercial, proprietary

disparate layers of top-down and bottom-up models as crucial [25]. Amongst predominant challenges Pfenninger *et al.* count temporal and spatial resolution, handling complexity across time scales (second by second grid operation *vs.* system evolution over decades), and modelling behavioural and social factors [28]. A recent review points out the inclusion of energy vectors (electricity, heat, hydrogen, *etc.*), treatment of uncertainty, behaviour of various actors (companies, consumers, policy), temporal and spatial resolution as areas of improvement [30]. An explicit description of the industrial sector is usually absent from energy systems models. If present, it is only as a source of power demand and heat demand.

1.3 The ESO framework

The basis of the modelling in this work is the Energy System Optimisation framework (ESO), a bottom-up, technology-rich energy systems model. Prior to this work, it was used to determine least-cost design and operation of the power sector for various scenarios and research questions. Multiple versions of ESO have been developed: ESO-X with capacity expansion over time, ESO-XEL with endogenous technology learning, ESO-ANCIL with focus on ancillary services, and ESONE, a spatially disaggregated version of ESO [37]. The main constraints of ESO-X are summarised in table 1.2:

Table 1.2: ESO-X constraints.

capacity expansion	initial capacities (supply, storage, transmission)
	build rate constraints (supply, storage, transmission)
	life time constraints
	maximum resource constraints
technology-wise constraints	power, reserve, inertia provision
	flexibility of generation/storage units
	carbon emissions by technology
	uptime and downtime scheduling
	import of power
system-wide constraints	electricity demand
	reserve requirements
	inertia requirements
	emission target and carbon price
objective	cost minimisation (CAPEX + OPEX)

The model assumes perfect foresight, decisions are made by an omnipotent system planner, and outcomes are deterministic. Depending on the version, it uses 2015/2020 as base year, covers 5-year periods up to 2050/2100 as planning periods, and uses representative days with hourly resolution. Demand and prices are set exogenously. The resulting mathematical model is a linear programming problem (LP) or mixed-integer linear programming problem (MILP), depending on the version. Complete formulations of ESO, ESO-X, ESO-XEL, and ESONE are provided in the publications by Heuberger *et al.* [38, 39, 40, 37].

Models of the ESO family have been successfully utilised to quantify the system value of low-carbon technologies such as onshore wind power, CCGT-CCS, and energy storage [38, 41], investigate the impact of technology learning on the design of the power sector [39], and model a 100% renewable energy system [42]. In ESONE, the evolution of the power system and the transmission grid under electrification of transport has been modelled [40]. ESO models have further been employed to explore the role and value of negative emissions technologies (NETs) and CO_2 removal (CDR) up to 2100 [43, 44, 45], and simulate a carbon tax as incentive [46]. Recently, they have been applied to compare low-carbon dispatchable power generation technologies [47, 48], and examine the value of ancillary services in energy systems [49]. ESO has been used to model power systems and their decarbonisation in various countries and territories, including the UK, Poland, Spain, Germany, Australia, Indonesia, the US, Nigeria, and others [50, 51, 52, 53].

1.4 Research questions and structure

A plethora of open questions remains concerning the path to net zero. Which technologies can enable the provision of energy services and commodities while decarbonising? When are technologies optimally deployed? What are the challenges and benefits of sector coupling? What are potential pathways for the hard to decarbonise industrial sectors? How can policy instruments influence the transition? How can climate change mitigation be combined with economic growth? Which sectors could see a decline, which an increase in employment?

This thesis aims to contribute to finding answers to questions surrounding decarbonisation of power, heat, transport, and industry. The UK is chosen as case study, owing to its intention to lead the way globally in climate change mitigation. For the purposes of this work, only CO_2 as main GHG is considered, with net zero referring to net zero CO_2 emissions. In this thesis, the ESO framework is expanded in multiple dimensions. Figure 1.1 summarises the model developed in this work, encompassing the technological, economic, and socio-economic layer. In addition to the literature overviews in the previous sections, each of the chapters contain reviews of the literature specific to the chapter topic. First, in chapter 2, the technology viewpoint is taken, the model is modified to allow inter-day storage and a full-hourly data set, and electrification of heat and transport is modelled, to then analyse the role and value of inter-seasonal grid-scale energy storage in the power sector. In chapter 3, a description of the industrial sector is developed, the corresponding data set is curated, and trajectories for combined decarbonisation of power and industry are examined, including pathways for the industrial sub-sectors. Lastly, in chapter 4, the perspective of the public sector is assumed, and the decarbonisation of power and industry is connected to socio-economic KPI such as gross value added (GVA) and employment, to identify pathways which combine decarbonisation and economic growth. Multiple policy instruments are included in the analysis. Every chapter concludes with a summary and suggestions for next steps. The final chapter summarises the thesis achievements and provides directions for future work.

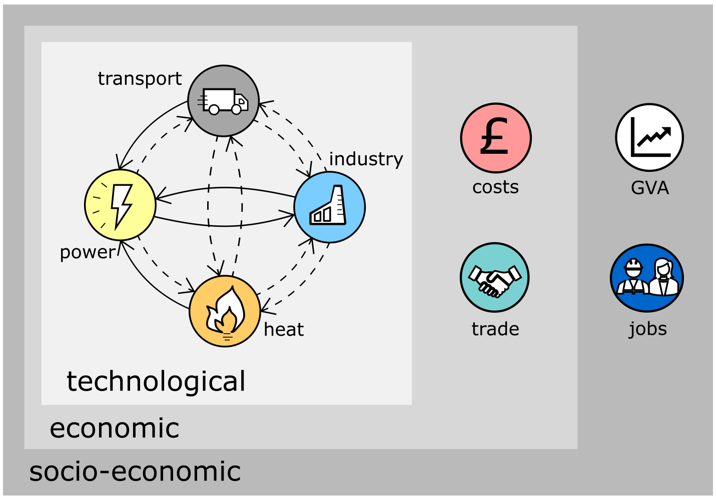


Figure 1.1: Simplified model topology. Solid lines represent interactions modelled in this work; dashed lines are interactions to be addressed in future work.

This work touches on several areas for improvement in energy systems modelling outlined in section 1.2. The challenging topic of temporal resolution and adequate time representation is addressed within the context of modelling inter-seasonal storage in chapter 2. The viewpoints of distinct actors with regard to the transition are taken in chapter 3. Sector coupling is addressed in both in the dimension of electrification and in the combined modelling of power and industry. With chapter 4, the model further overcomes the gap between technology-focused bottom-up energy systems modelling and the macroeconomic layer.

1.5 Presentations and outreach

The following publications, contributions to conferences, and presentations are a result of the research conducted for this thesis:

- C. Ganzer, Y. W. Pratama, and N. Mac Dowell. The role and value of inter-seasonal grid-scale energy storage in net zero electricity systems. *International Journal of Greenhouse Gas Control*, 120:103740, 2022. `https://doi.org/10.1016/j.ijggc.2022.103740`.
- C. Ganzer, Y. W. Pratama, and N. Mac Dowell. Exploring the Role and Value of Grid-Scale Energy Storage in Deep Decarbonisation: Synergies with CCS? In *15th International Conference on Greenhouse Gas Control Technologies – GHGT-15 (virtual)*. International Energy Agency Greenhouse Gas R&D Programme (IEAGHG), 2021. `https://dx.doi.org/10.2139/ssrn.3817715`.
- C. Ganzer, Y. W. Pratama, and N. Mac Dowell. The potential role and value of power-to-gas storage in the UK energy system. In *2021 AIChE Annual Meeting (virtual)*. American Institute of Chemical Engineers, 2021. `https://aiche.confex.com/aiche/2021/meetingapp.cgi/Paper/623643`.
- C. Ganzer and N. Mac Dowell. The role and value of inter-seasonal grid-scale energy storage in deep decarbonisation. In *Imperial College London – Energy Futures Lab (EFL) webinar series*, 2020.
- C. Ganzer and N. Mac Dowell. Pathways to net zero for power and industry in the UK. *Submitted manuscript*, 2022.
- C. Ganzer and N. Mac Dowell. Pathways for UK power and industry to net-zero. In *2021 AIChE Annual Meeting (virtual)*. American Institute of

Chemical Engineers, 2021. https://aiche.confex.com/aiche/2021/meetingapp.cgi/Paper/623621.

- C. Ganzer and N. Mac Dowell. Decarbonisation of power and industry in the UK and the role of CCS. In *United Kingdom Carbon Capture and Storage Research Centre (UKCCSRC) webinar series*, 2021.

1.6 Computational methods

A fundamentally new workflow for solving the ESO model was developed for the purposes of this work. The previous model relied on an excel sheet holding all model data, and a GAMS file with the model equations [37, 40]. The workflow comprised multiple manual steps. After saving the input excel file, the GDXXRW utility is run, generating a *.gdx* file containing the database in a for GAMS readable format. This file is then copied to the linux cluster. Then the GAMS file is executed, reading from the *.gdx* file and running the model. After the run has concluded, the data is written to an output *.gdx* file, which is copied, and translated back to excel using the GDXXRW utility. Individual data sets are selected and visualised. This workflow requires a number of steps and substantial amounts of time for each individual run. Furthermore, the model file itself needs to be edited in order to conduct multiple successive runs in one instance.

The improved workflow is advantageous in several dimensions, and is summarised in figure 1.2. The input data is separated in country data and scenario data, reducing the size of the document which needs to be edited when submitting a new run. The model utilises the GAMS Python API [61]. Python [62, 63] scripts read data and execute pre-processing, then hand over the database to GAMS [64], initiate the run, receive data from GAMS after the run, and perform post-processing and visualisation. Model output is automatically saved as *.gdx* and *.pkl*, as GAMS and python formats, exported to *.xlsx*, and the output files and plots are saved in a dedicated output folder. Everything is automated, without the need for user input for the intermediate steps after submitting a run. The results in the form of output graphs can be interpreted directly after the run has concluded. This simplifies the procedure for running the model immensely, enabling more runs, and making the model accessible for a wider user base. The use of Python as platform also allows the integration of sensitivity runs where the model is run repeatedly, varying uncertain parameters. CPLEX is used as solver [65]. More complex visualisations are carried out in Python, using the data already saved in a format accessible to Python (*.pkl*). The new version of ESO with Python input and output (power sector only) has been used by multiple researchers and students and applied to many countries (UK, various EU countries, Serbia, Switzerland, California, Wyoming, Texas, South Korea) [66].

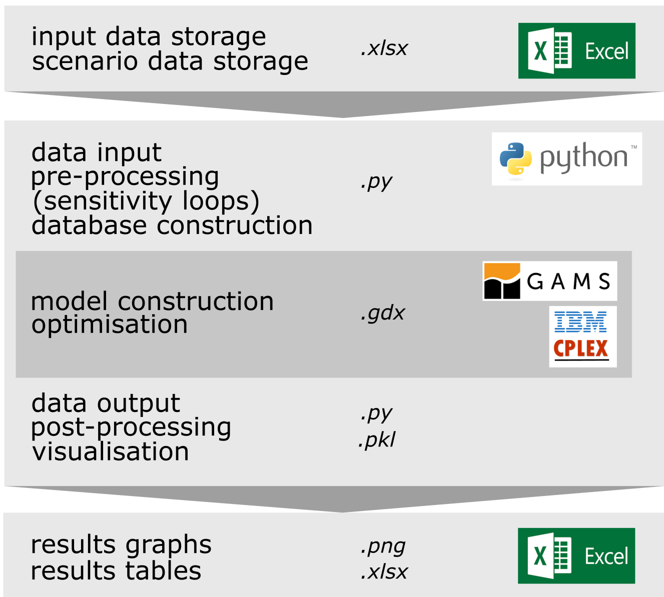


Figure 1.2: Optimised computational workflow developed in this work. The GAMS-Python API is utilised, combining pre-processing, running the model, post-processing, and data visualisation in Python.

Chapter 2

The Technological Viewpoint: Long-Term Storage in Deep Decarbonisation

2.1 Power systems on the way to net zero

Owing to its relatively large contribution to CO_2 emissions, and traditional domination by large, fixed-point emitters, the power sector has historically been the primary focus of decarbonisation efforts. Furthermore, a low/zero-carbon power sector enables the subsequent partial decarbonisation of the heating, mobility, and industrial sectors *via* electrification. Whilst there is focus on technological solutions for the electrification of heat and transport, *i.e.*, electric vehicles (EV) and heat pumps (HP), concerns remain regarding the system impacts of large-scale electrification [67]. The challenges in the design of a power system which provides carbon-neutral electricity for power applications but also for carbon-neutral heat and transport services go beyond a mere expansion of grid capacity. Not only is the quantity of power demand expected to change, but so too is the qualitative shape of this demand profile. Importantly, peak demand may significantly increase as a result of the cumulative demand of the three sectors during peak hours of the day [68]. Moreover, the inter-seasonal variation in power demand may become more pronounced due to the impact of the electrification of heat. This is especially true for countries, such as the UK and most other European countries, with a seasonal climate and resulting seasonal variation in heating needs.

One major point of discussion with regard to the decarbonisation of the energy system is the optimal capacity mix, *i.e.*, the combination of power generation and storage technologies which can best satisfy the requirements of the power grid. It is worth noting that when designing the power system in particular, ancillary services – reserve capacity and inertia provision – and the ability to maintain them throughout the day and the year, must also be considered [41, 42, 69]. Here, we take the system perspective, and view individual technologies as archetypes characterised by the grid services they provide and their advantages and challenges in that context. A brief overview of these archetypes is as follows:

- Intermittent renewable energy sources (iRES) , *e.g.*, onshore & offshore wind, solar, provide zero-carbon power, but are limited in their ability to provide ancillary services, such as firm reserve and inertia. The level to which their intermittency poses an issue for their integration into the system is highly dependent on their share of the capacity mix, the level of interconnection, and available transmission capacity. Limited flexibility can be provided in the form of curtailment. Their expansion may be limited by consideration of ecological constraints [70]. Beyond a certain level of deployment, synchronous compensator technology may be needed to provide synthetic inertia and maintain grid stability [71].

- Non-dispatchable generators, *e.g.*, most nuclear plants, geothermal, tidal, supply a steady level of power and ancillary services with reduced flexibility and emissions.

- Dispatchable emitters, *e.g.*, combined cycle and open cycle gas turbines (CCGT & OCGT), oil, coal, provide power from fossil fuels with (relatively) high CO_2 emissions at (relatively) low CAPEX and OPEX. They can provide flexibility and ancillary services. The presence of a carbon price can substantially increase their operating cost.

– Low-carbon dispatchable power generation technologies, *e.g.*, gas-fired CCGT with carbon capture and sequestration (CCS), coal with CCS, blue/green H_2-CCGT, blue/green H_2-OCGT, provide power from fossil fuels with reduced CO_2 emissions. They can provide flexibility and ancillary services at higher CAPEX compared to unabated plants.

– Negative emissions technologies (NETs), *e.g.*, bioenergy with CCS (BECCS), direct air capture with CO_2 sequestration (DACCS), operate a net negative CO_2 balance, while either producing or consuming heat and power.

– Short-term energy storage, *e.g.*, battery storage, can smooth the variation of power demand and power production at sub-hourly or hourly, or inter-daily time scales. It can further provide ancillary services.

– Inter-seasonal energy storage, *e.g.*, power-to-gas-to-power, power-to-liquid-to-power, balances inter-seasonal variation in power demand. The exact classification amongst storage technologies as short-term, long-term, or inter-seasonal storage may depend on the context. These storage technologies may provide ancillary services.

The way in which technology archetypes interact with each other influences both the design and the operation of the electricity system. For example, the level of deployment of intermittent renewable energy impacts the necessity and, depending on the structure of the market, profitability of storage technologies. Similarly, the presence or absence of low-OPEX peaking plants can shift the role of dispatchable technologies between load-following and baseload. Further, the choice of BECCS or DACCS will impact the broader structure and operation of the electricity system [43, 46, 45]. It has been shown elsewhere that low-carbon dispatchable generation can provide value across a wide range of scenarios [69, 72, 38, 39, 73], and the operation of negative emissions technologies is key to reaching net zero in a technologically feasible way [43, 74, 75]. Furthermore, systems with 100% intermittent renewables and storage may encounter challenges with demand satisfaction and ancillary services [42, 76].

As the power system evolves to incorporate a greater proportion of renewable power, electricity storage technologies are expected to be key in balancing any potential mismatch between availability and demand [77]. While a representation of hourly/daily storage and an inclusion of short-term storage technologies such as battery storage and pumped hydro storage is standard in energy systems models, there is a paucity of work which incorporates grid-scale inter-seasonal energy storage in power systems modelling. Seasonal energy storage may be of interest in countries where the operation of low-carbon dispatchable power may be limited, or the potential of iRES is particularly high. Importantly, the deployment of energy storage capacity in electricity systems impacts investment and market decisions for generation capacity [78, 79, 80, 81] emphasising the need for detailed study in this area.

The majority of work on energy storage has focused on short-term electrochemical (batteries) and mechanical storage (compressed air, flywheel) storage technologies [82, 83, 84, 85, 86]. In the context of grid-scale energy storage, the most mature option is pumped hydro [87]; the currently installed capacity in the EU is on the order of 0.6 TWh. However, the potential for expansion is inherently limited; and there is an insufficient amount to balance inter-seasonal variations [88], leading to a search for alternatives, such as chemical storage in the guise of so-called "power-to-x". However, when chemical storage is discussed, this tends to be limited to hydrogen [82, 83, 84, 85, 86], despite there being limited evidence that it is the most cost-effective option [89]. Research efforts in this space have, thus far, focused on the techno-economics of standalone power-to-gas systems in Germany, possibly due to the focus of the *Energiewende* on the expansion of renewable energy generation [90, 91, 92, 93]. System-level studies in Germany have shown promise for power-to-gas, however they do not include nuclear or CCS which may compete with power-to-gas [94, 95]. US-based analysis suggests power-to-gas only has merit in systems lacking dispatchable power options and highly renewable systems [96, 97]. Studies for the EU energy system and the global energy system indicate potential for power-to-gas for balancing intermittent renewables [98, 99, 100]. However the studies exclude CCS and nuclear and arrive at low-carbon – not net zero – systems. Recent analyses for multiple electricity systems in the US discern which technology characteristics would be required for long-term storage to be competitive [81, 101]. In the UK context, power-to-hydrogen has been explored as a link between the electricity system and the natural gas grid and shown to potentially reduce the curtailment of wind power [102, 103]. Further, in recent UK case studies Cárdenas and colleagues model 100% renewable systems, using multiple years of data and an algorithmic approach, and include hydrogen as energy storage, to determine optimal wind/solar ratios, storage capacities, storage durations, and over-generation. They show the significant inter-annual variation in renewable power supply, highlighting the need for shifting energy along long-term / multi-month time scales, which is reflected in their optimal storage capacities being in the range of tens of TWh [104, 105]. Other UK-focused work has optimised individual parts of storage (charging, storage, discharging) and evaluated the economic viability of liquid-air energy storage participating in the energy and ancillary services markets [106]. Regulatory challenges in valuing the services provided by energy storage have also been discussed, emphasising the importance of taking the system's perspective [107]. However, all of this work notwithstanding, there is a marked absence of the evaluation of grid-scale energy storage technology in the context of the whole system [108]. To our knowledge, no study has assessed the potential role of power-to-gas-to-power in the UK energy system. There also seem to exist gaps in the analysis of power-to-gas competing in a diverse system with nuclear and CCS. Furthermore, analysis of net zero, as opposed to low-carbon, systems becomes increasingly important.

Thus, we have identified a research gap for technology agnostic system analysis of grid-scale energy storage and a resulting lack of road maps for developing impactful energy storage technology. In this chapter, we therefore explore the potential for inter-seasonal energy storage in the context of a net zero energy system.

2.2 Characterisation of the power system

2.2.1 Full-hourly formulation of the ESO-X model

Analysing inter-seasonal storage necessitates the use of a full-hourly time representation as opposed to isolated days. The 11 clusters c of the original formulation of the ESO-X model are therefore replaced with 365 days – optimising

8760 hours in the year. Furthermore, the energy balance around the storage technologies is reformulated to allow inter-day and inter-seasonal storage:

$$s_{is,a,c,t} = s_{is,a,c,t-1}(1 - SDis_{is}) - s2d_{is,a,c,t} + p2is_{is,a,c,t}SEta_{is} \qquad \forall\, is, a, c, t \geq 2 \tag{2.1}$$

$$s_{is,a,c,1} = s_{is,a,c-1,24}(1 - SDis_{is}) - s2d_{is,a,c,1} + p2is_{is,a,c,1}SEta_{is} \quad \forall\, is, a, c \neq 1 \tag{2.2}$$

$$s_{is,a,1,1} = s_{is,a,365,24}(1 - SDis_{is}) - s2d_{is,a,1,1} + p2is_{is,a,1,1}SEta_{is} \quad \forall\, is, a \tag{2.3}$$

During each day, the storage level is balanced between hour t and $t+1$ (equation 2.1). The storage level at the end of each day is linked to the storage level at the beginning of the next day in equation 2.2. Equation 2.3 connects the storage level at the end of the year to the beginning of the year, closing the annual balance. $SDis_{is}$ denotes the self-discharge rate of the storage technology.

Solving the full-hourly MILP is not possible within a reasonable time frame. Therefore, the linear relaxation is implemented.

2.2.2 Capacity expansion and retirement

The remaining lifetime of existing capacity is estimated using the plant commissioning year from BEIS data [109]. This is then translated to a retirement schedule, *i.e*, the number of units d^{eol}_{ia} of technology i retiring in planning period a. The total number of units d^{out}_{ia} removed from the capacity stack is then defined as the sum of units in the retirement schedule d^{eol}_{ia} and those built during the time horizonn $b_{i,a-LT_i/\Delta a}$, retiring after their lifetime LT_i:

$$d_{ia} = d_{i,a-1} + b_{ia} - d^{out}_{ia} \qquad \forall\, i, a > 1 \tag{2.4}$$

$$d^{out}_{ia} = d^{eol}_{ia} + b_{i,a-LT_i/\Delta a} \qquad \forall\, i, a > 1 \tag{2.5}$$

Capacity is retired at the end of its normal lifetime, but early retirement is not permitted, in order to reduce the degrees of freedom and thus solution time. The capacity expansion is limited by maximum build rate constraints for individual technologies. These constraints are a substitute for a description of the hurdles in the system which restrict large-scale deployment of technologies. Reference case build rates are based on historical capacity deployment in order to provide a reasonable starting point for analysis (see table A.2 in the appendix) [39, 109]. In addition to existing technologies (coal, bioenergy, CCGT, OCGT, solar, onshore & offshore wind, interconnection, pumped hydro storage), CCGT-CCS, BECCS, battery storage, and power-to-methane storage are included in the technology portfolio. For novel technologies, build rate limits are estimated based on similar technologies. Scenarios are run with relaxed build rate constraints when baseline build rate limits do not result in a feasible system design, and to study the impact of higher build rates on the results.

2.2.3 Costs

Technology CAPEX are based on a combination of BEIS assumptions and literature review [110, 111, 112, 113] and can be found in table A.2 in the appendix. Since technology learning has been evaluated in previous work [39], it is neglected in this study. The OPEX includes start-up OPEX, no-load OPEX, fixed variable OPEX, and the carbon price for emitters.

2.2.4 System reliability

ESO-X includes constraints for system inertia and reserve requirements. We assume these constraints remain the same regardless of system design, *i.e.*, the demands for system stability are identical for systems with high shares of intermittent capacity or firm capacity. The lower bound on the system inertia is 100,000 MWs [69, 114], and the reserve margin is set to 4%. Onshore and offshore wind technologies are assumed to be deployed with synthetic inertia providing technologies. Unmet demand is penalised by the value of lost load (40,000 £/MWh) [69, 115]. Plant flexibility is constrained via up-time and down-time constraints. Interconnection, a contributor to balancing intermittency, is included in the model. Both model features are detailed in Heuberger *et al.* [39].

2.2.5 Availability of renewable energy

Full-hourly country average profiles for the capacity factors of onshore wind, offshore wind, and solar power for 2016 are obtained from *renewables.ninja* [116, 117]. These profiles are assumed to remain constant throughout the planning horizon. We recognise that capacity factor profiles, and with them optimal renewables capacity in the system, may change for different years and with increased renewables penetration. However, sampling from multiple years of data and analysing the magnitude of this impact is beyond the scope of this study. It is expected that when optimising for multiple individual years, the resulting optimal capacities would vary by year as a result of the fluctuating capacity factor profiles. A system design robust to the intermittency of the renewable generation would have to exhibit a higher capacity stack, able to meet power demand for a variety of scenarios, resulting in higher cost and lower average utilisation.

2.2.6 Bioenergy

Previous work on bioenergy has demonstrated the impact of embodied emissions of biomass on its carbon balance and resulting abatement potential [118, 119, 120, 74]. In this work, biomass is therefore assumed to have a non-zero amount of embodied emissions (0.25 t-CO_2/t) associated with the cultivation, harvesting, processing, and transportation of biomass [121]. The amount is kept constant over all planning periods by default. This is due to the fact that while the bioenergy infrastructure may decarbonise leading up to 2050, one also moves up the biomass supply curve with increased utilisation of bioenergy, potentially using biomass sources with lower accessibility and larger carbon footprint. A full analysis of the impact of the trajectory which the embodied emissions of biomass may take over time is beyond the scope of this work and is left for future work.

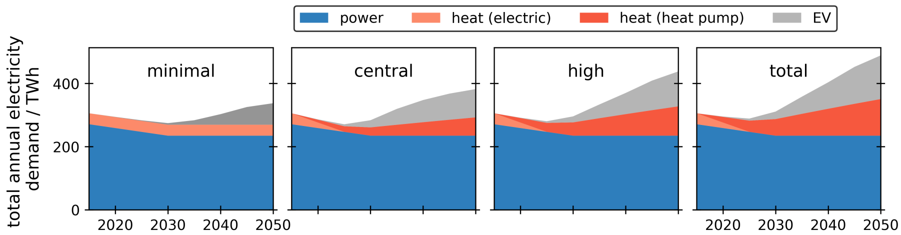
In terms of biomass cost and availability, a UK-specific biomass supply curve is taken from Zhang *et al.* [121] and comprises waste wood, forest residue, virgin biomass, municipal solid waste (MSW), crop residue, and imported biomass (table A.3). This provides a representation of biomass utilisation in terms of feedstock type and availability.

2.2.7 Carbon price and carbon target

We consider a carbon price which ramps up from 18 £/t-CO_2 to 236 £/t-CO_2 in 2050 [122]. A net zero carbon target in 2050 is imposed since previous work suggests a carbon price does not suffice to reach net zero [46]. No intermediate carbon budgets are enforced as to not bias the results with regard to the optimal trajectory.

2.3 Modelling electrification of heat and transport

We obtain historical full-hourly power demand data describing the UK grid (spatially aggregated) from *OPSD* [123], full-hourly heat pump coefficient of performance (COP) data from *when2heat* [124], and EV profiles from the *Element Energy EV charging behaviour study* [125]. Estimates for total power, heat, and EV demands are derived based on BEIS/DECC data [126, 127] and scenarios [128] as well as on the *National Grid Future Energy Scenarios* [129]. Figure 2.1 summarises the main assumptions around the electrification scenarios which were constructed for this work. Total power demand is assumed to be the aggregate of electricity demand, added demand from heat pumps, and added demand from EVs. The share of deployment varies for each of the scenarios, and with it the power demand profile. The impact of electrification becomes visible in the demand profile when comparing summer *vs.* winter – shown in figure 2.2 – as increased seasonality and "peakiness". The resulting peak demand of the central electrification scenario increases from 52 GW in 2020 to 81 GW in 2050. The total electricity demand in 2050 for the central electrification scenario comprises 235 TWh of baseline power demand, 90 TWh of added demand from EVs, and 58 TWh of added demand from the heating sector.



power	demand reduction through efficiency improvements until 2030, then offset by growth; profiles from one year of full-hourly power demand			
EV	steady progression	by 2050 ∼50% of road transport	by 2050 ∼80% of road transport	by 2050 ∼100% of road transport
heat	maintain level of electric heating, no heat pump deployment	70% air-sourced, 30% ground-sourced heat pumps, no heat storage; profiles from one year of full-hourly heat pump COP & heat demand		
		by 2050 ∼50% of residential & commercial heat demand	by 2050 ∼80% of residential & commercial heat demand	by 2050 ∼100% of residential & commercial heat demand

Figure 2.1: Total annual electricity demand, comprised of baseline power demand, power demand for electric vehicles (EV) and power demand for heat (electric heating and heat pumps), for electrification scenarios; as well as corresponding assumptions. This study neglects the potential impact associated with the electrification of the industrial sector, which could increase future demand.

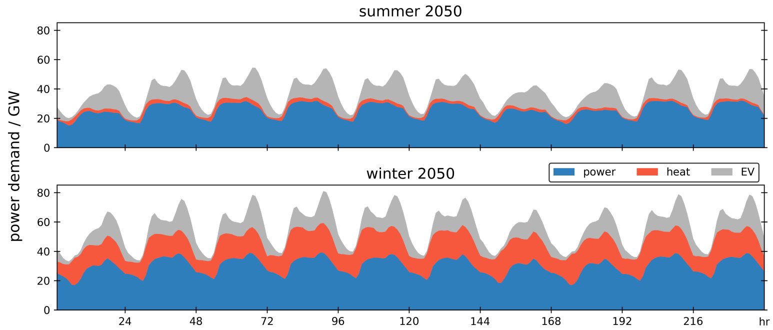


Figure 2.2: Excerpt of power demand profile for central electrification in 2050, for 10 consecutive days in summer and winter.

2.4 Description of energy storage technologies

Pumped hydro storage, battery storage, and power-to-gas storage are included in this analysis as established storage technology, novel short term and novel long term technology, respectively. Table A.1 in the appendix summarises relevant technology data. The parametrisation of the power-to-gas technology is based on the recent detailed techno-economic analysis of Yao *et al.* [89]. They suggest that power-to-methane (synthetic natural gas (SNG)) may be more cost-effective compared to power-to-hydrogen, when considering the complete balance of chemical conversion, storage, and re-electrification. Consequently, power-to-methane (P2M) is used as power-to-gas technology for inter-seasonal storage in this work.

A schematic representation of the process is shown in figure 2.3. The charging process of the storage comprises electrolysis to form H_2 and the Sabatier reaction converting it to SNG. The SNG is then stored in a salt cavern, and combusted in a combined cycle gas turbine (CCGT), which represents the discharging process. In *case A* of figure 2.3, all carbon in form of CO_2 is recycled via the atmosphere and re-captured using direct air capture (DAC), whereas *Case B* incorporates a carbon capture (CC) unit to recover the majority of the CO_2. All electricity requirements are satisfied with grid electricity, heat requirements are met by conversion of CH_4, energy requirements of the capture unit are covered by the CCGT. Almost the entire technology cost is contributed by the power conversion systems, with the storage system representing only ~10% of the total cost. For technological details concerning the storage technology, the reader is referred to Yao *et al.* [89]. Both cases are relatively close with regard to efficiency and cost. Case A may be preferred due to the presence of fewer process units and reduced complexity, and case B may be optimal due to the smaller size of the potentially expensive DAC unit. For the main runs, we assume 1700 MW charging power and 500 MW discharging power per unit, 8400 hours of storage duration, and a round-trip efficiency of 29%. This can represent both case A and B, or a similar power-to-gas-to-power technology. Results therefore apply to both configurations. It is assumed the storage site is taken into operation once at the beginning of its lifetime and remains available thereafter. Therefore, all storage levels refer to the working capacity.

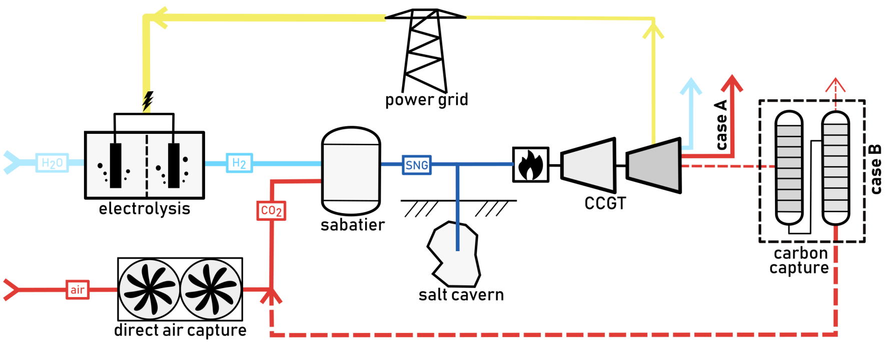


Figure 2.3: Power-to-gas storage types used in this work following Yao *et al.* [89]. In Case A, the CO_2 is vented to atmosphere and is subsequently recaptured via DAC; in Case B, the CO_2 is recovered via a carbon capture plant and is recycled to the Sabatier process.

2.5 The role and value of inter-seasonal storage

2.5.1 Deployment and role in the system

This analysis proceeds *via* a scenario-based approach where we discuss

- a system with neither power-to-gas storage (P2M) or CCS,

– a system with P2M, without CCS,

– and a system with both.

Figure 2.4 shows the capacity stack arising for each scenario. Total capacity decreases when P2M and CCS are added to the system. Build rate constraints are relaxed for systems without CCS in order to maintain grid reliability. The performance indicators in table 2.1 suggest that the presence of P2M leads to a reduction in curtailment almost to zero. Without CCS in the system, more P2M is needed to balance seasonality. A significant amount of storage volume is achieved through P2M, ranging up to 12.9 TWh, or 3.4% of total power demand in 2050. The lowest system cost is achieved when CCS and P2M are combined, and build rate constraints are relaxed.

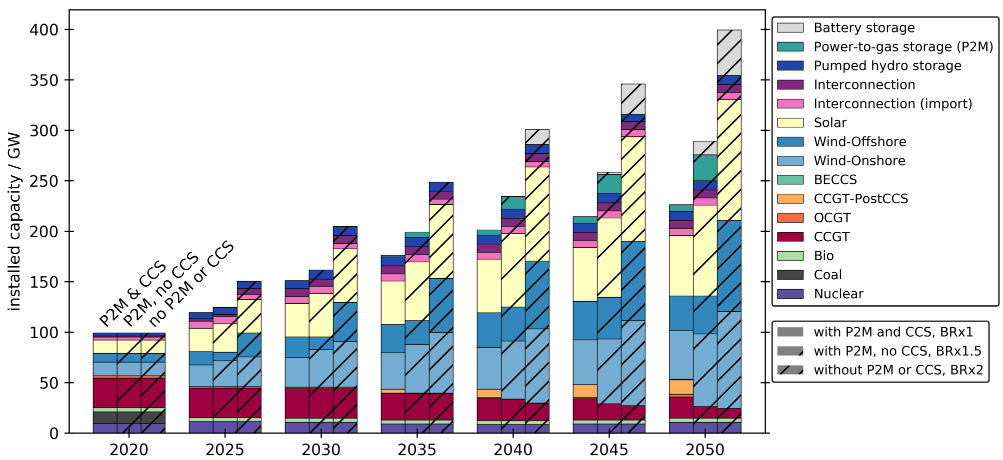


Figure 2.4: System design for scenarios with P2M and CCS, with P2M without CCS, and with neither. CCGT and Bio capacity in 2050 in scenarios without CCS is unused. The presence of P2M reduces the capacity stack compared to the scenario with only renewables and short-term storage. When adding CCS, even less generation capacity is needed, and P2M capacity is replaced with CCGT-CCS and CCGT for balancing seasonality.

A key emerging characteristic of systems without the option of either CCS or P2M is that renewable capacity must be deployed at rates which significantly exceed that which has been historically achieved. In the scenario shown here, build rates are double the historical precedent, reflecting a very significant and sustained policy commitment to this effect. This scenario precipitates the

			tsc	curtailment in 2050			P2M in 2050		unmet dem.
			b£	TWh			GW	TWh	GWh
CCS	P2M	BR		solar	on-wind	off-wind			
✓	✓	1	237			0.83 (<1%)	6.4	3.6	
✓		1	240		0.54 (<1%)	15.4 (16%)			
✓	✓	1.5	228		0.02 (<1%)	1.3 (1.7%)	9.3	6.0	
✓		1.5	232	0.007 (<1%)	8.8 (6%)	12.9 (26%)			
	✓	1.5	233				25.9	12.9	4.3
		2	458	0.58 (<1%)	44 (20%)	193 (69%)			1,630

Table 2.1: Total system cost (tsc), curtailment, power-to-gas storage (P2M) capacity in terms of output power and maximum energy stored, and unmet demand for different combinations of technology options and maximum build rate (BR) multipliers. The presence of P2M reduces curtailment and lost load substantially, adding CCS achieves further reduction of tsc.

significant deployment of both renewable capacity and large amounts of short-term storage. Nevertheless, as shown in table 2.1, 1.63 TWh, or 0.43% of demand is unmet, and up to 69%, or 193 TWh of offshore wind power are curtailed.

A system with P2M but without CCGT-CCS and BECCS will also require higher than historical build rates in order to decarbonise while maintaining demand satisfaction. In the scenario shown in figure 2.4, 1.5× baseline build rates are allowed. The absence of a NET precludes the operation of low-carbon dispatchable power (CCGT-CCS & bioenergy) and unabated peaking plants (CCGT & OCGT). This means all differences in renewables supply and power demand are satisfied by interconnection and storage. In the case of the UK, 26 GW of P2M are used in the system in 2050, with a maximum storage level of 13 TWh. This indicates that in a high-renewables system, seasonal storage will be key to maintain system reliability. In this scenario, the amount of storage volume required cannot be provided by short-term storage alone.

It is important to recognise that the optimum system design with CCS and P2M still comprises a high share of intermittent renewable generation. Here, renewable energy is complemented by CCGT-CCS, interconnection, pumped hydro, and inter-seasonal storage (P2M), with residual carbon emissions being mitigated via BECCS. Importantly, the availability of BECCS allows the retention of existing CCGT assets which are now used as peaking plants, thus avoiding early retirement. In this scenario, the system can reach net zero by

2050 under historical build rate constraints. These observations serve to underscore and emphasise the value of a technology agnostic portfolio strategy when pursuing an ambitious decarbonisation agenda. The presence of P2M in a system with CCS indicates that inter-seasonal storage continues to provide value even when dispatchable power is available. It provides the function of storing excess renewable energy and thereby maximising the utilisation of the renewable power generation capacity.

Inspection of the dispatch schedules for the three scenarios illustrated in figure 2.5 gives further insight into the role of individual technologies within the system. A sample of one day every 30 days out of the full year is shown, illustrating how the system responds across a range of weather patterns and demand levels. In the scenario without either P2M or CCS (figure 2.5c)), most of the demand has to be met by wind, solar, and short term storage. However, the storage duration of the storage options limits the shifting of renewable power produced, and large amounts of power remain unused. Arguably, this power could be utilised by renewable fuel production, however it is questionable how much these potential concepts could cope with a very intermittent and uncertain power supply [130, 131]. Despite the large amount of storage, some demand remains unserved, potentially leading to damaging impacts on the economy [50]. Notably, the utilisation of the existing nuclear capacity in 2050 is also reduced dramatically in the system. This indicates that not only the utilisation of renewables themselves but also the utilisation of zero-carbon stable generation is decreased. While this may not cause issues for maintaining system reliability, it shows that a sub-optimal system design could prohibit the optimal use of existing assets. This observation is consistent with previous work on the value of low-carbon dispatchable technologies [51].

A system with seasonal storage (P2M), shown in figure 2.5b)), allows more renewable power to be transferred to storage. Curtailment is reduced to almost zero, meaning the installed capacity can be utilised optimally. The dispatch shows that short term storage is used whenever possible, *i.e.*, when enough power is produced on the same day, such as day 160 in figure 2.5, owing to the higher round-trip efficiency. When shifting the power within a 24 hour period does not suffice, long-term storage is utilised, such as in day 70. This observation suggests a merit order for storage technologies, where the storage

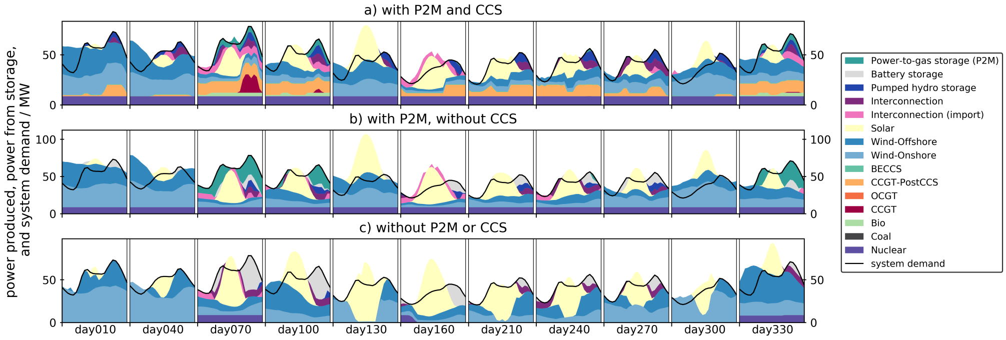


Figure 2.5: Excerpts of full-hourly dispatch schedules in 2050 (one day every 30 days) for scenarios a) with P2M and CCS, b) with P2M, and c) without either. When power exceeds system demand, the excess power is fed to storage. Peak demand is met with a) CCGT, CCGT-CCS and P2M, b) P2M, and c) battery storage. High levels of renewable power are integrated in each scenario. c) requires high levels of curtailment, whereas in a) and b) renewable power can be used to charge P2M storage.

technologies with higher round-trip efficiency are utilised first, and when those storage levels are depleted, storage technologies with longer storage duration but lower round-trip efficiency supply power. Examination of the storage level throughout the year in figure 2.6 indicates that the increasing seasonality in the system, introduced by the combination of intermittent renewable energy capacity and electrification, could further increase the value of long-term storage. The quantity of stored energy rises over the summer, with the maximum storage level reached in October. It then decreases as heat demand increases and the availability of solar power reduces. The availability of wind power in the UK context typically remains strong during the autumn and winter months, and, during this period, a substantial fraction of wind energy is directed to long term storage. Ultimately, reserves of stored energy reach a minimum in April.

The exact storage level is, of course, a function of the individual shares of the renewables energy sources, the capacity factor profiles of the year, and the level of electrification of other sectors of the economy. The effective storage duration utilised by the model is 500 hrs, or 21 days (measured by output power). In other words, the system in this scenario optimally includes P2M with enough storage volume to discharge continuously over multiple weeks. This service cannot be provided by other storage options such as pumped hydro storage, battery storage, or compressed air storage, *etc.* [132].

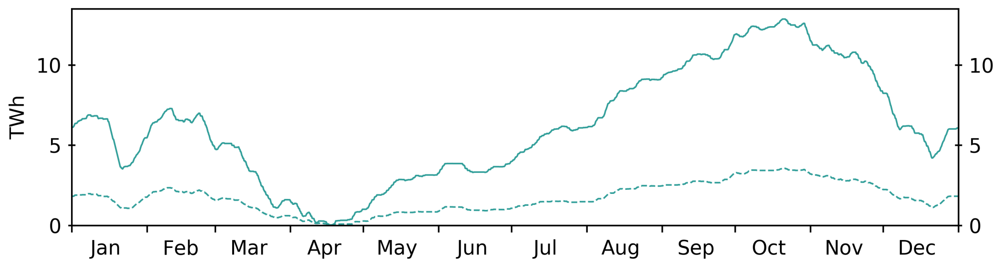


Figure 2.6: Storage level of power-to-gas storage, for scenarios with all technologies (- -) and no CCS (—). Storage is filled by solar in summer and wind in winter, utilised to meet heating demand in winter and peak demand throughout the year.

In a system with all the options including negative emissions (BECCS), low-carbon dispatchable power (CCGT-CCS) and inter-seasonal storage (figure 2.5a)), the cost optimal combination of technologies to achieve zero carbon depends on the day and season. Renewable energy contributes most of the power on days with high availability, with surplus fed into storage. By 2050, BECCS has evolved to operate as a baseload asset, providing value through both power generation and negative emissions. CCGT-CCS provides load-following throughout the year, while CCGT is exclusively utilised as a peaking plant. The flexibility provided by BECCS and low-CAPEX CCGT significantly reduces the quantity of required capacity - this can be observed on day 70 in the dispatch schedule. Delivering an equivalent amount of power from CCGT-CCS or renewables would add considerable cost to the system [41]. Power-to-gas storage reduces the level of renewables curtailment to zero, and contributes to the power mix on high demand days. The evolution of the storage level over the year is as previously described. Notably, where P2M is available, it is deployed in greater amounts than battery storage despite the higher CAPEX and lower round-trip efficiency, indicating the increased need for inter-seasonal as opposed to short-term storage. Thus, the value of balancing inter-seasonal variations appears greater than the service of balancing daily fluctuations.

2.5.2 Impact of electrification on system design

When comparing the scenarios with P2M without CCS, and with both, for minimal, central, and high levels of electrification, as detailed in section 2.3, the qualitative structure of the system design does not change. The amount of capacity needed naturally increases with the amount of electrification, with P2M deployed in every scenario. Using our estimates for electrification, it seems high electrification scenarios with CCS, and minimal electrification without CCS with P2M, could be achieved under baseline build rate constraints, but in more ambitious scenarios, build rates had to be increased, as shown in figure 2.7. The challenge associated with greatly increasing build rates should not be underestimated; this parameter consistently emerges as being decisive for the viability or otherwise of a great range of decarbonisation strategies, but delivering this result in practice requires the substantial and sustained upward flexing of existing supply chains – not a trivial exercise. The EVs in the system might act as energy storage, smoothing out the demand slightly, decreasing peak demand and thereby reducing the required power generation capacity. However, in addition to being inherently unreliable, they can only act as daily storage – which does not address the need for dispatchable power in a seasonal system.

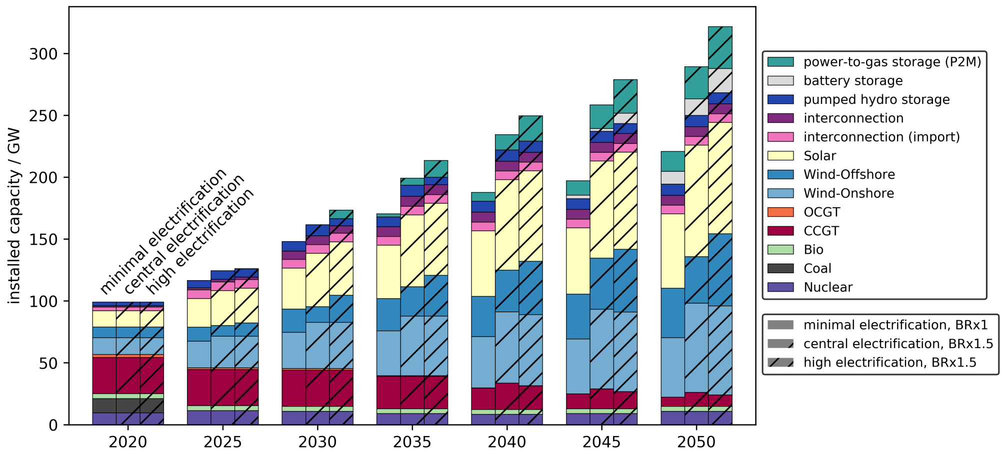


Figure 2.7: Capacity deployed in a no-CCS scenario for minimal, central, and high electrification. Qualitative structure of the system remains the same. More generation and storage capacity is needed, and build rates are higher for central and high electrification.

We further examine the difference in model results for the demand profile with and without electrification. Specifically, we compare the profile used in this work with the 2015 power demand profile, inflated 1% per year, which approximates the change in total power demand but neglects the evolution of the shape of the demand curve. We find that while the inflated profile equals a slightly higher total annual power demand, the model determines a slightly smaller capacity stack. In a scenario predicated on the availability of CCS, it is specifically the amount of dispatchable generation which is significantly higher, when the profiles with electrification are used. This could be a result of the impact of the seasonality and the peak demand in particular. It could indicate that the amount of flexible capacity required in the system increases with the level of electrification.

2.5.3 Bottlenecks

For the central electrification scenario, we evaluate the potential for periods of low availability of renewable energy to become bottlenecks for system design. First, the capacity factor profiles of solar and onshore wind are searched for periods of consecutive days with low capacity factor in one or both of the energy sources. Subsequently, the dispatch schedule for these periods is analysed.

The results indicate that weeks with low solar availability alone do not seem to introduce particular challenges in meeting demand, as there is enough wind availability to compensate. Lows during the day are addressed with interconnection and short-term storage, short-term storage and P2M, or CCGT-CCS and storage, depending on the scenario. However, weeks with low wind availability seem to present greater difficulties for the system, even when solar energy is available. Either load-following CCGT-CCS or larger amounts of storage are required to complement the available renewable power. Unsurprisingly, it is a period where the availability of both solar and wind are low and demand is high that becomes constraining to the system. Figure 2.8 shows the dispatch schedules for the three scenarios during a bottleneck period. Using the iRES availability data discussed previously, we identify a period of four days in winter when all capacity factors are low, yet demand is relatively high. In the scenario without P2M or CCS, this is when a significant amount of demand goes unmet.

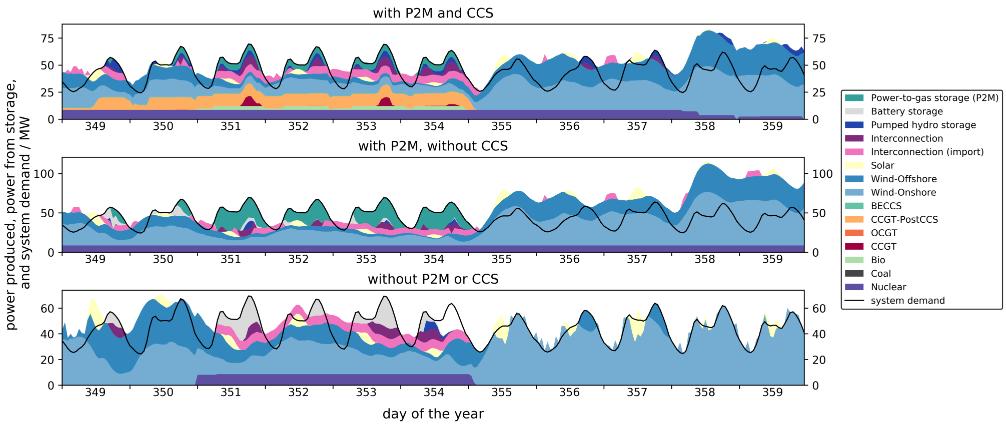


Figure 2.8: Dispatch schedules for systems during a period of low wind and solar availability. It shows CCGT-CCS in a load-following role and CCGT being utilised (top), P2M discharging every day over four days (middle), as well as a day where demand cannot be met due to lack of seasonal storage or dispatchable power (bottom). This sequence may function as a bottleneck for the system design.

For three days, interconnection and short-term storage are sufficient to satisfy demand. On the fourth day, storage levels are depleted, and demand cannot be met in full. When P2M is added, it can discharge varying amounts throughout the period due to its long storage duration, supplying around a third of the total power. In the CCS scenario, unabated CCGT are used during this period in addition to CCGT-CCS, P2M, and interconnection. Increasing electrification of the economy may exacerbate the gap between power demand and availability and present similar challenges to the system more frequently.

This result ties into larger questions in energy systems modelling, design of energy systems, and policy for capacity expansion. A strong fluctuation of power capacity required depending on the day and season may result in a great variation in the utilisation of different dispatchable generators or inter-seasonal storage. However, since unmet demand and associated economic loss are to be avoided, the presence of this flexible capacity in the system could be crucial. The distinction between baseload, load-following, and peaking plants for dispatchable capacity may impact not only the design and operation of these plants but also inform the policies needed for the transition.

2.5.4 Importance of charging rate and round trip efficiency

In addition to capital cost and round trip efficiency, grid-scale energy storage technologies are further characterised by the charging and discharging rates. Greater charging rates implies a larger power-to-fuel component, *i.e.*, greater electrolyser, DAC and sabatier capacity, and thus there is a likely implication to capital cost. Given the low TRL of this technology, and its potential importance to future energy systems, it is instructive to evaluate the impact of these technology parameters on the P2M capacity deployed, and overall system value, articulated here *via* the total system cost (tsc). These results are presented in figure 2.9. As can be observed, higher charging rates and round trip efficiencies lead to a reduction in total system cost. There are, however, diminishing returns for increases in charging ratio. This means that a ratio of higher than 2 does not yield much more reduction in system cost. The additional power-to-fuel components of the technology cannot be used and the storage would operate sub-optimally.

In the context of total system cost, depending on the charging ratio and round-trip efficiency, one can compare cases where technological advances (improved charging rates and increased round trip efficiency) come at the cost of a greater capital intensity. This kind of analysis is important for both setting goals for technology innovation and also defining the value proposition for public investment into improved technologies. As can be observed from figure 2.9, improved round trip efficiency or charging rates do not obviously provide value at the system level, if they come at the cost of significantly increased capital cost, thus the viable budget for improving this technology may be limited. Hence, a less costly technology with lower charging rate and round-trip efficiency may provide more value to the system than expensive technology with ostensibly improved performance when viewed in isolation.

It is worth noting that the relatively low round-trip efficiency of the power-to-gas technology does not prevent it from adding value to the system. This may be primarily due to the fact that the power being subjected to the round-trip efficiency comes at near-zero marginal cost in conventional terms, though, the

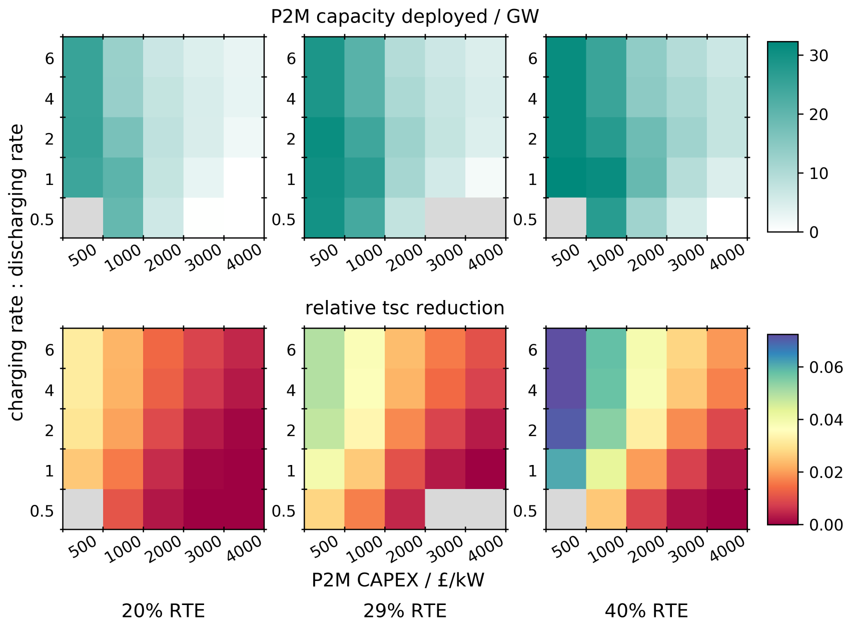


Figure 2.9: Power-to-gas (P2M) capacity deployed (measured by output power) and total system cost (tsc) reduction relative to a system without P2M for varying round trip efficiency (RTE), and charging to discharging power ratio. Grey indicates model did not converge in allocated time. P2M is deployed even at low RTE and low charging rate. Higher charging rate and RTE reduce tsc, however benefits may be offset by higher CAPEX.

capital intensity of this capacity has a cost. Thus, in the context of a high renewable energy plus storage paradigm, minimising the capital cost of power generation is key. By considering the value proposition of future energy systems through this lens, the limits of evaluating technologies in isolation comes into focus, as does the value of adopting a whole-systems perspective. While it might seem intuitive that a round trip efficiency of 20% would be too low for a storage technology to have value, our results suggest that in a system characterised by a high penetration of intermittent renewable energy sources, it could provide substantial value, providing this service is available at a low capital cost.

2.5.5 Synergies with other technologies

Building on the argument in the foregoing section, it is thus key to understand how advances in one technology systemically impact the deployment of others. Thus, in figure 2.10 the capacity in 2050 of P2M, iRES, CCGT-CCS, BECCS, as well as total system cost reduction, are evaluated as a function of capital costs. Large cost ranges are deliberately used for this analysis, with minimum costs estimated on the basis of a hypothetical limiting scenario, *i.e.*, CCGT CAPEX for CCGT-CCS, CCGT and natural gas storage for P2M, and the lowest historical value for onshore-wind. It is important to emphasise that we are not suggesting that these limits are likely, or even possible – they simply provide context for this thought experiment. The maximum values represent 2× the central value for P2M, and 1.5× central value for CCGT-CCS and onshore wind. Exact values are presented in table A.4 of the appendix . Finally, it is important to recognise that this evaluation is intended to be an exploration of how technologies interact with each other rather than an assertion of the likelihood or plausibility of specific scenarios.

The results illustrate a strong correlation link between the deployment of renewables and P2M. Lower P2M CAPEX appears to enable higher amounts of renewables, the same is true to a certain extent in reverse. Furthermore, wind CAPEX has greater influence on the total system cost than P2M or CCGT-CCS CAPEX due to its large share in the capacity stack. The value of renewables and storage depends on their CAPEX and combined deployment, whereas the

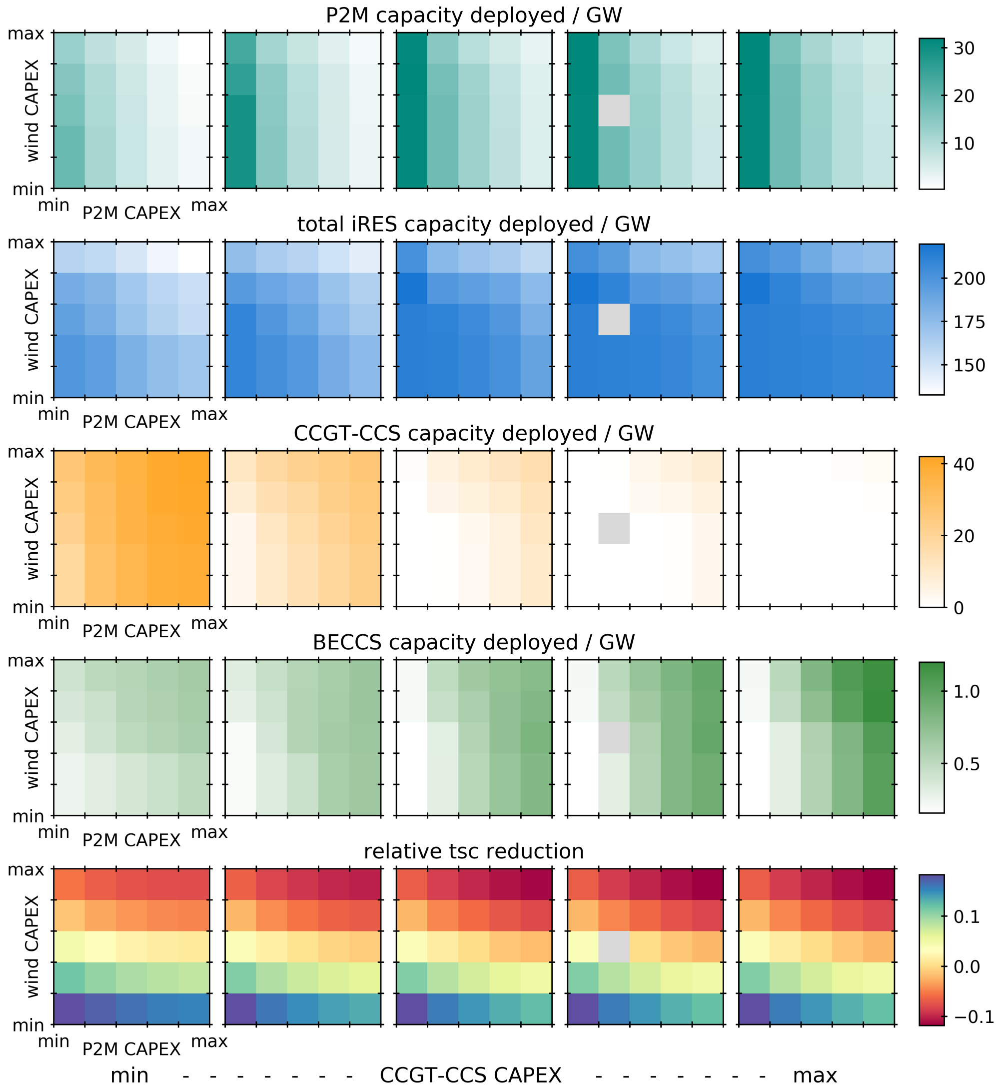


Figure 2.10: Results of the sensitivity analysis: installed capacity in 2050 for key technologies and total system cost (tsc) for varying onshore-wind, CCGT-CCS, and power-to-gas storage (P2M) CAPEX. Build rate limits set to 2× historical values for all cases. Grey indicates model did not converge in allocated time. Higher CCGT-CCS CAPEX leads to more deployment of renewable generation capacity and storage. P2M CAPEX influences both P2M capacity as well as optimal capacity of CCGT-CCS and iRES. Wind CAPEX has the largest influence on tsc but less impact on the optimal design.

CAPEX of CCGT-CCS hardly impacts the system cost. This is plausible considering intermittent renewables and storage are CAPEX-dominated technologies, while CCGT-CCS requires continuous operating expenditure. Thus, in the context of this energy system archetype, cost reduction of wind power ought to be emphasised.

It is also evident that the combination of renewables plus seasonal storage and low-carbon dispatchable power provide similar functions and thus may compete in the system. Depending on the CAPEX of the three technologies, there are cases dominated by P2M, and cases dominated by CCGT-CCS. This suggests that when the deployment of low-carbon dispatchable power is limited, seasonal storage becomes crucial, and *vice versa*. The optimal combination of inter-seasonal storage and CCS may depend on the country, the seasonality of its power demand, its endowment of renewable energy resources and infrastructure.

Importantly, the flexibility provided by BECCS appears valuable in almost all scenarios. When all technologies are assumed to be expensive, more BECCS is deployed to offsets emissions from the required CCGTs. Only when P2M is assumed to be at its lower bound of cost, and CCGT-CCS it at its upper bound does BECCS deployment minimise.

In conclusion, the optimal system design depends on a range of factors. High shares of intermittent renewable energy can be complemented by inter-seasonal storage and/or low-carbon dispatchable power. A diverse system with many options for power generation and storage – renewable energy, low-carbon dispatchable generators such as CCGT-CCS/H_2/bioenergy, flexible high-carbon, negative emissions, daily and seasonal energy storage – would appear to minimise cost under a net zero constraint. Such a system could also be the most resilient to future uncertainty in technology cost, demand profiles, availability of renewable power, *etc.*

2.6 Summary

In this chapter, the role and value of long-term storage in decarbonising energy systems was analysed with the UK as case study. The demand increase due to the electrification of transport and heat was explicitly accounted and a full-hourly time representation was used. Systems with and without CCS and inter-seasonal storage were evaluated. It was found that seasonality increasingly impacts the design when intermittent renewables are deployed at high rates, and electrification of heat and transport are considered. When the deployment of low-carbon dispatchable power, such as CCGT-CCS, is limited, the presence of an inter-seasonal storage technology becomes crucial to shift renewable power on the annual time scale, thereby reduce renewables curtailment and ensure a reliable power supply. The high storage volume of power-to-gas storage optimally deployed indicates the need for inter-seasonal – gas- or liquid-based – storage as opposed to short term storage (batteries or mechanical storage). Even in systems with dispatchable power present, inter-seasonal storage was shown to reduce overall cost by maximising the utilisation of renewable generation capacity. High CAPEX and low round-trip efficiency of the technology do not *per se* preclude its value in a net zero energy system. Exploring the system value of the technology, as opposed to viewing the technology in isolation, revealed the opportunities for its deployment.

The power sector is key in energy decarbonisation efforts, as transport and heat emissions can be mitigated to an extent via electrification. The implications of electrification on the power sector should not be underestimated, and adjustments in the power sector will be required to account for the additional demand, its fluctuations and seasonality. This work provides further evidence that sector-coupling, *i.e.*, the linking of individual sustainable and renewable energy vectors (electricity, heat, fuel), could represent a critical element in the decarbonisation of energy systems with significant seasonality in demand. The ability to store renewable energy in dense energy carriers enables the integration of renewable power in other aspects of the economy. Gaseous and liquid energy storage media allow the cost of intermittency of wind and solar power to be borne by central pieces of infrastructure, such as the gas grid, and achievements in the decarbonisation of power to be passed on to heat and transport, which have proven harder to decarbonise.

Further work is needed in evaluating the potential emergence of a "merit order" within energy storage technologies, and the position of inter-seasonal storage in this context, and further quantifying the value of grid flexibility and resilience they provide. Additional critical questions for future work include how to incentivise the deployment of technologies which aid decarbonisation in different ways, and how to define criteria for the set of services they need to deliver.

A limitation of this work arises from the use of one year of demand and capacity factor data, capturing seasonal effects, but neglecting inter-annual variation. Optimal results likely vary for different years, therefore including multiple years in the analysis could produce a more robust system design [133]. The demand profile used in this work incorporates a fixed demand from the electrification of heat and transport. EVs, household level energy storage, and the industrial sector could, however, have the potential of providing demand side management, and smoothing the demand profile, reducing peak demand and the capacity required in the power sector. Exploring this is another possible direction for future work. Moreover, the UK was used as case study, hence there is limited applicability in other countries. It is expected that P2M could have potential in countries with similarly seasonal power demand and renewables availability. In countries with limited access to CO_2 storage sites, inter-seasonal storage may be required to balance renewable energy – this would have to be evaluated for the country in question. Furthermore, disaggregating the inter-seasonal storage technology by power-to-storage, storage, and storage-to-power, instead of using one archetype of storage, may provide further insight into optimal configurations [101]. Another aspect not currently captured in the model is technology learning. It is estimated to have effects similar to those observed in the sensitivity analysis, but future analysis is needed to confirm this. Lastly, the assumption of perfect foresight over the year ensures optimal operation of the storage technologies. Modelling inter-seasonal storage with limited foresight could reveal more realistic charging/discharging profiles.

Finally, this study has demonstrated the value of evaluating technologies in the context of their services to the whole energy system as opposed to in isolation as has traditionally been the convention. Considering the technologies' portfolios of services provided to the system, the relative scarcity of those services in a given scenario, and a set of potential costs and drawbacks (economical, environmental, social) enables a movement beyond zero-sum technology advocacy. Bridging between techno-economic assessment of novel generation and storage technologies and system-level modelling and thinking identifies new perspectives and informs priorities for future work. A future energy system comprised of a broad portfolio of technologies and energy vectors, each with its individual competence, may evolve as the most capable to achieve the transition with the highest amount of economic, ecological, and social benefits.

Chapter 3

The System Viewpoint: Pathways for Power and Industry to Net Zero

3.1 Decarbonisation of power *vs.* industry

Power and industry are the largest contributors to point source CO_2 emissions in the UK. Their decarbonisation is therefore crucial for the UK to reach its carbon targets. The two sectors vary greatly with regard to their pathways to net zero. While the decarbonisation of the power sector is well-analysed, industrial emissions are generally considered more difficult to abate, and the general heterogeneity of the sector increases the complexity of the roadmapping that is common to the power sector. Power as largest single emitter has long been in the focus. The transition in power, although facing challenges such as intermittency and grid stability, is well understood, technically and economically feasible, and advancing in the UK [134]. It is also considered key to facilitate the reduction of heat and transport emissions through electrification, as explored in the previous chapter. Many options for low- and zero-carbon power (renewable energy, carbon capture and storage (CCS), energy storage, and nuclear power) exist, and the provision of carbon-negative electricity can be achieved by bioenergy with CCS (BECCS). Industrial emissions account for 21% of UK GHG emissions and industrial decarbonisation is therefore essential in a net zero paradigm. Furthermore, it is characterised by point sources, and can be decarbonised without behavioural changes in society, which should be taken advantage of. Pathways forward are much less clear; they can vary greatly depending on import and export of commodities. Considerable work is conducted within the subsectors (iron and steel, cement, chemicals, paper, *etc.*) in isolation. Abatement options for industry vary greatly – from economic efficiency improvements (CHPs and improved insulation), fuel-switching, retrofitting carbon capture, to entirely new processes which are currently at lab or pilot scale. Further efforts have been directed towards CCS for various CO_2 concentrations in the flue gas, corresponding to different industries. Many technologies rely on CCS, and substantial residual emissions are to be expected. Power may need to offset these – the most critical of several connections between the two sectors. Industry is heterogeneous [135], without simple solutions for all subsectors, and considered a "difficult area" by the CCC and the sector with the "weakest data on industrial energy use and potential for GHG emissions reduction" [136]. Industry is also closely connected to international markets; CO_2 abatement and consequential increases in product costs may impact the competitiveness of UK industry. CCS as key abatement technology has been in the focus of UK BEIS within their Clean Growth Strategy. CO_2 storage sites are available in the North Sea and the Irish Sea, enabling the sequestration of large amounts of CO_2 from potential CCS clusters. Combining CCS in power and industry may become crucial, as the utilisation of CO_2 infrastructure for both sectors reduces cost and risk [136]. Studying the amounts of CO_2 for transport and storage contributed by power and industry for different scenarios is therefore of interest.

The following paragraph contains a brief introduction of the industrial sectors and the status of abatement [135, 137]. A more detailed characterisation of the sectors modelled is provided in the following section.

- *Cement.* Process and combustion CO_2 are combined in the production of cement due to the use of limestone. This results in a relatively high CO_2 concentration in the flue gas (~30%). Pilot projects exist for carbon capture based on absorption, membranes and calcium looping [138, 139, 140].

- *Iron and steel.* The steelmaking process is particularly carbon-intensive due to iron ore and coal introduced to the process. Novel processes relying on switching coal as reducing agent for hydrogen or biochar exist. There is a noticeable paucity of pilot plants.

- *Refineries.* Refineries feature a number of point sources of varying CO_2 concentration and flow rate [141]. Combining them is a starting point for carbon capture. Replacing natural gas for heat with blue/green hydrogen also offers emissions reductions.

- *Chemical industry.* Several processes in the chemical industry, such as ethylene production, ethylene oxide production, biochemical ethanol production, and ammonia processing, produce CO_2 streams of high purity as byproducts [135]. These may represent low-hanging fruit among CO_2 sources.

- *Pulp and paper.* Data for this sector are scarce despite it representing 2% of global CO_2 emissions [142]. The locations of the point sources are often remote, not close to industrial clusters, complicating CO_2 capture [137].

- *Natural gas processing.* The Claus unit in the process of purifying natural gas produces a high purity CO_2 stream [135]. With most of the separation achieved in the existing process, capturing the CO_2 could be possible at minimum cost.

Large energy system models are starting to include industrial sectors as energy users (PRIMES, MARKAL, ETSAP-TIAM, TIMES) [143]. There still remains a gap in analysis of industry as a whole and its connection with the power sector. For instance, there is no agreement on the level of abatement possible in industry. While it was suggested that 60-75% emissions reduction is possible with CCS from large industrial point sources [144], work on decarbonisation of heavy industry shows emissions reductions by 90% are feasible in multiple sectors [145]. Open questions remain regarding where to focus decarbonisation efforts in industry. Should high purity sources be targeted first, or larger point sources, or plants connected to industrial clusters? Furthermore, there is no clear consensus on the negative emissions requirement from industry and how this will effect the power sector.

In order to address these questions and help to fill the gap in the analysis of industrial decarbonisation, in this chapter, the combined decarbonisation of power and industry and their pathways to net zero in 2050 are modelled. In section 3.2 the ESO framework is expanded to include the industrial sector, the two sectors are linked in terms of power demand and emissions. Industrial sectors are characterised, and a data set is created in section 3.3. A representation of trade is defined in section 3.4 and multiple scenarios with regard to import and export are analysed. We aim to estimate how much abatement is possible in industry, and which technologies are determined optimal for the industrial sectors. It is further of interest to investigate the amount of resulting residual emissions, how much carbon offset is required from power, and the level of CO_2 captured for each scenario. Results for the core scenarios are presented in section 3.5, and trajectories under policy instruments are analysed in sections 3.6 and 3.7. The final section provides a summary and outlook.

3.2 Industrial sector extension for the ESO framework

The power system characterisation follows the previous chapter to an extent. Since seasonal effects and inter-seasonal storage are not in the focus when modelling the industrial sector, the time representation with 11 isolated days is used. However, the demand curve now includes demand from the heat and transport sectors according to the central electrification scenario, *i.e.*, its overall magnitude and shape reflect the increased uptake of heat pumps and electric vehicles. In addition to meeting demand, the provision of ancillary services – reserve and inertia – also need to be ensured. The voltage of the electricity grid is maintained by the inertia of spinning mass, such as the generator in a gas turbine, and a minimum inertia needs to be connected to the grid at all times. Since intermittent renewable energy sources can supply only very limited inertia, their large-scale deployment can pose problems for system stability. Therefore, synchronous compensator technology is added to the technology portfolio [146]. It can provide inertia to the system under consumption of small amounts of electricity and thereby help stabilise the electricity grid.

In the context of energy systems modelling, industry tends to only be included as a source of fixed power demand, or a provider of demand side response [25]. In the literature, abatement in industry exists as techno-economic analysis of novel technologies. Further, there are some qualitative and quantitative assessments of pathways for individual subsectors such as steel [147, 148, 149], cement [150], and pulp & paper [151]. There is little work on industry as a whole; with some entirely qualitative [152]. Notable is the work by Rootzén and colleagues, who perform bottom-up modelling of the EU power and industry sectors including refineries, steel, and cement, each with specific technologies, yielding trajectories for the subsectors as well as the power sector [153, 144]. However, their industrial scenario appears fixed, and the exclusion of novel abatement technologies such as CCS results in a system unable to achieve emissions reductions consistent with carbon targets. The recent study by Bogdanov *et al.* similarly shows a decarbonisation pathway for industry, with fixed estimated trajectories for industrial subsectors (cement, steel, chemicals, aluminium) [154]. Our approach is innovative in multiple directions. The novel formulation we introduce below allows for the inclusion of various industrial sectors, technologies, and scenarios, in addition to a full power sector representation. We further address demand and trade, explicitly calculating import and export, which to our best knowledge presents another novelty. In the analysis, we focus on four core scenarios for industry, and then simulate the system behaviour under varying policy instruments, again going beyond literature precedent.

As detailed in the nomenclature, existing sets are renamed ip for power technologies, ipg and ips for generating and storage technologies, and the sets ii for industrial technologies and m for industrial products are added. The formulation is revised to allow for retrofitting technologies. Below the changes and additions are detailed, for the remaining equations the reader is referred to the corresponding references.

To allow retrofit, the balance of capacity is modified in equation 3.1. It balances units d in planning periods $a-1$ and a with the units built b_{ia} and the units removed from the capacity stack d_{ia}^{out}. Equation 3.2 sums all possible paths for the removed capacity – being decommissioned (d_{ia}^{dec}), being retrofitted in the same planning period ($d_{ia}^{ret,now}$) or the next ($d_{ia}^{ret,later}$). Units built of retrofit capacity are connected to original capacity in equation 3.3, where $\rho_{i,i'}$ relates original with retrofit technologies. The units taken from the existing capacity are limited by equation 3.4. Equation 3.5 enforces the units repurposed to amount to at least the number of units that are retired according to the retirement schedule (d_{ia}^{eol}) and the units built during the time horizon b_{ia} that reach the end of their lifetime LT_i. The formulation allows capacity to be retired or retrofitted before they reach the end of their lifetime. The number of active industrial units $q_{ii,a}$ is limited to the capacity (equation 3.6). Several variables are set to zero at the boundaries of the time horizon to close the balances.

$$d_{ia} = d_{i,a-1} + b_{ia} - d_{ia}^{out} \qquad \forall\, i, a > 1 \tag{3.1}$$

$$d_{ia}^{out} = d_{ia}^{dec} + d_{ia}^{ret,now} + d_{ia}^{ret,later} \qquad \forall\, i, a > 1 \tag{3.2}$$

$$d_{ia}^{ret,now} + d_{i,a-1}^{ret,later} = \sum_{i'} \rho_{i,i'} b_{i'a} \qquad \forall\, i, a > 1 \tag{3.3}$$

$$d_{ia}^{out} \leq d_{i,a-1} \qquad \forall\, i, a > 1 \tag{3.4}$$

$$\sum_{a'}^{1<a'\leq a} d_{ia'}^{out} \geq \sum_{a'}^{1<a'\leq a} d_{i,a'}^{eol} + b_{i,a'-LT_i/5} \qquad \forall\, i, a > 1 \tag{3.5}$$

$$q_{ii,a} \leq d_{ii,a} \qquad \forall\, ii, a \tag{3.6}$$

$$d_{i,1}^{out} = 0 \qquad \forall i \tag{3.7}$$

$$d_{i,1}^{ret,later} = 0 \qquad \forall i \tag{3.8}$$

$$d_{i,7}^{ret,later} = 0 \qquad \forall i \tag{3.9}$$

The static build rate formulation of the original publications is updated for the purposes of this work. Equation 3.10 defines the number of new units built b_{ia} as the sum of $BR1_{ia}$ and $BR2_{ia}$. The latter remains constrained by a static build rate limit BR_i (equation 3.12), whereas the former is now limited by an S-curve constraint (equation 3.11). This allows for emerging technologies to grow beyond historical precedent. The build rate multiplier BRM_i is set to 1 and 2, for conventional and novel technologies, respectively (see tables A.2 and B.1 in the appendix). Equations 3.13 – 3.15 ensure that only one build rate component is utilised simultaneously, M representing a sufficiently large number, with $bBR1$ and $bBR2$ as binary variables. $b_{i,0}$, the number of units built in the first planning period, is set to the number of units built in 2015-2020, which is available from databases.

$$b_{ia} \leq BR1_{ia} + BR2_{ia} \qquad \forall\, i, a > 1 \tag{3.10}$$

$$BR1_{ia} \leq b_{i,a-1} BRM_i MA_{ia} \qquad \forall\, i, a > 1 \tag{3.11}$$

$$BR2_{ia} \leq BR_i \Delta_a MA_{ia} \qquad \forall\, i, a > 1 \tag{3.12}$$

$$BR1_{ia} \leq bBR1_{ia} M \qquad \forall\, i, a > 1 \tag{3.13}$$

$$BR2_{ia} \leq bBR2_{ia} M \qquad \forall\, i, a > 1 \tag{3.14}$$

$$bBR1_{ia} + bBR2_{ia} = 1 \qquad \forall\, i, a > 1 \tag{3.15}$$

$$bBR1_{ia}, bBR2_{ia} \in \{0, 1\} \tag{3.16}$$

The power demand balance, equation 3.17, comprised of the power-to-demand $p2d_{ipg,act}$, storage-to-demand $s2d_{ips,act}$ and the power demand SD_{act}, is expanded to include the additional power demand from industrial units $IFeat_{ii}^{powreq}$ $g_{a,ii,m}$, where $g_{a,ii,m}$ denotes the production of commodity m in planning period a by industrial technology ii. Industrial emissions from the sectors modelled explicitly $e_{ii,a}^{ind}$ and other sectors $e_{a}^{ind,other}$ are added to the emissions balance (equation 3.18) which enforces the carbon target SE_a.

$$\sum_{ipg} p2d_{ipg,act} + \sum_{ips} s2d_{ips,act} = SD_{act}(1 + TL) - slak_{act} + \sum_{ii,m} IFeat_{ii}^{powreq} g_{a,ii,m}/8760 \qquad \forall\, a, c, t \tag{3.17}$$

$$\sum_{ipc,ct} e_{ipc,act} WF_{ca} + \sum_{ii} e_{ii,a}^{ind} + e_{a}^{ind,other} \leq SE_a \qquad \forall\, a \tag{3.18}$$

Industrial emissions are determined in equation 3.19 by the industrial production $g_{a,ii,m}$ and the specific emissions $IFeat_{ii}^{ems}$. Equations 3.20 and 3.21 close the balances around domestic production $g_{a,ii,m}$, import imp_{am}, export exp_{am} and demand $IDem_{am}$ with f_{am} denoting the domestic delivery. This follows representation of the market in literature, which is explained in detail in section 3.4. Equation 3.22 limits industrial production to the operational units multiplied by the capacity and the maximum operation factor.

$$e_{ii,a}^{ind} = \sum_{m} g_{a,ii,m} IFeat_{ii}^{ems} \qquad \forall\, ii, a \qquad (3.19)$$

$$IDem_{am} \leq f_{am} + imp_{am} \qquad \forall\, a, m \qquad (3.20)$$

$$f_{am} + exp_{am} \leq \sum_{ii} g_{a,ii,m} \qquad \forall\, a, m \qquad (3.21)$$

$$g_{a,ii,m} \leq IProd_{ii,m} Des_{ii} q_{ii,a} IFeat_{ii}^{opfac} \qquad \forall\, a, m, ii \qquad (3.22)$$

Finally, the CAPEX and OPEX (fixed and variable) of the industrial units as well as the import cost and the export revenue are added to the objective function.

3.3 Characterising UK industry

To obtain a picture of the UK industrial emissions we utilise the National Atmospheric Emissions Inventory (NAEI) which contains the point sources disaggregated by greenhouse gas, sector, and source [155]. Half of the 60 Mt-CO_2/yr of industrial emissions are contributed by three sectors – cement, steel, and refining. These sectors are chosen for explicit representation. Unit sizes, operation factors and specific emissions are derived from the database as well as other sources. Abatement for smaller point sources, including the chemical industry, pulp & paper, natural gas processing, *etc.*, may often be costly or impractical, due to the aforementioned heterogeneity of the sources and their remote locations. Whether or not CCS is cost-effective for these source, for instance, is the subject of ongoing discussions. The remaining 30 Mt-CO_2/yr are therefore included in the system as a parameter and assumed constant over time, requiring carbon offsets. Adding detailed modelling for sectors with smaller shares of industrial CO_2 emissions is planned for future work.

Brief explanations of the abatement options included in this study are provided below. The references offer more comprehensive information about the abatement concepts to the reader. The technology data is detailed in the appendix in tables B.1, B.2, and B.3.

3.3.1 Cement

Existing capacity of cement plants is taken from the NAEI database [155]. The age of the plants [156] determines the remaining lifetime. At the end of it, the capacity needs to be replaced or retrofitted.

The abatement options considered for the cement sector are based on literature research. In an effort to use consistent data we adapt the results of a recent study by SINTEF [157, 158]. We include oxy-combustion (oxy), post-combustion capture (PCC), membrane assisted liquefaction (MAL), tail-end and integrated calcium looping (CaL). The principle of oxy-combustion is suitable for cement plants. An air separation unit (ASU) is installed and the pre-calciner and calciner are operated in an oxygen-rich atmosphere. The resulting flue gas consists almost entirely of CO_2 and is ready for transport and storage after a CO_2 purification unit (CPU). Post-combustion capture, which typically utilises amine-based absorption separating CO_2 from flue gas, can also be applied to cement kilns. The configuration used in this work employs MEA for PCC. Similarly, end-of-pipe capture is also possible through membrane assisted liquefaction (MAL), which uses a membrane to separate CO_2 from the flue gas. Calcium looping – making use of the carbonation reaction – is a promising option for cement, as it can be integrated into the process. We include both tail-end as well as integrated calcium looping.

Every cement plant is different and the optimal capture technology and whether it can be retrofitted depends on the specific kiln. Considerations have to be made with regard to the space available for the capture unit and the level to which the kiln can be adapted. For this study, we assume all capture technologies to be available and retrofittable to all cement plants. The results do not aim to predict the technology mix in the cement sector – they will point towards a cost-optimal potential pathway. Real-world solutions may be slightly more costly, and have marginally different residual emissions. However, the costs for the abatement options are similar enough that the decision between abatement or offset (through BECCS) is likely to be identical regardless of the chosen abatement option.

3.3.2 Steel

The two blast furnace - basic oxygen furnace steel plants in the UK are of significant age. It is assumed for this work that investment is required to extend the lifetime of the plants, regardless of whether they are operated conventionally or retrofitted with carbon capture. This maintenance cost is therefore omitted from the objective function and the two steel plants are not forced to retire based on age.

Steelmaking from scrap in electric arc furnaces is an economical and low-carbon alternative to steelmaking from iron ore and accounts for a small share of steel production in the UK. It is included in the model and its expansion is limited by the forecasted availability of scrap [147].

Post-combustion capture can be applied to the blast furnace offgas in steel plants, resulting in ~60% capture [159]. When CO_2 is captured from more point sources in the steel plant, the capture rate rises to ~80%. Both configurations are modelled. Some of the coal required for the reduction of iron ore (PCI coal, for pulverised coal injection) can be replaced with biochar – carbon isolated from biomass. When carbon capture is added, the result is carbon-negative steel [160, 161]. PCC and bio-steel technologies are assumed to be retrofittable. The reducing agent can also replaced with hydrogen. This technology is referred to as hydrogen direct reduction (HDR). Since small amounts of coal are still required, the production is only low-carbon. The cost of the technology can be reduced by using a higher amount of scrap metal in the production. Electrowinning (EW) is a novel technology whereby ore is reduced to iron using electricity. Its current technology readiness level is low, but due to its potential as zero-carbon technology, it is included here. More pilot plants and projects on innovative steelmaking are needed in the steel industry to provide better data and allow the comparison of the various options.

3.3.3 Refineries

Refineries are notoriously difficult facilities to directly abate. They are a collection of point sources of varying flue gas flow rate, CO_2 concentration, and accessibility. The level of abatement possible at a refinery depends on the specific plant. For this work, results from a case study for two configurations of PCC are used [162]. The *lowPCC* and *highPCC* options achieve 22% and 63% of emissions reduction, respectively. Heat integration within the refinery is carried out in both cases, reducing cost and power requirement. Retrofit is the only technology for carbon capture considered for refineries.

3.4 Modelling industrial demand and trade

For the purposes of this work, we use a representation of the market illustrated in figure 3.1, based on market analysis in literature. The UK demand is satisfied by the domestic delivery and the import; the domestic delivery and the export sum up to the domestic production. We term the ratio of import to total demand *import ratio* and the export over the total production the *export ratio*. This allows to keep the ratios constant over time to preserve the structure of the market, reflecting the previously mentioned connection to international markets. These ratios are not proposed as immutable factors, but rather provide the basis for subsequent analysis. Demand for the three sectors is based on projections in literature. Current import and export ratios are calculated based on versions of the flow diagram in figure 3.1 available in the literature. Both are detailed in table B.4 in the appendix. Based on the projections used in this work, the demand for cement is constant. The steel demand is assumed to increase over the time horizon, assuming continued industrialisation and no

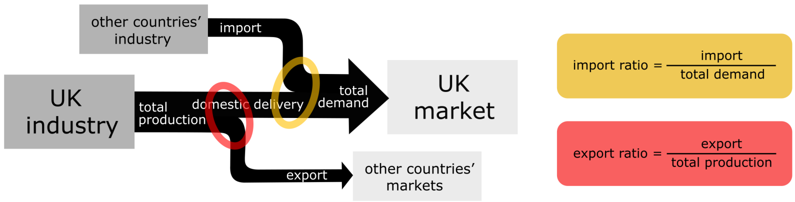


Figure 3.1: Definition of import and export ratios.

carbon leakage in Europe. Conversely, the demand for petrochemicals is projected to decrease as a result of the decarbonisation of the transport sector and the corresponding reduced requirement for fossil transport fuels. The import and export cost for all industrial products is set to the OPEX of the conventional technology. The carbon intensity of imported products is assumed to be the carbon intensity of conventional production, approximating global average emission factors.

Our formulation of import and export further allows us to change the import and export ratios over time and simulate multiple trajectories for the UK industries. We define four scenarios regarding import, export, and the availability of abatement, summarised in table 3.1.

Table 3.1: Scenarios regarding abatement availability, import and export for industry.

	abatement	import ratio	export ratio
BAU & offset	× unavailable	↔ fixed	↔ fixed
abate & offset	✓available	↔ fixed	↔ fixed
import & offshore	× unavailable	↗ increasing	↔ fixed
abate & export	✓available	↔ fixed	↗ increasing

In case of *BAU & offset*, no deployment of abatement technologies is carried out. The burden of decarbonisation is passed on to the power sector, and substantial amounts of carbon offsets are required from BECCS. Abatement is made available in the *abate & offset* scenario. It is of interest to determine for every sector whether abatement is chosen over BECCS offsets in this scenario – and when abatement is optimally deployed. Import and export ratios are kept constant in both scenarios.

Since industrial emissions are difficult to abate, it is an option to offshore them, and import the commodities instead, increasing the import ratio to 1 over time. The purpose of investigating the *import & offshore* scenario is analysing a hypothetical system and how the power sector would respond in this case.

Finally, the antithesis to the previous scenario is the *abate & export* case. It is assumed here that abatement can be deployed, and the export ratio is increased over time – imagining a UK industry that is boosted by exporting low-carbon products.

Other assumptions

A target of 30 GW of offshore wind capacity by 2030 is set, in line with the UK sector deal. For the analysis of the four scenarios, no carbon price (CP) or negative emissions credit (NEC) is applied. We impose a linear trajectory reaching a net zero carbon target for the total emissions of all sectors in 2050.

3.5 Transition pathways for power and industry

Figure 3.2 shows the results for the four scenarios in the industrial sector. In the BAU & offset scenario, retiring capacity is replaced with new-built high-carbon plants. Low-carbon secondary steelmaking from scrap via electric arc furnaces is expanded, adding electricity demand to the power sector. The abate & offset scenario indicates that abatement is preferred over carbon offsets from BECCS in all of the sectors. In the cement sector, abatement starts being deployed in 2030, and in the steel and refining sectors, abatement is optimally deployed in 2035, 10 years after it is made available in the model. Retrofit oxycombustion is preferred in the cement sector. The share of secondary steelmaking in steel production is increased and existing capacity is retrofitted with bio-CCS technology. High amounts of PCC with higher cost and higher emissions reduction is determined optimal for refineries. Notably, all optimal technologies, except EAF in the steel sector, rely on CCS. The import & offshore scenario sees existing capacity being retired at the end of its lifetime or shut down and replaced with imports. In the abate & export scenario, domestic production is expanded. New cement plants with oxycombustion are added. The steel production capacity is increased by new-built bio-CCS steel plants. PCC with a high capture rate are preferred for refineries. Note that these are results are not predictions, they are optimal pathways under the aforementioned constraints. In practice, actual results will be a function of prevailing market conditions and policy decisions. Addressing this in detail is outside of the scope of this study. Furthermore, since perfect foresight is assumed in this model, the years in which abatement is deployed may be viewed as latest possible points in time. A sooner deployment is favorable from a risk-minimisation perspective.

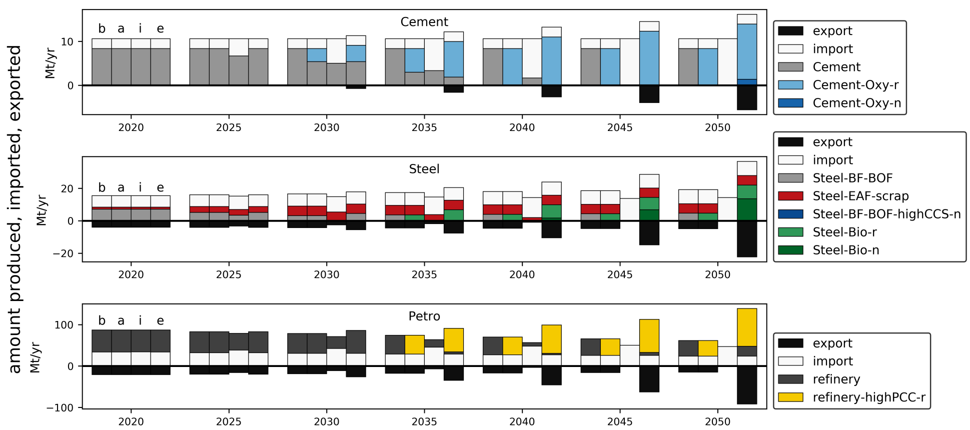


Figure 3.2: Trajectories for industry for BAU & offset (**b**), abate & offset (**a**), import & offshore (**i**) and abate & export (**e**) scenarios.

We analyse the impact of the industrial scenarios on the power sector in figure 3.3. The scenarios are relatively close regarding the capacity expansion – indicating that a wide variety of industrial pathways can be supported by the power sector. The pathways see the expansion of renewables (solar, onshore and offshore wind), pumped hydro storage, and synchronous compensator technology, maintaining the current level of nuclear power, reducing the utilisation of the CCGT capacity, and the deployment of BECCS. They differ in the year BECCS is added to the capacity stack. For BAU & offset retrofit BECCS is introduced in 2035, while it is first deployed in 2040 in the abate & offset, import & offshore, and abate & export scenarios. The amount of BECCS in

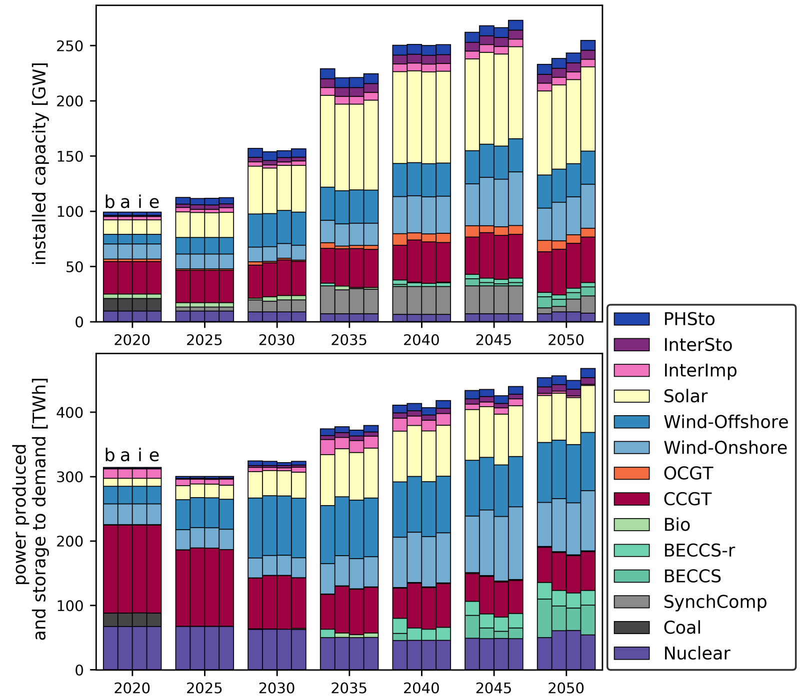


Figure 3.3: Power sector pathways for BAU & offset (**b**), abate & offset (**a**), import & offshore (**i**) and abate & export (**e**) scenarios.

2050 depends on the scenario and the associated carbon offset requirement. Import & offshore narrowly requires the least amount of BECCS with 10 GW. For abate & offset and export & offset 10.5 and 12 GW of BECCS, respectively, are deployed. Offsetting all of industry (BAU & offset) requires 14 GW of BECCS, significantly higher compared to the other scenarios.

Inspection of the emissions trajectories (figure 3.4) reveals further insights into the combined pathways of power and industry. In all scenarios, power emissions are reduced substantially in 2025 and 2030 via a reduction in coal-fired and gas-fired power and the expansion of renewables. In 2035, when CCS is deployed in industry in the a and e scenarios, industrial emissions drop while power emissions stay constant. In case of the BAU & offset scenario, the early introduction of BECCS leads to a carbon-negative power sector in 2040. For the other three scenarios, power emissions are further decreased by BECCS in 2040, and power reaches carbon negativity in 2045. The emissions balance at the end of the time horizon is similar for scenarios a, i and e, whereas the offset requirement is significantly higher in scenario b. In 2050, BECCS provides 71 Mt-CO_2 of negative emissions in the BAU & offset scenario, including 18 Mt-CO_2 for power (CCGT and OCGT), and 49-58 Mt-CO_2, including 19-20 Mt-CO_2 for power, in the other scenarios. This range of negative emissions equates to 8-13 BECCS plants of 1 GW operating at 80% average utilisation (assuming an emissions factor of -0.83 t-CO_2/MWh). It also requires ~180-270 TWh/yr of biomass, with domestic biomass supply limited at ~200 TWh. Demand reduction and secondary steelmaking reduce emissions in the three sectors modelled explicitly by 23% overall (scenario b). The additional deployment of CCS in industry increases the overall emissions reduction in cement, steel and refining to 90%. The corresponding low level of residual emissions explains the proximity of the abatement scenarios to the import & offshore scenario. Steel production with bio-CCS contributes 1 and 6 Mt-CO_2/yr of negative emissions in the a and e scenarios, respectively.

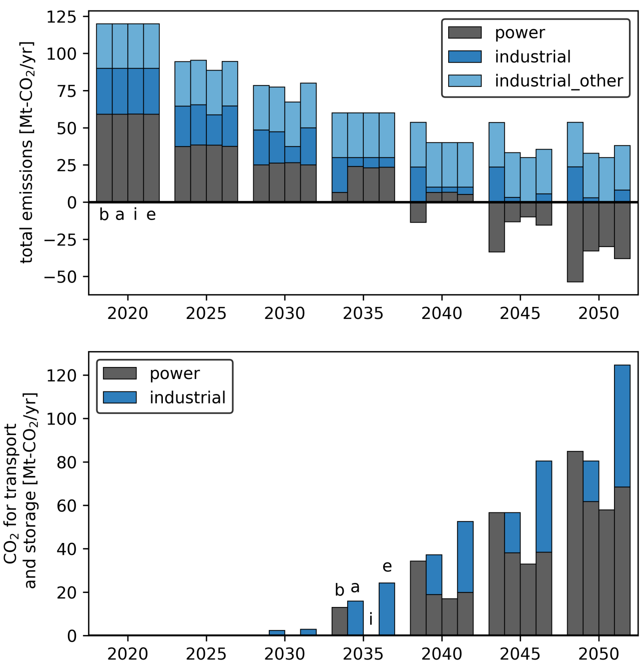


Figure 3.4: System emissions and emissions for transport and storage for BAU & offset (**b**), abate & offset (**a**), import & offshore (**i**) and abate & export (**e**) scenarios.

The level of CO_2 captured, *i.e.*, the CO_2 which will require transport and sequestration, rises throughout 2035-2050 in all scenarios. When abatement in industry is permitted, it is deployed first in industry in 2030/35, power is added in 2040, and overtakes in terms of captured emissions in 2045. A lack of industrial abatement forces CO_2 in power to be captured sooner. Predictably, offshoring industrial emissions leads to the lowest possible captured emissions at 58 Mt-CO_2/yr in 2050. Increasing domestic production requires capturing 125 Mt-CO_2/yr in our scenario. When no changes to import and export are assumed, CO_2 captured amounts to 80-85 Mt-CO_2/yr.

In this analysis, our scenarios are driven by a carbon target only. Since abatement is costly, the system will delay action as much as possible. Hence the years in which technologies are introduced in the system here may be viewed as latest possible points in time, optimal from a total cost perspective yet assuming perfect foresight and perfect coordination between the sectors. Pathways aiming to meet net zero while mitigating risk and uncertainty should target an earlier deployment of abatement technologies. In our model, when a high enough CP is added, abatement is deployed in industry as soon as possible as it is reduces cost over the entire time horizon.

3.6 Impact of BTA as incentive

It is of interest to investigate how UK industries can retain competitiveness while decarbonising. The industrial sectors are connected to global markets hence low-carbon British products may compete with high-carbon products from other countries. One option to protect British industry may be a border tax adjustment (BTA). It would entail taxing imports by their carbon intensity, advantaging local low-carbon production. A BTA would aim to balance out the cost of carbon capture, the carbon price on residual emissions, and the cost of BECCS offsets.

We allow the import ratio to vary and conduct runs under varying BTAs for cement, steel, and petrochemicals. Figure 3.5 shows the results for steel. With the current assumption for import costs, without a BTA, secondary steelmaking and imports are preferred. Raising it forces conventional production, and a high enough BTA leads to local low-carbon production being optimal.

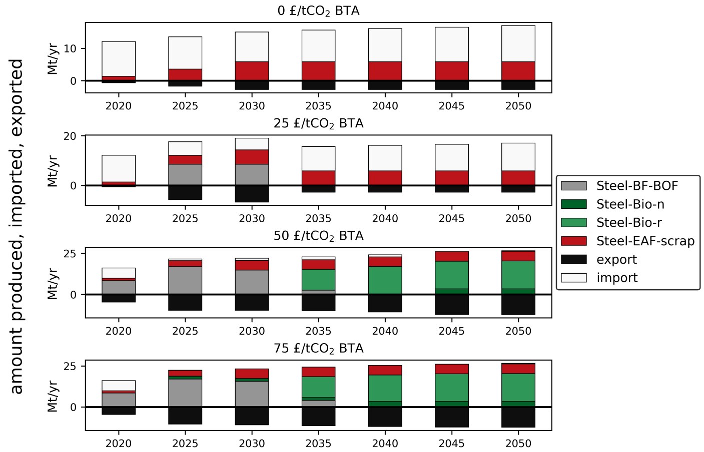


Figure 3.5: Sensitivity of steel production to a border tax adjustment (BTA). Rising BTA forces first conventional domestic production, then retrofit of capacity, and new-build low-carbon plants.

3.7 Trajectories under varying CP and NEC

Pathways to net zero for power and industry may be incentivised not only with carbon budgets, but with other policy instruments as well. Importantly, given the importance of carbon removal to achieving climate targets, it is important to recognise that this will not be deployed in the absence of a commercial incentive [75]. To this end, we investigate the impact of carbon price (CP) and negative emissions credit (NEC) on power and industry without an emissions constraint. Here the CP is added to the operating cost for emitters, while the NEC is subtracted from it in the case of BECCS and Steel-Bio. The CP and NEC in 2020 are set to 18 and 0 £/t-CO_2, their respective current values. They then increase linearly to their final value in 2050 by which they are identified. We choose a range of 0-300 £/t-CO_2 for the CP and 50-200 £/t-CO_2 for the NEC in 2050. For the sensitivity analysis with both CP and NEC, the optimality gap (optcr/epgap) is adjusted to 1%.

First, the CP necessary to force decarbonisation in industry in the abate & offset scenario is analysed in figure 3.6. Even without a CP, secondary steelmaking from scrap is expanded up to the projected availability of scrap. At 30 £/t-CO_2, the remaining capacity of BF-BOF steel plants is retrofitted with bio-CCS.

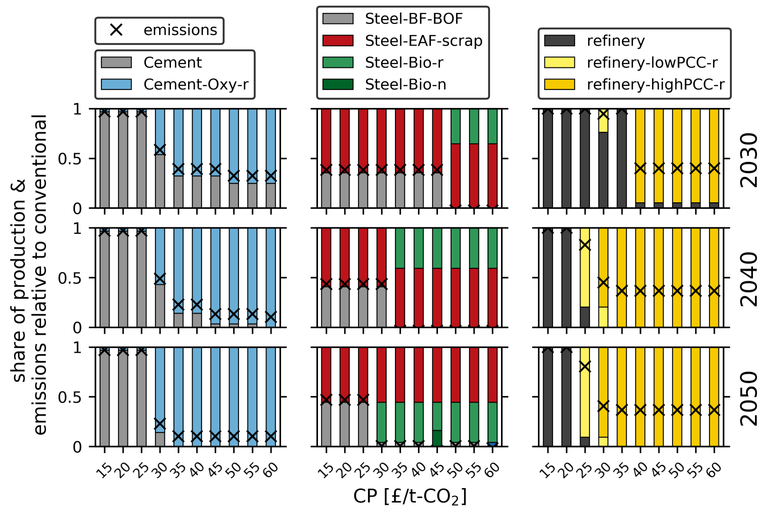


Figure 3.6: Breakdown of industrial production by technology and emissions reduction relative to conventional production for cement, steel, and refining, under a varying carbon price (CP).

The higher the CP, the sooner this transition is made (2040 for 35 £/t-CO_2 *vs.* 2030 for 50 £/t-CO_2). Refineries are retrofitted with low levels of PCC starting at 25 £/t-CO_2. At 30 £/t-CO_2, high levels of PCC are used instead in 2050. Higher CPs force this development to occur sooner. In the case of cement, 30 £/t-CO_2 leads to the deployment of some oxy-combustion as retrofit. The higher the CP, the greater the proportion of abatement at a given time. The emissions reduction differs by sector; while steel turns carbon-negative with the deployment of bio-CCS steel production, cement and refining emissions are reduced by a maximum of 90% and 63%, respectively.

In the power sector, as detailed in figure 3.7, a rising CP first results in power generation from natural gas being replaced by onshore wind and nuclear. Higher CPs shift the flexible generation from unabated CCGT to CCGT-CCS. Retrofit CCGT-CCS is first deployed at 115 £/t-CO_2, and its share of the power production increases with rising CP, until it almost completely replaces CCGT and OCGT. Even at high CP, significant amounts of CCGT and OCGT capacity (~30 GW in 2050 at CP=300 £/t-CO_2) are retained in the system and utilised on peak days and during peak hours.

The minimum CP to incentivise abatement technology deployment in industry

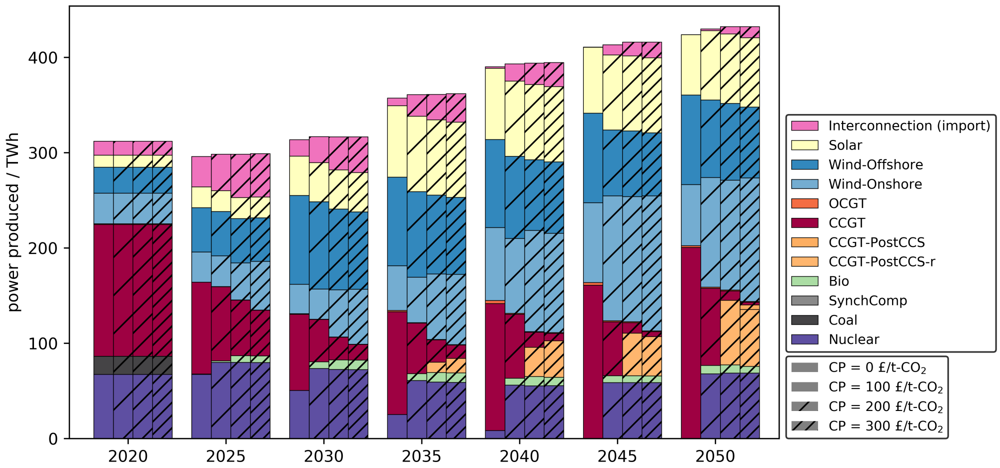


Figure 3.7: Power produced under varying carbon price (CP). Power generation is shifted from unabated gas-fired power to onshore wind and nuclear, then to CCGT-CCS.

determined using our model, with the current technology characterisation, is within the range of cost per CO_2 avoided reported in the literature [137]. They may appear to be located in the lower range of cost-of-capture estimates. It should be noted that due to the power requirements of industrial plants being covered implicitly in the model, CP tipping points are expected to be slightly lower. Additionally, the system balance being drawn around the entire power and industry sectors rather than one individual plant, as well as the characterisation of the time horizon, the costing, and cost of capital, might further contribute to discrepancies. Furthermore, several hurdles hindering the deployment of low-carbon technologies, such as risk and uncertainty, are not captured in the model. Forcing the real-world transition may therefore require higher CP.

Figure 3.8 summarises the emissions trajectories arising from the runs with CP and NEC. Several trajectories arrive at positive emissions in 2050, some lead to net zero or negative emissions, and others achieve even cumulative net zero emissions. Pathways which meet the net zero target do so at varying amounts of cumulative emissions, exemplified by the optimal trajectories of the public and private sector. Higher levels of abatement and lower emissions correspond to higher costs, and different trajectories may entail equal total costs.

The emissions in 2050, the total private sector cost, including all system CAPEX

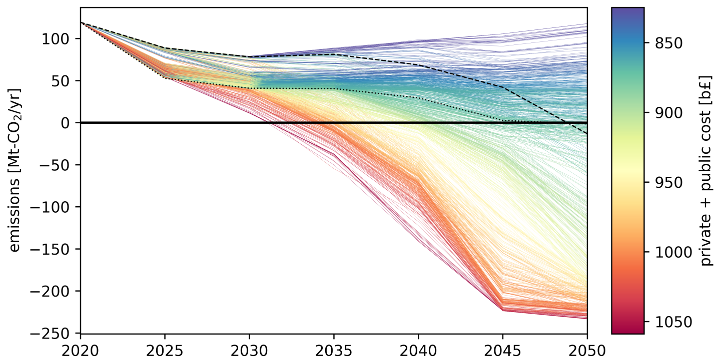


Figure 3.8: Resulting emissions trajectories from CP & NEC sensitivity runs. ⋯ is optimal from a public spending perspective; – – denotes the private sector optimum.

and OPEX, the CP paid and NEC earned, the public sector cost, comprised of CP income and NEC expenditure, total cumulative emissions, cumulative negative emissions, and private + public cost, for all cases are detailed in figure 3.9. Many combinations of CP and NEC are able to deliver net zero in our model (thin solid contour line). Higher combinations of both can achieve cumulative net zero (thick solid contour line). The discontinuities in both contour lines are estimated to be results of the increased optimality gap. With our assumptions and data, NEC values above at least 95 and 150 £/t-CO_2 combined with a sufficiently high CP lead to net zero in 2050 and cumulative net zero, respectively. The results show that a NEC is necessary to reach net zero, in line with previous findings. A NEC alone of at least 135 £/t-CO_2 accomplishes net zero at the minimum cost to the private sector – relying solely on BECCS to offset all emissions. Adding the CP reduces the cost to the public sector and decreases cumulative emissions. Indicated in the graph is the break-even line for the public sector. For every NEC granted to the negative emissions technologies, there is a minimum CP necessary to offset the cost to the public. A higher CP allows the public sector to use the penalties on emitters to support other decarbonisation efforts, such as funding R&D. The highest possible CP and the lowest required NEC constitute the public sector optimum, which is plausible as it combines highest income through penalising emitters and lowest expenditure towards BECCS. In our model, this public sector optimum is located at a NEC of 95 £/t-CO_2 and CP of 300 £/t-CO_2. In this scenario, industrial CCS, renewables, and CCS in power contribute to decarbonisation. The lowest private cost at public break-even is achieved at CP ~30 £/t-CO_2, NEC ~130 £/t-CO_2. However, this may not result in a suitable system design. At a CP this low, the deployment of industrial abatement is uncertain, so the industrial sector may not contribute to reducing emissions, and substantial emissions from gas-fired power plants remain. This places almost the entire burden of decarbonisation on BECCS – increasing the likelihood of missing climate targets. Additionally, along with other biomass-related concerns [118], it is of interest to utilise the limited biomass resources sparingly, as they might also be required for heat and transport. The public sector optimum may be closer to an acceptable target as industry would contribute here, cumulative and residual emissions would be lower, and public funds would be available for other incentives. Still, one might argue such a high carbon price would place an undue burden on industry and emitters in power. A compromise might therefore be located at a point where industrial decarbonisation is forced but further increases in CP do not meaningfully reduce cumulative emissions, for instance, at CP ~200 £/t-CO_2 and NEC ~100 £/t-CO_2. The total, *i.e.* public + private sector cost, which is equal to the system cost without incentives and a measure of total transition cost, rises both with rising CP and NEC, with a much higher sensitivity to the NEC. This is indicative of the fact that policy instruments move the system away from lowest cost and BAU emissions to lower emissions at higher cost.

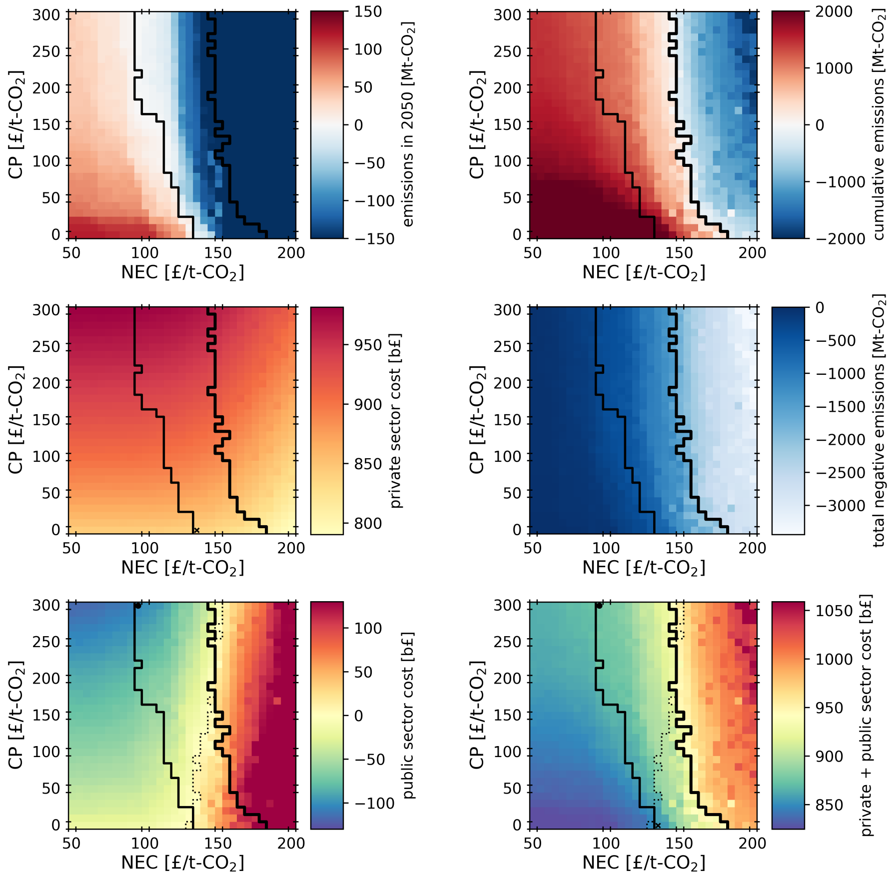


Figure 3.9: Emissions in 2050, private sector cost, public sector cost, cumulative emissions, total negative emissions, and total cost for varying carbon price (CP) and negative emissions credit (NEC). Thin and thick solid contour lines show the boundaries for net zero in 2050 and cumulative net zero, respectively. $\cdots$ shows the break-even for the public sector. $\times$ denotes the private sector optimum, $\bullet$ denotes the public sector optimum.

3.8 Summary

In this chapter, a model was built to optimise pathways for power and industry undergoing decarbonisation, and a corresponding data set for the UK was curated. Cement, steel, and refining were modelled explicitly, including various abatement options. A description of trade and scenarios for import and export were developed, to then analyse trajectories for both sectors. Results suggest that under a net zero carbon target in 2050 with a linear trajectory, deploying abatement is cost-optimal over BECCS offsets in all three industrial sectors. CCS is optimally deployed first in industry, where an emissions reduction of 90% overall is achieved, and then in power. Offshoring industrial emissions, maintaining domestic production, or expanding it and exporting low-carbon products is found to have little impact on the trajectory for the power system as the amount of residual emissions in industry is low.

It was demonstrated how a border tax adjustment might incentivise domestic low-carbon production rather than import of high-carbon commodities. The model was further utilised to identify pathways which achieve net zero as a result of a carbon price and negative emissions credit. More work is needed on comparing policy instruments to prevent carbon leakage and retain competitiveness in industry.

We continuously improve our model formulation and data set. We hope to add more granularity and abatement technologies, for example, calcium looping for steel [163], as well as industrial sectors – such as the chemical industry with its high purity sources. Modelling industrial demand side response, how it might reduce peak demand or seasonality for the power sector, is also of interest.

Better data on industrial abatement technologies is required to accurately assess decarbonisation in industry. Pilot projects can offer better insights on the true cost of the technology and function as crucial step on the way to actual low-carbon production of industrial goods. Carbon capture in industry may be cheaper than and therefore optimally precede CCS in power – hence progress in this area is needed. Power and industry are the two sectors where capture from large point sources is possible – they should be at the forefront of decarbonisation efforts. Furthermore, industry and BECCS at least are expected to generate captured CO_2, therefore systems providing transport and sequestration can ease the transition and de-risk CCS projects.

Furthermore, it is worth pointing out that the optimal way for an economy to operate would not only be zero-carbon, but also post-fossil, independent of non-renewable resources, and environmentally friendly. Every step toward a circular economy, every resource recycled rather than produced from raw materials can reduce emissions today and mitigate the overall environmental impact outside of global warming potential in the long-term. New concepts, processes, and technologies are needed in many sectors of the economy on the path toward a sustainable future.

Chapter 4

The Public Viewpoint: The Transition through a Socio-Economic Lens

4.1 The energy transition and the economy

Transition pathways to net zero emissions have impacts on a socio-economic layer. The power and industry sectors generate gross value added (GVA) in the economy, contributing to economic growth, and provide employment opportunities. Climate change mitigation is linked with the sustainable development goals (SDGs) [164], most closely with goal 7 – affordable and clean energy, goal 8 – economic growth, employment and decent work, goal 9 – resilient infrastructure, sustainable industrialisation, and goal 13 – combat climate change and its impacts. Both trade-offs and synergies between the goals are conceivable. Conflicts can exist between labour and environmental movements, manifesting in trade-offs between saving jobs and saving the climate [165]. This becomes apparent, for instance, in discussions around the coal sector and supply chain [166]. Conversely, when strategies for power and industry not only mitigate climate change but also result in economic growth and job creation, synergies between the individual goals are achieved. This connection is referenced by the IPCC [2], and a potential for "green collar jobs" and "value of exports from the low carbon economy" is proclaimed by the UK government [13]. In addition, the concept of a "fair" or "just" transition is recently gaining interest. It is mentioned in the preamble of the Paris Agreement [7], the IPCC special report [2], and pledges from both the public and private sectors at COP26 [167]. The EU maintains a Just Transition Mechanism as well as a Just Transition Fund [168, 169], aiming to support regions which are projected to be adversely effected by the energy transition *via* financing research, reskilling workers, transforming existing, and creating new firms. Just transition initiatives exist in countries around the world, many of them focusing on jobs [170]. In the UK, the private sector claims to generate jobs in decarbonisation efforts, however, there is no synchronised methodology across projects and sectors [171].

Value and job creation of low-carbon technologies and energy transition scenarios have been assessed using several methods, including employment ratios/factors/values, supply chain analysis, input-output modelling, ex-post analysis of historical data, and computable general equilibrium (CGE) models [172, 173]. Some analyses distinguish between direct, indirect, and induced jobs [174], however there exists variation with regard to their definitions [175]. Generally, direct effects are associated with construction and operation of assets, indirect effects originate within the supply chains of these assets, and induced effects result from the increased spending in the economy due to the direct and indirect effects [176]. In the literature, the power sector has received more attention compared to the industrial sector, with a pronounced focus on the potential job creation by renewable energy sources [173]. Furthermore, the amount of qualitative analysis and arguments appears to outweigh modelling results and quantitative analysis. One author asserts that the field lacks empirical studies in favour of analytical frameworks [165], another declaring the field exhibits a high degree of reusing and recycling existing data but little original research [173].

The minority of reviewed sources present transition impacts on gross value added (GVA) or gross domestic product (GDP). Turner *et al.* estimate value added, GDP and job creation for industrial supply chains undergoing decarbonisation, with a focus on the German cement sector. They consider offshoring industrial emissions and carbon leakage, noting it will likely displace jobs and GDP along the supply chain [177]. More recently, they calculate macroeconomic impacts of deploying CO_2 transport and storage (T&S) infrastructure in Scotland using a dynamic CGE, casting doubts on socio-economic benefits [178]. Patrizio *et al.* estimate socio-economic impacts of a range of scenarios across SDG indicators including GVA and employment for the power sector, finding both improvements and declines depending on country and decarbonisation strategy [50]. In a recent study, they focus on hydrogen as low-carbon fuel as part of the decarbonisation strategy and quantify the value creation on a regional level in the UK [179].

Greater numbers of publications centre around the effects of transition scenarios on employment. Research focused on renewable energy suggests there is a high variation of employment factors for PV, concentrated solar power (CSP), and wind, expected to decrease due to technology learning and economies of scale [173], and that hydro and bioenergy have the highest economic impacts among the renewable energy sources [180], noting that these are diminished by increased import shares. Several analyses maintain that transformations towards renewable energy offer a gross job creation [174, 181], and renewable and low carbon energy sources generate more jobs per unit energy compared to fossil energy [175]. Jacobson *et al.* use the JEDI model to determine jobs lost and created for an energy transition to wind-water-solar (WWS) for the entire economy (including electricity, transport, heat, industry, *etc.*) for various countries and regions world-wide. They compare WWS *vs.* a BAU scenario, seeing job losses in the mining & extraction, refining, and other fossil fuel infrastructure sectors, and gains in construction and operation of renewable energy capacity, which offset the lost jobs, creating more jobs overall [182]. Similarly, using employment factors or job creation by technology, a study calculates employment generated for 50 countries and finds that decarbonisation creates jobs compared to a reference, with job losses in fossil resources and job gains in wind and solar [183]. The Inter-American Development Bank and International Labor Organization also project job losses in fossil electricity and extraction, which are offset by job gains in agriculture, renewable electricity and other sectors, calling for policy to support the reallocation of workers [184]. An EU-centred analysis estimates that the potential of replacing coal jobs with employment in renewable energy (PV, wind, geothermal, bio, CCS) varies by region, and suggests that coal regions can actively contribute to the energy transition with cooperation between the actors – private sector, policy makers, communities – being essential [185]. A study by the European Commission estimates the impact of the transition on GDP and employment as "small but positive" [20]. The report emphasises the need for reskilling, retraining, and reallocating workers. A study of the US coal sector suggests employment can be saved by deploying BECCS, and even create jobs along the BECCS supply chain [166]. Analysis utilising an input-output methodology also finds job losses in mining & extraction, refining, and related to coal and natural gas, and job creation in construction, manufacture of electrical parts and machinery, related to renewable power generation, totalling at slightly positive net effects [186]. They further suggest there may be disparities in location and skill, so incentives may be needed to reallocate jobs. Trajectories will depend on the country, and transitions need to be guided by policy to mitigate negative effects and take advantage of positive effects. A constant world trade structure is assumed, neglecting adjustment effects and productivity increases. A meta analysis of publications relating to the question of green jobs arrives at "reasonable evidence from the literature that renewable energy and energy efficiency are more labour-intensive than fossil-fired generation" [187]. The need for an appropriate counterfactual to which to compare a given scenario is emphasised. The study also alerts to the question of whether a shift of the technology mix towards more labour intensive is desirable in the long-term compared to a more efficient system, recognising that the main benefit of the transition remains a low/zero carbon economy. Another analysis using a multi-region, multi-sectoral dynamic CGE model quantifies the employment per energy produced for various energy sources. Job reallocation is calculated for a decarbonisation scenario, estimating job losses in fossil fuels and energy-intensive industries, opposite job gains in agriculture, construction, and electricity, with narrowly net positive employment [188]. When the skill level is included in a calculation of employment based on employment factors of energy activities, a higher level of qualification is forecast for decarbonisation scenarios in addition to rising employment levels [189]. With regard to the protection of local economies, some argue incentivising local production and taxing production elsewhere disrupts global supply chains and impedes progress of the transition rather than create jobs [190]. Recovery from the economic shock of COVID-19 in a green way could be a chance to protect jobs and generate new green jobs [191]. It is worth noting that whilst fossil energy vectors – oil, coal, natural gas – are traded internationally, supply chains for components of low-carbon technologies are also global, energy transition pathways therefore remain inherently linked to geopolitics [192]. Further, access to several scarce resources required for the manufacture of low-carbon technologies, such as lithium, cobalt, iridium, and rare earth metals, is unevenly distributed internationally, potentially leading to the replacement of old with new global dependencies [190, 192, 193].

Again, there appears to be significant qualitative discussion around the topics of the "just transition" [194], the "green state" [195], economic growth and job creation associated with the energy transition, and only limited quantitative analysis. Existing work focuses on the power sector, with few sources discussing industry. Therefore, in this work, the impact of various transition pathways on GVA and employment in the power and industry sectors is quantified. In section 4.2, a calculation of GVA and jobs is integrated into the modelling framework. The required data set is collected, and the necessary pre-processing is carried out. In section 4.3, scenarios with varying local share of production are defined, enabling an empirical assessment of the importance of import dependence. Value and job creation per sector, technology, over time, for various scenarios, and compared to a BAU reference case, are analysed in section 4.4. A summary of the findings, conclusions, and directions for future work are provided in section 4.5.

4.2 Estimating GVA and employment for power and industry

For the purposes of this work, the *Jobs and Economic Development Impacts (JEDI)* methodology is applied to the model [196]. The approach follows previous work with JEDI [166, 50] to an extent. It is summarised in figure 4.1. As the model objective is cost minimisation, the expenditure is known for a given scenario. It is comprised of CAPEX of building new capacity, fixed OPEX and various variable OPEX components, such as fuel cost, of operating the capacity, in both the power and the industrial sector. In the

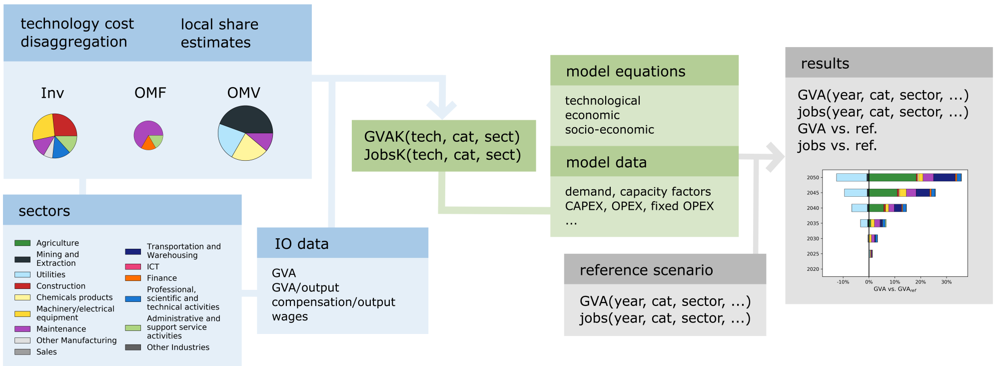


Figure 4.1: JEDI methodology. In pre-processing, expenditure is disaggregated and assigned to sectors, local shares are estimated, both are combined with input/output data from socio-economic databases into multipliers. GVA/jobs calculations are integrated into the model. Results, per sector, time, and overall, are reported in total and in comparison to reference case.

JEDI context, the costs are termed *output* and separated by category – Inv for investment, *i.e.*, CAPEX, OMF for fixed operating and maintenance costs, and OMV for variable operating and maintenance cost. The output is further disaggregated into its components based on techno-economic analysis in the literature. Inv costs consist of equipment cost, installation cost, building cost, engineering, land, *etc.*, OMF includes maintenance cost and insurance, while fuel and raw material costs are counted towards OMV. All the individual cost/output components are then assigned to the sector of the economy in which they are assumed to generate GVA and jobs. The allocation to 31 OECD sectors is carried out based on the *International Standard Industrial Classification of All Economic Activities (ISIC)* by the UN [197], then these sectors are condensed to 15 JEDI sectors (see table C.2). The costs of coal, limestone, iron ore, and crude oil, for instance, are assigned to the mining & extraction sector; installation costs and cost of buildings are assigned to the construction sector; *etc.* Further, for every cost component the *local share* – the fraction of all value that is created in the local economy as opposed to abroad – is estimated and then multiplied by the output. The $\frac{\mathrm{GVA}}{\mathrm{output}}$ and $\frac{\mathrm{jobs}}{\mathrm{output}}$ specific to every sector are calculated based on socio-economic databases. Multiplication of the output and the GVA/jobs per output finally yields the GVA/jobs generated per technology, sector, category and year.

In practice, this approach is split into pre-processing and calculations within the model. Both are detailed in the following. The pre-processing includes the disaggregation of the technology costs, their assignment to the economic sectors, estimation of the local shares, and calculations of GVA and jobs per output based on the socio-economic databases. First, for every cost component, the real cost $\mathrm{cost'}^{\mathrm{cat}}_{i,\mathrm{sect}}$ is defined as product of the cost component $\mathrm{cost}^{\mathrm{cat}}_{i,\mathrm{sect}}$ and its assumed local share $\mathrm{LS}^{\mathrm{cat}}_{i,\mathrm{sect}}$ for technologies i, economic sectors sect and cost categories cat:

$$\mathrm{cost'}^{\mathrm{cat}}_{i,\mathrm{sect}} = \mathrm{cost}^{\mathrm{cat}}_{i,\mathrm{sect}} \cdot \mathrm{LS}^{\mathrm{cat}}_{i,\mathrm{sect}} \tag{4.1}$$

The multipliers $\mathrm{GVAK}^{\mathrm{cat}}_{i,\mathrm{sect}}$ for GVA (in units of $\frac{\mathrm{m£}}{\mathrm{m£}}$) are then obtained by considering the share of output per sector of the total output and multiplying it by this sector's $\left(\frac{\mathrm{GVA}}{\mathrm{output}}\right)$:

$$\mathrm{GVAK}^{\mathrm{cat}}_{i,\mathrm{sect}} = \frac{\mathrm{cost'}^{\mathrm{cat}}_{i,\mathrm{sect}}}{\sum_{\mathrm{sect}} \mathrm{cost}^{\mathrm{cat}}_{i,\mathrm{sect}}} \cdot \left(\frac{\mathrm{GVA}}{\mathrm{output}}\right)_{\mathrm{sect}} \tag{4.2}$$
$$\mathrm{cat} \in \{\mathrm{Inv}, \mathrm{OMF}, \mathrm{OMV}\}$$

Similarly, equation 4.3 defines the multipliers $\mathrm{JobsK}^{\mathrm{cat}}_{i,\mathrm{sect}}$ (in units of $\frac{\mathrm{jobs}}{\mathrm{m£}}$) for jobs. Here, the $\frac{\mathrm{jobs}}{\mathrm{output}}$ is calculated based on the sector's $\left(\frac{\mathrm{GVA}}{\mathrm{output}}\right)$, $\mathrm{GVA}_{\mathrm{sect}}$, compensation $\mathrm{comp}_{\mathrm{sect}}$ and wages $\mathrm{wage}_{\mathrm{sect}}$.

$$\mathrm{JobsK}^{\mathrm{cat}}_{i,\mathrm{sect}} = \frac{\mathrm{cost'}^{\mathrm{cat}}_{i,\mathrm{sect}}}{\sum_{\mathrm{sect}} \mathrm{cost}^{\mathrm{cat}}_{i,\mathrm{sect}}} \cdot \left(\frac{\mathrm{GVA}}{\mathrm{output}}\right)_{\mathrm{sect}} \cdot \frac{\mathrm{comp}_{\mathrm{sect}}}{\mathrm{GVA}_{\mathrm{sect}}} \cdot \frac{1}{\mathrm{wage}_{\mathrm{sect}}} \tag{4.3}$$
$$\mathrm{cat} \in \{\mathrm{Inv}, \mathrm{OMF}, \mathrm{OMV}\}$$

The multipliers are specific to the technology i, cost category cat and economic sector sect. They further reflect the assumptions around the country's economy *via* the inclusion of the socio-economic indicators and the estimated local shares. They are saved and then constitute input parameters to the optimisation model, where they are incorporated in the following equations. The investment GVA in power and industry is calculated in equations 4.4 and 4.5, respectively, as functions of technology CAPEX and GVA multipliers:

$$\text{GVASectInv}^{p}_{sect,a} = \sum_{ip} \text{CAPEX}_{ip} b_{ip,a} Des_{ip} \text{WFA}_{ip,a} \text{GVAK}^{\text{Inv}}_{ip,\text{sect}} / Disc_a \tag{4.4}$$

$$\text{GVASectInv}^{i}_{sect,a} = \sum_{ii} \text{CAPEX}_{ii} b_{ii,a} Des_{ii} \text{WFA}_{ii,a} \text{GVAK}^{\text{Inv}}_{ii,\text{sect}} / Disc_a \tag{4.5}$$

Equations 4.6 and 4.7 define the operating and maintenance GVA for power and industry as the sum of OMF and OMV GVA. They each contain a separate term for CO_2 transport and storage (TS).

$$\begin{aligned} \text{GVASectOM}^{p}_{sect,a} = & \sum_{ipg,c,t} (OPEXSU_{ipg} u_{ipg,a,c,t} + OPEX_{ipg,a} p_{ipg,a,c,t} \\ & + OPEXNL_{ipg} n_{ipg,a,c,t}) WF_{ca} \text{GVAK}^{OMV}_{ipg,\text{sect}} / Disc_a \\ & + \sum_{ips,c,t} (OPEX_{ips,a} s2d_{ips,a,c,t} + OPEXNL_{ips} o_{ips,a,c,t}) \\ & WF_{ac} \text{GVAK}^{\text{OMV}}_{ips,\text{sect}} / Disc_a \\ & + \sum_{ip} d_{ip,a} Des_{ip} CAPEX_{ip} OPEXFix_{ip} \text{GVAK}^{OMF}_{ip,\text{sect}} / Disc_a \\ & + \sum_{ipg,c,t} p_{ipg,a,c,t} TE^{emsts}_{ipg} TScost_a WF_{ca} \text{GVAK}^{\text{OMV}}_{\text{"}TS\text{"},\text{sect}} / Disc_a \end{aligned} \tag{4.6}$$

$$\begin{aligned} \text{GVASectOM}^{i}_{sect,a} = & \sum_{ii,comm} OPEX_{ii,a} pInd_{a,ii,comm} \text{GVAK}^{\text{OMV}}_{ii,\text{sect}} / Disc_a \\ & + \sum_{ii} Des_{ii} q_{ii,a} IOPEXFix_{ii} \text{GVAK}^{\text{OMF}}_{ii,\text{sect}} / Disc_a \\ & + \sum_{ii,comm} pInd_{a,ii,comm} ITech^{emsts}_{ii} TScost_a \text{GVAK}^{\text{OMV}}_{\text{"}TS\text{"},\text{sect}} / Disc_a \end{aligned} \tag{4.7}$$

The GVA can then be summed up across power and industry:

$$\text{GVASectInv}_{sect,a} = \text{GVASectInv}^{p}_{sect,a} + \text{GVASectInv}^{i}_{sect,a} \tag{4.8}$$

$$\text{GVASectOM}_{sect,a} = \text{GVASectOM}^{p}_{sect,a} + \text{GVASectOM}^{i}_{sect,a} \tag{4.9}$$

When defining the total GVA per sector over the time horizon in equation 4.10, the weights for each of the planning periods (years) have to be considered. Following the trapezoid rule, 2020 and 2050 as first and last planning periods each represent 2.5 years, while every other year represents 5 years.

$$\begin{aligned}\text{GVASect}_{sect} = \sum_{a} \text{GVASectInv}_{sect,a} \\ + 2.5 \cdot \sum_{a \in \{1,7\}} \text{GVASectOM}_{sect,a} + 5 \cdot \sum_{2 \leq a \leq 6} \text{GVASectOM}_{sect,a}\end{aligned} \tag{4.10}$$

Total direct GVA generated by the system can then be calculated as the sum over all sectors.

$$\text{GVAdir} = \sum_{sect} \text{GVASect}_{sect} \tag{4.11}$$

The equations governing the employment created by the system design and operation follow the same principle. Equations 4.13 and 4.12 define the investment jobs. Note that the weighing factor WFA_{ia} for the end of the time horizon is not applied here since the jobs are created during the construction period of the plant regardless of planning period and plant lifetime.

$$\text{JobsSectInv}^{p}_{sect,a} = \sum_{ip} \text{CAPEX}_{ip} b_{ip,a} Des_{ip} \text{JobsK}^{\text{Inv}}_{ip,\text{sect}} \tag{4.12}$$

$$\text{JobsSectInv}^{i}_{sect,a} = \sum_{ii} \text{CAPEX}_{ii} b_{ii,a} Des_{ii} \text{JobsK}^{\text{Inv}}_{ii,\text{sect}} \tag{4.13}$$

The operating and maintenance jobs are calculated in equations 4.14 and 4.15 by summing the various OPEX contributions. In contrast to GVA, the employment estimates are not subjected to the discount factor $Disc_a$. Any effect of the changing value of money should cancel out in this calculation as the results are in terms of jobs and not in monetary units.

$$\begin{aligned}\text{JobsSectOM}^{p}_{sect,a} = &\sum_{ipg,c,t} (OPEXSU_{ipg} u_{ipg,a,c,t} + OPEX_{ipg,a} p_{ipg,a,c,t} \\ &+ OPEXNL_{ipg} n_{ipg,a,c,t}) WF_{ca} \text{JobsK}^{\text{OMV}}_{ipg,\text{sect}} \\ &+ \sum_{ips,c,t} (OPEX_{ips,a} s2d_{ips,a,c,t} + OPEXNL_{ips} o_{ips,a,c,t}) \\ &WF_{ac} \text{JobsK}^{\text{OMV}}_{ips,\text{sect}} \\ &+ \sum_{ip} d_{ip,a} Des_{ip} CAPEX_{ip} OPEXFix_{ip} \text{JobsK}^{\text{OMF}}_{ip,\text{sect}} \\ &+ \sum_{ipg,c,t} p_{ipg,a,c,t} TE^{emsts}_{ipg} TScost_a WF_{ca} \text{JobsK}^{\text{OMV}}_{\text{"}TS\text{"},\text{sect}}\end{aligned} \tag{4.14}$$

$$\begin{aligned}\text{JobsSectOM}^{i}_{sect,a} = &\sum_{ii,comm} OPEX_{ii,a} pInd_{a,ii,comm} \text{JobsK}^{\text{OMV}}_{ii,\text{sect}} \\ &+ \sum_{ii} Des_{ii} q_{ii,a} IOPEXFix_{ii} \text{JobsK}^{\text{OMF}}_{ii,\text{sect}} \\ &+ \sum_{ii,comm} pInd_{a,ii,comm} ITech^{emsts}_{ii} TScost_a \text{JobsK}^{\text{OMV}}_{\text{"}TS\text{"},\text{sect}}\end{aligned} \tag{4.15}$$

Employment can then be summed up over the power and industrial sectors (equations 4.16 and 4.17), over time (4.18), and finally, across economical sectors (4.19).

$$\text{JobsSectInv}_{sect,a} = \text{JobsSectInv}^{p}_{sect,a} + \text{JobsSectInv}^{i}_{sect,a} \tag{4.16}$$

$$\text{JobsSectOM}_{sect,a} = \text{JobsSectOM}^{p}_{sect,a} + \text{JobsSectOM}^{i}_{sect,a} \tag{4.17}$$

$$\begin{aligned}\text{JobsSect}_{sect} = &\sum_{a} \text{JobsSectInv}_{sect,a} \\ &+ 2.5 \cdot \sum_{a\in\{1,7\}} \text{JobsSectOM}_{sect,a} + 5 \cdot \sum_{2\leq a\leq 6} \text{JobsSectOM}_{sect,a}\end{aligned} \tag{4.18}$$

$$\text{Jobs} = \sum_{sect} \text{JobsSect}_{sect} \tag{4.19}$$

Parts of the total system cost do not generate value or employment and therefore do not enter the GVA/employment calculations. This includes the carbon price paid, negative emissions credit earned, cost of imported power, and the cost and revenue from import and export of industrial products. Further, only the explicitly modelled industrial sectors (cement, iron and steel, refining) have influence on the GVA and employment.

The socio-economic data for the UK (GVA/output, GVA, compensation, compensation/output, wages) is obtained from the Office for National Statistics (ONS) [198, 199, 200] for the year 2016, and summarised in table C.1 in the appendix. One job in this context refers to one year of full time equivalent (FTE), *i.e.*, full time employment for one person for one year. Within this methodology, only direct jobs are considered, indirect and induced jobs are not estimated. The power sector data is adapted based on a previous study employing ESO and JEDI [50], originally obtained from IRENA, NREL, US EIA and other sources [201, 202, 203, 204, 205]. Interconnection and synchronous compensator are excluded in this analysis due to a lack of data. Their impact on GVA and jobs is estimated to be minor. Techno-economic data for the industrial sectors appears to be scarce. For the cement sector, the cost disaggregation follows the recent study by SINTEF [157, 158], which provided the basis for the cost data used in the model, and the economic evaluation therein [206, 207]. The breakdowns of capital and operating costs are derived using the published techno-economic data, estimates are added when needed. Electricity is again excluded from the breakdowns since it is accounted for implicitly in the model. In case of steel, the literature sources used in the previous chapter as the basis for the emissions and cost data do not provide cost breakdowns in sufficient detail. Therefore, new sources with techno-economic analysis are used. For conventional steel production (Steel-BF-BOF), and steel with CCS archetypes (Steel-BF-BOF-CCS-r, Steel-BF-BOF-CCS-n, Steel-BF-BOF-highCCS-r, Steel-BF-BOF-highCCS-n) data is adapted from Hooey *et al.* [208]. A recent report by the IEAGHG on negative emissions technologies [209] is used as source for cost breakdowns of steel production with biomass (Steel-Bio-r, Steel-Bio-n). Cost disaggregation for steelmaking *via* direct reduction with hydrogen is performed using data in Jacobasch *et al.* [210]. Gaps in the data are filled with estimated based on similar technologies. Electrowinning (Steel-EW) is excluded from this analysis due to its low technological readiness and corresponding lack of data. There is little data available for the refinery sector. The OPEX breakdown in Robinson [211] is adapted, and the capital cost breakdown is based on the original source used for cost data [162]. Transport and storage (TS) costs are separated from the operating cost for all technologies and added as a separate technology with a specified cost and cost breakdown. The biomass supply chain formulation is not used in this analysis, instead the biomass consumption is included in the OPEX, and thereby covered by the JEDI equations.

The scenarios outlined below are usually compared to a reference/BAU scenario. Here, it is assumed that the system maintains at most the current level of emissions, and no other incentives are provided. In this case, retiring capacity in industry is replaced with new-built conventional capacity, except for Steel-EAF, whose share of production increases over time. In the power sector, the capacity mix shifts towards renewable power and gas-fired CCGTs, each providing about half of the total power production in 2050.

The approach detailed above enables an examination of the socio-economic implications of a given decarbonisation scenario. It is, however, associated with shortcomings owing to its relatively simplistic nature. One major drawback is the assumption of constant socio-economic data over time. GVA, compensation, wages, are assumed to be constant throughout the time horizon, effectively presuming no changes in the structure of the economy over the decades. In actuality, these indicators are expected to change over time, which would impact the KPI defined here. Projecting these changes and impacts is outside the scope of this study and of interest in future work. Analysing the implications of automation in manufacturing, for instance, could be particularly interesting. Indirect and induced GVA and jobs are also excluded in this analysis. JEDI grants quantitative insights into GVA/employment outcomes, yet the results are inherently imprecise due to the uncertainties and assumptions in this extension of the model. They are therefore to be treated as estimates revealing tendencies, not absolute numbers.

4.3 Scenarios for local production and import dependence

The fraction of the output attributed to local production *vs.* production abroad as a function of total production directly impacts the estimated GVA and jobs contributed by a technology in a specific scenario. Certain technologies, such as solar panels and nuclear fuel, are very likely to be imported in a UK context. The maintenance included in the fixed OPEX, on the other hand, is most certainly always entirely local. In order to analyse the effects of varying local share of production and import dependence, several scenarios are analysed. In the *all local* case, almost all effects are assumed to generate GVA and jobs locally. It can be considered an optimistic scenario from the UK's perspective. It is also a way to estimate the total impact, local and abroad, of a transition scenario. For the *partial import* scenario, parts of the technologies and services are assumed to be imported, reducing the locally induced effects. The *high import* scenario presents a pessimistic case in which most local shares are zero. Table 4.1 contains an overview of the three scenarios and the local shares assumed in the power and industry sectors and the subsectors and technologies.

The UK currently depends on imports for 45% of natural gas, 89% of coal, and

83% of crude oil consumption [50, 212, 213]. These fractions are used for the partial import scenario. The import shares are set to 0 in the high import and 100% in the all local scenario. Significant shares of capacity of solar, onshore wind, nuclear power, and batteries are also currently imported, representing the partial import scenario. For many technologies there is a lack of data concerning the local share and import dependence. For those, a local share of 50% is estimated for the partial import scenario, whereas the high import scenario assumes complete import. Expenditure towards CO_2 transport and sequestration infrastructure is assumed to entirely benefit the local economy. Again, these numbers are to be understood as estimates, enabling an analysis of systems with mostly local sourcing *vs.* systems heavily dependent on imports.

Table 4.1: Assumptions for scenarios for local share and import dependence.

			local share all local	 partial import	 high import	reference
industrial sector						
cement	construction		100%	50%	0%	
	OMF		100%	100%	100%	
	OMV	coal	100%	11%	0%	[50, 212]
		other	100%	100%	100%	
steel	construction		100%	50%	0%	
	OMV	fluxes	100%	50%	0%	
		ore	100%	50%	0%	
		scrap	100%	50%	0%	
		energy: coal	100%	11%	0%	[50, 212]
		energy: NG	100%	52%	0%	[50, 212]
		biomass	100%	50%	0%	
		other	100%	100%	100%	
refineries	construction		100%	50%	0%	
	OMV	crude	100%	17%	0%	[213]
		fuel oil & gas	100%	17%	0%	[213]
		other	100%	100%	100%	
power sector						
solar	construction	hardware	100%	varies	0%	[50, 203, 214, 215]
		installation	100%	50%	0%	
	OM		100%	100%	100%	
onshore wind	construction	turbine module	100%	varies	0%	[50, 215]
		other	100%	50%	0%	
	OM		100%	100%	100%	
nuclear	construction	island & project	100%	varies	0%	[50, 205]
		other	100%	50%	0%	
	OM	fuel	0%	0%	0%	[216]
		other	100%	100%	100%	
battery	construction	battery	100%	52%	0%	[50, 217]
		other	100%	50%	0%	
	OM		100%	100%	100%	
other	construction		100%	50%	0%	
	OM	coal	100%	11%	0%	[50, 212]
		NG	100%	52%	0%	[50, 212]
		other	100%	100%	100%	

4.4 Impact of transition pathways on GVA and employment

4.4.1 Investment *vs.* maintenance, power *vs.* industry

First, the value creation for the abate & offset scenario combined with the all local assumptions is analysed. In figure 4.2 the total GVA is disaggregated by sector, category, and time. The GVA contribution of power and industry is estimated to be similar, with industry contributing 56% in this scenario. In the power sector, the most GVA is generated in the utilities, machinery, and maintenance sectors. In industry, mining and extraction represents the largest share, with smaller proportions from utilities and maintenance. Operation and maintenance accounts for most of the GVA, around 5 times the total investment GVA. Most of the operation GVA stems from mining and extraction, including coal, crude oil, iron ore, and limestone consumption, utilities, mainly from natural gas consumption, and maintenance. Machinery represents the largest share of investment GVA, followed by construction, maintenance, and finance.

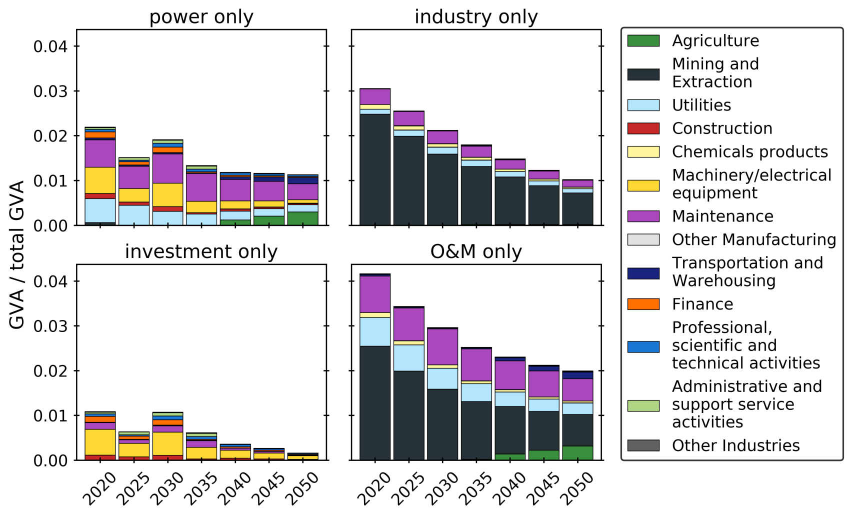


Figure 4.2: GVA as fraction of total GVA in power and industry, generated by investment and operation, by sector and over time for the abate & offset, all local scenario.

The high GVA in machinery and construction in the early time steps reflects the capacity expansion in the power sector. Utilities GVA decreases over time as a result of the reduced share of gas-fired power. Towards the end of the time horizon GVA in agriculture and transportation increases alongside the deployment of BECCS and industrial CCS.

Figure 4.3 shows the same breakdowns for job creation. It appears more jobs – around two thirds of total jobs – are created in the power sector compared to industry, and by O&M – also around two thirds of total jobs – compared to investment. Annual jobs increase in the power sector and overall, while decreasing slightly in industry. The majority of jobs in industry are maintenance jobs, whereas the jobs in the power sector are a combination of construction and maintenance jobs. The sectors machinery, maintenance, construction, and professional activities contribute the most among the investment jobs. Most of the O&M jobs are within the maintenance and mining sectors, with smaller shares in the utilities and agriculture sectors. The utilities sector notably contributes more to GVA than to jobs. The stable level of investment jobs throughout the decades reflects the constant investment and capacity expansion necessary to achieve the transition. Again, an increase in employment in agriculture and transportation is a result of the deployment of BECCS and industrial CCS.

In figures 4.4 and 4.5, the total GVA and total jobs over the time horizon created by individual technologies are detailed. More than half of power GVA and jobs are contributed by intermittent renewable energy sources – solar, onshore and offshore wind, with offshore wind alone accounting for more than 30%. BECCS, new-built and retrofit, is estimated to create similar levels of value and employment as nuclear power, around 10% of GVA and 14% of jobs. Gas-fired power contributes a higher share to GVA compared to jobs relative to the other technologies.

In industry, the refinery sector generates around three quarters of the GVA and employment. Steel production, conventional, low carbon and carbon negative, accounts for most of the remaining quarter, while cement plants create very little value added and jobs. The breakdown within the industrial sectors by technology mirrors the technologies' shares of production summarised over time.

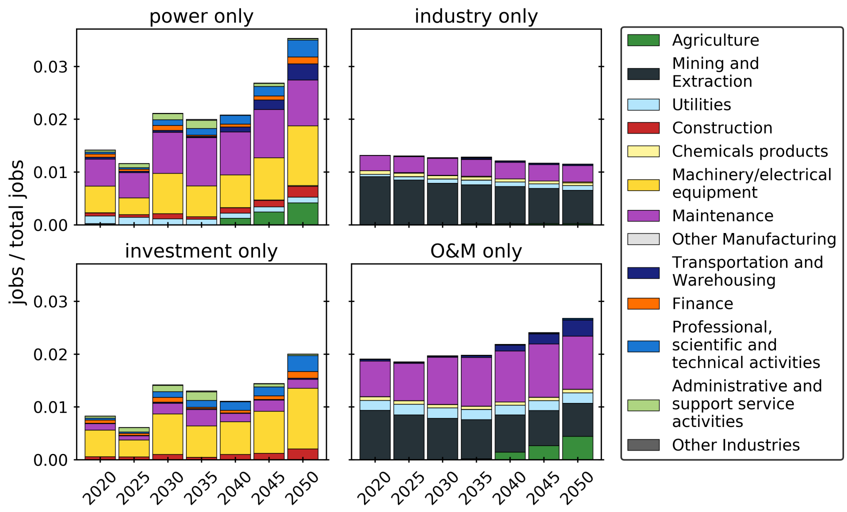


Figure 4.3: Jobs as fraction of total jobs in power and industry, generated by investment and maintenance, by sector and over time for the abate & offset, all local scenario.

The total GVA per technology differs by scenario. In the BAU reference scenario (maintaining at most the current level of emissions), CCGT generates 31% of power sector GVA. In the presence of a net zero target, this is displaced by GVA from nuclear and BECCS. In scenarios without abatement in industry (reference/BAU, BAU & offset, import & offshore) the only low carbon technology in industry is Steel-EAF with 10% of GVA. The compositions are very similar amongst scenarios with abatement in industry (abate & offset, export & offset).

The breakdowns of jobs are similar to the GVA breakdowns. In the reference scenario, almost three quarters of jobs are generated by intermittent renewable generation capacity. The contribution of Steel-EAF to jobs is higher than to GVA, while CCGT capacity induces less employment than GVA.

When higher import shares are assumed, the relative contributions of offshore wind, nuclear, steel, particularly EAF-scrap, and the cement technologies increase, while those of the other technologies decrease. In most of the scenarios the power sector generates more value (41-79% of total GVA) than industry, and in all scenarios it generates more employment (52%-83% of all jobs) compared to industry.

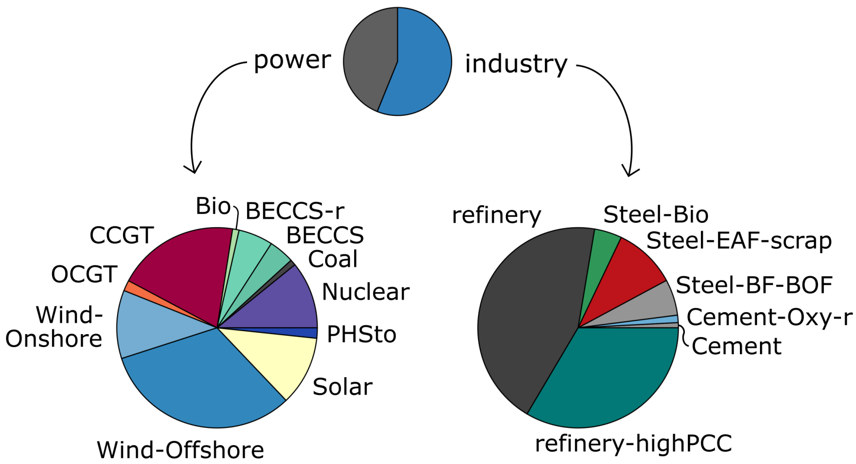


Figure 4.4: Total GVA by technology for the abate & offset, all local scenario.

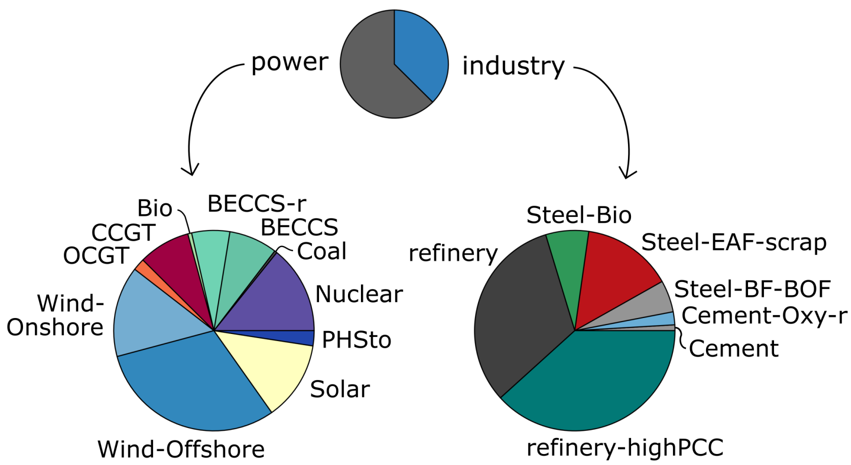


Figure 4.5: Total jobs by technology for the abate & offset, all local scenario.

Analysis of GVA and employment by technology at the end of the time horizon reveals that in the all local case in net zero systems around half of GVA and jobs in 2050 are contributed by BECCS, retrofit and new-built. In scenarios with lower local shares, BECCS represents around a third of total GVA and employment. The next highest contributions in the power sector is offshore wind, with a quarter to a third of GVA and jobs in 2050. When abatement in industry is permitted, almost the entire GVA and job creation in 2050 stems from low carbon or carbon negative technologies, following the technology mix.

4.4.2 Value and job creation for varying scenarios

In this section, value and job creation are compared across both the trade scenarios for the industrial sector – reference/BAU (ref), BAU & offset (b), abate & offset (a), import & offshore (i), abate & export (e) – and the scenarios for local and import share of the technologies and services – all local, partial import, high import. Figure 4.6 depicts the total GVA as well as the GVA increase and decrease relative to the respective reference case for all combinations of the scenarios. It is clear that the assumptions around local *vs.* import share dictate the magnitude of estimated total GVA over the time horizon. In partial import scenarios, total GVA is around half compared to all local, and GVA in the high import scenarios is halved again compared to partial import. The reference scenarios generate roughly 260 b£, 121 b£, and 60 b£ of GVA, for all local, partial, and high import, respectively. Under all local assumptions, the highest contributing sectors are mining & extraction, maintenance, utilities, and machinery/electrical equipment. In scenarios with partial import, GVA in most sectors is reduced, and maintenance provides half the GVA, with mining, utilities, and machinery supplying most of the remaining half. In the case of high import, the bulk of GVA is generated in the maintenance sector, with minor contributions in utilities and transport. This reflects the assumptions of fixed OPEX always contributing to the local economy, whereas output towards construction and variable OPEX such as fuel and raw material costs are varied for the local/import scenarios.

A comparison of the industrial sector scenarios *vs.* the respective reference scenario reveals the impact of deploying abatement in power and industry on

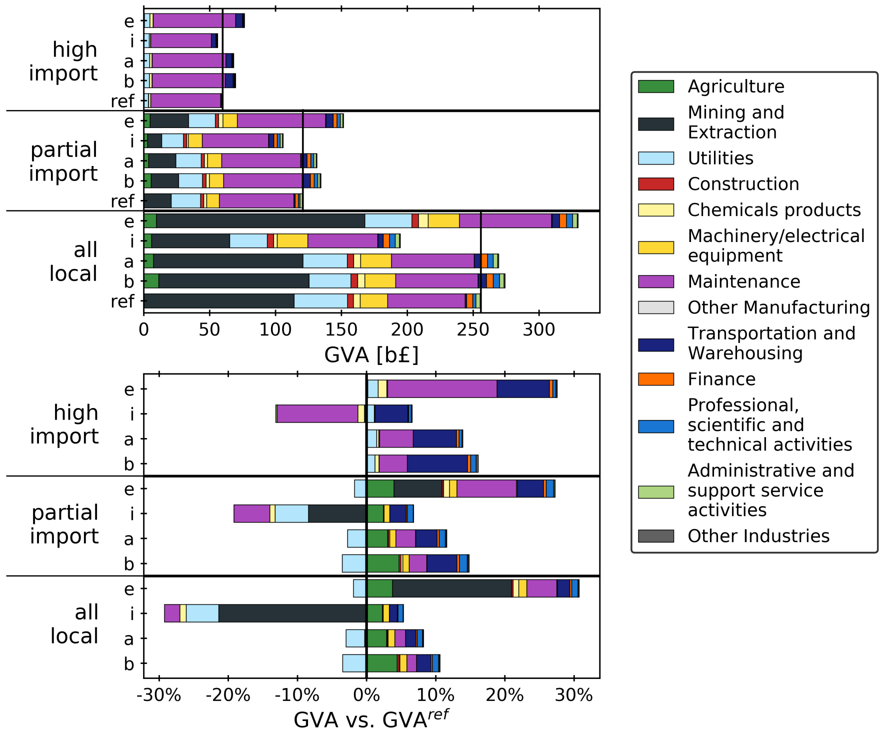


Figure 4.6: Total GVA and GVA *vs.* reference/BAU (ref) case for all combinations of import share scenarios (all local, partial import, high import) and industrial sector scenarios (BAU & offset (**b**), abate & offset (**a**), import & offshore (**i**), abate & export (**e**)). Vertical lines indicate reference scenarios.

GVA. The results show a significant increase in GVA when a net zero target is applied and import and export remain unchanged. BAU in industry and offsetting industrial emissions in the power sector (BAU & offset) is estimated to result in a GVA increase of +7%, +11%, and +16%, depending on the scenario. Abating industrial emissions (abate & offset) incurs similar changes in GVA: +5%, +9% and +14%, depending on the scenario. Importing industrial goods and thereby offshoring the emissions (import & offshore) appears to lower GVA by -24%, -12%, and -7%, for all local, partial import, and high import, respectively. In the contrary scenario, abate & export, where an increase in production and export of low-carbon cement, steel, and petrochemicals is presumed, increases in GVA by +29%, + 26%, and +28% are estimated.

All scenarios see lower utilisation of gas-fired power, reducing GVA in utilities, and the deployment of BECCS, increasing GVA in agriculture in the all local and partial import scenarios. Changes in maintenance GVA are a result of the overall increase or decrease in output. The increase in transportation GVA reflects the deployment of CO_2 transport and sequestration infrastructure.

The same comparisons for employment are illustrated in figure 4.7. The results mirror the GVA results to an extent. The amount of jobs created is reduced by 43% from the all local to the partial import reference scenario, and by another 43% from partial import to high import. The total employment created throughout the planning time amounts to an estimated 6.6, 3.7, and 2.1 million jobs for the three reference scenarios. When all effects are assumed locally, most jobs are generated in the maintenance, mining, machinery, utilities, and agriculture sectors. The partial import scenario sees substantial reduction in mining and machinery jobs. In the high import case, almost all jobs are attributed to the maintenance sector, with a smaller share in the transportation sector.

When comparing the job creation *vs.* the reference scenarios, trends similar to GVA can be observed. A net zero target with constant import and export ratios results in an increase in employment amounting to +20-24% in the BAU & offset scenario and +17-21% in the abate & offset scenario. The import & offshore scenario is estimated to reduce overall employment by -7-8% in the all local and high import cases. When assuming a combination of importing

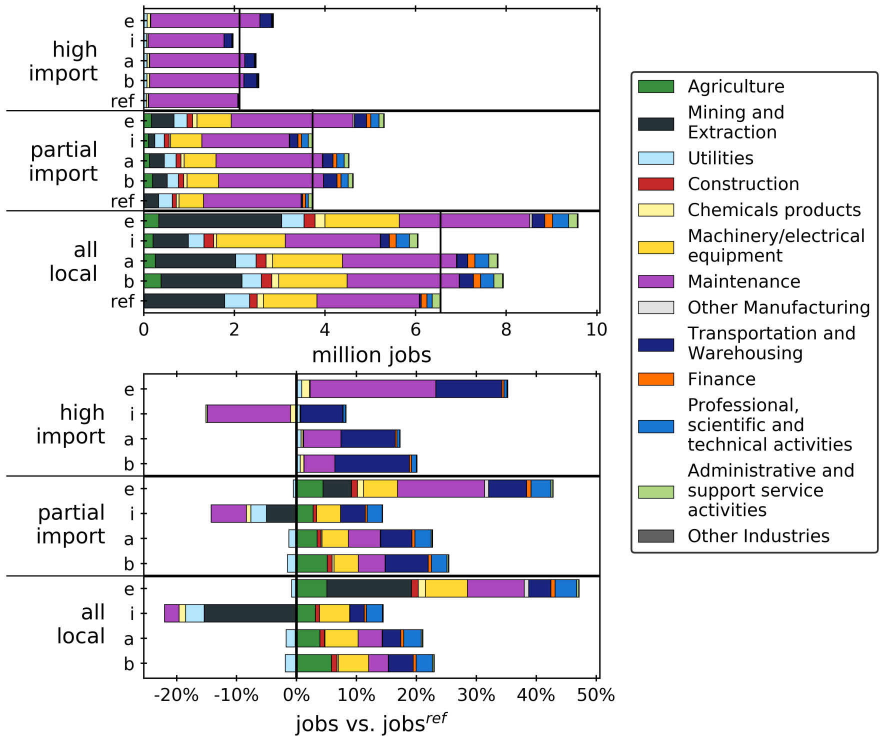


Figure 4.7: Total employment and employment *vs.* reference/BAU (ref) case for all combinations of import share scenarios (all local, partial import, high import) and industrial sector scenarios (BAU & offset (**b**), abate & offset (**a**), import & offshore (**i**), abate & export (**e**)). Vertical lines indicate reference scenarios.

industrial goods and partial import, the job creation incurred by the net zero target is outweighed exactly by the loss of jobs that are replaced with imports, resulting in a 0% change compared to the reference scenario. The abate & export scenarios sees an overall increase in employment by +35-46%.

Gains in machinery, maintenance, and professional activities are generally related to building and maintaining capacity in power and industry. The rise in employment in agriculture reflects the operation of a biomass supply chain for BECCS in the power sector and for Steel-Bio. Jobs in the transportation sector are needed to support the CO_2 transport and sequestration infrastructure.

When comparing GVA and jobs for the scenarios, it is helpful to analyse the changes relative to the costs with which they are associated. Figure 4.8 sums up the total system cost (tsc), factor cost (FC), GVA, and employment for all the scenarios. Factor cost in this context is defined as total system cost without import cost or export revenue from the industrial sectors. Furthermore, value creation and job creation, measured in GVA/tsc and tsc/job, are detailed in table 4.2. It is evident that the increase in tsc for all the scenarios relatively minor at +3-4%, while the factor cost increases slightly for scenarios b and a (+5% and +4%), decreases by -24% for the import scenario, and increases by +26% in the export scenario. In the scenarios which see a rise in GVA and jobs it seems to be higher than the increase in tsc and FC, indicating relatively large socio-economic benefits at relatively low cost. GVA and employment appear to move in parallel with FC to an extent. The import & offshore scenario is estimated to have an increase in tsc similar to the other scenarios, but a reduction in FC as well as GVA and jobs. The job creation increases seem to be higher than GVA increases in all cases, although this may be a result of the way GVA and employment are calculated (specifically the use of the end-of-life weighing factor and the discounting).

The GVA/tsc can be regarded as overall indicator for value creation, reflecting the proportion of total cost which generates GVA. The value creation is estimated to be higher in the power sector than the industrial sector in almost every case, ranging from 12.2% to 33.4% compared to 2.2% to 41.1%. In the power sector every net zero scenario achieves a higher relative value creation than the reference scenario. The industrial sector exhibits nearly the same GVA/tsc

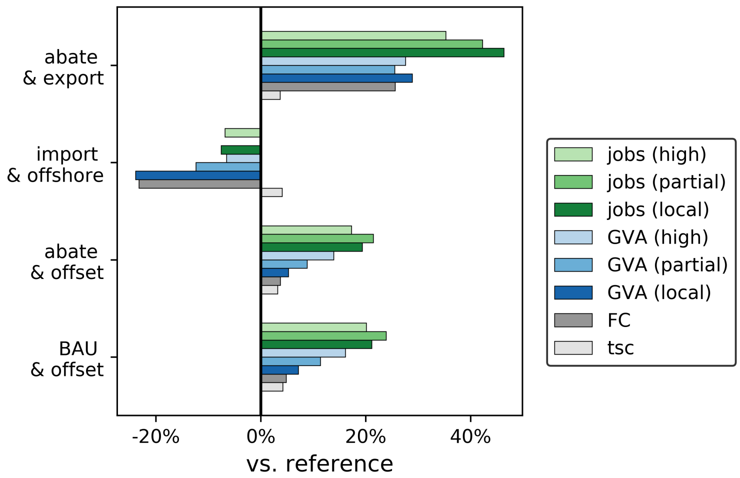


Figure 4.8: Total system cost (tsc), factor cost (FC), GVA, and jobs relative to the reference (BAU) case for all combinations of industrial sector and import share scenarios.

Table 4.2: Value creation and job creation across scenarios.

		GVA/tsc			jobs/tsc (jobs/m£)		
		total	power	industry	total	power	industry
all local	ref	30.3%	31.5%	29.5%	7.77	10.96	5.65
	B	31.2%	33.4%	29.5%	9.03	13.65	5.65
	A	30.9%	32.8%	29.6%	8.98	13.60	5.73
	I	22.2%	32.8%	14.9%	6.90	13.52	2.38
	E	37.7%	32.9%	41.1%	10.96	13.70	9.01
partial import	ref	14.3%	21.4%	9.6%	4.42	7.43	2.43
	B	15.3%	23.1%	9.6%	5.26	9.13	2.43
	A	15.1%	22.6%	9.8%	5.20	9.04	2.50
	I	12.0%	22.7%	4.8%	4.25	9.01	1.01
	E	17.3%	22.7%	13.5%	6.07	9.12	3.90
high import	ref	7.1%	11.2%	4.4%	2.51	3.93	1.56
	B	7.9%	12.7%	4.4%	2.89	4.71	1.56
	A	7.8%	12.6%	4.5%	2.85	4.61	1.60
	I	6.4%	12.5%	2.2%	2.24	4.58	0.65
	E	8.7%	12.5%	6.1%	3.27	4.61	2.31

in the reference scenario, BAU & offset, and abate & offset. The import & offshore scenario reduces GVA/tsc by around half, whereas abate & export significantly increases it. Overall, the relative value creation is higher for the b, a, and e scenarios, and lower in scenario i, compared to the reference scenario. Furthermore, reducing the local share decreases GVA/tsc, and appears to have a higher impact in industry compared to power.

Similarly, the power sector is estimated to generate more jobs for the same cost compared to industry. The relative job creation in the power sector is significantly higher for net zero systems compared to BAU. In industry, the relative job creation is similar for BAU and abatement, while importing commodities and exporting low carbon goods lead to a decrease and increase in jobs/tsc, respectively.

4.4.3 Maximising GVA

As the final results in this chapter, a thought experiment is presented where GVA is increased artificially beyond its value in a system with purely minimised cost. The following equation is added to the model formulation, where GVAdir is the total GVA across all technologies, economic sectors, and time steps, as calculated by the equations in section 4.2, $\mathrm{GVAdir}^{\mathrm{ref}}$ denotes the total GVA from a previously concluded cost minimisation scenario, and α represents a factor set exogenously:

$$\mathrm{GVAdir} \geq (1+\alpha)\,\mathrm{GVAdir}^{\mathrm{ref}} \tag{4.20}$$

The model is then solved with this lower bound on the GVA, minimising total system cost, for increasing factors α. A net zero carbon target, the abate & offset and the all local assumptions are used in this analysis. The results simulate systems which operate sub-optimally, *i.e.*, are more costly compared to the reference scenario, but achieve a specified increase in GVA at least cost.

In the industrial sector, higher lower bounds on the total GVA lead to later and reduced deployment of abatement. The low-carbon technologies are added

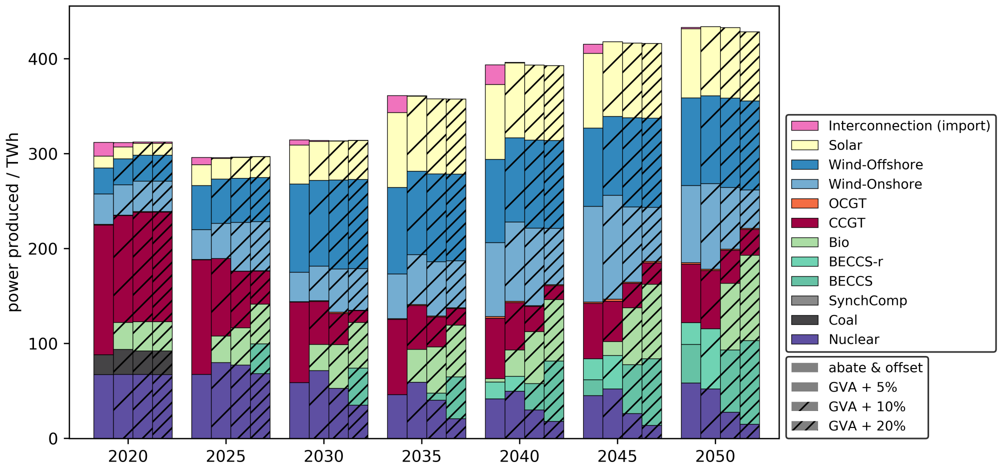


Figure 4.9: Power produced for abate & offset (all local) scenario with GVA increased by 5%, 10%, and 20%.

to the system later, then first disappear in the cement sector, then the steel sector, and then the refinery sector. At 10% GVA increase, almost the entire capacity in 2050 is still low-carbon, and at 20%, no abatement is deployed at all (beyond EAF-scrap).

The results in the power sector are shown in figure 4.9 in terms of power produced. In the early decades, substantial amounts of gas-fired power are replaced by bioenergy for all scenarios with increased GVA. At 5% GVA increase, the power production remains the same otherwise. The scenarios with 10% and 20% GVA increase see an earlier deployment of BECCS in addition, as well as higher amounts of electricity generated by bioenergy and BECCS. In these scenarios, bioenergy and BECCS replace substantial fractions of nuclear power, CCGT, and onshore wind generation towards the end of the time horizon.

Figure 4.10 details the breakdown of the GVA increase by sector. GVA in the utilities sector declines with the reduced utilisation of gas-fired capacity. The highest GVA gains are achieved in the agriculture sector as a result of the rise in power generation from biomass. The transportation sector also contributes to the higher GVA, reflecting the increased operation of T&S infrastructure for BECCS. At 20% GVA increase, almost half of the power sector GVA and jobs are contributed by bioenergy and BECCS.

The change in system design and operation towards bioenergy and BECCS,

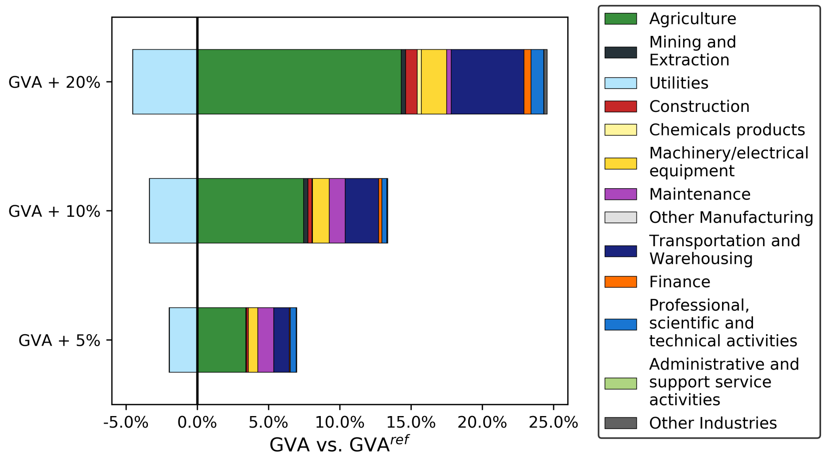


Figure 4.10: Breakdown of GVA increase relative to abate & offset (all local) for systems with increased GVA.

away from other power generation technologies including CCGT, under a minimum GVA constraint reflects the relatively high GVA per output in agriculture compared to utilities and other sectors. The biomass supply chain is more complex compared to the natural gas supply chain, resulting in higher value added. The change to BECCS offsets instead of industrial CCS could be a result of the higher GVA/output of BECCS compared to the industrial sector. The minimum GVA requirement shifts the technologies from the most efficient to those which produce higher value per cost. Essentially, the design and operation of a less efficient system creates additional value.

The biomass required for these scenarios, listed in table 4.3, increases drastically with increased lower bound on GVA. The biomass used per year in 2050 alone is doubled for the cases with 10% and 20% GVA increase. It reaches 491 TWh/yr in the latter case, which amounts to more than double the estimated indigenous biomass supply of the UK (198 TWh) [121]. The total biomass utilised over the time horizon is multiplied for cases with increased GVA. This raises concerns with regard to the viability and overall sustainability of these scenarios.

When comparing GVA, employment, tsc, and GVA/tsc for the scenarios in table 4.3, it becomes apparent that the higher value creation comes at relatively little additional cost. A 10% GVA increase is achieved with only a 3.5% higher tsc.

Table 4.3: GVA, employment, total system cost (tsc) changes, GVA/tsc, total and 2050 biomass consumption for cases with fixed GVA increase.

GVA	jobs	tsc	GVA/tsc	total biomass	2050 biomass
269 b£	7.8 b	871 b£	30.9%	1,430 TWh	199 TWh
+5%	+5.5%	+1.1%	32.1%	×2.1	±0%
+10%	+9.4%	+3.5%	32.9%	×3.8	×1.9
+20%	+18%	+9.9%	33.8%	×6.1	×2.5

The relative value creation, GVA/tsc, is therefore estimated to rise for higher GVA. Furthermore, higher value creation coincides with higher job creation, in this scenario total jobs increase around as much as GVA.

4.5 Summary

In this chapter, socio-economic aspects of the transition to net zero emissions were explored, providing novel quantitative analysis for the power and industry sectors. The JEDI methodology was applied to the model, a corresponding data set was collected, enabling analysis of GVA and employment for various decarbonisation scenarios. Under constant assumptions for trade, the net zero target leads to an increase in GVA and jobs. The estimated gains in value added and employment are slightly higher when industrial emissions are offset by the power sector compared to the case of deploying abatement in industry. Offshoring industrial emissions by reducing the production to zero is shown to reduce GVA and employment, whereas both are significantly increased under the assumption of rising exports from a domestic low-carbon economy. The fraction of GVA and employment effects which is assumed to contribute to the local economy is shown to impact the GVA and employment, both can be drastically diminished under high import shares. It is demonstrated that GVA can be increased artificially beyond its value in a system with minimised cost. Under current cost and economic impact assumptions, scenarios with increased GVA and jobs are centred around a sustained deployment of bioenergy and BECCS and a corresponding biomass supply chain.

This work can be expanded in multiple dimensions. GVA and employment multipliers as measure of the structure of the economy have so far been assumed constant over time. It is of interest to estimate time-dependent input-output data, to more accurately model the trajectories of the systems over the decades, and evaluate the impact of large-scale economic trends, such as automation, on the GVA and employment estimates. Incorporating skill levels could shed light on the changing requirements of the transition with regard to the labour force and the potential need for reskilling and reallocating workers. The influence of policy on value and job creation is also of interest, aiming to save and create jobs, or potentially supporting said reskilling and reallocation.

Modelling the socio-economic layer of decarbonisation reveals connections to larger questions in discussions of climate change mitigation and the economy. Which jobs are worth preserving? What constitutes decent employment? Many industrial clusters in the UK are located in economically challenged areas [17], how can it be ensured that the achievements of a low-carbon economic boost benefit these communities? Should paths towards more or less labour-intensive systems be favoured? Does an economy focused on climate change mitigation still exist within a paradigm of continuous economic growth, or is there perhaps a pathway to a post-growth economy [218]?

Chapter 5

Conclusions and Outlook

5.1 Summary

In this thesis, the transition of the economy to net zero emissions was analysed on the technological level, from the system viewpoint, and on a socio-economic layer. To this end, the energy systems optimisation (ESO) framework was expanded in multiple directions. Owing to its interest in leading the world in climate change mitigation, the United Kingdom was used as case study throughout the work.

First, a full-hourly version of the model with inter-day storage was written, enabling the examination of seasonal effects. The impact of electrification and the role and value of inter-seasonal storage were analysed. It was found that seasonal effects do matter when considering increased sector coupling, especially with the heat sector, and in case of integration of high shares of intermittent renewable energy. In this context, inter-seasonal storage is shown to add value to a decarbonised energy system. High CAPEX and low round-trip efficiency do not prohibit the technology from contributing in a net zero system. Without low-carbon dispatchable power and negative emissions, long-term storage becomes vital, and *vice versa*. Ideally, a combination of all can reduce cost as well as risk and uncertainty. Assessing the value of a technology, in this case inter-seasonal storage, from the system point of view uncovered its true potential.

Second, a representation of the industrial sector was developed to model integrated pathways for power and industry. The paucity of techno-economic data in the context of industrial decarbonisation presented a challenge. A data set for cement, iron and steel, and refining was curated nonetheless. A representation of trade and corresponding scenarios were introduced. Optimal pathways see power reaching net zero in the 2040s and offsetting residual emissions in 2050. The deployment of abatement in industry is cost-optimal compared to offsets. With the current data set, the technologies which are optimally deployed all rely on CCS. The amount of CO_2 for sequestration was calculated. Policy instruments – border tax adjustment, carbon price, and negative emissions credit – were included in the analysis. Certain combinations of carbon price and negative emissions credit appear effective in decarbonising power and industry. Discrepancies emerge between optimal trajectories from a private sector point of view, optimal trajectories from a public sector view. They are indicative of the need for compromise and the difficulties in providing incentives for decarbonisation.

Third, the socio-economic impacts of transition pathways were explored. Model equations were added, and the data set was expanded, and pre-processing was carried out. Scenarios for the import share of the components for the technologies were constructed. GVA and employment were estimated and compared for various scenarios. It was demonstrated that transitions to net zero can have socio-economic benefits. Whilst a net zero target raises system cost, it can also lead to even higher increases in GVA and employment. The consequences of offshoring *vs.* expanding UK industry – reductions and increases in value added and jobs, respectively – were further quantified.

This thesis has produced a model for the analysis of power and industry on the technological, economic, and socio-economic level. Various decarbonisation scenarios can be simulated with regard to optimal technology deployment, emissions, costs, GVA, employment, *etc.* Sector integration is tackled in the dimension of electrification of heat and transport and in the form of a combined electricity balance and emissions balance for power and industry. It further integrates bottom-up technology modelling, including hourly power dispatch, with system-level constraints and macro-economic KPI. It bridges gaps between techno-economic analysis and system-level thinking as well as system-level analysis and the socio-economic layer. It is therefore qualified to contribute to the many ongoing debates concerning pathways to a net zero economy and answer questions from various viewpoints and stakeholders.

In addition to the suggestions provided in the preceding chapters, the following section summarises potential areas for future work.

5.2 Directions for future work

Addition of model features. The time resolution in the industrial sector could be increased to an hourly level. This would enable the investigation of demand side response of industrial plants, and the impact of higher shares of intermittent generation on the operation of industrial assets, especially those with high power consumption.

Spatially disaggregate. The current model is formulated for a country/territory in aggregate. Formulating a spatially disaggregated version, analogous to ES-ONE for the power sector, could enable analysis of the impacts of decarbonisation on specific parts of the country. It would allow modelling CO_2 transport and sequestration infrastructure, which could prove vital in the decarbonisation of industry.

Expansion of data set. Several industrial sectors have so far been summed into "other" industrial emissions instead of being modelled explicitly. Representations of the chemicals sector, natural gas processing, pulp and paper, *etc.*, with conventional and low-carbon technology options, could deliver a more granular analysis of the industrial sector. Furthermore, the technology portfolio of both power and industry could be expanded. In case of the power sector, direct air capture as negative emissions technology and hydrogen fuelled power plants could be added. In case of the cement, steel, and refining sectors, more technologies could be included, as more techno-economic analysis and pilot plant research emerges.

Policy instruments. The transition to net zero is driven by public policy. Various policy instruments could be evaluated with regard to their effectiveness, efficiency, cost, *etc.* Potential policies include contracts for difference, portfolio standards, tax credits, *etc.*

Application to other national contexts. The version of ESO for the power sector with enhanced computational workflow which was developed for this work has already been applied to several countries and territories, including various European countries, several US states, and South Korea [66]. Decarbonisation trajectories depend on the national context, and analysis of power and industry for other countries using this tool can grant valuable insights.

Model extensions for heat and transport. As alluded to in the introduction, the present work is an intermediary step on the path to an integrated model for power, heat, transport, and industry. Subsequent efforts will therefore be directed to modelling the heat and transport sectors. Some of this work is already underway [219].

Life cycle assessment module. Future pathways for the economy have environmental impacts outside of emissions and corresponding global warming potential. Indicators such as resource depletion, human health, and ecosystems impact, can be quantified and compared across scenarios using life cycle assessment (LCA). Developing an LCA module for ESO, similar to the JEDI module, could enable integrated assessment of the environmental impacts of transition scenarios.

Carbon neutral vs. climate neutral vs. post-fossil. The pathways analysed in this work aim to reach net zero CO_2 emissions. Carbon neutrality, however, is not equal to climate neutrality, and neither implies a post-fossil system. Whether or not net zero systems still include some form of fossil energy continues to be a point of discussion. It could be valuable to quantify the additional cost, and potential trade-offs or co-benefits on the socio-economic and environmental layers, of achieving a post-fossil – in addition to carbon neutral – system.

Nomenclature

Sets

cat JEDI categories (Inv, OMF, OMV)

sect JEDI sectors

a planning periods (years)

c clusters (days)

i technologies

ic/ipc thermal generators

ig/ipg power generating technologies

ii industrial technologies

is/ips electricity storage technologies

m commodities (cement, steel, petrochemicals)

t time periods (hours)

Parameters

$\mathrm{GVAK}^{\mathrm{cat}}_{i,\mathrm{sect}}$ GVA generated in sector sect and category cat per output for technology i m£/m£

$\mathrm{JobsK}^{\mathrm{cat}}_{i,\mathrm{sect}}$ Jobs generated in sector sect and category cat per output for technology i jobs/m£

$\rho_{i,i'}$ 1 if i can be retrofitted to i', 0 otherwise -

d_{ia}^{eol} capacity reaching end-of-life in a #units

Des_i unit size MW or Mt/yr

$e_a^{ind,other}$ industrial emissions from sectors not modelled explicitly t-CO_2/yr

$IDem_{a,m}$ commodity demand Mt/yr

$IFeat_{ii}^{*}$ industrial technology features (ems,$emsts$, $powreq$, $opfac$) t-CO_2/Mt, MWh/Mt, %

$IProd_{ii,m}$ 1 if ii produces m, 0 otherwise -

LT_i technology lifetime yrs

SD_{act} system electricity demand, incl. electrified heat & transport MWh/h

$SDis_{is}$ self-discharge rate %-MWh

SE_a system emissions target t-CO_2

$SEta_{is}$ round-trip efficiency %-MW

TL transmission losses %-MW

WF_{ac} demand weighing factor -

Variables

GVAdir total direct GVA generated m£

$\mathrm{GVASectInv}_{\mathrm{sect},a}^{i}$ industrial sector investment GVA in year a and sector sect m£

$\mathrm{GVASectInv}_{\mathrm{sect},a}^{p}$ power sector investment GVA in year a and sector sect m£

$\mathrm{GVASectInv}_{\mathrm{sect},a}$ investment GVA in year a and sector sect m£

$\mathrm{GVASectOM}_{\mathrm{sect},a}^{i}$ industrial sector maintenance GVA in year a and sector sect m£

$\mathrm{GVASectOM}_{\mathrm{sect},a}^{p}$ power sector maintenance GVA in year a and sector sect m£

$\mathrm{GVASectOM}_{\mathrm{sect},a}$ maintenance GVA in year a and sector sect m£

$\mathrm{GVASect}_{\mathrm{sect}}$ total GVA in sector sect m£

$\mathrm{JobsSectInv}^{i}_{\mathrm{sect},a}$ industrial sector investment jobs in year a and sector sect jobs

$\mathrm{JobsSectInv}^{p}_{\mathrm{sect},a}$ power sector investment jobs in year a and sector sect jobs

$\mathrm{JobsSectInv}_{\mathrm{sect},a}$ investment jobs in year a and sector sect jobs

$\mathrm{JobsSectOM}^{i}_{\mathrm{sect},a}$ industrial sector maintenance jobs in year a and sector sect jobs

$\mathrm{JobsSectOM}^{p}_{\mathrm{sect},a}$ power sector maintenance jobs in year a and sector sect jobs

$\mathrm{JobsSectOM}_{\mathrm{sect},a}$ maintenance jobs in year a and sector sect jobs

$\mathrm{JobsSect}_{\mathrm{sect}}$ total jobs in sector sect jobs

Jobs total direct jobs generated jobs

b_{ia} capacity built MW or Mt/yr

d_{ia}^{dec} decommissioned capacity MW or Mt/yr

d_{ia}^{out} total capacity retrofitted or decommissioned MW or Mt/yr

$d_{ia}^{ret,later}$ capacity retrofitted in $a+1$ MW or Mt/yr

$d_{ia}^{ret,now}$ capacity retrofitted in a MW or Mt/yr

d_{ia} installed capacity MW or Mt/yr

$e_{ii,a}^{ind}$ industrial emissions t-CO_2/yr

$e_{ipc,act}$ power emissions t-CO_2

$exp_{a,m}$ export of m in a Mt/yr

$f_{a,m}$ domestic delivery Mt/yr

$g_{a,ii,m}$ production of m in a by ii Mt/yr

$imp_{a,m}$	import of m in a	Mt/yr
$p2d_{ipg,act}$	power to demand	MW
$p2is_{is,act}$	power to storage	MW
$s2d_{is,act}$	storage to demand	MW
$s_{is,act}$	storage level	MWh

Appendix A

Power Sector Data

Table A.1: Central storage technology data [110, 112, 89].

	PHSto	battery	P2M
CAPEX	1,220 £/kW	1,800 £/kW	2,400 £/kW
round trip efficiency	75%	85%	29%
storage duration	5 h	5 h	8,400 h
input : output power ratio	1	1	3.4
self-discharge rate	0	0.005%/h	0

Table A.2: Power technology data. CAPEX from [110, 111, 112, 113]; baseline build rate limits based on [39, 109]; build rate multipliers (BRM).

	CAPEX £/kW	max. build rate MW/yr	BRM
Nuclear	5,270	360	1
Coal	1,550	0	1
Bio	1,860	300	1
CCGT	565	900	2
OCGT	846	500	2
CCGT-PostCCS	2,050	900	2
CCGT-PostCCS-r	1,620	900	2
BECCS	4,250	900	2
BECCS-r	2,780	900	2
Wind-Onshore	1,430	1,600	2
Wind-Offshore	2,770	1,500	2
Solar	606	2,000	2
SynchComp	20	720	2
Interconnection	1,000	1,000	1
Pumped hydro storage	1,220	600	1
Battery storage	2,470*	1,500	2

*Battery storage assumptions were updated for chapter 3.

Table A.3: Biomass supply curve [121].

biomass type	max. availability TWh/yr	cost £/MWh
waste wood	17	16
forest residue	7	20
indigenous virgin miscanthus	98	23
crop residue	41	25
municipal solid waste	35	27
import (US)	800	28
import (EU)	800	36

Table A.4: CAPEX ranges for sensitivity analysis [110, 89, 220].

£/kW	P2M	CCGT-CCS	onshore wind
min	530	565	606
low	1,460	1,310	1,020
central	2,400	2,055	1,430
high	3,590	2,570	1,790
max	4,780	3,080	2,150

Appendix B

Industrial Sector Data

Table B.1: Industrial technology data – unit sizes, maximum and initial capacities, baseline build rate limits, build rate multipliers (BRM), maximum operation factors, adapted from [156, 221, 155, 222, 223, 224, 159, 147, 225, 226].

	retrofit	unit size Mt/yr	max. #units	initial #units	BRM	build rate #units/yr	max op. factor
Cement		1		11	1	1	0.9
Cement-PCC-r	✓	1			1	1	0.9
Cement-PCC-n		1			1	1	0.9
Cement-Oxy-r	✓	1			1	1	0.9
Cement-Oxy-n		1			1	1	0.9
Cement-MAL-r	✓	1			1	1	0.9
Cement-MAL-n		1			1	1	0.9
Cement-CaLtail-r	✓	1			1	1	0.9
Cement-CaLtail-n		1			1	1	0.9
Cement-CaLint-r	✓	1			1	1	0.9
Cement-CaLint-n		1			1	1	0.9
Steel-BF-BOF		5		2	1	1	0.85
Steel-EAF-scrap		0.5	13	3	1	1	0.9
Steel-BF-BOF-CCS-r	✓	5			1	1	0.85
Steel-BF-BOF-CCS-n		2			1	1	0.85
Steel-BF-BOF-highCCS-r	✓	5			1	1	0.85
Steel-BF-BOF-highCCS-n		2			1	1	0.85
Steel-H-DR		2			1	1	0.85
Steel-H-DR-scrap		2			1	1	0.85
Steel-Bio-n		2			1	1	0.85
Steel-Bio-r	✓	5			1	1	0.85
Steel-EW		2			1	1	0.85
refinery		12		6	1	1	0.95
refinery-highPCC-r	✓	12			1	1	0.95
refinery-lowPCC-r	✓	12			1	1	0.95

Table B.2: Lifetimes, emissions, power consumption of industrial technologies, adapted from [156, 155, 157, 158, 159, 162].

	available	lifetime yrs	emissions t-CO_2/Mt	CO_2 for T&S t-CO_2/Mt	power requ. MWh/Mt
Cement		40	856,000	0	132,000
Cement-PCC-r	2025	40	256,000	772,000	244,000
Cement-PCC-n	2025	40	256,000	772,000	244,000
Cement-Oxy-r	2025	40	88,000	792,000	281,000
Cement-Oxy-n	2025	40	88,000	792,000	281,000
Cement-MAL-r	2035	40	84,000	772,000	414,000
Cement-MAL-n	2035	40	84,000	772,000	414,000
Cement-CaLtail-r	2025	40	78,000	1,156,000	58,000
Cement-CaLtail-n	2025	40	78,000	1,156,000	58,000
Cement-CaLint-r	2025	40	57,000	997,000	174,000
Cement-CaLint-n	2025	40	57,000	997,000	174,000
Steel-BF-BOF		50	1,718,000	0	
Steel-EAF-scrap		50	77,000	0	563,000
Steel-BF-BOF-CCS-r	2025	50	763,000	955,000	333,000
Steel-BF-BOF-CCS-n	2025	50	763,000	955,000	333,000
Steel-BF-BOF-highCCS-r	2025	50	343,600	1,374,400	455,000
Steel-BF-BOF-highCCS-n	2025	50	343,600	1,374,400	455,000
Steel-H-DR	2030	50	90,000	0	3,639,000
Steel-H-DR-scrap	2030	50	70,000	0	2,290,000
Steel-Bio-n	2025	50	-262,000	1,490,000	455,000
Steel-Bio-r	2025	50	-262,000	1,490,000	455,000
Steel-EW	2040	50	0	0	2,583,000
refinery		50	213,000		0
refinery-highPCC-r	2025	40	78,000	135,000	9,700
refinery-lowPCC-r	2025	40	167,000	46,000	0

Table B.3: Cost data for industrial technologies, adapted from [157, 158, 159, 227, 226, 228, 162].

	CAPEX m£/Mt	fixed OPEX m£/Mt	variable OPEX m£/Mt
Cement	188	15	17
Cement-PCC-r	70	36	21
Cement-PCC-n	258	36	21
Cement-Oxy-r	114	15	23
Cement-Oxy-n	296	15	23
Cement-MAL-r	228	15	29
Cement-MAL-n	415	15	29
Cement-CaLtail-r	191	26	27
Cement-CaLtail-n	384	26	27
Cement-CaLint-r	209	21	28
Cement-CaLint-n	402	21	28
Steel-BF-BOF	379		429
Steel-EAF-scrap	184		365
Steel-BF-BOF-CCS-r	106		429
Steel-BF-BOF-CCS-n	486		429
Steel-BF-BOF-highCCS-r	106		429
Steel-BF-BOF-highCCS-n	486		429
Steel-H-DR	750		601
Steel-H-DR-scrap	750		471
Steel-Bio-n	491		436
Steel-Bio-r	112		436
Steel-EW	548		601
refinery	292		337.0
refinery-highPCC-r	20		337.7
refinery-lowPCC-r	7		337.3

Table B.4: Commodity demands, import and export ratios, derived from [229, 222, 147, 230, 213].

	demand [Mt/yr]		
	Cement	Steel	Petrochemicals
2020	10.6	11.5	66.4
2025	10.6	11.9	63.1
2030	10.6	12.3	59.9
2035	10.6	12.9	56.6
2040	10.6	13.4	53.4
2045	10.6	13.8	50.1
2050	10.6	14.3	46.9
import ratio	0.21	0.61	0.51
export ratio	0	0.47	0.39

Appendix C

Socio-economic Data

Table C.1: Input/output data for the UK [198, 199, 200].

OECD code	OECD sector	GVA/output m£/m£	GVA m£	compensation m£	wages £/yr	comp./GVA m£/m£	jobs/output jobs/m£
1	Agriculture, forestry and fishing	46%	12,064	4,419	22,145	37%	7.69
2	Mining and quarrying	39%	11,511	4,773	38,795	41%	4.16
3	Manufacture of food, beverages and tobacco	28%	28,881	17,009	28,683	59%	5.82
4	Manufacture of textiles, wearing apparel and leather	36%	5,558	3,659	28,683	66%	8.35
5	Manufacture of wood and paper products and printing	37%	13,095	8,600	28,683	66%	8.54
6	Manufacture of coke, refined petroleum and chemicals	18%	13,379	7,004	28,683	52%	3.24
7	Manufacture of pharmaceutical products	44%	13,360	4,866	28,683	36%	5.59
8	Manufacture of rubber, plastic and non-metallic minerals	37%	13,669	9,436	28,683	69%	9.01
9	Manufacture of basic and fabricated metal products	35%	19,957	14,444	28,683	72%	8.92
10	Manufacture of computer, electronic and optical products	44%	12,527	7,293	28,683	58%	8.91
11	Manufacture of electrical equipment	35%	4,697	3,735	28,683	80%	9.68
12	Manufacture of machinery and equipment	34%	14,085	9,273	28,683	66%	7.78
13	Manufacture of transport equipment	22%	26,319	15,270	28,683	58%	4.35
14	Other manufacturing, repair and installation	40%	16,021	11,072	28,683	69%	9.67
15	Electricity, gas, steam and air-conditioning supply	24%	26,372	7,260	37,311	28%	1.74
16	Water supply; sewerage and waste management	49%	23,117	7,750	29,480	34%	5.62
17	Construction	35%	108,281	48,524	30,350	45%	5.23
18	Wholesale and retail trade; repair of motor vehicles	14%	185,958	120,248	23,075	65%	4.04
19	Transportation and storage	40%	74,244	53,190	28,784	72%	10.02
20	Accommodation and food service activities	54%	50,023	34,832	18,206	70%	20.70
21	Information and communication	50%	117,227	68,693	38,001	59%	7.77
22	Financial and insurance activities	40%	128,405	68,454	38,886	53%	5.48
23	Real estate activities	68%	249,199	14,550	27,170	6%	1.45
24	Professional, scientific and technical activities	54%	134,860	83,262	34,426	62%	9.75
25	Administrative and support service activities	57%	90,028	56,299	24,109	63%	14.82
26	Public administration and defence	40%	86,795	61,623	31,914	71%	8.90
27	Education	53%	102,378	83,479	30,347	82%	14.26
28	Human health and social work activities	64%	133,621	103,740	25,363	78%	19.69
29	Arts, entertainment and recreation	29%	28,079	15,408	23,171	55%	6.89
30	Other service activities	48%	29,463	14,598	24,870	50%	9.57
31	Activities of households	54%	4,961	4,961	1	100%	

Table C.2: Assignment of OECD sectors to JEDI sectors.

JEDI code	JEDI sector	OECD code	OECD sector
1	Agriculture	1	Agriculture, forestry and fishing
2	Mining and Extraction	2	Mining and quarrying
3	Utilities	15	Electricity, gas, steam and air-conditioning supply
		16	Water supply; sewerage and waste management
4	Construction	17	Construction
5	Chemicals products	6	Manufacture of coke, refined petroleum and chemicals
6	Machinery/electrical equipment	11	Manufacture of electrical equipment
		12	Manufacture of machinery and equipment
7	Maintenance	14	Other manufacturing, repair and installation
8	Other Manufacturing	3	Manufacture of food, beverages and tobacco
		4	Manufacture of textiles, wearing apparel and leather
		5	Manufacture of wood and paper products and printing
		7	Manufacture of pharmaceutical products
		8	Manufacture of rubber, plastic and non-metallic minerals
		9	Manufacture of basic and fabricated metal products
		10	Manufacture of computer, electronic and optical products
		13	Manufacture of transport equipment
9	Sales	18	Wholesale and retail trade; repair of motor vehicles
10	Transportation and Warehousing	19	Transportation and storage
11	ICT	21	Information and communication
12	Finance	22	Financial and insurance activities
13	Professional, scientific and technical activities	24	Professional, scientific and technical activities
14	Administrative and support service activities	25	Administrative and support service activities
15	Other Industries	20	Accommodation and food service activities
		23	Real estate activities
		26	Public administration and defence
		27	Education
		28	Human health and social work activities
		29	Arts, entertainment and recreation
		30	Other service activities
		31	Activities of households

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