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A Prospective Net Energy and Environmental Life-Cycle Assessment of the UK Electricity Grid

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Abstract: National Grid, the UK's largest utility company, has produced a number of energy transition scenarios, among which "2 degrees" is the most aggressive in terms of decarbonization. This paper presents the results of a combined prospective net energy and environmental life cycle assessment of the UK electricity grid, based on such a scenario. The main findings are that the strategy is effective at drastically reducing greenhouse gas emissions (albeit to a reduced degree with respect to the projected share of "zero carbon" generation taken at face value), but it entails a trade-off in terms of depletion of metal resources. The grid's potential toxicity impacts are also expected to remain substantially undiminished with respect to the present. Overall, the analysis indicates that the "2 degrees" scenario is environmentally sound and that it even leads to a modest increase in the net energy delivered to society by the grid (after accounting for the energy investments required to deploy all technologies).

Keywords: LCA; EROI; net energy; energy scenario; energy transition; electricity; grid mix; storage; decarbonization

1. Introduction

Energy is an essential commodity for productivity, economic growth and well-being. However, ensuring the delivery of the energy that societies need while preventing major environmental disruption is quickly becoming one of the major challenges of this century. The worldwide increase in energy demand and continuous burning of fossil fuels for energy production since industrialization has led to a rapid increase in carbon dioxide (CO_2) concentration in the atmosphere from 280 ppm (parts per million) to over 400 ppm [1].

Historically, the UK was one of the first countries to experience massive industrialization across all sectors. Before industrialization, most of the UK energy demand was fairly renewable, met by water and wind mills and by burning woody biomass, mostly for agricultural and heating purposes [2]. Subsequently, with the onset of industrialization, the UK population and its appetite for energy grew rapidly. The UK economy shifted from reliance on agriculture to manufacturing, and most manufacturing sectors were based on coal consumption. This propelled UK economic growth in the 18th and 19th century [3] but, as a consequence, it also led to a rapid increase in CO_2 and other greenhouse gas (GHG) emissions to the atmosphere. The burning of coal and peat for manufacturing and heating purposes created a visual smog in major UK cities, too. This led to the first 1956 and 1968 Clean Air Act to reduce the emissions caused by coal [3]. In 2008, the UK legislated the Climate Change Act to reduce its contribution to global warming by cutting down GHG emissions by 80% by 2050, relative to its 1990 level [4].

While the UK was not the only country with legislation already in place aimed at reducing GHG emissions, the Paris Agreement held in December 2015 was the first global agreement to combat climate change signed by 195 countries. It aims to keep the global temperature below 2 °C above pre-industrialization level, while encouraging further efforts to limit global warming to below 1.5 °C to reduce the risk of irreversible climate consequences [5]. To accomplish this target, all parties of the United Nation Framework Convention for Climate Change (UNFCCC) understood the necessary action to limit the CO_2 and other GHG concentration in the atmosphere by decarbonizing their current energy system. In 2019, the UK Committee on Climate Change (CCC) recommended a new national target to fulfil the commitment made when signing the Paris Agreement. This new ambitious target aims to bring all GHG emissions to net zero by 2050 [6].

The current UK energy system comprises of three main energy carriers: oil-derived fuels, natural gas and electricity. Electricity is known to be one of the most desirable energy carriers for a low-carbon future due to its flexibility to operate a wide range of services such as lightning, heating, and transportation, with its transportability over long distances with comparatively little loss, and the efficiency with which it can be converted into useful work at the point of use [7]. Electricity can be generated from a range of primary sources, and in order to meet the climate target, there has recently been an increased deployment of various low-carbon technologies in the UK electricity grid (primarily wind and solar photovoltaics), with an on-going shift away from the combustion of fossil fuels in thermal power plants, and a concomitant increase in the electrification of the heating and transportation sectors. Such trends are expected to be sustained for the coming decades, with a positive overall effect in terms of decarbonization; however, the increased reliance on electricity as the energy carrier of choice for all sectors, paired with the shift to more and more variable renewable energy (VRE) generation, has also led to growing concerns about the future requirement for large-scale energy storage (including lithium-ion batteries) and the possible associated adverse consequences.

Over the past decade, a growing body of literature has analyzed the feasibility and environmental consequences of various energy transition pathways characterized by an increased degree of electrification across all sectors, coupled with a larger reliance on renewable technologies to generate the required electricity. Among such studies that appeared relatively early, a few attracted significant attention by non-specialist media, such as Fthenakis et al.'s seminal "Solar Grand Plan" [8,9], while others seemed to polarize scientific opinion and generated strong controversy [10–14]. More recently, a string of similarly-framed studies respectively focusing on Europe [15], the Americas [16] or the whole world [17,18] have seemingly pointed to a degree of high-level agreement on the general desirability of such transition pathways, albeit with a number of caveats.

Crucially, although key electricity generation technologies such as wind, solar photovoltaics and nuclear are often considered to be "zero carbon" at the point of consumption, the same is not true for their manufacturing, nor are they necessarily 100% environmentally sound in all respects. Life cycle assessment (LCA) is the preferred methodology in order to address all these points while taking into consideration all the life-cycle stages of the various energy supply chains (resource extraction, processing, and delivery, and power plant manufacturing, operation and decommissioning). For instance, a comprehensive LCA of a range of International Energy Agency (IEA) world electricity supply scenarios indicated that, in broad terms, those scenarios that rely more heavily on renewable technologies do indeed tend to stabilize or even reduce global pollution, but entail larger (and sometimes potentially critical) demand for key materials, noticeably among which is copper [19]. Another recent study, whose scope also extended to the whole world, found that those decarbonization strategies relying heavily on wind and solar technologies are comparatively more effective in reducing human health impacts than those relying on carbon sequestration, while the use of bioenergy in the mix raises concerns in terms of land use and associated ecosystem damage [20]. Pehl et al. [21] carried out a thorough life-cycle comparison of all the direct and indirect GHG emissions from various renewable and non-renewable low-carbon technologies, also including seldom-considered factors such as indirect carbon emissions from land use change. Their study produced ranges of results for each technology that reflect the sometimes-large variability that is not only due to technological aspects, but also, critically, system siting (from insolation level for solar photovoltaics, to the rather less obvious methane emissions from biomass degrading in poorly-chosen hydro reservoir sites).

Coming to more UK-centric LCA studies, Stamford and Azapagic [22] compared a range of possible grid mix scenarios up to 2070, and concluded that a low-carbon mix with nuclear and renewables provides the best overall environmental performance, albeit with some increased impacts in terms of terrestrial eco-toxicity, and material resource depletion (elements). Raugei et al. [23] investigated a number of stakeholder-informed photovoltaic-heavy grid mix options, and found that, despite the comparatively low insolation levels that are characteristic of the UK, no such scenarios would be detrimental to the grid performance from a wide range of technical and environmental metrics.

There also remains a question about whether the future electricity grid can continue providing the same level of "net" energy for all societal needs as before, to support continued economic growth and prosperity. The concept of net energy was first described by ecologist Howard T. Odum in 1973 [24] and then reprised by his former student Charles A.S. Hall, who went on to coin the popular term "energy return on investment" (EROI) [25]. Net energy is intended to represent the "true value" of the energy that is delivered to society. In other words, for a society to prosper, the energy delivered to the society must at least be higher than the energy invested in the chain of processes required to convert primary energy resources into useful energy carriers. Carbajales-Dale et al. [26] discuss the importance of carrying out net energy analysis (NEA) to measure the productivity of the energy system and support a sustainable energy transition. Moving towards a low carbon future would require a different re-investment of energy for the electricity grid due to the deployment of new energy generation and storage technologies, and NEA is the way to identify the ensuing changes in the final net energy delivered to society by the electricity grid.

To this date, however, literature is divided as to this important question, with some studies questioning the capability of future renewable-heavy grid mixes to deliver sufficient net energy (e.g., for the case of Australia [27]), and others instead concluding that the net energy set-backs could be minor (e.g., for New York state [28]) to non-existent (e.g., for Chile [29]). Ultimately, the devil is, once again, in the details, and the answer is likely to depend on specific conditions such as the exact grid mix composition, location, degree of gird-level storage, and the demand profile.

This paper presents the results of a joint environmental LCA and NEA of one of the leading energy transition scenarios for the UK, specifically to understand the changes that may be expected in environmental impacts as well as net energy delivery when moving from the current UK grid mix to a future one featuring larger amounts of VRE and associated energy storage (the latter including dedicated stationary solutions as well as mobile—also referred to as "vehicle-to-grid"—schemes).

2. Materials

2.1. Current and Future (Projected) UK Grid Mix

National Grid Electricity System Operator, the UK's largest utility company, produced a study called "Future Energy Scenarios (FES)" [30] analyzing the energy demand and supply of the future electricity and gas networks in Great Britain based on policy support, customer engagement, technological development, economic growth and energy efficiency (National Grid does not provide electricity to Northern Ireland, which instead is served by three interconnectors with the Republic of Ireland. Consequently, while the FES are based on targets set at the national (UK) level, all the data contained therein are actually for Great Britain (GB) only, i.e., excluding Northern Ireland. For the sake of clarity and simplicity, however, in this paper the distinction between GB and UK is dropped in favour of a unified reference to "UK" throughout). Four potential energy pathways to achieve various degrees of decarbonization for the UK are described in the FES report, respectively named: "steady progression", "consumer evolution", "community renewables" and "2 degrees". Out of these, "community renewables" and "2 degrees" are the more aggressive in terms of decarbonization. Both target 80% reduction in GHG emissions by 2050 compared to 1990, based on the 2008 Climate

Change Act, and the main difference between the two is that "2 degrees" assumes more "large-scale", centralized electricity generation, while "community renewables" relies more on smaller, decentralized installations. This paper focuses on the "2 degrees" scenario, due to it being the one for which a greater level of detail is provided in the FES report.

The FES "2 degrees" scenario projects electricity generation capacities for all the grid mix technologies and the associated annual electricity generation for the next 30 years. The overall electricity generation is estimated to increase by 35% in 2035 and 72% in 2050, relative to 2019, in response to the increasing demand partly due to the electrification of transport and heating. Figure 1 illustrates the UK grid mix composition in terms of total electricity generated in the year 2019, and Figures 2 and 3 the corresponding projected grid mix compositions in the years 2035 and 2050.

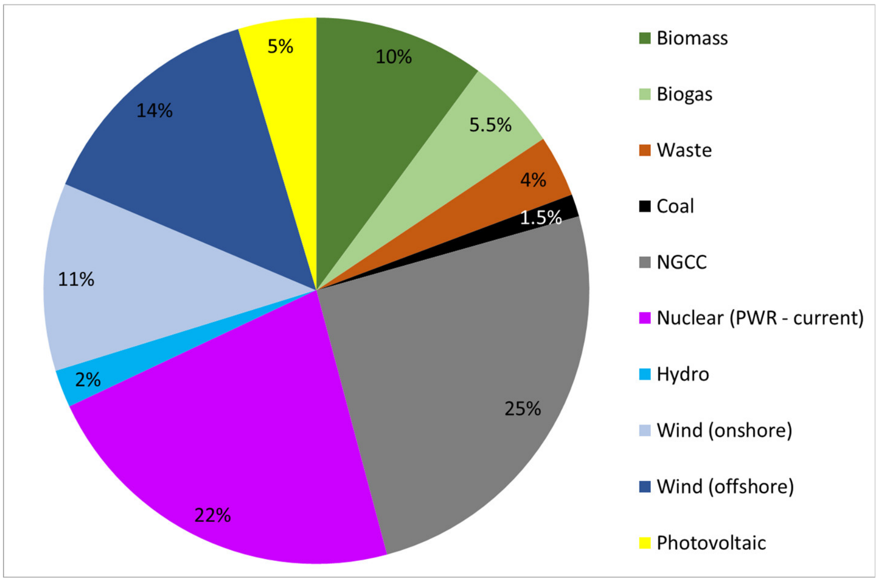

Figure 1. Current (2019) UK grid mix composition, in terms of total electricity generated. NGCC = natural gas combined cycles; PWR = pressure water reactors.

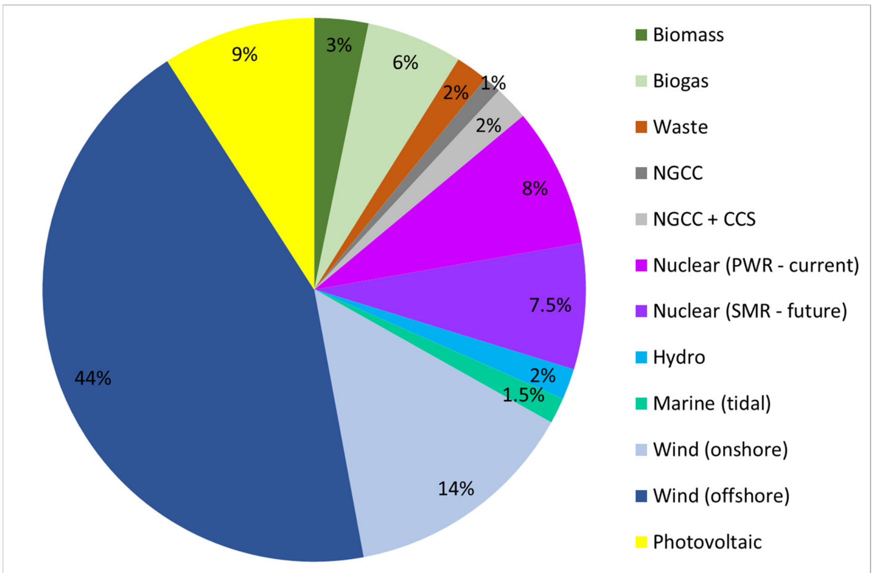

Figure 2. Expected UK grid mix composition in 2035, in terms of total electricity generated (under "2 degrees" scenario assumptions). NGCC = natural gas combined cycles; NGCC + CCS = natural gas combined cycles plus carbon capture and storage; PWR = pressure water reactors; SMR = small modular reactors.

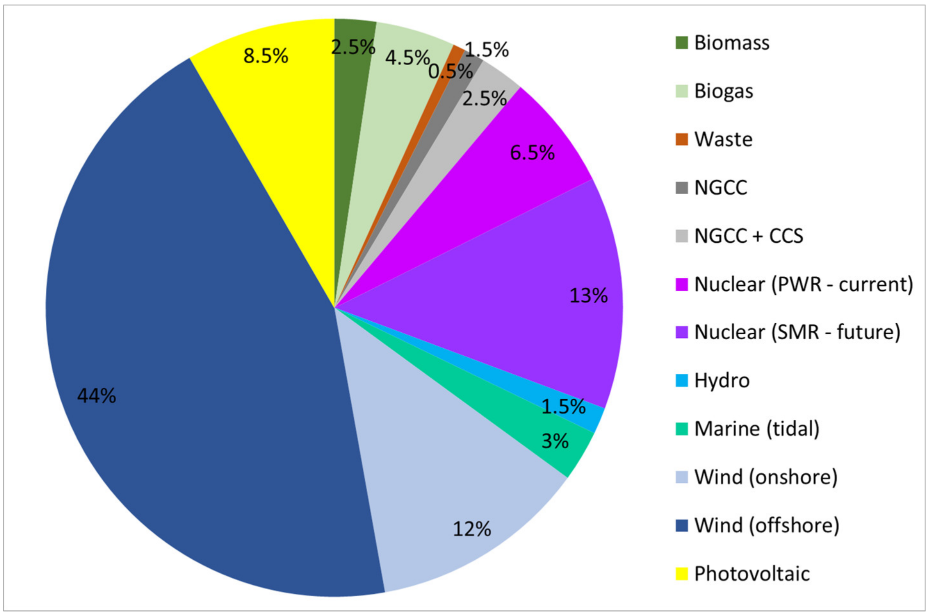

Figure 3. Expected UK grid mix composition in 2050, in terms of total electricity generated (under "2 degrees" scenario assumptions). NGCC = natural gas combined cycles; NGCC + CCS = natural gas combined cycles plus carbon capture and storage; PWR = pressure water reactors; SMR = small modular reactors.

The 2019 grid mix includes a small share of coal-fired electricity, which is expected to be completely phased out within the next few years. Gas-fired generation, currently accounting for 25% of the grid mix, is expected to move towards a peaking plant role in the coming years to provide flexibility in the electricity grid by supplying electricity when the demand is high or when renewable generation is low. While most conventional combined-cycle gas-fired generation is also expected to be phased out (−92% by 2050), a non-negligible share of gas-fired generation is expected to re-emerge from 2030 onwards but equipped with carbon capture and storage. Nuclear generation in 2019 provides 22% of the total electricity generation, but over half of the existing power plants are expected to reach their designated end of life and close down before 2035. However, small modular reactors are then projected to take over, eventually providing around 16 GW of generation capacity, and 13% of total electricity generation, by 2050.

By 2035, 99% of electricity generation is expected to come from "zero carbon" technologies at the point of use (i.e., nuclear, biogas, biomass, waste, hydro, tidal, wind and solar)—cf. blue line in Figure 4. Out of this, a large proportion will be met by renewable technologies (cf. green line in Figure 4), and especially by offshore wind (accounting for approximately 44% of total generation in 2035 and 2050). In fact, most renewable technologies (wind, solar, tidal, and biogas) are projected to increase significantly in output over the next decades, with the sole exceptions of hydro, which is already essentially maxed out in the UK, and biomass, which is expected to drop significantly by 2035. It should be mentioned that in the "2 degrees" scenario tidal generation is expected to account for 76% of total marine generation, with the remaining marine output to be provided by wave technologies; however, due to the lack of data on the latter, in this study, the simplifying assumption was made to consider all marine generation to be tidal.

More specifically, the yellow line in Figure 4 shows that approximately 68% of total generation in 2035 and 2050 is expected to be provided by VRE technologies (i.e., wind, solar and tidal), which, as the phrase implies, are inherently intermittent. As the cumulative share of these technologies increases over the next decades, the grid will thus require increased levels of energy storage to provide the required flexibility to match the energy demand profile.

Storage technologies will therefore increasingly be deployed alongside VRE, to provide such flexibility, as shown by the red line in Figure 4.

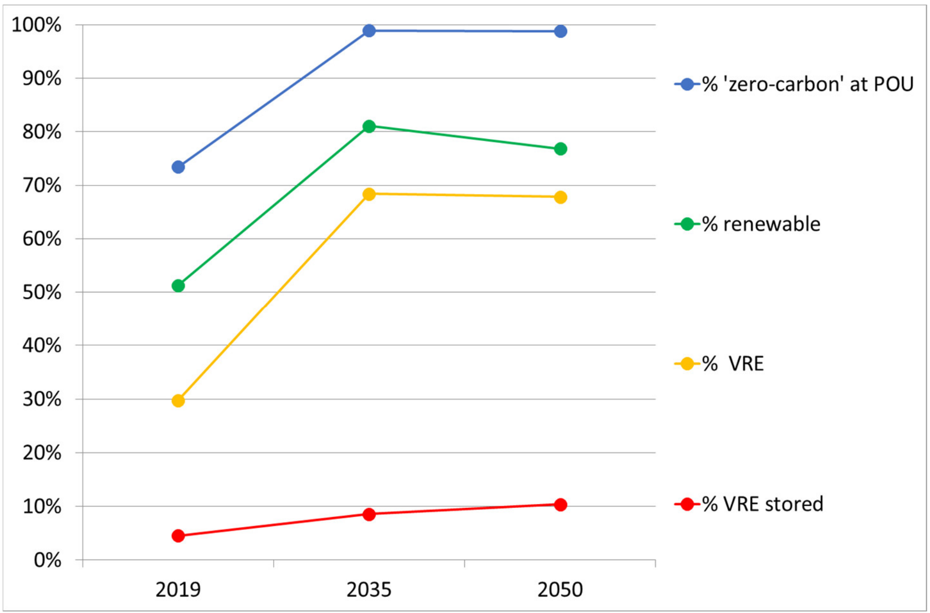

Figure 4. Expected trends (under "2 degrees" scenario assumptions) for, respectively: % of total generation that is considered "zero-carbon" at point of use (i.e., nuclear, biogas, biomass, waste, hydro, tidal, wind and solar); % of total generation that is considered "renewable" (same as above but excluding nuclear); % of total generation that is classified as "Variable Renewable Energy" (VRE; i.e., wind, solar and tidal); % of VRE generation that is sent to energy storage (as opposed to used directly).

National Grid's "2 degrees" scenario considers the deployment of five energy storage technologies: pumped hydro storage (PHS)—in large part relying on existing dammed hydro installations located overseas and tapped via interconnectors, compressed air energy storage (CAES), dedicated lithium-ion batteries (LIB), vehicle-to-grid (V2G) storage provided by the electric vehicle (EV) fleet, and liquid air energy storage (LAES). The first two technologies are generally capable of providing longer-duration storage than the latter three. Specifically, LAES is a fairly new technology that is only projected to ultimately provide 4% of the total storage capacity; due to the very limited information available on its supply chain, in this study the associated storage capacity was instead lumped together with that provided by LIB. The resulting specific assumptions on storage technologies for the future of the UK grid mix are summarized in Table 1.

Table 1. Scenario assumptions on grid-level energy storage.

Technology	Installed Power (GW) 2019	Installed Power (GW) 2035	Installed Power (GW) 2050	Average Daily Storage Duration (h) [1]	Round-Trip Storage Efficiency
PHS	2.7	5.2	5.8	6	80% [31]
CAES	0	1.0	2.0	6	67% [32]
LIB	2.0	8.6	14.0	2	80% [31]
V2G	0	2.7	8.3	2	80% [31]

[1] Own assumption.

Electricity transmission was also included within the boundary of this assessment, albeit limited to the high voltage (HV) network. This was deemed an acceptable simplification, since the vast majority of the electricity generation plants comprising the grid mix at present and in the "2 degrees" scenario are large centralized units which inject HV electricity into the grid (the only exception being rooftop-mounted PV systems). The current HV transmission lines were modelled using the UK-specific life-cycle inventory (LCI) information provided in the Ecoinvent database [33], and then scaled for 2035 and 2050 by simple linear extrapolation based on the projected total gross electricity generation. In terms of energy balance, transmission losses were conservatively set at 5% [34].

Finally, electricity interconnectors with the continent are expected to provide net electricity imports during the demand peaks in winter in the early 2020s. Such imports are, however, expected to decrease significantly in the following years, and to become almost negligible by 2035, eventually leading to very slight net exports by 2050. The choice was therefore made to limit the scope of this analysis to the electricity generated and delivered domestically within the UK, disregarding all electricity exchanged via the interconnectors (with the sole exception of a relatively small share of the future VRE that is assumed to be sent to be stored in PHS facilities located on the continent).

2.2. Electricity Generation and Storage Technologies

2.2.1. Coal

Currently, there are six coal-fired power stations in UK; all are expected to shut down by 2025, except for Drax Power Station, for which there are plans to convert its units to biomass- and gas-fired generation in the near future [35]. The Ecoinvent LCI database "GB" (Great Britain) hard coal electricity production model was adopted for the life cycle inventory of coal-fired electricity generation in the UK.

2.2.2. Natural Gas Combined Cycles

UK natural gas combined cycle (NGCC) inventory was based on the corresponding Ecoinvent GB database model. The model output was reduced by 19% to account for the difference in assumed vs. reported natural gas energy input per kWh of electricity output at the power plant stage, as well as the actual average heating value of the UK gas feedstock [36].

2.2.3. Natural Gas Combined Cycles Plus Carbon Capture and Storage (Future Technology)

At present, there is no detailed inventory information available for natural gas combined cycles with carbon capture and storage (NGCC-CCS). Literature data on the carbon capture process were adopted for 90% CO_2 capture, and incorporated in the adjusted model for conventional NGCC plants. The electricity output of the plant was reduced by 15% to account for the CO_2 capture and compression process (in addition to the initial output adjustment described in Section 2.2.2) [37,38]. The life cycle inventory for the transportation of CO_2 captured and stored is excluded from the study due to the uncertainty involved in the location of the plant and possible storage size.

Appendix A—Tables A1 and A2 provide the construction and operational inventory quantities and the adjusted emissions per kWh of electricity generated.

2.2.4. Biomass

The biomass used for electricity generation in the UK mainly consists of wood pellets from North America forestry, domestic wood chips from UK forests, and a small percentage of domestic residues [39,40]. According to the digest of UK energy statistics (DUKES) 2019 report, based on the 2018 renewable flow-chart, 45% of the biomass share was domestically sourced and 55% was imported [36]. The GB heat and power co-generation model from the Ecoinvent database was selected to represent biomass electricity generation. However, this model does not include mixed inputs of woody biomass feedstocks, and it was therefore modified to account for such. Specifically, the Ecoinvent "RER" (regional European) wood chip model was used to represent the share of wood chips used (since there is not one available specifically for the UK), and two additional processes were added to the model to account for the wood pellet imports. The first process accounts for wood pellet production, and the second one for the transportation of the wood pellets from North America by freight ship. The transport distance was assumed to be 5300 km [41] and the mass of the dry pellets was multiplied by a factor of 1.2 to account for the average moisture content in the transported pellets [42].

2.2.5. Biogas

Biogas is a mixture of gases (mainly methane and carbon dioxide, but with multiple trace gases such as ammonia and hydrogen sulphide) produced by the anaerobic degradation ("digestion") process of organic waste from landfills and, to a lesser extent, agricultural sludge. The biogas is fed into a combined heat and power plant station (CHP), where it is combusted to generate electricity and heat [43]. The Ecoinvent GB biogas-fired heat and power co-generation model was selected to assess biogas electricity generation, and all energy and environmental impacts of the CHP multi-output process were allocated on an energy content basis.

2.2.6. Waste

Electricity generation from waste incineration is also a co-product of a multi-output process. According to ISO recommendations [44], in this case system expansion was adopted in preference to allocation, since waste incineration with energy recovery represents an almost textbook example in which: (i) a primary function is clearly identified (i.e., getting rid of the waste), and (ii) a comparable alternative process exists which delivers only one of the two outputs (i.e., an incinerator without energy recovery). Consequently, the energy recovery process and associated electricity generation was calculated to have negligible emissions assigned to it, since the only additional up-front inputs required vs. the incinerator without energy recovery are those for the boiler and turbine system, while the use-phase emissions at the stack are virtually the same.

2.2.7. Nuclear

There are 15 operating nuclear reactors in UK, 14 of which are advanced gas-cooled reactors (AGR) which are expected to shut down before 2035, and one is a large pressurized water reactor (PWR) which was initially also expected to shut down in 2035, but whose operation may be extended for 20 more years [45]. Out of the currently operating nuclear reactor technologies in the UK, life cycle information in Ecoinvent was only available for PWRs, and therefore the latter was used to model the life cycle inventory associated to nuclear electricity generation

2.2.8. Nuclear (Small Modular Reactors—Future Technology)

Small Modular Reactors (SMR) are factory-built nuclear reactors of less than 300 MWe installed power, inspired by the current large nuclear power plants [46]. They are also known as integral PWR since their main components, such as the stream generator, reactor and pressurizer, are all located in one vessel. SMRs offer the opportunity to add nuclear generating capacity with a smaller capital cost and thus reduce construction risks. They can be categorized in two groups: (1) Generation III water-cooled SMR based on existing large nuclear plants but on a smaller scale, and (2) Generation IV SMRs based on the use of novel fuels and coolants, which can provide other services such as heat for industrial processes [47]. Generation IV small modular reactors are not expected to achieve commercial maturity until 2030 onwards [48], while Generation III SMR are considered to be more mature technologies as they are based on the existing large nuclear plants concept. According to the world nuclear association there are currently two potential SMR projects, one with NuScale and other with Rolls Royce both based on light-water pressurized SMR designs [45].

At present there is no existing LCI database model for SMR technologies, therefore, in this study the Ecoinvent model for PWRs was adopted as a basis for the life cycle inventory of light-water pressurised SMR. The latter are the scaled-down version of large PWR which utilize the same working concepts, but instead of having pumps and coolant loops for directing the flow of water, they utilize natural circulation to direct the cool water to the reactor core after going through the steam generator to turn the turbine to generate electricity [49]. The main components of both systems are considered to be the same, and both are expected to have the same lifetime of 60 years. The Ecoinvent model was adjusted to account for the reduction in efficiency and improvement of the capacity factor (CF) for SMRs compared to large PWRs, which lead to an overall reduced output (−15% in relative terms) [48] (The Capacity Factor is defined as the ratio of the actual power generated by a system, averaged over its service lifetime, to its nominal installed power).

2.2.9. Hydroelectric

Hydropower electricity generation in UK consist of 24% run-of-river and 76% reservoir [36]. The Ecoinvent model for GB run-of-river hydroelectricity model was adopted, and the Ecoinvent "DE" (Germany) model for hydro-reservoirs was used as a proxy, as the database does not contain a corresponding GB model.

2.2.10. Marine Tidal (Future Technology)

Tidal energy is generated through the rise and fall of tides, due to the interaction of gravitational pull of moon and to a lesser extend the sun on the ocean and the rotation of the Earth [50]. There are three types of tidal technologies: lagoon, barrage and stream turbines. National Grid's FES 2019 scenarios assume that the target tidal capacities will be met primarily using tidal lagoons, and secondarily stream turbines. However, there is mounting uncertainty on the future development of tidal technologies, with on the one hand, the recent cancellation of one large tidal lagoon project [51], and on the other hand, new upcoming developments and installed projections on stream turbine [52]. In this study, the assumption was therefore made that the electricity generated by tidal will be harnessed by tidal stream turbines.

There is no model in the Ecoinvent database for this technology. Therefore, all life-cycle inventory and technical information for use in this study was sourced from published scientific literature [53] on an OpenHydro tidal stream turbine. The inventory information includes energy inputs for the installation, manufacturing and maintenance of the system and the material inputs for the construction of the device, power cabling and foundation. The system as described was expected to have a lifetime of 20 years and was rated at 2 MW. The average CF for the stream turbine tidal plant was taken as 5.5% from the DUKES 2019 report [36], and all energy and material inputs were duly scaled to 1 kWh of electricity generated over the life-time of the system.

The resulting foreground inventory information is provided in Appendix A-Table A3.

2.2.11. On-Shore Wind

The Ecoinvent electricity production model for GB 1–3 MW onshore wind turbines was used to represent the total onshore wind electricity generation in UK. The model assumes a 20-year lifetime for all moving components and a 40-year lifetime for all the stationary components of the wind installation [33], and a 26% CF.

2.2.12. Off-Shore Wind

The Ecoinvent electricity production model for GB 1–3 MW offshore wind turbine was used to represent the total offshore wind electricity generation in UK. The model assumes the same lifetimes as for onshore wind turbines, and a 30% CF.

2.2.13. Solar Photovoltaic

National Grid's "2 degree" scenario considers distribution-connected and micro-connected solar capacity and accordingly in this study the assumption was made that most of the solar photovoltaic (PV) generation will come from roof-top mounted systems; additionally, the latest Fraunhofer Institute for Solar Energy report [54] confirms that multi-crystalline silicon (mc-Si) continues to be the leading PV technology by far in terms of global annual production. In order to limit the complexity of the model, a single Ecoinvent process (GB roof-top mounted mc-Si PV) was therefore adopted as the basis for the assessment of solar PV electricity generation in UK. However, since PV systems are still on a continuously and rapidly improving trend, the model was adjusted to reflect the current and expected future mc-Si module efficiencies, respectively reported at 17% in 2019 [54], and estimated at 20% in 2035 and 25% in 2050 [55]. This information was used to adjust the area of solar panels required to produce 1 kWp of installed power in the model.

An average insolation of 1000 kWh/(m^2·yr) was then assumed [56], which, combined with a performance ratio (PR) of 80% [57], led to a calculated CF of 9.1%. Finally, the expected lifetime of the PV modules was kept at 30 years until 2035 [57], and then increased to 35 years for 2050 [55].

2.2.14. Pumped Hydro Storage (PHS)

Pumped hydro storage (PHS) uses electricity to pump water into the high-elevation reservoirs during high generation and low demand, and then releasing the water to generate electricity at peak demand. Since PHS for the UK is projected to utilize pre-existing hydro reservoir systems (mainly located overseas and accessed via the interconnectors), which were built for the primary function of generating hydroelectricity, and since the electricity used for pumping the water uphill would otherwise have to be curtailed, the life-cycle impacts associated with PHS were taken to be zero, thus avoiding any double-counting.

2.2.15. Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) systems store excess electricity by compressing air to high pressure in underground reservoirs such as pre-existing salt mines. The stored air is then heated and expanded to drive a turbine to generate electricity when the electricity demand is high and the generation is low [32]. Currently there are two CAES systems operating worldwide, one is in Huntorf, Germany since 1969 and the other is in McIntosh, United States since 1991 [58]. Both work by burning natural gas to provide heat for the expansion of air to drive the turbine generator.

However, the FES 2019 "2 degrees" scenario expects CAES systems to be deployed from 2030 onwards, and therefore in this study the assumption was made that by that time the UK's CAES installed capacity will be of the more advanced adiabatic type (A-CAES). This type of CAES works by retaining and storing the heat generated during the compression of the air using a thermal energy storage (TES) system, and then reusing the stored heat for the expansion process instead of burning natural gas. There has been a lot of on-going research on A-CAES over the last decade, including the planned EU-based research Project "ADELE" [59], the Storelectric project planning to build large-scale A-CAES in Holland [60], and a recently completed demonstration project by Hydrostor in Toronto Island, Canada [61].

Life cycle inventory (LCI) information on A-CAES is not available in the Ecoinvent database. The technical data were therefore adopted from available literature; specifically, the maximum number of storage cycles was taken to be 10,000 [62], and the cycle efficiency of the plant was taken to be 67% [32]. It was also assumed that the compressed air will be stored in pre-existing underground caverns, with a cumulative energy storage capacity of 6 GWh deployed by 2035 (cf. Table 1). The information on material and energy inputs for plant construction, compression unit, heat expander and thermal energy storage system was adopted from published literature [63] and rescaled linearly in terms of storage capacity.

The inventory information for the input quantities per kWh of electricity storage capacity is provided in Appendix A-Table A4.

2.2.16. Lithium-Ion Battery Storage (LIB)

Dedicated grid-level lithium-ion battery (LIB) storage was modelled on the basis of the Ecoinvent model for lithium manganese oxide (LMO) technology. LMO is among the most mature options for LIBs, and although it lags behind some of the other cathode formulations in terms of energy density [64,65], this was deemed relatively unimportant for dedicated stationary applications, and counterbalanced by its comparatively long cycle life, its overall stability, and its reliance on abundant and eco-friendly materials [64]. The maximum number of charge-discharge cycles was assumed to be 7000 [66].

2.2.17. Vehicle-to-Grid Storage (V2G)

For each year of analysis, vehicle-to-grid (V2G) storage schemes rely on the Li-ion batteries already installed in the existing electric vehicle (EV) fleet, when connected to the network of charging points, to provide short-duration storage (i.e., frequency response services) for grid support. In order to avoid incurring in double-counting, energy storage made available through V2G is therefore regarded to have zero impacts assigned to it, since the primary function of vehicle batteries is to provide electricity storage for transportation.

3. Methods

3.1. Life Cycle Assessment (LCA)

From a methodological perspective, the work presented here was conducted in strict adherence to the current International Organization for Standardization norms on LCA [44,67].

The functional unit (FU) of this study was set as 1 kWh of electricity delivered by the UK grid as a whole, including energy storage and transmission.

The main data source used for the life cycle inventory (LCI) analysis was the reputable and widely-used Ecoinvent version 3.5 database [33], complemented where appropriate and required by a range of other literature sources as described in detail in Section 2.2.

As concerns life cycle impact assessment (LCIA), the choice was made to focus on a set of key impact categories, individually discussed in Sections 3.1.1–3.1.5, and all evaluated at "mid-point" using the widely-adopted and well-regarded CML method [68]. Normalization and weighting were not conducted because, while potentially facilitating the interpretation of the results by a less technical audience, they inevitably remain the most arbitrary steps in any LCA, and the choice of the weighting factors is to a large extent political, with very little if any scientific relevance. In fact, because of this, according to ISO, normalization and weighting are always optional steps and are discouraged for any "comparative assertion intended to be disclosed to the public" [44].

Finally, from a practical point, the whole analysis was carried out using the latest release of the dedicated LCA software package GaBi [69].

3.1.1. Global Warming Potential (GWP)

Global Warming Potential is calculated applying IPCC-derived characterization factors to gaseous emissions, on the basis of their respective equivalent warming potential relative to carbon dioxide (CO_2), with a time horizon of 100 years.

Two alternative accounting rules are possible with regard to biogenic carbon emissions, i.e., those that arise from the combustion of biomass (wood chips and pellets, and biogas derived from the anaerobic degradation of organic matter). The argument for excluding them from the calculation of the grid's GWP is that the same amount of carbon (on a molar basis) was previously absorbed from the atmosphere during the biomass growth phase (including the trees used for the wood chips and pellets, as well as those used for paper and cardboard and all the agricultural and food crops that are eventually biodegraded to produce biogas), thereby effectively "closing the loop" and resulting in net zero carbon emissions. Of course, this calculation only applies to C emitted as CO_2 (i.e., under complete combustion conditions), otherwise each mole of C that is absorbed as CO_2 and later emitted as CH_4 would result in a net contribution to GWP, as quantified by Equation (1):

$$\text{Net GWP per mole of biogenic C} = MM_{CH4}\ (CF_{CH4}\text{-}1)\ [\text{g } CO_2\text{-eq}]$$

where:

$$MM_{CH4} = \text{molar mass of } CH_4\ [\text{g/mol}]$$
$$CF_{CH4} = \text{GWP characterization factor for } CH_4\ [\text{g } CO_2\text{-eq / g } CH_4] \quad (1)$$

Even so, the argument for excluding biogenic C from the accounting only holds fully if it can be proven that the totality of such biomass was in fact grown sustainably (e.g., from well-managed short-rotation forestry that leads to net zero standing biomass change over time). In reality, this condition can rarely be expected to be met completely. Specifically, wood chips coming from domestic forestry residues may often be closer to being net zero C than wood pellets imported from overseas and paper and cardboard coming from a wide range of international sources. As a result, the real-world net carbon emissions of biogenic feedstocks will always be higher than zero, with considerable uncertainty on the exact figures, depending on often hard-to-ascertain factors such as feedstock origin and supply chain practices.

To reflect such uncertainty, in this work the choice was made to calculate and report GWP under both assumptions, i.e., respectively including and excluding biogenic carbon emissions, and to discuss the results in the light of the considerations made above.

3.1.2. Acidification Potential (GWP)

Acidification Potential is calculated applying stoichiometry-derived characterization factors to airborne emissions, on the basis of their respective acidification potential relative to sulphur dioxide (SO_2).

3.1.3. Human Toxicity Potential (HTP)

Human Toxicity Potential is calculated applying characterization factors to all emissions (to air, water and soil), on the basis of their respective toxicity potential relative to 1,4-dichlorobenzene (1,4-DB).

It is noteworthy that HTP results are inevitably affected by a larger margin of uncertainty than those for all other impact categories, due to the intrinsic methodological difficulty of comparing and combining the individual toxicity potentials of a wide and diverse range of organic and inorganic emissions into a single indicator. The uncertainty is especially large in the case of metal emissions [70].

3.1.4. Abiotic Depletion Potential (ADP)

Abiotic Depletion Potential is calculated applying characterization factors to all non-living LCI inputs from the geosphere, expressing their respective scarcity relative to the element antimony (Sb), based on estimates of ultimate reserves and current extraction rates. In order to avoid partially duplicating the information provided by the nr-CED indicator (cf. Section 3.1.5), and potentially obfuscating the impact arising from the depletion of non-energy resources, this indicator is calculated excluding the contributions of all energy inputs (such as fossil fuels and uranium).

It should be noted that abiotic depletion is an impact category that is still frequently the object of methodological discussion, and alternative approaches exist to the quantification of the associated impact, often reflecting differences in problem definition [71–73]. Additionally, ADP's specific dependence on the estimate of ultimate reserves makes it susceptible to obsolescence, especially when using this indicator to assess a depletion-related impact taking place several decades into the future [74].

3.1.5. Non-Renewable Cumulative Energy Demand (nr-CED)

Non-renewable Cumulative Energy Demand is calculated by applying characterization factors to all LCI inputs, based on the total non-renewable primary energy directly and indirectly harvested from the environment for their provision, and expressed in terms of Joules of crude oil equivalent [75].

3.2. Net Energy Analysis (NEA)

Net Energy Analysis (NEA) provides a different and complementary viewpoint to LCA [23,26,28,29,76], and it is carried out here using the same underlying inventory analysis, thereby providing an internally coherent platform for the calculation and discussion of the results. Specifically, while LCA draws the boundary of the system under analysis so as to account for all natural resources used as inputs (and all emissions to the environment as outputs), NEA is only concerned with those energy inputs that are already available as energy carriers within the technosphere, and which are deliberately "invested" in the system (Inv) for the purpose of harvesting more primary energy (PE) from nature and delivering (the term "returning" is also often used) a usable energy carrier (EC) to society. This is illustrated in Figure 5 with a simplified diagram of a generalized energy supply chain.

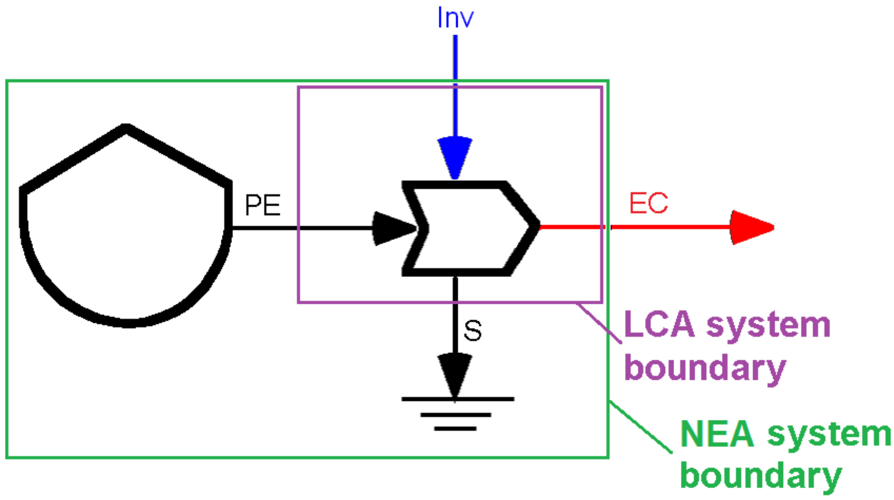

Figure 5. Simplified diagram of a generalized energy supply chain, illustrating the different boundaries set by life cycle assessment (LCA) and net energy analysis (NEA). PE = Primary Energy; Inv = energy "investment"; EC = Energy Carrier (the energy "return"); S = energy dissipated to the environment.

For the purpose of consistency, all energy "investments" (Inv) to the energy system are accounted for in terms of the total (i.e., renewable plus non-renewable) primary energy directly and indirectly harvested from the environment for their provision (expressed in MJ of oil equivalents). This corresponds to including in the analysis the whole supply chain for "Inv", like in LCA.

The energy "returned" by the same system in the form of a usable energy carrier may then alternatively be accounted for either on the basis of the actual energy in the carrier (EC), or on the basis of its equivalent primary energy ($EC_{PE\text{-}eq}$, measured in MJ of oil equivalents).

When EC is electricity, its equivalent primary energy may be calculated according to an LCA substitution logic, i.e., by calculating how much primary energy is directly and indirectly harvested (in total) from the environment to produce one unit of electricity using the current grid mix. Expressing the electricity "return" in terms of equivalent primary energy thus makes the NEA of any of the individual electricity technologies (e.g., natural gas combined cycles, wind, PV, etc.) inextricably linked to the specific grid mix into which it is embedded. However, doing so also has the following advantages:

(i) It enables the calculation of an "energy return ratio", often referred to in literature as Energy Return on Investment (EROI) [25,77], which features consistent units of primary energy equivalents at both the numerator and denominator. This simplifies the interpretation, since otherwise, "if the numerator and denominator are not measured by the same rule, one loses the intuitively appealing interpretation that EROI > 1 is the absolute minimum requirement a resource must meet in order to constitute a net energy source" [78]. In order to clarify when EROI is calculated using units of equivalent primary energy at the numerator, the notation $EROI_{PE\text{-}eq}$ is used in this work—cf. Equation (2).

$$EROI_{PE\text{-}eq} = EC_{PE\text{-}eq}/Inv \tag{2}$$

(ii) It enables the methodologically consistent calculation of the Net-to-Gross (NTG) energy return ratio, defined as per Equation (3). NTG thus provides a clear and easy-to-interpret indication of how much of the "gross" energy delivered to society by the UK grid is a "net" energy output that remains available for all societal uses, vs. how much needs to be re-invested to keep the grid itself operational.

$$NTG = (EC_{PE\text{-}eq} - Inv)/EC_{PE\text{-}eq} \tag{3}$$

By combining Equations (2) and (3) and simply re-arranging the terms, NTG may also be expressed as in Equation (4), which leads to what has often been referred to as the "Net energy cliff" [28,79–81] (Figure 6).

$$NTG = 1 - 1/EROI_{PE\text{-}eq} \tag{4}$$

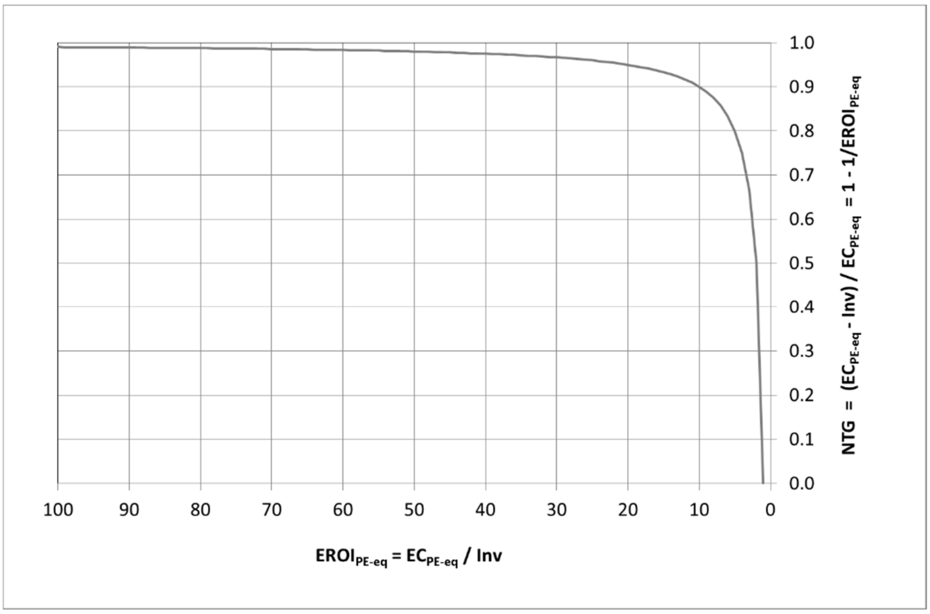

Figure 6. "Net energy cliff" diagram displaying the relation between Energy Return on Investment ($EROI_{PE\text{-}eq}$) and Net-to-Gross ratio (NTG).

The interpretation of the "Net energy cliff" is that once the $EROI_{PE\text{-}eq}$ of an energy system starts dropping below approximately 10, the share of its gross energy output that remains available for other societal uses (after subtracting the primary energy required to sustain the operation of the energy system itself) starts being reduced significantly for each additional reduction in $EROI_{PE\text{-}eq}$; in other words, for $EROI_{PE\text{-}eq} < 10$, NTG quickly "falls off a cliff". Conversely, for all values of $EROI_{PE\text{-}eq} > 10$, NTG remains safely > 0.9, which means that beyond such "threshold" there is less and less significant competitive advantage to a system characterized by increasingly larger $EROI_{PE\text{-}eq}$.

4. Results and Discussion

4.1. Life Cycle Impact Assessment Results

4.1.1. Global Warming Potential

Figures 7 and 8 both illustrate the expected life-cycle GHG emissions associated to the future UK grid mix in 2035 and 2050, expressed per unit of electricity delivered, and relative to the emissions in 2019. The difference between the two figures is that the former includes the contribution of biogenic carbon, while the latter excludes it.

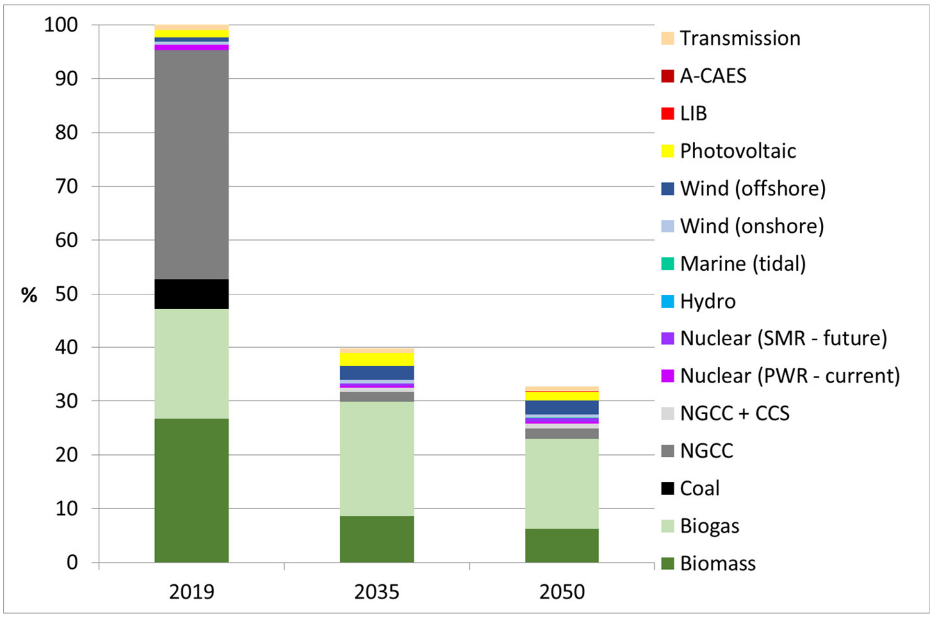

Figure 7. Global warming potential (including biogenic carbon) per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = 269 g CO_2-eq/kWh).

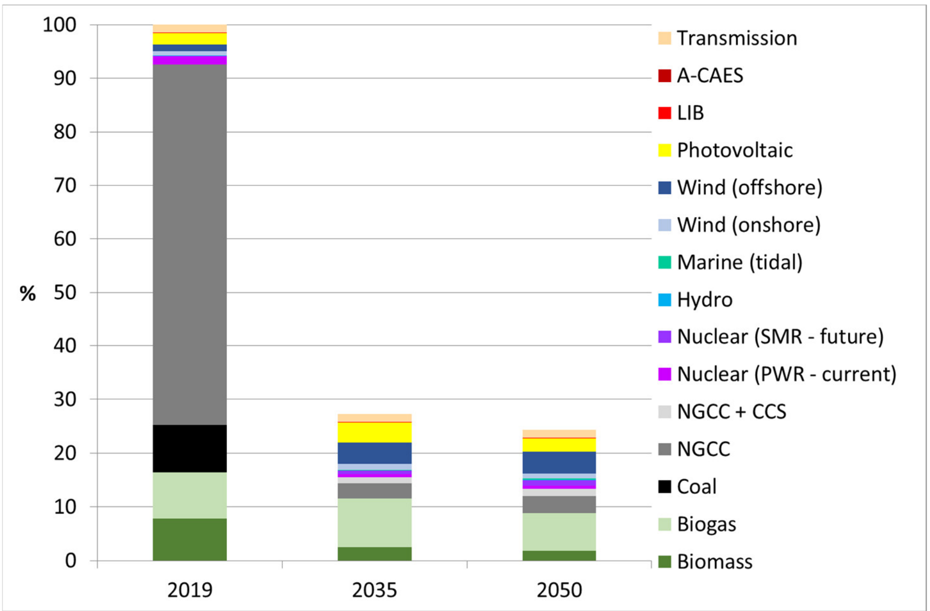

Figure 8. Global warming potential (excluding biogenic carbon) per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = 170 g CO_2-eq/kWh).

As expected, the two technologies that are most significantly affected by the different assumptions on how to account for biogenic C are biomass- and biogas-fired electricity generation. Additionally, it is noteworthy that even when excluding biogenic C emissions (Figure 8), the life-cycle GHG emissions caused by biogas-fired electricity are expected to still amount to 9% of the grid mix total in 2035, despite such technology delivering only 5.7% of the total electricity generation (cf. Figure 2). This points to biogas being almost twice as carbon intensive as the grid mix as a whole at that point in time, and definitely nowhere near as deserving of the "zero carbon" designation as the leading renewable technology for the UK, i.e., wind, which is responsible for just 5% of total GHG emissions while generating 58% of the total electricity. On the one hand, this might lead to question of whether retaining, and if fact increasing, biogas-fired electricity generation in the future grid mix even makes sense at all. On the other hand, though, one must also consider what the alternative would be, i.e., what would happen to the biogas that is produced by anaerobic degradation of organic matter in landfills and in sewage sludge if it were not used as a feedstock for electricity generation. Clearly, releasing it directly to the atmosphere would not be an option, as biogas is rich in methane and would cause even more global warming. Therefore, the focus really shifts from the energy sector to the waste management sector, and points to a need to reduce the reliance on all landfills (municipal, industrial and agricultural) to the maximum extent possible, and instead incentivize the reuse, recycling and thermovalorization of waste flows (as applicable, and broadly in that order of merit), as well as composting (the latter providing the added benefit of returning valuable nutrients to the soil).

Unsurprisingly, the planned decommissioning of coal- and gas-fired power plants is shown to have the largest effect on the decarbonization of the grid mix. It is also noteworthy that the contribution of energy storage technologies (A-CAES and LIB) to the total carbon budget is absolutely negligible, even out to 2050 when 10% of the total yearly VRE generation is assumed to be routed into storage. This is a reassuring result that dispels any potential concerns about the negative effect that the requirement for energy storage might have on the planned decarbonization of the grid.

Considering the total grid mix results as a whole, from 2019 to 2035, GHG emissions may be expected to drop by 60% (i.e., from 263 to 106 g CO_2-eq/kWh, when including biogenic C emissions), or even as much as 73% (i.e., from 170 to 46 g CO_2-eq/kWh, when excluding biogenic C emissions). Further, but less significant, emission reductions are then expected when extending the analysis to 2050. As discussed in Section 3.1, the real total net GHG emissions lie somewhere in between those reported respectively in Figures 7 and 8, but are likely to be somewhat closer to the latter. Be that as it may, it is worth noting that in neither case does the reduction in the total life-cycle grid mix emissions approach 99%, as one might naively assume when considering the share of electricity output that is generated by technologies that are considered “zero carbon at point of use” (cf. blue line in Figure 4). This should not be interpreted as a damning result per se, but rather as a stark reminder of the importance of always duly including all life cycle stages in the analysis.

4.1.2. Acidification Potential

When looking at the results for acidic emissions (Figure 9), two things are readily apparent: (i) the total reductions in potential impact that may be expected for 2035 and even 2050 are much less significant than in the case of global warming potential (respectively, only −8% and −28% with respect to 2019); and (ii) biogas-fired electricity is by far the worst offender in the mix (>80% of total acidic emissions). The latter result is striking, but it is broadly confirmed by other independent studies [82,83], and it may be understood if one considers that the anaerobic degradation of biomass produces significant levels of ammonia and hydrogen sulfide alongside methane, and that those two gases are readily oxidized to, respectively, NO_2 (then hydrated to nitric acid) and SO_2 (then hydrated to sulphuric acid).

While these AP results may look somewhat discouraging, it should also be recognized that there is potentially ample scope for improvement if the biogas is “upgraded” to biomethane by subjecting it to water scrubbing and membrane separation prior to feeding it to the thermal power plant, which would essentially rid it of most ammonia and hydrogen sulfide and render it almost indistinguishable from natural gas [84]. While not yet common practice in the UK, such pre-treatment of the biogas feedstock may become more widespread in the future and contribute to curbing the acidic emissions of biogas-fired electricity, and hence of the whole grid mix, by 2035 or 2050.

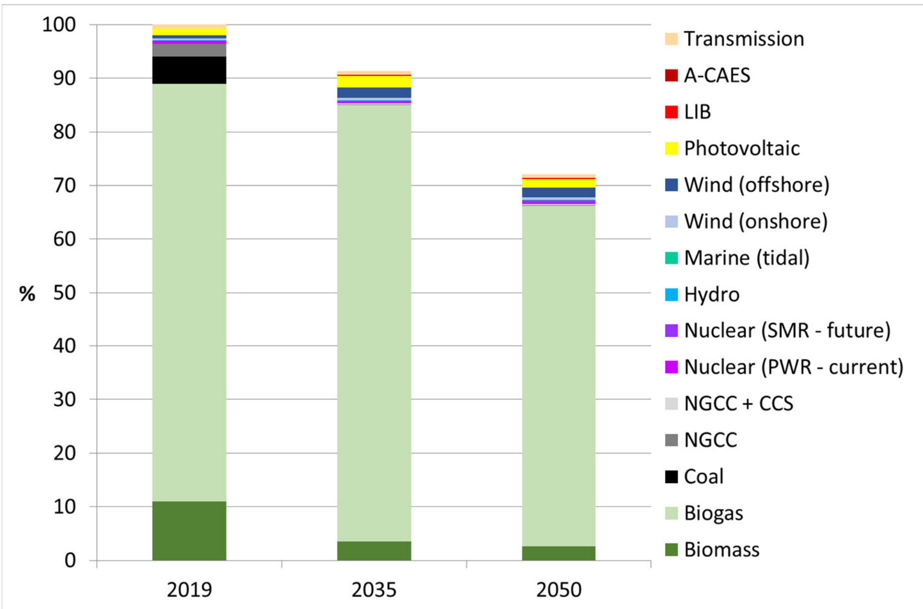

Figure 9. Acidification potential per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = 2.1 g SO_2-eq/kWh).

4.1.3. Human Toxicity Potential

When moving to consider the life-cycle environmental impacts of the grid mix in terms of human toxicity (Figure 10), a reversal of the trend is observed for the first time, whereby the total impact increases going from 2019 to 2035 (+10%), only to then decrease again slightly in 2050 (+8% relative to 2019). Because of the unavoidably large uncertainty associated with the quantification of HTP (cf. Section 3.1.3), such relatively small changes are probably at the limit of what ought to be considered statistically significant, and another, possibly more scientifically valid way of looking at the results is that the overall human toxicity potential of the grid mix is expected to remain broadly stable for the next three decades.

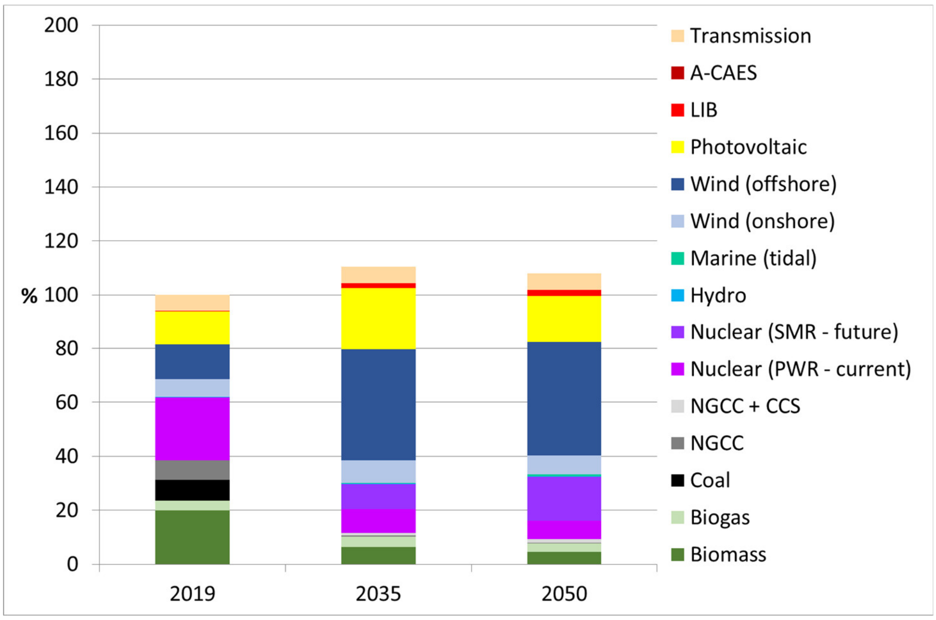

Figure 10. Human toxicity potential per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = 83 g 1,4-DB-eq/kWh).

What is interesting, nonetheless, is that the relative contributions of the various technologies to the total impact are significantly different than for GWP or AP, and for the first time even those technologies that are conventionally regarded as the "greenest" (i.e., wind and solar PV) end up being responsible for sizeable shares of the total impact. These results are due to a combination of these technologies' comparatively large demand for heavy metals (mainly Cu, Al and Ni) per functional unit (also corroborated by previous independent studies [19,85]), and the toxic emissions associated to the respective metal supply chains (mainly at the mining and beneficiation stages) [33,86]. For the same reasons, electricity transmission lines and LIBs are also non-negligible contributors to this impact category. The HTP of nuclear electricity is likewise significant in the mix, almost entirely due to the emissions arising from the uranium supply chain.

4.1.4. Abiotic Depletion Potential (Elements)

The abiotic resource depletion results illustrated in Figure 11 ("elements", i.e., excluding energy resources such as fossil fuels and uranium) are even more striking, in that they point to a significant increase of the total grid mix impact: initially +76% in 2035 and then down to +55% in 2050 (both values relative to 2019). Even more so than for HTP, these results are mainly driven by wind and PV's increased demand for metals (mainly Cu) per unit of electricity delivered, and LIB and transmission lines once again play a non-negligible role.

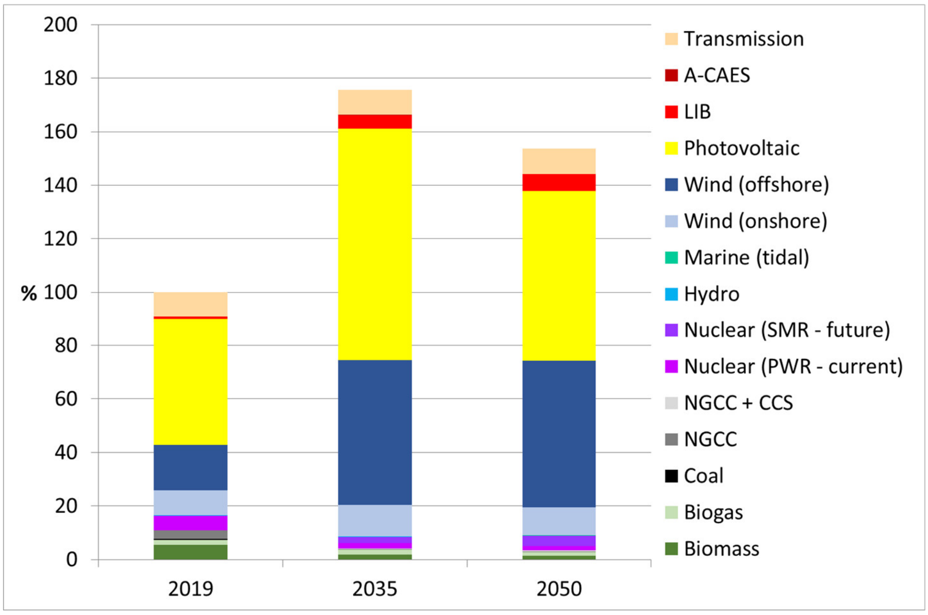

Figure 11. Abiotic depletion potential (elements) per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = $3.6 \cdot 10^{-4}$ g Sb-eq/kWh).

4.1.5. Non-Renewable Cumulative Energy Demand

The analysis of the grid's overall demand for non-renewable primary energy (Figure 12) is straightforward to interpret, with those thermal technologies relying on non-renewable energy feedstocks (i.e., coal, natural gas and uranium) being responsible for the vast majority of the impact. The continued reliance on nuclear power as a significant contributor to the future mix (15.8% in 2035 and up then to 19.5% in 2050—cf. Figures 2 and 3) also poses a major constraint on the achievable improvement at grid level (only −24% in 2035 and −40% in 2050), which contrasts with the more significant gains in terms of decarbonization (cf. Figures 7 and 8).

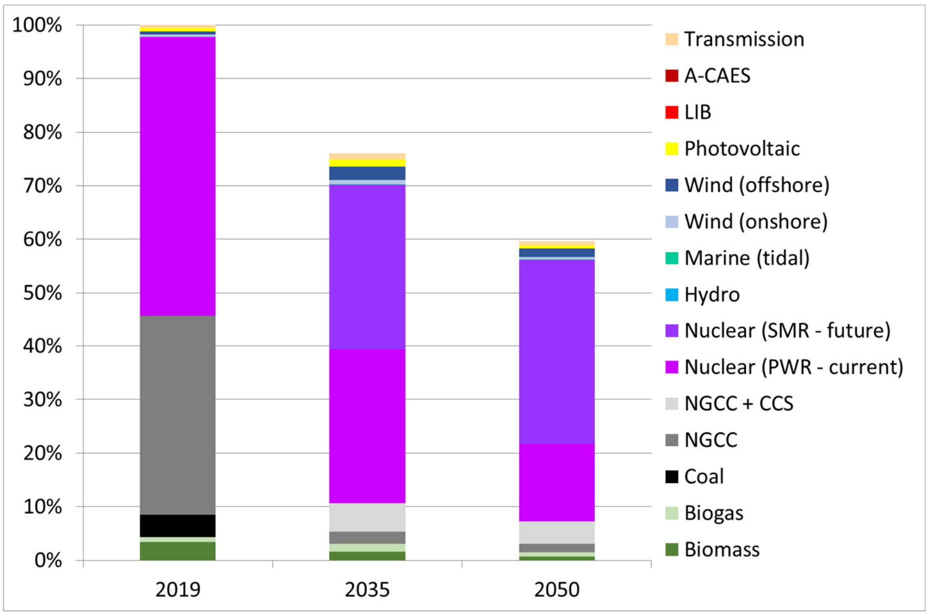

Figure 12. Non-renewable Cumulative Energy Demand (nr-CED) per unit of electricity delivered by the UK grid mix (including energy storage and transmission), expressed as relative to the 2019 value (100% = 6.0 MJ oil-eq/kWh).

4.2. Net Energy Analysis Results

Figure 13 illustrates the total primary energy that must be invested to operate the various energy supply chains that "feed" the UK grid, per unit of final electricity delivered by the grid itself. It is important to recall that, as explained in Section 3.2, these figures exclude the primary energy resources that are directly harvested from nature and converted into electricity (e.g., the coal itself that is extracted, pulverized and delivered to the coal-fired power plants; the woody biomass is harvested, compressed into pellets and delivered to the biomass-fired power plants; the solar energy is captured by the PV panels; and so on and so forth). What these results show is that, over time, the UK grid mix will require less and less commercial energy to be diverted from other societal uses and (re)invested to support its operation, per unit of electricity delivered.

In terms of the break-down of the total energy investment by technology, the results for the three years considered in the analysis broadly reflect the changing grid mix composition, with a few notable observations to be made, as follows.

(i) The energy investment for biomass-fired electricity is disproportionally large (over 30% of the total in 2019, vs. a share of only 10% of electricity generated). The planned reduced reliance on biomass as an energy resource for electricity generation in the future (3% of the grid mix in 2035 and 2% in 2050—cf. Figures 2 and 3) therefore seems justified from a net energy perspective.

(ii) At the opposite end of the scale, the expected future energy investment for wind electricity (approximately 30% of the total in 2035 and 2050) appears to be well justified in view of the associated energy returns (the share of total electricity generated by wind approaches 60% in the same years—cf. Figures 2 and 3).

(iii) The energy investment required for energy storage technologies (A-CAES and LIB) remains very small, even when such technologies are relied upon to store 10% of the VRE generated. This is a reassuring result that indicates that, from an energy balance perspective, there likely will not be any disruptive consequences when moving to a future grid mix which will rely heavily on intermittent renewable generators and will therefore require energy storage.

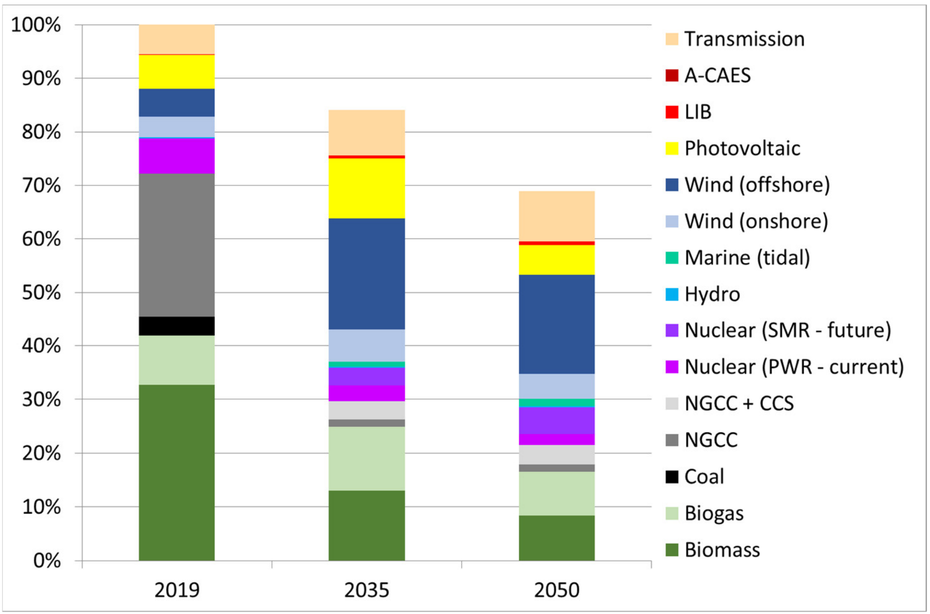

Figure 13. Total energy investment per unit of electricity delivered by the UK grid mix (results include the effects of energy storage and transmission), expressed as relative to the 2019 value (100% = 0.65 MJ oil-eq/kWh).

Figure 14 then illustrates the same overall results, but in terms of the Net-to-Gross primary energy return ratio. NTG is shown to creep steadily upwards on the "net energy cliff", from 2019 to 2050, once again indicating that the planned energy transition according to National Grid's "2 degrees" scenario is sound from a net energy perspective. This is a significant result, which should allay some of the often-voiced concerns about potentially reduced future availability of net energy.

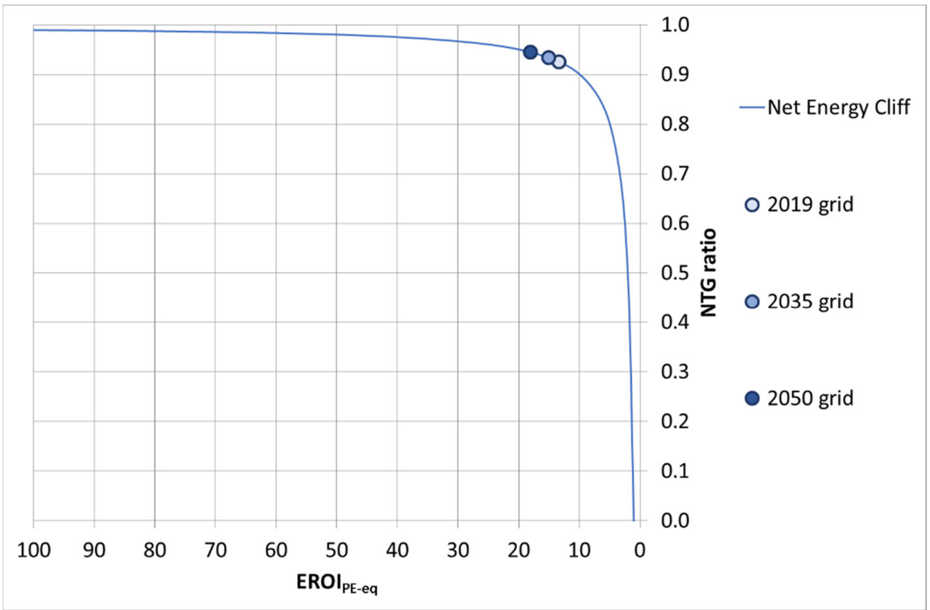

Figure 14. Evolution of the Net-to-Gross (NTG) primary energy return ratio of the UK grid mix (results include the effects of energy storage and transmission).

Having said all this, it is also important to underline that the present analysis was carried out using an "integrative" approach [87], which is characteristic of LCA and which "discounts" (i.e., virtually spreads out) all inputs and emissions associated to each individual energy system over its respective full life cycle. In other words, each individual energy supply chain is treated as a "black box" from a temporal perspective, irrespective of exactly when, during its life cycle, a particular (energy) input is supplied or a specific emission occurs. Instead, in reality, most of the material and energy inputs required for renewable technologies such as wind and PV take place up front during their manufacturing phase, while the associated energy "returns" are reaped over the course of approximately three decades (the typical lifetime of these systems). When these technologies are deployed quickly and on a massive scale, this type of temporal mismatch could, in some instances, result in a temporary reduction in the initial year-by-year availability of net energy, as discussed elsewhere in literature [88]. While this fact needs to be duly taken into account in terms of energy policy planning, it is fair to argue that, in light of the overall positive longer-term NTG trend identified here, it should not be seen as reason to dismiss the fundamental soundness of the whole long-term strategy, but instead as a further call for the application of a "sower's strategy" (whereby today's energy "seeds" are planted to reap the energy "crops" of tomorrow) [89].

5. Conclusions

This thorough life-cycle analysis of National Grid's "2 degrees" future energy scenario has produced a wide range of quantitative results which, when analyzed together, allow for a comprehensive and balanced appraisal of its strengths and weaknesses. To summarize, the following considerations may be made, which capture the key findings and provide policy guidance.

Firstly, these life-cycle carbon budget calculations have confirmed that the "2 degrees" strategy would be very effective at decarbonizing UK electricity, albeit not to the radical extent that might have been inferred by just taking at face value the share of electricity that is projected to be generated by "zero carbon" technologies (nuclear, wind, tidal, hydro, biogas, biomass and gas with CCS).

Secondly, the analysis has shown that biogas and, to a lesser extent, biomass are not especially benign energy resources for electricity production, despite their intuitively reassuring "bio" designation. Both are negatively affected by low energy return on investment, and biomass-fired electricity is responsible for very large acidic emissions. However, while reducing the reliance on biomass would be relatively easy to achieve by just curbing imports of wood pellets from North America, biogas-fired electricity may prove difficult to phase out, since biogas is produced in landfills and agricultural sludge, and using it to produce electricity may be the lesser evil in terms of global warming. Cleaning up biogas electricity generation by either upgrading the biogas feedstock to biomethane or applying drastic scrubbing at the power plant stack output would however still be recommendable.

Thirdly, the results have indicated that moving to the large-scale penetration of variable renewable energy (VRE) generation entails some trade-offs in terms of the depletion of metal resources and potential associated life-cycle toxicity impacts. This is partly due to wind and PV's demand for technology-specific metals and semi-metals, but also in large part simply determined by their less spatially concentrated nature, which calls for more copper transmission lines per unit of electricity delivered.

Fourthly, the planned continued (and even increased, after 2030) reliance on nuclear generators puts a hard cap on the achievable gains in terms of decreased dependence on non-renewable (and imported) energy resources. While the ultimate availability of nuclear ore reserves may not pose a major issue for a long time still, this fact does have immediate negative consequences in terms of the UK's energy sovereignty (since no such ores are available domestically).

Importantly, the deployment of energy storage technologies has shown not to cause any major set-backs in terms of any of the impact categories (with the possible partial exception of human toxicity and abiotic depletion). This is a welcome and reassuring result in and of itself, and it may also be interpreted to indicate that perhaps an even more aggressive roll-out of wind and PV might be attempted (the intermittency of which could be mitigated with even more energy storage), which would lead to a reduced demand for new small modular nuclear reactors.

However, a margin of uncertainty remains on the possible residual requirement for some curtailment of VRE, despite the substantial energy storage capacity that is assumed to be deployed in the "2 degrees" scenario. Such uncertainty could potentially be reduced by employing a high-temporal-resolution modelling approach whereby the hourly electricity supply and demand profiles are extrapolated on the basis of historical datasets.

Additionally, further research is already under way, whereby the interlinkages between the electricity and transport sectors will be explicitly modelled dynamically, with specific focus on the twin roles played by lithium-ion batteries (LIBs). On the one hand, LIBs are expected to be used as on-board storage in electric vehicles (EVs), which may be privately-owned or used for transport-as-a-service (TaaS), and in both cases potentially provide vehicle-to-grid (V2G) storage capacity. On the other hand, LIBs will also be used for dedicated stationary grid-level storage, in which case they may be produced using a combination of virgin and recycled materials, or even re-purposed after their first use in EVs (i.e., a second life application). The ensuing coupled mass-flow model will enable a more detailed and robust assessment of the energy and environmental impacts of energy storage on the future electricity grid mix, by improving on the current blanket assumptions about the future deployment of LIB and V2G storage.

Finally, this analysis has produced significant, and to some extent, possibly even ground-breaking results by dispelling the often-voiced concerns that a massive transition to renewable energy technologies must necessarily entail a worrisome reduction in the net energy that is made available to society. In fact, it was shown that the evolution of the UK grid under "2 degree" scenario conditions would even result in a modest increase of its net-to-gross energy return ratio.

All in all, this study's results should be taken as a sobering reminder that there is more to "greening the grid" than meets the eye, and that forecasting the complex effects of any energy policy strategy calls for a holistic life-cycle approach.

Author Contributions: Conceptualization, M.R.; methodology, M.R.; software, M.R. and M.K.; validation, M.R., M.K. and A.H.; formal analysis, M.R.; investigation, M.R. and M.K.; resources, M.R. and M.K.; data curation, M.K.; writing—original draft preparation, M.R. and M.K.; writing—review and editing, M.R. and A.H.; visualization, M.R.; supervision, M.R. and A.H.; project administration, A.H.; funding acquisition, A.H. All authors have read and agreed to the published version of the manuscript.

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Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

This appendix contains foreground life-cycle inventory tables for those electricity generation and storage technologies for which no pre-existing data were available in the Ecoinvent database, and which had to be modelled from scratch on the basis of literature information.

Table A1. Foreground inventory of life-cycle inputs for carbon capture and storage (CCS) technology, complementing natural gas combined cycle (NGCC) power plants. All values are per kWh of electricity generated.

Item	Quantity	Unit
Activated Carbon	$3.2 \cdot 10^{-5}$	kg
Concrete	$2.1 \cdot 10^{-7}$	kg
Electricity [1] (for CO_2 compression)	$4.7 \cdot 10^{-2}$	kWh
Monoethanolamine (MEA)	$1.8 \cdot 10^{-4}$	kg
Polyethylene, high density (HDPE)	$7.1 \cdot 10^{-7}$	kg
Sodium hydroxide (NaOH)	$5.5 \cdot 10^{-5}$	kg
Steel (low alloyed)	$7.7 \cdot 10^{-5}$	kg

[1] Accounted for by deduction from plant output.

Table A2. Foreground inventory of use-phase emissions per kWh of electricity generated by the NGCC + CCS system.

Item	Quantity	Unit
Carbon dioxide (CO_2)	47	g
Nitrogen oxides (NO_x)	$1.7 \cdot 10^{-1}$	g
Sulphur dioxide (SO_2)	$3.8 \cdot 10^{-3}$	g
Particulate matter (PM)	$2.2 \cdot 10^{-3}$	g
Formaldehyde (HCHO)	$1.1 \cdot 10^{-1}$	g
Acetaldehyde (CH_3-CHO)	$7.0 \cdot 10^{-2}$	g
Ammonia (NH_3)	$1.5 \cdot 10^{-2}$	g
Monoethanolamine (MEA)	$2.6 \cdot 10^{-2}$	g

Table A3. Foreground inventory of life-cycle inputs for stream turbine tidal electricity generation. All values are per kWh of electricity generated.

Item	Quantity	Unit
Cast Iron	$1.5 \cdot 10^{-6}$	kg
Cement	$2.5 \cdot 10^{-5}$	kg
Copper	$3.2 \cdot 10^{-6}$	kg
Electricity (for plant construction)	$1.9 \cdot 10^{-2}$	kWh
Glass fibre reinforced plastics (GRP)	$9.4 \cdot 10^{-6}$	kg
Polyethylene (PE)	$4.7 \cdot 10^{-7}$	kg
Steel (low alloyed)	$1.6 \cdot 10^{-4}$	kg

Table A4. Foreground inventory of life-cycle inputs for adiabatic compressed air energy storage (A-CAES) technology, including plant construction, compressors, thermal energy storage (TES) and heat expanders. All values are per MWh of electricity storage capacity.

Item	Quantity	Unit
Aluminium	$4.4 \cdot 10^{-1}$	kg
Cast Iron	48	kg
Concrete	$5.2 \cdot 10^{2}$	kg
Copper	4.0	kg
Diesel (burnt in building machines)	$9.1 \cdot 10^{2}$	MJ
Electricity (for plant construction)	18	kWh
Foam Glass	3.2	kg
Heavy fuel oil (burnt in industrial machines)	$9.1 \cdot 10^{2}$	MJ
Insulation (rock wool)	19	kg
Limestone	4.6	kg
Lubricating oil	$2.5 \cdot 10^{3}$	kg
Polypropylene (PP)	$6.3 \cdot 10^{-1}$	kg
Sand-lime brick	24	kg
Steel (high alloyed)	91	kg
Steel (low alloyed)	$1.3 \cdot 10^{2}$	kg
Steel (unalloyed)	$1.1 \cdot 10^{2}$	kg

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