A multi-disciplinary analysis of UK grid mix scenarios with large-scale PV deployment

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Abstract

The increasing contribution of renewable energies to electricity grids in order to address impending environmental challenges implies a reduction in non-renewable resource use and an alignment with a global transition toward a low-carbon electric sector. In this paper, four future UK grid mix scenarios with increased photovoltaic (PV) installed capacity are assessed and compared to a benchmark "Low PV" scenario, from 2016 to 2035. The complexity of the issue requires a multi-disciplinary approach to evaluate the availability of net energy, environmental aspects and technical performance. Hence, the comparison between scenarios includes short-term and long-term energy metrics as well as greenhouse gas (GHG) and technical metrics. Also, the paper considers the viewpoints offered by both an "integrative" and a "dynamic" approach to net energy analysis. Results for all five analysed scenarios indicate that increased PV deployment will not be detrimental to the UK grid performance from the points of view of a wide range of system-level technical (% renewable energy curtailment to ensure grid stability), energy (energy return on investment and non-renewable cumulative energy demand) and environmental (greenhouse gas emissions) metrics.

Keywords: grid mix; LCA; EROI; prospective; consequential; scenarios.

1) Introduction

A transition to low-carbon energy technologies is a key challenge to preventing pervasive and irreversible impacts on the world's peoples and ecosystems [1]. In fact, during the recent 21st Conference of the Parties (COP21) [2], national agreements were discussed to reduce emissions and limit global warming to below a 2°C increase relative to pre-industrial levels [3]. This will require a radical change of the whole energy sector, both in terms of energy supply and energy transformation, including power generation, and energy consumption in buildings, industry, transport and agriculture, which currently accounts for two-thirds of all anthropogenic greenhouse-gas emissions [4]. In addition, continued population growth and increasing use of energy for human development compound the problem and further highlight the importance of achieving these goals.

Although fossil fuels are still the dominant global energy resources – in the UK these account for 84.5% of total final consumption (including both fuels and electricity) [5] –

recent years have seen progressive change away from fossil fuel electricity generation towards alternative resources of energy, such as renewables, driven by the UK environmental policies aimed at reducing carbon emissions[1]. The overall contribution of renewable energies to UK electricity generation, including wind, natural-flow hydro, solar, wave, tidal and bioenergy, increased by 21% in a single year between 2013 and 2014 [5]. As a result, renewable resources provided approximately 20% of the electricity generated in 2014. Although wind energy has been the major contributor to this increase, in 2014 and 2015 a significant increase in renewable electricity generation from solar photovoltaics (PVs) was also seen. The global cumulative installed capacity of PV at the end of 2015 was 229 GW, of which 9 GW have so far been installed in the UK, which results from the UK having been the largest European market for the second year running in 2015 (in which year new PV installations in the UK totalled 4.5 GW, *vs*. 1.4 GW in Germany as the second-largest European market) [6]. This recent increase of PV capacity in the UK electricity mix has stimulated interest in the exploration of future scenarios in which solar energy may be more widely deployed across the UK electricity grid.

The complexity and uncertainty of the potential future energy system–as well as the far-reaching consequences that any major change in a country's energy mix may be expected to have – call for the careful exploration of a range of future grid mix scenarios. Of special relevance to this whole topic is the issue of intermittency and its consequences on how intensively the various electricity production technologies may be exploited. The latter is expressed by means of technology-specific capacity factors (CFs), which are defined as the ratio of the average effective power output to the nominal installed power. Renewable technologies such as PV and wind are intrinsically variable in their capacity to generate

[1] UK Climate Change Act 2008 (http://www.legislation.gov.uk/ukpga/2008/27/pdfs/ukpga_20080027_en.pdf)

electricity, and, in lack of any “built-in” means of storing the captured primary energy, the only way to modulate their output is to curtail it during times of excessive production (the technical term to refer to this condition is “non-dispatchable”). All else being considered equal, this often results in lower CFs for wind and PV *vs*. conventional thermal technologies relying on fossil or nuclear feedstocks.

In the literature, a number of energy system modelling tools have been employed to develop and analyse future grid mix scenarios, to schedule electricity dispatch, and to plan the operation of power systems. Among these we note: MARKAL (MARKet ALlocation) - a dynamic linear programming model developed by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) [7-8-9-10-11], TIMES (The Integrated MARKAL-Energy Flow Optimization Model System) [12-13], LEAP (Long range Energy Alternatives Planning) [10], and others. All these tools are essentially economic model generators for local, national or multi-regional energy systems, which provide a technology-rich basis for estimating energy dynamics over a long-term, multi-period time horizon. Their common main goal is invariably to achieve the minimum overall cost in supplying energy services, while simulating the technological, economic and to a lesser extent environmental impacts of energy supply, with an emphasis on cost optimisation. The structures of these optimisation tools are based on solid theoretical foundations and rigorous mathematical equations. However, such tools do not fully take into consideration the political and social aspects of energy policy, which are arguably also relevant for a comprehensive energy policy analysis [14]. Also, crucially, the very fact that the core focus of all these tools is on *economic* optimization makes them somewhat susceptible to potential economic-induced distortions in the ways and extent to which they take into account *physical* performance parameters (examples of such distortions include those resulting from sector-specific economic incentives, feed-in tariffs, subsidies, discount rates, etc.).

This paper, instead, presents the results of an original investigation, in which key economic elements (which underpin the adopted unit commitment model) are combined with socio-political input (in the form of a stakeholder consultation) to arrive at a multi-dimensional assessment of the electricity system's performance *from a purely bio-physical[2] perspective, with a special focus on energy and greenhouse gas emissions as the key numeraires of interest.* This work thus addresses issues of technical feasibility, carbon emissions, non-renewable resource depletion, and availability of net energy, from both "integrative" and "dynamic" points of view. The whole investigation is set within the UK EPSRC-funded WISE-PV (Whole-System Impacts and Socio-Economics of Wide Scale PV Integration) project [15-20].

Section 2 describes the analysed system and the original approach to the analysis of the considered future scenarios; Section 3 explains the individual assessment methods used and the associated metrics; Section 4 presents and discusses the method-specific results; and, finally, Section 5 provides some overarching conclusions.

2) The analysed system

2.1 The current UK electricity grid

[2] The term "bio-physical" refers to a reading of techno-economic processes that eschews conventional economic numeraires and instead seeks to describe and explain their operation making exclusive use of physical units such as kg, MJ, etc. and their derivatives.

The analysed system consists of the whole UK electricity grid, incorporating the full range and scale of electricity production technologies which includes nuclear, hydro, wind (on-shore and off-shore), coal, oil, gas, biomass and PV (ground-mounted and installed on rooftops) generation capacities. The current composition of the UK grid in terms of yearly electricity generation by the eight main families of technologies is illustrated in Table 1. The shares listed in Table 1 refer to the cumulative electricity produced at power plant gate by all power plants.

Table 1 HERE

The schematic in Figure 1 illustrates the conceptual model that is used to analyse the UK electric grid. The model includes the full set of electricity generation technologies ((i) = 1 to 8 in Table 1), and the diagram illustrates the key difference between those systems directly harvesting a renewable primary energy flow such as hydro, wind and PV and the thermal systems relying on a feedstock of nuclear fuel, gas, oil, coal, and biomass. The system boundaries also include pumped hydro energy storage at the grid level. Pumped hydro storage offers useful back-up during periods of peak demand by maintaining grid stability, and it may also be used in order to address intermittency issues related to other renewable technologies, such as PV and wind [21, 22]. Additionally, UK domestic production is supplemented by a relatively small amount of electricity (less than 6%), supplied via the interconnectors with mainland Europe [23]. However these imports via interconnectors are excluded from our analysis.

Figure 1: Streamlined energy system diagram of UK electric grid. Arrows labelled "In" or "Out" represent electricity flows, while arrows labelled "Inv" represent energy investments (calculated on the full life-cycle scale, and including both direct operational inputs and indirect inputs such as capital investments). Electricity imports from abroad (dashed arrow originating from Interconnector) are excluded from the analysis. E = feedstock extraction; R = feedstock refining; D = feedstock delivery; PP = power plant; NPP = natural primary production; PH = Pumped Hydro; N = transmission and distribution network; G = grid. Symbolic conventions after Odum [24].

2.2 An original approach to the analysis the future evolution of the grid

There are a diversity of ways in which the UK energy system may evolve in the coming decades, due to numerous factors, such as environmental legislation, energy cost, and developments in individual technologies. Therefore, this paper considers five different scenarios for the future electricity technology grid mix, and incorporates a number of socio-economic and bio-physical aspects to arrive at a comprehensive, multi-disciplinary analysis of such scenarios. Specifically, the study is structured according to the following five main steps:

1. Selection of a first reference scenario for the future composition of the UK grid mix (in terms of installed GW of each technology) over the years 2015 - 2035 (*cf.* Section 2.3). The choice of this scenario was driven by the desire to be consistent with what has already been put forth by National Grid with their "Gone Green" scenario, and <u>in line with the current political objectives in terms of overall grid decarbonisation and the strategies to achieve it</u>.

2. Setting of a common ambitious target for the deployment of PV in the UK grid (i.e., 50 GW of PV installed capacity in 2035), to be adopted in four alternative “High PV” scenarios via key stakeholder consultation. The choice of this specific target ensued from one of our key research aims, namely <u>to analyse the potential effects of such a large deployment of PV</u> on the stability and on the net energy and environmental performance of the entire grid.

3. Quantitative definition (in terms of installed GW of each technology) of the four alternative “High PV” grid mix scenarios, which differ in terms of the relative shares on nuclear, wind and biomass installed capacities (*cf.* Section 2.3). The definition of these scenarios derived from the stakeholder consultation exercise, and as such <u>introduces a further socio-political element to our analysis</u>.

4. Calculation of the amount of electricity produced by each technology (i.e., of the technology-specific Capacity Factors) by means of a Unit Commitment (UC) model that <u>responds to an economic imperative</u> (i.e., the minimization of the unit cost of electricity), with selected additional assumptions and operational constraints (*cf.* Section 2.4) that are normally not part of other analysis tools that only have a very simplified representation of power system operation. Also, the implicit assumption made in this work - which is line with typical considerations when carrying out system level studies that cannot deal with the distribution network level of detail - is that local issues (especially due to potential voltage constraints) will be dealt with locally through technologies such as on-load tap changers, active and reactive power controls, etc.

5. *Ex-post* analysis of the technical (*cf.* Section 3.1), energy (*cf.* Sections 3.2 and 3.3) and environmental (*cf.* Section 3.4) performance of the five analysed grid mix scenarios. This original multi-dimensional analysis is performed on a purely bio-physical level (i.e., without converting any data into "equivalent" economic costs), and it offers comprehensive insight into the system beyond what might have been achieved by the application of pre-existing methods.

2.3 The analysed scenarios

The scenario illustrated in Figure 2 and referred to as "Low PV" has been adopted as a reference benchmark for the grid mix evolution. It is derived from the "Gone Green" scenario developed by National Grid and assumes that the UK's carbon emissions targets are achieved [25]. Electricity demand over the time period for all scenarios is also taken from this dataset (*cf.* Section 2.4).

Figure 2 – UK electricity production mix in the "Low PV" benchmark scenario [25].

As outlined in Table 2, four alternative "High PV" scenarios have been constructed to investigate how different patterns of grid development affect its performance, while considering a common target of 50 GW of PV installed capacity by 2035. These scenarios were developed on the basis of the outputs of a WISE-PV project stakeholder consultation exercise, involving a range of actors from the public sector and private industry [26].

Table 2 HERE

In all the “High PV” scenarios, PV installations are expected to be installed primarily on domestic and non-domestic rooftops (approximately 80% of the total estimated installed capacity). This is consistent with the intended preference for distributed generation expressed in the consultation.

The four scenarios differ in terms of the non-PV element of electricity supply in response to stakeholder concern about the effects of PV intermittency on different future grid mixes. On the one hand, in the “High PV (1)” and “High PV (3)” alternatives, PV is assumed to displace part of nuclear power, with the result that intermittent resources of energy feature more prominently in the grid mix. On the other hand, in the “High PV (2)” and “High PV (4)” alternatives, PV technology is assumed to be deployed *in lieu* of part of the projected wind capacity, which results in a higher relative share of thermal electricity technologies. Also, another major difference is that the “High PV (3)” and “High PV (4)” scenarios do not feature any carbon capture and sequestration (CCS) deployment, with the shortfall being picked up by nuclear in “High PV (3)” or a combination of nuclear and biomass in “High PV (4)”.

Table 3 lists the resulting 2035 installed capacities of all technologies in the five analysed scenarios.

2.4 Main assumptions and boundaries

The following assumptions and boundaries of the study were used to evaluate the scenarios described in section 2.2.

A first key assumption relates to the technology-specific capacity factors (CFs).

The CFs of non-intermittent technologies, such as all thermal technologies, tend to be relatively stable, with the notable exception of combined-cycle gas turbines (CCGT) when these are used as easily-dispatchable backup rather than as main generators, in which case their capacity factors could be lower. The CF of dammed hydroelectricity often tends to be relatively stable, too (within the upper bound imposed by the geomorphology of the water basins), given that this is the only renewable technology that features “built-in” storage that allows it to be dispatched as the need arises.

On the other hand, the CFs of non-dispatchable, intermittent resources of energy, such as PV and wind, are not only conditioned by seasonal and annual weather variations, which make them intrinsically more variable, but also by the possible curtailment required by a mismatch between intermittent production and demand profile. More specifically, the wind, solar and hydro generation profiles are all in half-hourly resolution. The wind and solar generation profiles are calculated based on the historical wind speed and solar irradiance data shown in [27, 28] and the corresponding installed capacities of wind and solar. The hydro generation profile is extracted from historical profiles [29] published by Elexon. The hydro production is assumed to be fixed for the future scenarios, as the installed capacity is only 1.1 GW and no hydro plant is planned to be built after 2015 as shown in [25].

In this study, a detailed unit commitment (UC) model that features a linear programming optimisation [30] is utilised to simulate in detail the power system operation for the proposed scenarios of the UK grid mix, and thus take into account all foreseeable fluctuations of the CFs. The classic unit commitment uses binary variables to represent the operation states of individual generators [31]. However, recent research [32] shows that clustering similar generators into one group and using integer variables to represent the on/off states of generators would substantially improve the computational efficiency of UC calculation. The UC model applied in [30] and in this paper has relaxed those integer variables representing generator states to continuous variables, such that further reduction in the computational time can be achieved with minor impact on the accuracy of simulation results. The power plants are clustered based on their fuel types and technologies to gain a substantial improvement in terms of computational efficiency while preserving substantial accuracy, as demonstrated in [30]. The objective function of the UC model is to minimise the total system cost including the operational cost of generators and renewable curtailment penalty. The constraints considered in the UC model include the energy balance constraint, the technical constraints of non-renewable generators (such as, ramping capability limit and minimum up and down times), and the constraints representing system requirement on ancillary services. The detail of constraints can be found in [30]. The adopted UC model has a half hourly resolution, and simulated on a weekly basis for a year. This resolution and simulation time length is used to ensure that the deployment of secondary reserve can be properly captured and the cycling of pumped hydro storage is modelled. Then, the CFs of different generation technologies are calculated based on the simulated generation dispatch of the corresponding generation technology.

Detailed information on the resulting assumed CFs for all electricity generation technologies is provided in the Supplementary Information, available via the Internet at: http://www.sciencedirect.com.

The characteristics of the conventional generators and their corresponding fixed operational cost, variable cost and start-up cost are also included, as in [30] and summarised in Table 4. The fixed operational cost and variable cost are referred to as the two components in the operational cost curve of generators. The start-up cost is used to represent the total cost to bring an offline generator online. It needs to be noticed that there is no start-up cost for nuclear power plants in the model. This is because the nuclear plants are considered as “must-run” units in the modelling. Although, this assumption will not affect the validity of the annual production figure of the nuclear plants, as an average availability factor (also shown in Table 4) is applied to the nuclear plants to limit its output level, which accounted the shutdown activities based on historical data shown in [33]. Meanwhile, in this paper the cost of plants with CCS is assumed to include the subsidy from Contracts for Difference (CfD) paid by the Low Carbon Contracts Company (LCCC) [34], leading to a higher dispatch merit order for plants with CCS. Therefore, the variable cost of CCS plants is set to a lower value in comparison to the same generator type without CCS in Table 4. Additionally, biomass plants are also assumed to be dispatched with merit order priority relative to CCGT plants. This is in line with the historical CF data in DUKES 2015 [5]. The generation cost parameters are summarised in Table 4. Moreover, for the impact of scheduled maintenance and unexpected outages of thermal power plants, the average availabilities of these generation technologies are used to de-rate the relevant installed capacities. The average availabilities used in the study are also listed in Table 4, which are based on the available information in [33]. The availability factor of coal is set to a value lower than the one provided in [33] due to the consideration of another constraint based on historical data shown in [25] and the future operation time limit of coal plants described in Large Combustion Plant Directive [35]. As seen in [25], the historical capacity factor for coal plants is 65% in the 2014/15 period. However, due to the low variable cost of coal plants in the UC model, the simulation result would lead to a high coal plants energy production in comparison to the historical data, if the availability factor for coal was assumed to be 88% as in [33]. Therefore, the availability factor of coal plants is set to 65% before 2024 to constrain its output. In addition, the operation time of coal plants will be capped to 1500 hours (corresponding to 17% load factor) after 2020 based on the Transition National Plan (TNP) given in [35]. Thus, the availability factor of coal is further reduced to 17% from 2025. Furthermore, in the model a penalty factor is assumed for solar curtailment, as opposed to no penalty for wind curtailment, to ensure that wind generation is curtailed prior to solar generation. This is because the system operator may have more visibility and control over (mostly transmission connected and high voltage distribution network connected) wind generation, whilst the majority of solar generation is distributed in medium and low voltage networks.

Table 4 HERE

The half hourly demand profile of UK power system in 2015 is extracted from electricity demand datasets published by National Grid[3]. The data is recorded at transmission network level, which already considers the grid loss and station load. For the simulation of future scenarios, the demand profile is scaled up/down based on the projection of annual electricity consumption in the National Grid "Gone Green" scenario [25].

In terms of technology-specific assumptions, all of the PV systems are assumed to be of the multi-crystalline silicon (mc-Si) type, since this is the most widely adopted technology worldwide [36]. At present, mc-Si PV modules are mainly manufactured in China and Europe [37], and current grid mix assumptions for these countries have been used [38]. Also, the required PV module and balance of system (BOS) energy investments are assessed using the latest literature data [38, 39]. Since relatively large technological improvements in future PV

[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/

systems may be expected in terms of module efficiency and energy demand for manufacturing, these have been modelled by extrapolating values for each future year based on a linear trend. Specifically, mc-Si PV module efficiency is expected to improve from 16% in 2013 [36] to 23.3% in 2035 [40]. Conversely, PV module lifetime has been kept fixed at 30 years [41], and a suitable yearly degradation coefficient of 0.6% has been applied [42]. The PV performance ratio is also assumed fixed at 75% [41]. Although individual parts of the UK are characterised by different levels of irradiation from 900 to 1,300 $kWh \cdot m^{-2} \cdot yr^{-1}$ [43], an average value of 1,000 $kWh \cdot m^{-2} \cdot yr^{-1}$ has been assumed for all PV installations, as is often adopted in other studies [44, 45]. Use of an average value allows for the aggregation of the results at a UK scale, and enables potential comparisons with other studies.

Additionally, three of the future scenarios for the evolution of the UK electricity system include the partial deployment of CCS technology for coal and gas-fired power plants. According to the literature, it is assumed that fitting such CCS devices incurs in +19.5% and +16.5% increased fuel demand penalties, respectively for coal and combined cycle gas power plants (both cases for 90% active CO_2 capture efficiency) [46, 47].

Finally, pumped hydro storage capacity has been assumed to increase in all future scenarios, in parallel with the growth of wind and PV installations.

3) Methodology

3.1 Technical impacts

Based on the adopted UC model, the following metrics are proposed to quantify the technical impacts of the increasing PV penetration:

- Annual capacity factor (CF) of conventional thermal plants (%);

- Annual renewable energy curtailment (% of total available renewable energy per year).

The annual capacity factor (CF_i) for each cluster of power plants (i) is calculated as from Equation 1 by using the power output ($P_{i,t}^{G}$) from the cluster, the number of maximum available units (N_i), and average unit nameplate capacity ($P_i^{G\_max}$). The annual wind and solar curtailment values are calculated based on the simulation result.

(1) $$CF_i = \frac{\sum_{t=1}^{T} P_{i,t}^{G}}{N_i \cdot P_i^{G\_max} \cdot T}$$

The CF metric is able to represent the operational role of different conventional thermal plants. For instance, a high CF means that the corresponding thermal plants are operated mainly to supply electricity demand; on the contrary, a low capacity factor implies that the corresponding thermal plants are operated mostly to provide operational services (e.g., fast reserves) to the system. The annual renewable energy curtailment provides direct indication with regards to the system's capability of integrating renewable energy.

Additionally, these metrics are also key inputs for the short-term energy impacts as will be introduced in the following part.

3.2 Short-term energy impacts: Net Energy Analysis metrics

Net Energy Analysis (NEA) is a scientific discipline developed to evaluate the effectiveness of a system at exploiting primary energy resources and upgrading environmental stocks and flows into usable energy carriers [48-55].

One of the main indicators of NEA is the Energy Return on (Energy) Investment (EROI), which is defined as the ratio of the total (gross) amount of energy "returned" to society by the analysed system in the form of a useful energy carrier to the total energy diverted from other societal uses and deliberately invested in the supply chain for the analysed system (such as, e.g.: prospecting for, locating, extracting, processing, and delivering a fuel feedstock, and eventually transforming it into electricity).

It is recommended to express all contributions to the energy investment (Inv) in terms of their life cycle primary energy demand, calculated as the total primary energy harvested from the environment in order to produce and deliver them [56, 57, 58]. The energy that is "returned" (Out) may instead be accounted for either in direct energy units of the delivered energy carrier (e.g., Out measured in units of electrical energy), or in terms of equivalent primary energy ($Out_{PE\text{-}eq}$). Therefore we need to differentiate between:

(2) $EROI_{el} = Out/Inv$

Energy Return on Investment, expressed in terms of direct electricity output

and

(3) $EROI_{PE\text{-}eq} = Out_{PE\text{-}eq}/Inv = EROI_{el}/\eta G$

Energy Return on Investment, expressed in terms of equivalent primary energy output, where η_G is the life-cycle energy efficiency of the grid mix.

It is noteworthy that $Out_{PE\text{-}eq}$, and hence $EROI_{PE\text{-}eq}$, depend not only on the performance of the individual technology on its own, but also, critically, on the average energy conversion efficiency of the electric grid into which it is embedded.

For simplicity, and to avoid the added complications of incorporating η_G into the EROI formula, in this paper we focus on the discussion of the $EROI_{el}$ trends.

EROI as defined above is traditionally considered an “integrative” metric defined over a fixed time horizon, which generally coincides with the lifetime of the analysed technology. Therefore, such EROI intrinsically refers to the time-averaged performance of an energy production system (i) over its lifetime (T), where:

$Out_{i,T}$ as cumulative electricity output by system (i) over its lifetime (T)

$Inv_{i,T}$ as overall energy investment required by system (i) over its lifetime (T)

In our case, however, the entire UK electricity grid is composed of a number of sub-systems (i.e. the individual electricity generation technologies, and the energy storage, transmission and distribution infrastructure) which are all characterised by a range of different lifetimes. This makes it difficult to unequivocally define a single “system lifetime”. The way to deal with this situation from an “integrative” perspective is then to calculate all metrics on the basis of one functional unit (FU) of output, e.g., 1 MJ of electricity delivered by the grid, while expressing all reference flows of energy throughout the system as relative to that same FU.

Alternatively, an analysis based on a “dynamic” approach [19] is also interesting, whereby the energy delivered to society by the complete system in a given year is compared to the sum of the energy investments made in the same year. In this latter case, it has been argued that the corresponding NEA indicator is more accurately defined as Power Return On Investment (PROI), because it measures the ratio of flows of energy per year [59].

Table 5 shows the alternative definitions of main energy flows within the system as modelled in Figure 1, according to the “integrative” and “dynamic” approaches.

Table 5 HERE

The following further inter-related definitions also apply:

η_N = energy efficiency of network transmission and distribution

$(1 - \eta_N)$ = energy dissipation factor of network transmission and distribution

The relation of Out to the individual electricity flows within the system is then given by Equation (4), where each individual flow is to be interpreted depending on the adopted approach, as specified in Table 5:

$$(4) \qquad \text{Out} = \left[\sum_{i=1}^{8} \text{Out}_i - \left(\frac{\text{In}_{PH}}{\eta_N}\right)\right] \cdot \eta_N + \text{Out}_{PH} \cdot \eta_N = \left(\sum_{i=1}^{8} \text{Out}_i + \text{Out}_{PH}\right) \cdot \eta_N - \text{In}_{PH}$$

Overall, these NEA metrics provide a valuable indication of whether the analysed future grid mixes featuring increased deployments of PVs and other energy resources may still be able to maintain (and potentially even increase) the current rate of delivery of readily-usable energy to society (in the form of electricity) per unit of primary energy invested.

3.3 Long-term energy impacts: Life cycle assessment energy metrics

Life Cycle Assessment (LCA) offers a different point of view on the evaluation of the energy performance of alternative grid mix scenarios. In fact, as distinct scientific disciplines, NEA and LCA aim to address fundamentally different questions: whereas NEA provides recommendations on short-term net energy effectiveness, LCA's energy metrics are geared towards assessing long-term energy sustainability.

Specifically, a key energy demand metric in LCA (Equation 5) is focused on the total non-renewable primary energy that is harvested per unit of system output over its full life cycle (including extraction of primary resources, use phase, and disposal and recycling) [56, 57], adopting an "integrative" approach (as discussed in Section 3.2).

(5) $nr\text{-}CED = (PE_{nr}+Inv_{nr})/Out$

Non-Renewable Cumulative (primary) Energy Demand per Functional Unit

where: PE_{nr} is the non-renewable primary energy that is extracted, processed and used by the system directly, while Inv_{nr} is the non-renewable primary energy diverted from other societal uses and deliberately invested in the supply chain for the analysed system.

In the literature, NEA and LCA have often been used separately, even if their structures and procedural features share many elements in common. Instead, we argue that it is possible to implement both methodologies jointly to provide a more comprehensive description of the issue, both in terms of short-term and long-term energy impacts [18, 19, 20].

3.4 Long-term climate impacts: Life cycle assessment greenhouse gas metric

The global nature of climate change means that all greenhouse gas (GHG) emissions attributed to electricity generation should be accounted for [60], regardless of where or at which stage of the life cycle of a system they happen. GHG emissions do arise at different life cycle stages and within different national boundaries, depending upon country of manufacture or of fuel extraction and processing. LCA provides a way to compile and aggregate GHG emissions across all product stages so as to meaningfully and consistently compare electricity generation technologies with different temporal and spatial emissions profiles. The goal of this part of the work is thus to use LCA to compare the life cycle emissions of electricity supply by the different generation mixes specified in Section 2.3, within the common time frame of the analysed scenarios.

Scenarios are used to describe indirect emissions for installed generating capacity, including raw material extraction to commissioning, and decommissioning. The WISE-PV unit commitment model is used to characterise direct use-phase emissions including fuel supply and operational phases related to utilisation of that capacity. Incorporating direct use-phase emission values determined by a dynamic power systems model follows the work of Pehnt et al. (2008) [61] and Turconi et al. (2014) [62] on the consequential impacts of wind electricity generation on electricity grids. The analysis compares the “High PV” scenarios with the “Low PV” reference to assess the consequential differences in system GHG emissions arising from dynamic interactions between generators in the mix and different life cycle emission profiles.

The direct and indirect GHG emission values for the technologies are drawn from the LCA literature, with the exception of PV, which is based on an attributional LCA of multi-crystalline silicon (mc-Si) PV module and balance of system manufactured in China and installed in the UK with foreground inventory data from Frischknecht et al. [39] and with assumed inverter replacement after 15 years. In the case of wind energy, nuclear pressurised water reactors (PWR), coal and gas (CCGT) generation, the mean values from harmonisation studies by Dolan and Heath [63], Warner and Heath [64], Whitaker et al. [65] and O'Donoughue et al. [66] are used. Thornley et al. [67] on biomass combustion for electricity generation in the UK, and Cuéllar-Franca and Azapagic's [68] review of CCS LCA studies are used for the remaining technologies. The capacity factor and operational lifetime assumptions in these studies and their apportioning of emissions to different stages of the life cycle are used to determine the direct and indirect emissions as in Table 6.

Table 6 HERE

GHG emissions related to generating capacity installed and operated within the 2016-2035 timeframe are accounted for. For capacity installed before 2016 and still operating within the timeframe, pre-operational phase life cycle emissions are not included. A static temporal allocation is used to apportion a relative share of indirect emissions to the analysis timeframe to account for generating capacity installed within the timeframe but with a lifespan beyond 2035. This is done to enable an equitable comparison between technologies with primarily indirect emissions and those with mostly direct emissions.

4) Results and discussion

Throughout this section, the “Low PV” scenario is presented as a reference baseline in order to compare the four “High PV” alternatives.

4.1 Technical impacts

The evolution of the CF of conventional CCGT plants over the next two decades is presented in Figure 3 (as mentioned in Section 2.4, a full list of CFs for all technologies and scenarios is reported in the Supplementary Information). The overall trend of the average CF of CCGT suggests that as a relatively flexible generation technology, CCGT would be used more and more to provide operational dispatchability in a system with high penetration levels of renewable generation, rather than to supply baseload electricity to the system. The initially slower rate of decline between 2015 and 2025 is due to the fact that while the initial rapid retirement of coal plants takes place, CCGT is still used to provide part of the system's base load, which helps to keep the capacity factor of existing CCGT plants from dropping even further. Conversely, after 2025, the more marked decrease in the CF is caused not only by the high renewable penetration levels, but also by the increasing deployment of CCGT CCS in the "Low PV", "High PV (1)" and "High PV (2)" scenarios.

Figure 3. Average annual Capacity Factor of conventional combined cycle gas turbines (CCGT).

Then, as shown in Figure 4, a substantial increase in wind curtailment is expected to take place between 2020 and 2035 in all scenarios. On the one hand, this is because a large amount of wind energy is generated during low demand periods, mostly during the night; on the other hand, wind generation is also curtailed with priority relative to PV, as mentioned in Section 3.1 (PV generation ends up being curtailed for less than 1.5% of its annual available energy generation in all scenarios).

Figure 4. Annual curtailment of wind electricity (% of total annual available wind energy).

Comparing across the analysed scenarios, there are only minor differences in the CFs of conventional thermal generation until 2030. More marked differences can be found nearing 2035; however, these differences among the five scenarios are due to the overall generation mix of each scenario (and especially to the presence or lack of CCS), rather than to the increased deployment of PV in particular. Taking the CF of CCGT as an example, it can be seen in Figure 3 that the trend lines for the "Low PV", "High PV (1)" and "High PV (2)" scenarios are extremely close to each other. Meanwhile, the higher average CFs in the "High PV (3)" and "High PV (4)" scenarios are mostly due to the absence of CCS.

On the other hand, as illustrated in Figure 4, the "High PV (3)" and "High PV (4)" scenarios, which feature the largest shares of wind electricity, are also those that end up requiring the largest percentages of wind curtailing. In particular, the absence of CCS, and the concomitant increase in nuclear deployment, is what causes the sharp rise in wind curtailment in the "High PV (4)" scenario after 2030.

4.2 Short-term energy impacts

Figure 5 illustrates the evolution of the $EROI_{el}$ of the UK electric grid as a whole (calculated with the "integrative" approach discussed in Section 3.2) for all analysed scenarios from 2016 to 2035. In order to provide a frame of reference, the calculated $EROI_{el}$ of the individual electricity generation technologies comprising the UK grid mix in 2015 are provided in the Supplementary Information, available via the Internet at: http://www.sciencedirect.com. For a more detailed discussion of the latter, the reader is referred to a previous publication by some of the same authors [18].

In all developed projections, the general trends indicate a gradual improvement of the $EROI_{el}$ of the UK grid mix in future years. Each scenario shows, by and large, a similar evolution, with the only exception of “High PV (3)” from 2029 onward. The more marked improvement of $EROI_{el}$ in the “High PV (3)” scenario is mainly due to the fact that this scenario features the largest growth in nuclear generation, which is assumed to displace the projected CCS deployments of the reference “Low PV” scenario. It is important to note that nuclear electricity has an intrinsically higher $EROI_{el}$ than all other thermal technologies [18]).

Figure 5. $EROI_{el}$ (“integrative” approach) – trend from 2016 to 2035.

Figure 6 illustrates the resulting $PROI_{el}$ of the UK electric grid for each analysed scenario from 2016 to 2035, estimated with the “dynamic” approach discussed in Section 3.2. All “High PV” scenarios are generally characterized by a slower growth in $PROI_{el}$ with respect to the reference “Low PV” scenario, in part due to the up-front energy investments required for the deployment of the increased PV capacity. Also, as expected, and differently from the relatively smooth evolution of $EROI_{el}$, the trend of $PROI_{el}$ is more jagged because the latter provides information on the *annual* performance of the grid. In other words, it means that the $PROI_{el}$ trend is influenced by energy investments made in that specific year (mainly for increased installed power capacity). Hence, each trough in the $PROI_{el}$ graph indicates a large energy investment in that specific year, due to large (> $1GW_p$) new nuclear installed capacities coming on-line in 2026, 2029 and 2031 in scenarios “Low PV”, “High PV 2” and, to a lesser extent, “High PV 4”. Instead, the relatively smooth and shallow dip of the $PROI_{el}$ in all scenarios in the first analysed decade (from 2016 to 2025) depends mainly on the early large deployments of new wind power.

Figure 6. $PROI_{el}$ ("dynamic" approach) – trend from 2016 to 2035.

4.3 Long-term energy impacts

Figure 7 illustrates the resulting nr-CED of the UK electric grid as a whole, calculated with the integrative approach discussed in section 3.2, for each projection scenario from 2016 to 2035. The overall performance of the UK grid improves in each analysed scenario, with a remarkable decrease in the demand for non-renewable primary energy in the first decade. This is mostly due to the ramp-up in wind installed capacity and the phasing out of coal power plants. The improvement is even more marked in the "High PV (1)" and "High PV (3)" scenarios, which feature the largest generation shares by wind and PV. Equally, the "High PV (2)" and "High PV (4)" scenarios initially perform slightly worse than the reference "Low PV" scenario, because the intrinsic nr-CED of PV electricity in the UK is higher than that of the wind electricity that it is made to replace [18].

Figure 7. nr-CED ("integrative" approach) – trend from 2016 to 2035.

4.4 Long-term climate impacts

Figure 8 shows that the total system GHG emissions over time follow a similar trend for all the generation mixes, which indicates a notable decrease (≈ -70%) of GHG emissions from 2015 to 2035 in all analysed scenarios.

In the four “High PV” scenarios, the additional PV generation with respect to the “Low PV” benchmark is assumed to replace other generators with negligible to zero operational GHG emissions (namely, wind or nuclear). Therefore, the differences in overall GHG emissions are driven by emissions from non-operating stages of the life cycles or changes in the utilisation of generating capacity determined by the unit commitment model. Yearly emissions for “High PV (2)” and “High PV (4)” scenarios (where increased PV capacity displaces wind) are slightly higher for 2020-2030, which is primarily the result of greater coal and CCGT utilisation over this period. Total GHG emissions attributed to electricity generation for 2016-2035, accounting for all life cycle stages have minimal variation (±2%).

Overall, the results suggest no significant additional consequential system emissions from increased PV deployment, relative to the reference “Low PV” scenario, when all life cycle stage emissions are included and dynamic grid operation is considered.

Figure 8. Total yearly GHG emissions – trend from 2015 to 2035.

5) Conclusion and Policy Implications

Table 7 provides a synoptic overview of the relative performance of the four “High PV” scenarios with reference to the benchmark “Low PV” scenario, when analysed in the light of four of the key "integrative" metrics discussed in Section 5, namely: wind curtailment, energy return on investment ($EROI_{el}$), non-renewable cumulative energy demand (nr-CED), and greenhouse gas (GHG) emissions.

Table 7 HERE

The large growth in nuclear energy that is deployed after 2030 in the "High PV (4)" scenario to replace thermal carbon capture and sequestration (CCS) generation leads to an over-generation of baseload electricity which, in turn, calls for a concomitant reduction in the utilisation of conventional combined cycle gas turbines (CCGTs) (Figure 3) and wind curtailment (Figure 4). As a result, towards the end of the analysed timeframe the "High PV (4)" scenario joins the "High PV (3)" scenario to become the least preferable grid development strategy from this point of view, leaving "High PV (1)" and "High PV (2)" as the better-performing options.

Instead, the "High PV (3)" scenario looks promising from the Net Energy Analysis perspective, since nuclear electricity - a technology characterised by a high intrinsic EROI - displaces thermal technologies with much lower EROI values (among which particularly coal CCS) [9, Fig. 2].

Finally, when looking at the energy performance results from the point of view of the long-term depletion of non-renewable resources, it is the "High PV (1)" scenario that looks the most promising, closely followed by the "High PV (3)" scenario. This result is explained by the large penetration of wind and PV in these two scenarios, together with the lowest relative share of nuclear energy (whose nr-CED is 50% higher than that of CCGT [10, Fig. 5]) in “High PV (1)”.

What appears to be a potentially different order of preference among the analysed scenarios depending on which metric is considered should not be surprising, given their different underlying logics, as explained in Section 3.

Instead, it is important to observe that all scenarios, including the “Low PV” benchmark as well as the four “High PV” ones, are characterised by a general improvement in all energy and GHG emissions indicators over the analyse time frame (2016 – 2035). Also, none of the “High PV” scenarios entail a significant departure from the benchmark in terms of the overall yearly GHG emissions, even when emissions from all life cycle stages are accounted for. As discussed in Section 5, this is not unexpected, since, according to the stakeholder consultation results, any permutations in installed capacities between the alternative scenarios are expected to occur between low-carbon technologies such as PV, wind, nuclear and CCS.

At the same time, our analysis and the ensuing results may be deemed to be somewhat conservative in that further improved performance due to the possible adoption of system-level measures such as extensive demand-side management has not been considered.

Ultimately, then, it may be concluded that, across a broad range of low-carbon electricity mixes, an increased deployment of PV in the UK will not produce wider impacts that cause a substantial adverse performance of the grid from the points of view of a wide range of system-level technical (% renewable energy curtailment to ensure grid stability), energy (EROI and nr-CED) and environmental (GHG emissions) metrics.

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