

The Implications of the Paris Agreement on Electric Power Systems Transitions

Technoeconomic and sociopolitical assessments of the United Kingdom and Nigeria

Habiba Ahut Daggash

Centre for Environmental Policy
Imperial College of Science, Technology and Medicine

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Declaration

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I hereby declare that except where specific reference is made to the work of others, the contents of this dissertation are original and have not been submitted in whole or in part for consideration for any other degree or qualification in this, or any other university. This dissertation is my own work and contains nothing which is the outcome of work done in collaboration with others, except as specified in the text and the Acknowledgements.

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Abstract

The electrification of the global energy system is cited as necessary to transform economies away from fossil fuel dependence at least-cost because of increasingly cheap intermittent renewable energy sources (iRES). Consequently, power sector decarbonisation is expected to be critical to delivering the Paris Agreement which seeks to limit global warming to “well-below 2°C” by 2100. Integrated Assessment Models that assess global decarbonisation pathways fail to do so at national-scale. This thesis investigates the power system transitions needed to meet the UK and Nigeria’s commitments to the Paris accord. For the UK, we find that the least-cost systems that deliver decarbonisation are dominated by baseload and dispatchable low-carbon generation complemented by carbon dioxide removal (CDR) technologies, with limited expansion of iRES. It was found that CDR deployment could reduce decarbonisation costs by up to 48%. In the long-term, centralised systems consisting of large-scale thermal generation (mostly CCS) and extensive transmission infrastructure are cost-optimal, thus current policies pursuing decentralisation may lead to overbuilt and obsolete systems. For Nigeria, we find that the least-cost systems are dominated by natural gas and hydroelectric generation. Such a system was found to have emissions that were significantly lower than the power sector’s carbon budget. This surplus carbon budget could be traded to offset the emissions of other sectors or countries via carbon offsetting mechanisms. The UK utilises expensive CDR to meet its targets, however the purchase of emissions offsets from developing countries such as Nigeria could prove cheaper, and be a vital source of financing for developing countries. In both countries, iRES were found to play a non-central role in meeting NDCs. Their low availability and variability means that significant capacity coupled with energy storage is required and this proves particularly costly in a context where both power generation and CDR are required.

This PhD thesis is dedicated to my mother Aisha, for the many sacrifices that she has made to make me the person that I am today. May Allah's infinite mercy envelope her always in this life and the next. Amīn.

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It really does take a village.

سُبْحَانَ رَبِّيَ رَبِّ الْعَرْشِ عَمَّا يَصِفُونَ
وَسُبْحَانَكَ عَلَى الْمُسَلِّينَ
وَالْحَمْدُ لِلَّهِ رَبِّ الْعَالَمِينَ

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Chapter 1

Introduction

1.1 Background

Widespread public acceptance of the existence of accelerated climate change, and its devastating impacts on natural and human systems has brought it to the forefront of political discourse¹. In 2015, through the Paris Agreement, all nations committed to limiting average global temperature rise to “well below 2°C” above pre-industrial levels by the end of the century, and to pursue further efforts to restrict it to 1.5°C². In their Fifth Assessment Report, the Intergovernmental Panel on Climate Change (IPCC) highlighted that delivering the Paris accord requires deep reductions in greenhouse gas (GHG) emissions. Global *net* carbon dioxide (CO₂) emissions—the most abundant GHG—, in particular, must fall to zero by 2070 and become negative afterwards³. Global energy supply, 85% of which is derived from fossil fuels⁴, is the largest contributor to anthropogenic GHG emissions and thus, climate change³. Deep decarbonisation of the global economy therefore necessitates an unprecedented transformation of the global energy system away from its reliance on polluting fossil fuels, to low-carbon energy sources.

Several strategies have been proposed to decarbonise the energy supply industry. These include:

- **Low-carbon energy sources:** Many alternative energy sources—less polluting energy not derived from fossil fuels—have been developed and commercially deployed globally. These include renewable energy sources which are naturally-replenishing: solar, wind, hydro, geothermal, tidal, marine and biomass energy*⁶. Although finite in supply and thus non-renewable, nuclear energy is also low-carbon as fission (the process by which energy is generated) does not emit GHGs⁷. Finally, carbon capture and storage (CCS) is a technology that captures the CO₂ emitted by fossil fuel combustion and stores it underground in geological

*Although biomass is a carbon-neutral fuel at harvest, and can be naturally replenished, its categorisation as a renewable energy resource is subject to the sustainability of its rate of harvest and supply chain. The processes involved with its utilisation at scale—land-use and land-use change, processing and transport of the raw biomass—produce additional GHG emissions which contribute to its life-cycle emissions and can make it a high-carbon fuel⁵.

reservoirs. When fossil fuel power plants are equipped with CCS, they are considered a source of low-carbon energy⁸. It has been shown that even when the life-cycle emissions[†] of these alternative energy sources are considered, they are significantly less carbon-intensive than fossil fuel-derived energy⁹.

- **Energy efficiency and demand reduction:** This includes any measure that reduces the amount of energy required to deliver a given energy service. Energy efficiency can be achieved through: improved efficiency of energy conversion technologies and end-use devices, *e.g.* more efficient power plants, internal combustion engines, lightbulbs, *etc.*; design of infrastructure, such as buildings, to minimise energy consumption; behavioural changes that encourage energy conservation by consumers, *e.g.* increased use of public transport instead of personal vehicles; digitalisation of energy services to allow real-time monitoring of energy consumption and demand-response^{3,10}.
- **Reduced fugitive emissions:** Fugitive emissions comprise accidental emissions from process equipment or flaring. Fossil fuel extraction is a significant contributor of global fugitive GHG emissions, particularly methane (CH₄) which has a higher global warming potential than CO₂¹¹. Fugitive emissions can be reduced through improved equipment monitoring practices, flare gas recovery, fuel switching and equipping processes with CCS technology¹².
- **Fossil fuel switching:** This involves switching from the use of fossil-derived fuels to lower-carbon alternatives, including to natural gas (from coal or oil). Cleaner fuels being developed include biomass-derived fuels such as bioethanol for transport, electrification of residential heating, and the use of hydrogen in a range of sectors (heating, transport and power)³.
- **Carbon dioxide removal (CDR):** CDR, sometimes called negative emissions, involves any anthropogenic activity that results in a net removal of CO₂ from the atmosphere¹³. Several natural and engineered methods of delivering CDR have been proposed in the literature. They are discussed in Table 1.1[‡]. It has been suggested that CDR can minimise historic emissions¹⁴, and offset the emissions of hard-to-abate sectors, including industry, aviation and shipping¹⁵. With the exception of AR, none of these solutions have been implemented at scale. BECCS and DACCS have been demonstrated as technically-feasible, but they are not yet commercially viable^{16–18}.

[†]Total GHG emissions from construction, operation, fuel supply and decommissioning.

[‡]Biomass is sometimes described as a carbon-neutral fuel because it absorbs CO₂ during its growth, which is then re-emitted when it is burned to release energy. However large-scale biomass, such as in BECCS, requires processing of ‘raw’ biomass to produce a homogeneous fuel and subsequent transport of the fuel to the point of use. The biomass supply-chain requires energy and this contributes additional CO₂ emissions that must be considered in the life-cycle of the biomass. If supply chain emissions are sufficiently low, the BECCS delivers negative emissions⁵.

Table 1.1 Carbon dioxide removal methods that have been proposed in the literature.

CDR method	Description
Afforestation/reforestation (AR) ^{13,19}	Planting new or restocking existing forests which are natural carbon sinks
Bioenergy with carbon capture and storage (BECCS) ^{13,19}	Burning biomass (a low-carbon fuel) and sequestering the resulting emissions in geological reservoirs using CCS
Direct air carbon capture and storage (DACCS) ^{13,19}	Direct extraction of CO ₂ from the atmosphere using chemical sorbents
Enhanced weathering (EW) ^{13,19}	Accelerating the removal of CO ₂ via natural weathering of some minerals in soils
Ocean fertilisation (OF) ¹³	Biological or chemical manipulation of oceans (<i>e.g.</i> through iron addition to stimulate algal growth) to improve carbon uptake
Soil carbon sequestration (SCS) ¹³	Implementation of agricultural practices that increase carbon fixation in soils

It is widely accepted that no one of the aforementioned climate change mitigation measures in isolation is sufficient to decarbonise the global energy system. Instead, the implementation of all of them is necessary³.

1.2 Motivation: why focus on the power sector?

Many countries have sought to facilitate the transition away from fossil fuels through the implementation of legislation, policies and programmes that encourage the deployment of climate change mitigation technologies, with varying degrees of success²⁰. Subsidies have particularly been effective in encouraging innovation and lowering the costs of intermittent renewable energy sources (iRES), particularly wind and solar power. The levelised cost of electricity (LCOE) which is used to compare the cost of power generation is the total cost of ownership of a generator divided by the total amount of electricity it generates during its lifetime. Between 2010 and 2018, the LCOEs of iRES have fallen significantly: solar photovoltaics (77%), concentrating solar power (46%), onshore wind (35%), offshore wind (20%), and costs are expected to fall further²¹. In many countries, unsubsidised iRES have achieved cost parity with incumbent fossil fuel technologies on an LCOE basis²². Energy storage technologies, which can be used to compensate for the variability in the supply of iRES, have also experienced cost declines and this trend is expected to continue^{23,24}. The LCOE has been criticised as a flawed metric for comparing the economic attractiveness of energy technologies because of its failure to consider holistically all the services that technologies provide to the system including (dispatchable) power generation and ancillary services^{25–27}. Additionally, some studies have found that optimistic *n*th-of-a-kind battery cost projections of as low as \$100/kWh may be unrealistic because of higher essential material costs^{23,28}. Despite these criticisms, it is evident that low-carbon electricity generation will play an increasingly important role in the energy transition owing to their cost reductions.

Whilst technological innovation and the improving economics of low-carbon power generation have accelerated the decarbonisation of electricity supply, other sectors (industry, heating, transport, aviation and shipping) have lagged owing to more difficult or expensive mitigation solutions²⁹. Consequently, the electrification of energy end-uses within these hard-to-abate sectors has been proposed as a means to reduce their GHG emissions. To limit planetary warming to 2°C, it is expected that electricity will become the central energy carrier, with its share of global final energy consumption estimate to rise from 20% today, to 50-60% by 2050^{30,31}. Thus, delivering low-carbon electricity systems is critical to the sustainable energy transition.

The economic and technical feasibility of delivering the Paris Agreement is often evaluated using integrated assessment models (IAMs). IAMs simulate the interactions of human decision-making about energy systems and land use with the natural Earth system³². The IPCC assesses scientific literature from IAMs to inform policymakers on the development of effective climate policies. In their Fifth Assessment Report and “Global Warming of 1.5°C” report, the electrification of energy was highlighted as a feature of the cost-optimal global energy transition^{3,14,30}. Owing to their relatively low spatial granularities, the IAMs assessed fail to provide insight on the electricity systems transitions that are necessary at a national-scale, which the level at which climate policy is implemented. Furthermore, IAMs assume that CDR can be delivered at scale from the power system, principally via BECCS technology, but fail to elaborate on how CDR technologies integrate with the rest of the system and how their deployment should be incentivised³³.

To address the aforementioned knowledge gaps, this thesis seeks to use a national-scale power systems model to determine how electric power systems need to transition to deliver the deep decarbonisation that is consistent with the Paris Agreement. In particular, it seeks to assess the role and value of nascent technologies, such as CDR technologies, for power sector decarbonisation. Different countries have varying historical GHG emissions, and thus responsibilities for climate change. Consequently, their emissions reductions commitments differ. Furthermore, countries at different stages of development face different challenges in trying to deliver low-carbon electricity systems. Therefore, it is important to consider the role of equity and sustainable development in assessing system transitions.

1.3 Climate change and equity

It has been established that the countries with the greatest responsibility for climate change and the capacity to address its consequences, are not the most vulnerable to its impacts^{34,35}. Developing countries constitute the majority of those vulnerable owing to their low adaptive capacities¹ and, because of this inequity, they are reluctant to bear the economic costs of climate change^{36,37}. Consequently, the United Nations Framework Convention on Climate Change (UNFCCC) calls for “common but differentiated responsibilities and respective capabilities, in

light of different national circumstances” in delivering the targets set-out in the Paris Agreement². Considerations of climate equity under the accord are addressed through nationally determined contributions (NDCs) – each country defines its own intended contributions to global climate action commensurate with its domestic circumstances and capabilities, and within the context of sustainable development and poverty eradication².

For countries to deliver their sustainable energy transitions, several objectives, commonly referred to as the ‘Energy Trilemma’, must be achieved: energy security, energy equity and environmental sustainability. There is no single definition of these objectives. Within the context of this thesis, ‘energy security’ is the ability to meet current and future demand, and the reliability of energy infrastructure to withstand disruptions; ‘energy equity’ is the widespread accessibility and affordability of energy supply across the population; and ‘environmental sustainability’ is the transition to low-carbon energy sources that do not facilitate environmental degradation^{38,39}. Balancing these often competing aims poses challenges, of varying degrees, to countries because of their different geographies, natural resources, economic capabilities and geopolitical landscapes.

Historically, there has been a significant positive correlation between growth in a nation’s energy use and growth in gross domestic product (GDP), although not necessarily proportional^{40,41§}. An even stronger correlation has been found to exist between electricity consumption (which is essential to the production of many goods and services) and wealth creation, compared to that between total energy use and wealth creation⁴². Additionally, there is a positive and statistically-significant relationship between GDP and per capita GHG emissions⁴³. Fig. 1.1 illustrates the relationship between per capita GDP, power consumption and CO₂ emissions for some countries.

In accordance with the literature, it is observed that high-income countries have higher per capita electricity consumption and GHG emissions relative to poorer ones. Power consumption can be expected to rise with the increased electrification of other sectors, such as transport and heat³. Thus, they face the challenge of having to transition to low-carbon energy systems while maintaining relatively high levels of reliable supply. For lower-income (‘developing’) countries, the energy transition presents a different challenge. It is believed that increased energy consumption (particularly electricity) is critical to economic and social development, because of its necessity for the production of goods and services⁴⁶. The need to mitigate climate change, however, means that developing countries cannot exclusively rely on fossil fuel resources to drive that growth, as was the case during the industrialisation of many high-income countries. It is important to note that, within income groups, per capita electric power consumption differs greatly. For a high-income country such as the UK, relatively low power consumption is desirable as it highlights more efficient energy use compared to other advanced economies. However, for a lower income country such as Nigeria, its relatively low electricity consumption

[§]The rate at which electric consumption increases is not equal to economic growth

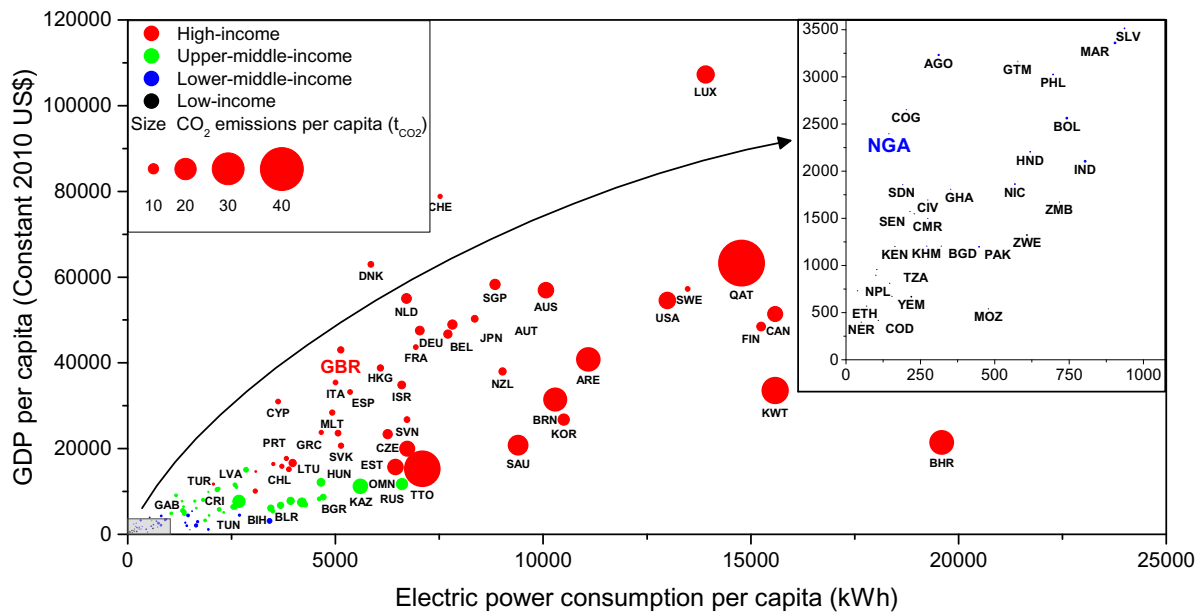


Fig. 1.1 Relationship between per capita gross domestic product (GDP), power consumption and CO₂ emissions for countries. All data represented are the latest available from the World Bank⁴⁴. Country income classifications are based on the United Nations' *World Economic Situation and Prospects 2019* report⁴⁵.

is not desirable as it highlights that the power sector is underperforming relative to countries at a similar stage of development.

Despite the increasingly favourable economics of low-carbon electricity generation, a review of the literature shows that there are many barriers to their proliferation in developing countries:

- **Technical and technological barriers:** poor resource availability⁴⁷; insufficient transmission and distribution (T&D) infrastructure to match supply and demand; high T&D losses due to distance between optimal generation sites and demand centres⁴⁸; need for backup energy supply or storage for intermittent renewable energy sources (iRES)^{3,48}; lack of skilled labour to support development and operation of low-carbon projects^{3,48-50}.
- **Economic and financial barriers:** underinvestment in research and development (R&D)⁴⁷; unaffordability due to high upfront investment cost^{3,51}; lack of financing mechanisms^{8,48,52}; lack of financial incentives (subsidies, tax credits, low-interest loans, *etc.*)^{3,48,50}; higher project returns demanded due to risk perception.
- **Policy and regulatory barriers:** lack of investment-friendly regulations and liberalised market policies⁴⁷; lack of standards, codes and certification for low-carbon energy systems⁴⁹.
- **Socio-cultural and institutional barriers:** public unwillingness to pay for energy services^{3,48}; lack of public acceptance owing to a lack of awareness of technologies and related benefits⁴⁷.

From the above, it is evident that the challenges that developed and developing countries face to deliver their NDCs under the Paris Agreement greatly differ. Thus, any holistic study of energy system transitions necessitates the consideration of issues of equity and sustainable development. Different power technologies will be preferable in different geographic, economic and sociopolitical contexts. This thesis recognises the importance of equity in climate change discourse and seeks to investigate the electric power system transitions needed within developed and developing country contexts. Due to limited time and data, it is impossible to study all countries. Consequently, two case studies have been selected which represent the contrasting situations that developed and developing countries face to deliver climate change mitigation in their respective electric power systems.

1.3.1 Case Studies

The United Kingdom and Nigeria are used as case studies in this thesis for the reasons explained below.

Owing to its fossil-fuelled industrial revolution and subsequent economic growth, the UK is responsible for 6.3% of cumulative anthropogenic GHG emissions (5th country rank)^{53–57}. The UK is also a high-income country and the fifth largest economy globally (GDP basis)⁴⁴. The principles of distributive fairness applied in international climate policy seek to distribute the economic costs of climate action in accordance with a country's responsibility for climate change, and/or its capacity to address it^{58–60}. Consequently, the UK is expected to bear significant costs of delivering the Paris Agreement. Thus far, the UK has shown political will to be at the forefront of climate action. In 2008, the *Climate Change Act* legislated an 80% reduction in economy-wide GHG emissions relative to pre-industrial levels by 2050⁶¹. In 2019, the act was amended to mandate a 100% reduction in emissions, thus aiming to end the UK's contribution to global climate change by 2050⁶². Thus, the UK is an exemplar of a developed country that has recognised its significant responsibility for climate change, and has legislated targets to pursue the deep decarbonisation of its economy. Given its advanced stage of development, it faces the challenge of maintaining high per capita GDP and power consumption (relative to poorer countries) whilst decarbonising the economy.

Nigeria is the largest economy in Africa and is classified as a lower-middle-income⁴⁴. Despite this, it holds the largest number of people living below the poverty line (94 million, or 47%)^{63,64}. It is currently the seventh most populous nation in the world with 200 million people (2019 estimate)⁶⁵. Nigeria's population is projected to double by 2050 when it is expected to be the third most populous country⁶⁵. Nigeria also possesses abundant fossil fuel reserves and renewable energy resources⁶⁶; crude oil exports have historically been responsible for 47–85% of fiscal revenues. However, average annual electricity consumption has stagnated at 0.1 MWh/capita (global average: 3.2 MWh/capita)⁶⁷ and access to electricity is 54%⁴⁴. Due to its high deforestation rate and oil and gas industry, Nigeria has greater historic emissions relative to

other countries at similar stages of development^{55–57}. Thus it is expected to have a commensurate contribution to meeting the Paris Agreement target. In its first NDC submission to the UNFCCC, Nigeria committed to an unconditional reduction in economy-wide GHG emissions of 20% by 2030 (relative to the business-as-usual emissions projects), and to pursue a 45% reduction if “international support, in the form of finance and investment, technology and capacity building” are provided⁶⁸. These targets must therefore be achieved in spite of a demographic explosion, poor economic indices, and a dependence on fossil fuel rents which currently constitute 65% of government revenues⁶⁹. Nigeria is representative of many developing countries, especially fossil fuel exporters, that must transform both their energy systems and economies away from fossil fuel dependence to advance climate change mitigation and achieve fiscal sustainability in a low-carbon world, respectively.

The rest of this chapter details the research questions that this thesis seeks to answer and the structure of subsequent chapters.

1.4 Objectives and structure

This thesis assumes the centrality of delivering low-carbon—in some cases, carbon-negative—electric power systems to achieving a global sustainable energy transition. It also recognises that equity and sustainable development issues are critical to holistic assessments of system transitions. Thus, the work presented in this thesis investigates the transitions that electric power systems must undergo to deliver countries’ climate change mitigation commitments, and how this transition differs within developed and developing country contexts. Using the United Kingdom and Nigeria as case studies, this thesis seeks to:

- determine the implications of nationally-determined contributions for greenhouse gas emissions reductions in the power sector;
- determine the power system decarbonisation pathways that are consistent with climate change mitigation commitments and their associated costs;
- identify the necessary technologies and how can they be incentivised to realise cost-optimal decarbonisation pathways;
- quantify the roles and values of different low-carbon energy and carbon dioxide removal technologies in delivering deep decarbonisation in the power sector; and
- identify the synergies between the potential mitigation pathways of the UK and Nigeria, and the cost reductions that can be achieved if they are realised.

1.4.1 Structure

The rest of the thesis is structured as follows:

- Chapter 2 describes the power systems modelling framework that it used throughout this thesis. The system parameters and technology costs assumed for the UK and Nigeria are also detailed in the chapter.
- Chapter 3 investigates the least-cost decarbonisation pathways that deliver a completely decarbonised electricity system in the UK by 2050, in accordance with the climate change mitigation targets legislated in the Climate Change Act (2008). The chapter particularly quantifies the role and value of CDR technologies in delivering cost-optimal transitions and potential incentives to encourage their deployment at the scale required.
- Chapter 4 assesses the share of climate change mitigation (to meet the Paris Agreement) that the UK is responsible for, according to established burden-sharing principles. The long-term transition (until 2100) of the electricity system that is need to deliver this ‘fair’ share of mitigation at least-cost is then investigated. Finally, policies that can enable such a transition are proposed.
- Chapter 5 determines the GHG emissions reductions needed in the power sector by 2050, according to Nigeria’s nationally-determined contributions. A power systems model is then used to determine the least-cost system evolution that delivers these targets, and the implications of the potential pathways on sustainable development indices.
- Chapter 6 delivers a comparative analysis of power sector decarbonisation pathways for the UK and Nigeria, identifies potential cost synergies, and proposes how these synergies can be realised. Finally, it provides a conclusion for this thesis and outlines possible next steps to further the work.

1.4.2 Publications

This thesis builds heavily on the following peer-reviewed journal publications that I have authored or co-authored, and conference presentations that I have given. Papers that are relevant to a particular chapter only are specified below.

Chapter 2

1. H. A. Daggash, M. Fajardy, and N. Mac Dowell, “Chapter 14. Negative Emissions Technologies,” in *Carbon Capture and Storage (Energy and Environment Series)*, pp. 447–511, Royal Society of Chemistry, 2019
2. H. A. Daggash, M. Fajardy, P. Heptonstall, N. Mac Dowell, and R. Gross, “Bioenergy with carbon capture and storage, and direct air carbon capture and storage: Examining the evidence on deployment potential and costs in the UK,” Apr. 2019. Available at: <https://tinyurl.com/t54uths>. Accessed on 28/12/2019

Chapter 3

3. H. A. Daggash and N. Mac Dowell, “The implications of delivering the UK’s paris agreement commitments on the power sector,” *International Journal of Greenhouse Gas Control*, vol. 85, pp. 174–181, June 2019
4. H. Daggash, C. Heuberger, and N. Mac Dowell, “The role and value of negative emissions technologies in decarbonising the UK energy system,” *International Journal of Greenhouse Gas Control*, vol. 81, pp. 181–198, Feb. 2019
5. H. A. Daggash and N. Mac Dowell, “The role of negative emissions technologies (NETs) in decarbonising the UK energy system,” in *International Conference on Negative CO₂ Emissions*, (Gothenburg, Sweden), Chalmers University of Technology, May 2018

Chapter 4

6. H. A. Daggash and N. Mac Dowell, “Higher Carbon Prices on Emissions Alone Will Not Deliver the Paris Agreement,” *Joule*, vol. 3, pp. 2120–2133, Sept. 2019
7. H. A. Daggash and N. Mac Dowell, “Structural Evolution of the UK Electricity System in a below 2°C World,” *Joule*, vol. 3, pp. 1239–1251, May 2019

General

8. M. Fajardy, P. Patrizio, H. A. Daggash, and N. Mac Dowell, “Negative Emissions: Priorities for Research and Policy Design,” *Frontiers in Climate*, vol. 1, Oct. 2019
9. H. A. Daggash, C. F. Patzschke, C. F. Heuberger, L. Zhu, K. Hellgardt, P. S. Fennell, A. N. Bhave, A. Bardow, and N. Mac Dowell, “Closing the carbon cycle to maximise climate change mitigation: power-to-methanol vs. power-to-direct air capture,” *Sustainable Energy & Fuels*, vol. 2, no. 6, pp. 1153–1169, 2018
10. H. A. Daggash, “Power-to-Transport: Using Curtailed Wind to Run CCU Processes,” in *CO₂ Summit III: Pathways to Carbon Capture, Utilization, and Storage Deployment*, (Calabria, Italy), Engineering Conferences International, May 2017
11. H. A. Daggash and N. Mac Dowell, “CO₂ Utilisation vs Direct Air Capture for Climate Change Mitigation,” in *2017 AIChE Annual Meeting*, (Minneapolis, USA), American Institute of Chemical Engineers, Nov. 2017

Chapter 2

The Electricity Systems Optimisation (ESO) modelling framework

Chapter Roadmap

This thesis seeks to investigate the national-scale electricity system decarbonisation pathways that are consistent with climate change mitigation commitments under the Paris Agreement. Additionally, it seeks to quantify the role and value of different low-carbon technologies in delivering those targets. Typically, a family of models known as generation expansion planning (GEP) problems is used to determine the optimal type, quantity and time construction of power plants, while minimising the total cost over a planning horizon and subject to a set of constraints⁸¹. Unit commitment (UC) models are used to determine the optimal scheduling and of power plants to maintain system reliability and operability, while also minimising costs and meeting a set of constraints⁸². As this thesis seek to investigate both long-term system transitions and shorter-term operation of power technologies, a power systems modelling tool that combines traditional GEP and UC problem formulations is required. The Electricity Systems Optimisation (ESO) modelling framework was found to be most suitable. This chapter describes the ESO modelling framework, the modifications that were made to the original mathematical formulation, and the system and technology parameters assumed for both the UK and Nigerian electricity systems in the subsequent analyses.

2.1 Introduction

The analyses presented in this thesis were carried out using the Electricity Systems Optimisation modelling framework. ESO consists of a family of models that combine capacity expansion planning and unit commitment model formulations to determine the optimal system design and hourly dispatch of electricity for a power system in equal time steps. The ESO models are mixed-integer linear optimisation problems (MILPs). Several variants of the model have

been published which emphasise detailed technology operation (ESO⁸³), capacity expansion planning (ESO-X⁸⁴), the effects of technology cost learning on the system (ESO-XEL⁸⁴), and the spatio-temporal distribution of generation and transmission infrastructure (ESONE⁸⁵). The mathematical formulations of the model variants have been described previously^{83–86} and are accessible as open-source and open data models⁸⁷. The objective function of the ESO models is to minimise the Total System Cost (TSC) of the system, *i.e.* the total capital and operating costs incurred by the system during the modelled period, subject to a set of constraints. The model can be run under perfect or myopic foresight conditions. As the analyses presented in this thesis are concerned with cost-optimal system transitions, perfect foresight was assumed to be most suitable. Myopic foresight and reduced temporal granularity are only implemented for the Nigeria case study using the ESONE variant of model, as computation is infeasible (solve time for a single run >1 week) under perfect foresight conditions. How myopic foresight is implemented in ESONE is described in Section 2.4.

For the purpose of this thesis, three variants of the model were adapted: the ESO-X, ESO-XEL and ESONE models. Their key features and adaptations for subsequent analyses are described in the following sections.

2.2 Technology availability

The following types of power technologies are considered in the ESO modelling framework. How they are modelled within the UK and Nigerian electricity systems are described in Sections 2.3 and 2.4.

- Conventional fossil fuel generation: coal, open-cycle gas turbine (OCGT), and combined-cycle gas turbine (CCGT) power plants. Electricity imports are also included*.
- Firm low-carbon generation: nuclear, biomass, coal with post-combustion CCS (Coal-CCS), large-scale hydroelectric power (“large hydro”), small-scale ‘run-of-the-river’ hydroelectric power (“small hydro”), and CCGT with post-combustion CCS (CCGT-CCS). We assume a conventional CO₂ capture rate of 90% for CCS using monoethanolamine (MEA)⁸. An assumption of 90% capture rate has become ubiquitous in the literature with little justification—it is not as a result of optimisation—other than costs appear to increase non-linearly beyond this rate^{88,89}. Although it is taken as the base case for CCS technologies, sensitivity analysis is carried out on capture rates in Chapter 3.
- Intermittent renewable generation: solar photovoltaics (Solar PV)—both grid-scale and off-grid, onshore wind and offshore wind.

*Interconnection with external electricity markets is modelled as infinitely-flexible power generation, with limits on generation capacity

- Energy storage: batteries (parameterised as lead-acid type) and pumped hydroelectric storage (PHES).
- Carbon dioxide removal technologies: bioenergy with carbon capture and storage (BECCS) which also contributes to power generation, and direct air carbon capture and storage (DACCS), which is modelled as an additional power demand that provides atmospheric CO₂ removal at a cost.

2.3 Modelling the UK electricity system

The Electricity Systems Optimisation with capacity eXpansion and Endogenous technology Learning (ESO-XEL) model determines the evolution of power supply in a system over a time period considering cost reductions in immature technologies. The key features of the model are described below.

2.3.1 Key model features and assumptions

- The optimisation determines optimal system design in five-yearly time steps, a . The initial model year is 2015. The final year is 2050 or 2100, depending on the analysis. The system operation (electricity dispatch profiles, reserve and inertia provision, storage charging/discharging etc.) is determined in hourly time steps t . For ease of computation, annual temporal data were represented as 11 weighted days, hereafter referred to as clusters, c . The process by which temporal data is clustered is described in Section 2.5.
- Perfect foresight is assumed. We take the perspective of a monopolistic system planner that has all the relevant information.
- The model is deterministic so uncertainties in the input parameters are not considered. Sensitivity analyses are carried out to assess the implications of uncertainties in key parameters such as technology costs and fuel prices on system design. The uncertainty analyses will be discussed in detail in subsequent chapters.
- Electricity demand and electricity import prices are perfectly inelastic.
- Initial capacity available is specified. Technology-specific lifetimes, maximum deployment (due to geographic or resource limits) and maximum build rates are also specified. For the existing generation capacity in 2015, remaining lifetimes are not specified for individual power plants; instead, an average lifetime is estimated for each technology after which the initial capacity is not available.
- System-wide constraints ensure electricity demand is always met; and 4% of peak load and 15% of intermittent power output must be available to provide reserve capacity. Some unmet

demand is allowed but this is limited to 0.5% of total annual demand and is penalised at a ‘Value of Lost Load (VoLL)’. See Table 2.2 for VoLL assumptions for the UK.

- A minimum level of system inertia that provides frequency and voltage control services ensures system reliability and operability is maintained[†]; maximum annual carbon emissions from power generation are specified.
- Power, reserve and inertia provision capability; flexibility of generation/storage units; carbon emissions; and ramping (up and down) times are specified for each technology.
- GHG emissions reduction targets are implemented using a constraint that restricts total emissions derived from technologies in each time step a . A shadow carbon price, detailed in Table 2.1 is also assumed.
- Electricity interconnectors are modelled in two ways: 1) as a storage system to which electricity excess can “charged” and from which electricity can be “discharged” or imported which is the type of operation common for the interconnectors between the British and the Irish power systems, denoted as *Interconnection (IE)*, and 2) as a pure electricity import possibility, which is the common mode of operation for the French and Dutch interconnectors, denoted as *Interconnection (FR,NL)*⁸⁴. The emissions associated with imported electricity are included in the carbon emissions for the system.
- Two main types of energy storage technologies are considered: pumped hydroelectric storage and battery storage which is parameterised as lead-acid batteries.
- Technology cost learning is included (in the ESO-XEL formulation only) to reflect how technologies experience cost reductions with increasing deployment. Learning curves are implemented endogenously so that the capital cost of a technology is a function of its deployment level within the system. A piecewise linear representation of each learning curve was determined using the learning rate (LR) of each technology. The learning rate is the factor by which the capital cost of a technology reduces when cumulative installed capacity doubles. Cumulative installed capacity estimates were estimated from forecasts in the literature. Learning rates applied to technologies for the UK electricity system are listed in Table 2.2.
- A discount rate of 3% is used for future cash flows, based on the Social Time Preference Rate (STPR) provided by Her Majesty’s Treasury for appraisal and evaluation of policies/programmes by government departments⁹⁰. Social time preference is defined as “the value society attaches to present, as opposed to future, consumption. It is based on comparisons of utility across different points in time or different generations⁹⁰.”

[†]system inertia is the amount of kinetic energy stored in the spinning parts of synchronous generators

2.3.2 System parameters

The annual demand and other system parameters assumed in the ESO-XEL model for the UK electricity system are provided in Table 2.1, along with the data sources. All temporal data inputs assume 2015 (the base year) values in the initial time planning period. A range of studies on future electricity demand in the UK were reviewed, including National Grid's 'Future Energy Scenarios' reports. It was found that, to be consistent with the Paris Agreement, a 0.5-1% year-on-year increase in electricity demand was projected^{91,92}. To be conservative, the subsequent analyses on the UK electricity system assume the upper-bound demand growth rate of 1%. This is in accordance with the expectation that, although demand in the UK has fallen in recent years, increasing electrification of other sectors of the economy (heating and transport) will result in rising demand^{91,92}. The Value of Lost Load (VoLL) quantifies the economic damage caused by not meeting electricity demand⁸⁶. A wide range of £1,000-45,000/MWh has been estimated for VoLL in the UK⁹³⁻⁹⁵; this work assumes the lower-bound which is from the Office for Gas and Electricity Markets (Ofgem), the power sector's regulator. Other minimum requirements for power system reliability and operability were provided by the relevant system operators.

Hourly wind and solar availability profiles were collected from Renewables.ninja⁹⁶ using Python. For the UK, availability profiles had been previously determined⁸⁶ and were implemented in ESO-X and ESO-XEL model.

Table 2.1 Data sources for system parameters assumed in the ESO-XEL model

UK electricity system parameters	Value	Data source(s)
Hourly electricity demand	-	97
System inertia requirement	100,000 MW.s	98
Capacity reserve for intermittent renewables	15%	99
CO ₂ emissions targets until 2050	-	100
Price of imported electricity	-	101
Power transmission and distribution losses	7.7%	102-104
Value of lost load	4,000 £/MWh	94
Hourly availability of solar, onshore wind and offshore wind	-	96,105,106
Carbon price	-	107
CO ₂ transport and storage costs	£10/tCO ₂	108

2.3.3 Technology parameters

It has been observed that technology costs reduce over time owing to a range of factors: technological improvement, process advancement (economies of scale, industry integration), market-push (competition, R&D), and demand pull (government policies)⁸⁴. The aggregate

effects of these factors on cost reductions have been studied extensively for different energy technologies¹⁰⁹. In the ESO-XEL model, we assume individual learning rates LR —the factor by which capital costs reduce when capacity deployed doubles—for the technologies modelled based on the literature surveyed. Table 2.2 provides the initial (2015) capital costs of the technologies and their learning rates, along with the data sources. Conventional thermal generators that have achieved widespread global deployment and have shown no cost reductions in recent years are assumed to be mature so a learning rate of 0% is specified—that is, the capital costs remain constant throughout the planning horizon. Large-scale nuclear power plants have been observed to show a negative learning rate—the capital costs increase with deployment. This has been attributed to regulatory uncertainty, increased public opposition to projects, more stringent safety requirements and increased systems complexity—the complexity of both construction and operation of large-scale nuclear limits the effectiveness of classical mechanisms of cost reduction such as standardisation¹¹⁰.

For CDR technologies that are yet to be deployed at scale, technology learning rates were deduced from the first-of-a-kind and n^{th} -of-a-kind cost estimates in the literature. In the case of direct air carbon capture and storage (DACCS), cost estimates were obtained from two developers of the technology, Carbon Engineering^{18,111} and Climeworks¹⁷. Bioenergy with carbon capture and storage (BECCS) FOAK costs were obtained from literature (shown in Table 2.2) and NOAK costs were calculated as described in Section 2.3.5.

The operating costs and efficiencies of the technologies are also included below.

Table 2.2 Data sources for the technology costs and operational parameters implemented in the ESO-XEL model. Technology capital costs (average), learning rates and efficiencies are highlighted.

Technology	2015 CAPEX (£/kW)	2018 CAPEX (£/kW)	No-load OPEX (£/hr)	Start-up OPEX (£/hr)	Learning rate	Efficiency (HHV basis)	Data sources reviewed
Nuclear	3,673	4,363	3,510	4,000,000	-1%	37.0%	109,112
Coal (super-critical)	1,237	1,439	3,356	198,528	0%	42.2%	108,109,113–123
Dedicated biomass-fired	1,590	2,995	3,153.5	198,528	0%	40.0%	112
Combined cycle gas turbine (CCGT)	540	525	2,226	79,564	0%	52.7%	109,112,113,117–120,122,124–126
Open cycle gas turbine (OCGT)	459	815	89	3,770	0%	39.0%	109,112,113,118,121,122,124,125,127
Coal post-combustion CCS	2,368	3,600	4,228.6	250,145.28	5.5%	33.6%	108,114,116,119,122,123,128–130
CCGT post-combustion CCS	1,187	1,838	2,337.7	83,542.20	4.5%	45.5%	109,116,117,119,129–131
Bioenergy with CCS (BECCS)	2,721	3,800	4,228.6	250,145.28	11%	35.0%	5,108,130,132–134
Onshore Wind	1,105	1,421	-	-	12%	-	96,109,112,124,125,135
Offshore Wind	2,600	2,731	-	-	20%	-	96,109,112,124,125,135
Solar Photovoltaic (PV)	1,157	646	-	-	23%	-	96,109,112
High-voltage direct current interconnection (HVDC)	1,000	930	-	-	0%	52%	136–138
Pumped hydro	1,875	1,087	1	-	1.4%	-	112,130,139
Lead-acid battery	1,400	771	-	-	19%	-	140–143
Direct air carbon capture and storage (APS report)	33,074	-	-	-	7%	-	18
Direct air carbon capture and storage (DACCS-CE)	-	21,190	-	-	9%	-	18
Direct air carbon capture and storage (DACCS-CW)	-	12,670	-	-	9%	-	17,144

2.3.4 Fuel prices

Projections of fuel prices for power generation in the UK were obtained from the Department of Energy and Climate Change (DECC)[‡]. The range of prices considered are provided in Table 2.3.

Table 2.3 Data sources for fuel costs assumed in the ESO-XEL model

Fuel	Scenario	Cost of fuel in year (£/MWh)								Data sources
		2015	2020	2025	2030	2035	2040	2045	2050	
Uranium (UO ₂ fuel)	Low	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	145
	Central	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
	High	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
Coal	Low	4.8	4.9	6.4	6.4	6.4	6.4	6.4	6.4	146
	Central	5.4	6.3	7.5	7.9	7.9	7.9	7.9	7.9	
	High	6.00	7.8	9.0	9.9	9.9	9.9	9.9	9.9	
Natural gas	Low	13.1	10.1	12.9	15.7	15.7	15.7	15.7	15.7	146
	Central	15.9	17.8	22.8	23.3	23.3	23.3	23.3	23.3	
	High	18.6	25.8	33.8	33.8	33.8	33.8	33.8	33.8	

UK biomass supply chain

The cost of biomass fuel is implemented using a supply curve. Three local sources of biomass are considered: municipal solid waste (MSW), waste wood, and indigenous virgin biomass (Miscanthus is the grass considered). It is also assumed that biomass can be imported from the United States (US) and the European Union (EU). For the local biomass, full supply chain (harvest, processing and pelletisation) emissions and costs are considered. Raw material and pellet production costs are provided in Table 2.4.

Table 2.4 Biomass supply and processing costs. Land availability is obtained from¹⁴⁷.

Biomass type	Raw material (£/tonne)	Pellet conversion rate	Pellet production cost (£/tonne)	Availability (tonne/ha yr)
Municipal solid waste	10 ¹⁴⁸	28.6% ¹⁴⁹	18.14 ¹⁵⁰	151,152
Waste wood	20 ¹⁵³	85.3% ¹⁵⁴	17.55 ¹⁵⁰	151,155
Miscanthus	49 ¹⁵⁶	83.7% ¹⁵⁴	17.86 ¹⁵⁰	157
Imported pellets (US)	120 ¹⁵⁸	-	-	
Imported pellets (EU)	159.5 ¹⁵⁸	-	-	

The capital costs of the pellet plant used to process heterogeneous biomass into pellets were determined from the information summarised in Table 2.5.

For the imported biomass, transport costs from UK ports are considered. Transport *via* road, rail and ship were considered. The unit costs and associated CO₂ emissions resulting from each transport mode are provided below.

The feedstock potentials for indigenous virgin biomass (Miscanthus) was calculated as follows. Land suitable for biomass planting includes all types of grassland. Based on the EDINA land

[‡]DECC was disbanded in July 2016 and merged into the Department of Business, Energy and industrial Strategy (BEIS).

Table 2.5 Cost of biomass pellet production plant

Pellet plant	
Unit capacity	20 tonnes/hr ¹⁵⁰
Capital costs	12,000,000 £/unit ¹⁵⁰
Lifetime	30 years ¹⁴⁸

Table 2.6 Transportation costs and associated GHG emissions assumed

Transportation	Unit transport cost (£/t km) ¹⁴⁸	Unit emissions (kgCO ₂ /t km) ¹⁴⁸
Truck	0.47	0.062
Rail	0.17	0.022
Ship	0.06	0.005

cover of the UK¹⁴⁷, the total UK grassland availability was found to be 8.4 million hectares (Mha), mostly located in the west of the UK. This excluded land required for agriculture (including future projections) to avoid competition with food production. Permanent grasslands of about 6.1 Mha are dedicated to livestock farming. After deducting the land used for livestock, the maximum land available to grow biomass crops is 2.3 Mha. Based on this estimated land availability and yields of *Miscanthus* highlighted in Table 2.4, the availability of virgin biomass was calculated. MSW and Waste wood potentials are calculated based on population.

With the above information, a biomass supply curve was developed (illustrated in Fig. 2.1) and implemented in the ESO-XEL model such that as domestic bioenergy is exhausted, costs rise to reflect the costlier nature of imported biomass pellets.

2.3.5 Modelling Carbon Dioxide Removal

Bioenergy with carbon capture and storage (BECCS)

Plants extract CO₂ from the atmosphere during their growth and convert it into carbohydrates *via* photosynthesis. When burned, the CO₂ captured is returned to the atmosphere hence net emissions from growth and combustion are zero. Biomass use for large-scale power or fuel production, however, requires processing due to its high moisture content and heterogeneous nature. Raw material and processed feedstock must also be transported to processing facility and the power plant, respectively. Land-use change (LUC), and in particular indirect LUC, may also be a significant contributor to GHG emissions, and these will likely need to be quantified on a case by case basis as they are dependent on a range of factors (location, type of land, *etc.*)^{5,159,160}. These processes comprise the biomass supply chain and each contributes an additional energy input and carbon footprint that must be considered in the life-cycle emissions of biomass. Integrating a dedicated biomass-firing plant with CCS allows for CO₂ that would be otherwise released, to be captured and permanently sequestered, thereby can result in a

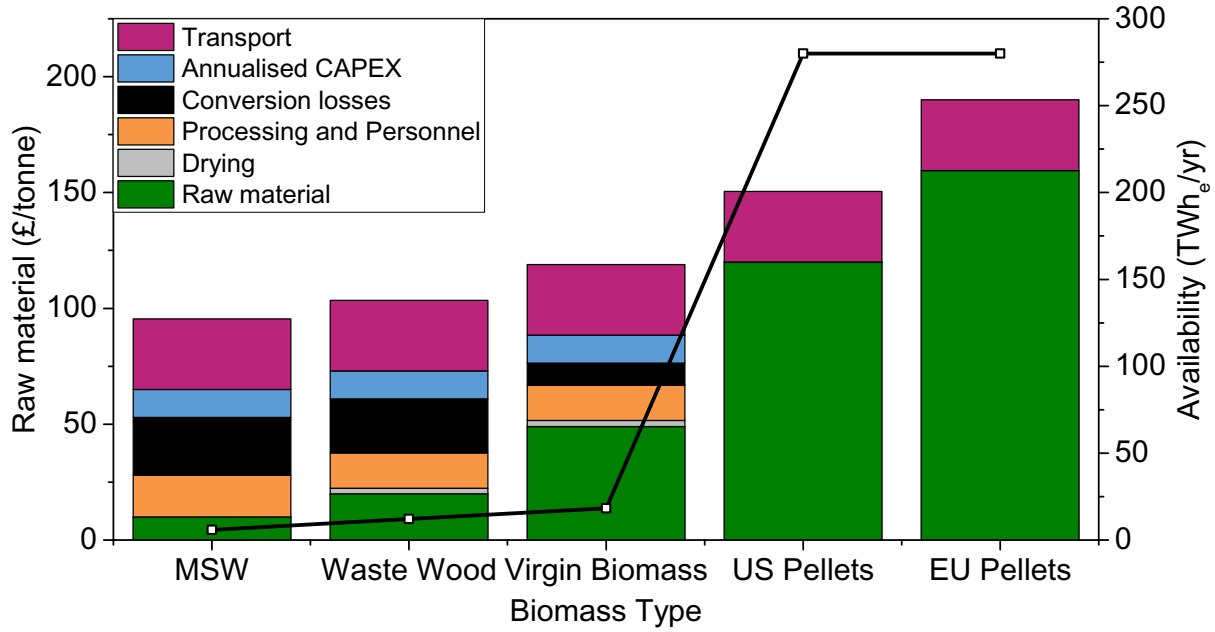


Fig. 2.1 Costs and availabilities of local and imported biomass pellets assumed in the ESO-XEL model. Processing costs—the cost of converting harvested raw biomass to pellets for power plant firing—are only considered for local biomass. Imported biomass is already pelletised when shipped so only additional transport costs are considered.

net removal of CO₂ from the atmosphere (subject to sufficiently low supply chain emissions), *i.e.* negative emissions. As CCS capture efficiency is often around 90%, there are residual emissions from BECCS but the overall carbon balance is negative. Fig. 2.2 provides a simplified representation of the biomass supply chain from harvest to combustion in a power plant.

To capture the above information in the ESO model, the reference BECCS technology assumed is a 500 MW ultra-supercritical power plant with post-combustion capture using conventional MEA solvent ($\eta_{\text{net}} = 35\%$)¹³³. The CDR provided by a BECCS plant is dependent on the type of biomass used and its associated supply chains⁵. The supply chain emissions assumed will be specified for subsequent analyses presented. The load factor range for stable generation is 30-85%, as for a conventional coal-fired plant. BECCS is yet to be developed at utility-scale, so costs cited in the literature are estimates. Eq. 2.1 was used to estimate the capital costs (CAPEX) of the BECCS technology considered. The CAPEX of an ultra-supercritical coal-fired plant with post-combustion CCS (UK: £2368/kW¹¹⁶) was added to the cost of converting coal-fired generating units to full biomass-firing. This comprises modifications to fuel mills and boilers, and construction of pellet storage facilities; it is approximately £354/kW¹⁶¹§. Thus, CAPEX_{BECCS} was estimated to be £2721/kW.

$$\text{CAPEX}_{\text{BECCS}} = \text{CAPEX}_{\text{Coal-CCS}} + \text{CAPEX}_{\text{Biomass-conversion}} \quad (2.1)$$

§Based on £700 million conversion cost of three 660 MW units to full biomass-firing by Drax Power

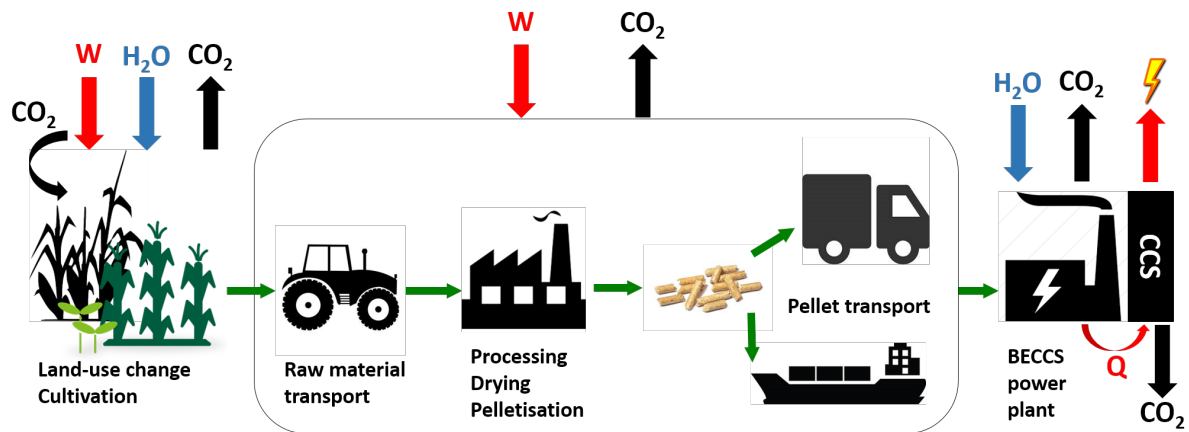


Fig. 2.2 A simplified biomass supply chain from harvest to combustion in a BECCS power plant, showing inputs and outputs of CO_2 , water (H_2O) and energy (W , Q) at different stages. This figure is adapted from⁵.

Direct air carbon capture and storage (DACCS)

CO_2 can be removed directly from the atmosphere by contacting the air with a range of sorbents. The low atmospheric concentration of CO_2 (approximately 408 ppm¹⁶²) means very large energy input and volumes of air are required to obtain a pure CO_2 stream. Commercial DACCS technology manufacturers typically employ amine-functionalised sorbents^{17,163,164} or wet-scrubbing systems with sodium or calcium cycling^{111,144,165}. The two archetypes of DACCS that are being developed commercially, henceforth described as DACCS-CE and DACCS-CW, are considered in this thesis. The first, DACCS-CE, which is being developed by Carbon Engineering Ltd is a wet scrubbing system using calcium cycling to regenerate the capture solution. It is illustrated in Fig. 2.3. A potassium or sodium hydroxide solution captures CO_2 in air and stores it as a carbonate. Calcium carbonate ($CaCO_3$) is then calcined in a kiln to produce calcium oxide (CaO) and CO_2 . Hydrated CaO is then used to regenerate the hydroxide solution for further CO_2 capture. The process description has been detailed previously^{111,144} and will not be repeated here. The majority of the energy input into DACCS – $6.1 \text{ GJ}_{th}/t_{CO_2 \text{ captured}}$ – is heat required for the calcination of $CaCO_3$ at 900°C . This is supplied *via* oxy-fired natural gas combustion, to avoid nitrogen (from burning in air) in the capture exhaust which would require a further separation step. The resulting CO_2 emissions are also captured and sequestered by the DACCS plant. Approximately $1.8 \text{ GJ}_e/t_{CO_2 \text{ captured}}$ is required for fans, liquid pumping, air separation (to provide oxygen for combustion) and CO_2 compression¹⁴⁴.

The high-temperature regeneration step (thermal decomposition of $CaCO_3$) does not allow for flexible operation as repeated cooling and heating of the kiln may threaten process stability. Therefore, it has been assumed that the plant is operated continuously at maximum CO_2 removal rate (utilisation factor of 100%). Based on the energy requirements above, a DACCS-CE plant removing $1 \text{ Mt}_{CO_2}/\text{yr}$ from the atmosphere requires 56 MW_e input. This is equivalent to a CO_2

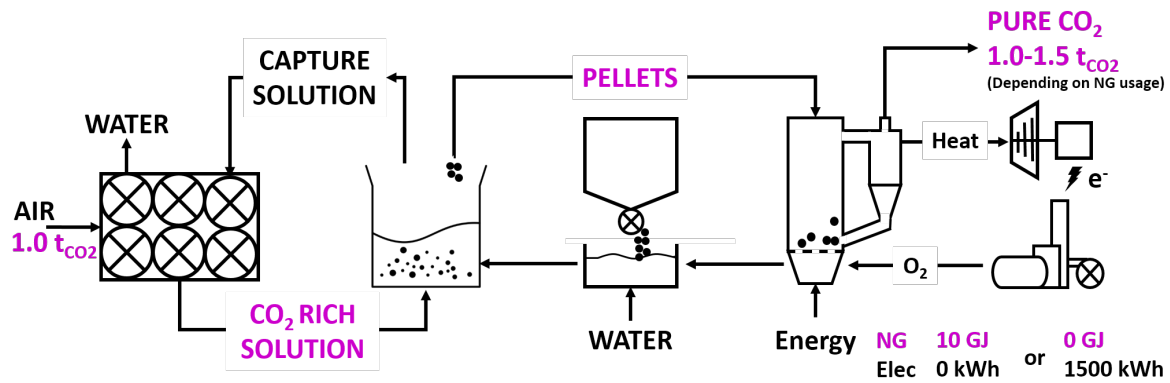


Fig. 2.3 Simplified representation of a wet-scrubbing system for direct removal of CO₂ from the air, adapted from¹¹¹. Capture solution is often sodium hydroxide (NaOH) or potassium hydroxide (KOH). Pellets of calcium carbonate are used to regenerate the capture solution.

removal rate of 2 t_{CO₂e}/MWh consumed¹⁴⁴. The bulk of the energy input to the air capture process, however, is high-grade heat to the kiln which is assumed to be supplied via oxy-fired natural gas combustion. Therefore the heat input does not contribute additional electricity demand to the system. DACCS systems might potentially be composed of a number of small and modular CO₂ collectors^{166,167}. Consequently, the cost of CO₂ collection, transport and storage is expected to be higher than for conventional power plants with CCS. This has been included as an added OPEX of £30/t_{CO₂}¹⁶⁸. Other DACCS technology costs were taken from the APS report¹⁴⁴.

Both archetypes of DACCS currently being developed for commercial purposes are considered in the model. The first, DACCS-CE, uses a hydroxide sorbent to remove CO₂ from air at a cost of \$94-232/t_{CO₂}. Due to this high-temperature nature of the DACCS-CE process, flexible operation may threaten process stability, thus inflexible operation at its maximum load factor—hence constant power and heat consumption—is assumed⁷⁸.

Table 2.7 Description of BECCS and DACCS in the ESO modelling framework. Note that DACCS is a net consumer of power, therefore its unit capacity is shown as negative. DACCS CAPEX¹⁴⁴ has been levelised against the electricity consumption of the plant only; heat consumption not included.

	Unit	BECCS	DACCS (APS report)
Unit capacity	MW	500	-56
Efficiency (HHV basis)	-	35%	7%
Economic lifetime	years	30	25
Plant load factor	-	30-85%	100%
Inertia potential	MW.s/MW	10	-
CO ₂ emissions rate	t _{CO₂} /MWh	-0.8037	-2.022
CAPEX	£/kW _e	2,721	33,074
Fixed OPEX	£/hour	4,229	-
Variable OPEX	£/MWh	96-115	260
Start-up OPEX	£/hour	4,000,000	-
CO ₂ transport & storage	£/t _{CO₂}	10	30 ¹⁶⁸
UK pellet costs	£/tonne	118	-
Imported pellet costs	£/tonne	190	-
Natural gas price	£/MMBTU	-	3.74
Electricity price	£/MWh	-	44

The second archetype, DACCS-CW, is a modular technology that uses an amine-functionalised sorbent and low-grade heat to capture atmospheric CO₂ at a cost of \$600/t_{CO₂}; this is being developed by Climeworks¹⁷. This archetype can utilise waste heat at relatively low temperatures (100°C), so it is assumed to be suitable for flexible operation. Other costs of carbon capture *via* DACCS that have been cited in the literature vary greatly (from \$30-1000/t_{CO₂}¹⁶⁹), as they are based on a range of theoretical engineering approaches (*e.g.* deduced from separation efficiency¹⁷⁰) or have considered only one aspect of the technology^{171,172}. This uncertainty presented a challenge to this study.

2.3.6 Adapted ESO-XEL model formulation

The original formulation of the ESO modelling framework did not consider carbon dioxide removal (CDR) technologies. Given the increasing importance of CDR to delivering the Paris Agreement target, it is necessary that any analysis of the implications of delivering the Paris accord includes them. With the exception of BECCS, CDR technologies are not similar to conventional power generation technologies. In contrast, majority of them either consume energy (direct air capture, enhanced weathering) or have no direct interactions with the energy system (afforestation, ocean fertilisation). The ESO-X and ESO-XEL model variants were

therefore extended to allow for the modelling of CDR technologies and their interactions with the rest of the power system. The complete mathematical formulation of the adapted model which is used to model the UK electricity system is presented below.

Table 2.8 Nomenclature used in the mathematical formulation of the ESO-XEL model

Type	Symbol	Description	Unit
Sets	i	all technologies considered in the system	-
	ig	power generating technologies, $ig \subseteq i$	-
	ic	conventional generating technologies, $ic \subseteq ig$	-
	is	storage technologies, $is \subseteq i$	-
	ir	intermittent renewable technologies, $ir \subseteq ig$	-
	id	carbon dioxide removal technologies, $id \subset i$	-
	il	technologies for which learning rate is applied, $il \subseteq i$	-
	t	time	hours
	a	planning period	years
	c	cluster set obtained using k-means clustering	-
	l	line segments for piecewise linear approximation of learning curve	-
Parameters	Δ_a	interval between planning periods	years
	WF_c	weighting factor for cluster c	-
	$Disc_a$	discount factor $(1 + r)^a$ in year a	-
	$DIni_i$	number of units of technology i in initial year $a = 1$	-
	$DMax_i$	maximum available units of technology i	-
	Des_i	unit capacity of technology i	MW/unit
	BR_i	build rate of technology i	unit/yr
	$LTIni_i$	average lifetime of existing capacity of technology i	years
	LT_i	lifetime of new build of technology i	years
	TL	transmission network losses	%
	$Pmin_i$	minimum power output from technology i	%-MW
	$Pmax_i$	maximum power output from technology i	%-MW
	$Cmax_i$	maximum capacity provision by technology i	%-MW
	RP_i	ability of technology i to provide reserve 0,1	%-MW
	IP_i	ability of technology i to provide inertia 0,1	%-MW
	Ems_i	carbon emissions from technology i	tCO ₂ /MWh
	$CAPEX_i$	capital cost of technology i	£/unit
	$OPEX_{i,a}$	operational cost of technology i	£/MWh
	$OPEXSU_{ig}$	start-up costs of technology ig	£
	$OPEXNL_i$	fixed operational costs of technology i	£/MWh
	$ImpElecPr_t$	import electricity price at time t of cluster c	£/MWh

	$VoLL$	value of lost load	£/MWh
	UT_{ig}	minimum uptime for technology ig	hours
	DT_{ig}	minimum downtime for technology ig	hours
	$SE_{ta,s}$	storage round-trip efficiency	%
	$SOC_{min_{is}}$	minimum state of charge of technology is	%-MW
	$SOC_{max_{is}}$	maximum state of charge of technology is	%-MW
	$AV_{ir,c,t}$	availability factor of technology ir at time t in cluster c	%-MW
	$SD_{c,t,a}$	electricity demand at time t in year a of cluster c	MWh
	UD	maximum share of unmet electricity demand	%-MW
	PL_a	peak load in year a	MW
	CM	capacity margin	%-MW
	RM	reserve margin	%-MW
	WR	dynamic reserve for intermittent renewables ir	%-MW
	SI	minimum system inertia demand	MW.s
	SE_a	maximum system carbon emissions allowed in year a	tCO ₂
	$UKNET_a$	UK negative emissions target in year a	tCO ₂
	$CDRTarget$	UK cumulative CDR target at the end of planning horizon	tCO ₂
	$Xlo_{il,l}$	lower segment x-value of cumulative capacity of technology il installed for piecewise linear function of learning curve	MW
	$Xup_{il,l}$	upper segment x-value of cumulative capacity of technology il installed	MW
	$Ylo_{il,l}$	lower segment y-value of cumulative CAPEX of technology il	£
	$Ylo_{il,l}$	upper segment y-value of cumulative CAPEX of technology il	£
Integer Variables	$b_{i,a}$	number of units of technology i built in year a	-
	$d_{i,a}$	number of units of technology i installed in year a	-
	$n_{ig,a,c,t}$	number of units of technology ig operating at time t in year a of cluster c	-
	$o_{is,a,c,t}$	number of units of technology is operating at time t in year a of cluster c	-
	$f_{id,a,c,t}$	number of units of CDR units id operating at time t in year a of cluster c	-
Positive Variables	$P_{ig,a,c,t}$	energy output of technology ig to demand at time t in year a of cluster c	MWh

	$p2d_{ig,a,c,t}$	energy from technology ig to demand at time t in year a of cluster c	MWh
	$p2s_{ig,a,c,t}$	energy from technology ig to storage	MWh
	$p2CDR_{ig,a,c,t}$	energy from generating technology ig to CDR id	MWh
	$p2is_{is,a,c,t}$	energy to storage technology is	MWh
	$r_{ig,a,c,t}$	reserve capacity provided by technology ig	MW
	$s_{is,a,c,t}$	effective state of charge of technology is at the end of time t in year a of cluster c	MWh
	$s2d_{is,a,c,t}$	energy from storage technology is to demand	MWh
	$s2r_{is,a,c,t}$	energy from storage technology is to reserve	MWh
	$s2CDR_{is,a,c,t}$	energy from storage technology is to CDR id	MWh
	$slak_{a,c,t}$	unmet electricity demand	MWh
	$CDROPEX$	total operational costs of CDR technologies	£
	$TotOPEX_a$	total annual operational costs	£
	$CDR_{id,a,c,t}$	negative emissions provided by CDR id	tCO ₂
	$xs_{il,a,l}$	position of technology il in year a on line segment l	MW
	$y_{il,l}$	cumulative CAPEX of technology il in year a	£
Free Variables	$e_{ig,a,c,t}$	carbon emissions from technology ig at time t in year a of cluster c	tCO ₂
	$u_{ig,a,c,t}$	number of units of technology ig starting up	-
	$w_{ig,a,c,t}$	number of units of technology ig turning down	-
	tse_a	total system carbon emissions in year a	tCO ₂
	tsc	total system cost	£
Binary variables	$\rho_{il,a,l}$	1, if cumulative CAPEX of technology il in year a is on line segment l	-

System design constraints

The following equations describe the system design and capacity expansion constraints implemented in the model. Equation 1 sets the number of units of each technology i that is available in the initial planning period to the existing (2015) capacity in the UK electricity system. Eq. 2 limits the number of new build units of technology i in each planning period to the annual build rate multiplied by the planning interval (5 years). Eq. 3 limits the maximum number of units of technology i that can be deployed in any given year a according to a pre-specified parameter which is based on resource availability, space or potential. Eq. 4 ensures that the initial capacity stock is no longer operational after its lifetime. Eqs. 5 and 6 represent the capacity balances for newly built units. Eqs 7-9 limit the number of units of power generation, energy storage, and CDR technologies, respectively, operating at time t to the number of units of the technology installed in year a .

$$d_{i,a} \leq DIni_i \quad \forall i, a = 1 \quad (1)$$

$$b_{i,a} \leq BR_i \Delta_a \quad \forall i, a > 1 \quad (2)$$

$$d_{i,a} \leq DMax_i \quad \forall i, a = 1 \quad (3)$$

$$d_{i,a} = d_{i,a-1} - b_{i,a-\frac{LTIni_i}{\Delta_a}} + b_{i,a} \quad \forall a \leq \frac{LTIni_a}{\Delta_a} + 1 \quad (4)$$

$$d_{i,a} = d_{i,a-1} + b_{i,a} \quad \forall \frac{LTIni_i}{\Delta_a} < a \leq \frac{LT_a}{\Delta_a} + 1 \quad (5)$$

$$d_{i,a} = d_{i,a-1} - b_{i,a-\frac{LT_i}{\Delta_a}} + b_{i,a} \quad \forall a > \frac{LT_a}{\Delta_a} + 1 \quad (6)$$

$$n_{ig,a,c,t} \leq d_{ig,a} \quad \forall ig, a, c, t \quad (7)$$

$$o_{is,a,c,t} \leq d_{is,a} \quad \forall is, a, c, t \quad (8)$$

$$f_{id,a,c,t} \leq d_{id,a} \quad \forall id, a, c, t \quad (9)$$

System reliability and operability constraints

The following equations that system reliability and operability is maintained throughout the planning horizon. Eq. 10 ensures that system electricity demand is met throughout the planning horizon. Some unmet electricity demand $slak_{a,c,t}$ is allowed and is penalised at an additional system cost equivalent to the $VoLL$ (see Eq. 44). Eq. 11 and 12 ensures that minimum reserve requirements are met. Power system operability is guaranteed by Eq. 13 which ensures that there are sufficient generation and storage units operating at time t to meet the minimum level of system inertia. Eq. 14 calculates the total CO₂ emissions from power generating and CDR units, and limits it to the specified system carbon emissions target. Eq. 15 calculates the cumulative CDR provided by BECCS and DACCS throughout the planning horizon and ensures that it meets a pre-specified CDR target. This constraint is only applied for the analysis presented in Chapter 4. Eq. 16 limits the amount of unmet electricity demand annually.

$$\sum_{ig} p2d_{ig,a,c,t} + \sum_{is} s2d_{is,a,c,t} = SD(1 + TL) - slak_{a,c,t} \quad \forall a, c, t \quad (10)$$

$$\sum_i d_{i,a} Des_i Cmax_i \geq PL_a(1 + CM) \quad \forall a, t \quad (11)$$

$$\sum_{ig} r_{ig,a,c,t} RP_{ig} + \sum_{is} s2r_{is,a,c,t} RP_{is} \geq SD_{c,t,a} RM + \sum_{ir} p2d_{ir,a,c,t} WR \quad \forall a, c, t \quad (12)$$

$$\sum_{ig} n_{ig,a,c,t} Des_{ig} IP_{ig} \geq SI \quad \forall a, c, t \quad (13)$$

$$\sum_{ig,c,t} e_{ig,a,c,t} WFc + \sum_{id,c,t} CDR_{id,a,c,t} WFc \leq SE_a + UKNET_a \quad \forall a \quad (14)$$

$$\sum_{ig=BECCS,a,c,t} e_{ig,a,c,t} WFc + \sum_{id,a,c,t} CDR_{id,a,c,t} WFc \geq CDRTarget \quad (15)$$

$$\sum_{c,t} slak_{a,c,t} WFc \leq UD \sum_t SD_{c,t,a} \quad \forall a \quad (16)$$

Power generation technology constraints

The following equations detail the constraints on power plant operation. Eqs. 17 and 18 ensures that each conventional thermal power plant unit ic operates between its minimum and maximum capacity factors, respectively. Eq. 19 represents the power balance for each generating unit; each unit can send power to the grid, to energy storage or to a CDR technology. For intermittent renewable technologies (except interconnectors which are modelled as such), power output range is determined by availability factor $AV_{ir,c,t}$ according to Eqs. 20 and 21. The CO₂ emissions from each generating technology are determined by Eq. 22. Eq. 23-26 describe the switching behaviour of power plants, and their uptime/downtime constraints.

$$p_{ic,a,c,t} \geq n_{ic,a,c,t} Des_{ic} Pmin_{ic} \quad \forall ic, a, c, t \quad (17)$$

$$p_{ig,a,c,t} + r_{ig,a,c,t} \leq n_{ig,a,c,t} Des_{ig} Pmax_{ig} \quad \forall ig, a, c, t \quad (18)$$

$$p_{ig,a,c,t} = p2d_{ig,a,c,t} + p2s_{ig,a,c,t} + p2CDR_{ig,a,c,t} \quad \forall ig, a, c, t \quad (19)$$

$$p_{ir,a,c,t} \geq n_{ir,a,c,t} Des_{ir} Pmin_{ir} AV_{ir,c,t} \quad \forall ir \setminus Interconnection, a, c, t \quad (20)$$

$$p_{ir,a,c,t} + r_{ir,a,c,t} \leq n_{ir,a,c,t} Des_{ir} AV_{ir,c,t} \quad \forall ir \setminus Interconnection, a, c, t \quad (21)$$

$$e_{ig,a,c,t} = (p_{ig,a,c,t} + r_{ig,a,c,t}) Ems_{ig} \quad \forall ig, a, c, t \quad (22)$$

$$u_{ig,a,c,t} \geq n_{ig,a,c,t} - n_{ig,a,c,t-1} \quad \forall ig, a, c, t \quad (23)$$

$$w_{ig,a,c,t} \geq n_{ig,a,c,t-1} - n_{ig,a,c,t} \quad \forall ig, a, c, t \quad (24)$$

$$u_{ig,a,c,t} \leq n_{ig,a,c,\tau} \quad \forall ig, a, c, \tau = t + t' - 1, t' \leq UT_{ig} \quad (25)$$

$$w_{ig,a,c,t} \leq d_{ig,a} - n_{ig,a,c,\tau} \quad \forall ig, a, c, \tau = t + t' - 1, t' \leq DT_{ig} \quad (26)$$

Storage technology constraints

The following equations describe the operation of storage technologies. Eq. 27-29 define the lower- and upper-bound of stored electricity that can be sent to the grid to meet demand or reserve requirements. Eq. 30 sets the initial state of charge of each storage technology is . Eq. 31 and 32 define the maximum and minimum storage capacity of each technology, according to its maximum and minimum state of charge, respectively. Eq. 33 ensures that the power sent to storage by generators is equal to the power received by storage units throughout the planning horizon. Eq. 34 limits the maximum charging of each technology. Finally, Eq. 35 represents a

power balance (charging and discharging) for each storage technology.

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2CDR_{is,a,c,t} \geq o_{is,a,c,t}Des_{is}Pmin_{is} \quad \forall is,a,c,t \quad (27)$$

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2CDR_{is,a,c,t} \leq o_{is,a,c,t}Des_{is} \quad \forall is,a,c,t \quad (28)$$

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2CDR_{is,a,c,t} \leq s_{is,a,c,t}SEta_{is} \quad \forall is,a,c,t \quad (29)$$

$$s_{is,a,c,t} = Des_{is}SOCIni_{is}SDur_{is} \quad \forall is,a,c,t = 1 \quad (30)$$

$$s_{is,a,c,t} \leq o_{is,a,c,t}Des_{is}SOCMax_{is}SDur_{is} \quad \forall is,a,c,t \quad (31)$$

$$s_{is,a,c,t} \geq o_{is,a,c,t}Des_{is}SOCMin_{is}SDur_{is} \quad \forall is,a,c,t \quad (32)$$

$$\sum_{ig} p2s_{ig,a,c,t} = \sum_{is} p2is_{is,a,c,t} \quad \forall a,c,t \quad (33)$$

$$p2is_{is,a,c,t} \leq o_{is,a,c,t}Des_{is} \quad \forall is,a,c,t \quad (34)$$

$$s_{is,a,c,t} = s_{is,a,c,t-1} - s2d_{is,a,c,t} - s2CDR_{is,a,c,t} + p2is_{is,a,c,t}SEta_{is} \quad \forall is,a,c,t > 1 \quad (35)$$

CDR technology constraints

The following equations describe the operation of CDR units. These set of constraints apply to CDR technologies that consume power such as DACCS. Eq. 36 and 37 ensure that CDR units operate within the allowable range of capacity factors. It is assumed that power to CDR can come directly from generating units $p2CDR_{ig,a,c,t}$, or from energy storage units $s2CDR_{is,a,c,t}$. Eq. 38 determines the total amount of CO₂ removed from the atmosphere at a given time t in year a , and Note that Eq. 14 includes the negative emissions delivered in the overall carbon emissions constraint for the system; $UKNET_a$ is the amount of CDR that the UK wants to deliver in year a .

$$\sum_{ig} p2CDR_{ig,a,c,t} + \sum_{is} s2CDR_{is,a,c,t} \leq f_{id,a,c,t}Des_{id}Pmax_{id} \quad \forall id,a,c,t \quad (36)$$

$$\sum_{ig} p2CDR_{ig,a,c,t} + \sum_{is} s2CDR_{is,a,c,t} \geq f_{id,a,c,t}Des_{id}Pmin_{id} \quad \forall id,a,c,t \quad (37)$$

$$CDR_{id,a,c,t} = (\sum_{ig} p2CDR_{ig,a,c,t} + \sum_{is} s2CDR_{is,a,c,t})Ems_{id} \quad \forall id,a,c,t \quad (38)$$

Technology cost learning constraints

The following equations describe the implementation of technology cost learning in the model. These constraints only apply to technologies with a non-zero learning rate il (see Table 2.2). Learning curves are approximated using a piecewise linear function which shows the relationship between cumulative capacity of technology installed in year a , $xs_{il,a,l}$, and the cumulative

CAPEX in year a , $y_{il,a}$. Eq. 39 ensures that only one segment of the cost curve is selected. Eq. 40-42 determines the position of the cumulative capacity on the x-axis. Eq. 43 determines the cumulative CAPEX of technology il via linear interpolation of the piecewise linear function.

$$\sum_l \rho_{il,a,l} = 1 \quad \forall il, a \quad (39)$$

$$xs_{il,a,l} \geq Xlo_{il,l} \rho_{il,a,l} \quad \forall il, a, l \quad (40)$$

$$xs_{il,a,l} \leq Xup_{il,l} \rho_{il,a,l} \quad \forall il, a, l \quad (41)$$

$$\sum_{a'=1}^a b_{il,a'} = \sum_l xs_{il,a,l} \quad \forall il, a, a' \leq a \quad (42)$$

$$y_{il,a} = \sum_l Ylo_{il,l} + \rho_{il,a,l} \frac{Yup_{il,l} - Ylo_{il,l}}{Xup_{il,l} - Xlo_{il,l}} (xs_{il,a,l} - Xlo_{il,l} \rho_{il,a,l}) \quad \forall il, a \quad (43)$$

Objective function

Changes were also made to the objective function which is to minimise the total system cost $mintsc$, shown in Equation 44, to capture intra-interval OPEX. In the original formulation, only the OPEX incurred during the planning intervals a (*i.e.* every 5 years) was considered. Consequently, low-OPEX technologies such as iRES, were disadvantaged as their operating costs were overestimated relative to other technologies. Linear interpolation was used to determine the total system OPEX for the years between the planning intervals. The implementation of the model in GAMS is provided in Appendix B.

$$\begin{aligned} tsc = & \sum_i CAPEX_i b_{i,a} Des_i / Disc_a + \sum_{a < 8} TotOPEX_a \Delta_a / Disc_a \\ & + \sum_{a > 1} (TotOPEX_a - TotOPEX_{a-1}) \left(\frac{\Delta_a}{2} - 1 \right) / Disc_a + \sum_{a=8} TotOPEX_a / Disc_a \quad (44) \end{aligned}$$

The total annual OPEX is calculated as follows.

$$\begin{aligned} TotOPEX_a = & \sum_{ig,c,t} (u_{ig,a,c,t} OPEXS U_{ig} W F_c) \\ & + \sum_{ig,c,t} (OPEX_{ig,a} p_{ig,a,c,t} W F_c + OPEX N L_{ig} n_{ig,a,c,t} W F_c) \\ & + \sum_{is,t} (OPEX_{is,a} (s2d_{ig,a,c,t} + s2CDR_{is,a,c,t}) W F_c + OPEX N L_{is} o_{is,a,c,t} W F_c) \\ & + \sum_{id} OPEX_{id,a} \left(\sum_{ig,c,t} p2CDR_{ig,a,c,t} W F_c + \sum_{is} s2CDR_{is,a,c,t} W F_c \right) \\ & + \sum_{i=InterImp,t} ImpElecPr_t p2d_{i,a,c,t} W F_c + \sum_{c,t} slak_{a,c,t} W F_c VoLL \quad \forall a \quad (45) \end{aligned}$$

2.3.7 Marginal cost of electricity

The MILP formulation does not allow for the direct calculation of shadow prices, as this is dependent on the algorithmic approach used to solve the model^{173–175}. The shadow price associated with a particular constraint represents the increase in the optimal value of the objective (in this case, total system cost) per unit increase in the amount of resources available. In this thesis, the marginal system cost of electricity (MC) has been estimated using the shadow price of the electricity balance constraint (*supply = demand*). Sensitivity analysis on the electricity demand (+/- 1 MW) was carried out to validate the MC estimates. This is illustrated in Fig. 3.8.

2.4 Modelling the Nigerian electricity system

The ESONE model is the spatially-disaggregated version of the ESO modelling framework⁸⁵. This allows for both generation and transmission capacity expansion planning, where the transmission network is modelled as power flow between zones. This was used for the Nigeria analysis, presented in Chapter 5. The detailed mathematical formulation of the model has been described previously⁸⁵ and how it is implemented in GAMS is provided in Appendix B. The key features of the model that differentiate it from the ESO-X/ESO-XEL model versions are described in Section 2.4.1.

The ESONE model was developed for the UK electricity system, with the UK divided up into 29 zones between which power could be transmitted⁸⁵. However, it was adapted to model the Nigerian electricity system. The model was found to be suitable for this purpose for the following reasons: 1) the spatial granularity could be increased to reflect the number of states in Nigeria which represent the smallest entities that have some autonomy over energy policy; 2) it was important to understand the geographical distribution of energy infrastructure because of Nigeria's fragile geopolitical landscape so the ESO-XEL model (which has no spatial disaggregation) was insufficient; 3) data on intra-state generation and transmission infrastructure are widely available therefore could be accurately modelled; 4) the study carried out on Nigeria (see Chapter 5) was concerned with the cost-optimal electricity supply mix, therefore the detailed modelling of power transmission or distribution networks was not necessary; and 5) owing to the focus on cost-optimal electricity supply, the objective function of the model is to minimise the total system cost—the total capital and operating costs invested into power generation and transmission over time—, thus even off-grid technologies can be represented using a constraint limiting their ability to export power to the grid, and different costs of generation compared to their large-scale equivalents (e.g. solar PV vs mini-grids or off-grids).

2.4.1 Key model features and assumptions

- The country (for the purpose of this thesis, Nigeria) has been discretised into 37 zones. These correspond to the 36 states and the Federal Capital Territory, which are semi-autonomous regions in the Nigerian federation.
- The initial year in the model is 2020. Optimal system design—both generation and transmission capacity—are determined in time steps each of 10 years duration. Planning time step is increased from 5 years (in ESO-XEL model) to 10 years to reduce computation time.
- Initial capacity availability, maximum deployment, and electricity demand are specified for each zone. Wind, solar and hydro resource availability is specified for each zone (see Section 2.4.5 for methodology applied). Other system-wide constraints such as annual carbon emissions allowed, minimum reserve capacity and minimum system inertia required are specified for the whole system.
- Owing to the computational difficulty of running the model with perfect foresight (single run solve times of > 1 week), the planning time step is increased from 5 to 10 years, and myopic foresight of two planning periods of 20 years is assumed. This is implemented by first solving the model for two planning periods (2020-2030 and 2030-2040). The solutions of the first iteration are then fixed as input parameters for the final iteration (2040-2050).
- Initial transmission network is specified according to Fig. A.1. It is assumed that power flow is between the centroid of each zone, *i.e* demand is concentrated at each transmission node. Power distribution to consumers is not considered. Power transmission is assumed to be possible between bordering zones only.
- Optimal power flow is modelled as direct current (DC) flow, assuming constant current, generator voltages, angles and power factor (VAr/Watt ratio). Energy losses are a function of transmission line length and power flow⁸⁵.
- Owing to the relatively small size of Nigeria's neighbouring countries to which it exports electricity, electricity import potential was not considered.
- Unmet electricity demand is penalised through the Value of Lost Load (VoLL) – an added system cost of \$10,000/MWh. This value was selected because it ensures that unmet electric load is limited to less than 2% of annual demand when the system demand constraint is relaxed, as was the case for the ESO-XEL model.
- Maximum power flow between zones, transmission line build rate, and maximum transmission capacity between states are all specified.

- To reduce computation time to less than a day per model run, technology cost learning is implemented exogenously, *i.e.* capital costs vary temporally irrespective of their deployment level within the system. The cost projections input into the model are detailed in Table 2.10.
- No shadow carbon price is included in the model.

2.4.2 System parameters

Electricity demand: present and future

Hourly demand data for Nigeria is not publicly available and difficult to obtain. However, a study by Fichtner in collaboration with the Transmission Company of Nigeria (TCN) completed an investigation to determine the amount of actual electricity demand in the country, *i.e.* including the demand connected to the grid but not being met. The demand profile for two days in July 2016 was published and is illustrated in Fig. 2.4. This was extended and used as the demand profile for the country over the year. As there is minimal seasonality in Nigeria's demand patterns[¶], this was considered to be a reasonable approximation. An economic analysis carried out by the same Fichtner study also forecast the electricity demand for each distribution region until 2050. The analysis presented in Chapter 5 of this thesis scales the 2016 demand profile (by dividing the peak forecast demand for a future year by the peak during the days shown) to determine hourly demand in future years. Demand for each state is assumed to be equal to its share of population in its distribution zone, which is shown in Fig. 2.5.

[¶]Nigeria has two seasons: rainy and dry. Discussions with staff at the Transmission Company of Nigeria suggest that no changes in demand are observed between the two seasons. Additionally, no studies have been published suggesting otherwise.

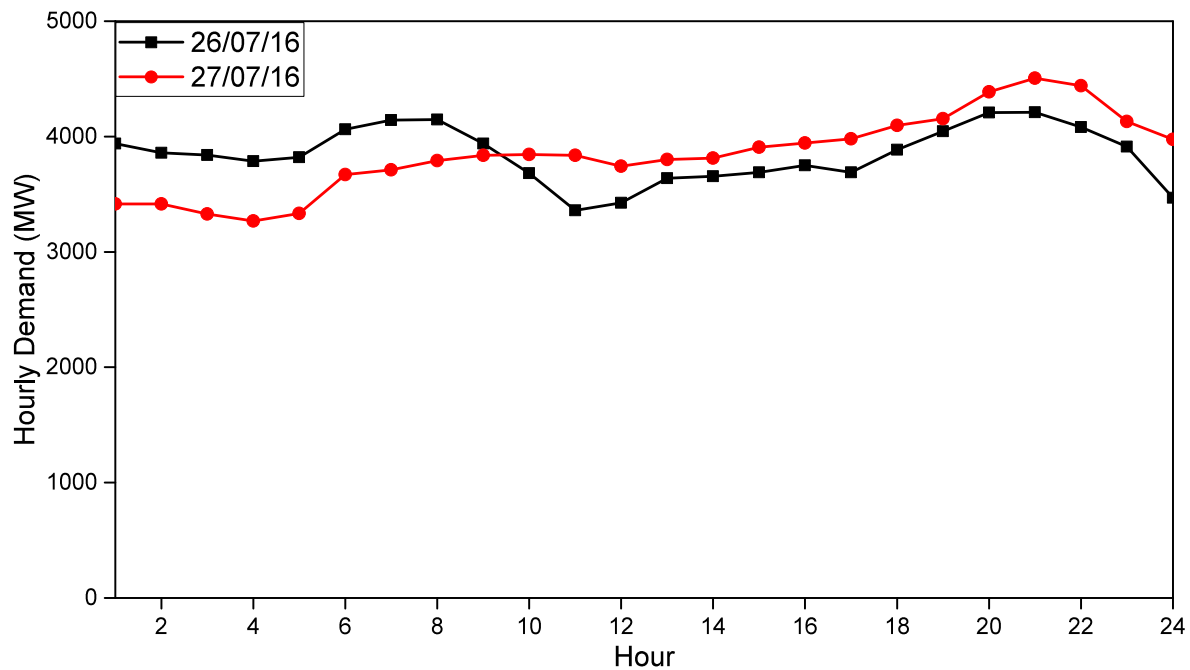


Fig. 2.4 Hourly power demand on 26/07/16 and 27/07/16 from the TCN National Control Centre, Osogbo¹⁷⁶

After the partial privatisation of the power sector in 2013, 11 successor distribution companies (DISCOs) were established and sold to private entities. Each DISCO is responsible for serving electricity consumers in a group of states. Fig. 2.5 shows the distribution zones established: Abuja Electricity Distribution Company (AEDC) – Kogi, Nassarawa and Niger states, and the Federal Capital Territory; Benin Electricity Distribution Company (BEDC) – Delta, Edo, Ekiti and Ondo states; Eko Electricity Distribution Company (EKEDC) – Lagos Island; Enugu Electricity Distribution Company (EEDC) – Abia, Anambra, Ebonyi, Enugu and Imo states; Ibadan Electricity Distribution Company (IBEDC) – Kwara, Ogun, Osun and Oyo states; Ikeja Electricity Distribution Company (IKEDC) – Lagos Mainland; Jos Electricity Distribution Company (JEDC) – Bauchi, Benue, Gombe and Plateau states; Kaduna Electricity Distribution Company (KAEDCO) – Kaduna, Kebbi, Sokoto and Zamfara states; Kano Electricity Distribution Company (KADCO) – Jigawa, Kano and Katsina states; Port-Harcourt Electricity Distribution Company (PHEDC) – Akwa-Ibom, Bayelsa, Cross-River and Rivers states; Yola Electricity Distribution Company (YEDC) – Adamawa, Borno, Taraba and Yobe states.

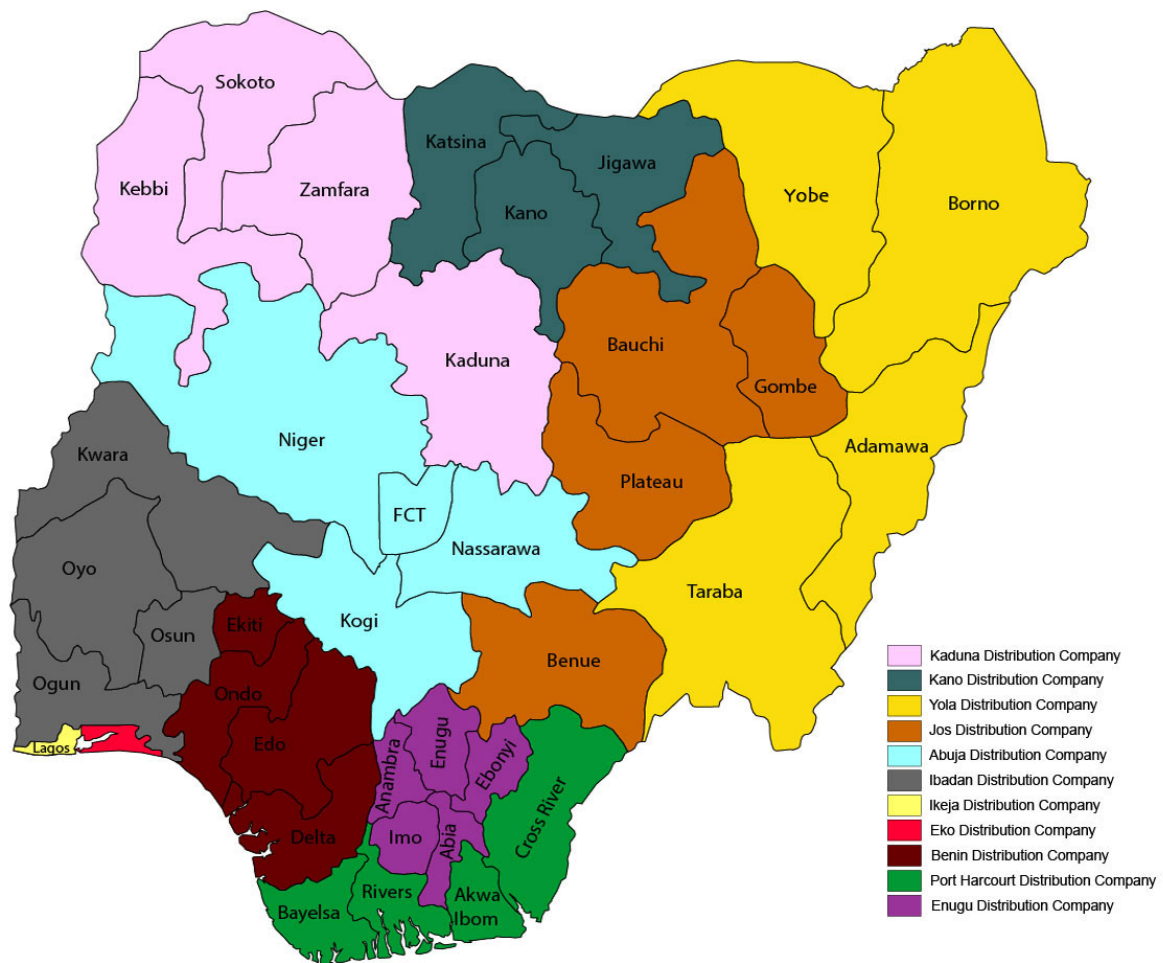


Fig. 2.5 Map showing the geographical remit of the 11 successor distribution companies established after the privatisation of the Nigerian power sector in 2013¹⁷⁷

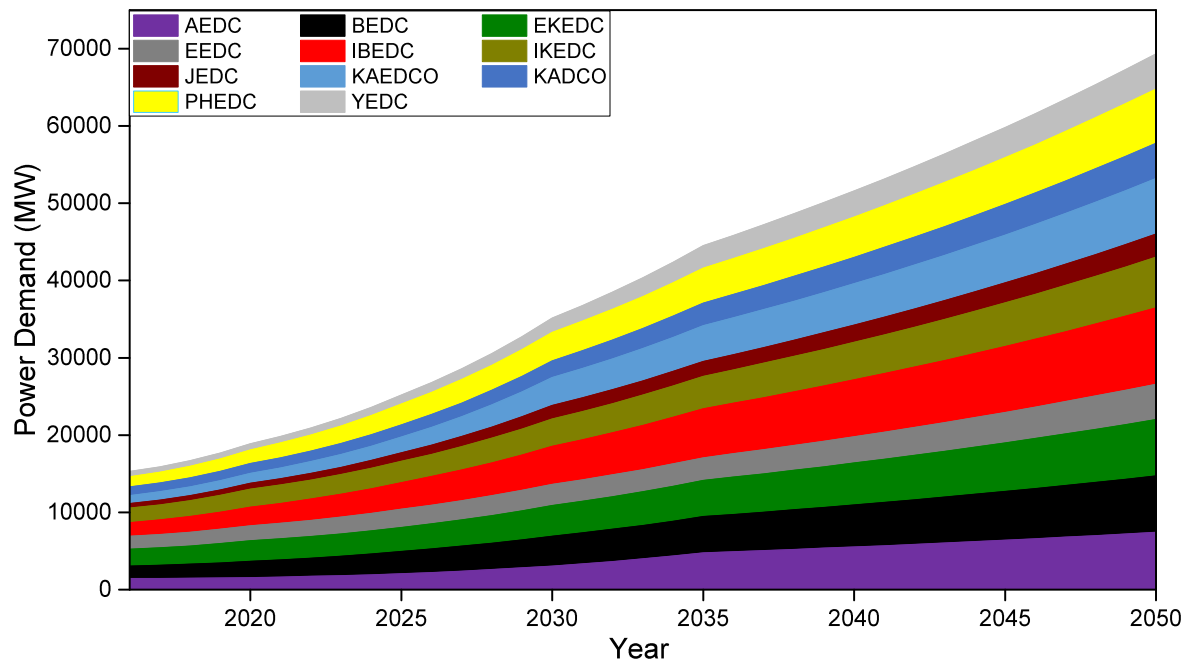


Fig. 2.6 Total forecast demand (including suppressed demand) by distribution zone from 2016 to 2050¹⁷⁶

The other system parameters implemented in the ESONE model are as provided in Table 2.9. A minimum reserve capacity margin of 5% and dynamic reserve (added capacity reserve due to increasing penetration of iRES) of 15% of iRES generation is implemented in the ESONE model. This is based on the UK electricity system because the current security and reliability requirements in the Nigerian power system are well-below international security and reliability standards²⁸¹. Network losses are provided by the Nigerian Electricity Regulatory Commission, the sector's regulator. The amount of dynamic reserve to compensate for the variability of intermittent renewables is taken from a study for the UK⁹⁹, as there are no studies available on the effects of intermittency on system operability within the Nigerian or sub-Saharan African (SSA) context. The availabilities of solar and wind are obtained using *Renewables.ninja*, a tool that simulates hourly power output from solar and wind power plants using historical satellite data⁹⁶. Hydro availability profiles are determined from the three existing hydroelectric power stations in Nigeria. How availability profiles are determined for each zone are described in detail in Section 2.4.5. A discount rate of 5-15% was used in several studies to reflect the greater uncertainty of future cash flows (relative to developed economies)^{176,178}. 10% was selected for base case scenarios and a sensitivity analysis was carried out on the value in Chapter 5. No carbon capture and storage (CCS) technology has been deployed at scale in SSA and discussion of the technology within the African context is minimal so there are no reliable cost estimates for CO₂ transport and storage (T&S) infrastructure in SSA in the literature. The UK CO₂ T&S cost (implemented in the ESO-XEL model) was also assumed in the Nigeria case study. CCS is considered to be unavailable in the planning horizon considered for the Nigeria case study

(2020 to 2050), with the exception of one sensitivity analysis carried out (see Fig. 5.15). Finally, the Value of lost load is estimated to be \$10,000/MWh; this ensures that unmet electric load is limited to <2% of annual demand even when the system demand constraint is relaxed.

Table 2.9 Data sources for system parameters assumed in the ESONE model

Nigeria electricity system	Value	Data source(s)
Hourly electricity demand	-	176
Reserve margin	5% of demand	176
System inertia requirement	260 MW	176
Capacity reserve for intermittent renewables	15%	99
CO ₂ emissions targets until 2050	-	56,179
Power transmission and distribution losses	15.4%	176
Value of lost load	10,000 \$/MWh	-
Hourly availability of solar, onshore wind and offshore wind	-	96,105,180–182
Discount rate	10%	176
CO ₂ transport and storage costs	£10/tCO ₂	108

2.4.3 Technology parameters

Technology costs differ from country to country for technical, economic and sociopolitical factors. Typically, power generation costs in sub-Saharan Africa are lower than in developed countries because of fewer regulatory requirements and planning hurdles. The capital costs and efficiencies assumed for power generation in Nigeria are provided in Table 2.10. Technology capital cost reduction forecasts are taken from the International Energy Agency's (IEA) *World Energy Outlook 2018*.

2.4.4 Fuel prices

The operating costs of different power technologies are determined based on the following factors: fuel prices, efficiencies, carbon prices (not included for Nigeria) and cost of CO₂ T&S. A range of fuel prices for power generation in Nigeria, obtained from the sources listed in Table 2.11, is considered in the analysis presented in Chapter 5. Where no range is provided (coal and uranium), data was insufficient as those resources have never been mined or used for power generation at scale in Nigeria.

Table 2.10 Data sources for the technology costs and operational parameters implemented in the ESONE model

Technology	2020 CAPEX (\$/kW)	2030 CAPEX (\$/kW)	2040 CAPEX (\$/kW)	Fixed O&M (\$/kW/yr)	Efficiency (HHV basis)	Data sources reviewed
Steam	1,040	1,040	1,040	25	31%	183
Nuclear	4,000	4,000	4,000	170	37%	112,183
Coal (super-critical)	1,600	1,600	1,600	75	43%	183
Dedicated biomass-fired	2,150	2,150	2,150	75	35%	183
Combined cycle gas turbine (CCGT)	700	700	700	25	58%	183
Open cycle gas turbine (OCGT)	400	400	400	20	38%	183
Diesel (Off-grid)	2,981	2,981	2,981	15	50%	183–186
Coal post-combustion CCS	4,500	4,250	3,900	160	33%	183
CCGT post-combustion CCS	2,450	2,300	2,050	80	51%	183
Bioenergy with CCS (BECCS)	4,500	4,250	3,900	160	35%	5,108,130,132–134
Onshore Wind	1,860	1,740	1,720	46	100%	183
Offshore Wind	3,900	2,900	2,900	145	100%	183
Solar Photovoltaic (PV)	2,180	1,320	1,140	22	100%	183
Concentrated solar power (CSP)	5,050	5,050	5,050	180	100%	183
Solar (Off-grid)	2,580	1,580	1,360	26	100%	183
High-voltage direct current interconnection (HVDC)	1,000	1,000	1,000	1	52%	136–138
Hydro (large-scale)	2,100	2,100	2,100	55	100%	183
Hydro (small, <1 MW)	3,300	3,300	3,300	65	100%	183
Lead-acid battery	1,000	1,000	1,000	1	-	183,187
Direct air carbon capture and storage (DACCS-CE)	28,250	28,250	28,250	100	-	18
Direct air carbon capture and storage (DACCS-CW)	16,890	16,890	16,890	200	-	17,144

Table 2.11 Fuel costs inputs in the ESONE Nigeria model

Fuel	Scenario	Fuel Cost (\$/MWh)				Data sources
		2020	2030	2040	2050	
Natural gas	Low	10.24	10.24	10.24	10.24	184,188
	Central	13.0	13.0	13.0	13.0	
	High	23.88	23.88	23.88	23.88	
Biomass	Low	4.0	4.0	4.0	4.0	188,189
	Central	6.04	7.75	8.98	9.91	
	High	22.0	22.0	22.0	22.0	
Coal		17.4	17.4	17.4	17.4	188,189
Diesel		62.2	62.2	62.2	62.2	184,189
Uranium (UO ₂) fuel		2.9	2.9	2.9	2.9	189

2.4.5 Regional wind, solar and hydro resources

The spatial and temporal variation in the capacity factors of wind, solar and hydro power were considered in the ESONE model. Hydro availability was calculated based on the daily generation

profiles of the three operational hydroelectric power stations in the country: Kainji, Shiroro and Jebba dams, all located in Niger state. Fig. 2.7 illustrates their seasonal variations in power output in 2018. The availability factor was calculated by daily peak generation for the year by the daily generation. Hourly availability of wind and solar were obtained from *Renewables ninja*, a tool which uses weather data from global reanalysis models and satellite observations to simulate the output of wind and solar power plants^{96,105,180–182}. Nigeria is made up of 36 states and the Federal Capital Territory. These are further subdivided into 774 local government areas (LGAs). Owing to the diverse geography within states and thus varying weather/climate data, the hourly wind and solar availability were not obtained for a single location within each state. Instead, the availabilities were obtained for the 774 LGAs in 2018 to ensure higher-resolution data. For each state, the LGAs were ranked according to mean availability (highest to lowest). The average availability of the top third of LGAs was then calculated and used to represent the availability profile for the state. The hourly availability profiles were then clustered using the k-means clustering algorithm described in Section 2.5.

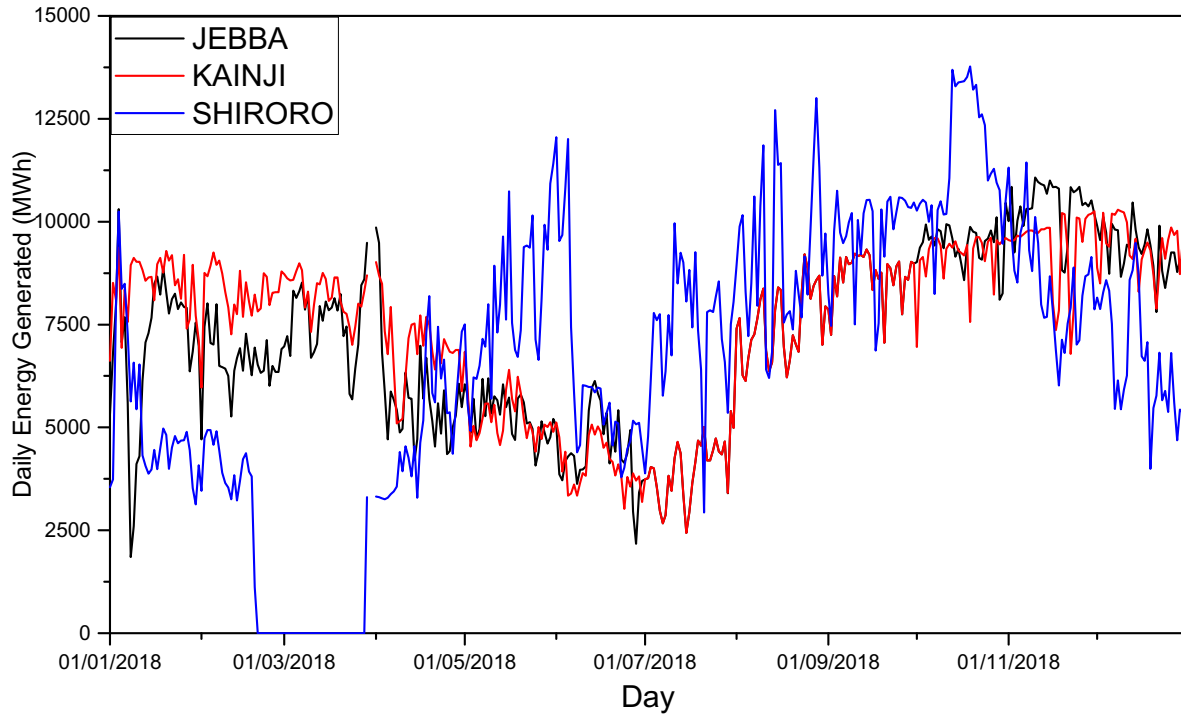


Fig. 2.7 Power generated daily by Nigeria's three hydroelectric power stations: Jebba, Kainji and Shiroro dams

2.5 Data clustering

2.5.1 Data clustering

The ESO model was selected for its ability to determine both optimal capacity expansion (on a multiyear timescale) and electricity dispatch (on an hourly timescale). For ease of model

computation, temporal data implemented in the model (electricity demand, import prices, and wind, solar and hydro availabilities) were clustered using the k-means clustering algorithm. The algorithm is an iterative one which seeks to partition a dataset into distinct sub-groups where each data point belongs to only one group. Data points are assigned to a cluster such that the sum of the squared distance between the data points and the cluster's centroid (arithmetic mean of all data points in that cluster) is minimised.

The algorithm was used to determine a number, n , of representative days ("clusters") for each temporal data parameter. The clustering algorithm was implemented in R¹⁹⁰ as follows:

1. Collate hourly resolution data for all temporal parameters (electricity demand, electricity import prices, and solar, onshore wind, offshore wind and hydro availabilities). Data sources for each parameter are detailed in Table 2.2 for the UK, and Section 2.4.5 for Nigeria.
2. Divide the collated dataset into days. This sets the cluster size to 24 hours. For the ESONE model, the clustering algorithm was applied to zone-specific parameters (37 zones were used to represent Nigeria).
3. Extract the days with the peak values for each parameter. These will be the $(n + 1)^{\text{th}}$ representative days with an assigned weighting factor of 1.
4. Normalise the electricity demand and import prices parameters so that the values are between 0 and 1. Availabilities are already normalised.
5. Specify the number of clusters, n , which is 10 for the analyses presented in this thesis^{73,76}. This value was selected based on previous work with the model which assessed incurred errors due to data clustering^{84,86,120}. The ESO model was run with full temporal resolution (8760 hours), and then with data clustered into 20 and 10 representative days. It was found that using 10 clusters reduced the computational time significantly—solve time was reduced to 1-4 hours for the ESO-XEL model, and 1-12 hours for the ESONE model. For non-technology specific variables (optimised total costs and capacity installed), clustering resulted in an accuracy loss of -6% to 0% relative to the full resolution case, which was considered to be acceptable for the increased ease of computation.
6. Apply the k-means clustering algorithm to the collated multidimensional data set. This preserves the hourly and zonal correlation between the parameters. Each daily profile will now be allocated to a cluster.
7. For each parameter, extract the n representative days given by the final iteration of the algorithm and their corresponding weighting factors.
8. Add the $(n + 1)^{\text{th}}$ representative day determined in Step 3.

2.6 Model implementation

All models used for the analysis presented in this thesis were implemented in GAMS 25.0.3 and solved using CPLEX 12.8.0 solver on a x86_64 machine using 24 threads. The GAMS code for the ESO-XEL and ESONE models is provided in Appendix B.

Chapter 3

Delivering a Decarbonised Electricity System: The Case for the UK

Chapter Roadmap

In 2008, the UK legislated an 80% reduction in economy-wide greenhouse gas emissions relative to 1990 levels by 2050 through the Climate Change Act⁶¹. The Committee on Climate Change (CCC) projected that the power sector needs to be virtually decarbonised by mid-century¹⁰⁷. Additionally in the Intergovernmental Panel on Climate Change Fifth Assessment Report, it was highlighted that the deployment of carbon dioxide removal (CDR) technologies is critical to delivering the Paris Agreement³. A 2016 CCC report stated that the UK would have to provide, in addition to a decarbonised power system, 50 Mt_{CO₂}/yr of CDR by 2050 to deliver GHG emissions reductions that are consistent with the Paris accord¹⁹¹. This study, *via* the ESO-X power supply capacity expansion model described in Chapter 2, investigates the least-cost decarbonisation pathways that: 1) deliver a zero-carbon UK electricity system by 2050 in accordance with the Climate Change Act, and 2) deliver the additional CDR needed to be consistent with the Paris accord. There is a particular focus on the potential role and value of two CDR technologies: bio-energy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS), in meeting the UK's GHG emissions reduction targets. Section 3.1 provides an overview of the UK electricity system and the challenges that it faces to decarbonise. Section 3.2 describes the different scenarios that are investigated and the modelling assumptions that are made in this study. Section 3.3 discusses the results from the ESO-X model. Section 3.4 determines the role and quantifies the value of CDR technologies in decarbonising the UK electricity system. Section 3.5 discusses the effects of uncertainty in key parameters on the cost-optimal system design. Finally, Section 3.6 provides a conclusion.

3.1 Introduction

3.1.1 The Paris Agreement and the UK power sector

Through the Paris Agreement, most nations committed to keeping average global temperature rise to well below 2°C (above pre-industrial levels) by 2100². Global decarbonisation pathways consistent with this target are reliant on the extensive deployment of CDR, usually BECCS³. The UNEP Emissions Gap Report 2017 states that CDR are necessary in addition to other mitigation options to manage possible overshoot of near-term GHG emissions targets. In the UK, the *Climate Change Act 2008*⁶¹ (CCA) set a 2050 target to reduce economy-wide greenhouse gas (GHG) emissions by 80% relative to 1990 levels. Fig. 3.1 illustrates the projected reductions in sectoral emissions required to achieve this. The power sector must be essentially completely decarbonised by 2050¹⁰⁷.

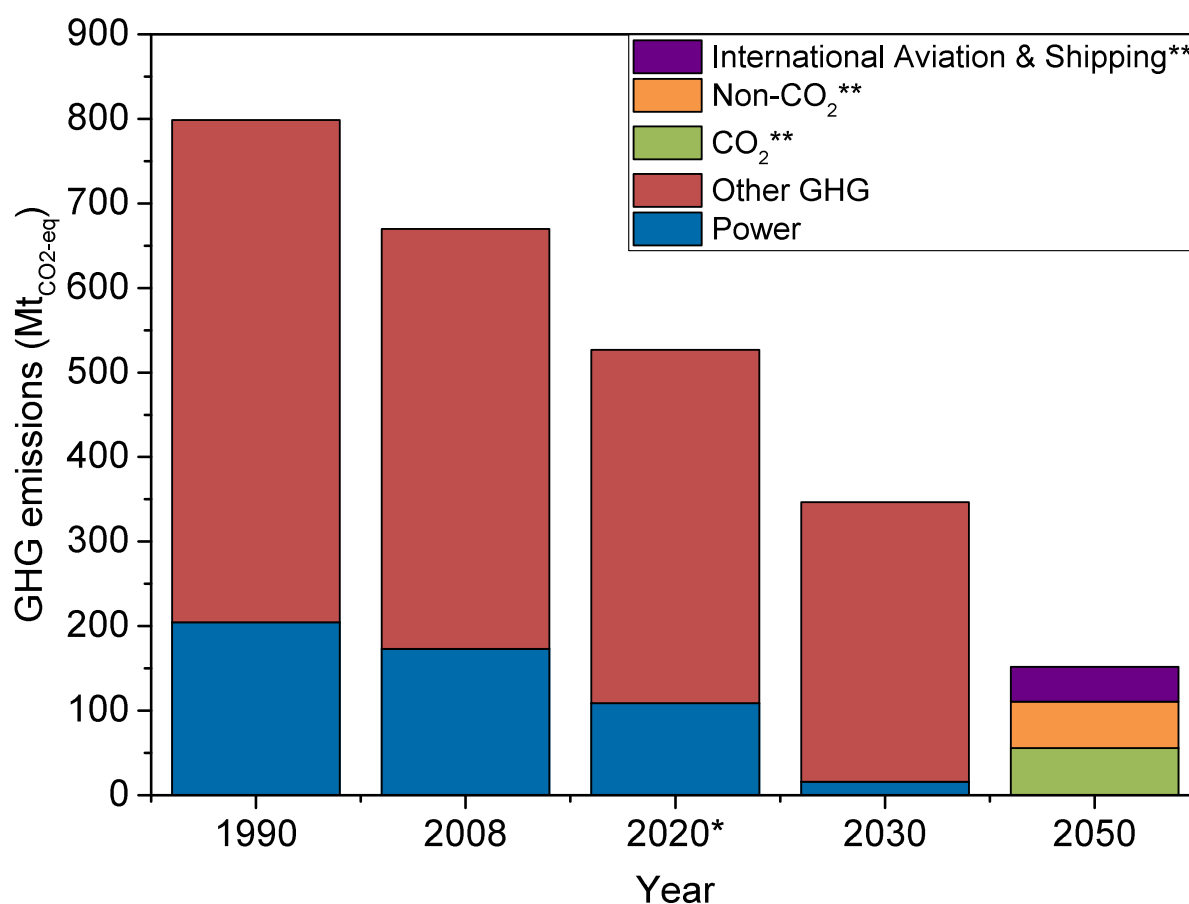


Fig. 3.1 Power sector emissions in the context of UK greenhouse gas emissions (1990-2050). Figure reproduced from CCC report. * Assuming recommended implementation of measures proposed by the CCC¹⁰⁷. ** Based on CCC projections.

To meet its commitments to the Paris Agreement, however, the UK requires deeper decarbonisation pathways (relative to the CCA target). Fig. 3.2 shows the sectoral emissions

that must be achieved by 2050 to keep a 50% likelihood of keeping global temperature rise to 1.5°C by 2100. Approximately 50 Mt_{CO₂}/yr of negative emissions are needed by 2050 to offset CO₂ emissions from sectors with more difficult or expensive mitigation solutions, including aviation, shipping and transport^{191,192}.

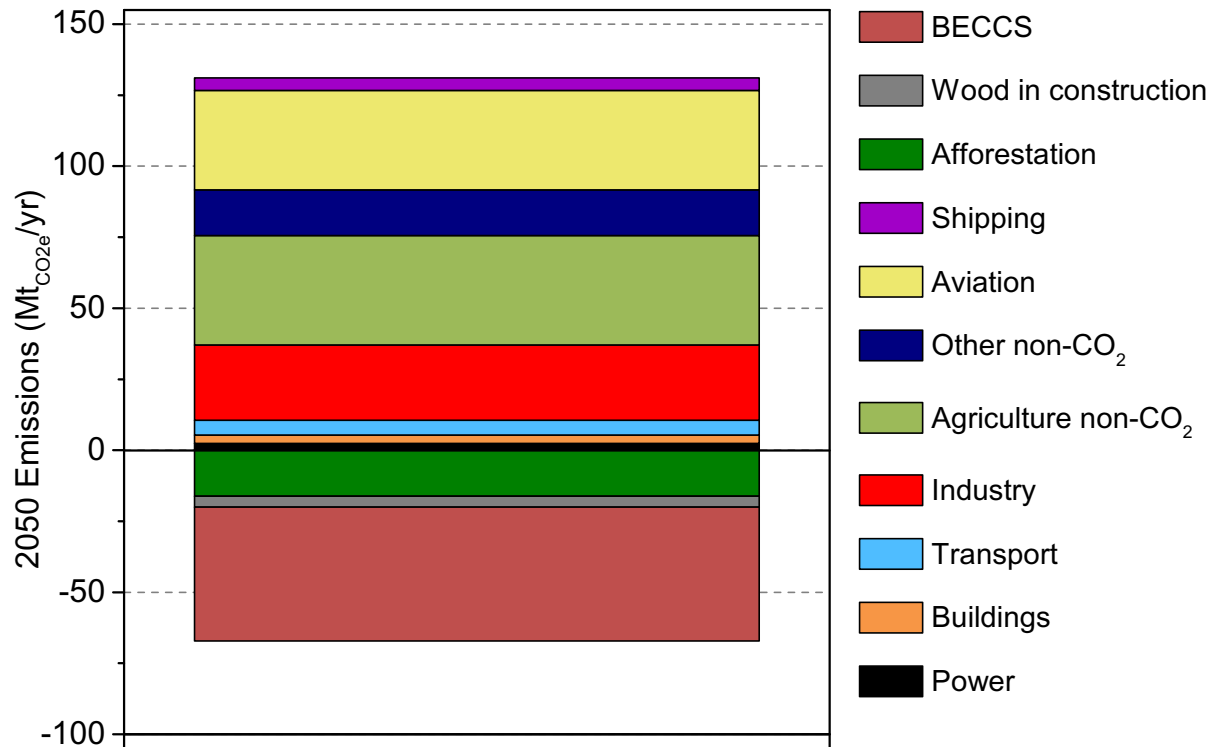


Fig. 3.2 Residual UK greenhouse gas emissions in 2050 under the CCC's Max deployment scenario¹⁹¹. 92% GHG emissions reduction (relative to 1990 levels) is achieved by 2050. This is within the range of 86-96% suggested by the most ambitious paths available from global climate-economy models (which keep a 50% likelihood of 1.5°C in 2100 after overshooting). Figure has been reproduced from the CCC report¹⁹¹.

Whilst large-scale afforestation/reforestation has long been practised^{193,194}, BECCS¹⁶ and DACCS^{111,166,167} are the only engineered CDR being pursued at demonstration scale. These technologies are the focus of this study. Studies that have evaluated the negative emissions achievable through deployment of BECCS or DACCS have considered them in isolation¹⁹ and have neglected to consider the operation of these technologies within the broader energy system, and thus have not provided any insight into the extent to which they provide value to these systems, or the way in which they might operate therein. There is therefore a lack of understanding of the services they can provide and the incentives needed for each service (*e.g.*, power generation, CO₂ removal).

3.1.2 The UK electricity system

Fossil fuels have historically dominated the fuel mix for power generation in the UK and still provide the majority of power generation today. Fig. 3.3 shows that coal and gas contributed

53% of the fuel input for electricity generation in 2016. Imminent emissions reductions targets have spurred a transition to less-polluting fuels and renewable sources of energy^{61,195,196}. Most notably, a planned phase-out of coal-fired plants by 2025¹⁹⁷ and an increase in the carbon price floor in 2015 (from £9/tCO₂ to £18/tCO₂¹⁹⁸) has led to a rapid decline in coal's share of generation. In 2016, coal supplied 9% of electricity, down from 22% in 2015¹⁹⁸. This decline has been compensated by increased gas-fired and renewable electricity generation, the latter enabled by policies and incentives favouring renewable energy sources^{196,199–202}.

Total electricity supply to the UK was 357 TWh in 2016, including net imports via interconnectors¹⁹⁸. The UK has 4.1 GW of interconnection capacity allowing trade with France (2 GW), the Netherlands (1 GW) and Ireland (1.1 GW)²⁰⁰. By source, electricity supply was: 40% gas, 20% nuclear, 15% non-thermal renewables (natural flow hydro, wind, solar, wave and tidal), 9% coal, 8% bio-energy (mostly from biomass co-fired with coal in Drax power station), 5% imports and 1% pumped hydro storage¹⁹⁸. The rest is used by generators for their own plant works. Final electricity consumption was 304 TWh due to network losses (26 TWh) and consumption from within the energy industry (27 TWh)¹⁹⁸.

Although unabated gas plants—gas plants not equipped with carbon capture and storage (CCS) technology—emit less than half of the CO₂ of coal-fired plants, they still emit approximately 360–390 kgCO₂/MWh of electricity generated¹⁹⁸. As the UK seeks to transition to a decarbonised electricity system, unabated gas plants cannot continue to dominate the generation mix without being equipped with CCS and negative emissions to compensate for residual emissions from the CCS plants.

The variability in the supply of wind and solar energy poses challenges to the electricity system⁹⁹. Limited transmission capacity and energy storage, and the relative inflexibility of base load generators (*e.g.*, nuclear plants) result in curtailment of power generation from intermittent renewable energy sources (iRES) during periods of surplus generation and low demand^{204,205}. This is a necessary security measure required to maintain power system stability and operability, and to prevent equipment damage⁹⁷. In the UK, constraint payments at an electricity price of £157/MWh are made to wind farms to curtail their generation²⁰⁶. In the absence of increased energy storage and flexibility in the electricity system, further penetration of iRES will see increased curtailment levels and hence, constraint payments. Approximately 2.7 GW of pumped hydroelectric energy storage (PHES) provide all the bulk electricity storage in the UK currently¹⁹⁸. Although there are plans to increase this by up to 2 GW²⁰⁷, long-term expansion of PHES is limited by geography. Current plans are to install 7.3 GW of additional interconnection capacity by 2022²⁰⁸. This will add further flexibility to the electricity system, which will serve to minimise curtailment.

The future role of nuclear power in the UK is threatened by its high upfront investment costs and lengthy construction times – the recently approved Hinkley Point C (HPC) plant will cost

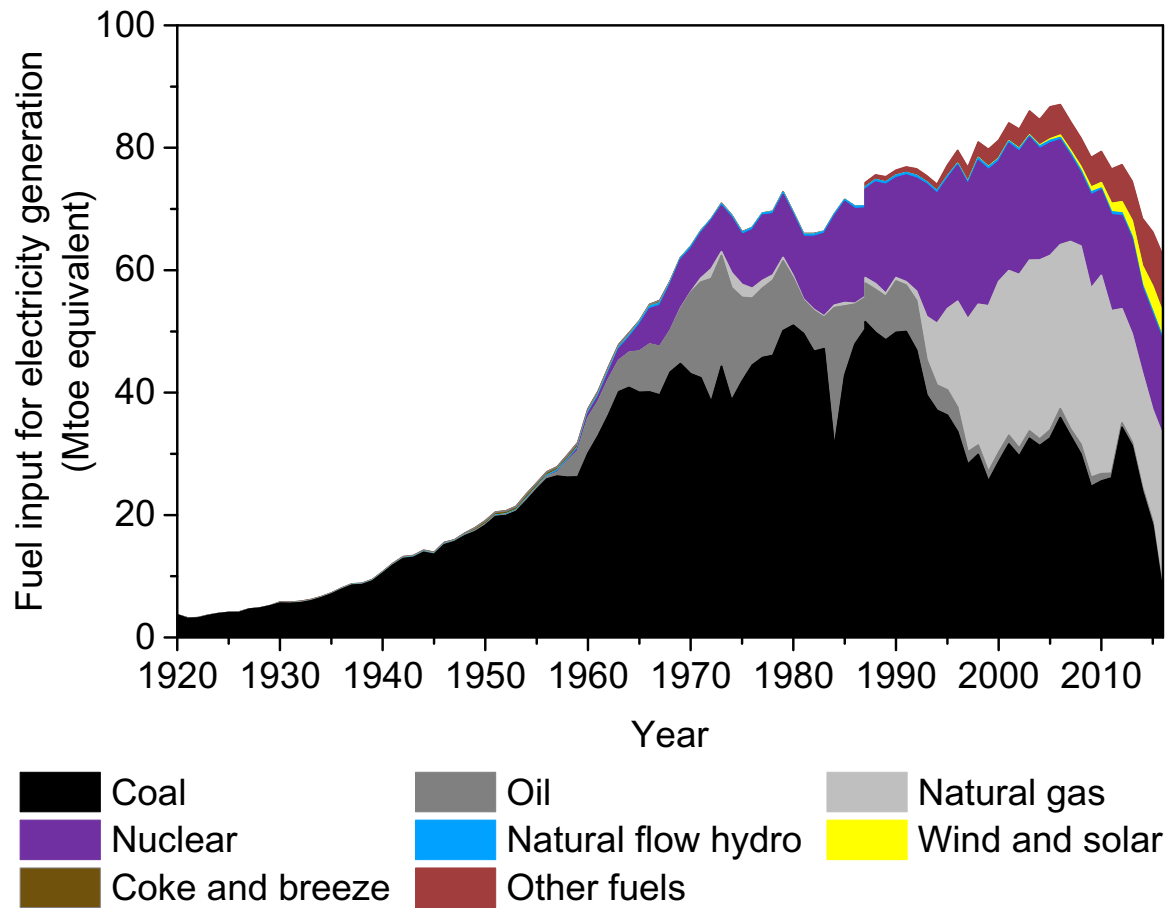


Fig. 3.3 Fuel inputs for electricity generation in the UK from 1920 to 2016²⁰³. “Other fuels” include coke oven gas, blast furnace gas, waste products from chemical processes, refuse-derived fuels and other renewable sources including wind. Industrial hydro data are not available before 1951. Natural gas includes colliery methane from 1987 onwards.

£30 billion and take 10 years to build^{209,210}. Its long payback periods leave it susceptible to government policy changes that may reduce revenues hence financing is difficult to raise, leading to very large financing costs such as for HPC²¹¹. HPC has since been shown to provide marginal value-for-money for consumers because of its high strike price of £92.50/MWh under the contracts-for-difference (CfD) scheme²¹¹. Increasing costs of the technology due to more stringent safety requirements further compound to the difficulties^{109,212}.

The above highlights some of the challenges that the UK faces as it seeks to transition to a low-carbon electricity system. This study will focus on the integration of CDR into the future electricity system, their impact(s) on the optimal system design, including how the challenges discussed can be avoided or overcome.

3.2 Scenario definition

It has been suggested that CDR is too expensive as a climate change mitigation solution, however integrated assessment models rely on their deployment (usually BECCS in the power sector) to deliver the GHG emissions reductions necessary to deliver the Paris Agreement^{33,213}. The analysis presented in this chapter seeks to determine whether the technological CDR solutions currently being developed, BECCS and DACCS, have a role to play—even at their relatively high removal costs—in decarbonising the UK electricity system by 2050, in accordance with the 2008 Climate Change Act. The ESO-X model, described in Chapter 2, was used for the analysis. Unlike the ESO-XEL model used in Chapter 4, the ESO-X model does not include technology cost learning so the capital costs of technologies are assumed to be constant throughout the planning horizon (2015 to 2050). This was considered to be suitable for the purpose of this work: to determine the value proposition of BECCS and DACCS relative to other low-carbon technologies in the power sector, at current costs.

Model inputs

The planning horizon considered is 2015 to 2050, when the decarbonisation of the electricity system is to be achieved. The UK is assumed to be a single node, hence transmission and distribution constraints have not been taken into account explicitly, but overall transmission losses are included (as 7.7% of demand). The system parameters implemented in the ESO-X model to ensure the reliability and operability of the UK electricity system are as described in Section 2.3. An initial electricity demand of 304 TWh/yr¹⁰⁰, with a 1% year-on-year increase in electricity demand and an unchanged demand profile, illustrated in Fig. 3.6, are assumed throughout the planning horizon considered. As described in Section 2.3, this was the upper-bound demand growth rate determined from a range of studies that show that, despite decreasing demand in recent years, the increasing electrification of other sectors of the economy (heating and transport) is expected to result in rising electricity demand in the UK^{91,92}. The technology costs assumed are as provided in Table 2.2. No learning rate is implemented for any technologies. A discount rate of 3% is used for future cash flows, based on the Social Time Preference Rate (STPR) provided by Her Majesty's Treasury for appraisal and evaluation of policies/programmes by government departments⁹⁰. Social time preference is defined as “the value society attaches to present, as opposed to future, consumption. It is based on comparisons of utility across different points in time or different generations⁹⁰.”

The ESO-X model includes a constraint that limits total annual CO₂ emissions from power generation (see Eq. 14). For this study, annual emissions are limited to the UK power sector carbon budget illustrated in Fig. 3.1.

In this study, all the power technologies described in Section 2.2 are available for deployment. The ‘2015 CAPEX’ in Table 2.2 is used for their technology capital costs throughout the planning horizon.

Scenarios investigated

The following scenarios were investigated and are discussed in Section 3.3.

- **‘No CDR’**: a least-cost pathway that delivers a zero-carbon electricity system by 2050 without any CDR technologies available.
- **‘DACCS available’**: a least-cost pathway that delivers a zero-carbon electricity system by 2050 when DACCS technology is the only CDR method available for deployment.
- **‘BECCS available’**: a least-cost pathway that delivers a zero-carbon electricity system by 2050 when BECCS technology is the only CDR method available for deployment.
- **‘A 1.5°C system’**: a least-cost pathway that delivers 50 Mt_{CO₂}/yr of CDR by 2050, in addition to zero-carbon electricity, by 2050. Because CDR is necessary, both BECCS and DACCS are made available for deployment in this scenario.

No ‘DACCS and BECCS available’ scenario is discussed in the results section because it is identical to the ‘BECCS available’ scenario. According to the results from the ESO-X model, as long as BECCS is available for deployment in the system, DACCS is not required.

3.2.1 Assumptions for BECCS and DACCS

BECCS

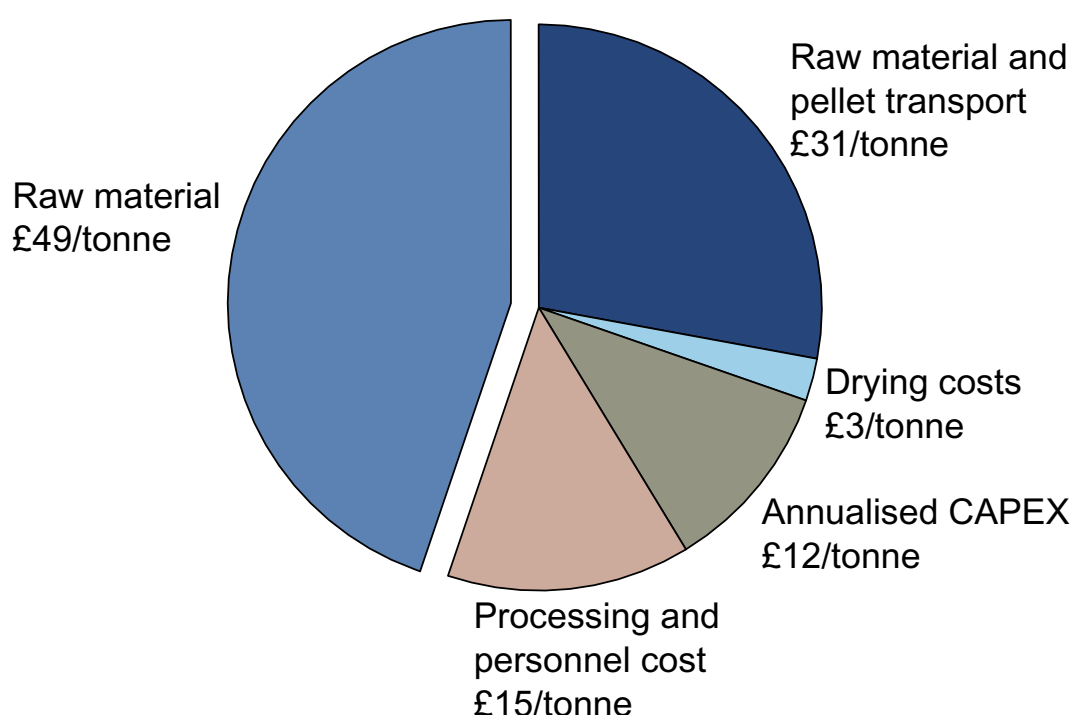
The reference BECCS technology assumed uses Miscanthus pellets fired in a 500 MW ultra-supercritical power plant with post-combustion capture using conventional MEA solvent ($\eta_{\text{net}} = 35\%$)¹³³. A study on the resource efficiency of BECCS has shown that its CDR potential is largely-dependent on the biomass supply chain⁵. A range of supply chain emissions for UK-sourced Miscanthus were obtained from a biomass supply chain model. It was found that, on average, 39.2 g_{CO₂-eq}/MJ_e (-0.80 t_{CO₂}/MWh_e) are emitted. This is well-below the sustainability limit in the UK (79 g_{CO₂-eq}/MJ_e)²⁰⁸, thus was assumed as the CDR potential of the BECCS plant in the UK.

For the purpose of this study, we assume two sources of biomass for biomass-fired power plants: indigenous virgin Miscanthus and imported pellets. The maximum availability of Miscanthus in the UK was calculated as follows. There are approximately 8.4 Mha of grassland available in the UK²¹⁴. Excluding 6.1 Mha necessary for livestock production²¹⁵, there is 2.3 Mha of land potentially available for Miscanthus production. With average yield of 10 tonnes per hectare per year¹⁵⁷, 21 Mt of pellets can be produced locally (after taking into account the losses

that occur during processing and transport). Locally-sourced Miscanthus raw material costs £49/tonne¹⁵⁶, however transport and processing increases the pellet cost to £118/tonne. This comprises majority of the operational costs (OPEX) for the BECCS plant. Fig. 3.4 shows the contribution of the different supply chain processes to the final pellet price.

Imported pellets are assumed to cost £190/tonne¹⁵⁸ and supply is assumed to be unlimited. This higher cost has been taken into account in the model as an added OPEX when BECCS biomass demand exceeds domestic supply. CO₂ transport and storage costs of £10/tCO₂¹⁰⁸ have been assumed, although power plant and storage siting are not explicitly considered in the model.

Other technical features and costs are as described in Section 2.3.5 (see Table 2.7 and 2.2).



Conversion rate of 83.7% brings Miscanthus pellet price to £118 per tonne

Fig. 3.4 Cost composition of UK grown and processed Miscanthus pellets

DACCS

Owing to the uncertainty in the energy requirements and costs of DACCS technologies that use amine-functionalised sorbents, they were not considered in this study. The archetype considered, DACCS-CE, is a hydroxide-based capture process that uses calcium cycling to regenerate the capture solution. The process is described in detail in Section 2.3.5. The DACCS-CE archetype is currently being developed by Carbon Engineering Ltd^{18,111}. At the time of this study, the developer had not published costs estimates for their technology. However, a 2011 report by the American Physical Society (APS) provided detailed costing of a first-of-a-kind DACCS-CE

plant. The capital and operating costs for DACCS-CE in this study were taken from the APS report and are provided in Tables 2.2 and 2.7. Since the publication of the report and the work in this chapter⁷³, lower DACCS cost estimates have been published^{17,18}. The sensitivity analysis presented in Section 3.5 illustrates the effect of DACCS CAPEX on optimal system design.

Owing to the high-temperature regeneration of the capture solution, intermittent and flexible operation of DACCS-CE is considered infeasible because of process stability considerations. Therefore, it has been assumed that the plant is operated continuously at its maximum CO₂ removal rate (utilisation factor of 100%). Based on the APS report, a DACCS plant removing 1 MtCO₂/yr from the atmosphere requires 56 MW_e input¹⁴⁴. This is equivalent to a CO₂ removal rate of 2 tCO₂/MWh_e consumed. We assume that the high-grade heat required for the process, which constitutes the bulk of the energy input, is to be supplied via oxy-fired natural gas combustion. Therefore the heat input does not contribute additional electricity demand to the system. The CO₂ resulting from natural gas combustion is also captured by the process.

DACCS systems might potentially be composed of a number of small and modular CO₂ collectors^{18,166,167}. Consequently, the cost of CO₂ collection, transport and storage is expected to be higher than for conventional power plants with CCS. This has been included as an added OPEX of £30/tCO₂¹⁶⁸.

The technology costs, fuel prices and carbon prices considered in this study are as provided in Section 2.3 (see Table 2.7).

3.3 What might a decarbonised electricity system look like?

3.3.1 Zero emissions by 2050

No CDR

Figs 3.5 and 3.6 show the optimal capacity and electricity generation mix, respectively, to achieve power sector decarbonisation by 2050 for the scenarios discussed in section 3.2. We observe that complete decarbonisation of the electricity system – defined here as a carbon intensity of less than 10 kgCO₂/MWh – is achievable by 2050 without CDR. Such a scenario would see installed capacity increase by 208%, from 98 GW in 2015 to 301 GW in 2050, primarily due to the extensive expansion of iRES. Solar dominates the capacity mix in 2050, making up 30% (90 GW), but satisfies only 11% of annual demand due to its low availability. Offshore and onshore wind contribute 30% and 19% of demand, respectively. As the existing nuclear plants reach the end of their lifetimes in the next decade, 24 GW of new nuclear is added between 2030 and 2050 and its share of generation rises to 30% by mid-century.

Power plant utilisation factor, UF_i , is defined as the power output from a power plant i divided by the maximum possible power output during a given time period. Eq. 3.1 defines the annual

utilisation factor for plant i .

$$UF_i = \frac{\text{annual power output (MWh)}}{\text{plant capacity (MW)} \times 24 \text{ hours} \times 365 \text{ days}} \quad (3.1)$$

The absence of negative emissions results in the underutilisation of unabated gas plants by 2050, as there is no CO₂ removal to compensate for their emissions. By 2050, UF_{CCGT} and UF_{OCGT} fall to <0.5%, despite having 29 GW of capacity installed. Unabated gas plants, however, provide 30% of the reserve capacity requirements in the system. Abated gas plants (CCGT-CCS) are also aggressively deployed from 2025, with 15 GW added over the next 15 years. $UF_{\text{CCGT-CCS}}$ decreases from 69% initially to 16% in 2050, as residual emissions from the CCS are minimised to meet the decarbonisation objective.

The dominance of iRES in this scenario leads to greater requirement for grid flexibility leading to increased energy storage and interconnector capacity installed. Storage service to demand peaks at 11 TWh/yr in 2035 – a twofold increase from current levels. 9 GW of additional interconnector capacity are also built, with their share of electricity supply peaking at 18% in 2025, and subsequently falling to 4% by 2050. This is because electricity imports have an associated carbon footprint²¹⁶ which is attributed to the UK electricity system. As emissions targets become more stringent towards 2050, interconnection utilisation falls to minimise these associated emissions. Despite the increase in energy storage and flexibility services, incidences of curtailment still abound – 99 TWh/yr (22% of demand) of iRES are curtailed in 2050. This is a lower-bound estimate as the model does not account for transmission congestion constraints.

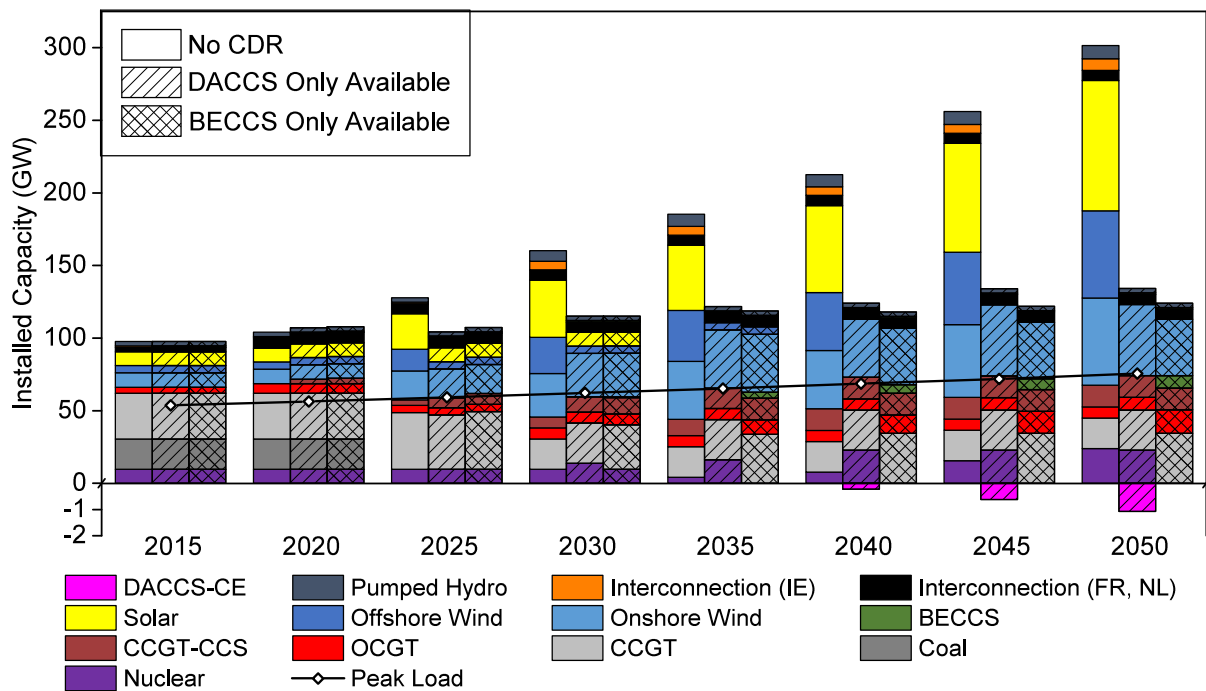


Fig. 3.5 Optimal installed capacity mix for the UK from 2015 to 2050 given the availability of negative emissions technologies for large-scale deployment

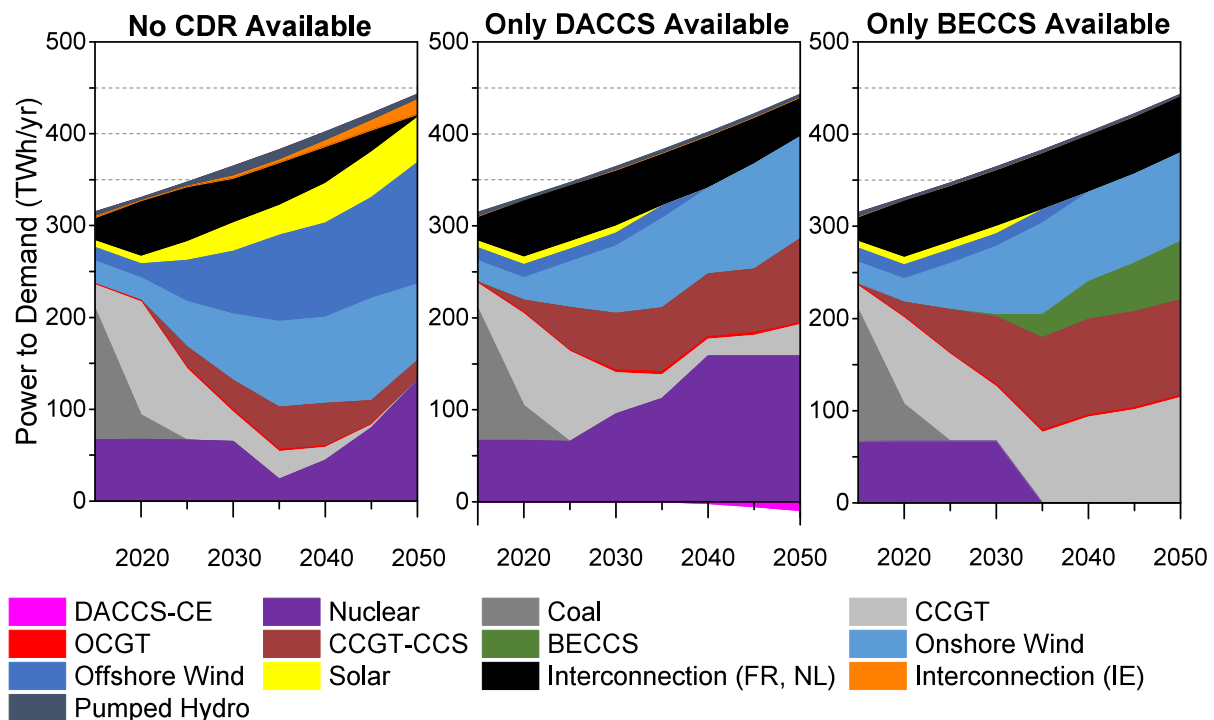


Fig. 3.6 Optimal electricity generation mix for the UK from 2015 to 2050 given the availability of negative emissions technologies for large-scale deployment

While the *No CDR* system described is technically feasible, it is dominated by capital-intensive technologies. This is reflected in the large total system cost (TSC) – £307 billion of investment (CAPEX and OPEX) is needed in the power sector over 35 years. As a reference, total annual investment in the UK power sector (including generation, transmission and distribution) averaged around £10 billion between 2013 and 2017¹⁵. The TSC calculated suggests that an average annual investment of £8.8 billion is needed in power generation alone for 35 years if no CDR is available. Fig. 3.8 illustrates the range of marginal costs of electricity (MC) for each scenario considered. In all scenarios, MCs are seen to be consistently higher than contemporary levels till 2050, when they peak. Peak MC is highest when no CDR are available to the system – it is approximately £200/MWh in 2050. This is because new iRES and energy storage capacity is required to provide an additional MWh of carbon-neutral electricity, as current capacity is maximally utilised. Underutilised (and cheaper) unabated or abated gas power plants cannot provide the electricity due to the decarbonisation constraint. The rapid expansion of iRES capacity must also be accompanied by expansion of transmission and distribution (T&D) networks, which incurs additional costs that are not included in the total system cost. Should constraint payments to iRES generators continue, curtailment will also contribute to additional costs.

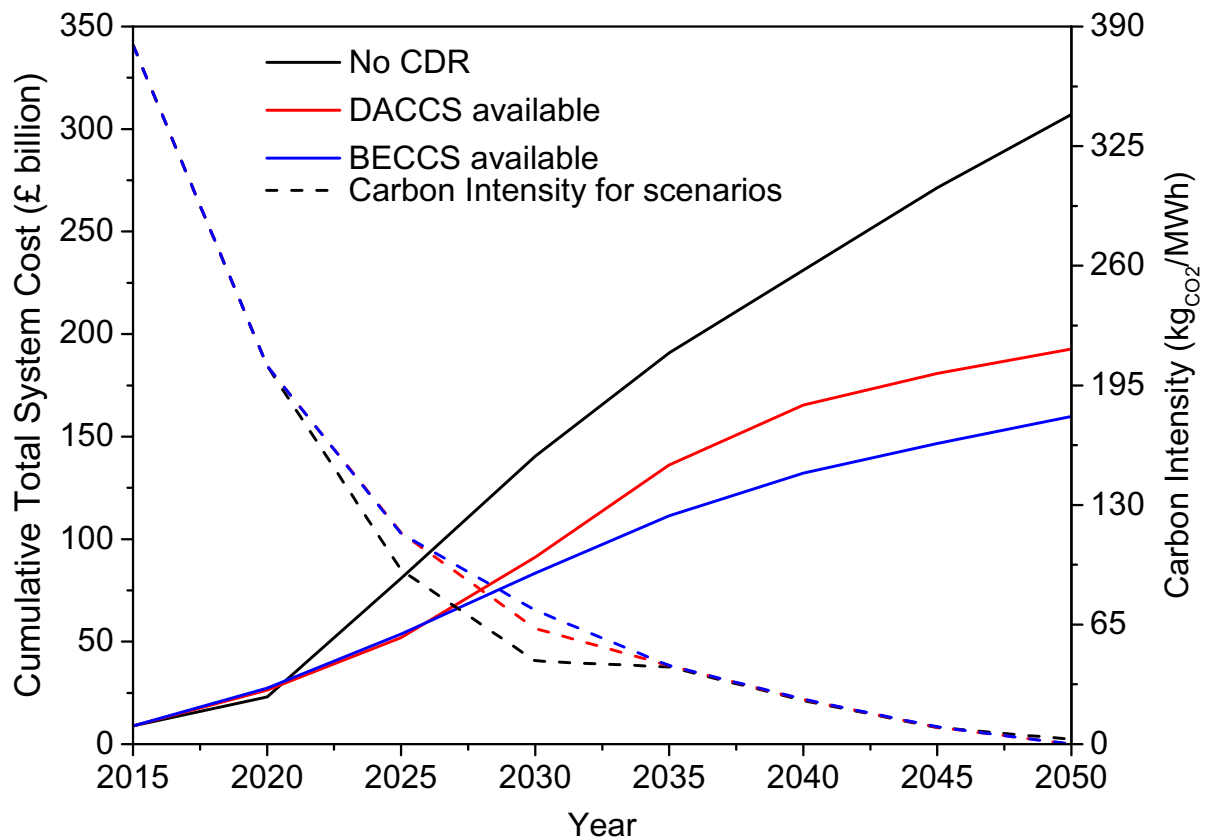


Fig. 3.7 The cumulative total system cost of an optimal UK electricity system from 2015 to 2050, given the availability of negative emissions technologies for large-scale deployment

DACCS available

The availability of direct air capture and storage is observed to reduce the cost of complete decarbonisation considerably. Despite the costliness of DACCS, it is seen to be deployed from 2040 and to reduce the total investment needed to £193 billion (Fig. 3.7), 37% less than with *No CDR*. This is because the negative emissions from DACCS allow for continued utilisation of cheaper thermal plants. DACCS consumes 9.4 TWh/yr (2% of projected annual electricity demand) by 2050 to provide 19 Mt_{CO₂}/yr of negative emissions that offset CO₂ emissions from unabated and abated gas plants (shown in Fig. 3.11). The offset allows for increased gas utilisation; UF_{CCGT} doubles to 14% from 2040 to 2050 (period when DACCS is operational), and $UF_{CCGT-CCS}$ increases to >70% in the same period—a fourfold increase from its utilisation when no CDR are available.

Increased power generation from gas plants also completely displaces the need for new Solar and Offshore Wind, with no new capacity built after the existing plants reach their end life. However, 49 GW of new Onshore Wind capacity is added by 2050. Onshore Wind is preferred because it has a relatively high availability and the lowest CAPEX of the iRES technologies available (Solar-PV - £1,105/kW, Onshore Wind - £1,105/kW, and Offshore Wind - £2,600/kW). Consequently, iRES share of generation falls from 70% (when no CDR are available) to 36%,

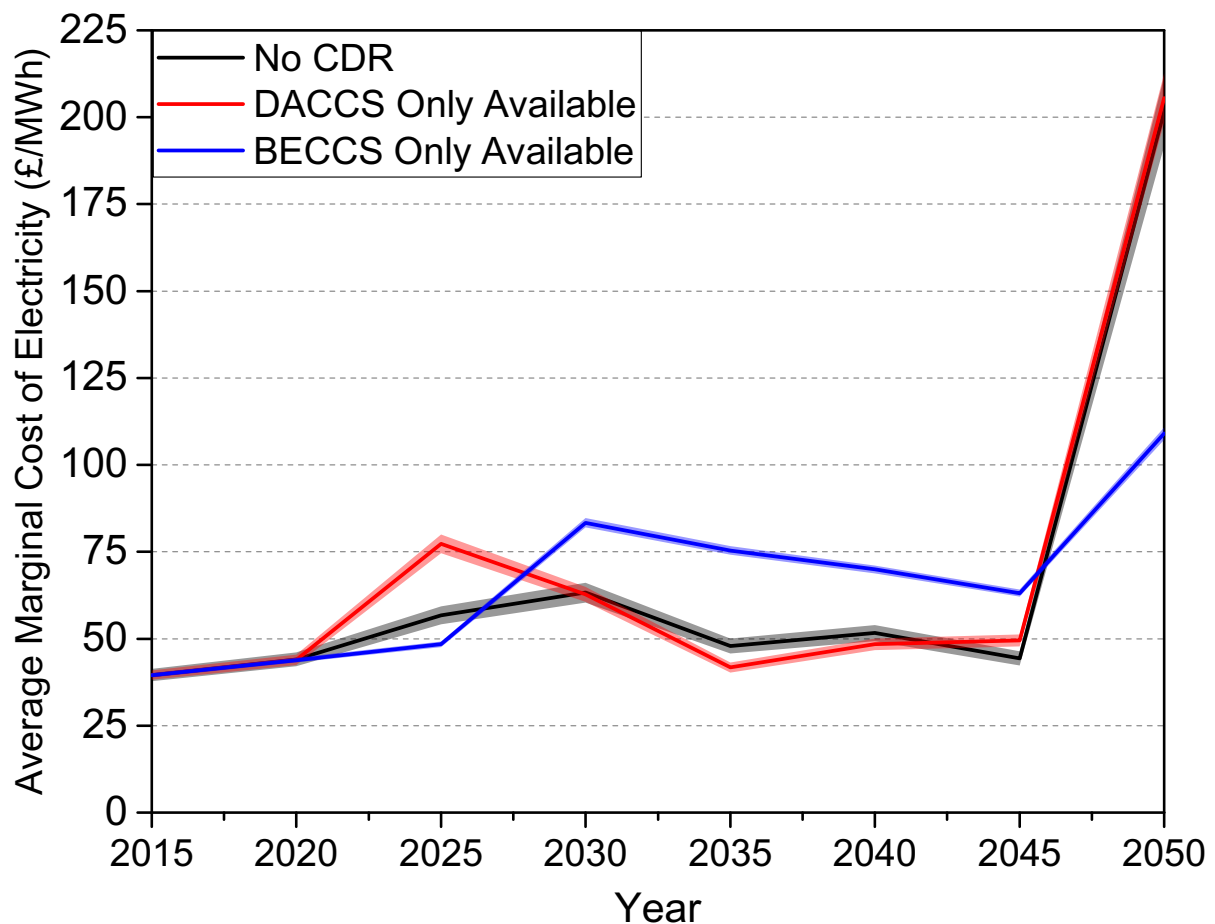


Fig. 3.8 Average annual marginal cost of electricity in the UK depending on the deployment of BECCS or DACCS in the system

and energy storage requirements remain at contemporary levels. Reduced penetration of iRES also reduces flexibility needs with only 4 GW of interconnector capacity added. The availability of negative emissions to compensate for ‘imported emissions’, however, results in increased interconnector utilisation and hence reliance on electricity imports. Imports satisfy 9-18% of demand, up to three times its current share. The 24 GW of nuclear build after 2030 remains necessary to meet the bulk of electricity demand – 159 TWh/yr by 2050 (35%). This share peaks at 39% in 2040 before falling slightly. Therefore to achieve power sector decarbonisation, a system dominated by firm and dispatchable low-carbon generators with DACCS to compensate for their associated emissions is significantly cheaper than a system dominated by iRES and energy storage.

Annual MCs are seen to be similar with and without DACCS availability. Similar peaking at £206/MWh occurs in 2050, approximately four times the current average electricity cost of £47/MWh²¹⁷. The high MC in 2050 occurs due to the large OPEX of DACCS plants. A marginal increase in demand is satisfied by the increased operation of cheap thermal plants or imports (Nuclear and iRES are already maximally utilised) and DACCS is needed to compensate for the resulting emissions, which in turn results in an added electricity demand.

The challenges surrounding social attitudes to land-based iRES²¹⁸, particularly Onshore Wind, will remain as installed capacity increases fivefold by 2050. Issues surrounding the feasibility of future conventional nuclear projects and CCS, discussed in section 3.1.2, also persist. Lastly, an increased reliance on electricity imports may also raise energy security concerns.

BECCS available

When BECCS is made available to the system, total investment needed in the power sector by 2050 falls to £160 billion, a 48% decrease relative to the *No CDR* scenario. Therefore, BECCS deployment provides the greatest reduction in total system cost. We observe that 8.5 GW of BECCS capacity are built by 2050 to provide 51 Mt_{CO₂}/yr of negative emissions. This offsets emissions from gas plants and interconnectors, thereby allowing UF_{CCGT} and $UF_{CCGT-CCS}$ to rise to 38% and 79%, respectively. In addition to the CO₂ removal service it provides, BECCS produces 63 TWh/yr by 2050. Together, BECCS and natural gas-fired generation satisfy 64% of demand: CCGT (26%), CCGT-CCS (23%), BECCS (14%) and OCGT (0.5%). Increased generation from thermal plants displaces more expensive low-carbon electricity generators from the system. No new Nuclear, Solar or Offshore Wind power plants are built after the existing fleet reach the end of their operational lifetimes. However, 39 GW of Onshore Wind is added by 2050, resulting in an increase of iRES penetration from 25% of capacity installed today to 31% in 2050. No added energy storage is needed to accommodate increased iRES penetration – 3 GW of pumped hydroelectric storage currently available however continue to provide 0.6% of demand.

When CDR is not available, the utilisation of gas-fired plants is very low to ensure that the emissions targets are met. Thus, the type of iRES preferred for deployment in the ‘No CDR’ scenario is one with the highest availability so that it can meet the shortfall in electricity supply. Consequently, a significant amount of Offshore Wind (60 GW) and Onshore Wind (60 GW) is installed by 2050. When BECCS or DACCS is available, the utilisation of gas-fired plants increases because the CDR provided compensates for their emissions. Given the increased generation from gas-fired plants, the shortfall in supply is reduced. Consequently, cost matters more than availability for the type of iRES that is preferred for deployment. Consequently, Onshore Wind, the cheapest iRES, is deployed significantly with no new solar or offshore wind built after their existing capacities reach the end of their respective lifetimes.

The generation of 63 TWh/yr of electricity by BECCS requires 12 Mt_{pellets}/yr of fuel-grade biomass, assumed to be provided by Miscanthus in this work. Domestic Miscanthus supply – 21 Mt_{pellets}/yr – can satisfy the biomass demand and more expensive pellet imports are not required. The necessity for a sustainable supply of biomass in order for BECCS to result in net removal of CO₂ from the atmosphere has been discussed at length elsewhere^{5,219}, and as such are not discussed further here.

In this scenario, MC consistently rises until 2050 when it peaks at £109/MWh, more than twice the current price. This is however approximately half of the MC observed in the *No CDR* or *DACCS available* scenarios.

3.3.2 A “1.5°C system”

The emissions target for 2050 is adjusted to -50 Mt_{CO₂}/yr in the model, so the UK can meet its commitment to the Paris Agreement¹⁹¹, illustrated in Fig. 3.2. BECCS and DACCS are also made available for deployment from 2015. All other model parameters remain unchanged. Fig. 3.9 illustrates the electricity supply mix necessary to meet this target by 2050. We observe that at least 93 Mt_{CO₂}/yr of negative emissions are needed by 2050 – 43 Mt_{CO₂}/yr compensates for the fossil generators in the system while the rest serves as available offset for other sectoral emissions. This is all provided by BECCS as it has cheaper abatement cost (£190/t_{CO₂}) compared to DACCS (£390/t_{CO₂}), and can contribute to electricity supply.

To satisfy the CO₂ removal target above, approximately 23 Mt/yr of Miscanthus pellets are needed by 2050. This is greater than current projections of domestic biomass availability, thus necessitating the import of potentially more expensive biomass. The optimal electricity generation mix needed to achieve the Paris Agreement target is shown in Fig. 3.9. This system requires £176 billion to be invested in the power sector from 2015 to 2050, a 10% increase compared to the *BECCS Only* scenario. BECCS capacity installed in 2050 increases from 8.5 to 15.5 GW as more negative emissions are required to meet the deeper decarbonisation target. The corresponding increase in generation displaces further unabated gas generation. Consequently, less negative emissions are needed to offset fossil-derived emissions, thereby allowing more offset for non-power sectoral emissions. By 2050, unabated gas capacity is 46.8 GW, 3.8 GW less than installed capacity when mid-century decarbonisation is the objective. CCGT utilisation, UF_{CCGT} also falls from 38% to 31%.

Nuclear, Solar and Offshore Wind are phased out as the existing power plants are not replaced at the end of their lifetime, while 30 GW of new Onshore Wind capacity is added by 2035. 15 GW of CCGT-CCS are deployed, as in all scenarios previously discussed. Share of generation in 2050 is 26% BECCS, 23% CCGT-CCS, 20% CCGT, 16% Onshore Wind, 14% Imports, 0.7% Pumped Storage, and 0.5% OCGT. Therefore, should BECCS technology be available for deployment, it would need to supply more than a quarter of the UK’s electricity demand to provide sufficient negative emissions for compliance with the Paris Agreement. Furthermore, such a scenario would see biomass and electricity imports meet approximately 16%* of demand, a threefold increase in imports’ share of generation today.

Onshore Wind features significantly in all the scenarios discussed, satisfying 16-36% of demand. More expensive Offshore Wind, however, is phased out in all but the *No CDR* scenario, as

*14% from interconnectors and 2% from imported biomass

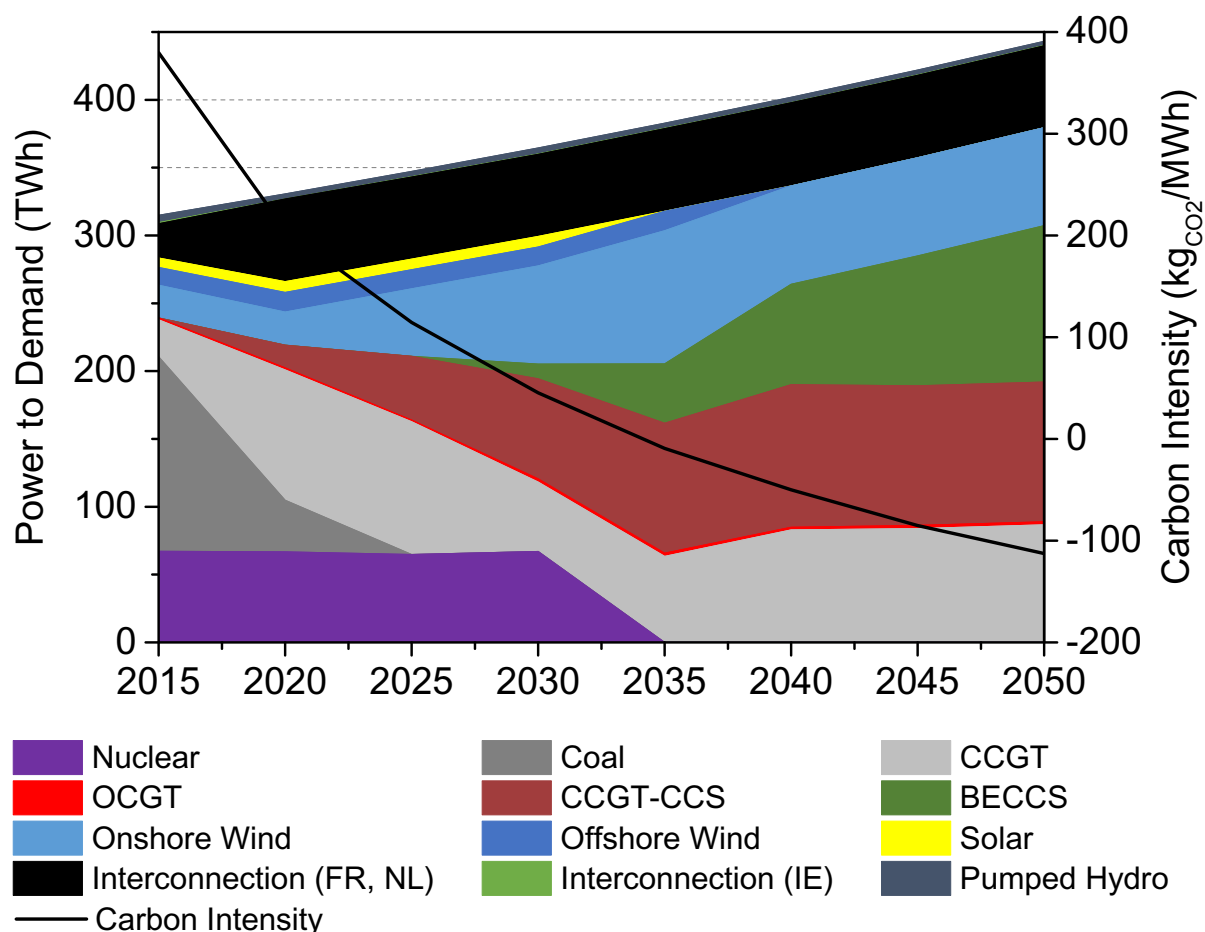


Fig. 3.9 Optimal electricity generation mix for a UK electricity system consistent with the Paris Agreement target

existing capacity is not replaced after it reaches the end of its lifetime. Only lower cost iRES are therefore valuable to the system. The most recent auction in the UK saw falling costs of Offshore Wind²²⁰. In addition, public attitudes may favour unseen Offshore Wind farms over (new) onshore farms that disrupt landscapes. Reduced availability of Onshore Wind and cheaper Offshore Wind may therefore lead to the deployment of Offshore Wind in the future, contrary to what we observe here.

We also observe direct competition between BECCS and Nuclear, as BECCS deployment displaces the need for new nuclear plants in the system. Therefore, flexible carbon-negative generation to augment gas generation, and offset gas-derived emissions (from CCGT and CCGT-CCS), proves more valuable to the system than base load zero-carbon generation.

3.4 What is the value of CDR?

The reductions in system costs and marginal electricity costs achievable due to the availability of CDR have been shown to be significant, especially for BECCS. To quantify the value that

each technology adds to the system, two metrics have been employed: the System Value⁸⁶ and the Value Transfer, as introduced in this work.

3.4.1 System value

The System Value (SV) metric quantifies the value of a technology, i , to the power system as the reduction in total system cost (TSC) caused by the deployment of the technology⁸⁶. This is shown in Eq. 3.2. The reference year from which the reduction in TSC is calculated is 2050, when the decarbonisation objective is to be met.

$$SV_{i,k} = \frac{TSC_{i,k=0} - TSC_{i,k}}{k_i} \quad (3.2)$$

where TSC_k is the total system cost (TSC) in 2050 for a given deployment, k (kW), of technology i , and $TSC_{i,k=0}$ is the TSC in 2050 when technology i is not available to the system. As DACCS is a net consumer of heat and power, k_{DACCS} is the installed capacity required to meet its energy needs. An electricity-to-heat conversion factor of 45%[†] was used to determine the installed capacity required to satisfy its energy input. Hence its SV is given in £/kW_{required}.

The ‘economic deployment level’ (EL) of a technology is defined as the installed capacity beyond which additional deployment of the technology in the system does not result in a reduction in the total system cost⁸⁶. Using the ESO-X model, the EL of a technology is determined by gradually increasing its maximum available capacity; the EL is when additional available capacity is not deployed. To determine the EL of BECCS and DACCS, their available capacities for deployment was increased until there was no marginal decrease in TSC. That is, should more of the technology be made available, it is not deployed as the resulting capacity mix is not cost-optimal. The System Value curves for both BECCS and DACCS are illustrated in Fig. 3.10. On initial deployment, BECCS has an SV of approximately £124,000/kW, three times that of DACCS – £43,000/kW_{required}. As more BECCS is made available, the marginal reduction in TSC per installed capacity falls until BECCS reaches its EL. BECCS and DACCS were found to have an ELs of 8.5 GW_{installed} and 8.4 GW_{required}, respectively. As can be observed from Fig. 3.10, BECCS provides significantly greater value to the electricity system than DACCS, though the difference in their system values does decrease substantially once more than 4 GW of capacity of either are installed.

3.4.2 Transfer Value

In section 3.3, we showed that the availability of both BECCS and DACCS increased the utilisation of CCGT power plants. In the absence of CDR, they would have been constrained off the system owing to their CO₂ emissions. Fig. 3.11 illustrates the contributions of different

[†]Efficiency of CCGT-CCS power plant

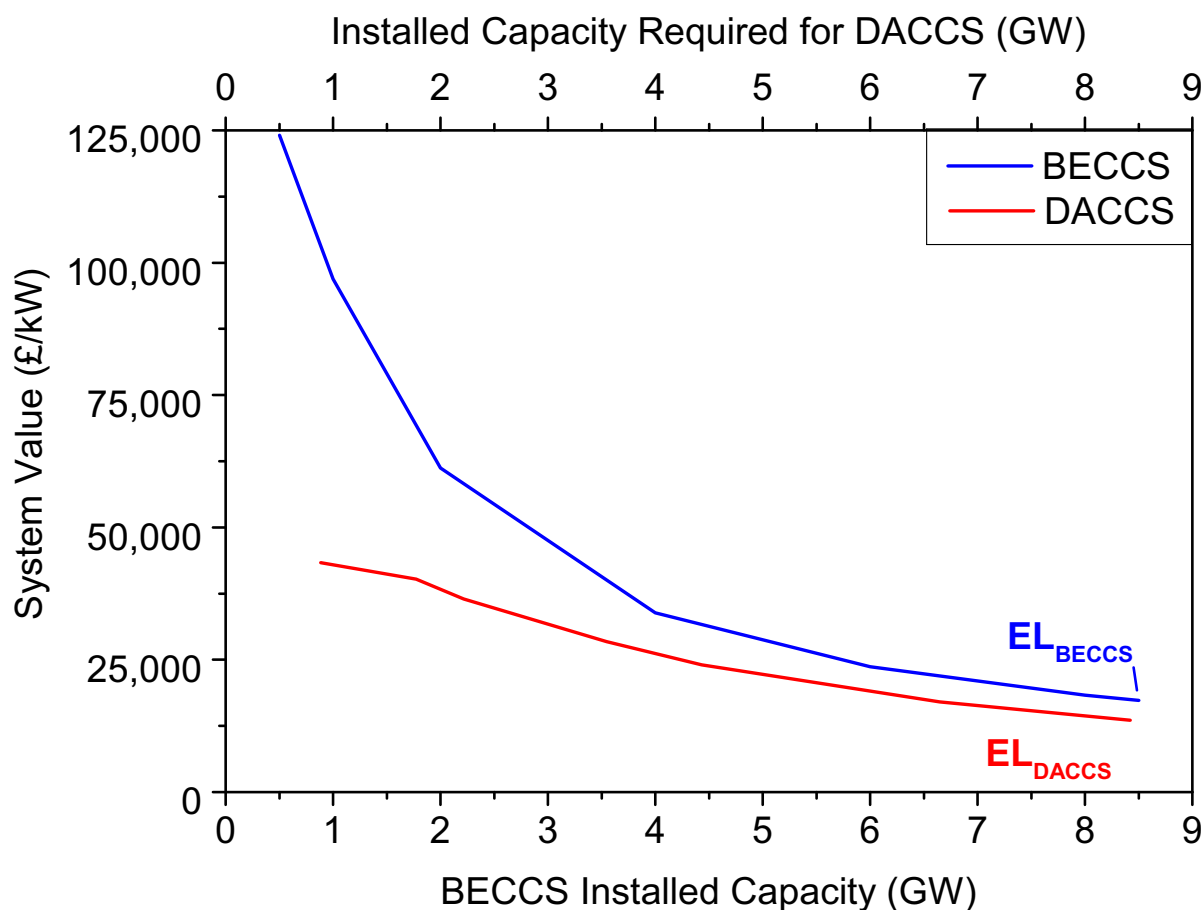


Fig. 3.10 System value of BECCS and DACCS to the UK electricity system. Their economic levels (EL) of deployment are highlighted.

technologies to power sector emissions from 2015 to 2050 when CDR are available to the system.

It is observed that, with increasing availability of CDR, the asset utilisation of CCGTs is also substantially increased, whilst only marginal increases are observed for interconnection, OCGT and CCGT-CCS assets. In other words, the availability of CDR allows for increased revenue to be earned by those generation assets that would be otherwise constrained off the electricity grid owing to their carbon emissions. In order to fairly distribute the cost of providing this service, it is essential to allow some of that value to accrue to the CDR facilities that are providing this service, thus reducing the societal cost of delivering negative emissions. In this section, we propose a proportional transfer value mechanism, and illustrate how it might be calculated.

Fig. 3.12 shows how CCGT utilisation factor (UF_{CCGT}) vary with different availabilities of BECCS technology. It is evident that higher UF_{CCGT} are associated with BECCS deployment. In the period 2015-2020, UF_{CCGT} peaks at approximately 35% due to the phase-out of coal plants, and in the absence of BECCS (i.e., the "No CDR" scenario), UF_{CCGT} falls to less than 5% by 2050. At maximum BECCS deployment, however, UF_{CCGT} is seen to be consistently

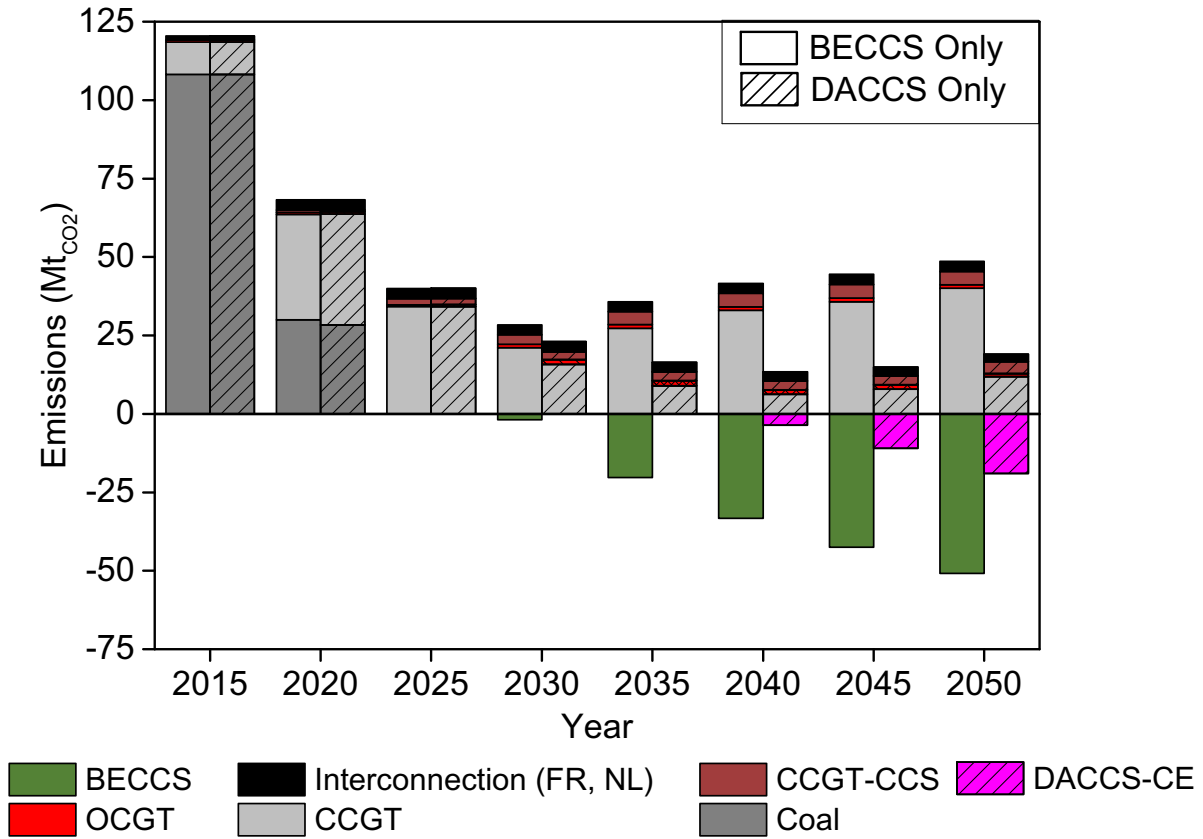


Fig. 3.11 Carbon emissions by technology in a least-cost UK electricity system that achieves complete decarbonisation by 2050

higher than current levels, reaching 49% by 2050. To quantify the value of the emissions offset provided by BECCS to CCGT, a Value Transfer metric is used.

The Value Transfer ($VT_{i,j}$) metric, presented in Eq. 3.3, quantifies the value transferred to technology j by the increased operation of negative emissions technology i at deployment level d , $NE_{i,d}$. It has been defined as the change in revenue generated by technology j divided by the change in negative emissions provided by technology i .

$$VT_{i,j} = \frac{R_{j,d} - R_{j,initial}}{CDR_{i,d}} \quad (3.3)$$

where: VT is the value added to technology j plants by increased deployment of i ; $R_{j,d}$ is the total revenue generated by j from 2015 to 2050 when i is deployed at capacity d ; $R_{j,initial}$ is the total revenue generated by j when no negative emissions technologies are deployed in the system; and $CDR_{i,d}$ is the total negative emissions provided by i at capacity d .

Revenue generated by j , R_j has been calculated as the sum of its revenue from electricity generation to meet demand and revenue from provision of reserve capacity. This is shown in the equation below:

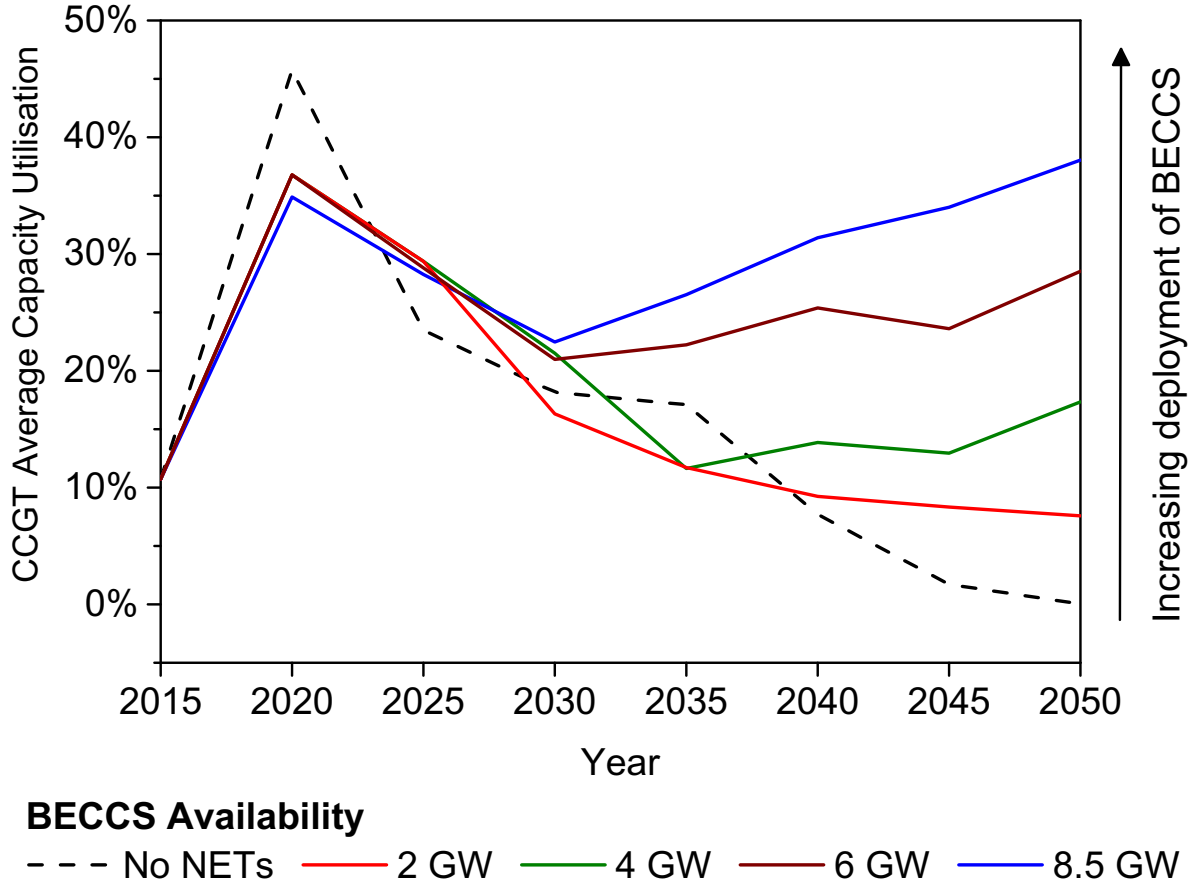


Fig. 3.12 Variation in the utilisation factor of CCGT power plants with increased BECCS deployment in the electricity system

$$R_j = \sum_{a,t} p2d_{j,a,t} \times MC_{a,t} + \sum_{a,t} r_{j,a,t} \times MRP_{a,t} \quad (3.4)$$

where t is time, discretised hourly; a is the year in which j is providing that service to demand; $p2d_{j,a,t}$ is the electricity generated hourly by technology j to meet demand at time t in year a (MWh/hr); $MC_{a,t}$ is the marginal cost of electricity (£/MWh) at time t in year a , derived as explained in section 3.2; $r_{j,a,t}$ is the reserve provided by j at time t in year a (MWh); and $MRP_{a,t}$ is the marginal cost of reserve at time t in year a (£/MWh).

Fig. 3.13 shows how CCGT revenues and total CO₂ removal vary with the deployment of BECCS and DACCS in the UK electricity system. The graph shows that as BECCS or DACCS installed capacity increases, the revenues generated by CCGT also increases. Eq. 3.2 was used to determine the value transferred from DACCS and BECCS to CCGT power plants. $VT_{DACCS\text{Only}}$ and $VT_{BECCS\text{Only}}$ were calculated to be approximately £460/t_{CO₂} and £230/t_{CO₂}. Therefore, for each tonne of CO₂ removal delivered by DACCS, CCGT revenues increase by £460. Similarly, for each tonne of CO₂ removed by BECCS, CCGT revenues rise by £230. Therefore, DACCS deployment accrues twice as much revenues to CCGTs as BECCS does. This is because when

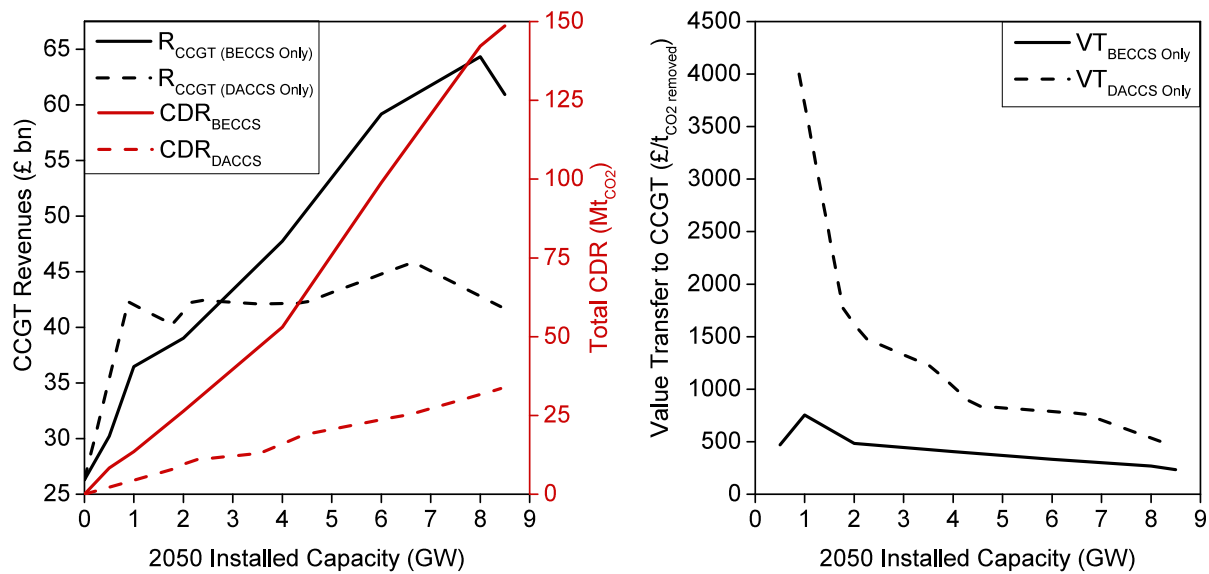


Fig. 3.13 Variation in the total revenues generated by CCGT power plants and negative emissions provided with increasing deployment of BECCS and DACCS (left). Value transfer from BECCS and DACCS to CCGT power plants at different installed capacities (right).

DACCS is deployed, the marginal cost of electricity and marginal cost of reserve are higher (compared to when BECCS is deployed); this is illustrated in Fig. 3.8. Furthermore, CCGT reserve provision is higher in a *DACCS Only* scenario; CCGT reserve provision and MRP peak at 70% and £43/MWh, respectively, compared to 59% and £22/MWh, respectively, in a *BECCS Only* scenario. Consequently, CCGTs have larger revenues despite reduced operation (see Fig. 3.6) thereby resulting in higher VT_{DACCS} . Conversely, BECCS' ability to provide reserve capacity reduces CCGT reserve provision in the system in a *BECCS Only* scenario. Additionally, marginal electricity costs are lower. Consequently, CCGTs experience lower revenues, resulting in a lower value transferred from BECCS VT_{BECCS} . From 2015 to 2050, £35 billion and £16 billion of additional revenue was generated by CCGTs when BECCS and DACCS are deployed to their economic limit, respectively.

3.4.3 Operation of BECCS within the electricity system

BECCS has been shown to provide three distinct services to the electricity system: power generation to meet demand, CO₂ removal from the atmosphere, and value transferred to CO₂ emitting assets that would be otherwise constrained off the electricity grid. As the value of, and thus appropriate compensation for, each service is likely to differ in value, it is important to understand the role of BECCS in the electricity system in which it is deployed. BECCS operation, described by its utilisation factor, UF_{BECCS} , is investigated to understand this role.

Fig. 3.14 shows the average hourly UF_{BECCS} and UF_{CCGT} in 2030 (when deployment begins) and 2050 (when decarbonisation is to be achieved) compared to the average annual hourly demand. In 2030, BECCS power generation is seen to fluctuate with hourly demand, *i.e.* it

is load-following. CCGTs are observed to exhibit the same behaviour. BECCS is therefore operating to meet some electricity demand and provide some offset for CCGT emissions. The levelised cost of BECCS electricity is calculated to be £234/MWh (£64/MWh is contributed by biomass costs alone). Alternatively, the levelised CO₂ abatement cost (total investment in BECCS per tonne of CO₂ removed) is approximately £185/tCO₂. These do not include the value it should accrue by providing a service to CCGT, discussed in section 3.4. In 2050, however, UF_{BECCS} is consistently at its maximum of 85%, hence it is operating base load. Therefore as the system emissions target tends to zero, BECCS transitions from load-following to base load behaviour, with the latter allowing for maximum CO₂ removal to meet the decarbonisation objective.

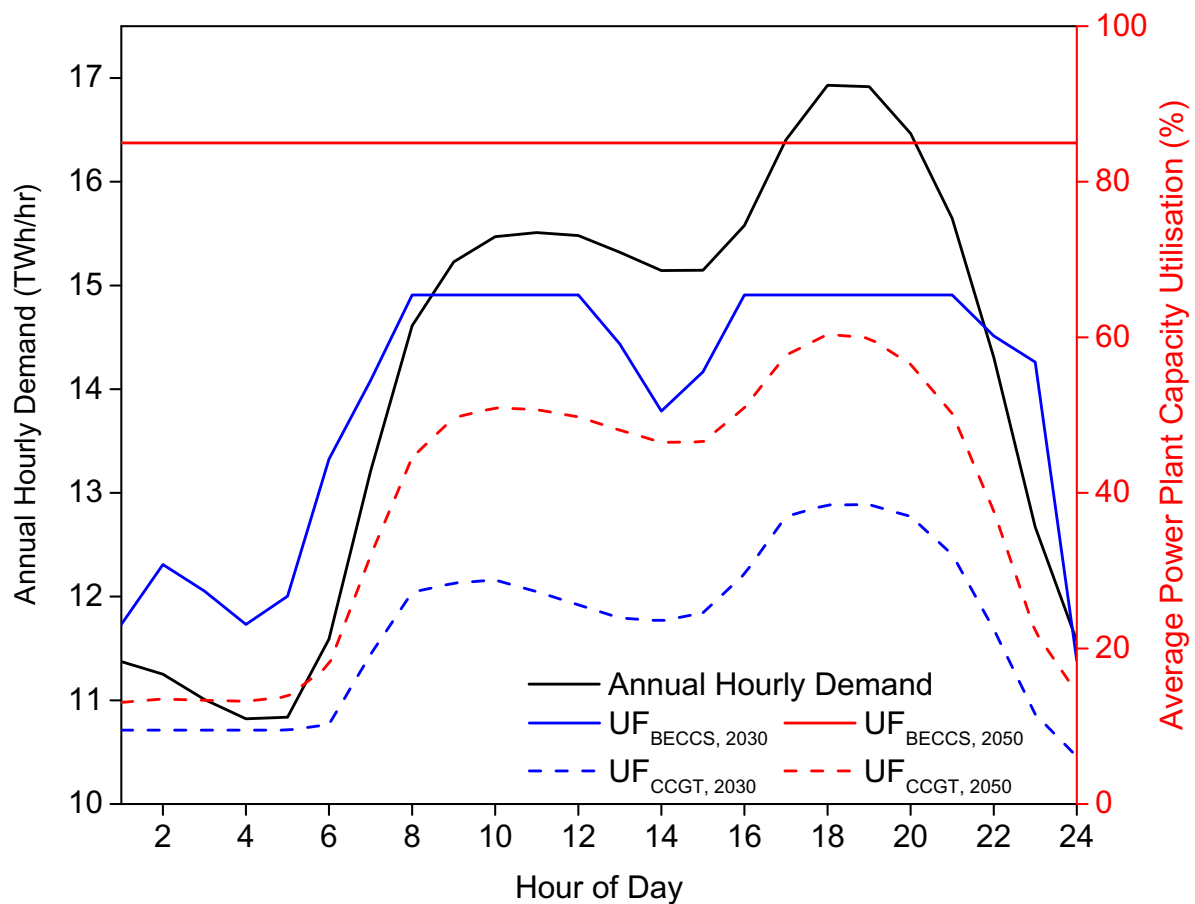


Fig. 3.14 Variation in the average utilisation factor of BECCS plants in 2030 and 2050 with hourly electricity demand. The load factors are to be read of the right vertical axis (red), while the annual hourly demand is given on the left vertical axis (black).

There is currently no incentive to support the deployment of CDR. The above analysis has, however, described the potential value that can be added by BECCS and DACCS to the electricity system as a whole. In practice, this added value should accrue to the CDR in the form of a negative emissions credit, as discussed in previous work²¹⁹. This has not been considered in this study.

Although the services to the electricity system provided by BECCS (electricity generation, reserve provision and CDR) and DACCS (CDR) differ, they can both provide emissions offset that allows for continued operation of cheaper unabated and abated thermal plants, especially CCGTs, and consequently drive down system cost. The Value Transfer metric, $VT_{i,j}$, discussed in section 3.4.2 shows that this continued utilisation translates into larger revenues for CO₂ emitting assets. The compensation of CDR by carbon emitters (at a price of $VT_{i,j}$) can potentially reduce the public burden of delivering negative emissions, *i.e.* reduce the negative emissions credit that needs to be provided for CDR ‘social service’ of CO₂ removal.

3.5 Sensitivity analysis

The scenarios discussed in section 3.3 are dependent on the availability of CCGT-CCS technology, which is not currently deployed. In addition, estimates for BECCS and DACCS technology costs have been used in the analysis. The influence of varying CCGT-CCS availability and CDR costs on the need for, and source of, negative emissions was investigated and is discussed below.

3.5.1 CCS availability

CCGT-CCS contributes 15 GW to installed capacity in all the scenarios that achieve complete decarbonisation by 2050. It has been argued that the deployment of CCS technology presents a moral hazard to climate change mitigation as it allows for the continued consumption of fossil fuels^{221,222}. It has also been shown that CCS can achieve capture rates of >90%, which is conventionally assumed, with limited efficiency penalty^{156,223}. The amount of BECCS or DACCS needed to decarbonise by 2050 at different CCGT-CCS availabilities and capture rates was investigated. Four scenarios are illustrated in Fig. 3.15: a) Low CCS (5 GW), b) Central CCS (15 GW), c) High CCS (45 GW), and d) Central CCS with $\eta_{\text{capture}} = 95\%$.

In the *DACCS Only* scenario, increased CCGT-CCS availability initially reduces the need for negative emissions. However, at CCGT-CCS capacity of >15 GW (*Central CCS*), more CO₂ removal is needed to compensate for rising residual CCS emissions. Fig. 3.15 shows that DACCS removes 1 MtCO₂/yr more in a *High CCS* scenario, compared to a *Central CCS* scenario. This is because increased CCGT-CCS operation largely displaces Nuclear from the system, although CCGT generation is also reduced. As CCGT-CCS capacity increases from 5 to 45 GW, added Nuclear capacity decreases from 24 GW to 1.2 GW. In 2050, electricity demand met by Nuclear falls from 167 to 8 TWh/yr; CCGT service to demand also falls from 66 to 16 TWh/yr. Overall, CO₂ removal by DACCS falls from 28 to 20 MtCO₂/yr, from low to high CCS availability. Therefore, from a systems perspective, it is cheaper to operate more abated gas plants with DACCS compensating for their residual emissions than to have a Nuclear-dominated

electricity system. Furthermore, even at very high CCS availabilities, CDR are deployed in the optimal electricity system.

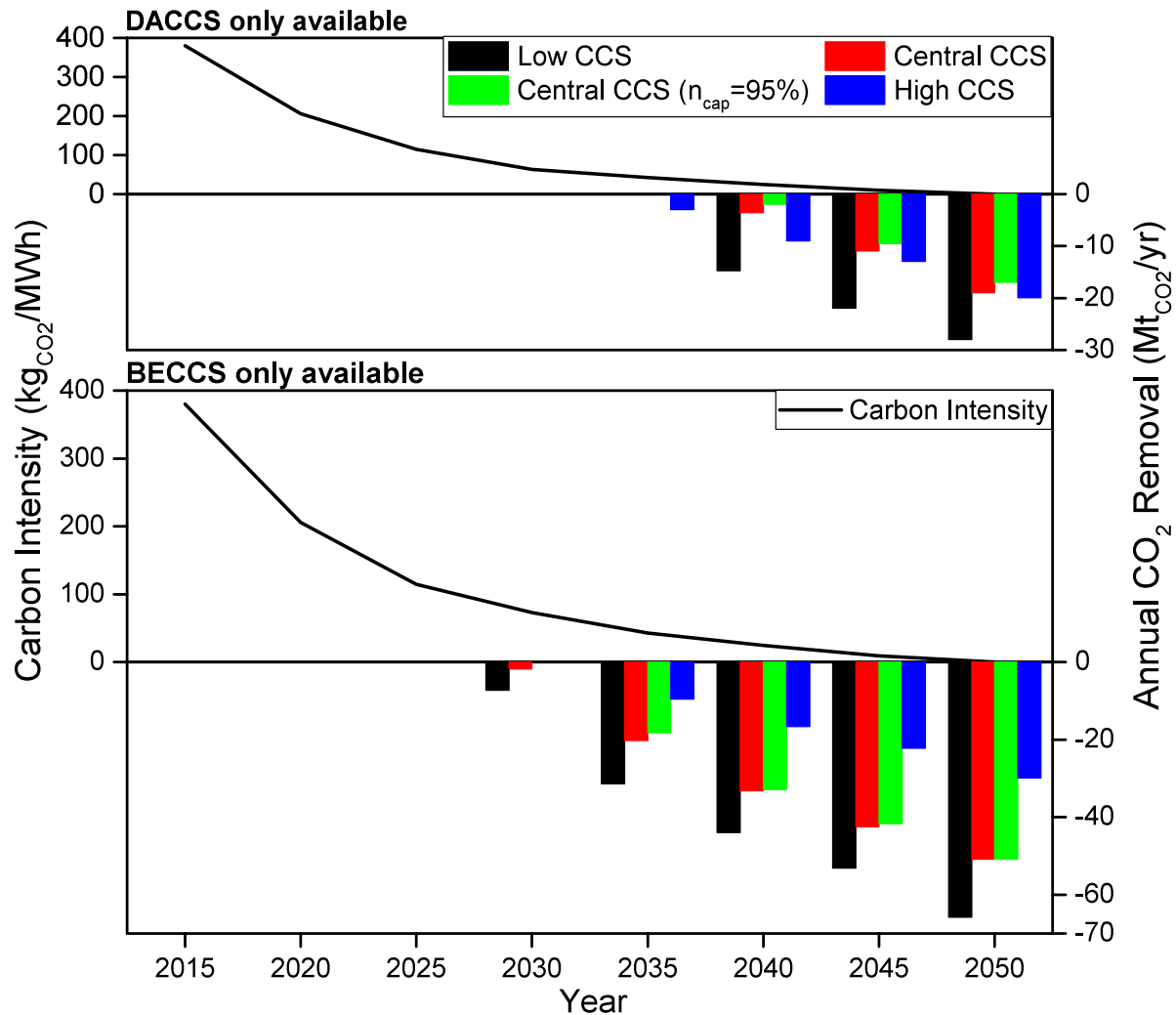


Fig. 3.15 Variation in the amount of negative emissions deployed in the system from 2015 to 2050 with different CCGT-CCS availabilities, subject to a zero emissions target for the electricity system in 2050. Note that the vertical axis (negative emissions provided) has different scales for the *DACCS Only* and *BECCS Only* scenarios.

CCGT-CCS installed capacity is found to have greatest influence in the *BECCS Only* scenario. As capacity increases from 5 GW to 45 GW, negative emissions needed reduces from 66 Mt_{CO₂}/yr to 30 Mt_{CO₂}/yr in 2050. This is because increased CCGT-CCS generation displaces CCGT generation from the system – as CCGT-CCS capacity increases, CCGT generation falls from 164 to 42 TWh/yr in 2050. Less emissions resulting from CCGT outweigh the increased residual emissions from CCGT-CCS, hence the need for negative emissions to compensate is reduced.

Increased capture rate, however, is found to have much less influence as a 5% increase in capture rate reduces the need for negative emissions by approximately 2 Mt_{CO₂}/yr in the *DACCS Only* scenario. In the *BECCS Only* scenario, the change is negligible (within model error). This occurs

as reduced CCS emissions do not increase CCGT-CCS utilisation, rather cheaper CCGT plants produce 6 TWh/yr more. The resulting CCGT emissions cancel out reduced CCS emissions, hence the need for CO₂ removal remains the same.

3.5.2 Scope for Cost Reduction

Thus far, we have evaluated the system with only one of BECCS or DACCS available in any given scenario. However, given the relative immaturity of both technologies, and the potential for cost reduction, it is instructive to evaluate how they would interact in an electricity system if they were both available and competing. Thus, in this section, we present a sensitivity analysis quantifying the extent to which each technology would contribute to meeting a given negative emissions target should both technologies be available over a wide range of capital and operational costs.

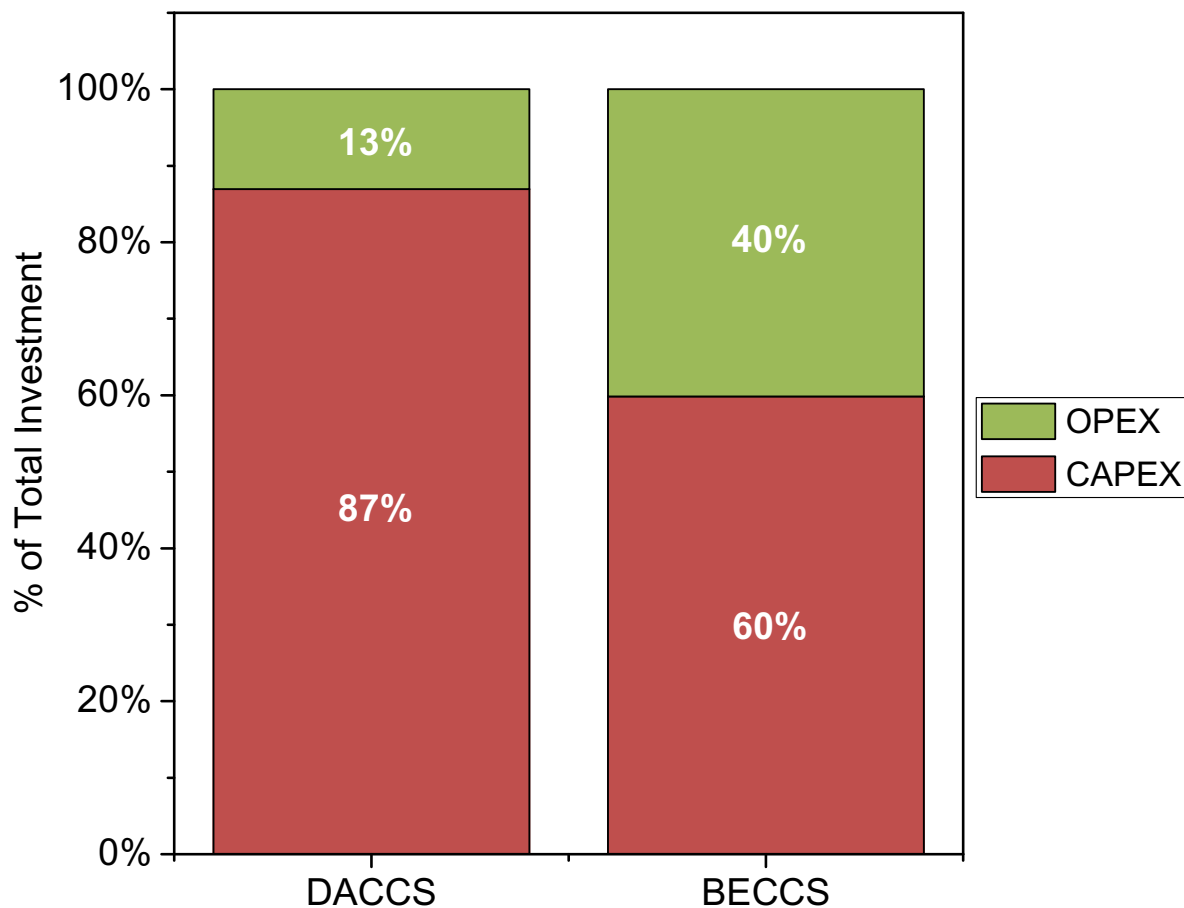


Fig. 3.16 Contribution of CAPEX and OPEX to the total investment required for the operation of BECCS and DACCS in the *BECCS Only* and *DACCS Only* scenarios, respectively

CAPEX

A wide range of cost estimates for first-of-a-kind plants BECCS and DACCS plants appear in the literature^{71,111,144,166,167}. These FOAK costs are likely to reduce with increased R&D and

deployment, especially for DACCS because of the increased potential for modular units^{111,166} that may also benefit from economies of scale through mass production. For BECCS, lower-bound CAPEX (£2368/kW) was calculated as previously described. The upper-bound CAPEX was calculated from the IEA World Energy Outlook 2018 (EU Coal-CCS CAPEX of £5500/kW plus the cost of conversion of boiler units is approximately £6000/kW)¹⁸³. For DACCS, the literature cites removal costs of £10-1000/t_{CO2}⁷¹. These ranges informed the sensitivity analysis carried out below. Note that a wide range of CAPEX was investigated for DACCS to reflect the uncertainty in the cost estimates. Furthermore, the CAPEX for DACCS are levelised against its electricity consumption only (majority of DACCS energy input is heat) so that it can be implemented in the ESO-XEL model so figures may appear relatively large.

Using the costs provided in Table 2.7, it was found that 87% of the investment in DACCS was dedicated to CAPEX, with 17% for OPEX (Fig. 3.16). In contrast, investment in BECCS was made up of 60% CAPEX and 40% OPEX. We assess the implications of different BECCS and DACCS CAPEX and biomass costs on the relative value that they add to delivering the UK's emissions reduction targets.

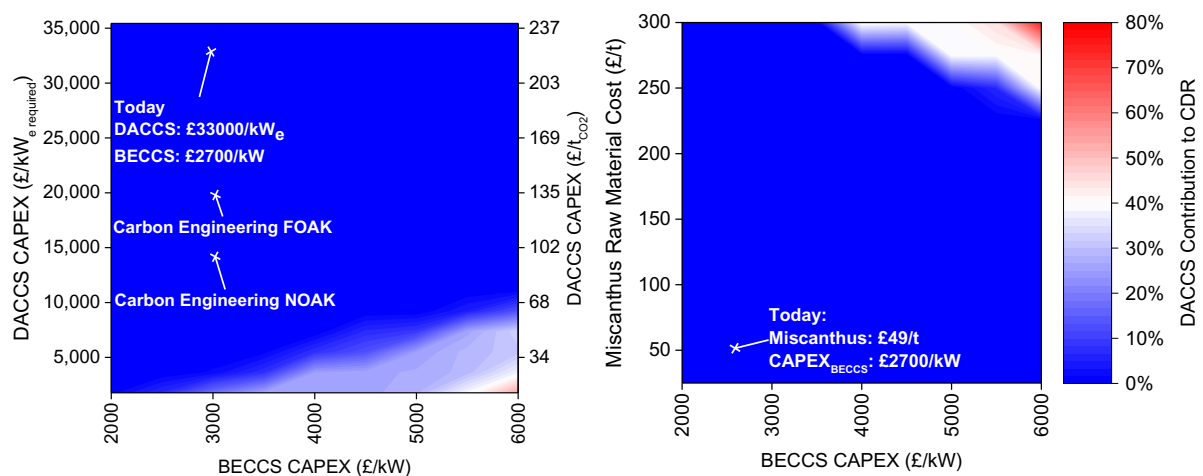


Fig. 3.17 Contribution of DACCS to the UK's negative emissions target at different biomass, BECCS and DACCS costs

Fig. 3.17 shows the contribution of DACCS to the UK's Paris Agreement target at different BECCS and DACCS CAPEX. At current BECCS costs, $CAPEX_{DACCS}$ must fall by a factor of 10 before its deployed for negative emissions. If the capital cost of DACCS is reduced below 3500/kW_e[‡], DACCS contributes 1-13% of -50Mt_{CO2}/yr target in 2050 (Fig. 3.2). At current cost estimates however, DACCS remains uncompetitive with BECCS technology, even if $CAPEX_{BECCS}$ increases more than twofold from estimates in section 3.2.

[‡]Note that this is the capital costs of DACCS levelised against its electricity consumption only, as discussed in section 3.2

Biomass cost

Miscanthus costs comprise the greatest contribution to $OPEX_{BECCS}$. Fig. 3.17 shows that despite a sixfold increase in Miscanthus raw material costs, BECCS is still the preferred source of all negative emissions. In addition to this increase, $CAPEX_{BECCS}$ must be $>4000/kW$ (1.5 times the current CAPEX) for DACCS to contribute to meeting negative emissions targets.

3.6 Discussion

This study finds that, while power sector decarbonisation by 2050 is theoretically achievable without negative emissions technologies (CDR), this would require significant expansion of capital-intensive intermittent renewables and nuclear technologies. This results in a fivefold increase in electricity costs by 2050. Public acceptability is likely to hinder such a transition due to the lack of affordability of electricity. In addition, there are further sociopolitical barriers that must be considered. The large penetration of land-based iRES will require land dedicated to solar and onshore wind farms. Issues arising due to competition for land and social attitudes²¹⁸ must be overcome. Lastly, conventional nuclear technology faces challenges of large financing costs and long payback periods (discussed in section 3.1.2), which may dissuade from the pursuit of further projects^{210,211}. Should CDR not be considered, it is unlikely for deep decarbonisation targets to be met.

Despite their relative costliness, CDR deployment could reduce total investment needed for electricity generation by 37-48% as their negative emissions allow for increased utilisation of cheaper CO_2 emitting generators within the system. BECCS provides the greatest opportunity for cost reduction. It is found to provide three times greater reduction in total system cost of the electricity system than DACCS, per installed capacity. Whilst DACCS still adds value to the system, its deployment will drive up electricity prices to levels seen in a *No CDR* system due to its large operating costs. A significant ramping of nuclear capacity installed is also needed. In contrast, BECCS deployment displaces the need for new nuclear plants as the services it provides – flexible carbon-negative generation to meet demand, reserve, and enable the continued utilisation of cheaper gas plants – are more valuable than the base load low-carbon generation offered by Nuclear. Local grassland yield and availability is sufficient to satisfy the biomass demand for decarbonisation by 2050. However for the deeper decarbonisation pathways needed to be compliant with the Paris Agreement, 7% of biomass demand needs to be imported. The more stringent targets will also increase total electricity system cost by at least 10% (when BECCS is deployed).

The emissions offset that negative emissions provide for CO_2 emitting generators, especially CCGTs, has been observed to translate to larger revenues for CCGTs. In the absence of an incentive for negative emissions, a value transfer mechanism between CDR and CO_2 emitting assets could serve to reduce the public-borne cost of delivering negative emissions. This study

concludes that CDR significantly reduce the cost of decarbonisation of the UK electricity system by 2050, and compensation by CO₂ emitting assets could offer a potential route to commercial deployment.

3.7 Contributions Made

In this study, a power system model was adapted to include carbon dioxide removal technologies. The amount of CDR needed and its relative value for power system decarbonisation—which were absent from the literature—were quantified for the UK. BECCS and DACCS were shown to offer system cost reductions of up to £124,000/kW_{installed} and £43,000/kW_{consumed}. Additionally, the complementarity of CDR and baseload low-carbon generation was identified—their combination proves cheaper than the expansion of iRES, which is often suggested, to meet emissions reductions targets. Finally, a new metric, the Transfer Value, was developed to quantify the effect of CDR deployment on the profitability of conventional fossil fuel generators. It was found that CDR, by allowing for greater utilisation of fossil fuels, leads to larger revenues for the fossil fuel power plants thus an emissions allowance mechanism (which allows polluters to buy negative emissions credits) could be used to incentivise investment in CDR.

Chapter 4

Delivering the Paris Agreement: The Case for the United Kingdom

Chapter Roadmap

In June 2019, the UK amended the 2008 Climate Change Act to mandate a 100% reduction (previously 80%) in economy-wide greenhouse gas (GHG) emissions relative to 1990 levels by 2050⁶². Thus, all sectors need to be decarbonised by mid-century. The IPCC Fifth Assessment Report however showed that achieving net-zero greenhouse gas (GHG) emissions is not sufficient to deliver the Paris Agreement. To deliver the accord, global net GHG emissions need to fall to zero by 2070, and become negative afterwards³. Cumulative carbon dioxide removal (CDR) of 430-820 Gt_{CO₂} is needed by 2100³³, with CDR deployment beginning as early as 2020. The Integrated Assessment Models (IAMs) used to assess global decarbonisation pathways are not sufficiently spatially-disaggregated to determine the amount of CDR deployment by individual countries, which is the level at which climate policy is implemented. Additionally, IAMs assume that virtually all CDR is delivered by BECCS in the power sector³³ but the electricity system transition needed to deliver a significant CDR has not been discussed in the literature. This chapter seeks to address this knowledge gap for the UK by: 1) quantifying the burden of CDR that should be delivered by the UK according to established burden-sharing principles in climate policy; 2) assessing the cost-optimal decarbonisation pathways for the UK power system that deliver their fair share of global CDR requirements; and 3) comparing the structure and costs of the system(s) that deliver significant CDR burden to a zero-carbon electricity system, as mandated by the Climate Change Act. The chapter is structured as follows. Section 4.1 discusses the role of equity in climate policy and quantifies a ‘fair’ CDR burden for the UK according to burden-sharing principles. Section 4.2 discusses the modelling assumptions made in this study and the challenges of modelling long-term system transitions. Section 4.3 uses a central planner approach to determine the power system transition(s) necessary to deliver the UK’s CDR burden, and proposes how CDR technologies can be incentivised. Section 4.4 investigates how

carbon pricing mechanisms can be used to deliver the UK's CDR burden, and the implications for system design and costs. Finally, Section 4.5 provides a conclusion.

4.1 Climate equity and the UK

4.1.1 Insights from Integrated Assessment Models

Several studies have shown that the relationship between cumulative greenhouse gas (GHG) emissions and global warming is insensitive to the emission pathway (*i.e.* the time and rate at which emissions occur)^{224,225}. Therefore, climate change risks and impacts can be mitigated by minimising historic emissions²²⁶. This has generated interest in the potential for large-scale greenhouse gas removal from the atmosphere. Integrated assessment models (IAMs)—climate-economy models that inform on the socio-economic consequences of GHG emissions—have estimated that cumulative anthropogenic GHG emissions (also known as the ‘carbon budget’) must be limited to 590-1240 GtCO_{2-eq} between 2015 and 2100 to deliver the Paris accord (>66% probability)²²⁷. Mitigation action (reducing the sources or enhancing the sinks of GHGs) pledged by countries in their nationally-determined contributions (NDCs), however, is insufficient to achieve this. Even if current NDCs are successfully implemented, the available carbon budget will be exhausted by 2045-2075²²⁸. Large-scale CDR from the atmosphere is therefore critical to compensate for an exceedance of the 2°C carbon budget³.

IAMs show that afforestation and reforestation (AR), a natural CDR technique, alone is not sufficient to deliver CDR at the scale required^{3,14,33}. It is estimated that, in addition to AR, a cumulative 430-820 GtCO₂ of CDR is necessary by the end of the century, beginning as early as 2020, and reaching 10-20 GtCO₂/yr in 2100^{3,14,33}. As BECCS has thus far been the only engineered-CDR solution included in IAMs, this additional CDR is assumed to be delivered by BECCS alone, often exclusively deployed in the power sector³³. This study therefore assumes that the additional CDR (*i.e.* excluding AR) needs to be delivered by the power sector alone.

Although yet to be explicitly included in many IAMs*, the success of several direct air carbon capture and storage (DACCS) demonstration projects^{17,111} have led to its consideration for large-scale CDR. All other forms of land- and ocean-based CDR techniques that are extensively discussed in the literature and in Section 2.3.5, remain largely theoretical^{192,230}. Studies that assess the CDR potential of BECCS and DACCS technologies have been carried out in the context of isolation, therefore they fail to quantify their relative values within the broader energy system. Additionally, they fail to qualify how the availability of CDR will affect power system decarbonisation pathways.

*The inclusion of a backstop in IAMs is representative of a DACCS-type technology. In IAMs, backstop technologies are modelled as technologies with very high CO₂ mitigation costs (>\$5000/tCO₂), that capture CO₂ and sequester it into the available geological storage space²²⁹.

Majority of the cumulative CDR needed to satisfy the 2°C carbon budget by 2100 is provided by BECCS in six regions[†]: China (20-170 GtCO₂), the United States (10-140 GtCO₂), India (0-90 GtCO₂), the European Union (20-70 GtCO₂), Brazil (20-150 GtCO₂) and Russia (10-80 GtCO₂)^{33,231,232}. Owing to the formulation of IAMs, the European Union's (EU) CDR requirements are not further geographically-disaggregated. How and where this CDR burden should be achieved at national-level where climate policy is implemented, is therefore unknown, and the implications of these quotas on country-level energy system transformations is largely absent.

4.1.2 Equity and the Paris Agreement

It has been established that the countries with the greatest responsibility for climate change and the capacity to address it differ greatly from those most vulnerable to its adverse impacts^{34,35}. Consequently, international climate policy has emphasised the need for fairness in establishing the relative burden of action to be taken by governments to stabilise GHG concentrations at non-dangerous levels²³³. The *United Nations Framework Convention on Climate Change* treaty states that member parties should protect the climate system “on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities”²³⁴. However, there is no objective definition of how fairness should be assessed within the context of international climate policy^{233,235}. Several sharing principles have been proposed to equitably distribute the economic burden of climate change mitigation. Some of these principles, and their implications for the UK's climate change mitigation burden have been illustrated in Fig. 4.1 and are detailed below.

Broadly, the principles can be categorised as:

1. Allocation-based^{59,60}: These principles apply a given equity criterion to the initial allocation of carbon quotas or abatement costs (see *Responsibility*, *Capacity*, *Inertia*, *Sovereignty* and *Egalitarian* metrics in Table 4.1).
2. Outcome-based^{59,60}: These principles apply a given equity criterion to the outcome of the implementation of a given treaty or agreement (see *Equity* and *Equality* metrics in Table 4.1).
3. Process-based^{59,60}: These principles are primarily concerned with the fairness of the process or institutional arrangement used to determine relative mitigation burdens between nations (see *Consensus* metric in Table 4.1).

The relative strengths and weaknesses of the burden-sharing principles discussed in Table 4.1 have been extensively discussed elsewhere^{236–238}, and are not repeated here. In this study, we focus on the *Allocation-based principles* that allow us to define a CDR burden for the UK. These equity criteria suggest that the UK meets 12-15% share of the EU's CDR burden

[†]The estimates of CDR required to be consistent with the Paris Agreement are obtained from four IAMs: IMAGE, MERGE-ETL, POLES and WITCH³³. All of these represent the EU as one or two geographic entities.

(see Table 4.1). ‘Blended’ versions combining one or more of the principles have also been proposed⁹². However, given the narrow range of the UK’s share based on these principles—and therefore similar implications for the electricity system transition—, this was not explored further.

Table 4.1 Implications of established burden-sharing principles on the proportion of the EU’s CDR burden that should be delivered by the UK

Principle	Interpretation	Implementation	UK burden	Data sources
Responsibility (sometimes called ‘polluter pays’) ^{35,59,239,240}	Nations should bear the economic burden of emissions reductions in proportion to their cumulative emissions	CDR burden = share of EU historic emissions	14%	Cumulative GHG emissions (1990-2016) ²⁴¹
Capacity (sometimes called ‘ability to pay’) ^{59,239,240}	The greater the ability to pay, the greater the economic burden	CDR burden = share of EU GDP or gross national income	15%	GDP (at 2017 market prices) ²⁴²
Inertia ^{59,92,233,238}	Current emission levels are a status quo right	CDR burden is distributed to maintain relative emissions levels between nations	12%	Current GHG emissions ²⁴¹
Equity ^{59,92,233,238}	‘Blended’ version of Responsibility and Capacity principles	CDR burden is distributed to equalise net welfare change between nations	–	–
Equality ^{59,240,243}	Individuals have equal rights	CDR burden is distributed to achieve equal per capita emissions (immediately or over time)	–	–
Egalitarianism ^{58–60}	All individuals have the right to pollute or be protected from pollution	CDR burden = share of EU population	13%	Population ²⁴⁴
Sovereignty ^{59,60}	All nations have the right to pollute or be protected from pollution	CDR burden distributed to achieve equal relative reduction in emissions between EU countries	–	–
Consensus ⁶⁰	The international negotiation process should be fair	CDR burden is distributed such that political stability is promoted	–	–

These burden-sharing principles seek to establish a politically-optimal distribution of responsibility for climate change mitigation. In reality however, CDR is more feasible in some countries than others due to bio-geophysical and socio-political factors, *e.g.* an abundance of bioenergy resources, availability of low-carbon energy or geological sinks for CO₂. Consequently, a cost-optimal distribution of the CDR burden may require cooperation between nations²⁴⁵. This is not taken into account in this study. Despite the weaknesses of these interpretations of distributive fairness^{236–238}, the principles have been used to ascribe regional carbon quotas and determine the sufficiency of existing climate change mitigation commitments to achieve them^{233,238}.

4.1.3 Long-term emissions reduction targets

Of the estimated cumulative 430-740 GtCO₂ of CDR required globally by 2100³³, the European Union (EU), including the UK, is expected to provide 20-70 GtCO₂ (median = 50). IAMs usually represent the world in a few regions, usually by aggregating neighbouring countries. Therefore, the relative proportion of CDR delivered by individual EU countries (the level at which climate policy is implemented) is not known[‡]. Consequently, we apply the established burden-sharing

[‡]The estimates of CDR required to be consistent with the Paris Agreement are obtained from four IAMs: IMAGE, MERGE-ETL, POLES and WITCH³³. All of these represent the EU as one or two geographic entities.

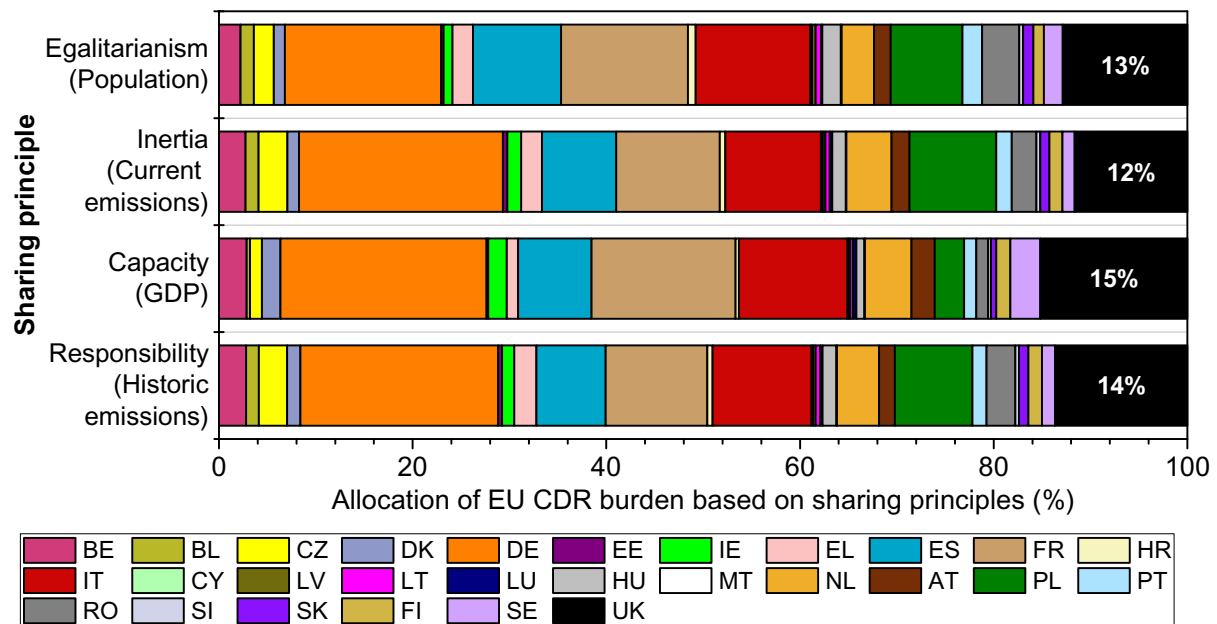


Fig. 4.1 Allocation of the European Union's CDR burden according to proposed 'fairness principles'. Population and GDP data are obtained from Eurostat^{242,244}; member states' historic greenhouse gas emissions are obtained from the European Environment Agency²⁴¹.

principles (discusses above) to determine the proportion of the EU CDR target that should be allocated to the UK.

According to the metrics in Table 4.1[§], the UK would be expected to provide 13-15% of the EU CDR burden, equivalent to a cumulative removal of 2.6-10.5 GtCO₂ by 2100.

The analysis presented below seeks to fill the identified knowledge gaps by: 1.) quantifying UK CDR requirements according to established fairness principles, and 2.) determining the electricity system transition necessary to meet those requirements, since scenarios obtained from IAMs attribute most, if not all, of CDR in the energy system to BECCS in the power sector³³.

It has been shown that different countries have varying potentials to deliver CDR owing to their different bio-geophysical resources²⁴⁶. This potential is often not commensurate with their responsibility for climate change. Additionally, it has been found that cooperation is necessary to meet the global CDR requirements in a cost-optimal fashion²⁴⁵. Therefore, whilst the CDR burden determined above reflects the UK's responsibility for climate change, it may not be realistic or desirable to deliver this CDR domestically. In this analysis, we still assume that the UK's CDR burden is met domestically by the power sector, not considering the possibility of cooperation, which is sub-optimal for two reasons. First, this assumption was found to be suitable for the purpose of this study which is to determine the power system transition needed to deliver a significant CDR burden and the policy implications of such a system, not just for the

[§]The 'inertia' metric has not been considered in this analysis because it allows for the largest emitters to continue emitting GHGs. This is at odds with the objectives of the Paris Agreement and the principles of 'common but differentiated responsibilities' enshrined in the UNFCCC²³⁴.

UK but for other countries that have large CDR burdens owing to their historic GHG emissions. Secondly, the UK possesses several resources that make it suitable to deliver CDR at scale: biomass resources, surplus energy from IRES, and access to geological reservoirs that can be used for CO₂ storage. Therefore, it can be expected that the UK will pursue CDR deployment if the Paris Agreement is to be met.

4.2 Modelling long-term power system transitions

The UK electricity system was modelled using the ‘Electricity System Optimisation with capacity eXpansion and Endogenous technology Learning (ESO-XEL)’ model described in Chapter 2. The ESO-XEL model determines the cost-optimal system design over a planning horizon subject to the set of constraints described by Eq. 1-45. Technology cost learning is implemented endogenously in the model, so the capital costs (CAPEX) of technologies that have a non-zero learning rate decrease (or increase) depending on the cumulative capacity deployed in the system. The planning horizon in this study from 2015 to 2100, when the Paris Agreement is to be delivered. Modelling so far into the future poses challenges because of the uncertainties in the input parameters that will vary over time, such as electricity demand and fuel prices. To account for this a range of values was considered for crucial input parameters, as discussed below.

Modelling inputs

The initial system design and system parameters are as described in Section 2.3.5 (see Table 2.1). As in Chapter 3, a 1% year-on-year increase in electricity demand is assumed until 2050; this was based on a range of studies that estimated a 0.5-1% annual demand growth for the UK from mid-century^{91,92,247}. Projections from integrated assessment models however show that in the longer-term (from 2050 to 2100), demand will remain flat because the growth (driven by the electrification of energy end-use, economic and/or population growth) will be offset by increased energy efficiency and behavioural changes⁹².

In Chapter 3, technology capital costs (CAPEX) were taken from 2015 data. In this chapter, the initial CAPEX of technologies were updated to reflect the most recent cost estimates at the time of writing (2018). Consequently, the ‘2018 CAPEX’ shown in Table 2.2 are used for the initial CAPEX in this study. As previously mentioned, a technology’s CAPEX in a given year changes depending on its learning rate and cumulative capacity installed in the system until that year. Other technology parameters assumed including efficiencies, learning rates and operating costs (OPEX) are also given in Table 2.2. A range of carbon prices and fuel prices are modelled to reflect the uncertainty in their price projections (see Table 2.3). This is further discussed in subsequent sections. For biomass-fired power plants, local and imported biomass sources are considered. Their different availabilities and costs are implemented using a biomass supply

curve which is illustrated in Fig. 2.1. The assumptions made in calculating biomass pellet costs and data sources are detailed in Tables 2.4-2.6.

Scenario definition

Two sets of scenarios are investigated in this chapter. In Section 4.3, the perspective of a central planner is taken to determine the least-cost power system decarbonisation pathways that are consistent with the Paris Agreement. Two sets of emissions constraints are implemented in the ESO-XEL model: the first restrict annual system CO₂ emissions to the sectoral carbon budget, and the second ensures that cumulative CDR meets a specified target. Three scenarios are then assessed: 1) a ‘zero-carbon system’ which delivers net-zero emissions by 2050 and remains decarbonised thereafter, as mandated by the Climate Change Act; 2) a ‘CDR lower bound’ system which delivers 2.6 GtCO₂ of cumulative CDR by 2100, in addition to a decarbonised electricity system; and 3) a ‘CDR upper bound’ system which delivers 10.5 GtCO₂ of cumulative CDR by 2100. This range of CDR requirements corresponds to the UK’s ‘fair’ share of cumulative CDR which were determined according to the burden-sharing principles discussed in Section 4.1. Insights from the results were used to assess potential incentive mechanisms for CDR technologies.

In Section 4.4, a market-based approach is used to determine the cost-optimal decarbonisation pathways. For the scenarios presented, the emissions target (annual and cumulative) constraints in the ESO-XEL model are not implemented. Instead, decarbonisation pathways is determined solely by costs including a carbon price. Three carbon price scenarios are investigated: 1) a carbon price equivalent to the projected prices under the European Union Emissions Trading Scheme, provided by the UK Department of Business and Industrial Strategy (‘BEIS’); 2) a shadow carbon price projections provided by the Committee on Climate Change (‘CCC’); and 3) a carbon price equivalent to the social cost of carbon determined by the UK Treasury (‘Treasury’). The insights from the results were then used to propose how carbon pricing mechanism can be adapted to facilitate climate change mitigation.

4.3 Delivering the Paris Agreement: a central planner perspective

The amended 2008 Climate Change Act mandates an 100% reduction in economy-wide GHG emissions (relative to 1990 levels) by 2050⁶². This requires a virtual decarbonisation of the power sector by 2050¹⁰⁷. For illustrative purposes therefore, we have compared the cost-optimal system transition needed to achieve a decarbonised electricity system by 2050, relative to a transition that meets the UK’s purported CDR requirements by 2100. Accordingly, Fig. 4.2 presents the least-cost capacity expansion and electricity dispatch for the UK from 2015 to 2100 in three scenarios: 1) achieving and maintaining a zero-carbon electricity system from 2050

onwards, 2) providing 2.6 GtCO₂ of CDR by 2100, and 3) providing 10.5 GtCO₂ of CDR by 2100.

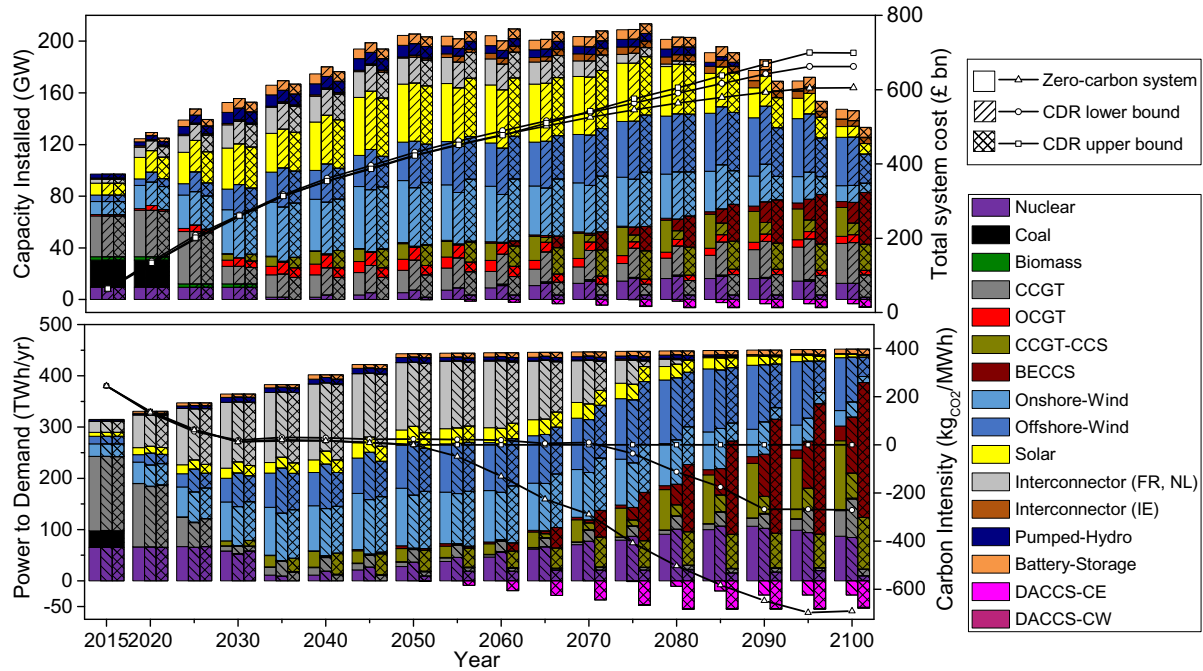


Fig. 4.2 Least-cost power generation capacity expansion and electricity dispatch mix from 2015 to 2100 for the UK electricity system, as forecast by the ESO-XEL model, in three scenarios: achieving a zero-carbon system by 2050 (left); providing cumulative CDR of 2.6 GtCO₂ by 2100 (middle); providing cumulative CDR of 10.5 GtCO₂ by 2100 (right).

We observe that until 2050, the decarbonisation pathway for all three scenarios is approximately the same, *i.e.* carbon intensity falls to zero by mid-century independent of the emissions target imposed. This is largely achieved through extensive expansion of intermittent renewable generation capacity (wind and solar) from 24 GW to 123-126 GW in 2050 (60-61% of installed capacity). The increasing variability of electricity supply in the system necessitates additional grid flexibility, consequently energy storage services and interconnection are expanded simultaneously. Pumped hydroelectric storage (PHES) deployment reaches its geographically-constrained maximum of 9 GW, with 7.2-7.5 GW of batteries built to supplement. Interconnection experiences similar rate of growth to renewables, with electricity import capability quintupling to 21 GW by mid-century. Concurrently, peaking gas power plants (OCGT) see a 550-670% increase in capacity installed to 8.5-10 GW, reflecting the need for faster generation output response to increasingly volatile power supply and, inherently, demand.

The proliferation of intermittent renewable energy sources (iRES) coupled with energy storage, however, is insufficient to reach net-zero emissions in a cost-effective manner. While coal is eliminated from the system after 2020, 38-41 GW of gas power plants, both unabated and abated (equipped with CCS), remain in the system to provide crucial ancillary services to maintain grid reliability, and/or dispatchable low-carbon power. Existing nuclear capacity (9.6 GW) is only replaced after it reaches operational end-life in 2030 in the ‘Zero-carbon system’ and ‘CDR

lower bound' scenarios; 1.8 GW of new build comes on-line in 2035 and peaks at 16-18 GW in the latter half of the century. In the 'CDR upper bound' scenario where existing nuclear is not replaced, CCGT-CCS deployment is seen aggressively from 2030 onwards, with a total of 15 GW built in 20 years; this highlights the need for dispatchable low-carbon electricity as renewables penetration rises in a carbon-constrained system. As CCS only captures 90% of gas-derived emissions, 0.5-1 GW of BECCS capacity is deployed to compensate for CCGT-CCS residual emissions.

Current global decarbonisation efforts largely seek to increase deployment of wind and solar power. The above shows that such a strategy is consistent with the cost-optimal pathway only up to a limit—in the case of the UK, this is until 2050. Beyond this limit, however, the optimal system design to either maintain a zero-carbon system or meet ambitious CDR burdens greatly differs.

4.3.1 Maintaining a zero-carbon system post-2050

Near- to medium-term decarbonisation objectives are satisfied by displacing fossil generation with iRES, as shown from 2020 onwards in Fig. 4.2. This is because, despite iRES' low energy density and intermittency—which require additional capacity, energy storage and grid flexibility to compensate—they provide the cheapest zero-carbon electricity. However, several factors conspire to reduce the relative competitiveness of iRES: rising demand[¶] and the retirement of old fossil and iRES power plants means there is a significant capacity shortfall that must be replaced quickly; even the modest learning rates assumed here (see Table 2.1) result in cheaper firm low-carbon power from CCS plants; exhaustion of storage and flexibility availability as interconnection and PHES are maximally deployed. Consequently, for the delivery of zero-carbon electricity, firm low-carbon thermal generation (complemented with some CDR from BECCS to offset residual emissions) proves cheaper than further expansion of iRES. From Fig. 4.2, we observe that iRES capacity falls by more than 50% to 58 GW, while firm low-carbon generation (nuclear, CCGT-CCS and BECCS) capacity rises from 18 to 40 GW, between 2050 and 2100. Total generation capacity, which peaks at 208 GW in 2075, also shrinks to 147 GW in 2100 due to the reduced reliance on iRES.

4.3.2 The challenges of gigatonne-scale CDR

The return to a system dominated by thermal power plants is accelerated when CDR targets are imposed because of the increased need for BECCS and DACCS. For the lower- and upper-bound CDR requirements, annual CO₂ removal rate rises until the end of the century when it reaches a peak of 159 and 358 Mt_{CO₂}/yr, respectively. In 2100, the 16-40 GW of BECCS capacity installed

[¶]Although UK electricity demand has been falling in recent years due to improved energy efficiency, the electrification of other sectors (transport, heating, *etc.*) is expected to result in demand growth⁹².

requires 1.2-2.9 EJ/yr^{||} of bioenergy to provide 57-63% of annual CDR. Despite the energy intensive nature of DACCS, it provides 46-61% of total CDR. This highlights the influence of increasing biomass costs as local supplies of waste and virgin biomass are exhausted, and import dependence rises (see Fig. 2.1). Increased BECCS costs and technology learning conspire to favour DACCS deployment over a marginal increase in BECCS capacity. Although DACCS-CE has limited learning potential (majority of the processes involved—absorption, calcination and compression—use mature technologies) and is unable to operate flexibly, it is the archetype of DACCS that is deployed owing to its lower capital and operating costs (relative to DACCS-CW). Inflexible operation limits DACCS-CE's capacity to integrate into an iRES-dominated system, so it is likely that DACCS deployment facilitates the resurgence of thermal generation in the system after 2050.

Meeting the required CDR commitments appears not to transgress any biophysical limits. However, the extent of their deployment poses other risks. Total system cost (capital and operating costs throughout the planning horizon) increases by 10-30%, relative to the 'Zero-carbon system', for the Paris Agreement-compliant systems. In the worst-case scenario, BECCS is required to generate 280 TWh_e/yr, equivalent to 55% of annual demand. Due to limited local bioenergy availability, 228 TWh_e/yr (81%) of BECCS generation relies on imported biomass. Such heavy import dependence will leave the power sector exposed to the volatilities of global supply chains and present energy security concerns. In addition, the large volumes of CO₂ need to be transported from 254 large-scale capture units (BECCS, CCGT-CCS and DACCS plants) to suitable storage sites. Therefore, extensive CO₂ transportation networks are necessary as this amount of infrastructure is unlikely to be geographically-concentrated. Lastly, DACCS deployment adds significant demand to the system. In the upper-bound scenario, DACCS consumes 53 TWh_e/yr in 2100, equivalent to 13% of the annual demand. Fig. 4.2 shows the increase in DACCS deployment required to meet more ambitious CDR requirements. From Fig. 4.3, it can be seen that greater electricity supply is needed earlier to satisfy this additional DACCS demand.

4.3.3 The evolution of the electricity system in a post-Paris world

The cost of electricity generated from iRES has fallen dramatically in recent years, and this trend is expected to continue in the near future to the extent that subsidy-free iRES will be competitive with conventional generation technologies²². This, in addition to the need to decarbonise economies, has resulted in calls for 100% iRES-dependent electricity systems²⁴⁸⁻²⁵¹. This study has shown that, in the long-term, such a system is not a cost-effective means to deliver either zero-carbon electricity or the Paris Agreement.

^{||}100 EJ/yr is widely-cited as the global sustainable biomass production potential²⁴⁶.

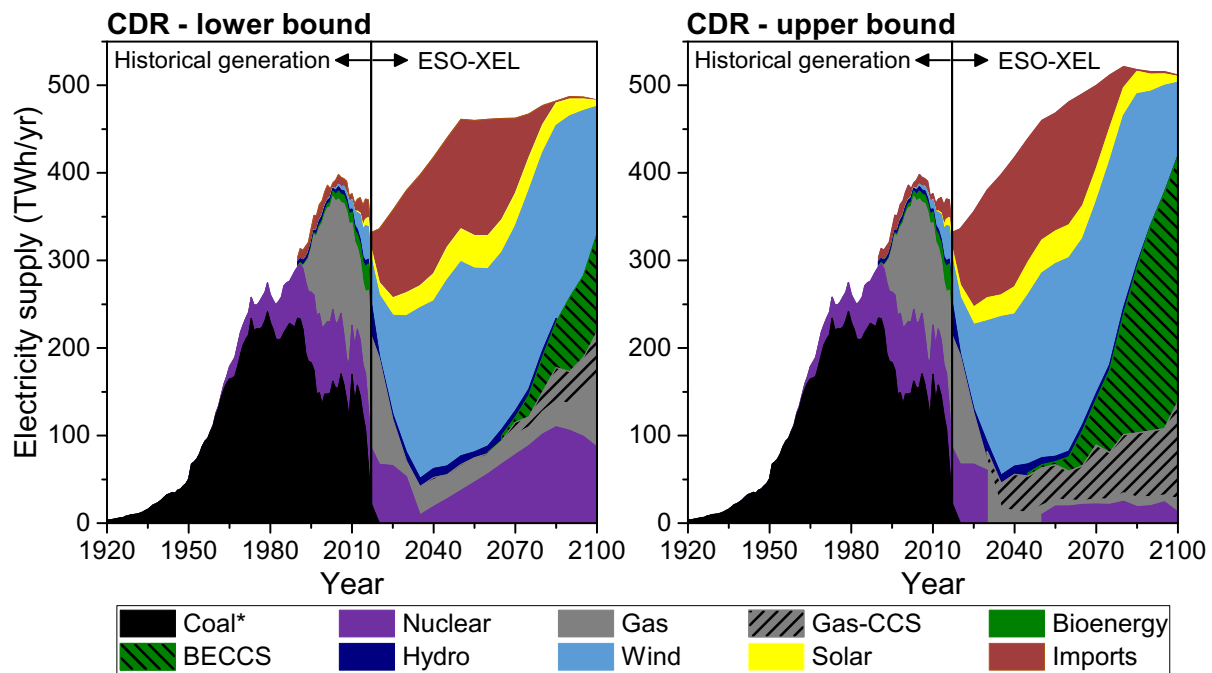


Fig. 4.3 Evolution of the UK electricity supply from 2020 to 2100 (as projected by the ESO-XEL model) when CDR requirements consistent with the Paris Agreement are imposed. Historical data from 1920 to 2017 is also shown.

Fossil fuels, particularly coal, has historically dominated the fuel mix for power generation in the UK. Since the 2000s, several policies and legislation have been implemented to spur a transition to less-polluting fuels and renewable sources of energy^{61,199,202}. Fig. 4.3 illustrates how the historical transition of electricity supply (from 1920 until 2017) compares with the projections obtained using ESO-XEL (until 2100). Two future transitions are apparent, with the first being imminent. Spurred by cheap iRES and an urgent need to completely decarbonise, the penetration of iRES—iRES available capacity relative to total system capacity—increases consistently until mid-century when it reaches a peak of 61%. Increased imports and energy storage compensate for the variability of iRES during this period. Fossil generation—which is from natural gas only as coal is eliminated from the system from 2020—is either abated with CCS or greatly reduced. Nuclear capacity is briefly eliminated from the system as existing power plants retire.

The second transition sees the deployment of significant BECCS and DACCS capacity to meet rising CDR burden. Retirement of old fossil and iRES capacity, and rising electricity demand (due to electrification, DACCS, economic/population growth *etc.*)⁹² result in a significant capacity shortage. New CCGT-CCS, nuclear and some unabated gas capacity prove a cheaper generation portfolio to compensate for this shortage, compared to further expansion of iRES and energy storage. This is due to falling CCS costs (due to cost learning from earlier deployment), limited additional storage capacity (PHES and interconnection capacity exhausted) and the higher availabilities of thermal power plants. Therefore we observe the electricity system return

to one dominated by thermal generation, although this is now dependent on bioenergy, nuclear and natural gas, as opposed to coal—the historically dominant fuel.

4.3.4 Shifting the conversation from low-carbon to negative-carbon

The ESO-XEL model assumes the perspective of a monopolistic system planner. However most countries have enacted some form of liberalisation reform in their electricity markets. Investment decisions in power generation are therefore no longer centralised, but driven by risk/return prospects. Investment in immature technologies that are unable to meet market-rate returns are incentivised through favourable policies or legislation. In the past two decades, the increased urgency to decarbonise led to a raft of such incentives for renewable energy technologies. Broadly, renewable energy support (RES) is given in the form of: quota systems that allocate a proportion of generation to iRES (renewables obligation certificates, competitive tendering or bidding); incentives that lower the cost of investment (tax credits or exemptions, soft or interest-free loans, *etc.*); additional payments for generation (feed-in tariffs, contracts-for-difference); carbon pricing to discourage fossil generation; and legislation discouraging CO₂-intensive generation (mandated carbon budgets, coal plant bans)^{197,252}.

This study has shown that despite the cost reductions in iRES—which are a result of some or all of the above incentives—their continued deployment (in the long-term) does not provide the least-cost pathway to the Paris Agreement. As subsidy-free iRES becomes commercially-viable, support should therefore be redirected to other technologies that are crucial to meeting long-term mitigation objectives, particularly CDR technologies. The services offered by BECCS and DACCS in the electricity system are qualitatively different in type and value, and their incentivisation should reflect this. That is, whilst iRES are an important part of a transition to zero-carbon, they are unable to achieve deeper decarbonisation objectives that require a negative-carbon electricity system—this is only possible through CDR deployment. Therefore incentives given to iRES and CDR technologies should reflect their relative importance to deeper decarbonisation objectives at the given stage of the energy transition. Table 4.2 summarises these services and the instruments that could be used to monetise them. Common to both BECCS and DACCS is the ability to provide an atmospheric CO₂ removal service, which is a public good that should be appropriately remunerated. In addition, they can provide CDR to compensate for GHG emissions from CO₂-emitting power plants or other sectors of the economy with more expensive or difficult mitigation options (such as heat or aviation). Here, BECCS or DACCS would allow value to accrue to other assets by allowing them to operate and generate revenue in a carbon-constrained system. The purchase of ‘negative emissions credits’ by the assets so enabled can be used to share some of this value with BECCS and DACCS.

Table 4.2 Potential incentives for services provided by BECCS and DACCS

CDR technology	Services provided	Potential incentives
BECCS	Power generation	Wholesale electricity market, revenue support <i>e.g.</i> contracts-for-difference
	Ancillary services	Capacity market, ancillary services market
	Atmospheric CO ₂ removal	Negative emissions credit
	CO ₂ emissions offset for other power plants or sectors of the economy	Auction-able credit to CO ₂ emitters
DACCS	Atmospheric CO ₂ removal	Negative emissions credit
	CO ₂ emissions offset for other power plants or sectors of the economy	Auction-able credit to CO ₂ emitters

4.3.5 Crediting negative emissions

The UK has recognised the social cost of carbon⁹⁰, and therefore recognised that emitting CO₂ to the atmosphere is imposing a public cost. CO₂ removal is consequently a public good, which could reasonably be expected to be compensated in line with the value of the avoided cost. We introduce the concept of a ‘negative emissions credit (NEC)’ as a payment for the net removal of one tonne of CO₂ from the atmosphere. Building on previous work²¹⁹, a cash flow analysis was carried out to understand the effect of remuneration through NECs on the economic viability of first-of-a-kind (FOAK) BECCS and DACCS plants. As BECCS also contributes to power generation, it is assumed that it receives revenues from electricity sales at the marginal cost of electricity of the system. Capacity utilisation throughout the operational lifetime of the plants is determined from the optimal electricity dispatch profile obtained using the ESO-XEL model .

For a FOAK BECCS plant, a NEC of £52/tCO₂ yields an internal rate of return of 4%, typical for regulated assets. Due to the greater cost of capture and the absence of any other revenue stream, DACCS-CE and DACCS-CW require NECs of £176/tCO₂ and £342/tCO₂, respectively, to achieve a similar return. High-risk investments, such as those in nascent technologies, often demand higher returns; Fig. 4.4 shows that much higher NEC payments will be needed to achieve higher IRRs. Nascent technologies typically have IRRs of greater than 10%. Achieving such a return would require NECs of at least £86/tCO₂ and £223-443/tCO₂ for BECCS and DACCS, respectively.

4.3.6 Revenue support for BECCS

In addition to providing negative emissions, BECCS can generate electricity to meet demand and provide ancillary services that help to maintain system reliability and operability. Owing to its added social utility (climate change mitigation), low-carbon electricity generation is often subsidised through feed-in tariff (FiT) or contract-for-difference (CfDs) schemes. Generally, both schemes guarantee stable revenues (at a pre-agreed tariff or ‘Strike Price’) for generators in a volatile wholesale market; FiTs target small or medium-scale renewable energy generators, while CfDs target utility-scale generators. In today’s paradigm, BECCS would—were it not for other

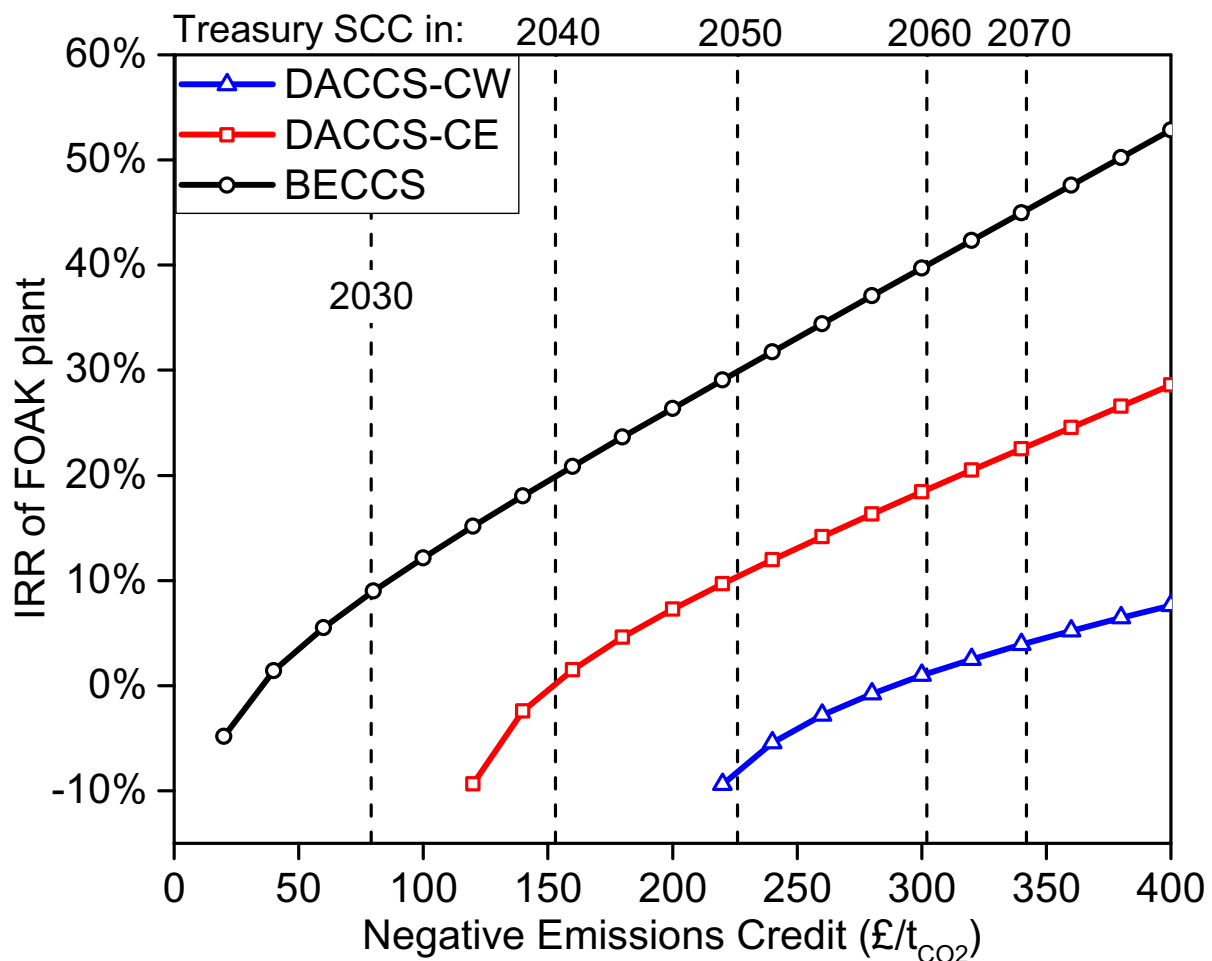


Fig. 4.4 IRR on investment in FOAK CDR technologies at different negative emissions credit payments. Dashed lines illustrate the social cost of carbon (SCC) in the years labelled, as projected by the UK Treasury.⁹⁰

barriers to deployment (lack of CO₂ transport and storage infrastructure, social acceptability of biomass use)—be eligible for such revenue support as it produces negative-carbon electricity that furthers mitigation. Fig. 4.5 illustrates the effect of a NEC and CfD-type incentive on the profitability of a FOAK BECCS plant.

In the absence of a NEC, BECCS would need a strike price guarantee of 133–188 £/MWh to achieve an IRR of 4–15%. If BECCS was recognised as a CDR technology solely and not remunerated for power generation, it would need a NEC of 166–234 £/t_{CO2} to generate the same return on investment. Remunerating BECCS for the CDR service alone may well be more politically feasible, as that enables BECCS to compete directly in the electricity market, *i.e.* ‘subsidy-free’.

The above highlights that BECCS and DACCS are not commercially-viable and need significant support before they can be deployed at the scale required. However, it is important to note that the NEC payments required by both technologies are comparable to the carbon prices assumed in IAMs at their time of deployment (2030 for BECCS, and 2050 for DACCS)³. In addition, the

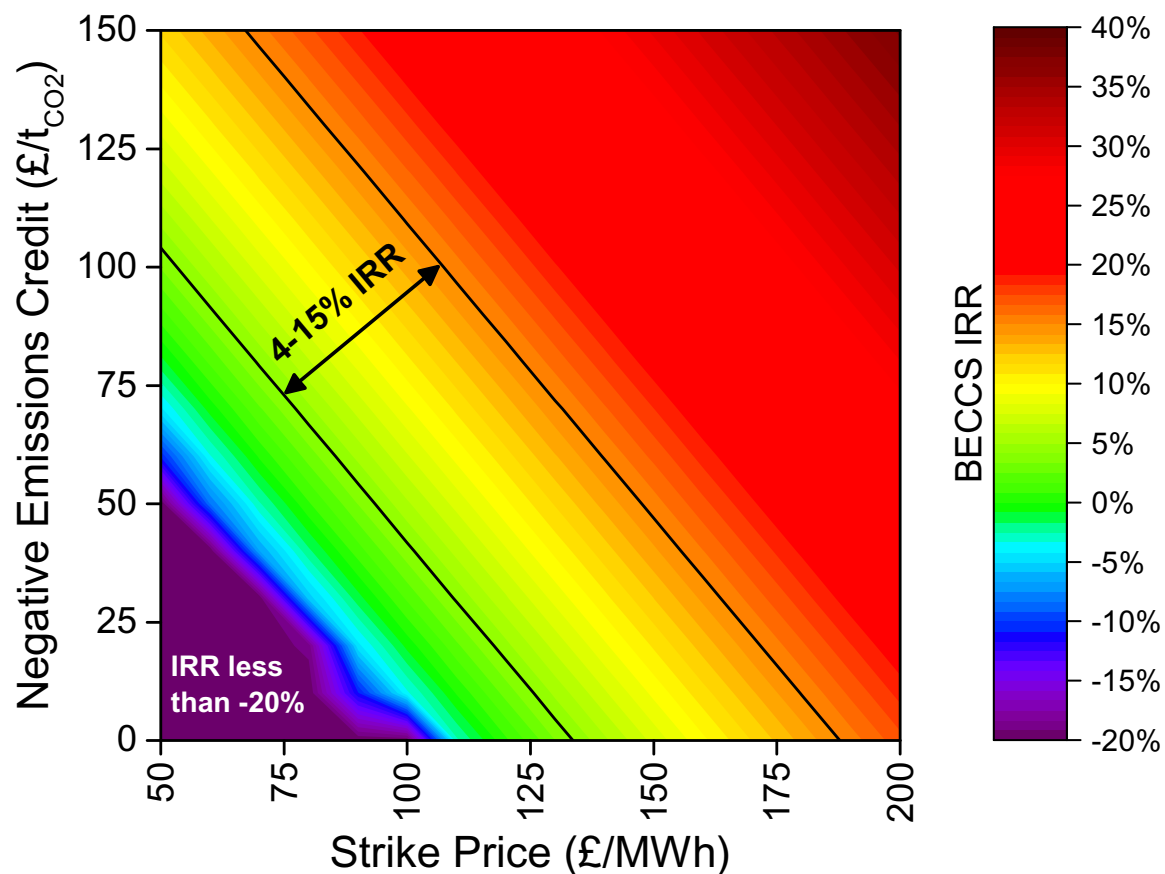


Fig. 4.5 IRR on investment in a FOAK BECCS power plant when it is credited for power generation at a strike price, and credited for CO₂ removal *via* a negative emissions credit. For illustrative purposes, scenarios that result in very negative IRRs (below -20%) are simply shown by the purple region.

price guarantee required by BECCS is consistent with what is awarded to iRES through various support schemes²⁵².

The above assesses the incentives or disincentives that need to be provided in the power sector to deliver this amount of CDR. Conventionally, this kind of work (including IAMs work), is done using a “scenario-based approach” where all models solve subject to hard end-point GHG concentration/emissions constraints²⁵³. This gives little to no insight as to what a liberalised economy might actually deliver. To address this gap, we run the ESO-XEL model with no constraint on GHG emissions, rather optimal system design is determined by technology costs, including taxes on CO₂ emissions and/or credits for CO₂ removal.

4.4 Delivering the Paris Agreement: a market-driven approach

Since scientific consensus established that anthropogenic greenhouse gas (GHG) emissions were responsible for climate change, solutions—both technological and policy-based—that

encourage a shift to a low-carbon economy have been proffered. Their foremost objective is a transition away from global reliance on unabated fossil fuels* to less-polluting energy sources such as renewable energy, nuclear power and plants equipped with carbon, capture and storage (CCS)³. Economists have advocated for a market-based approach to mitigation, citing climate change as a ‘market failure’ to account for the negative externalities of GHG emissions borne by society²⁵⁴. Placing a price on GHG emissions—particularly CO₂, the most abundant GHG—has been proposed as a means to reflect their true cost to society. The argument goes that should the carbon price be set and implemented correctly, market forces would deliver a low-carbon economy efficiently and in a non-prescriptive manner.

The social cost of carbon (SCC)—the net economic costs (and benefits)[†] of an additional tonne of CO₂—has been estimated for many countries²⁵⁵, carbon prices currently imposed *via* emissions trading schemes, or outright taxation have stagnated well below the SCC for reasons of political inexpediency⁴⁴. It has been argued that higher carbon prices result in energy price rises which can affect the economic competitiveness of a country and exacerbate fuel poverty^{256,257}. Additionally, recent reports by the Intergovernmental Panel on Climate Change (IPCC) have highlighted that, to mitigate the risks posed by climate change to an ‘acceptable level’—defined by the Paris Agreement as an average global temperature rise of “well-below 2°C” above pre-industrial levels by 2100—requires more than a shift to low-carbon energy^{3,14}. Anthropogenic CO₂ emissions need to fall to zero by 2070, and become negative afterwards³. This means that large-scale carbon dioxide removal (CDR) from the atmosphere (sometimes called ‘negative emissions’) is critical. CDR is a broad term for any anthropogenic activity that results in a net removal of CO₂ from the atmosphere. CDR methods are described in detail in Section 1.1.

4.4.1 Carbon pricing in the UK

Since 2013, the UK has implemented a carbon price floor (CPF) to support the EU Emissions Trading Systems (EU-ETS). Due to the recession in the Eurozone during Phase 2 of the EU-ETS (2008-2012), the carbon prices were too low to drive low-carbon investment²⁵⁸. The CPF is a ‘top-up’ carbon tax on fossil fuels used to generate electricity. Although the CPF has been capped at £18/tCO₂ until 2021, it is expected that carbon prices will rise in the future as climate change mitigation efforts expand²⁵⁸. Different forecasts have since been prepared:

1. The Department for Business, Energy & Industrial Strategy (BEIS) has its internal assessment of how short-term traded carbon values will evolve, which it uses for modelling purposes¹⁹⁷. BEIS’s short-term traded carbon values are used to demonstrate the financial cost of

*Unabated fossil fuel use refers to the use of fossil fuel technologies without carbon capture and storage (CCS). CCS is a technology that captures the CO₂ emissions that result from fossil fuel combustion or industrial processes, and stores them underground in geological formations.^{8,83}

[†]The social cost of carbon for a country can be negative if its current temperatures are below the economic optimum level; this has been shown to be the case for Canada and some parts of Northern Europe²⁵⁵.

purchasing allowances under the EU-ETS. These carbon price projections are used to determine BEIS's 'Energy and Emissions' projections, and in other models of electricity generation and investment across Government.

2. The Department of Energy & Climate Change (DECC – no longer existing) evaluated the shadow carbon price needed to meet the UK's 2008 *Climate Change Act* target to reduce economy-wide greenhouse gas emissions by 80% by 2050. The Committee on Climate Change (CCC)—the independent body that advises the government on addressing climate change—has since used that carbon price in their internal modelling to determine how emissions reduction targets are met²⁵⁹.
3. The social cost of carbon for the UK was evaluated by Her Majesty's Treasury. The UK has recently abandoned the use of the social cost of carbon for policy appraisal, but it was nonetheless included in this study⁹⁰.

The carbon price forecasts described above—henceforth referred to as 'BEIS', 'CCC', and 'Treasury', respectively—are illustrated in Fig. 4.6. The results below assess the implications of implementing carbon taxation and/or credit mechanisms at prices equivalent to the above forecasts.

4.4.2 Maintaining the status quo

Despite increasing consensus on the need for large-scale CO₂ removal from the atmosphere¹⁴, there has been little discussion of how CDR solutions can be financed. While CO₂ emissions are penalised, mainstream carbon pricing or emissions trading schemes are yet to credit CO₂ removal services. Fig. 4.6 illustrates how power generation capacity changes from 2015 to 2100 under the carbon price scenarios discussed previously, should the status quo of only penalising emissions be unchanged.

We find that, with the exception of 'BEIS', all scenarios deliver a decarbonised system—defined as a carbon intensity of electricity of less than 10 kgCO₂/MWh—by 2050. This is largely achieved through increased utilisation of intermittent renewable energy sources (iRES), and the expansion of energy storage and interconnection capacity to compensate for the variability of iRES. In all scenarios however, BECCS and DACCS are not deployed. Even when CO₂ emissions (including residual emissions from CCS power plants[‡]) are penalised at the social cost of carbon—which rises quickly from £6/tCO₂ in 2015, to a peak of £349/tCO₂ in 2075 and falling slightly after—no CDR solution is deployed throughout the planning horizon considered. This highlights that, in the current paradigm, even very high levels of carbon taxation may be unable to deliver CDR at scale.

[‡]CCS technology conventionally has a capture rate of 90%⁸. Although this could be higher, 100% capture is infeasible due to large energy and economic costs. Therefore some CO₂ emissions from fuel combustion are still released into the atmosphere. We account for these residual emissions in the annual carbon emissions of the power sector, and assume that they are penalised via the carbon tax.

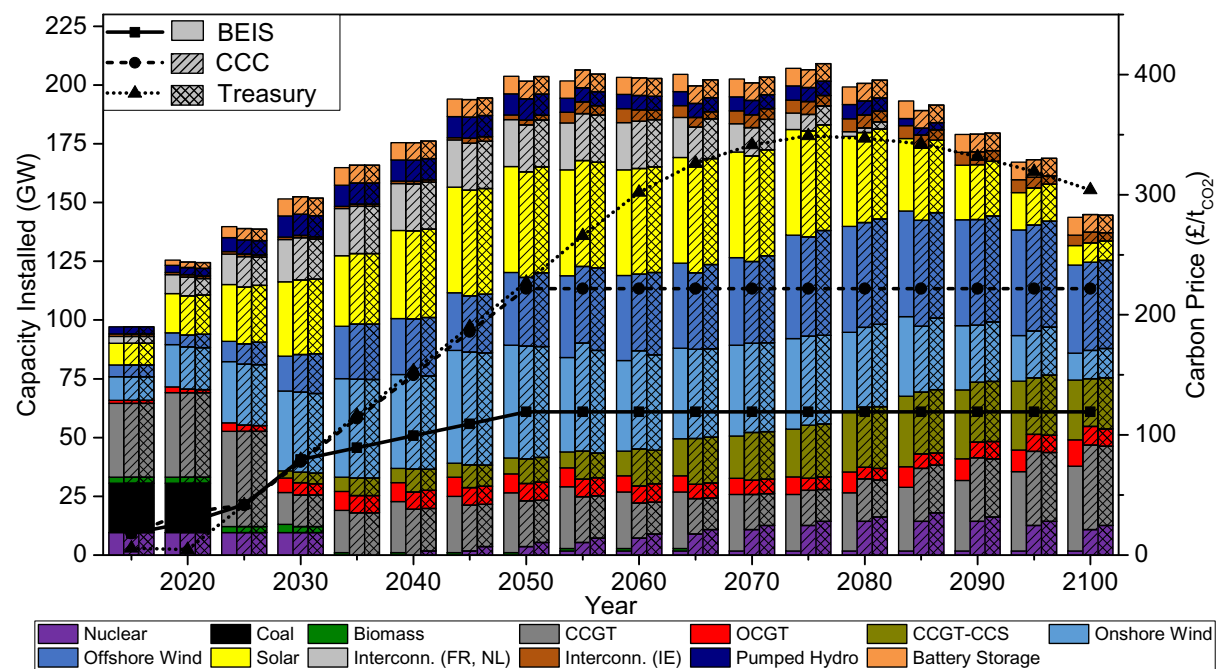


Fig. 4.6 Least cost evolution of power generation capacity from 2015 to 2100 under BEIS (unshaded bars), CCC (hatched bars) and Treasury (cross-hatched bars) carbon price scenarios, according to the ESO-XEL model. The left y-axis corresponds to the installed generation capacity (stacked columns), while the right y-axis corresponds to the carbon price forecasts (line graphs). Note that no credit for CO₂ removal is being provided in any of the above scenarios.

Fig. 4.7 shows how annual electricity demand is being met under the different carbon price scenarios. We observe that although a largely decarbonised electricity system is achieved by 2050, carbon intensity subsequently rises towards the end of the century. This is because of increased gas-fired generation (particularly from CCGT-CCS), which displaces electricity imports and renewables from the system. This is due to several factors: rising electricity demand[§] and the retirement of existing capacity leave a significant capacity shortfall that must be met quickly; interconnection and pumped hydroelectric storage maximum deployment limits are reached so there are limited sources of additional grid flexibility and energy storage[¶]; technology cost learning (due to earlier deployment) has resulted in lower costs of CCGT-CCS plants; and the higher availability of thermal power plants. These factors combine to make CCGT-CCS and nuclear power cheaper to deploy relative to iRES coupled with battery storage (despite aggressive learning curves assumed for iRES^{||}). Therefore a resurgence of thermal generation

[§] Although electricity demand has been falling in the UK in recent years due to increased energy efficiency, electrification of other sectors (transport, heating, *etc.*) is expected to result in demand growth⁹².

[¶] The maximum interconnection capacity (20 GW) has been assumed as the current import capacity in addition to the capacity of projects being developed (both existing and those that have sought regulatory approval)²⁶⁰. This is also approximately the limit beyond which added interconnection capacity no longer results in a net benefit²⁶¹, as prices have sufficiently converged with European markets, or Britain exports more frequently thereby increasing prices for British consumers. The deployment limit of pumped hydroelectric storage (9 GW) is estimated based on geographical constraints in Scotland.

^{||} Learning rates of 23%, 12% and 20% are assumed for solar PV, onshore wind and offshore wind power, respectively.

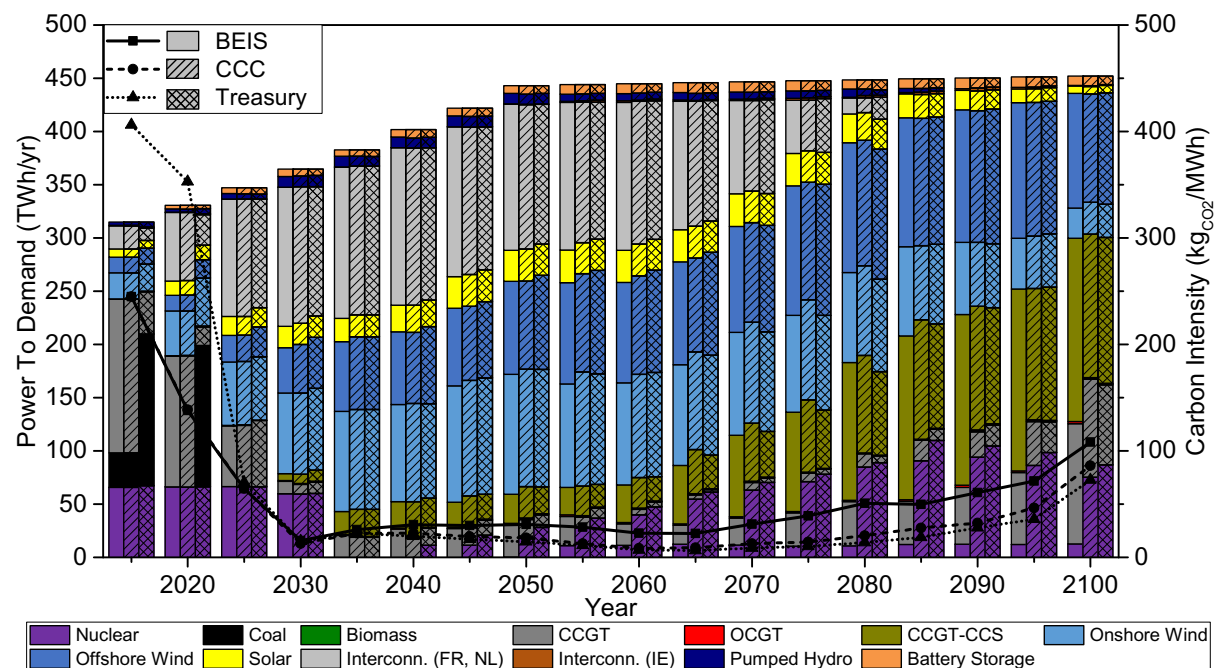


Fig. 4.7 Annual power sent to demand from 2015 to 2100 under BEIS (unshaded bars), CCC (hatched bars) and Treasury (cross-hatched bars) carbon price scenarios, according to the ESO-XEL model. The left y-axis corresponds to the annual power sent to demand (stacked columns), while the right y-axis corresponds to the carbon intensity of electricity generated (line graphs). Note that no credit for CO₂ removal is being provided in any of the above scenarios.

is seen in the system; the increased availability** of thermal power plants also means that less generation capacity is required to meet demand, consequently total system capacity falls going to 2100 (see Fig. 4.6).

The ESO-XEL model simulations show that high carbon prices on emissions alone could be unable to maintain a decarbonised electricity system or spur the deployment of CDR in the long-term. Therefore, they may be unable to deliver the climate mitigation objectives set out in the Paris Agreement.

4.4.3 Rethinking carbon pricing regimes

Fig. 4.6 highlighted that, even in a high carbon price environment, BECCS and DACCS are not deployed in the absence of a direct incentive for CDR. However, we would argue that if CO₂ emissions are penalised to reflect the social cost they impose on society, CDR—which is a public good—should be similarly remunerated. We therefore investigate the effect of crediting the provision of a CDR service on the uptake of BECCS and DACCS in the system, in addition to maintaining a carbon tax to disincentivise positive CO₂ emissions to the atmosphere. We

**The availability of a power plant is the amount of time that it can generate electricity over certain time period, relative to the time in that period. Due to the variable nature of intermittent renewable energy sources, they have very low availabilities. To deliver a given amount of electricity therefore, a greater capacity of iRES is required relative to a thermal power plant.

introduce the concept of a negative emissions credit (NEC) as a payment for the *net* removal of one tonne of CO₂ from the atmosphere. We recognise that, in reality, there are likely to be several ways to incentivise CDR other than a direct payment. These may be mandates for CO₂ emitters to do some CDR, tax credits to encourage investment, *etc.* However, the NEC being discussed in this study is a proxy for an incentive that lowers the cost of delivering CDR. In the scenarios subsequently shown, the NEC available in a given year is equivalent to the carbon price in that year; this is to illustrate the effect of valuing CO₂—emissions (negative value) and removal (positive value)—equally.

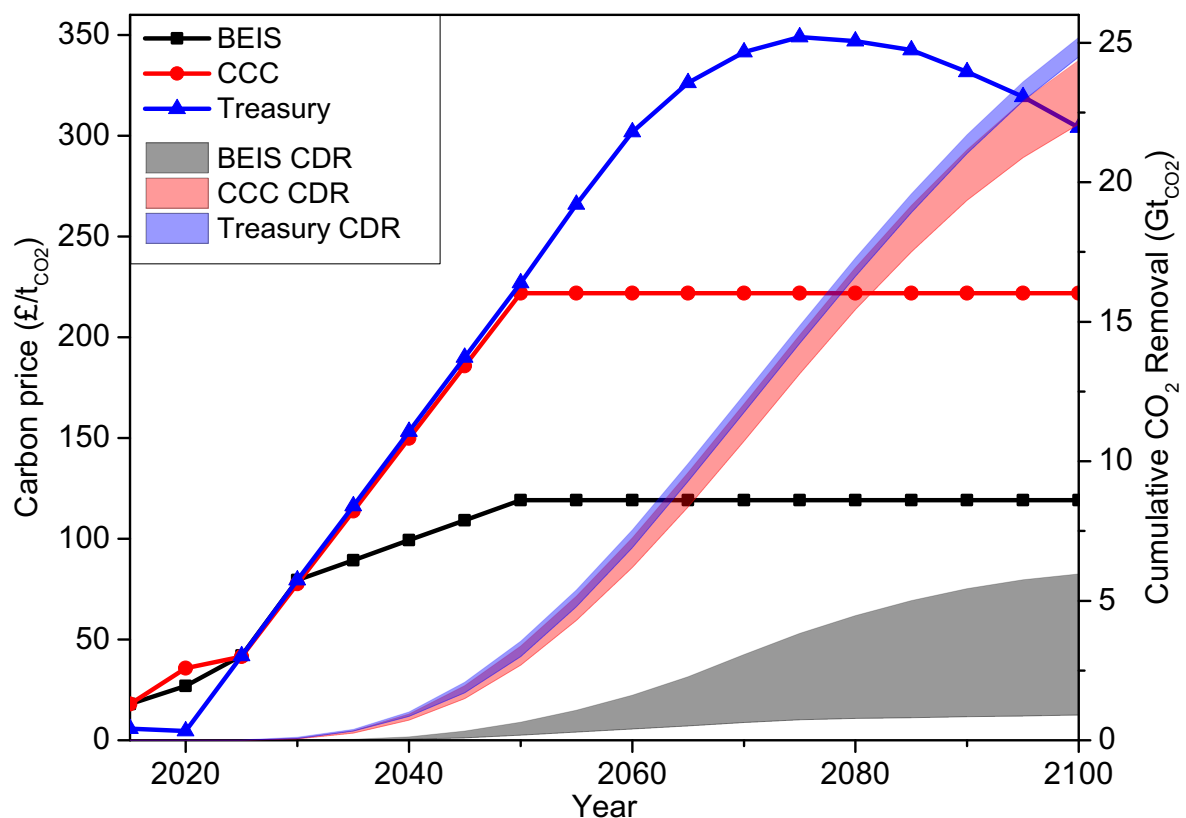


Fig. 4.8 Cumulative CO₂ removal provided by the electricity system by 2100 when carbon pricing is used to both tax CO₂ emitters and credit CO₂ removal (from BECCS and DACCS). A range of fuel prices was considered in this study (see SI); the shaded regions show the sensitivity of the cumulative CDR achieved to fuel prices.

Fig. 4.8 shows the cumulative removal of CO₂ from the atmosphere from 2015 until 2100 under different carbon price (including NEC) scenarios. We observe that crediting CDR even at the lowest carbon price ('BEIS' scenario) leads to the deployment of CDR from 2030 onwards. In the 'BEIS' scenario, the carbon price (and NEC) rises from 18 to 119 £/tCO₂ between 2015 and 2050, and remains constant afterwards. Although this is significantly lower than the social cost of carbon (SCC), it is sufficient to deliver 0.9-6 GtCO₂ (median of 5.1) of CDR by 2100, similar to what is expected of the UK, according to burden-sharing principles. The range is due to the fuel prices considered in this analysis, which are provided in Table 2.3. Providing NECs

equivalent to the SCC lead to cumulative CDR of 22-24 GtCO₂ in the same period, well above what is expected from the UK. Fig. 4.7 illustrated that having a carbon price equivalent to the SCC, but that did not credit CDR, does not deliver CDR or maintain a decarbonised electricity system. Therefore, adapting carbon pricing mechanisms to remunerate CDR services (as well as penalise emissions) could mean that lower (and more politically feasible) carbon prices are needed to achieve deep decarbonisation.

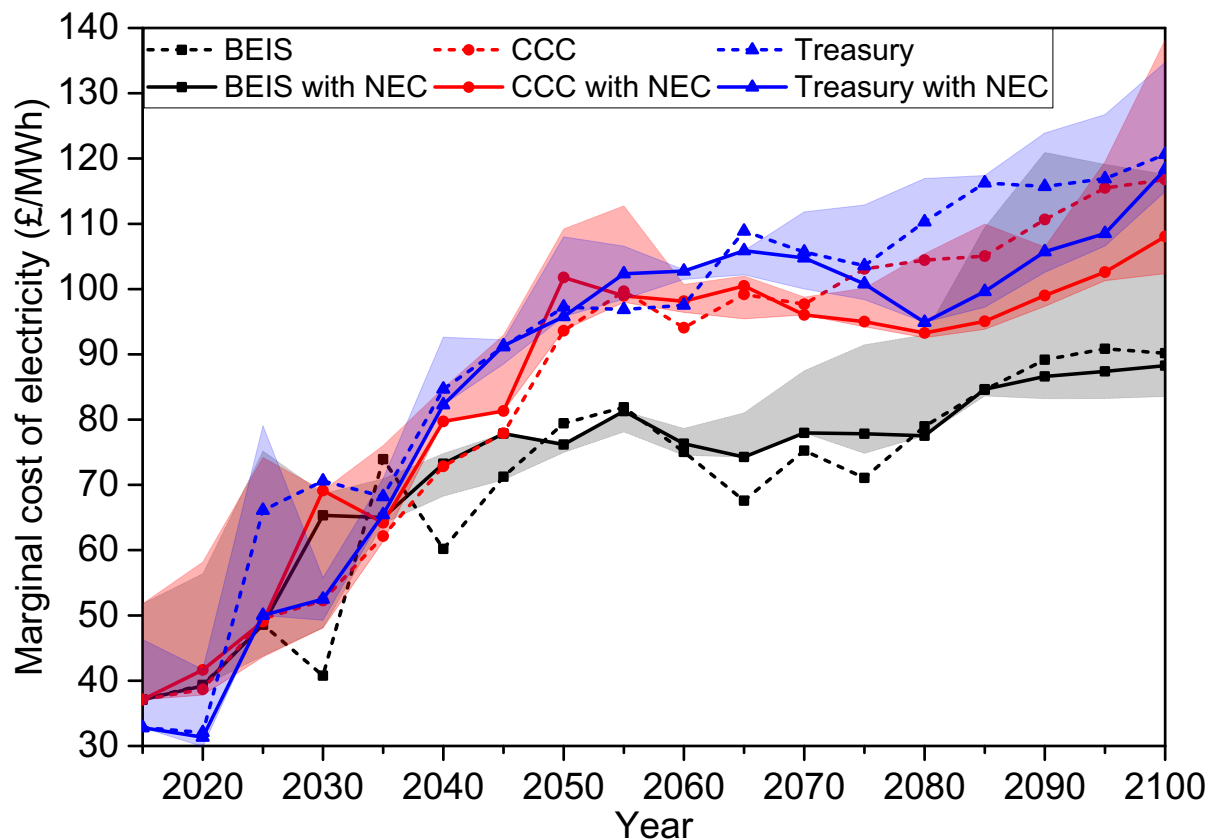


Fig. 4.9 Average annual marginal cost of electricity generation under different carbon pricing regimes; ‘With NEC’ represents carbon pricing schemes that penalise CO₂ emissions, as well as credit CO₂ removal at a NEC equal to the carbon price. The shaded regions represent the sensitivity of the costs to fuel prices.

In addition to being more politically deliverable, lower levels of carbon taxation could potentially reduce consumer electricity costs. Fig. 4.9 illustrates the average marginal cost of electricity generation under different carbon price forecasts and mechanisms (when CDR is incentivised or not). We observe that although electricity costs rise steadily until the end of the century in all scenarios considered, lower rates of carbon taxation result in reduced electricity costs. This is because the highest marginal cost generators are unabated gas power plants (OCGT and CCGT). As carbon prices increase, so too does their operating costs, and hence the marginal cost of generation. It was shown previously that adapting existing carbon pricing mechanisms to reward the service of CO₂ removal potentially means that lower carbon prices are needed to deliver deep decarbonisation, which would translate to reduced electricity costs (Fig. 4.9). Crediting CDR

could therefore result in lower consumer prices. This “credit” system is, therefore, a socially progressive method of incentivising deep decarbonisation^{††}. Importantly, this credit could be in the form of a tradable production tax credit, similar to the existing 45Q instrument in the US, where in this case, the commodity “produced” is the social good of atmospheric CO₂ removal.

4.4.4 Effects of crediting CO₂ removal

Fig. 4.8 illustrated that delivering CDR at the scale required in the UK is possible with even a modest carbon price, provided that the carbon pricing mechanism implemented rewards CDR. The following results analyse the implications of such an adapted carbon pricing regime on the rest of the power system. Two scenarios are considered: 1) achieving cumulative CDR of 5.1 GtCO₂ by 2100 using carbon taxes and NECs, as shown in Fig. 4.8 (‘NEC’ scenario), and 2) achieving cumulative CDR of 5.1 GtCO₂ by 2100 under current carbon pricing regime where credits for CDR are not provided, but meeting that target is mandated (‘No NEC’ scenario). The latter scenario is implemented in the model using a cumulative emissions target constraint.

Fig. 4.10 shows how the power generation capacity mix evolves in the ‘No NEC’ and ‘NEC’ scenarios described previously. We observe that crediting CO₂ removal results in the earlier deployment of CDR technologies. When a NEC is provided, BECCS and DACCS are deployed from 2030 and 2040, respectively. In the absence of a NEC however, BECCS and DACCS are deployed from 2035 and 2045, respectively, with the bulk of new units being built after 2070. Additionally, incentivising CDR reduces the peak deployment of BECCS and DACCS in the system. Whereas in the ‘No NEC’ scenario, the peak capacity of BECCS and DACCS in the system is 21 GW and 6.2 GW, respectively; in the ‘NEC’ scenario, this falls to 1 GW of BECCS and 6.2 GW of DACCS. This is because earlier deployment of CDR technologies allows for more time to meet CO₂ removal targets, so the rate of atmospheric CO₂ removal required—and hence deployment level—is lower.

The levelised costs of CDR from first-of-a-kind BECCS and DACCS plants are £140/tCO₂^{‡‡} and £170/tCO₂^{§§}¹⁸, respectively. Therefore, BECCS is a cheaper source of CDR relative to DACCS, and it provides additional value to the system through power generation to meet demand. Despite this we observe that early CDR incentives favour DACCS deployment over BECCS. This is because, as BECCS is increasingly deployed, the marginal cost of generation rises due to the exhaustion of local biomass supply—which is already more expensive than gas per MWh of electricity delivered—and increasing reliance on more expensive imported pellets. The net effect of a NEC on reducing BECCS costs is therefore limited. On the other hand, the availability of a NEC greatly lowers the cost of CDR *via* DACCS in two ways: 1) payment for CDR lowers

^{††}Other measures have been implemented to limit the burden of carbon taxation on lower income households and improve its public acceptability. These include using carbon tax receipts to lower other taxes (such as income taxes) and compensating affected households through lump-sum payments^{262–264}.

^{‡‡}Levelised cost of BECCS using UK-grown Miscanthus as fuel

^{§§}Converted from 2016 USD using 2016 average USD-GBP exchange rate

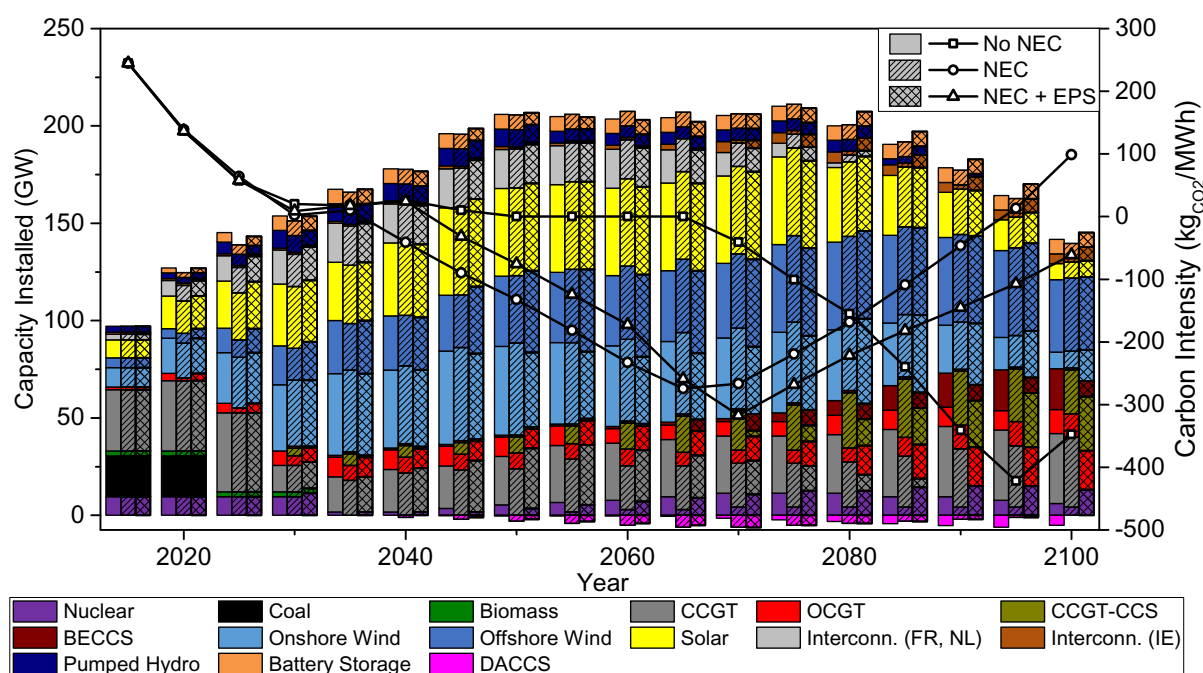


Fig. 4.10 Optimal capacity expansion from 2015 to 2100 when no NEC is provided and the cumulative CDR target is imposed ('No NEC'); when the target is achieved as a result of a NEC payment ('NEC'); and when an emissions performance standard is imposed in addition to a NEC payment ('NEC + EPS').

the technology cost, and 2) the lower carbon prices allowed by the provision of a NEC result in electricity generation costs, thereby reducing the operating costs of DACCS (which consumes power). Consequently, it proves cheaper to generate cheap power from CCGT-CCS and use it to power DACCS plants, than to deploy BECCS for the same purpose. The 'No NEC' and 'NEC' scenarios in Fig 4.8 illustrates the displacement of BECCS by CCGT-CCS and DACCS plants when a NEC is made available.

Table 4.3 Effect of incentivising CDR technologies on system costs under the 'BEIS' carbon price scenario

Cumulative until 2100 (£ billion)	No NEC	With NEC	Net cost
Total system cost	680	577	-103
Consumer electricity costs	497	511	+14
Revenue from carbon taxation	44	35	+9
Spend on negative emissions credits	-	120	+120
Total net costs			+40

Table 4.3 details the effect of crediting CO₂ removal on power system costs. We find that incentivising CDR results in an 18% reduction in TSC (the total capital and operational expenditure). This is because, in the absence of incentives for CDR, BECCS deployment is delayed until the latter half of the century; 20 GW is added after 2060 (see 'No NEC' in Fig. 4.10). In the interim, CCGT capacity is built to replace old power plants. BECCS deployment later displaces CCGT generation from the system as the CDR target must be met,

thereby resulting in underutilised CCGT capacity and an overbuilt power system. The cost of providing NECs is found to be £120 billion. Similarly, there is a net cost due to lower tax revenues; owing to a relatively high carbon price, CCGT-CCS displaces unabated gas generation from the system resulting in lower CO₂ emissions and hence carbon tax receipts which fall by £9 billion (cumulative from 2015 to 2100). The net effect of crediting CDR on electricity costs is approximately zero, within the accuracy of this modelling approach. This supports the earlier finding that carbon price is the key determinant of the marginal cost of generation; as the ‘BEIS’ carbon price is implemented in the scenarios compared in Table 4.3, electricity costs are similar. Overall, we find that despite the significant investment required to credit CDR, the savings made on the TSC result in a greatly reduced *net* cost—net cost falls from £120 to £40 billion.

Current GHG emissions trajectories suggest that the global carbon budget will be exceeded before 2050³. Large-scale CDR is therefore critical as it can correct this overshoot by minimising cumulative emissions. Therefore, in addition to lower systems costs, incentivising early deployment of CDR technologies will minimise the overshoot of carbon budgets and increase the likelihood of meeting climate mitigation objectives.

This study investigates the effect of carbon pricing and crediting CDR on the cost of meeting climate change mitigation targets. Fig. 4.8 and 4.10 illustrate that crediting negative emissions results in the earlier deployment of CDR technologies. This in turn spurs early innovation and encourages further deployment, both of which lead to falling technology costs (from learning-by-doing and economies of scale). In reality, as costs fall and CDR technologies achieve commercial viability, financial (or other) support for CDR would be expected to fall. Maintaining the same NEC payment, as is done in the scenarios presented in Fig. 3 and 5, would therefore create an inframarginal rent^{¶¶}. This unnecessary subsidy also presents an additional cost to the system. However, given the uncertainty in the nature and costs of CDR technologies and thus the possible rates of innovation, this study has not modelled efficient subsidisation mechanisms for CDR. This was considered beyond the scope of this study.

4.4.5 The moral hazard problem

We observe that the early CDR deployment (owing to the provision of a NEC) results in a reduction in the carbon intensity (CI) of electricity to a minimum of -265 kgCO₂/MWh in 2065 (see ‘NEC’ scenario in Fig. 4.10). Subsequently, CI rises consistently until 2100, by which it is positive again (*i.e.* the electricity system reverts to a *net* source of CO₂ emissions). This is because, after the CDR target is met, it proves cheaper to meet rising electricity demand and to replace old power plants (most of which are iRES) using thermal generation from CCGT and CCGT-CCS power plants—owing to their reduced costs due to technology learning and

^{¶¶}Inframarginal rent is the difference between the market price of a certain ‘resource’ (in this case, the NEC payment) and the minimum price at which the owner of a ‘resource’ would have a desire to put it up for sale (the cost of providing the service of CDR).

higher availability relative to iRES. This evolution of CI confirms the moral hazard that is often cited as a major drawback of using CDR technologies for climate change mitigation^{13,265,266}, which is that they could prolong the reliance on fossil fuels by allowing for its continued use in a carbon-constrained system. Until 2065, CDR deployment provides *net* negative emissions required to meet the Paris Agreement target, and also offsets the emissions from fossil power plants, thereby allowing for their continued operation. However, once the imposed CDR ‘target’ is met—in this case, 5.1 GtCO₂—further CDR deployment is limited and the system reverts to building the cheapest form of generation which, despite the imposition of a carbon tax, is largely CCGT plants. Consequently, CI rises to the levels observed.

The above highlights the need for a mechanism to deter the resurgence of CO₂-emitting power plants in the system after CDR targets are achieved. As a proxy for such a deterrent, we investigate the effect of disallowing new CCGT build after 2050 (when net-zero is to be achieved), in addition to the provision of a NEC. This is illustrated by the ‘NEC + EPS’ scenario in Fig. 4.10. We find that the CI of electricity still rises after the CDR target is met, however it remains well-below zero by 2100. This is because instead of additional CCGT capacity, dispatchable low-carbon generation capacity (nuclear, CCGT-CCS and BECCS) is increased in the system thereby resulting in lower emissions.

Therefore, whilst incentives are needed to achieve CDR deployment at the necessary scale, another mechanism is needed to prevent a resurgence of carbon-emitting generation in the system. This could be in the form of a progressively stringent emissions performance standards (EPS) for power plants; EPS are already legislated in many countries^{202,267,268}. The above also highlights the hazard of specifying cumulative CDR targets to determine optimal system design; a more dynamic method is likely to be necessary.

4.5 Discussion

Decarbonisation of the UK energy system has so far been driven by increased use of iRES, particularly wind and solar power which have experienced dramatic cost reductions. Consequently, entirely ‘wind, water and sunlight’ dependent power generation is being proposed as a long-term strategy that serves climate change mitigation ambitions at least cost. This study has however shown that the power system that can deliver the CDR burden consistent with the Paris Agreement, in a cost-effective manner, is dominated by thermal generation, mainly from bioenergy, gas (both with CCS) and nuclear power plants. Policies advocating for increasing penetration of iRES to near total levels therefore pose the danger of ‘lock-in’ to either an overbuilt power system or one incapable of delivering sufficient climate mitigation.

Cheap iRES also allow for the viability of smaller-scale and isolated power systems, and even the participation of traditional energy consumers in power generation. Consequently, decentralisation is cited as a major feature of the climate change-induced energy

transition^{247,269,270}. However a system dominated by utility-scale thermal generation is inherently centralised and requires extensive transmission and distribution networks. Pursuing decentralisation efforts in the short-term may lead to the disintegration of infrastructure that appears to be critical in the long-term.

Although the potential value of BECCS and DACCS for deep decarbonisation has been exhibited, several barriers—both techno-economic and socio-political—must be overcome for their commercialisation to be realised. Most notably, there exists few financial incentives for investment in the technologies. With the exception of voluntary carbon markets—whose traded volumes and price of carbon remain low²⁷¹—, carbon pricing or emissions trading schemes do not credit CDR from BECCS or DACCS. The lack of extensive CO₂ transport and storage infrastructure, or a credit for the sequestration of CO₂, further discourages investment. Significant BECCS and DACCS deployment are likely to require international supply chains, owing to biomass trade and the asymmetric distribution of CO₂ storage sites. How accreditation for CDR should be apportioned to sectors or nations involved in these value chains is yet unresolved. In the case of BECCS, certification schemes to guarantee the sustainability of the—domestic, but more so for the internationally-traded—biomass feedstock will be challenging due to the complexity of biogenic carbon accounting frameworks^{272–274}. Finally, the perception of CDR as a moral hazard, on which focus will redirect support from other components of the mitigation toolbox⁸, generates social acceptability concerns²⁶⁶.

Favourable policies and subsidisation mechanisms have been successfully resulted in iRES achieving grid parity. However, this study has shown that the marginal value of iRES deployment to deep decarbonisation efforts will diminish with time. Instead, new technologies (CCS with both gas and bioenergy) and services (CDR) are needed to achieve further climate mitigation. Whilst significant, the incentives required by these new technologies/services to achieve commercial viability are similar to those given to then nascent intermittent renewable energy technologies. Policy must therefore recognise their values in an increasingly carbon-constrained world, and adequately incentivise them to attract investment and encourage innovation.

Integrated assessment models that are used to assess potential global decarbonisation pathways and to inform policy estimate that carbon prices much higher than might be considered politically feasible today are necessary to deliver the Paris Agreement³. This study has shown that higher carbon prices can deter the deployment of CO₂-emitting technologies in the short-term and encourage the proliferation of low-carbon technologies, particularly intermittent renewable energy sources and fossil-CCS, both of which are sufficient for near-term decarbonisation objectives. In the long-term however, they fail to incentivise services such as CDR which are critical for ambitious climate change mitigation. To encourage the deployment of CDR technologies on the time-scale necessary, the service of providing CDR should be valued as a public good and be appropriately remunerated. This remuneration need not be a direct payment; mandates for CO₂ emitters to pay for some CDR, tax credits to encourage investment, or altering

carbon pricing regimes to credit CDR are possible incentivisation mechanisms. The relative success of a given incentive scheme will be dependent on the local economic and sociopolitical context in which it is to be applied.

This study has shown that, should carbon pricing schemes be adapted to credit CDR, the carbon prices required to deliver the Paris Agreement target are lower (relative to maintaining the status quo). As the marginal cost of electricity is determined by the CO₂ emitting generators (for the UK, these are gas-fired power plants), lower carbon prices in turn reduce the cost of generation. Additionally, early incentives for CDR decrease the likelihood of an overbuilt system in the long-term, thereby reducing the total system cost; for the UK, the TSC fell by 18% between 2015 and 2100. Crediting negative emissions leads to earlier deployment of CDR technologies which, if delayed, would have resulted in greater historic emissions within the electricity system that need to be compensated for in the future. Early incentives could therefore both reduce the cost of delivering the Paris Agreement and our long-term need for negative emissions.

Despite its benefits, the early deployment of CDR technologies presents a moral hazard. We observe that the CDR provided is more than needed to meet the Paris Agreement target—the additional CDR offsets emissions from CO₂ emitting assets, thereby allowing for the continued use of unabated fossil fuels in a carbon-constrained power system. To prevent such a scenario, a mechanism(s) to prevent the resurgence of CO₂ emissions must be implemented alongside the provision of incentives for CDR. This may be in the form of an emissions performance standard (EPS), a tool which has been implemented in some form in several countries^{202,267,268}. However, such ‘command and control’ regulation may prove politically-challenging to deliver in some environments. The design of market-based disincentives that will not promote the longevity of unabated fossil fuelled generation in the power system is therefore necessary.

4.6 Contributions made

This work investigated the implications of deeper decarbonisation to achieve a net-zero economy on the long-term transition of the UK power sector which was lacking in the scientific literature. CDR technologies were found to be critical but not currently commercially-viable for deployment. The value of the incentives required to achieve their commercialisation was then quantified; BECCS and DACCS technologies in the UK were found to need at least £166/tCO₂ and £176/tCO₂ for the CO₂ removal service they provide if they are to achieve an internal rate of return of 4%, a lower-bound return rate that would be typical for regulated assets. Additionally, we propose two potential mechanisms for the provision of these incentives: a direct payment for CO₂ removal (which may prove burdensome to the state), or an adaptation of existing carbon pricing mechanisms to remunerate the provision of CDR services. The latter could allow for GHG emissions trading between polluters and CDR providers. The moral hazard of CDR—its potential to prolong the use of fossil fuels by offsetting their emissions—were illustrated by the

findings of this study. Consequently, the need for an increasingly stringent emissions portfolio standard that will deter high-carbon providers in the long-term was highlighted. Finally, this work challenges the widespread opinion that decentralised energy systems, enabled by cheap renewable energy, will dominate future energy systems. The findings, which are applicable to countries with significant share of historical emissions, show that carbon dioxide removal is critical to delivering deep decarbonisation and the lowest-cost system that accommodates CDR technologies is one dominated by low-carbon baseload and dispatchable generation, not variable renewable energy sources. Such a system is inherently centralised and will require the maintenance and/or expansion of existing transmission infrastructure to meet demand. Thus, it may prove costly to pursue a policy of decentralising energy systems in short-term and to allow necessary infrastructure for the long-term to disintegrate.

Chapter 5

Delivering the Paris Agreement: The Case for Nigeria

Chapter Roadmap

In 2016, Nigeria became a signatory to the Paris Agreement, symbolising its commitment to the global effort to avoid catastrophic climate change. In its first nationally determined contribution (NDC) submission, Nigeria committed unconditionally to a 20% reduction in GHG emissions relative to business-as-usual projections by 2030, and to pursue a 45% reduction if sufficient international financial support is provided⁶⁸. The NDC identifies the power sector as having the greatest GHG emissions reduction potential through more efficient gas-fired generation, reduced transmission network losses, economy-wide energy efficiency improvements and increased utilisation of renewable energy sources. Nigeria must try and deliver its NDC alongside efforts to improve energy access and reduce its electricity deficit—power generation has never surpassed 5,000 MW and only 56.5% of the population (193 million) have access to electricity^{44,66}. This study seeks to determine: 1) the power system transition(s) required to deliver Nigeria's NDC alongside universal energy access by 2050; 2) the financial and policy implications of such a transition; and 3) the barriers and opportunities that such a transition presents to the country's sustainable development efforts. The chapter is structured as follows. Section 5.1 discusses the reasons for studying Nigeria's power sector, provides an overview of the sector, and quantifies the sectoral emissions reduction targets based on the NDC to the Paris Agreement. Section 5.2 details the modelling framework used, the assumptions made, and the scenarios investigated in this study. Section 5.3 assesses the implications of delivering Nigeria's unconditional and conditional NDCs for cost-optimal power system design. Section 5.4 discusses the cost implications of delivering Nigeria's NDC and evaluates the effectiveness of different green policies in facilitating the necessary system transition. Section 5.5 discusses the barriers and opportunities that climate change mitigation in the power sector presents to Nigeria. Finally, Section 5.6 provides a conclusion.

5.1 Introduction

5.1.1 Why study Nigeria?

Nigeria is vulnerable to the physical and socio-economic impacts of climate change to an extent that few other countries are. Its tropical rainforest and coastal lowlands in the south are susceptible to sea-level rise, flooding, surface erosion and increased frequency of rainstorms^{1,275,276}. Its arid north is already experiencing increasing desertification, droughts and water scarcity, which have been attributed to climate change. It is expected that unmitigated climate change will exacerbate these natural disasters and accelerate environmental degradation^{1,14}. This is worsened by its low adaptive capacity which is a result of the poor state of development of infrastructure and institutions in the country.

Nigeria is a lower-middle-income country and Africa's largest economy*. Much of its economic growth has been fuelled by its oil and gas sector which has historically been responsible for 47-85% of government revenues^{66,278}. This dependence on crude oil exports means that the economy is vulnerable to crude oil price volatility. Between 2000 and 2014, GDP growth rate averaged 7%. The 2014 oil price collapse led to the country's first recession in 25 years in 2016. Since then, growth has stagnated around 2%, lower than the population growth rate⁴⁴. A recovering oil price had resulted in higher government revenues but the COVID-19 pandemic again depressed prices with as yet unknown consequences²⁷⁹. A low-price environment in the short-term, and an energy transition which leads to lower demand for fossil fuels in the long-term, both present a threat to the current Nigerian economy.

Despite its relative large economy, electricity consumption in Nigeria has lagged other countries at similar stages of development. Fig. 5.1 illustrates the per capita electricity consumption and GDP for some lower-middle-income countries. Even amongst sub-Saharan African countries with similar income levels (Cameroon, Côte d'Ivoire, Ghana), Nigeria's per capita power consumption is over 50% lower than the average. The poor state of the power sector in the country is a result of decades of underinvestment due to several factors which are discussed later in Section 5.1.4. Several programmes and policies have been enacted to address the power generation deficit in the country with limited success—only the 500 MW Azura-Edo power plant has been built in the last decade^{280–282}. Most recently, the 2017 Power Sector Recovery Programme (PSRP) set out a series of policies to improve the sector's financial viability and institutional frameworks so that investor confidence can be restored²⁸¹. Nigeria must try and reform the power sector whilst dealing with a population explosion that will create additional demand.

*Nigeria has a GDP of \$397 billion (37th globally) and a per capita GDP of \$5,990 (130th)⁴⁴. These figures are in International US Dollar (Int \$) which is a hypothetical currency that has the same purchasing power parity (PPP) as the U.S. dollar had in the United States at a given point in time. It is used to compare the GDP and the real purchasing power of money of different countries²⁷⁷

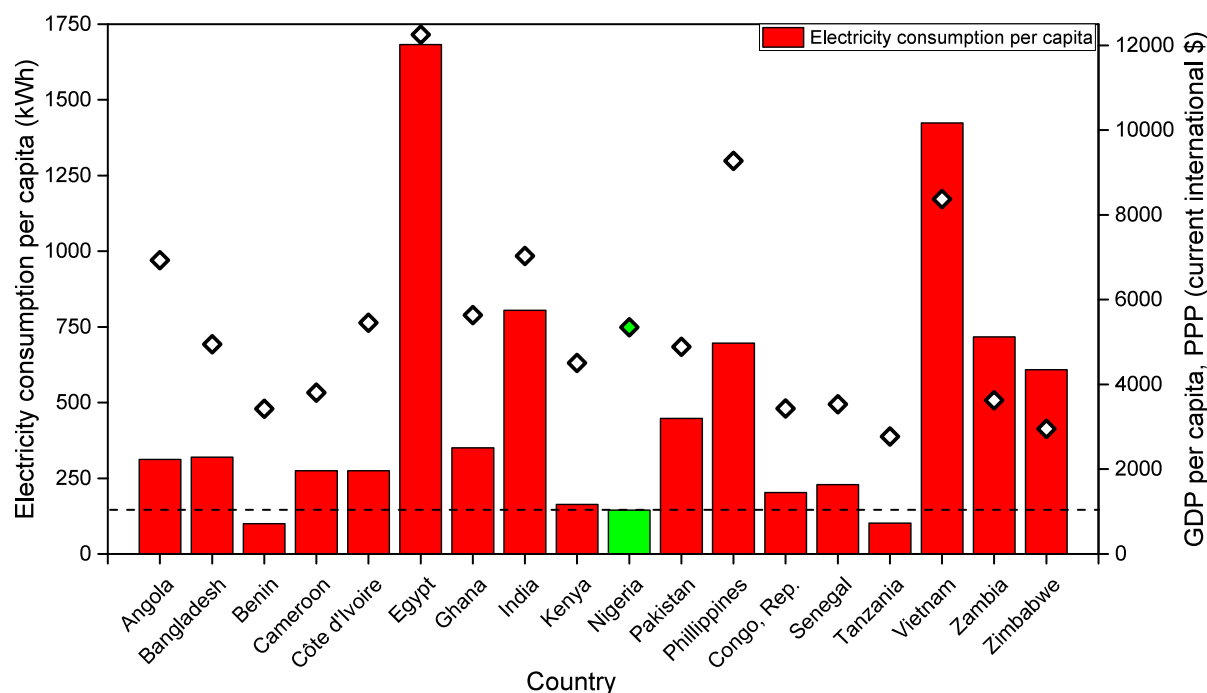


Fig. 5.1 Graph comparing the per capita GDP and electricity consumption of lower-middle-income countries, including Nigeria. Data obtained from The World Bank⁴⁴.

As of 2017, Nigeria was the largest African country with approximately 200 million people and the 7th largest globally. This is projected to double by mid-century when it is expected to be the 3rd most populous nation in the world⁶⁵. Additionally, 44% of the population is below the age of 14 years and urban population is rising at 4.3%⁴⁴. Thus, Nigeria faces demographic pressures from both urbanisation, which requires improved infrastructure, and a rapidly increasing working-age (15-64) population who requires jobs. It is estimated that Nigeria needs to create 3 million jobs annually to accommodate the new entrants into the labour market²⁸³.

With over 250 ethnic groups and two major religions, Nigeria is a country characterised by intense ethno-religious polarisation and conflict, which has historically spiralled into violence²⁸⁴. To contain these tensions, 'geopolitical zones' were established to ensure the proportionate sharing of political, economic and educational resources between the country's ethnic and religious groups²⁸⁵. Thus, all economic decision-making including the development of energy infrastructure must be planned within the context of these cultural sensitivities. Nigeria is a federation of 36 states and the Federal Capital Territory (illustrated in Fig. 5.2). The zones, described below, broadly group states with shared history, religion and/or culture.

- North-Central (NC): Benue, Kogi, Kwara, Nasarawa, Niger and Plateau states
- North-East (NE): Adamawa, Bauchi, Borno, Gombe, Taraba and Yobe states
- North-West (NW): Jigawa, Kaduna, Kano, Katsina, Kebbi, Sokoto and Zamfara states

- South-East (SE): Abia, Anambra, Ebonyi, Enugu, and Imo states
- South-South (SS): Akwa-Ibom, Bayelsa, Cross-River, Delta, Edo and Rivers states
- South-West (SW): Ekiti, Lagos, Ogun, Osun and Oyo states



Fig. 5.2 Map of Nigeria showing its 36 states and the Federal Capital Territory, and neighbouring countries.

Nigeria was chosen as a case study in this thesis because it exemplifies the many challenges that developing countries, especially those in sub-Saharan Africa, face in addressing climate change: vulnerability of physical environment to climate change impacts; poor adaptive capacity due to limited financial resources and technical expertise in institutions; a young and growing population; a fractured geopolitical landscape that makes it prone to conflict. Climate change impacts have already caused violent conflict in some parts of the country^{286,287}. Thus, addressing climate change has become a priority for the country, as evidenced by its commitment to the Paris Agreement and the establishment of an Inter-Ministerial Committee on Climate Change to ensure development policy aligns with climate action. The power sector is viewed as critical

to delivering climate change mitigation, a key driver of economic development and a potential source of jobs, hence the focus on the sector in this chapter^{68,280,281}.

5.1.2 Nationally determined contributions under the Paris Agreement

Nigeria ratified the Paris Agreement in 2017. For the purpose of developing its nationally determined contribution (NDC), a Low Emissions Analysis Platform (LEAP) model of the economy was developed and its emissions was constructed^{68,288}. LEAP uses a bottom-up approach to modelling that is grounded in sector-based analysis to determine an economy-wide emissions contributions. The model estimated that economy-wide GHG emissions will rise to 900 millions tonnes of CO_{2e} per year by 2030 in a business-as-usual (BAU) scenario; this would be equivalent to per capita emissions of 3.4 tCO_{2e} per person⁶⁸. The foundational assumption in this projection is an average annual economic growth rate of 5% until 2030. In its first nationally determined contribution, Nigeria committed to an unconditional reduction of 20% of economy-wide GHG emissions relative to the BAU scenario; this will henceforth be referred to as the ‘Unconditional NDC’. Furthermore, Nigeria committed to a conditional reduction of 45% relative to BAU if provided with sufficient international support “in the form of finance and investment, technology and capacity building”⁶⁸; this will henceforth be referred to as the ‘Conditional NDC’. Under the Conditional NDC, per capita emissions are expected to remain constant at 2 tCO_{2e} per person. Several measures, shown in Table 5.1, have been identified as the largest potential sources of GHG emissions reductions. It is seen that the power sector is considered most critical to climate change mitigation, with a GHG reduction potential of 159 MtCO₂ from more efficient gas power plants, reduced transmission network losses and increased utilisation of renewable energy sources²⁸⁹.

Table 5.1 GHG reduction potential of key mitigation measures in 2030⁶⁸

Measure	Potential GHG reduction (million tonnes of CO _{2e} per year in 2030)
Economy-wide energy efficiency	179
Efficient gas power stations	102
Work towards ending of gas flaring	64
Climate smart agriculture	74
Reduced transmission losses	26
Renewable energy	31

Targets for power sector decarbonisation have not been legislated in Nigeria, however the government has set a deployment target of 13 GW for off-grid solar PV by 2030. The annual GHG emissions allowance for the power sector was determined as follows. The BAU GHG emissions projections were defined in the Nigeria’s NDC, which also states that approximately 60% of emissions reductions by 2030 are achieved from electricity generation in an Unconditional NDC scenario. With this, a BAU projection for the power sector was derived

and the mitigation potential estimates were used to determine the emissions reductions delivered by the sector in 2030 given the NDC commitments. Having determined the sector's carbon budget from 2015 to 2030, linear extrapolation was used to estimate the carbon budget until 2050. The carbon budget—that is, the amount of GHG emissions allowed from the sector—under BAU, Unconditional NDC and Conditional NDC scenarios are illustrated in Fig. 5.3. In the BAU scenario, electricity is expected to contribute 639 Mt_{CO₂}/yr to economy-wide GHG emissions by mid-century. In the Unconditional and Conditional NDC scenarios, this is expected to fall to 414 and 134 Mt_{CO₂}/yr, respectively, by 2050. In all scenarios, there is a significant increase in electricity-derived GHG emissions, which are currently estimated at 23.5 Mt_{CO₂}/yr⁵⁶. The analysis presented in the rest of this chapter will seek to determine the power system transitions that are necessary to deliver these emissions scenarios.

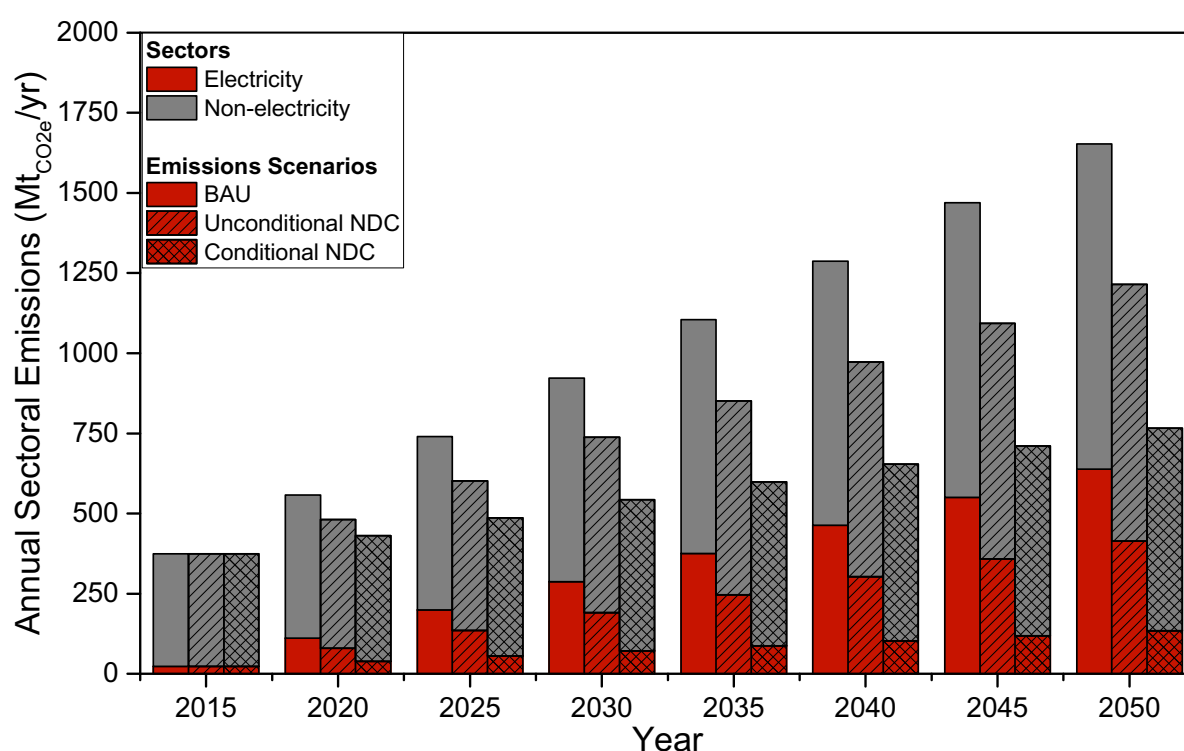


Fig. 5.3 Emissions scenarios for Nigeria's nationally determined contributions to the Paris Agreement

5.1.3 Energy resources for power generation

Nigeria possesses significant reserves of fossil fuel resources, majority of which are located in the coastal South-South region of the country. These are detailed in Table 5.2. It is the 13th largest oil-producing state globally³¹⁰. Production peaked at 2.55 million barrels per day in 2005 but has since declined due to a lack of investment and the destruction of oil and gas infrastructure by militants. Nigeria was also responsible for 6% of globally-traded liquefied natural gas (LNG) in 2018. Despite the abundance of natural gas in the country, dedicated exploration for the fuel has never occurred. The production figures shown below consist solely of associated petroleum

gas⁶⁶. The Nigerian Coal Corporation estimates the unproven reserves of coal at about 905 million tonnes, with the coals being mainly lignite and sub-bituminous types with small quantity of high volatile bituminous coal²⁹⁰. Coal seams are concentrated around Kogi and Enugu states (see Fig. 5.2).

Table 5.2 Nigeria's fossil fuel reserves and annual production rates⁴

Fossil fuel	Total proved reserves (end of 2018)	Annual production (2018)	Years remaining at current extraction rates
Oil	37.5 billion barrels	2.051 million barrels per day	50 years
Natural gas	5.3 trillion cubic metres	49.2 billion cubic metres	108 years
Coal (total recoverable)	209.4 million short tonnes	n/a	n/a

Nigeria also possesses significant renewable energy resources. Bioenergy (including waste) constitutes 74% of primary energy supply⁶⁷. This is principally used in the residential sector, which accounts for 78% of final energy consumption. This dependence on biofuels is the primary driver of the increased deforestation and desertification observed across the country⁶⁶. Hydro power potential has been estimated at 12,220 MW²⁹¹. The technical potential of other renewable energy sources are appreciable: Small hydro (735 MW), Solar CSP (36,683 MW), Solar PV (492,471 MW), Biomass (7,291 MW), and Wind (44,024 MW)¹⁷⁸. Table A.2 details the hydro sites in the country and their electricity generation potential.

5.1.4 History of power sector

Fig. 5.4 illustrates the type and amount of power generation capacity added in Nigeria from 1970 to present. Table A.1 details the individual power plants that are installed in the country today. In 2001, the Federal Government of Nigeria (FGN) outlined their reform agenda for the power sector in the National Electric Power Policy. The objective was to create efficient market structures, within clear regulatory frameworks, that encourage competitive markets for electricity generation and trading^{281,292}. Before then, the government had been responsible for all policy formulation, regulation, operation and investment in the power sector—with regulation handled by the Federal Ministry of Power and operation handled by the state-owned National Electric Power Authority (NEPA)⁶⁶. The Electric Power Sector Reform Act (EPSRA, 2005) provided the legal basis for the liberalisation of the sector^{281,293}.

In 2007, NEPA was restructured into the Power Holding Company of Nigeria (PHCN). In 2013, privatisation was purportedly finalised. PHCN was unbundled into 6 state-owned generation companies (GENCOs) and 11 distribution companies (DISCOs) and sold to private entities²⁸¹. The FGN retained ownership of the national transmission network under the Transmission Company of Nigeria (TCN), which consists of a system operator and a market operator^{66,292,294}. Between 2005 and 2007, a regulator, the Nigerian Electricity Regulatory Commission (NERC) and a bulk trader, Nigerian Bulk Electricity Trading Plc (NBET) were also established. NBET manages the purchase of electricity from GENCOs and sale to the DISCOs; the entity was

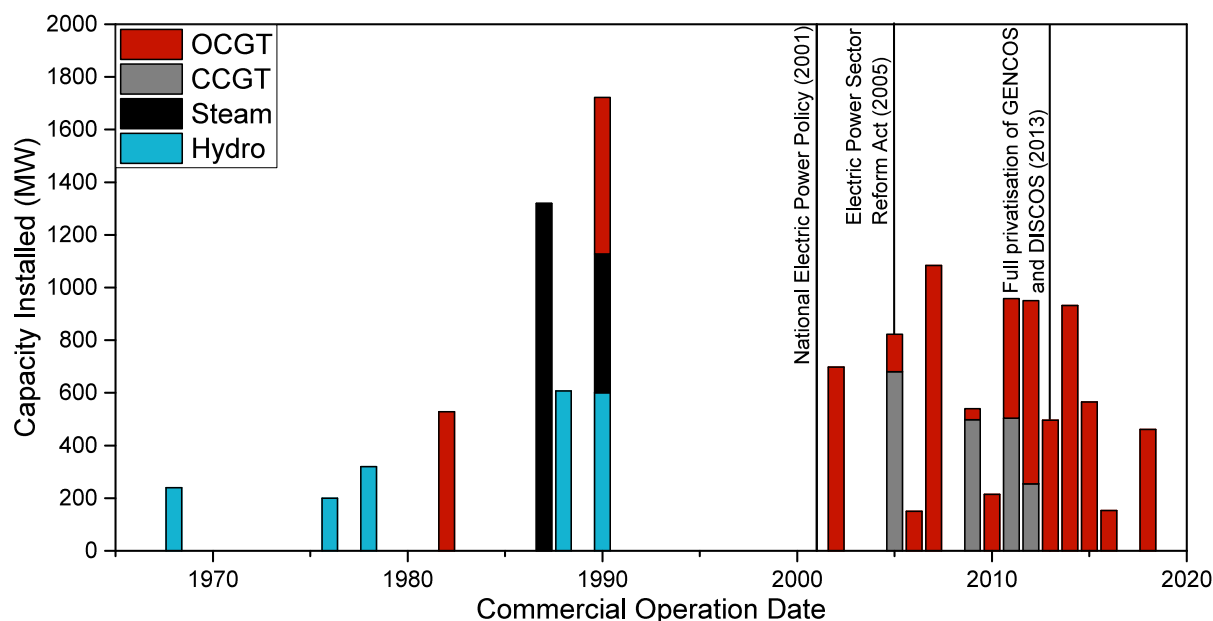


Fig. 5.4 Timeline of power generation capacity addition in Nigeria

to be made non-existent after full privatisation of the sector when it was to handover the Power Purchase Agreements (PPAs) to the DISCOs, however it is still operational as the power sector remains under a Transitional Stage Electricity Market (TEM) arrangement. The TEM is characterised by “contract-based arrangements for electricity trading and the introduction of competition for entry into the Market”^{66,292}. Consequently, all electricity trading occurs via PPAs. Under the TEM, electricity tariffs are set by NERC through the Multi-year Order Tariff (MYTO). The current structure of the power sector is illustrated in Fig. 5.5.

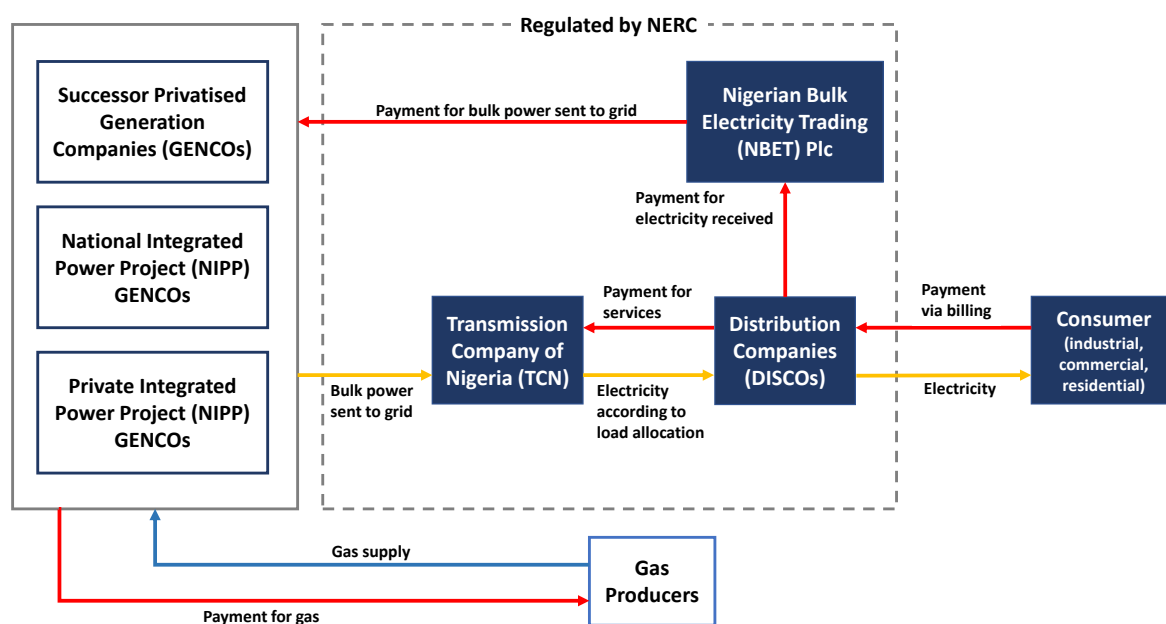


Fig. 5.5 Post-privatisation structure of the Nigerian power sector, adapted from^{66,292}

5.1.5 The transmission network

Power transmission across the country occurs at 330 kV and 132 kV. Currently, Nigeria has 5,000 km of 330 kV lines and 6,000 km of 132 kV lines. The type and location of all the high voltage transmission lines in the country are illustrated in Fig. A.1. The wheeling capacity of the network was estimated at 5,300 MW but the maximum that has been achieved is 5,074 MW on February 2, 2016^{281,282}. Implementation of the Transmission Expansion Plan which seeks to increase this to 10,000 MW has begun¹⁷⁶. The current power system is operating well-below international reliability and security standards resulting in frequent system collapses; in 2016 alone, 22 full collapses and 9 partial collapses occurred²⁸¹. System collapses are caused (besides gas pipeline vandalism) by inadequate reserves and maintenance, and the lack of a comprehensive and modern Supervisory Control and Data Acquisition (“SCADA”) system required for real-time data to control and keep the balance in the system²⁸¹.

5.1.6 Challenges in the power sector

Nigeria has one of the lowest per capita electricity consumption levels in the world. Its power sector has faced significant challenges which have deterred investment. They are discussed below:

- **Technical factors:** Although installed power generation capacity is near 13,000 MW, actual generation has never been greater than 5,000 MW¹⁷⁶. Fig. 5.6 illustrates the technical faults that contribute to this shortfall. The primary reason for poor power supply is the outage of generation units which require maintenance to resume operation (3,674 MW) and the inadequate gas supply to power plants (3,704 MW). Gas shortages have resulted from pipeline vandalism and insufficient investment in network expansion²⁸². Unavailability of generation units also results in low spinning reserve that can lead to system collapse. Seasonally-low water levels at the hydro power stations have also decreased generation capacity²⁸⁰.

The lack of maintenance and ageing of infrastructure has also rendered many of the transmission lines non-operational. Older lines such as the Anambra-Edo 330 kV line (137 km) which was constructed in 1964 are prone to failure and this results in system collapses. The radial structure of the network and single line contingency, shown in Fig. A.1, leaves the system prone to failure as alternative routing is not available²⁹⁵. 98 of the 114 inter-state high voltage lines were built before 2000. Finally, the long length of many lines result in significant network losses. The Kebbi-Niger (310 km) and New Haven-Oturkpo-Yandev (330 km) lines are examples of loss-incurring lines. These losses have recently been estimated at 14-20% of electricity generated^{66,176,295}.

- **Economic factors:** With the exception of low water levels at hydroelectric dams, the technical factors affecting the power system are a result of underinvestment. The foremost reason for a lack of investment in the power sector is the absence of a cost-reflective tariff^{66,280,282,296}.

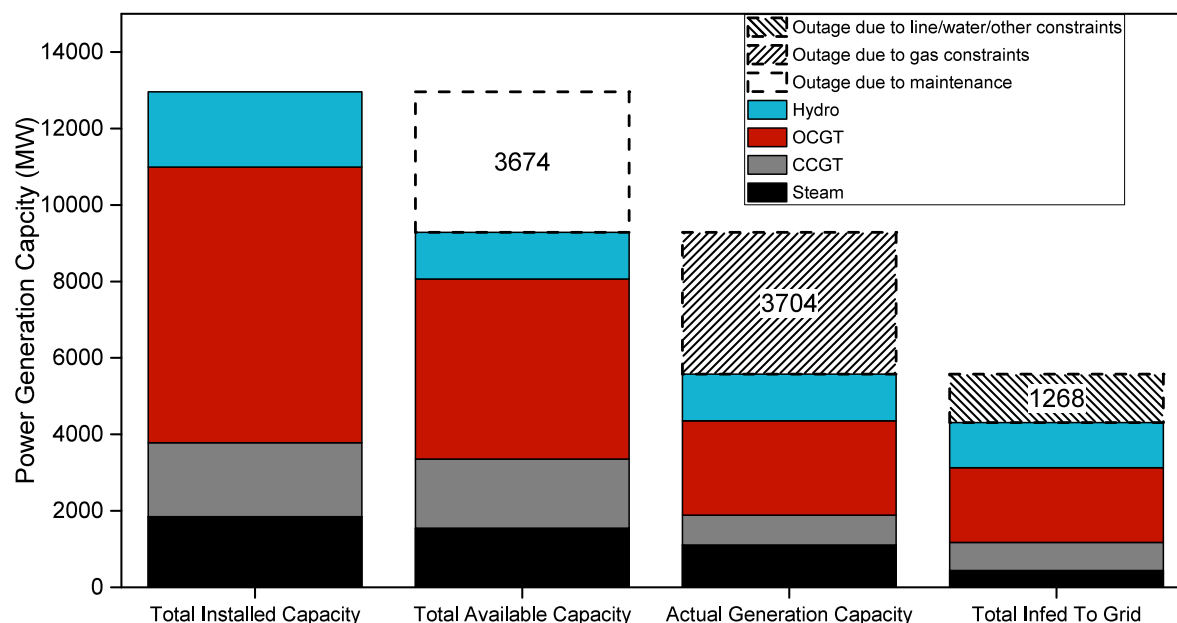


Fig. 5.6 Installed and available power generation capacity in Nigeria

Electricity tariffs set by NERC are below the cost of generation and distribution for reasons of political expedience. Government subsidies are supposed to support the sector, however a reduction in budgetary allocation has reduced the amount and frequency of sectoral subsidies²⁸⁰. Furthermore, DISCOs experience significant collection losses due to a lack of metering and consumer refusal to pay bills[†]. Their aggregate technical, commercial and collection (ATC&C) losses were 54% in 2019¹⁷⁷. Consequently, the DISCOs (at the end of the value chain) have accumulated losses. Additionally, domestic gas prices are capped at levels below the export price by the Ministry of Petroleum Resources⁶⁶. Consequently, the international oil companies (IOCs) operating in Nigeria sell gas to international markets instead of to power plants, despite a mandated quota for domestic consumption²⁸². The lack of financial viability of the DISCOs has affected the entire power value chain, as they are unable to pay the GENCOs for the electricity they supply. A liquidity crisis has persisted and government's failure to provide a lasting solution has deterred private investment²⁹⁷. Finally, barriers to investment in the Nigerian economy have also hindered the development of the power sector: perceived high risk environment due to security issues, widespread corruption, a multiple-rate foreign exchange regime, and political instability.

- **Regulatory factors:** The lack of appropriate regulatory frameworks for alternative energy technologies, such as power purchase agreements (PPAs) for renewable energy suppliers, discourages investment in the power system²⁹⁴. Additionally, standards for equipment such as solar panels also have not been defined by the government. This is largely due to poor coordination between the relevant MDAs and a general lack of competence within those

[†]Government ministries, department and agencies (MDAs) and the military are responsible for the largest share of outstanding electricity bills

authorities²⁹⁸. Finally, the inability of government to enforce the rule of law to ensure bill payment and to prevent illegal connections to the grid hampers the sector²⁹⁸.

- **Political factors:** Widespread corruption plagues every sector of the economy²⁹⁹.
- **Social factors:** Due to a lack of metering devices in households, NERC, the sector's regulator provides an estimated billing methodology that DISCOs use to determine consumer electricity bills¹⁷⁷. Disparities between the amount of electricity billed and the service received has resulted in a breakdown of trust between the providers and consumers, with many of the latter refusing to pay bills. After being disconnected for non-payment, it is common for consumers to reconnect themselves. The losses made by DISCOs due to these activities are compounded by the regulator's enforcement of a non-cost-reflective tariff¹⁷⁷. Consumers are also very sensitive to energy price hikes, as was observed during the 2012 *Occupy Nigeria* riots that broke out when the oil subsidy was removed³⁰⁰. The National Assembly—Nigeria's bicameral legislature—have on three occasions between 2017 and 2020 reversed electricity tariff hikes^{301,302}. The lack of public trust in DISCOs and more generally the government greatly limits the latter's ability to implement necessary reforms in the sector.

5.2 Modelling the Nigerian electricity system

The Nigerian electricity system was modelled using the ESONE model. The ESONE is a spatially-disaggregated version of the ESO-X model used in Chapter 3⁸⁵. It is a mixed integer linear optimisation problem (MILP) that combines generation expansion planning and unit commitment model formulations to determine the lowest-cost system design and electricity dispatch pattern over a planning horizon, subject to a set of constraints that maintain power system reliability, operability and limit GHG emissions. The spatial disaggregation allows for both generation and transmission capacity expansion planning, where the transmission network is modelled as power flow between zones. In ESONE, Nigeria is disaggregated into 37 zones, corresponding to its 36 states and Federal Capital Territory. The detailed mathematical formulation of the model has been described previously⁸⁵ and how it is implemented in GAMS is provided in Appendix B. The key features of the model that differentiate it from the ESO-X model have been described earlier in Section 2.4.1 along with the system and technology parameters assumed for the Nigeria model. The important parameters are briefly discussed again below.

5.2.1 Modelling assumptions

Future electricity demand

In 2015, the National Control Centre (NCC) Osogbo, part of the Transmission Company of Nigeria, released a daily operational report that showed a peak generation of 4,885 MW and

a peak demand (connected + suppressed load) forecast of 14,630 MW¹⁷⁶. This shows that Nigeria was then meeting only a third of estimated demand. Thus, power generation and transmission network must be expanded to both reduce suppressed load and cater to additional demand resulting from population and economic growth. Three scenarios for suppressed demand were considered in this analysis: S1 – suppressed demand proportion remains constant; S2 – suppressed demand decreases linearly until it reaches zero in 2050; S3 – suppressed demand decreases exponentially until it reaches zero in 2050. They are illustrated in Fig. 5.7. The results presented below will assume demand scenario S3 which matches the historical evolution of electrification rates across sub-Saharan countries since the 1990s⁴⁴.

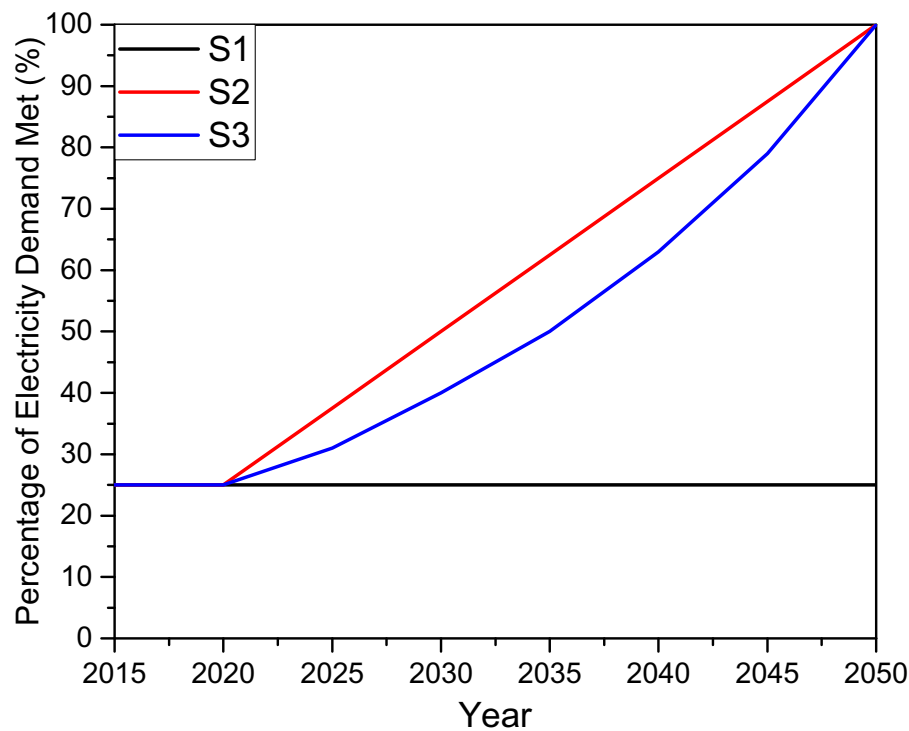


Fig. 5.7 Variation in the share of electricity demand that is met from 2020 to 2050 under different demand scenarios

A study by the Transmission Company of Nigeria showed that total electricity demand is expected to rise to approximately 70 GW by 2050. This projection and the daily electricity dispatch profile assumed in this study have been discussed previously in Section 2.4 (see Fig. 2.6 and 2.4).

System parameters

Currently, the Nigerian power system's frequency and reserve requirements are well-below international security and reliability standards²⁸¹. A minimum reserve margin of 5% and dynamic reserve (added capacity reserve due to increasing penetration of iRES) of 15% of iRES generation is implemented in the ESONE model. This is based on the standards for the UK

electricity system. A discount rate of 10% is applied to all future cash flows and transmission and network losses are assumed to be 15%¹⁷⁶. Other system parameters are provided in Table 2.9.

Technology availability

All conventional power generation technologies and iRES (solar PV, off-grid solar, and onshore wind) are made available for deployment throughout the planning horizon. Offshore wind is unavailable because Nigeria's Atlantic coastline is dominated by oil and gas exploration activities. In the base case scenarios presented, it is assumed that advanced low-carbon generation technologies (biomass, nuclear and CCS) cannot be built. This is because the necessary infrastructure such as geological CO₂ reservoirs, CO₂ pipelines, waste collection and sorting facilities are absent. Additionally, the necessary institutions and regulation to support those technologies such as biomass certification standards and nuclear safety procedures are yet to be developed. The effect of the availability of these technologies on optimal system design is investigated in the sensitivity analysis presented subsequently.

Nigeria is disaggregated into 37 zones which are still very large. This spatial granularity is not sufficient to model off-grid technologies such as solar and small-hydro accurately. Off-grid technologies are however still included in the ESONE model with two modifications: 1) the transmission constraint has been adapted to prevent off-grid technologies from exporting power from the zone in which they are located, and 2) their capital costs are typically higher than their large-scale or on-grid equivalents so they are included as separate technologies with higher CAPEX.

Build rates

Nigeria has added generation capacity slowly, as illustrated in Fig. 5.4. Historical data was used to determine the maximum rate at which Nigeria has added generation capacity historically was calculated. This was found to be 0.63 GW/yr for OCGTs, 0.25 GW/yr for CCGTs and gas-fired and 0.24 GW/yr for hydroelectric power stations. Initial model runs revealed that technology build rates need to be at least 0.5 GW/yr for the universal energy access target to be met by 2050. Consequently, all technology build rates were set to 0.5 GW/yr with the exception of OCGT and diesel generators (1.26 GW/yr) which have had higher build rates historically.

Technology parameters

For ease of computation, the ESONE model considers technology cost learning exogenously. Current and future technology cost assumptions are taken from the International Energy Agency World Energy Outlook 2018¹⁸³. It is important to note that whilst significant cost reductions have been experienced by iRES in other parts of the world, limited deployment of iRES and higher investment risk in sub-Saharan Africa means that iRES CAPEX are still well-above the global average. Current CAPEX for iRES in sub-Saharan Africa are: Solar PV – \$2,180/kW,

Off-grid Solar – \$2,580/kW, Onshore Wind – \$1,860/kW, and Offshore Wind – \$3,900/kW. These are significantly more expensive than most unabated fossil fuel generators which have higher availabilities: Super-critical Coal – \$1,600/kW, CCGT – \$700/kW, OCGT – \$400/kW and Off-grid Diesel – \$2,981/kW. Although aggressive cost reductions are assumed for iRES (see Table 2.10), the initial disparity in CAPEX between fossil fuel generators and iRES contributes to the limited deployment of the latter in the scenarios that will be discussed later in the chapter. Other technology costs and parameters assumed are provided in Table 2.10.

The emissions associated with electricity generation from different technologies are as assumed for UK-based generators, provided in Table 2.2. Upstream methane (CH₄) emissions for fossil fuel generation are not included in the system emissions calculation.

5.2.2 Scenario definition

Three sets of scenarios are modelled for the Nigerian power system:

- ‘BAU’ scenario: power sector carbon budget is consistent with business-as-usual GHG emissions projections (i.e. with no climate action pursued) – in this scenario, the power sector carbon budget rises from 111 MtCO₂/yr in 2020 to 639 MtCO₂/yr in 2050.
- ‘Unconditional NDC’ scenario: power sector carbon budget is consistent with the unconditional NDC commitment – the budget rises from 79 MtCO₂/yr in 2020 to 414 MtCO₂/yr in 2050
- ‘Conditional NDC’ scenario: power sector carbon budget is consistent with the conditional NDC commitment – the budget rises from 39 MtCO₂/yr in 2020 to 134 MtCO₂/yr in 2050

In Section 5.3, we assess the cost-optimal power system design and operation that delivers the emissions scenarios described above. In Section 5.4, we evaluate the impacts of several technological parameters (build rates, costs, availability and location) and policies (carbon taxes and discount rates) on cost-optimal system design and operation in these emissions scenarios. System emissions are restricted in the EOSNE model via a constraint which ensures that annual CO₂ emission from electricity generation are less than the sectoral carbon budget. It is possible for this budget to be exceeded through the use of a slack variable, however this is penalised at \$100,000/tCO₂.

5.3 What could the future look like?

5.3.1 System design

Fig. 5.8 illustrates the least-cost system design of the Nigerian power system under the three emissions scenarios described above. Other model inputs are as described for the base case scenarios previously.

It was found that if build rates are restricted to the maximum historical rates of technology deployment, particularly gas power plants, it is impossible to meet 100% of electricity demand by 2050. With the exception of demand scenario S1—where only 25% of demand is met—, all model runs assuming historical build rates were infeasible. Technology deployment rates of at least 0.5 GW/yr were necessary to meet all demand by mid-century. Thus, Nigeria must build power plants at, at least, twice the rate that it has done so in the past for it to deliver 100% energy access to the population by 2050. The results shown for the following scenarios assume that this technology build rate is feasible.

We observe that, until 2050, the least-cost system design for all three emissions scenarios is the same (within model error), *i.e.* a business-as-usual power system is sufficient to deliver even the conditional NDC under the Paris Agreement. Such a system sees the phasing out of diesel generation until 2050 when it is again deployed, and an aggressive expansion of thermal generation from coal, gas and hydro power plants. Between 2030 and 2050, CCGT capacity rises by 417% to 15 GW, OCGT capacity almost quadruples to 25.2 GW, and hydro capacity (both large-scale and smaller run-of-the-river scale) increases twelvefold to its geographically-constrained maximum of 13.9 GW. Gas and hydro generation are maximally-deployed, *i.e.* as much is built as allowed by the build rate constraints or geographic potential in the case of hydro. However, the expanded capacity is insufficient to meet nationwide demand which peaks at 69.3 GW in 2050. By 2030, the 10 GW of existing diesel generation reaches the end of its lifetime and is not replaced until 2050 when 11.9 GW are deployed. 10 GW of coal generation is also added by mid-century. Additionally, 18.6 GW of iRES are deployed by 2050: solar-PV (5 GW), off-grid solar (5 GW), and onshore wind (8.6 GW). 7.3 GW of battery storage is also deployed. This compensates for the variability in iRES supply and also stores energy from thermal generators to be dispatched during peak demand times.

Fig. 5.9 illustrates the relative share of demand being met by different technologies from 2020 to 2050. By mid-century, thermal generation provides 84.3% of demand: coal (8.8%), CCGT (29.5%), OCGT (39.1%), diesel (6.9%); non-thermal renewables meet 13.6% of demand: onshore wind (1.3%), solar PV (1.6%), offgrid solar (1.7%), hydro (6.6%) and small hydro (2.4%); battery storage provides the rest (2.2%). Gas generation dominates owing to its low OPEX and relative high build rate; government mandates natural gas price caps and domestic quotas from producers which keeps the fuel cheap⁶⁶. Unlike natural gas which is subsidised, the diesel market was deregulated in 2013 thus it is a relatively expensive fuel, resulting in high OPEX for the generators. Consequently, diesel's share of actual generation is approximately half of its share of capacity installed (12.5%). The low energy density of iRES, which contribute nearly 20% of capacity in 2050, also results in a low share of demand met.

Carbon intensity—the amount of CO₂ emitted per MWh of electricity generated—is seen to fall sharply between 2020 and 2030, because of the phasing out of diesel generation. However, the

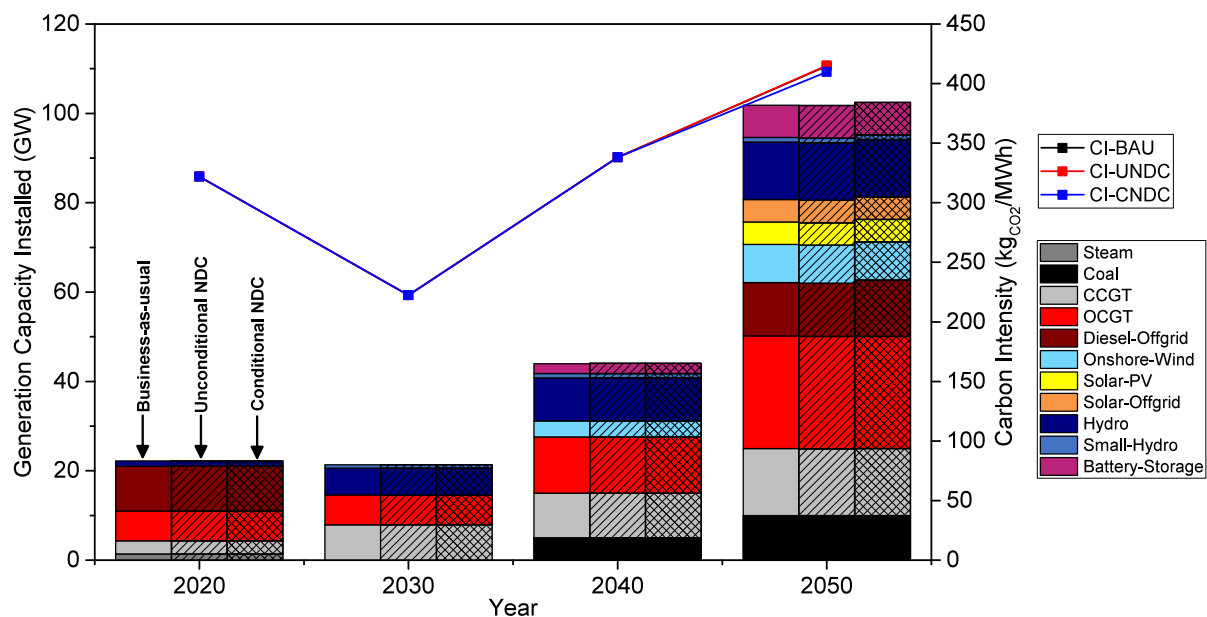


Fig. 5.8 Optimal system design for the Nigerian electricity system from 2020 to 2050 for different emissions targets, under base case assumptions for technology costs and build rates

deployment of fossil fuel power plants from 2030 onwards results in an increase in CI. Over the planning horizon, CI rises by only 29% (despite a 325% increase in generation capacity).

Spatial distribution of power generation

Owing to the fragility of Nigeria's geopolitical landscape, the spatial distribution of power infrastructure—and thus investment and job creation in the sector—between states/geopolitical zones is particularly important. Fig. 5.10 maps the distribution of generation capacity and actual generation in 2050 for the system(s) shown in Fig. 5.8 and 5.9. Fig. 5.11 illustrates the total amount of electricity traded between states via inter-state transmission lines during that year. As highlighted previously, natural gas-fired power plants dominate the energy mix in a least-cost power system, irrespective of the emissions target. CCGT and OCGT plants are concentrated in the south of the country where the oil and gas fields are located, and/or pipelines exist. This is unsurprising as the bulk of industrial capacity and economic activity occurs in this region. Lagos which contributes a fifth of national demand has the highest generation capacity installed (10 GW, all gas-fired plants). Due to its proximity to a major demand centre, Ogun (Lagos' only bordering state) has the third highest capacity per state (5.6 GW, all gas-fired) and is the largest exporter of power, mostly to Lagos. With the exception of the Ogun-Lagos line, south-south transmission is limited as states have gas plants that serve domestic demand, thereby minimising the need for imports. In the South-East, the added availability of coal and hydro generation in several states further diminishes the need for exports/imports, and hence added transmission lines (see Abia, Anambra, Cross-River, Ebonyi and Enugu in Fig. 5.11).

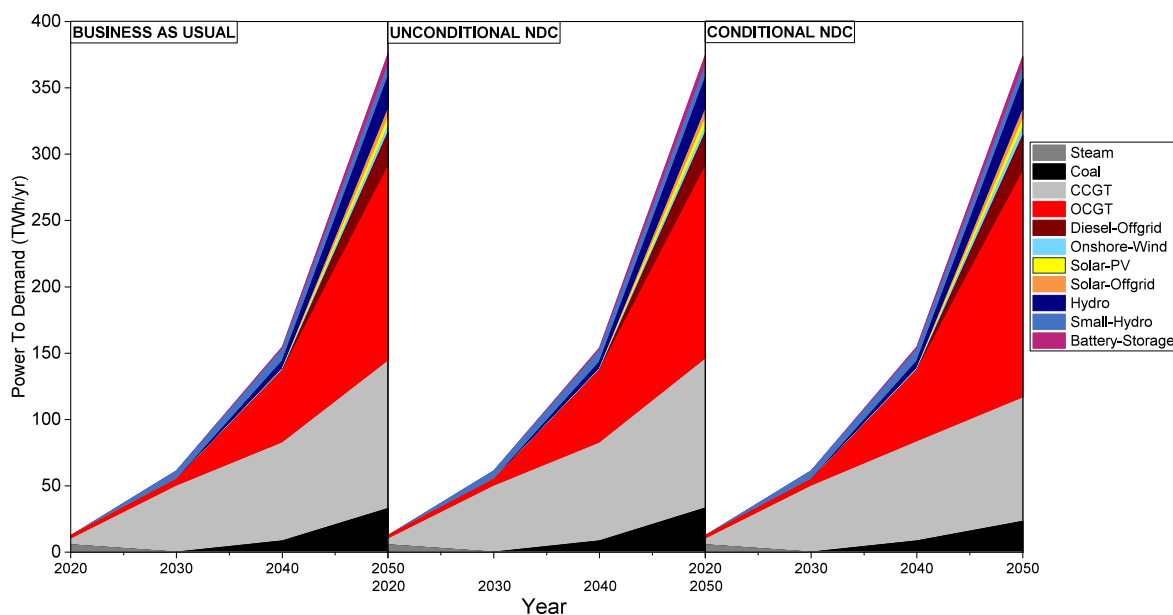


Fig. 5.9 Least-cost evolution of demand mix from 2020 to 2050 for different emissions scenarios, under base case assumptions of technology costs and build rates

The northern region of the country cannot rely on gas generation because of the unavailability of the resource indigenously and the lack of gas pipelines from the fields in the south. Historically, the extension of the existing pipeline network has proved infeasible because of the large distances that need to be overcome. Additionally, a history of attacks on oil and gas infrastructure has rendered such a project to be considered as a security risk. We find that, in the absence of gas generation, a diverse mix of energy sources is utilised to meet demand.

10.7 GW of large-scale hydro are deployed in the north, mostly in Taraba (4.7 GW), Niger (2.1 GW) and Kogi (2.7 GW), where either of the country's two major rivers traverse. Owing to its large hydro capacity and relatively small domestic demand, Taraba is the third highest exporter of power, serving neighbouring states in the North-East. 1 GW of 'run-of-the-river' hydro plants (on the tributaries of the major rivers) are distributed across fourteen states. 8.6 GW of onshore wind capacity is distributed across three states: Sokoto, Zamfara and Yobe, where availabilities are the highest. The North-West (NW), which accounts for a quarter of the country's population, relies significantly on diesel (9.6 GW) and solar (8.2 GW, both grid-scale and off-grid) generation to meet regional demand. 4 GW of battery storage is deployed to shift excess supply to the evening peak. A shortfall in demand remains, however, and this is met by imports from gas generation in the south, mostly via Osun and Niger states.

For the North-East region and some neighbouring states such as Jigawa, Kano and the FCT, hydro power from Taraba is insufficient to meet regional demand. It proves cheaper to rely on coal than on diesel generation (because of its high OPEX) or other imports (because of the additional investment required in transmission capacity over long distances). Coal plants in Bauchi (4 GW), Nasarawa (3 GW) and Gombe (1 GW) satisfy regional demand, and the high

UNCONDITIONAL NDC SCENARIO IN 2050 - BASE CASE

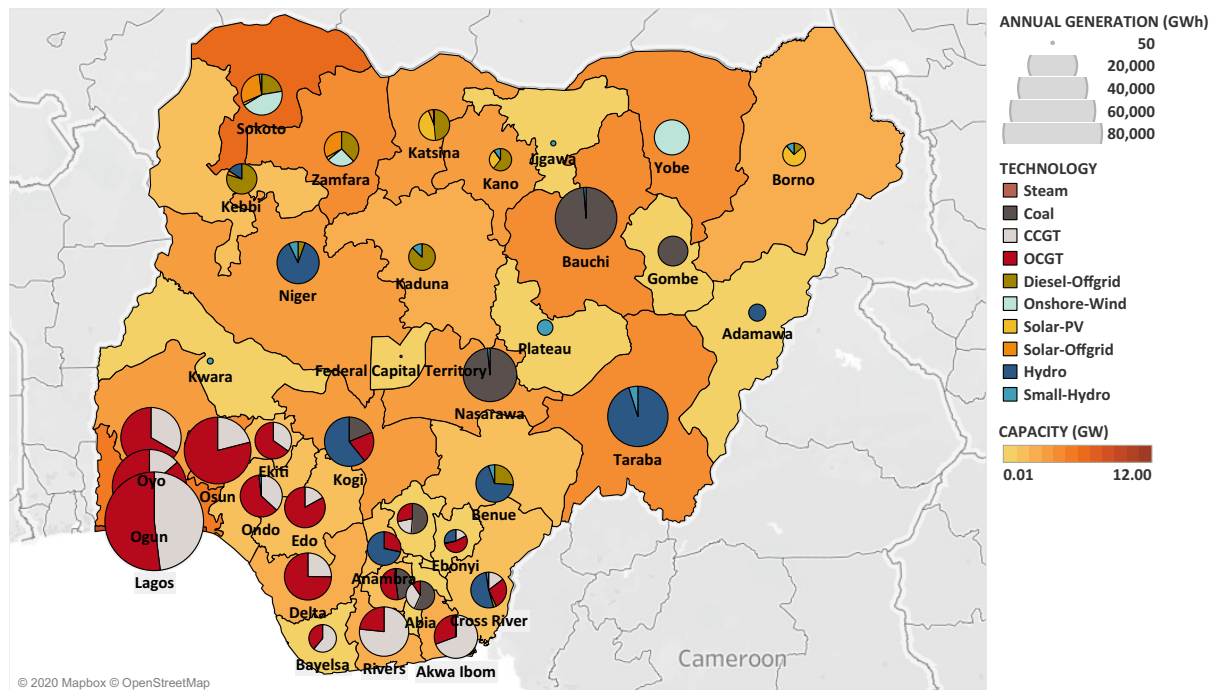


Fig. 5.10 Map showing power generation capacity and actual generation by state and by technology in 2050, when the Paris Agreement target is met. Base case technology costs and build rates are assumed.

utilisation of the plants (> 80%) make Bauchi (second) and Nasarawa (fifth) amongst the largest state-exporters of electricity.

The above highlights that the optimal system design differs significantly by region. Southern states rely on natural gas-fired plants and minimal inter-state/regional transmission lines. Despite the abundant landmass and relatively high availability of iRES in the north, renewables are insufficient to meet domestic demand. Electricity imports from states with large hydro and coal generation capacities is critical to meet the shortfall in demand. Off-grid generation via diesel, solar and small-scale hydro is also necessary.

5.4 Cost of delivering the Paris Agreement

Fig. 5.12 and 5.15 illustrate the costs of delivering the different emissions scenarios, for a range of modelling assumptions. The cumulative system cost (CSC) in year a is the total capital and operating costs incurred by the system from the initial planning year (2020) until year a . For the business-as-usual and unconditional NDC base case scenarios, the CSC rises to \$50 billion by 2050 (applying a 10% discount rate to future cash flows). For the conditional NDC target, there is a 4% increase in CSC to \$52 billion by mid-century. The base case scenarios limit technology deployment rates to 0.5 GW/yr which has only been historically achieved for OCGT power plants in Nigeria. Other power plant build rates been very lower zero because of minimal

UNCONDITIONAL NDC SCENARIO IN 2050 - POWER TRANSMISSION - BASE CASE

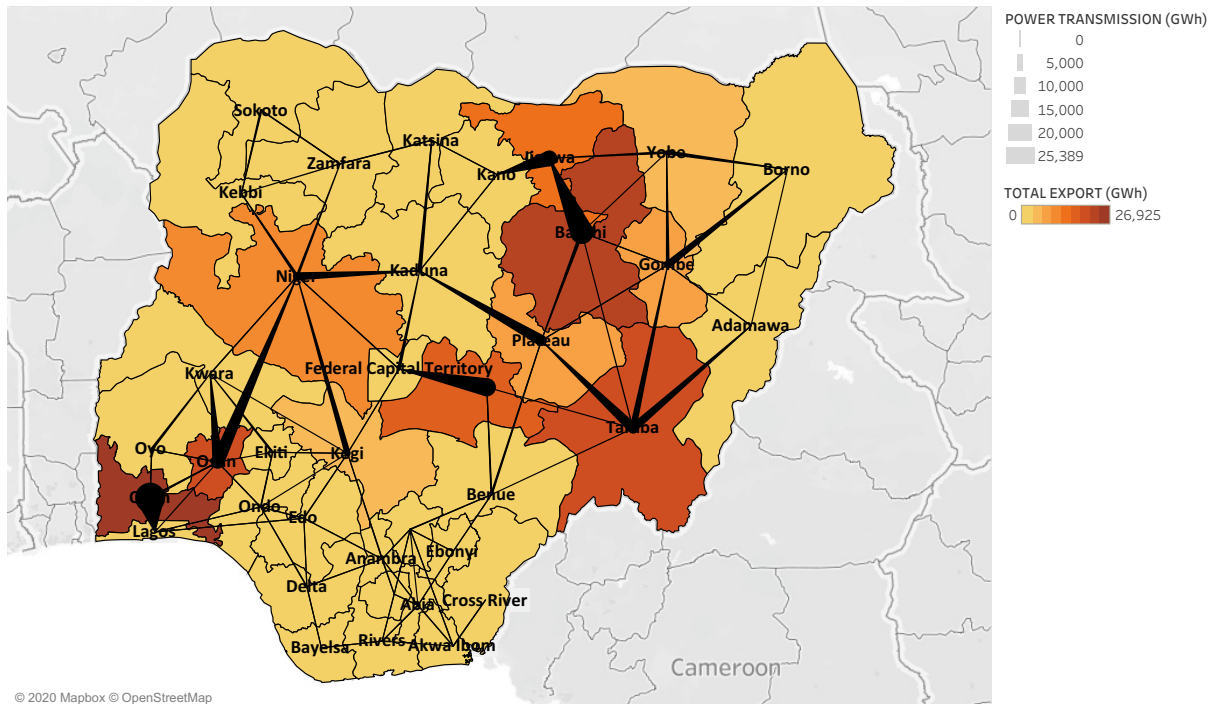


Fig. 5.11 Map showing inter-state power transmission in 2050 in the BAU and Unconditional NDC scenarios. Base case technology costs and build rates are assumed.

investment in the sector for reasons discussed in Section 5.1.6. Sectoral reforms—including the implementation of a cost-reflective tariff regime, government fiscal support to boost sector liquidity, improved sectoral governance, subsidies for renewable energy technologies—are underway, and are expected to rapidly increase generation capacity in the coming years^{281,303}. Thus, we assess the implications of new technology availability and quicker deployment rates on the optimal system design to deliver the Paris Agreement targets.

Three alternative scenarios are investigated: 1) a ‘High Build Rate’ scenario in which technology deployment rates are increased to 2.5 GW/yr – this is 10 times the historical plant build rate in Nigeria (as a reference, at least twice as quickly as power plants have been built in the UK, 2) an ‘Advanced Tech Available’ scenario in which nuclear, biomass and CCS technologies are available for deployment throughout the planning horizon, and 3) an ‘All Tech In All States’ scenario in which fossil generation (Coal, CCGT, OCGT) can be built in states where the resource is not available and pipelines do not exist.

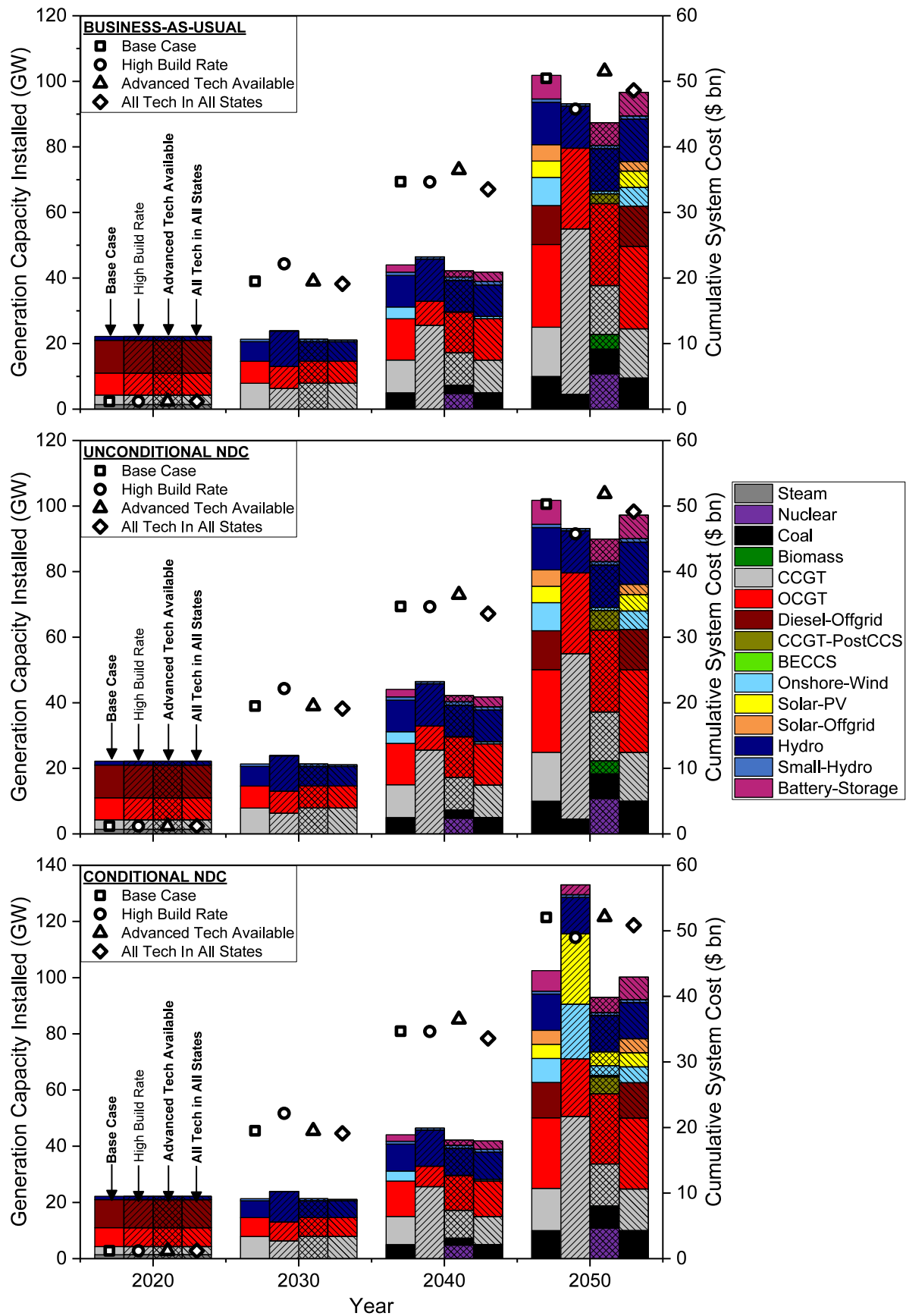


Fig. 5.12 Optimal design and cumulative system cost of the Nigerian power system under different emissions scenarios and modelling assumptions

BAU and Unconditional NDC

As illustrated in Fig. 5.12, the BAU and Unconditional NDC scenarios are identical throughout the planning horizon. When technology build rates are increased to 0.5 GW/yr, the total system cost and total capacity installed falls by 9% and 8%, respectively. CCGT and OCGT capacity rises from 40 to 71 GW in 2050. Increased gas generation displaces the need for any iRES, diesel generators and battery storage. Additionally, the amount of coal generation necessary by mid-century falls from 10 to 4.5 GW. Thus, it is possible to deliver Nigeria's Paris Agreement target without the deployment of iRES, and with the deployment of coal power.

When advanced technologies are available, the total system cost rises by 2% (within model error) whilst installed capacity in 2050 falls by 12%. By mid-century, nuclear (10.8 GW), biomass (4 GW) and CCGT-CCS (6 GW) are built. These are baseload power plants that operate with high capacity factors. Consequently, their deployment displaces all solar and diesel generation which have relatively low availabilities; this is due to the low energy density and intermittency of the solar and the high OPEX of diesel generators which results in their use only during peak hours. Onshore wind capacity is also displaced but 0.9 GW remain in 2050. The availability of advanced technology therefore could reduce the amount of infrastructure that needs to be built to meet demand, however their relative high capital costs means that this does not translate to reduced system costs.

When gas- and coal-fired power plants can be built in states that do not have the resource, the total system cost and installed capacity in 2050 both fall by 4%. These fossil plants are deployed in the North-West and North-East regions of the country, where they displace some off-grid solar and onshore wind capacity.

Conditional NDC

Under the Conditional NDC emissions pathway, an increase in technology deployment rates by a factor of 10 results in a 30% increase in total installed capacity in 2050. Total system cost, however, decreases by 6%. Gas generation capacity rises from 40 to 71 GW by mid-century. Increased gas capacity displaces all coal (10 GW) and diesel (12.6 GW) generation. The high carbon intensities of the latter fuels make their deployment incompatible with meeting the stringent emissions reduction target (45% reduction relative to BAU). Grid-scale solar PV and onshore wind capacities also rise significantly to 25 GW and 19.5 GW, respectively. No off-grid solar is built. Despite the increase in iRES, battery storage capacity falls by 52% to 3.5 GW.

When advanced generation technologies are available, the total capacity installed decreases by 9% however total system cost remains constant. This is owing to the deployment of higher availability but also higher CAPEX power plants, including nuclear (10.8 GW), biomass (0.5 GW), CCGT-CCS (6 GW) and BECCS (0.5 GW). Whilst solar remains in the least-cost energy mix, onshore wind and diesel are displaced entirely from the system. Reduced iRES capacity

translates to a lower need for energy storage—battery storage capacity falls by 26% to 5.4 GW in 2050.

As previously described, the availability of coal, CCGT and OCGT plants in all states results in the displacement of some iRES capacity—in the conditional NDC case, only onshore wind capacity falls from 8.6 GW to 5.7 GW. In contrast, battery storage capacity rises by 10% to 8 GW. Increased energy storage is required to supplement gas generation during peak hours in the North-West and North-East; batteries store surplus electricity from coal and gas during low demand hours. The rest of the energy mix remains unchanged. Total system cost and capacity installed fall by 2%, within the error of the model.

5.4.1 What does the lowest cost system look like?

We find that the lowest-cost system that delivers Nigeria's NDC is achieved when technology deployment rates are increased significantly (see Fig. 5.12). Fig. 5.13 and 5.14 show the spatial distribution of power generation and transmission in 2050 in this lowest-cost scenario where power plant build rates are very high (0.5 GW/yr). It proves sufficient to meet the Unconditional NDC by utilising only natural gas (75.1 GW), coal (4.5 GW) and hydro (13.6 GW) power. CCGTs are preferred over OCGTs because of their lower OPEX and higher availabilities; the latter is only deployed when the new build of CCGT reach the maximum allowed capacity. It may appear surprising that no iRES, not even Solar PV, is deployed in the lowest-cost BAU or Unconditional scenarios. However, it is important to note that the initial capital costs of solar power (\$2,180-2,580/kW) are several times greater than that of natural gas-fired generation (\$400-700/kW), as previously highlighted (see Table 2.10). Additionally, solar power has much lower availability than gas-fired power plants, and energy storage is often required to compensate for the variability in its supply. Consequently, when build rates are not limited, it proves cheaper to deliver dispatchable electricity using gas-fired power plants instead of iRES.

Owing to the concentration of generation in the south, inter-regional transmission becomes critical to meeting demand. Northern states such as Kwara, Kogi and Niger that border regions with gas generation are key conduits for power transmission. In addition to its proximity to the gas-rich South-West, its large hydro generation makes Niger state the largest exporter of power, principally serving states in the North-West. The availability of coal plants in Bauchi and Gombe, and hydro in Taraba means that the north-East is less reliant on imported electricity from the south.

5.4.2 Are green policies effective in Nigeria?

Greater awareness of climate change has led to the promotion of climate-friendly policies in many countries, including Nigeria which has enacted several measures to encourage the use of low-carbon energy sources. In 2015, the National Renewable Energy and Energy Efficiency

UNCONDITIONAL NDC SCENARIO IN 2050 - 10X HISTORICAL BUILD RATE

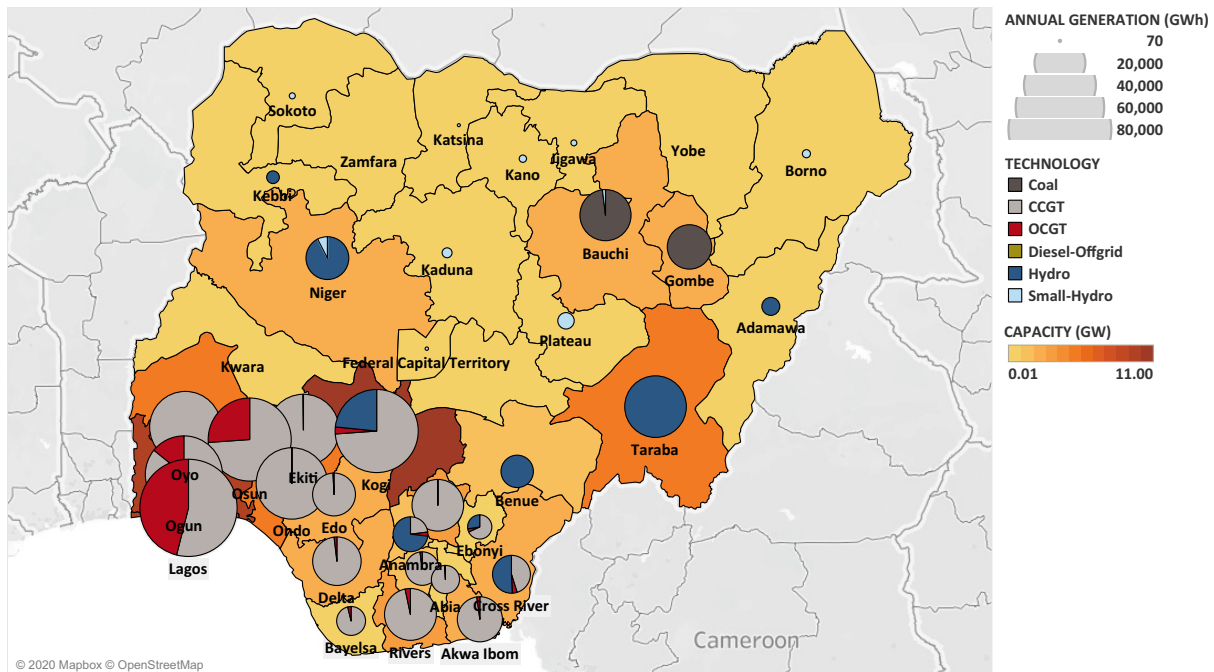


Fig. 5.13 Map showing power generation capacity and annual generation by state and by technology in 2050 under the lowest-cost Unconditional NDC scenario. In this scenario, technology deployment rates are assumed to be ten times their historical maxima.

Policy (NREEEP) which set out the government's intent to pursue renewable energy and energy efficiency as part of the country's energy strategy was approved²⁸⁹. The policy mandated the deployment of 3.6 GW of renewable energy by 2020, however this has not been achieved. To date, no on-grid renewables have been deployed. Subsequently, feed-in tariff regulation, tax incentives, mini-grid regulation, tax incentives and investment grants for low-carbon energy sources have been approved³⁰⁴. A biofuels blending mandate and an act to establish the Rural Electrification Fund came into force in 2007 and 2014, respectively³⁰⁴. Generally, the aim of these incentives is to drive down the costs of low-carbon energy. Due to a poor macroeconomic environment that has deterred investment in Nigeria, the effects of these policies are yet to be seen.

Renewable energy subsidies

To assess the potential implications of incentive mechanisms that drive down the cost of cleaner energy technologies, a 'Low CAPEX' scenario was assessed. In this scenario, the CAPEX of low-carbon generation technologies were assumed to be the global lower-bound estimates^{‡ 183}. It was found that lower iRES CAPEX results in increased deployment of solar PV, capacity built by 2050 doubles to 20 GW (both grid-scale and off-grid). Onshore wind capacities remain unchanged. Depending on the emissions pathway, the total system cost falls by 4-5% despite an increase in the total capacity installed by 4%. Added solar capacity does not displace fossil fuel

[‡] This is usually the overnight cost of the technology in China

UNCONDITIONAL NDC SCENARIO IN 2050 - POWER TRANSMISSION - 10X HISTORICAL BUILD RATE

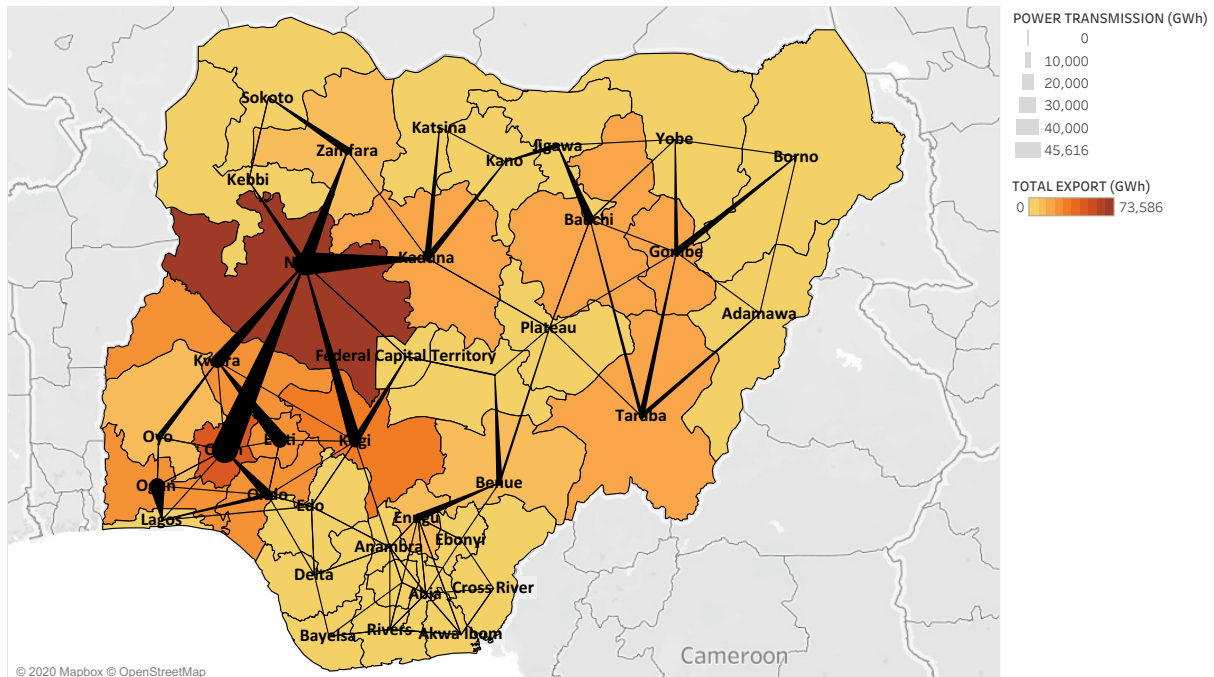


Fig. 5.14 Map showing inter-state power transmission in 2050 under the lowest-cost Unconditional NDC scenario. In this scenario, technology deployment rates are assumed to be ten times their historical maxima.

generation capacity, however coal and diesel plants experience a reduction in their utilisation rates as lower OPEX solar is preferentially deployed when available.

Carbon pricing

Carbon pricing via a carbon tax or a quota system ('cap and trade') is often suggested as the most efficient means to reduce GHG emissions. A carbon tax would penalise polluters for the costs that they impose on society, often described as the social cost of carbon (SCC). Owing to a lack of data and technical capacity, there is a lack of literature on the economic costs of climate change within the Nigerian context. A comparative study on African countries that have trialled carbon pricing mechanisms suggests a tax of \$8/tCO₂ for Nigeria's oil and gas industry³⁰⁵. Another study by Ricke *et al.* estimated an SCC of \$20-50/tCO₂ for the country²⁵⁵. We assess the effects of such a tax on the least-cost power system design for different emissions pathways.

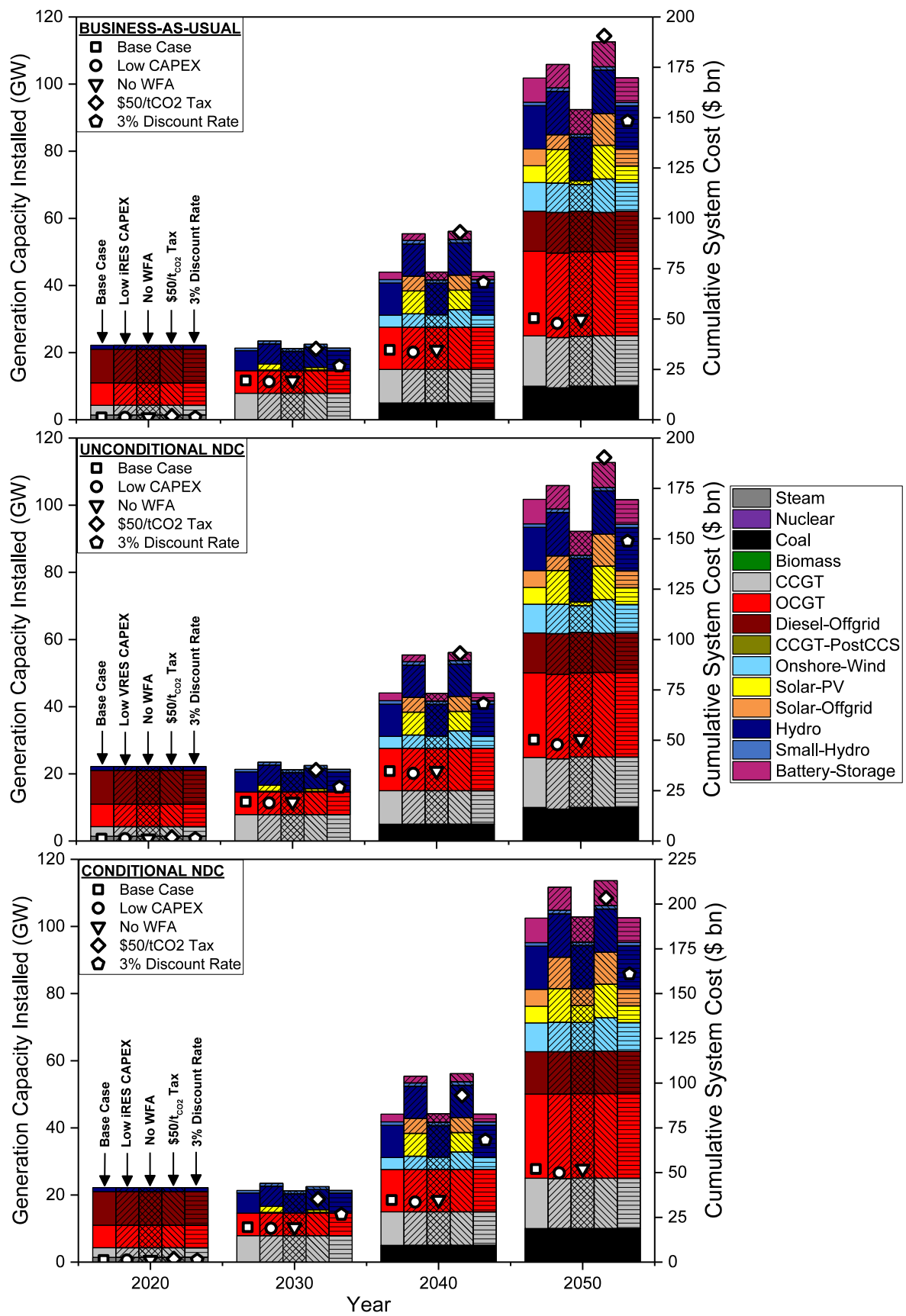


Fig. 5.15 Optimal system design and cumulative system cost of the Nigerian power system under different emissions pathways and policies

The implementation of a \$50/tCO₂ results in the increased deployment of iRES. Solar and onshore wind total capacity in mid-century rises by 59% to 29.5 GW. This additional iRES capacity however does not reduce the demand for fossil fuel power plants; instead, the utilisation of coal and diesel plants falls slightly. By 2050, 77% of annual electricity generation is derived from fossil fuels: coal (12%), natural gas (61%) and diesel (5%). The carbon tax yields an increase in the total system cost by a factor of 2.8-2.9. Thus, whilst carbon pricing—at the level assumed—promotes the proliferation of iRES, it fails to discourage the use of fossil fuels. The tax instead greatly increases the operating costs of fossil power plants, and thus the whole system. Fossil power plants remain critical to meeting all energy demand because of their higher availabilities, dispatchability and relatively low capital costs.

Other factors

The weighting factor parameter ('WFA') included in the ESONE model is used to address end-of-horizon effects. It is used to discount the CAPEX of a technology that will continue to operate outside the time period modelled. The WFA in year *a* is the technology's lifetime as a fraction of the remaining planning horizon. We found that without the WFA, the capacity of iRES decreases significantly in the BAU and Unconditional NDC scenarios. In the Conditional NDC scenario, the energy mix remains unchanged.

5.5 Decarbonisation and development: barriers and opportunities

Delivering universal energy access in Nigeria alongside its Paris Agreement commitment requires the extensive expansion power generation and transmission infrastructure. In addition to resolving the challenges that the power sector currently faces (see Section 5.1.6), there are several barriers that must be overcome to realise the scenarios that were presented in Fig. 5.8-5.14. These are discussed below.

Commercial viability of power infrastructure

The partial privatisation of the power sector in 2013 shifted the ownership of generation and distribution assets to private entities whilst the transmission network remained publicly-owned via the Transmission Company of Nigeria (see Fig. 5.5)⁶⁶. The privatisation of the transmission segment of the power value chain to complete the deregulation of the sector is currently being assessed by government³⁰⁶. Consequently, the future development of the sector is expected to be achieved largely through private investment. Private sector capital typically seeks higher returns than public financing because of the increased risk. Fig. 5.16 illustrates the utilisation factors of inter-state transmission lines under the Unconditional NDC scenario. The utilisation

factor is the ratio of the amount of power transmitted through a line to the maximum amount of power that can be transmitted annually.

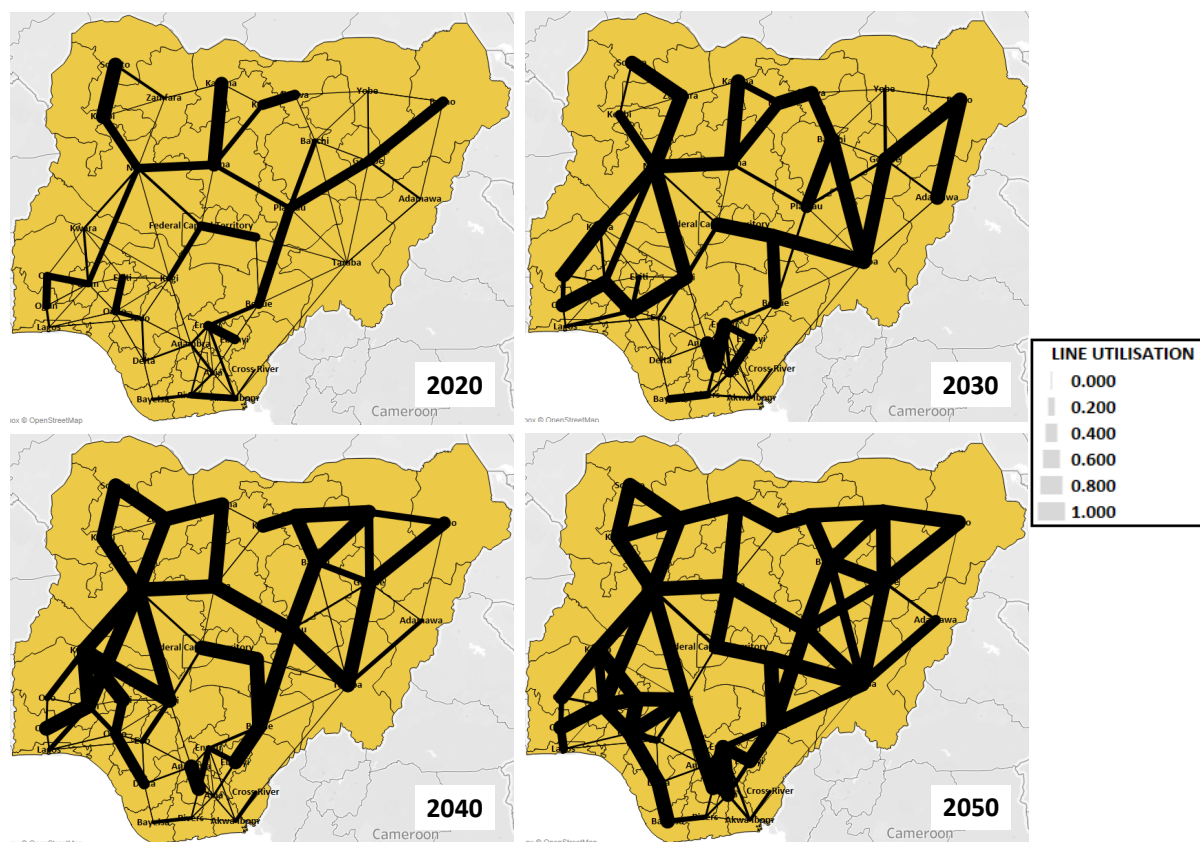


Fig. 5.16 Inter-state transmission line utilisation factors from 2020 to 2050 under the Unconditional NDC base case scenario. Utilisation factors range from 0 to 1, with the upper-bound representing 100% utilisation of available power transmission capacity.

We find that between 2020 and 2050, 49-92% of transmission lines have utilisation factors of less than 0.5. That is, less than 50% of their available annual transmission capacity is being used. The likelihood of asset underutilisation could discourage private investment in those parts of the transmission network. Thus, government support may be necessary, as has been the case historically even in the privatised generation and distribution segments of the value chain. Since 2015, the government has provided three bailouts totalling NGN 1.5 trillion (\$4.9 billion[§]) to the electricity sector to compensate for revenue shortfalls in GENCOs and DISCOs³⁰⁸.

Electricity tariffs are currently pre-determined by the sector's regulator, NERC, through the Multi-Year Tariff Order. The most recent revision of the MYTO sets prices at NGN 4-66/kWh (\$11-184/MWh[¶]) depending on the type and scale of the consumer^{309||}. Owing to the dearth of industrial and commercial users, majority of the electricity consumers are smaller-scale households that are charged at the lower-bound of the tariff range. These prices are a third of the

[§] Assuming the then official exchange rate of \$1 = NGN 305³⁰⁷

[¶] Assuming the current official exchange rate of \$1 = NGN 360.5

^{||} Consumer categories include residential, commercial, industrial, 'special' and street lighting.

current and projected marginal cost of generation according to the ESONE model^{**}. Therefore if tariffs are not increased, GENCOs and DISCOs will continue to face significant revenue shortfalls and investment in additional generation capacity will be deterred. Historically, tariff increases have proved difficult owing to a range of sociopolitical factors (see Section 5.1.6).

The above discussed issues suggest that government financial support for the power sector is necessary in the short- to medium-term, even if the deregulation of the sector is completed. The amount of support required will be dependent on when the implementation of a cost-reflective tariff regime is achieved and the resolution of other sources of poor revenue collection rates including poor metering and non-payment of bills by consumers.

Expansion of natural gas production and distribution

Natural gas-fired power plants dominate the optimal energy mix for the power sector in all the scenarios that were assessed in this study, irrespective of the emissions target. Consequently, the availability of natural gas is likely to be crucial to achieving universal energy access by mid-century. In 2018, Nigeria produced 44.3 billion cubic metres (bcm) of natural gas (NG) annually, of which 28.6 bcm was exported³¹⁰. Fig. 5.17 compares the historical production rates with the projected consumption for electricity generation according to the ESONE model. We find that in the base case scenarios, there is a 14-fold increase in NG consumption from 2020 to 2050. By mid-century, the amount of NG required for electricity per year is 60% greater than the current total production. In the upper-bound scenario, 79.9 bcm/yr of NG is required by 2050—this is nearly double of today's marketed production.

The above highlights that current NG production is insufficient to meet the needs of the power sector (and others) by 2050. An expansion of domestic production and/or a reduction of exports is therefore necessary. For NG exports to decline, producers must be incentivised to sell to the domestic market by the elimination of the price capping mechanism that keeps domestic NG prices significantly lower than international prices. Additionally, the pipeline network must be expanded alongside production to allow for greater volumes to be transported to power plants near demand centres, particularly in the South-West. The National Gas Policy (2017) outlined the government's vision to reform the gas industry³¹¹. The objectives of the policy include: encouragement of exploration of new gas supply sources from offshore and inland basins, liberalisation of access to gas transmission and processing infrastructure, and the development of domestic gas markets. However, quantifiable targets or a timeline were not included. To deliver energy access at low-cost, the objectives outlined must be achieved.

^{**}The highest-OPEX generators which typically set the marginal cost of electricity are OCGT and diesel plants which have OPEX of \$37.3/MWh and \$154.7/MWh, respectively. Section 2.4 details the sources of cost assumptions for each technology.

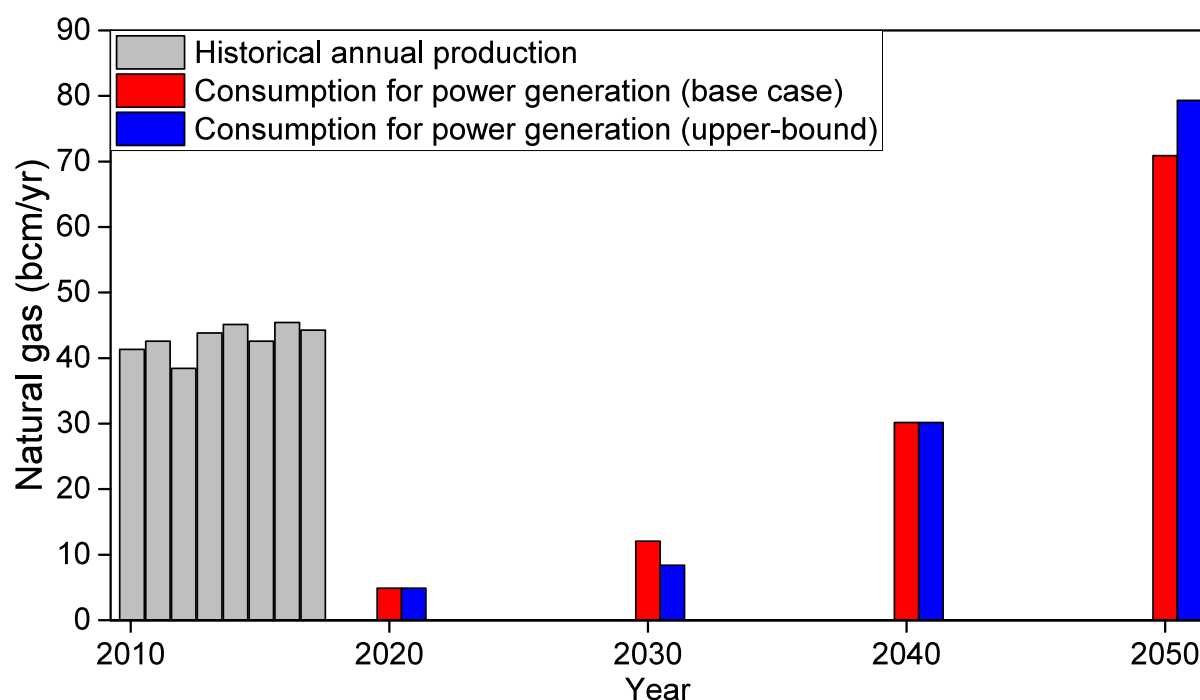


Fig. 5.17 Forecast for natural gas consumption by the power sector, according to the ESONE model. Historical annual natural gas production is also shown.

Carbon offsetting

In Section 5.1.2, we estimated the ‘carbon budget’ for the Nigerian power sector under a business-as-usual scenario with no climate action, and how this would change under the country’s unconditional and conditional NDC commitments. Previously discussed analyses investigated the power system transitions necessary to deliver the unconditional and conditional NDCs in the sector. Fig. 5.18 shows how the projected CO₂ emissions from power generation for all the emissions scenarios (BAU, Unconditional NDC and Conditional NDC) and modelling assumptions investigated in this study, and compares them to the sector’s carbon budget throughout the modelled period. We find that in the BAU and Unconditional NDC scenarios, the annual CO₂ emissions from the power sector are well-below the sectoral carbon budget. That is, the electricity-associated emissions are well-below the allowed limit. In the Conditional NDC scenarios, annual emissions remain below the carbon budget until 2050 when the budget is exceeded despite a penalty of \$100,000MWh for overshoot (implemented via an emissions slack variable in the ESONE model, see Chapter 2). This highlights the difficulty of delivering the Conditional NDC in 2050.

The difference between the actual annual system emissions and the maximum allowed is referred to here as the ‘surplus carbon budget’. In the Unconditional NDC scenarios, the surplus carbon budget peaks at 244 MtCO₂/yr by mid-century. In the Conditional NDC scenarios, the surplus peaks in 2030 at 54 MtCO₂/yr. This spare capacity could offset emissions from other sectors of the economy thereby alleviating some of their decarbonisation burden, or traded

internationally. Carbon offsets are measurable and verifiable emissions reductions activities that can be traded in voluntary or compliance markets (where government regulation mandates emissions reductions or the purchase of offsets)²⁷¹. Increasingly, organisations are purchasing offsets to minimise the carbon footprint of their operations³¹². Between 2005 and 2018, 435.4 MtCO₂ of voluntary offsets were issued, with 13% of the projects located in Africa (23 countries, including Nigeria)³¹³. Nigeria is also committed to the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) which seeks to limit the industry's emissions through offsets. In 2018, 98.4 MtCO₂/yr of voluntary carbon offsets were transacted at an average price of \$3.01/tCO₂ (Africa average = \$4.2/tCO₂)³¹⁴. Although the prices are currently low, increasingly stringent emissions reduction targets and/or carbon pricing mechanisms could drive up demand and thus prices. Assuming current prices, the Nigerian power sector could generate up to \$734 million in revenues annually if its surplus carbon budget is traded. This could be a source of much-needed financing into the sector, particularly for renewable energy and energy efficiency/fuel switching projects that avoid GHG emissions. Additionally, offset projects have been reported to provide co-benefits that contribute to the Sustainable Development Goals (SDGs), including supporting the local economy through job training and creation, preserving watershed areas that supply clean water, and safeguarding biodiversity³¹³.

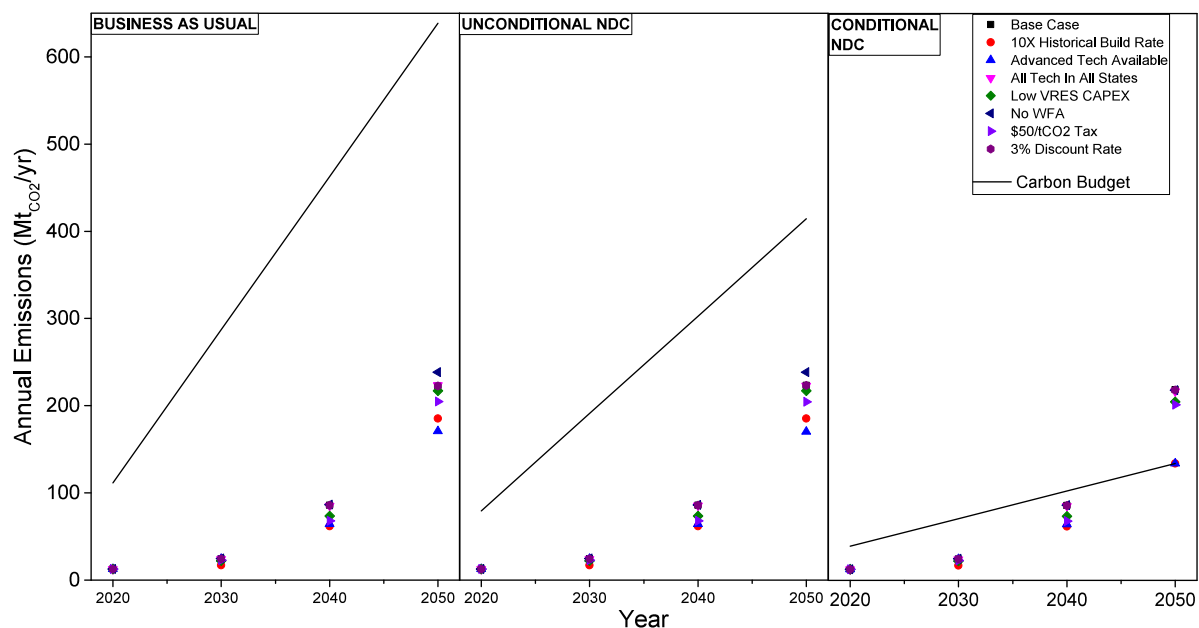


Fig. 5.18 Projected annual CO₂ emissions from power generation from 2020 to 2050 under different emissions targets and modelling assumptions. The black lines illustrate the annual carbon budget for the power sector as a reference.

Renewable energy as a tool for economic diversification

Fig. 5.12 showed that the lowest cost system that delivers Nigeria's Paris Agreement commitment is one that is dependent on coal, natural gas and hydro power only. To achieve this however, power plants must be built on average ten times faster than has been done historically in

Nigeria. Furthermore, the reliance on these resources, principally natural gas, concentrates power generation in the south of the country near the oil and gas fields. Fig. 5.19 shows the relative share of power generation capacity and actual electricity generation by region in 2050. In the described lowest-cost scenario, the South-West alone accounts for 51% of total capacity installed and electricity produced by 2050, whilst the North-West accounts for less than 1%. The remainder is distributed between the four geopolitical zones.

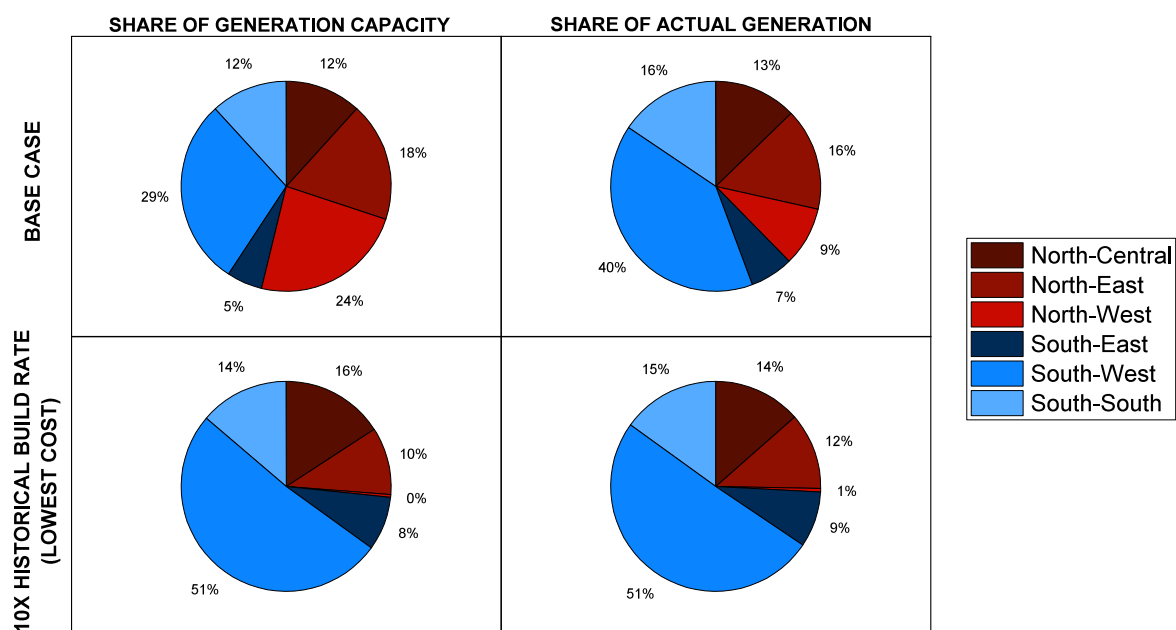


Fig. 5.19 Regional share of power generation capacity and actual generation under base case and lowest-cost NDC scenarios

In the ‘base case’ scenario where build rates are decreased to better reflect historical precedent, we find that a diverse energy mix is deployed to deliver Nigeria’s Paris Agreement commitment. This mix includes conventional fossil generation alongside hydro power and iRES (solar PV, off-grid solar and onshore wind). Hydro resources are distributed along the two main rivers that bifurcate the country and their tributaries, majority of which are in the north. Additionally, owing to their larger landmass and higher solar and wind availabilities, northernmost states are optimal sites for iRES deployment. Consequently, significant generation capacity is built in those states. Fig. 5.19 illustrates that the three northern region account for 54% of total generation capacity and 38% of total electricity produced by 2050.

The inability to deploy gas-fired plants rapidly leads to a more geographically-distributed power system. It is important to highlight that despite aggressive cost reductions assumed (see Table 2.10), iRES deployment does not occur because they are cost-optimal but because the lowest-cost generators (OCGT and CCGT) have been maximally-deployed. Oil and gas infrastructure, particularly pipelines, have historically been targets for attacks by militias and discontented citizens in Nigeria. Consequently, they are viewed as a security risk in a fragile geopolitical landscape²⁸⁵. Additionally, the proportionate sharing of political and

economic resources between different regions of the country has been institutionalised to minimise ethnic polarisation²⁸⁵. Accordingly, a diversified energy system—both spatially and technologically—is therefore more politically-expedient because of the increased (energy) security and better distribution of jobs and investment across the country. Owing to its relative lack of fossil fuel resources, the utilisation of the vast renewable energy resources of the north is the only way to ensure that an equitable distribution of investment in the power sector is achieved. Increased energy available could potentially spur economic activity in this region which has the highest poverty levels and lowest internally-generated revenue metrics in the country³¹⁵.

5.6 Discussion

Through the 2015 Paris Agreement, all countries committed to limiting average temperature rise “well-below to 2°C” above pre-industrial levels. In its nationally-determined contribution, Nigeria pledged an unconditional 25% reduction in its GHG emissions relative to a business-as-usual (BAU) forecast, and to pursue a conditional 45% reduction if financial and technical support is provided. This study sought to investigate the implications of these emissions reduction target on the transition of the power sector. It found that delivering the nationally-determined contributions (NDCs)—both unconditional and conditional—had no effect on the the least-cost power system design. That is, the cost-optimal system that delivers the Paris Agreement commitment for the power sector is the same as the business-as-usual forecast. Such a system sees the expansion of conventional fossil fuel generation from coal, natural gas and diesel (62 GW); the utilisation of hydro resources to their maximum potential (13.9 GW); and the deployment of renewable energy technologies using solar and wind power (18.6 GW) by 2050. Owing to the variable nature of solar and wind, energy storage services become critical to shift excess generation to peak hours. To provide this service, 7.3 GW of battery storage is built by mid-century. The total system cost—total capital (CAPEX) and operating (OPEX) costs invested in the system from 2020 to 2050—needed to achieve this is \$50 billion when future cash flows discounted at 10%.

The rapid reduction in the cost of intermittent renewable energy technologies (iRES) has led to the suggestion that they are crucial to delivering universal energy access at the lowest cost^{31,178}. However, this study finds that it is possible to deliver Nigeria’s unconditional NDC without the deployment of any iRES, and such a system is cheaper than one which has iRES deployed (despite aggressive cost reduction assumptions). This system utilises only natural gas, coal and hydro resources to meet all demand in 2050, and has a TSC that is 5% lower than the diverse system previously described. To achieve such a scenario would require technology deployment rates, particularly of gas-fired power plants, to increase tenfold relative to the historical maxima. Additionally, the geographical concentration of power generation where fossil fuel resources raises issues of pollution and equity. To meet the conditional NDC at the lowest cost however,

iRES and battery storage are critical technologies irrespective of technology deployment rates, and coal power is not deployed.

Energy resources in Nigeria are well-distributed with oil and gas fields in the space-constrained south, and majority of renewable energy resources distributed in the larger northern states. This study finds that the development of diverse energy mix—albeit more expensive than a system with only fossil fuels and hydro—will lead to a more equitable distribution of power generation infrastructure, and thus investment and jobs. Given the country's fragile political landscape, equity is critical for political expediency of projects and the deployment of renewable energy is the only means to achieve this in the power sector.

Many countries have implemented policies to encourage the use of low-carbon energy sources over fossil fuels. Most often, renewable energy subsidies and carbon pricing have been used to achieve this and they have been successful in driving down the costs of solar and wind power especially. In this study, we assessed the effects of cheaper low-carbon technologies—including iRES, CCS, biomass and nuclear—and a carbon tax on the deployment of low-carbon energy in Nigeria. We found that even when costs were assumed to be the lower-bound forecast, there is limited increase in the iRES capacity deployed. Only grid-scale solar PV experiences higher deployment with installed capacity increasing by a factor of 1.4-2 by 2050. Onshore wind capacity remains unchanged and no other low-carbon technologies are built. Although TSC falls by 4-5%, only 0.5 GW of fossil fuel generation (coal) is displaced by the added iRES. The lower CAPEX, higher availability and dispatchability of thermal generators prove critical to meeting demand and maintaining system reliability and operability. Similarly, a tax of \$50/tCO₂ increases iRES capacity by 59% but nearly triples the TSC; fossil fuel generation capacity remains unchanged. Consequently, subsidising low-carbon generation and/or penalising GHG emissions may have a negligible effect on limiting the use of fossil fuels for power generation whilst increasing system costs.

In 2013, the generation and distribution segments of the power value chain were privatised. Privatisation of the transmission network is being considered to complete the deregulation process and encourage private investment-led development of the sector. This study finds that in the short-term, power transmission infrastructure that are critical to ensuring universal energy access will be underutilised. Additionally, the electricity tariffs—set by the sector's regulator—of majority of consumers are lower than the marginal cost of electricity. These issues are likely to discourage investment to expand generation and transmission. Thus, the implementation of a cost-reflective tariff regime is critical to the development of the sector. Otherwise, government interventions will remain necessary to maintain liquidity and operation.

Natural gas dominates the energy mix for power generation in all of the scenarios assessed in this study. We find that natural gas consumption for electricity generation rises to 70-79 billion cubic metres per year (bcm/yr) by mid-century. Currently, Nigeria produces 44 bcm/yr with

65% of that being exported. Delivering Nigeria's NDCs at low-cost will require an expansion of gas production and distribution capacity, and a refocus of the industry towards the development of domestic gas markets.

5.7 Contributions made

This work presents the first detailed assessment of how Nigeria's power sector needs to transition to deliver its nationally-determined contribution to the Paris Agreement. The results identify: 1) the technologies that are key to delivering universal energy access at the lowest cost and the rate at which they need to be built; 2) the costs associated with such a transition; 3) the optimal locations for technology deployment, particularly iRES (based on high-resolution weather data); and 4) how the transmission network needs to evolve to achieve a cost-optimal power system. Secondly, this work qualifies the relative value of power generation technologies for meeting climate change mitigation targets in Nigeria. Contrary to the literature and mainstream opinion, this study shows that intermittent renewable energy sources are not critical to delivering current emissions reduction targets in Nigeria. However, the decentralised nature of iRES make them important for delivering an equitable power system (one that distributes investment and jobs fairly). Additionally, it was found that coal power could play a role in a Paris-compliant electricity system up to 2050. Finally, this work investigated the implications of common green policies—renewable energy subsidies and carbon pricing—in deterring fossil fuel use in Nigeria and found them to be limited in their effectiveness. From the resilience of fossil fuel generation, particularly natural gas, in all the scenarios investigated, the needed expansion of Nigeria's natural gas production and transmission infrastructure was quantified.

Chapter 6

Conclusions

The 2015 Paris Agreement was a watershed moment for climate diplomacy, with all countries agreeing to work together to limit average temperature rise to “well below 2°C” above pre-industrial levels by the end of the century. This thesis was built on the premise that power system decarbonisation is critical to delivering the Paris accord because of the falling costs of low-carbon electricity that makes the electrification of energy end-use the least-cost decarbonisation pathway. The absence of national-level assessments of the implications of climate change mitigation targets on optimal power system design further motivated this. As countries at different stages of development face myriad challenges in addressing climate change, this thesis sought to assess the implications of the Paris Agreement on power sector transitions within developed and developing country contexts using the United Kingdom and Nigeria as case studies. Several findings of the work challenge mainstream opinion of optimal decarbonisation pathways; they are discussed below.

6.1 Key conclusions

The value of carbon dioxide removal

Carbon dioxide removal technologies are often viewed as too costly for climate change mitigation. However, this thesis finds that even at the upper-bound cost estimates of first-of-a-kind CDR (direct air capture costs), CDR deployment can reduce the cost of achieving a zero-carbon system. The availability of BECCS and DACCS technologies can yield cost reductions of 37-48%. The value of CDR derives from their ability to offset CO₂ emissions from cheaper thermal power plants. By doing so, CDR enable the latter to continue to operate in a carbon-constrained system and generate additional revenues than would have otherwise been possible owing to low capacity factors to minimise system emissions. These additional revenues could be up to £460/tCO₂ removed. Even in the Nigerian context, where CCS costs are significantly higher, it was shown that BECCS is deployed and complements baseload low-carbon generators to deliver

low system costs. Incentivising the demonstration and deployment of these technologies so that they can be commercially-viable when they are necessary is critical. Additionally, the enabling infrastructure needed such as CO₂ pipelines and geological reservoirs must be developed.

The marginal value of variable renewable energy sources for NDCs

For both countries, it was shown that lower-carbon (including natural gas-fired plants), high-availability and dispatchable power generation technologies dominate cost-optimal systems despite the aggressive reductions in the costs of solar and wind power assumed. Such systems are inherently centralised and require extensive power transmission and distribution infrastructure to ensure demand is met. From now until 2050, limited expansion of iRES capacity was observed and afterwards, baseload low- or negative-carbon generators were preferred for deployment. Therefore, the current policies of these countries that aim to make iRES cheaper and enable the commercial viability of mini-grid and off-grid technologies²⁸⁹ appear inefficient. Instead, subsidies should be channelled to CCS and CDR technologies to facilitate their development.

The importance of carbon offsetting

Existing carbon pricing mechanisms penalise GHG emissions via a tax or a ‘cap and trade’ system that allows for the trading of emissions permits. However, they do not remunerate CDR services. Also, whilst voluntary offset markets exist, the traded volumes and prices remain very low and permits are often purchased by private organisations seeking to minimise the carbon footprint of their operations³¹³. It was found that adapting carbon pricing mechanisms to penalise emissions as well as credit CDR could reduce the carbon price—and thus electricity costs—needed to deliver deep decarbonisation. Two alternative mechanisms were also proposed: a negative emissions credit where direct payments are made to CDR providers and a quota system that mandates polluters to purchase CDR credits. Both prove costlier than the adaptation of carbon pricing mechanisms.

The UK has a significant emissions reduction burden because of its historical emissions. Consequently, it requires relatively costly CDR to deliver a net-zero economy (which necessitates negative emissions). The availability of natural gas in developing countries such as Nigeria allows for a relatively low-carbon power systems development at low-cost. Thus, their projected emissions could be well-below their carbon budget under their NDCs. This presents a opportunity for collaboration. The cost of offsets are significantly lower than incentives needed for CDR. Through the formalisation and expansion of offset market mechanisms, the UK could finance offset projects in Nigeria to obtain lower-cost emissions reductions whilst providing needed financing for improving energy access.

6.2 Further work

This thesis extended existing power systems modelling tools to include carbon dioxide removal technologies and assess the implications of climate change mitigation on power sector decarbonisation pathways. It also proposed a new metric to assess the relative value of technologies for decarbonisation and incentive mechanisms to facilitate the deployment of necessary technologies that are currently immature in both the UK and Nigeria. Ways in which the work presented in this thesis could be extended to add further value are outlined below.

6.2.1 Theoretical

There is considerable uncertainty in how electricity demand profiles will change with increased electrification of the energy end-use. In underdeveloped power systems such as Nigeria, the profile is difficult to determine as considerable demand is suppressed. A possible extension of this thesis will be a new model that investigates the behavioural changes that the aforementioned will yield and how they will influence demand profiles.

6.2.2 Methodological

The ESO modelling framework used in this work only considers power generation and transmission planning. The model can be extended to allow for more holistic evaluations of electricity system transitions by:

- Coupling of the ESO model with economic impact models such as the NREL Jobs and Economic Development Impact (JEDI) models³¹⁶ to determine in more detail the economic implications of decarbonisation pathways. This is especially important in countries such as Nigeria where the Sustainable Development Goals are the main objectives of policy.
- Extending the model formulation to include the optimisation of natural gas pipeline infrastructure. Advanced economies that are well-integrated into international markets often have developed oil and gas (O&G) pipeline infrastructure. In contrast, developing countries will need to develop their O&G production, processing and transport infrastructure to utilise the resources for power generation. These will require significant investment and should be included in the optimisation.
- Developing a multi-objective optimisation that considers other objectives in power system planning decisions *e.g.* electricity prices, job creation and distribution, pollution control *etc.* Weighting factors can be used to emphasise the relevant objective. This also allows for the comparison of the effects of different objectives on power system design.

6.2.3 Applications

Several further studies could be completed if the above additions to the modelling framework are made. They are described below.

- Investigate the different optimisation objectives (job creation, low energy costs) on the optimal system design in the UK and Nigeria. Quantify the relative value of power technologies for sustainable development in those countries.
- Assess the implications of alternative economic development pathways (manufacturing-, agriculture- or extractives-driven growth) on the type of power system needed in Nigeria.
- Determine the effects of different demand profiles on power system design and operation in both countries.

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Appendix A

Data inputs for the Nigerian electricity system

A.1 Current installed power generation capacity

Table A.1 lists all the power stations that have ever been built in Nigeria, their nameplate capacity, efficiency and their current generation capacity. Many of the power plants produce significantly less power than their nameplate capacity due to the outage of generation units resulting from a lack of maintenance, transmission line constraints and, in the case of the hydroelectric power stations, seasonally-low water levels.

A.2 Power transmission network

The figure below illustrates the current Nigerian power transmission network.

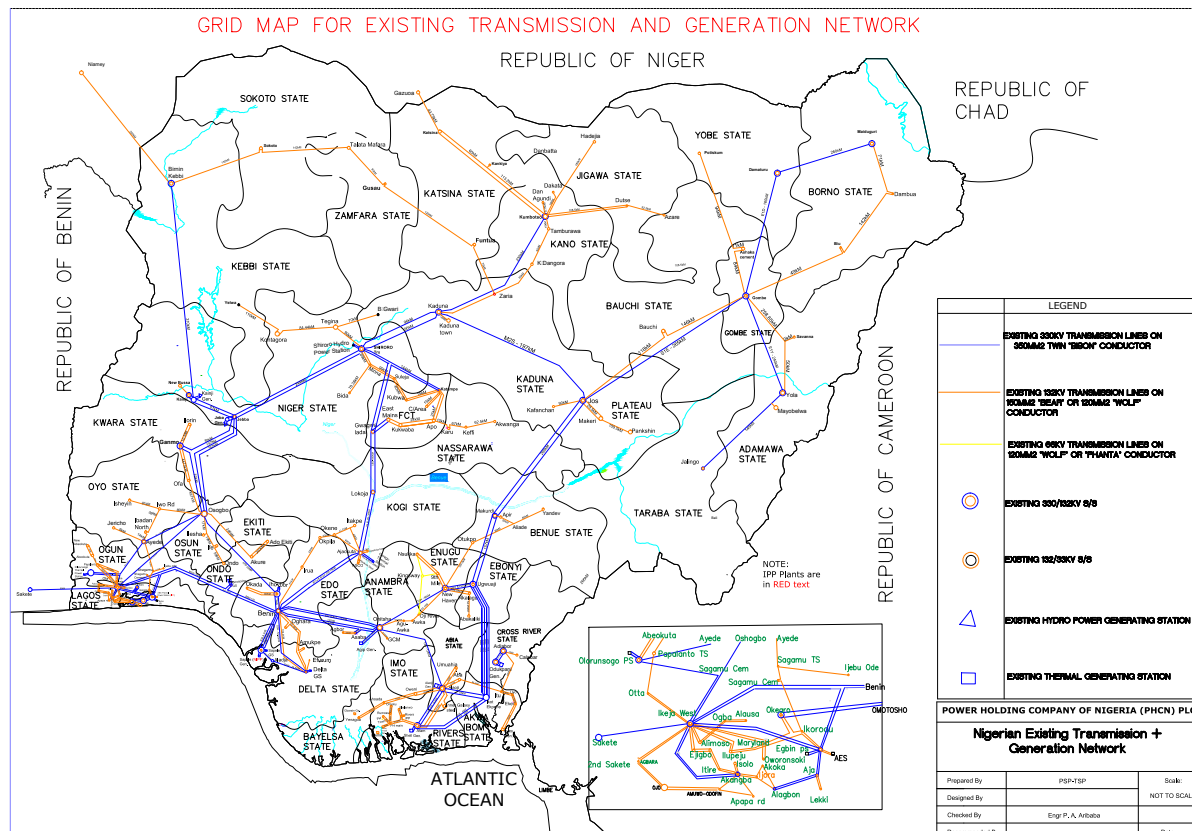


Fig. A.1 Location of existing transmission lines and power stations in Nigeria³¹⁷

A.3 Hydro potential in Nigeria

The spatial and temporal variation in the capacity factors of wind, solar and hydro power were considered in the ESONE model. Hydro availability was calculated based on the daily generation profiles of the three operational hydroelectric power stations in the country: Kainji, Shiroro and Jebba dams, all located in Niger state. Fig. 2.7 illustrates their seasonal variations in power output in 2018. The availability factor was calculated by daily peak generation for the year by the daily generation. Hourly availability of wind and solar were obtained from *Renewables ninja*, a tool which uses weather data from global reanalysis models and satellite observations to simulate the output of wind and solar power plants^{96,105,180–182}. Nigeria is made up of 36 states and the Federal Capital Territory. These are further subdivided into 774 local government areas (LGAs). Owing to the diverse geography within states and thus varying weather data, the hourly wind and solar availability was obtained for the 774 LGAs in 2018 to ensure high-resolution data. For each state, the LGAs were ranked according to mean availability (highest to lowest).

The average availability of the top tertile of state was used to represent the availability profile for the state.

Table A.2 List of hydro sites in Nigeria and their power generation potential^{291,318–321}

River or River Basin	Location/State (pre-1980)	State (present day)	Average Discharge (m ³ /s)	Maximum Head (m)	Installed Capacity (MW)	No. of Sites for Small Hydro
Gongola	Kiri	Adamawa	154	30.5	40	-
Benue	Yola	Adamawa	-	-	360	-
Niger	Onitsha	Anambra	6635	15.25	1050	-
Upper-Benue	Bauchi	Bauchi	-	-	42.6	20
Katsina Ala	Katsina Ala	Benue	740	49	260	-
Benue	Makurdi	Benue	3185	25.9	1060	-
Lower-Benue	Benue	Benue	-	-	69.2	19
Gongola	Kombo	Borno	128	37	35	-
Chad	Borno	Borno	-	-	20.8	29
Cross	Ikom	Cross-River	759	47	730	-
Cross	Atan	Cross-River	1704	10	180	-
Cross River	Cross River	Cross-River	-	-	28.1	18
Cross	Afikpo	Ebonyi	1621	15.5	180	-
Gurara	Izom	FCT-Abuja	55	30	10	-
Jama'are	Gwaram	Jigawa	75	50	30	-
Kaduna	Zurubu	Kaduna	55	40	20	-
Kongum	Kafanchan	Kaduna	2.2	100	5	-
Niger	Kaduna	Kaduna	-	-	59.2	19
Hadejia-Jama'are	Kano	Kano	-	-	46.2	28
Sokoto-Rima	Katsina	Katsina	-	-	8	11
Niger	Donko	Kebbi	1650	17	225	-
Niger	Lokoja	Kogi	6253	31.4	1950	-
Niger	Kwara	Kwara	-	-	38.8	12
Mada	Gudi	Nasarawa	41.5	100	40	-
Niger	Jebba	Niger	1767	27.1	500	-
Kaduna	Zungeru II	Niger	343	97.5	450	-
Kaduna	Zungeru I	Niger	343	100.6	500	-
Kaduna	Shiroro	Niger	294	95	300	-
Gurara	Gurara	Niger	-	-	300	-
Niger	Niger	Niger	-	-	117.6	30
Osse	Ifon	Ondo	80	50	30	-
Sanga	Kurra II	Plateau	5.5	430	25	-
Sanga	Kurra I	Plateau	5	290	15	-
Daffo	Richa II	Plateau	4	480	25	-
Mosari	Richa I	Plateau	6.5	400	35	-
Kurra	Mistakuku	Plateau	2	670	20	-
Lower-Benue	Plateau	Plateau	-	-	110.4	32
Sokoto-Rima	Sokoto	Sokoto	-	-	30.6	22
Kam	Karamti	Taraba	80	100	115	-
Taraba	Beli	Taraba	266	79.2	240	-
Taraba	Garin Dali	Taraba	323	36.6	135	-
Suntai	Sarkin Danko	Taraba	20	180	45	-
Donga	Gembu	Taraba	45	200	130	-
Katsina Ala	Kashimbila	Taraba	170	45	30	-
Danga	Mambilla	Taraba	-	-	3960	-
Upper-Benue	Gongola	Taraba	-	-	162.7	38

Appendix B

Mathematical formulation of the ESO modelling framework

B.1 k-Means clustering algorithm for data clustering

The R 3.6.0 code used to implement the k-means clustering algorithm described in Section 2.5 is detailed below. Temporal data with hourly resolution were clustered into 11 representative days (10 clusters and the peak day).

```
1 library(abind)
2 plot.new()
3
4 push = function(array, item) {
5   new_array = c(array, item)
6   eval.parent(substitute(array <- new_array))
7   which.closest = function(data, x) {
8     which.min(abs(data - x))
9   }
10  which.random = function(data) {
11    randomDay <- sample(1:nrow(data), 1)
12  }
13
14 finalDataFormat <- function(inputData, dataName) {
15   if (dataName == "hydro") {
16     result <- matrix(t(inputData), nrow=1, ncol=length(inputData))
17   } else if (dataName == "demand") {
18     A <- abind(lapply(split(seq_len(ncol(inputData)),
19       (seq_len(ncol(inputData))-1) %/% 24 + 1), function(x) inputData[,x]), along=3)
20     A_trans <- aperm(A, c(2,1,3))
21     tempResult <- matrix(A_trans, nrow=length(A_trans[1,1]), ncol=length(A_trans[,1]), byrow=TRUE)
22     result <- colSums(tempResult, na.rm=TRUE, dims=1)
23   } else {
24     A <- abind(lapply(split(seq_len(ncol(inputData)),
25       (seq_len(ncol(inputData))-1) %/% 24 + 1), function(x) inputData[,x]), along=3)
26     A_trans <- aperm(A, c(2,1,3))
27     result <- matrix(A_trans, nrow=length(A_trans[1,1]), ncol=length(A_trans[,1]), byrow=TRUE)
28     return(result)
29   }
30 }
31
32 nZones = 37
33
34 data_onwind <- read.csv("ESONE_Nigeria_raw_onwind_aggr.csv", header=TRUE)
35 data_offwind <- read.csv("ESONE_Nigeria_raw_offwind_aggr.csv", header=TRUE)
36 data_solar <- read.csv("ESONE_Nigeria_raw_solar_aggr.csv", header=TRUE)
37 data_demand <- read.csv("ESONE_Nigeria_raw_demand_2040_Scenario3.csv", header=TRUE)
38 data_hydro <- read.csv("ESONE_Nigeria_raw_hydro.csv", header=TRUE)
39
40 # normalise demand and hydro
41 max_demand = max(data_demand)
42 data_demand = data_demand/max_demand
43 max_hydro = max(data_hydro)
44 data_hydro = data_hydro/max_hydro
```

```

41 |
42 | # convert data from 37x8760 to 37x24x365 (for hydro: from 1x8760 to 365x24)
43 | arr_onwind <- abind(lapply(split(seq_len(ncol(data_onwind)),
44 | (seq_len(ncol(data_onwind))-1) %/% 24 + 1), function(x) data_onwind[,x ]), along = 3)
45 | arr_offwind <- abind(lapply(split(seq_len(ncol(data_offwind)),
46 | (seq_len(ncol(data_offwind))-1) %/% 24 + 1), function(x) data_offwind[,x ]), along = 3)
47 | arr_solar <- abind(lapply(split(seq_len(ncol(data_solar)),
48 | (seq_len(ncol(data_solar))-1) %/% 24 + 1), function(x) data_solar[,x ]), along = 3)
49 | arr_demand <- abind(lapply(split(seq_len(ncol(data_demand)),
50 | (seq_len(ncol(data_demand))-1) %/% 24 + 1), function(x) data_demand[,x ]), along = 3)
51 | arr_hydro <- matrix(data_hydro, ncol=24, byrow=TRUE)
52 |
53 | data_names <- c("onwind", "offwind", "solar", "demand")
54 |
55 | # Create an array with 37x24x365x4 dimensions (zones, hours, days, data set)
56 | arr_all <- abind(arr_onwind, arr_offwind, arr_solar, arr_demand, new.names = data_names, along=4)
57 | arr_all2 <- aperm(arr_all, c(2,1,4,3))
58 | arr_all3 <- matrix(arr_all2, prod(dim(arr_all2)[1:3]), dim(arr_all2)[4])
59 | final_arr <- aperm(arr_all3, c(2,1))
60 | final_arr <- abind(final_arr, arr_hydro, along=2)
61 |
62 | demand_perHr = colSums(data_demand, na.rm=TRUE, dims=1)
63 | demand_perDay = matrix(demand_perHr, ncol=24, byrow=TRUE)
64 |
65 | # find peak demand day and store data
66 | peakInd <- arrayInd(which.max(demand_perDay), dim(demand_perDay))
67 | peak_demand_perDay = demand_perDay[peakInd[1],]
68 | peak_final_arr <- final_arr[peakInd[1],]
69 |
70 | peak = list()
71 | peak$onwind = peak_final_arr[1:888]
72 | peak$offwind = peak_final_arr[889:1776]
73 | peak$solar = peak_final_arr[1777:2664]
74 | peak$demand = peak_final_arr[2665:3552]
75 | peak$hydro = peak_final_arr[3553:3576]
76 |
77 | final_arr <- final_arr[-peakInd[1],]
78 |
79 | ##### Calculate clusters #####
80 | nClusters = 10
81 | nHours = nClusters * 24
82 | set.seed(42)
83 | clusters = kmeans(final_arr, nClusters)
84 | clusterCenters = clusters$centers
85 |
86 | centroids = list()
87 | centroids$onwind = clusterCenters[,1:888] #24*37
88 | centroids$offwind = clusterCenters[,889:1776] # 888 + 24x37
89 | centroids$solar = clusterCenters[,1777:2664] # 1776 + 24x37
90 | centroids$demand = clusterCenters[,2665:3552] # 2664 + 24x37
91 | centroids$hydro = clusterCenters[,3553:3576] # 3552 + 24
92 |
93 | ##### Functions for Clusters #####
94 | get_cluster <- function(clustID){
95 | w = (clusters$cluster == clustID)
96 | days = final_arr[w, ]
97 | nDays = nrow(days)
98 | daily = list()
99 |
100 | daily$onwind = days[,1:888] # 24*37
101 | daily$offwind = days[,889:1776] # 888 + 24x37
102 | daily$solar = days[,1777:2664] # 1776 + 24x37
103 | daily$demand = days[,2665:3552] # 2664 + 24x37
104 | daily$hydro = days[,3553:3576] # 3552 + 24
105 | daily$clustID = clustID
106 | return(list(daily, nDays)) }
107 |
108 | get_cluster_item <- function(daily, item){
109 | clustID = daily$clustID
110 | centroid = centroids[[item]][clustID,]
111 | days = daily[[item]]
112 | return(list(days, centroid)) }
113 |
114 | build_profile = function(item, clustID, method) {
115 | output1 <- get_cluster(clustID)
116 | daily <- output1[[1]]
117 | nDays <- output1[[2]]
118 | output2 <- get_cluster_item(daily, item)
119 | days <- output2[[1]]
120 | centroid <- output2[[2]]

```

```

121 |
122 | if (method == 'specific_day') {
123 |   centroid_mean = mean(centroid)
124 |   daily_means = NULL
125 |   for (d in 1:nDays) {
126 |     dm = mean(days[d, ])
127 |     push(daily_means, dm) }
128 |   chosenDay = which.closest(daily_means, centroid_mean)
129 |   return(days[chosenDay, ]) } }
130 |
131 | build_all_clusters = function(method){
132 |   profiles = centroids
133 |   if (method != 'centroids'){
134 |     items = c('onwind', 'offwind', 'solar', 'demand', 'hydro')
135 |
136 |     for (i in items){
137 |       for (c in 1:nClusters){
138 |         profiles[[i]][c,] = build_profile(i, c, method) } }
139 |       return(profiles) }
140 |
141 | ##### Rebuild profiles #####
142 | profiles = build_all_clusters('specific_day')
143 |
144 | profiles$onwind = abind(profiles$onwind, matrix(peak$onwind, nrow=1), along=1)
145 | profiles$offwind = abind(profiles$offwind, matrix(peak$offwind, nrow=1), along=1)
146 | profiles$solar = abind(profiles$solar, matrix(peak$solar, nrow=1), along=1)
147 | profiles$demand = abind(profiles$demand, matrix(peak$demand, nrow=1), along=1)
148 | profiles$hydro = abind(profiles$hydro, matrix(peak$hydro, nrow=1), along=1)
149 |
150 | profiles$demand = profiles$demand*max_demand
151 | profiles$hydro = profiles$hydro*max_hydro
152 |
153 | ##### Format data output #####
154 | finalOutput = list()
155 |
156 | finalOutput$onwind <- finalDataFormat(profiles$onwind, "onwind")
157 | finalOutput$offwind <- finalDataFormat(profiles$offwind, "offwind")
158 | finalOutput$solar <- finalDataFormat(profiles$solar, "solar")
159 | finalOutput$demand <- finalDataFormat(profiles$demand, "demand")
160 | finalOutput$hydro <- finalDataFormat(profiles$hydro, "hydro")
161 |
162 | weightFactors = matrix("", nrow=nClusters, ncol=(24*(nClusters+1)))
163 | weightFactors[,1] = clusters$size
164 | rownames(weightFactors) <- rownames(weightFactors, do.NULL=FALSE, prefix="cluster")
165 |
166 | finalOutput$weights <- weightFactors
167 |
168 | write.csv(abind(finalOutput, along=1), "ESONE_Nigeria_Input_2040_Scenario3_Clustered.csv", row.names=TRUE)

```

B.2 GAMS code for ESO-XEL model formulation

The GAMS 25.0.3 code for the set definition, constraint equations and solver options in the ESO-XEL Nigeria model discussed in Chapter 2 are detailed below.

```

1 SETS
2   t      time steps for short-term operation (hours)
3   a      time steps for capacity expansion planning (years)
4   l      line segments in linearisation
5   h      line segments in linearisation of waste heat availability
6   c      cluster set
7   i      technologies available to the system
8   ig(i)  power generation technologies
9   ic(ig)  conventional power generation technologies
10  ir(ig)  intermittent renewable energy technologies
11  is(i)   energy storage technologies
12  nets(i) negative emissions technologies ;
13
14 # Define alias sets for mode transition constraints
15 alias(a, a_)
16 alias(t, t_)
17
18 PARAMETERS
19 # System-wide parameters
20 PlanningPeriod      planning period time step width
21 HoursInDay          length of annual scheduling horizon
22 HoursInYear         number of hours in one year
23 WeightingFactor(c) weighting factor for clustered hourly data
24 WFA(i, a)           weightign factor to compensate for end of horizon effects
25 SystemElectricityDemand(c, t, a) system electricity demand at time t in year a of cluster c
26 TotalSystemDemand(a) total electricity demand in year a
27 PeakLoad(a)         peak load in year a
28 UnmetDemandLevel    maximum proportion of demand that is unmet
29 EYdemand(c, t, a)   electricity demand from electric vehicles at time t in year a of cluster c
30 CapacityMargin      capacity margin for the electricity system
31 ReserveMargin       reserve margin for the electricity system
32 WindReserve         added reserve buffer due to intermittent renewable generation
33 SystemInertia        system inertia demand at time t
34 NetworkLosses        losses during transmission and distribution
35 ValueOfLostLoad      cost of unmet electricity demand
36 SystemEmissionsTarget(a) annual system carbon emissions target in year a
37 NegativeEmissionsTarget cumulative negative carbon emissions by the end of year a
38 DiscountRate         discount rate for future cash flows
39 DiscountFactor(a)    discount factor for year a
40 CarbonPrice(a)       carbon price in year a
41 ImportElectricityPrice(c, t) cost of imported electricity at time t in cluster c
42 # Technology-specific parameters
43 Maturity(i, a)       maturity parameter (whether technology can be built) in year a

```

44	InitialDesign(i)	number of units of technology i installed initially (in year 1)	# units
45	MaximumDeployment(i)	maximum number of units of technology i that can be deployed in year a	# units
46	UnitCapacity(i)	capacity per unit of technology i	MW
47	BuildRate(i)	build rate of technology i	# units
48	InitialLifetime(i)	lifetime of initial capacity stack of technology i	years
49	Lifetime(i)	lifetime of newly-built unit of technology i	years
50	Efficiency(i)	efficiency of technology i	%
51	MinimumPower(i)	minimum power output of technology i	%-MW
52	MaximumPower(i)	maximum power output of technology i	%-MW
53	MaximumCapacity(i)	maximum capacity provision of technology i	%-MW
54	InertiaPotential(i)	inertia potential of technology i	s
55	ReservePotential(i)	reserve potential of technology i (ability to provide reserve)	0 or 1
56	EmissionsRate(i)	carbon emissions rate of technology i	tCO2 per MWh
57	CAPEX(i)	capital costs of technology i	£ per # unit
58	OPEX(i,a)	operational costs of technology i in year a	£ per h or MWh
59	FixedOPEX(i)	no load operational costs of technology i	£ per h
60	OPEXFix(i,a)	fixed operational costs including insurance of technology i	£ per unit per year
61	StartUpOPEX(i)	starting up costs of technology i	£ per MWh
62	HeatDemand(nets)	natural gas demand for technology nets	MWh NG per tCO2 removed
63	HeatOPEX(nets,a)	gas and non-energy O&M costs for technology nets per tCO2 negative emissions	£ per tCO2 removed ;
64			
65	VARIABLES		
66	TotalSystemCost	total system cost (capital and operating costs)	£
67	TotalSystemEmissions(a)	total system emissions	tCO2
68	Emissions(ig,a,c,t)	emissions caused by technology ig at time t in year a of cluster c	tCO2
69	NegativeEmissions(nets,a,c,t)	negative emissions from technology nets at time t in year a of cluster c	tCO2
70	AnnualOPEX(a)	total annual operating costs for all technologies	£ ;
71			
72	INTEGER VARIABLES		
73	InstalledUnits(i,a)	number of units of technology i installed in year a	# units
74	NewBuildUnits(i,a)	number of newly built units of technology i in year a	# units ;
75			
76	POSITIVE VARIABLES		
77	* Unit variables for the technologies operating		
78	GeneratingUnitsOperating(ig,a,c,t)	number of units of technology ig operating at time t in year a of cluster c	# units
79	StorageUnitsOperating(is,a,c,t)	number of units of storage technology is operating at time t in year a of cluster c	# units
80	NETsUnitsOperating(nets,a,c,t)	number of units of neg emissions technology nets operating at time t in year a of cluster c	# units
81	UnitsStartingUp(ig,a,c,t)	number of units of technology ig starting up at time t in year a of cluster c	#units
82	UnitsShuttingDown(ig,a,c,t)	number of units of technology ig shutting down at time t in year a of cluster c	#units ;
83			
84	NewBuildUnits.lo(i,a) = 0;		
85	NewBuildUnits.up(i,a) = InitialDesign(i) + card(a)*BuildRate(i)*PlanningPeriod;		
86			
87	InstalledUnits.lo(i,a) = 0;		
88	InstalledUnits.up(i,a) = InitialDesign(i) + card(a)*BuildRate(i)*PlanningPeriod;		
89			
90	GeneratingUnitsOperating.lo(ig,a,c,t) = 0;		
91	GeneratingUnitsOperating.up(ig,a,c,t) = InitialDesign(ig) + card(a)*BuildRate(ig)*PlanningPeriod;		
92			
93	StorageUnitsOperating.lo(is,a,c,t) = 0;		
94	StorageUnitsOperating.up(is,a,c,t) = InitialDesign(is) + card(a)*BuildRate(is)*PlanningPeriod;		

```

95 NETsUnitsOperating.lo(nets,a,c,t) = 0;
96 NETsUnitsOperating.up(nets,a,c,t) = InitialDesign(nets) + card(a)*BuildRate(nets)*PlanningPeriod;
97
98
99 POSITIVE VARIABLES
100 * Power variables
101 PowerOutput(ig,a,c,t) MMh
102 ReserveProvided(ig,a,c,t) MMh
103 PowerToDemand(ig,a,c,t) MMh
104 PowerToStorage(ig,a,c,t) MMh
105 PowerToNETs(ig,a,c,t) MMh
106 PowerToGas(ig,a,c,t) MMh
107 PowerToStorageReceived(is,a,c,t) MMh
108 StateOfCharge(is,a,c,t) MMh
109 StorageToDemand(is,a,c,t) MMh
110 StorageToReserve(is,a,c,t) MMh
111 StorageToNETs(is,a,c,t) MW
112 StorageToGas(is,a,c,t) MW
113 PowerReceivedByNETs(nets,a,c,t) MW
114 StorageReceivedByNETs(nets,a,c,t) MW
115 HeatToNETs(nets,a,c,t) MW
116 UnmetDemand(a,c,t) MMh
117
118 # Technology-specific piecewise linear function variables
119 CumulativeCapacity(i,a,l) # units
120 CumulativeCAPEX(i,a) £
121 CumulativeBiomassOutput(a,l) MMh
122 CumulativeAdditionalBiomassOPEX(a) £
123 PelletPriceIncrease(a) £ per MWh;
124
125 BINARY VARIABLES
126 # Binary variables for piecewise linear functions
127 Alpha(i,a,l) -
128 Beta(a,l) -;
129
130 EQUATIONS
131 # System design constraints
132 InitialCapacityInstalled(i,a)$ord(a) eq 1).. InstalledUnits(i,a) = InitialDesign(i);
133 MaximumBuildRate(i,a)$ord(a) gt 1).. NewBuildUnits(i,a) = BuildRate(i,a)*Maturity(i,a)*PlanningPeriod;
134 MaximumCapacityInstalled(i,a).. InstalledUnits(i,a) = MaximumDeployment(i);
135 InitialCapacityLifetime(i,a)$ord(a) le InitialLifetime(i,a)$ord(a) le InitialLifetime(i,a) - NewBuildUnits(i,a-l) - NewBuildUnits(i,a-1) - NewBuildUnits(i,a)
136 + NewBuildUnits(i,a);
137 NewCapacityLifetime(i,a)$InitialLifetime(i)/PlanningPeriod + 1 lt ord(a) and ord(a) le Lifetime(i)/PlanningPeriod + 1).. InstalledUnits(i,a) = InstalledUnits(i,a-l) + NewBuildUnits(i,a);
138 RemainingCapacityLifetime(i,a)$ord(a) gt Lifetime(i)/PlanningPeriod + 1).. InstalledUnits(i,a-l) - NewBuildUnits(i,a-l) - NewBuildUnits(i,a-1) - NewBuildUnits(i,a)
139 + NewBuildUnits(i,a);
140
141 SystemDemandMet(a,c,t).. sum(ig, PowerToDemand(ig,a,c,t)) + sum(is, StorageToDemand(is,a,c,t)) = e= SystemElectricityDemand(c,t,a)*(1 + NetworkLosses) - UnmetDemand(a,c,t);
142 PeakLoadMet(a).. sum(i, InstalledUnits(i,a)*UnitCapacity(i)*MaximumCapacity(i)) = g= PeakLoad(a)*(1 + ReserveMargin);
143 DemandNotMet(a).. sum((c,t), UnmetDemand(a,c,t)*WeightingFactor(c)) = l= UnmetDemandLevel*sum((c,t), SystemElectricityDemand(c,t,a)*WeightingFactor(c));
144 ReserveMet(a,c,t).. sum(ig, ReserveProvided(ig,a,c,t)*ReservePotential(ig)) + sum(is, StorageToReserve(is,a,c,t)*ReservePotential(is)) = g= SystemElectricityDemand(c,t,a)*ReserveMargin
145 + sum(ir, PowerToDemand(ir,a,c,t)*WindReserve);

```

```

146 SystemInertiaMet(a,c,t)..      sum(ig, GeneratingUnitsOperating(ig,a,c,t)*UnitCapacity(ig) + sum(is, StorageUnitsOperating(is,a,c,t)*UnitCapacity(is)*InertiaPotential(is))
147
148 CCArTargetMet(a)..            sum((ic,c,t), Emissions(ic,a,c,t)*WeightingFactor(c)) - sum((nets,c,t), NegativeEmissions(nets,a,c,t)*WeightingFactor(c)) =l= SystemInertia;
149
149 ParisTargetMet..              sum((ic,a,c,t), Emissions(ic,a,c,t)*WeightingFactor(c)) + sum(a, sum((ic,c,t), Emissions(ic,a,c,t)*WeightingFactor(c))
150                                + sum((ic,c,t), Emissions(ic,a-l,c,t)*WeightingFactor(c))*2) - sum((nets,a,c,t), NegativeEmissions(nets,a,c,t)*WeightingFactor(c))
151                                - sum(a, sum((nets,c,t), NegativeEmissions(nets,a,c,t)*WeightingFactor(c)) + sum((nets,c,t), NegativeEmissions(nets,a-l,c,t)*WeightingFactor(c))*2)
152                                =l= NegativeEmissionsTarget;
153
154 * Power generating technology (ig) constraints
155 GeneratingUnitsOperational(ig,a,c,t).. GeneratingUnitsOperating(ig,a,c,t) =l= InstalledUnits(ig,a);
156
156 PowerGenerationBalance(ig,a,c,t).. PowerOutput(ig,a,c,t) =e= PowerToDemand(ig,a,c,t) + PowerToStorage(ig,a,c,t) + PowerToNETs(ig,a,c,t) + PowerToGas(ig,a,c,t);
157
157 MinimumPowerGeneration(ig,a,c,t).. PowerOutput(ic,a,c,t) =g= GeneratingUnitsOperating(ic,a,c,t)*UnitCapacity(ic)*MinimumPower(ic);
158
158 MaximumPowerGeneration(ig,a,c,t).. PowerOutput(ig,a,c,t) + ReserveProvided(ig,a,c,t) =l= GeneratingUnitsOperating(ig,a,c,t)*UnitCapacity(ig)*MaximumPower(ig);
159
159 GenerationEmissions(ig,a,c,t).. Emissions(ig,a,c,t) =e= PowerOutput(ig,a,c,t)*EmissionsRate(ig);
160
160 * UnitsStartingUpBalance(ig,a,c,t) =e= (PowerOutput(ig,a,c,t) + ReserveProvided(ig,a,c,t))*EmissionsRate(ig);
161
161 UnitsStartingUp(ig,a,c,t) gt 1).. UnitsStartingUp(ic,a,c,t) =g= GeneratingUnitsOperating(ic,a,c,t) - GeneratingUnitsOperating(ic,a,c,t-1);
162
162 UnitsShuttingDownBalance(ig,a,c,t)$(ord(t) gt 1).. UnitsShuttingDown(ic,a,c,t) =g= GeneratingUnitsOperating(ic,a,c,t-1) - GeneratingUnitsOperating(ic,a,c,t);
163
163 StartUpTime(ig,a,c,t,t_u)$(ord(t) gt 1 and ord(t_u) le RampUpTime(ic).. UnitsStartingUp(ig,a,c,t) =l= GeneratingUnitsOperating(ig,a,c,t + (ord(t_u)-1));
164
164 ShutDownTime(ig,a,c,t,t_u)$(ord(t) gt 1 and ord(t_u) le RampDownTime(ic).. UnitsShuttingDown(ig,a,c,t) =l= InstalledUnits(ic,a) - GeneratingUnitsOperating(ig,a,c,t + (ord(t_u)-1));
165
165 NoPowerToGas(ig,a,c,t)..      PowerToGas(ig,a,c,t) =e= 0;
166
167 * Intermittent renewable energy technology (ir) constraints
168
168 IRESMinimumAvailability (ir,a,c,t)$(ord(ir) le 3).. PowerOutput(ir,a,c,t) =g= GeneratingUnitsOperating(ir,a,c,t)*UnitCapacity(ir)*MinimumPower(ir)*AvailabilityFactor(ir,c,t);
169
169 IRESMaximumAvailability (ir,a,c,t)$(ord(ir) le 3).. PowerOutput(ir,a,c,t) + ReserveProvided(ir,a,c,t) =l= GeneratingUnitsOperating(ir,a,c,t)*UnitCapacity(ir)*AvailabilityFactor(ir,c,t);
170
170 NoInterconnectorCharge(ir,a,c,t)$(ord(ir) eq 4).. PowerToStorage(ir,a,c,t) =e= 0;
171
172 * Energy storage technology (is) constraints
173
173 StorageUnitsUnitsOperational(is,a,c,t)..
174
174 MinimumEnergyStorage(is,a,c,t).. StorageUnitsOperating(is,a,c,t) + StorageToReserve(is,a,c,t) + StorageToNETs(is,a,c,t) + StorageToGas(is,a,c,t)
175                                =g= StorageUnitsOperating(is,a,c,t)*UnitCapacity(is)*MinimumPower(is);
176
176 MaximumEnergyStorage(is,a,c,t).. StorageToDemand(is,a,c,t) + StorageToReserve(is,a,c,t) + StorageToNETs(is,a,c,t) + StorageToGas(is,a,c,t)
177                                =l= StorageUnitsOperating(is,a,c,t)*UnitCapacity(is);
178
178 EnergyFlowBalance(is,a,c,t).. StorageToDemand(is,a,c,t) + StorageToReserve(is,a,c,t) + StorageToNETs(is,a,c,t) + StorageToGas(is,a,c,t) =l= StateOfCharge(is,a,c,t);
179
179 InitialChargeLevel(is,a,c,t)$(ord(t) eq 1).. StateOfCharge(is,a,c,t) =e= UnitCapacity(is)*InitialStateOfCharge(is)*StorageDuration(is);
180
180 MinimumStorageLevel(is,a,c,t)$(ord(t) gt StorageDuration(is).. StateOfCharge(is,a,c,t) =g= StorageUnitsOperating(is,a,c,t)*UnitCapacity(is)*MinimumStateOfCharge(is)*StorageDuration(is);
181
181 MaximumStorageLevel(is,a,c,t).. StateOfCharge(is,a,c,t) =l= StorageUnitsOperating(is,a,c,t)*UnitCapacity(is)*MaximumStateOfCharge(is)*StorageDuration(is);
182
182 GenerationToStorageBalance(a,c,t).. sum(ig, PowerToStorage(ig,a,c,t)) =e= sum(is, PowerToStorageReceived(is,a,c,t));
183
183 MaximumStorageCharging(is,a,c,t).. PowerToStorageReceived(is,a,c,t) =l= StorageUnitsOperating(is,a,c,t)*UnitCapacity(is);
184
184 StoragePowerBalance(is,a,c,t,t_u)$(ord(t) gt 1 and ord(t_u) ge StorageDuration(is).. StateOfCharge(is,a,c,t) =e= StateOfCharge(is,a,c,t-1) - StorageToDemand(is,a,c,t)
185                                - StorageToNETs(is,a,c,t) - StorageToGas(is,a,c,t)
186
186 + PowerToStorageReceived(is,a,c,t)*StorageEfficiency(is);
187
187 NoStorageToGas(is,a,c,t)..      StorageToGas(is,a,c,t) =e= 0;
188
189 * Negative emissions technology (nets) constraints
189
189 NETsUnitsUnitsOperational(nets,a,c,t).. NETsUnitsOperating(nets,a,c,t) =l= InstalledUnits(nets,a);
190
190 NegativeEmissionsProvided(nets,a,c,t).. NegativeEmissions(nets,a,c,t) =e= (PowerReceivedByNETs(nets,a,c,t) + StorageReceivedByNETs(nets,a,c,t))*abs(EmissionsRate(nets));
191
191 MinimumNETsOperation(nets,a,c,t).. PowerReceivedByNETs(nets,a,c,t) + StorageReceivedByNETs(nets,a,c,t) =g= NETsUnitsOperating(nets,a,c,t)*abs(UnitCapacity(nets))*MinimumPower(nets);
192
192 MaximumNETsOperation(nets,a,c,t).. PowerReceivedByNETs(nets,a,c,t) + StorageReceivedByNETs(nets,a,c,t) =l= NETsUnitsOperating(nets,a,c,t)*abs(UnitCapacity(nets))*MaximumPower(nets);
193
193 TotalPowerToNETs(a,c,t)..      sum(ig, PowerToNETs(ig,a,c,t)) =e= sum(nets, PowerReceivedByNETs(nets,a,c,t));
194
194 TotalStorageToNETs(a,c,t)..      sum(is, StorageToNETs(is,a,c,t)) =e= sum(nets, StorageReceivedByNETs(nets,a,c,t));
195
196

```

```

197 * Piecewise linear function constraints
198 SingleSegment(i,a)..
199   LowerSegment(i,a,1)..
200   CumulativeCapacity(i,a,1) =g= XLo(i,1)*Alpha(i,a,1);
201   UpperSegment(i,a,1)..
202   CumulativeCapacity(i,a,1) =g= XUp(i,1)*Alpha(i,a,1);
203   LowerSegment(i,a,1)..
204   CumulativeCapacity(i,a,1) =l= XLo(i,1)*Alpha(i,a,1);
205   UpperSegment(i,a,1)..
206   CumulativeCapacity(i,a,1) =l= XUp(i,1)*Alpha(i,a,1);
207   XValue(i,a)..
208   CumulativeCAPEX(i,a) =e= sum(l, YLo(i,1)*Alpha(i,a,1) + ((YUp(i,1)-YLo(i,1))/(XUp(i,1) - XLo(i,1))*Alpha(i,a,1)));
209   SingleSegment_BiomassOPEX(a)..
210   LowerSegment_BiomassOPEX(a,1)..
211   XValue_BiomassOPEX(a,1)..
212   CumulativeBiomassOutput(a,1) =g= XBLow(1)*Beta(a,1);
213   UpperSegment_BiomassOPEX(a,1)..
214   CumulativeBiomassOutput(a,1) =l= XBU(1)*Beta(a,1);
215   XValue_BiomassOPEX(a)..
216   CumulativeBiomassOutput(a,1) =l= XBU(1)*Beta(a,1);
217   CumulativeBiomassOutput(a,1) =g= XBLow(1)*Beta(a,1) + (YBU(1) - YBLow(1))/(XBU(1) - XBLow(1))*(CumulativeBiomassOutput(a,1) - XBLow(1)*Beta(a,1));
218   PelletPrice_Increase(a)..
219   NETsHeatDemand(nets,a,c,t)..
220   TotalSystemEmissions(a) =e= sum((ic,c,t), Emissions(ic,a,c,t)*WeightingFactor(c)) - sum((nets,c,t), NegativeEmissions(nets,a,c,t)*WeightingFactor(c));
221   OperatingCosts(a)..
222   AnnualOPEX(a) =e= sum((ig,c,t), UnitsStartingUp(ig,a,c,t)*StartUpOPEX(ig)*WeightingFactor(c)/DiscountFactor(a))
223   + sum((ig,c,t), GeneratingUnitsOperating(ig,a,c,t)*FixedOPEX(ig)*WeightingFactor(c)/DiscountFactor(a))
224   + sum((ig,c,t), PowerOutput(ig,a,c,t)*OPEX(ig,a)*WeightingFactor(c)/DiscountFactor(a))
225   + CumulativeAdditionalBiomassOPEX(a)/DiscountFactor(a)
226   + sum((c,t), (PowerToDemand("Interconnector",a,c,t)*ImportElectricityPrice(c,t)*WeightingFactor(c))/DiscountFactor(a))
227   + sum((is,c,t), (StorageToDemand(is,a,c,t) + StorageToNETs(is,a,c,t)*OPEX(is,a,c,t))*WeightingFactor(c)/DiscountFactor(a))
228   + sum((is,c,t), StorageUnitsOperating(is,a,c,t)*FixedOPEX(is,a,c,t)*WeightingFactor(c)/DiscountFactor(a))
229   + sum((nets,c,t), (PowerReceivedByNETs(nets,a,c,t) + StorageReceivedByNETs(nets,a,c,t))*WeightingFactor(c)*OPEX(nets,a)/DiscountFactor(a))
230   + sum((c,t), UnmetDemand(a,c,t)*ValueOfLostLoad*WeightingFactor(c)/DiscountFactor(a))
231   + sum(i, sum[a_$ord(a_) le ord(a) and ord(a_) ge (ord(a) - [Lifetime(i)/PlanningPeriod]), [NewBuildUnits(i,a_)]*OPEXFix(i,a_)]/DiscountFactor(a))
232   - sum(i $ (ord(a) ge (2 + [InitialLifetime(i)/PlanningPeriod]) and ord(a) le (1 + [Lifetime(i)/PlanningPeriod])), InitialDesign(i) * OPEXFix(i,"1")/DiscountFactor(a))
233   + sum((nets,c,t), NegativeEmissions(nets,a,c,t)*HeatOPEX(nets,a)*WeightingFactor(c)/DiscountFactor(a));
234
235 *Define model structure
236 Model UKESModel /a11/ ;
237
238 option solvelink = 0;
239 option iterLim = 1e9;
240 option resLim = 1e6;
241 option optCR = 0.03;
242 maxerror = 1e5;
243
244 UKESModel.optfile = 1;
245
246 Solve UKESModel minimising TotalSystemCost using mip;

```

B.3 GAMS code for ESONE model formulation

The GAMS 25.0.3 code for the set definition, constraint equations and solver options in the ESONE Nigeria model discussed in Chapter 2 are detailed below.

1	SETS			
2	t	time steps for short-term operation		
3	a	time steps for capacity expansion planning – each time step is 5 years		
4	aa(a)	dynamic set of a		
5	i	power technologies		
6	ig(i)	power generating technologies		
7	ic(ig)	conventional technologies		
8	ir(ig)	intermittent technologies		
9	io(ig)	off-grid generation technologies		
10	is(i)	energy storage technologies		
11	iz(i)	locationally constrained technologies		
12	inoz(i)	locationally unconstrained technologies		
13	k	set of all possible stay times		
14	l	line segment in linearisation		
15	c	cluster set		
16	z	zones		
17	Line(z,z)	zone connection lines		
18	NoLine(z,z)	no zone connection lines;		
19				
20	#	Define alias sets for mode transition constraints		
21	alias(a,a_)			
22	alias(t,t_)			
23	alias(z,z_.,z_..)			
24				
25	PARAMETERS			
26	#	System-wide parameters		
27	PlanningPeriod	planning period time step width	years	
28	HoursInDay	length of annual scheduling horizon	hours	
29	HoursInYear	number of hours in one year	hours	
30	TotalAnnualDemand(a)	total electricity demand in year a	MWh	
31	TotalHourlyDemand(c,t,a)	system electricity demand in year a at time t	MWh per h	
32	DemandWeightingFactor(z,a)	zonal weighting factor for demand	–	
33	ZonalHourlyDemand(c,t,z,a)	system electricity demand by zone	MWh per h	
34	ZonalPeakLoad(a,z)	peak load over time period T	MW	
35	SystemInertia	system inertia demand at time t	MW	
36	ReserveMargin	system reserve margin and capacity margin	%MW	
37	WindReserve	system reserve buffer for wind power gen	%MW wind	
38	AnnualEmissionsTarget(a)	system carbon emission target	tCO2 per year	
39	DiscountFactor(a)	discount factor for year a	–	
40	WeightingFactor(c)	weighting factor for clustered hourly data	%	
41	CAPEXWeightingFactor(i,a)	weight factor for capex and remaining lifetime	\$ per MWh	
42	ImportElectricityPrice(c,t)	import electricity price	\$ per MWh	
43	LostLoadValue	value of lost load		

[illegible]

95	ReserveProvided (ig,z,a,c,t)	reserve provided by technology ig in zone z at time t in year a of cluster c	MW
96	StateOfCharge (is,z,a,c,t)	state of charge or storage of technology is in zone z at the END of t	MWh
97	StorageToDemand (is,z,a,c,t)	stored energy from technology is to demand in zone z at time t in year a of cluster c	MWh
98	StorageToReserve (is,z,a,c,t)	stored energy from technology is in zone z as reserve capacity at time t in year a of cluster c	MW
99	StorageToExport (is,z,a,c,t)	stored energy exported from zone z	MWh
100	LoadSlack (z,a,c,t)	slack variable for lost load as feasibility measure	MWh
101	EmissionsSlack (z,a,c,t)	slack variable for carbon emissions	tCO2
102	# Transmission variables		
103	TransmissionLinesAvailable (z,z_,a)	number of transmission lines between z and z_ in year a	MW
104	TransmissionFlow (z,z_,a,c,t)	net flow from zone z to z_ at time period t arriving	MWh
105	TransmissionToDemand (z,a,c,t)	flow from outside to demand in zone z at time period t	MWh
106	TransmissionToStorage (z,a,c,t)	flow outside to storage in zone z at time period t	MWh
107	TransmissionToStorageTech (is,z,a,c,t)	flow outside to storage technology is in zone z at time period t	MWh
108	# Unit operation variables		
109	UnitsStartingUp (ig,z,a,c,t)	number of units of technology ig in zone z starting up at time t in year a of cluster c	# units
110	UnitsShuttingDown (ig,z,a,c,t)	number of units of technology ig in zone z shutting down at time t in year a of cluster c	# units
111	# Cost variables		
112	TotalAnnualOpEx (a)	total opex in year a	\$
113	GenerationUnitsOperating (ig,z,a,c,t)	number of units of technology ig in mode m in year a at time t	# units
114	StorageUnitsOperating (is,z,a,c,t)	number of units storage technologies is operating at time t	# units ;
115	INTEGER VARIABLES		
116	NewBuildUnits (i,z,a)	number of units new built of technology i in zone z year a	# units
117	InstalledUnits (i,z,a)	number of operational units of technology i in zone z in year a	# units
118	NewTransmissionLines (z,z_,a)	number of new build transmission lines between z and z_ in a	# units ;
119	VARIABLE		
120	TotalSystemCost	total system cost	\$
121	TotalConsumptionEmissions	total system emissions consumption based	tCO2
122	TotalProductionEmissions	total system emissions national production	tCO2
123	Emissions (i,z,a,c,t)	emission caused by technology i	tCO2 ;
124			
125	# Bounds for number of generating and transmission units built or operating		
126	NewBuildUnits.lo (i,z,a) = 0;		
127	NewBuildUnits.up (i,z,a) = MaximumDeployment(i);		
128	InstalledUnits.lo (i,z,a) = 0;		
129	InstalledUnits.up (i,z,a) = MaximumDeployment(i);		
130	NewTransmissionLines.lo (z,z_,a) = 0;		
131	NewTransmissionLines.up (z,z_,a) = InitialTransmissionCapacity (z,z_)/TransmissionUnitCapacity + card(a)*TransmissionBuildRate*PlanningPeriod;		
132	GenerationUnitsOperating.lo (ig,z,a,c,t) = 0;		
133	GenerationUnitsOperating.up (ig,z,a,c,t) = MaximumDeployment(ig);		
134	StorageUnitsOperating.lo (is,z,a,c,t) = 0;		
135	StorageUnitsOperating.up (is,z,a,c,t) = MaximumDeployment(is);		
136			
137	EQUATIONS		
138	# SYSTEM DESIGN CONSTRAINTS		
139	# (3) aafirst - sets number of units to initial values		
140	InitialCapacityInstalled (i,z,aa(a))\$(ord(a) eq aafirst)..	InstalledUnits (i,z,aa) = InitialDesign (i,z);	
141	# (4) - limits new units built every aa		
142	MaximumBuildRate (i,aa(a))\$(ord(a) gt 1)..	sum(z, NewBuildUnits (i,z,aa)) = l= BuildRate (i)*Maturity (i,aa)*PlanningPeriod;	
143	*can be omitted since MaximumBuildRate provides same bound on final planning period		
144	# (5) - limits total number of units of technology that isn't constrained per zone		
145	MaximumUnitsInstalled (inoz(i),aa(a))..	sum(z, InstalledUnits (inoz,z,aa)) = l= MaximumDeployment (inoz);	

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146 # (6) – limits total number of units of technology constrained per zone
147 MaxZonalUnits(iz,z,aa)=l= MaxZoneDeployment(iz,z);
148 # (7) – balance between old, new, and retiring units between a and a-1 while pre-horizon units are retiring
149 InitialCapacityLifetime(i,z,aa(a))$(ord(a) le InitialLifetime(i)/PlanningPeriod+1)..
150   InstalledUnits(i,z,a) =e= InstalledUnits(i,z,a-1) – NewBuildUnits(i,z,a –
151   (InitialLifetime(i)/PlanningPeriod)) + NewBuildUnits(i,z,aa);
152 # (8) – balance between old, new, and retiring units between a and a-1 while nothing is retiring
153 NewCapacityLifetime(i,z,aa(a))$(InitialLifetime(i)/PlanningPeriod+1) lt ord(a) le Lifetime(i)/PlanningPeriod+1)..
154   InstalledUnits(i,z,a) =e= InstalledUnits(i,z,a-1) – NewBuildUnits(i,z,a –
155   (InitialLifetime(i)/PlanningPeriod+1)) + NewBuildUnits(i,z,aa);
156 # (9) – balance between old, new, and retiring units between a and a-1 while newly built units are retiring
157 RemainingCapacityLifetime(i,z,aa(a))$(ord(a)>Lifetime(i)/PlanningPeriod+1)..
158   InstalledUnits(i,z,a) =e= InstalledUnits(i,z,a-1) – NewBuildUnits(i,z,a –
159   (InitialLifetime(i)/PlanningPeriod+1)) + NewBuildUnits(i,z,aa);
160 # (10) – bound on #units operating
161 GenerationUnitsOnline(ig,z,aa(a),c,t)..
162   # (11) – bound on #units operating
163   StorageUnitsOnline(is,z,aa(a),c,t)..
164   StorageUnitsOperating(is,z,aa,c,t) =l= InstalledUnits(is,z,aa);
165   GenerationUnitsOperating(ig,z,aa,c,t) =l= InstalledUnits(ig,z,aa);
166 # TRANSMISSION DESIGN CONSTRAINTS
167 # (12) afirst – sets initial transmission grid
168 InitialTransmissionGrid(z,z,aa(a))$(ord(a) eq afirst)..
169 # (13) – limits transmission expansion in first period
170 InitialTransmissionLifetime(z,z,aa(a))$(ord(a) eq 1)..
171 # (14) – limits transmission expansion
172 NewBuildTransmission(z,z,aa(a))$(ord(a) gt 1 and Line(z,z,aa) =l= TransmissionBuildRate*PlanningPeriod;
173 # (15) – balance old and new transmission units
174 TransmissionLifetime(z,z,aa(a))$(ord(a) gt 1 and Line(z,z,aa) =l= TransmissionLinesAvailable(z,z,aa,a-1)
175 + NewTransmissionLines(z,z,aa)*TransmissionUnitCapacity;
176 # SYSTEM-WIDE CONSTRAINTS
177 # (16) – electricity demand satisfaction
178 ZonalDemandMet(aa(a),c,t)..
179 # (17) – constrains total capacity provided by all technology to be over peak load plus reserve
180 ZonalPeakMet(aa(a))..
181   =g= sum(z, ZonalPeakLoad(aa,z))*(1+ReserveMargin);
182   sum((ig,z), ReserveProvided(ig,z,aa,c,t)*TechnicalFeature(ig,"ReservePotential"))
183   + sum((is,z), StorageToReserve(is,z,aa,c,t)*TechnicalFeature(is,"ReservePotential"))
184   =g= sum(z, ZonalPeakLoad(aa,z)*ReserveMargin) + sum((ir,z), PowerToDemand(ir,z,aa,c,t)*WindReserve);
185 # (19) – lower bound on system inertia
186 SystemInertiaMet(aa(a),c,t)..
187   sum((ig,z), GenerationUnitsOperating(ig,z,aa,c,t)*UnitCapacity(ig)*TechnicalFeature(ig,"InertiaPotential"))
188   + sum((is,z), StorageUnitsOperating(is,z,aa,c,t)*UnitCapacity(is)*TechnicalFeature(is,"InertiaPotential")) =g= SystemInertia;
189 # (20) – whole system emissions target
190 EmissionsTargetMet(aa(a))..
191   sum((ig,z,c,t)$(TechnicalFeature(ig,"UnitEmissions")<>0), Emissions(ig,z,aa,c,t)*WeightingFactor(c))
192   + sum((is,z,c,t)$(TechnicalFeature(is,"UnitEmissions")<>0), Emissions(is,z,aa,c,t)*WeightingFactor(c))
193   =l= AnnualEmissionsTarget(aa);
194 # (21) – upper bound on unmet demand
195 ZonalUnmetDemand(aa(a),z)..
196   sum((c,t), LoadSlack(z,aa,c,t)*WeightingFactor(c)) =l= 0.001*sum((c,t), ZonalHourlyDemand(c,t,z,aa)*WeightingFactor(c));
197 # (22) – lower bound on power output
198 MinimumPowerGeneration(ic,z,aa(a),c,t)..
199   PowerOutput(ic,z,aa,c,t) =g= GenerationUnitsOperating(ic,z,aa,c,t)*UnitCapacity(ic)*TechnicalFeature(ic,"MinimumPower");

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197 # (23) – upper bound on power output
198 MaximumPowerGeneration (ig ,z ,aa (a) ,c ,t) ..
199
200 # (24) – balance of power to demand storage and transmission
201 UnitPowerBalance (ig ,z ,aa (a) ,c ,t) ..
202
203 # (25) – emission calculation for generators
204 GenerationEmissions (ig ,z ,aa (a) ,c ,t) $(TechnicalFeature (ig , " UnitEmissions "));
205 # (26) – emission calculation for storage
206 StorageEmissions (is ,z ,aa (a) ,c ,t) $(TechnicalFeature (is , " UnitEmissions "));
207
208 # === INTERMITTENT RENEWABLE TECHNOLOGY (ir) CONSTRAINTS
209 # (28) – lower bound on IR power output
210 IRESMinAvailability (ir ,z ,aa (a) ,c ,t) $(ord (ir) < > 8) ..
211
212 # (29) – upper bound on IR power output
213 IRESMaxAvailability (ir ,z ,aa (a) ,c ,t) $(ord (ir) < > 8) ..
214
215 # (30) – calculating #units in start–up
216 UnitsStartingUpBalance (ic ,z ,aa (a) ,c ,t) ..
217 # (31) – calculating #units in shut–down
218 UnitsShuttingDownBalance (ic ,z ,aa (a) ,c ,t) ..
219 # (32) – limit #units in start–up
220 StartUpTime (ic ,z ,aa (a) ,c ,t ,t_) $(ord (t_) le RampUpTime (ic)) ..
221 # (33) – limits #units in shut–down
222 ShutDownTime (ic ,z ,aa (a) ,c ,t ,t_) $(ord (t_) le RampDownTime (ic)) ..
223
224 # === STORAGE (is) TECHNOLOGY CONSTRAINTS
225 # (35) – minimum power output of storage
226 MinimumStorageOutput (is ,z ,aa (a) ,c ,t) ..
227
228 # (36) – upper bound on storage state of charge
229 MaximumStorageLevel (is ,z ,aa (a) ,c ,t) ..
230 # (37) – lower bound on storage state of charge
231 MinimumStorageLevel (is ,z ,aa (a) ,c ,t) $(ord (t) gt StorageDuration (is)) ..
232
233 # (38) – power to storage balance
234 GenerationToStorageBalance (z ,aa (a) ,c ,t) ..
235 # (39) – initial state of charge
236 InitialChargeLevel (is ,z ,aa (a) ,c ,t) $(ord (t) = 1) ..
237 # (40) – in and out power flow balance t and t–1
238 StoragePowerBalance (is ,z ,aa (a) ,c ,t) $(ord (t) gt 1) ..
239
240 # (41) – upper bound on discharging
241 MaximumStorageDischarging (is ,z ,aa (a) ,c ,t) ..
242
243 # (42) – upper bound on discharging
244 StoredEnergyBalance (is ,z ,aa (a) ,c ,t) ..
245 # (43) – upper bound on charging
246 MaximumStorageCharging (is ,z ,aa (a) ,c ,t) ..
247
248 # === TRANSMISSION CONSTRAINTS
249
250 PowerOutput (ig ,z ,aa ,c ,t) + ReserveProvided (ig ,z ,aa ,c ,t)
251 =| = GenerationUnitsOperating (ig ,z ,aa ,c ,t) * UnitCapacity (ig , " MaximumPower "));
252
253 PowerToDemand (ig ,z ,aa ,c ,t) + PowerToStorage (ig ,z ,aa ,c ,t) + PowerToExport (ig ,z ,aa ,c ,t) = e = PowerOutput (ig ,z ,aa ,c ,t);
254
255 Emissions (ig ,z ,aa ,c ,t) = e = PowerOutput (ig ,z ,aa ,c ,t) * TechnicalFeature (ig , " UnitEmissions "));
256
257 Emissions (is ,z ,aa ,c ,t) = e = StorageToDemand (is ,z ,aa ,c ,t) * TechnicalFeature (is , " UnitEmissions "));
258
259 PowerOutput (ir ,z ,aa ,c ,t) = g =
260 GenerationUnitsOperating (ir ,z ,aa ,c ,t) * UnitCapacity (ir , " MinimumPower ") * AvailabilityFactor (ir ,z ,c ,t);
261
262 PowerOutput (ir ,z ,aa ,c ,t) + ReserveProvided (ir ,z ,aa ,c ,t) =| =
263 GenerationUnitsOperating (ir ,z ,aa ,c ,t) * UnitCapacity (ir , " AvailabilityFactor " (ir ,z ,c ,t));
264
265 UnitsStartingUp (ic ,z ,aa ,c ,t) = g = GenerationUnitsOperating (ic ,z ,aa ,c ,t) – GenerationUnitsOperating (ic ,z ,aa ,c ,t – 1);
266
267 UnitsShuttingDown (ic ,z ,aa ,c ,t) = g = GenerationUnitsOperating (ic ,z ,aa ,c ,t – 1) – GenerationUnitsOperating (ic ,z ,aa ,c ,t);
268
269 UnitsStartingUp (ic ,z ,aa ,c ,t) =| = GenerationUnitsOperating (ic ,z ,aa ,c ,t + 1 + ord (t_) – 1);
270
271 UnitsShuttingDown (ic ,z ,aa ,c ,t) =| = InstalledUnits (ic ,z ,aa) – GenerationUnitsOperating (ic ,z ,aa ,c ,t + 1 + ord (t_) – 1));
272
273 StorageToDemand (is ,z ,aa ,c ,t) + StorageToReserve (is ,z ,aa ,c ,t) + StorageToExport (is ,z ,aa ,c ,t)
274 = g = StorageUnitsOperating (is ,z ,aa ,c ,t) * UnitCapacity (is , " TechnicalFeature " (is , " MinimumPower "));
275
276 StateOfCharge (is ,z ,aa ,c ,t) =| = StorageUnitsOperating (is ,z ,aa ,c ,t) * UnitCapacity (is , " MaximumStateOfCharge (is) " * StorageDuration (is));
277
278 StateOfCharge (is ,z ,aa ,c ,t) = g =
279 StorageUnitsOperating (is ,z ,aa ,c ,t) * UnitCapacity (is , " MinimumStateOfCharge (is) " * StorageDuration (is));
280
281 sum (ig , PowerToStorage (ig ,z ,aa ,c ,t)) = e = sum (is , PowerToStorageTech (is ,z ,aa ,c ,t));
282
283 StateOfCharge (is ,z ,aa ,c ,t) = e = UnitCapacity (is) * InitialStateOfCharge (is) * StorageDuration (is);
284
285 StateOfCharge (is ,z ,aa ,c ,t) = e = StateOfCharge (is ,z ,aa ,c ,t – 1) – StorageToDemand (is ,z ,aa ,c ,t) – StorageToExport (is ,z ,aa ,c ,t)
286 + TransmissionToStorageTech (is ,z ,aa ,c ,t) * StorageEfficiency (is) + PowerToStorageTech (is ,z ,aa ,c ,t) * StorageEfficiency (is);
287
288 StorageToDemand (is ,z ,aa ,c ,t) + StorageToReserve (is ,z ,aa ,c ,t) + StorageToExport (is ,z ,aa ,c ,t)
289 =| = StorageUnitsOperating (is ,z ,aa ,c ,t) * UnitCapacity (is);
290
291 StorageToDemand (is ,z ,aa ,c ,t) + StorageToReserve (is ,z ,aa ,c ,t) + StorageToExport (is ,z ,aa ,c ,t) =| = StateOfCharge (is ,z ,aa ,c ,t);
292
293 PowerToStorageTech (is ,z ,aa ,c ,t) + TransmissionToStorageTech (is ,z ,aa ,c ,t) =| = StorageUnitsOperating (is ,z ,aa ,c ,t) * UnitCapacity (is);
294

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248 # (44) – in and out power balance for zone
249 ZonalTransmissionBalance(z,aa(a),c,t)..
250
251 sum(ig, PowerToExport(ig,z,aa,c,t)) + sum(is, StorageToExport(is,z,aa,c,t)) + sum(z_$(Line(z,z_)), TransmissionFlow(z_,z,aa,c,t))
252 =e= sum(z_$(Line(z,z_)), TransmissionFlow(z,z_,aa,c,t)/(1-Distance(z_,z)*UnitTransmissionLosses))
253 + TransmissionToDemand(z,aa,c,t)/(1-UnitTransmissionLosses) + TransmissionToStorage(z,aa,c,t)/(1-UnitTransmissionLosses);
254
255 sum(is, TransmissionToStorageTech(is,z,aa,c,t)) =l= TransmissionToStorage(z,aa,c,t);
256
257 TransmissionFlow(z,z_,aa,c,t) =l= TransmissionLinesAvailable(z,z_,aa);
258
259 MaximumTransmission(z,z_,aa(a),c,t)$(Line(z,z_))..
260 # (47) – off-grid technologies cannot send power to transmission grid
261 NoGridTransmission(ig,z,aa(a),c,t)$(ord(ig) eq 7) or (ord(ig) eq 8) or (ord(ig) eq 19).. PowerToExport(ig,z,aa,c,t) =e= 0;
262 # (48) – some off-grid technologies cannot send power to storage
263 NoOffgridToStorage(ig,z,aa(a),c,t)$(ord(ig) eq 7) or (ord(ig) eq 8) or (ord(ig) eq 19)..
264
265 PowerToStorage(ig,z,aa,c,t) =e= 0;
266
267 # (2) – summation of all OPEX
268 TotalAnnualOPEX(aa) =e= sum((ig,z,c,t), UnitsStartingUp(ig,z,aa,c,t)*StartupOPEX(ig)*WeightingFactor(c))
269 + sum((ig,z,c,t), OPEX(ig,aa)*PowerOutput(ig,z,aa,c,t) + NoLoadOPEX(ig)*GenerationUnitsOperating(ig,z,aa,c,t)*WeightingFactor(c))
270 + sum((is,z,c,t), OPEX(is,aa)*StorageToDemand(is,z,aa,c,t) + NoLoadOPEX(is)*StorageUnitsOperating(is,z,aa,c,t)*WeightingFactor(c))
271 + sum((z,z_,c,t)$(Line(z,z_)), TransmissionOPEX*(TransmissionFlow(z,z_,aa,c,t))*WeightingFactor(c))
272 + sum((z,c,t), (LoadSlack(z,aa,c,t))*WeightingFactor(c)*LostLoadValue);
273
274 # OBJECTIVE FUNCTION
275 # (1) objective function CAPEX OPEX imported electricity emissions penalty
276 TotalSystemCost =e= sum((i,z,aa(a))$(ord(a)<=1), CAPEX(i,a)*NewBuildUnits(i,z,aa)*CAPEXWeightingFactor(i,a)*UnitCapacity(i)/DiscountFactor(aa))
277 + sum((z,z_,aa(a))$(Line(z,z_)), TransmissionCAPEX*Distance(z,z_)*NewTransmissionLines(z,z_,aa))
278 + (sum(aa(a)$(ord(a)<=4), TotalAnnualOPEX(aa)*PlanningPeriod/DiscountFactor(aa))
279 + sum(aa(a)$(ord(a)>1), (TotalAnnualOPEX(aa)-TotalAnnualOPEX(a-1))*PlanningPeriod/2-1)/DiscountFactor(aa))
280 + sum(aa(a)$(ord(a)=4), TotalAnnualOPEX(aa)/DiscountFactor(aa))
281 + sum((z,aa(a),c,t)$(ord(a)<=4), EmissionsSlack(z,aa,c,t)*WeightingFactor(c)*100000*PlanningPeriod/DiscountFactor(aa))
282 + sum((z,aa(a),c,t)$(ord(a)>1), (EmissionsSlack(z,aa,c,t)-EmissionsSlack(z,a-1,c,t))*WeightingFactor(c)*100000*(PlanningPeriod/2-1)/DiscountFactor(aa))
283 + sum((z,aa(a),c,t)$(ord(a)=4), EmissionsSlack(z,aa,c,t)/DiscountFactor(aa))
284
285 # Calculation of total system emissions based on consumption and production
286 TotalConsumptionEmissions(aa) =e= sum((ig,z,c,t), Emissions(ig,z,aa,c,t)*WeightingFactor(c))
287 + sum((is,z,c,t), Emissions(is,z,aa,c,t)*WeightingFactor(c));
288 TotalProductionEmissions(aa) =e= sum((ig,z,c,t)$(ord(ig)<=17), Emissions(ig,z,aa,c,t)*WeightingFactor(c));
289
290 # DEFINE MODEL STRUCTURE AND SOLVE OPTION
291 Model ESONE_Nigeria /all/;
292
293 option solvelink = 0;
294 option optCR = 0.03;
295 option iterLim = 1E9;
296 option resLim = 2E5;
297 option threads = 24;
298 maxexecerror = 1E5;
299
300 Solve ESONE_Nigeria minimising TotalSystemCost using mip;

```