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LETTER

A new approach for assessing synergies of solar and wind power: implications for West Africa

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Supplementary material for this article is available online

Abstract

West African countries' energy and climate policies show a pronounced focus on decarbonising power supply through renewable electricity (RE) generation. In particular, most West African states explicitly focus on hybrid mixes of variable renewable power sources—solar, wind and hydropower—in their targets for the electricity sector. Hydropower, the main current RE resource in West Africa, is strongly sensitive to monsoon rainfall variability, which has led to power crises in the past. Therefore, solar and wind power could play a stronger role in the future as countries move to power systems with high shares of RE. Considering the policy focus on diversified RE portfolios, there is a strong need to provide climate services for assessing how these resources could function together in a power mix. In this study, climate data from the state-of-the-art ERA5 reanalysis is used to assess the synergies of solar photovoltaic (PV) and wind power potential in West Africa at hourly resolution. A new metric, the stability coefficient C_{stab}, is developed to quantify the synergies of solar PV and wind power for achieving a balanced power output and limiting storage needs. Using this metric, it is demonstrated that there is potential for exploiting hybrid solar/wind power in a larger area of West Africa, covering more important centers of population and closer to existing grid structures, than would be suggested by average maps of solar and wind resource availability or capacity factor for the region. The results of this study highlight why multi-scale temporal synergies of power mixes should be considered in RE system planning from the start.

1. Introduction

Electricity demand in West Africa (WA) may increase fivefold by 2030 compared to 2013 [1]. To meet this rising demand while contributing to the objectives of the Paris Agreement [2], nearly all WA countries' energy policy targets envision a mix of renewable electricity (RE) sources in the future—typically solar, wind and hydropower. Most WA countries have targets for the RE share in power production and/or installed RE capacity in the near future [3–16]. The region-wide forecast in the ECOWAS (Economic Community Of West African States) Renewable Energy Policy (EREP) also foresees strong growth in solar, wind and hydropower capacity up to 2030 [17]. These power sources are all weather- and climate-dependent; therefore, if they are to be part of future power systems, their potential synergies must be estimated such that they can be optimally combined [18].

Solar, wind and hydropower potential in WA is governed by the monsoon, which causes the seasonal variability of solar potential due to changing monsoon cloud cover; that of wind potential due to the switch from Harmattan (strong) to monsoon (weak) conditions around the monsoon trough [19]; and that of water availability for rivers and reservoirs due to the seasonality of precipitation. Currently, most RE

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generation in WA is hydropower; for some countries it is even the main power source [20].

Clearly, other sources would have to be added to a future power mix to ensure reliable power supply, since the overdependence of some countries on rainfall for hydropower has been highlighted as principal reason behind past power crises [21–23]. The role of other sources in future power systems with substantial RE shares would thus be to mitigate this dependence, reducing power variability and shock risk. The 100%-RE scenarios for sub-Saharan Africa in [24], in fact, see only a limited future role for hydropower in WA.

Solar photovoltaic (PV) power has excellent technical potential in WA [25], but heavy reliance on solar PV causes balancing problems on diurnal timescales [26]. Across WA, wind power potential on its own is not estimated as particularly high [27, 28]; wind speed is quite variable temporally and geographically, with the highest potential found towards the north/northwest [25, 27, 29, 30]. However, wind speed has a pronounced diurnal cycle in many places in WA: pressure gradients drive nocturnal low-level jets (NLLJ) whose signatures are already discernible between 100–200 m [31, 32], and which disappear during daytime due to thermal turbulence [19, 31–34]. Thus, electric power production from large wind turbines could have an opposite diurnal cycle to solar power production, complementing it in a hybrid power system [34]. The potential for concentrated solar power (CSP) in combination with thermal storage is also promising [35], although it has not yet been deployed anywhere in WA [25]; it is currently still deemed less economic than solar PV for the short-term future according to the EREP [17], but this is poised to change as costs of CSP have recently decreased strongly [36].

Therefore, under the right circumstances, a mix of solar PV, CSP, wind and hydropower could be a good candidate for WA power systems, if (i) solar PV and wind power synergise well on diurnal scales, limiting the need for storage and other flexibility options; (ii) hydropower (e.g. conventional, pumped-storage, run-of-river) and CSP with storage can bring additional (e.g. seasonal, peak-shaving) stability; and (iii) the day-to-day and interannual variability of such a system remains small. Literature attempting to quantify RE resource synergies for WA is scarce; currently available data on RE potential in WA remains limited to annual average resource availabilities [1, 25, 27, 29, 30, 37]. This study is aimed at going beyond these averages by proposing a new metric for quantifying the synergies between solar PV and wind power potential for hybrid systems on diurnal and seasonal scales, and demonstrating its implications for the West African context. Solar/wind power mixes have received substantial attention recently [38–49], but assessments for WA, such as [50], are rare.

This paper is organised as follows. Section 2 focuses on methodological aspects concerning the assessment of hybrid power mixes and describes the new metric proposed in this study. Section 3 presents the main results. Section 4 brings forth several discussion points, and section 5 ends with conclusions. Methodological details are given in the supplementary material available online at stacks.iop.org/ERL/13/094009/mmedia.

2. Methodology and approach

2.1. Calculation of capacity factors (*CFs*)

In this study, the *CF* of solar PV cells is modeled based on monocrystalline silicon cell efficiency as function of global horizontal irradiation (GHI) G and air temperature T, following [51]. The wind turbine *CF* is modeled following [52] as function of hub-height wind speed V, based on Vestas V126-3.3 turbines with 117 m hub-height and 3.3 MW rated power, the type currently used for one of WA's largest wind power projects, in Taïba Ndiaye, Senegal [53]. (See supplementary material A for details.) The state-of-the-art European Centre for Medium-Range Weather Forecasts (ECMWF) ERA5 reanalysis is used to obtain G, T and V at 31 km spatial and hourly temporal resolution (see supplementary material B). Using ERA5 data allows following best-practice recommendations on estimating hub-height wind speed [54] (see supplementary material C).

Our domain covers [4°N–25°N; 26°W–16°E], covering all 15 ECOWAS member countries. Figure 1 shows solar and wind *CF* across the domain, using $CF = 0.15$ as lower threshold (stricter than [55, 56]). Solar potential is high on average, with *CF* generally increasing northward (due to diminishing monsoon influence) and reaching 0.30 over large parts of the territory. Wind power potential is weaker and concentrated in the north, with Mali, Niger and Senegal the only ECOWAS countries having substantial areas with $CF \geqslant 0.15$.

A prerequisite for using ERA5 data is an evaluation of the relevant reanalysis parameters by comparison to observations from the region. Irradiance, near-surface temperature, and near-surface wind speed measured by 15 meteorological stations, covering up to three years of data with sub-hourly resolution, spread across four WA countries, have been compared to hourly data from the corresponding ERA5 grid cells. An evaluation has been undertaken of (i) whether biases exist in ERA5, through the criterion that the Perkins skill score (S_{score}), reflecting the common area of probability density functions (PDFs) from reanalysis and observations, is larger than 70% as skill indicator [57, 58], and (ii) whether ERA5 reproduces diurnal wind cycles, using the correlation coefficient C_{corr} between reanalysis and observations.

This evaluation indicates that the median S_{score} is higher than 70% for 12 (GHI), 15 (temperature) and 11 (wind speed) out of 15 stations (see supplementary material D). For those stations, therefore, more than 70% of observed PDFs is captured by ERA5

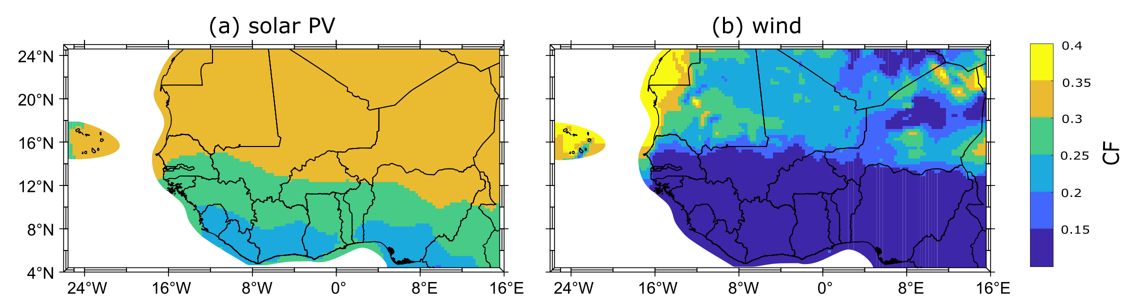

Figure 1. The annual average (a) solar PV and (b) wind power *CF*, based on nine full years (2009–2017) of ERA5 data. The Atlantic Ocean away from the continental and Cabo Verdean coast has been masked by white.

in a majority of recorded months. C_{corr} is found to be very high, between 80% and 90% on average, also in individual cases where $S_{\text{score}} < 70\%$ for wind speed, indicating that deviations are mostly mean value biases, not misrepresentations of diurnal wind cycles. In conclusion, we find no objections to using ERA5 for understanding solar-wind synergies across WA.

2.2. Power mixes

Several criteria exist for how mixing different RE sources can positively impact power systems, such as through smoothing (reducing variability) of power output [43, 44, 47, 49] or supply-demand balance [41, 42, 45, 48, 59], or lowering system costs [50, 60–62]. These are usually interlinked: e.g. smoothing of electric power output implies lower variability and fewer shocks, thus less need for storage and lower balancing costs [63]. In this study, smoothness of power output is used as criterion, i.e. without explicitly considering demand profiles; see section 4 for a discussion.

To quantify hybrid power output smoothness, many studies use statistical measures, such as (anti) correlation coefficients between power production from different resources [40, 43, 44, 47, 59], or variabilities of energy balance shapes, assuming (multi)-annual average power production is equal to average demand [41–43, 48]. Such approaches have been valuable in exploring synergies between renewable resources in various regions. However, when applied on diurnal timescales, they can cause the following issues:

1. Locations where resources are complementary (one is high when the other is low, and vice versa) will 'score high' even if actual resource strength is too low for practical exploitation, because using correlation coefficients between potential generation time series fails to put realistic constraints on the implied installed capacity. For instance, if a wind power potential cycle is complementary to solar PV potential—i.e. more wind at nighttime than during daytime—but the wind is weak, diurnal anticorrelation coefficients are high, but one would need to install large amounts of generating capacity running at very low efficiency to have a chance of using the wind resource for balancing.
2. Locations where resources are not complementary, but strong enough to still be useful, are undervalued. For instance, if wind does not vary diurnally, but is strong enough to result in high wind turbine *CF*, wind power could still replace solar PV power during nighttime, simply by virtue of the wind being strong, not by virtue of high anticorrelation coefficients.

   Several studies have addressed (1) by considering the *CF* of individual resources *before* calculating correlation coefficients [45, 47, 48]. A realistic constraint is then put on the amount of installed capacity *a priori*, removing locations where *CF* falls below a certain threshold, before assessing complementarities. This, however, also entails limitations:

3. It removes locations where resource synergy may result in good balancing but that fall just outside the individual resource *CF* threshold, for example if wind is strong at night, but too weak during daytime to move the average *CF* above the threshold. Such locations may be similarly suitable for hybrid systems as others where both resources are strong but less complementary.

Here, we attempt to address these issues by introducing a new metric, the *stability coefficient* C_{stab}, which represents the reduction in the coefficient of variance (c_v) [43–45, 49] on diurnal timescales of the *CF* of a hybrid solar/wind system with equal capacity for solar and wind (1:1 capacity ratio), as compared to a solar-only system. It is thus a measure of the added value of wind power to balance daily electric power production from solar PV. In our view, using a solar-only system as reference is instructive for WA, as it has the most widespread potential in WA of modern RE sources. Mathematically, C_{stab} is defined as follows:

$$C_{\text{stab}} = 1 - \frac{c_{v,\text{mix}}}{c_{v,s}} = 1 - \frac{\sqrt{\sum_{\text{day}}(CF_{\text{mix}}(t) - \overline{CF_{\text{mix}}})^2}}{\sqrt{\sum_{\text{day}}(CF_s(t) - \overline{CF_s})^2}} \frac{\overline{CF_s}}{\overline{CF_{\text{mix}}}}. \tag{1}$$

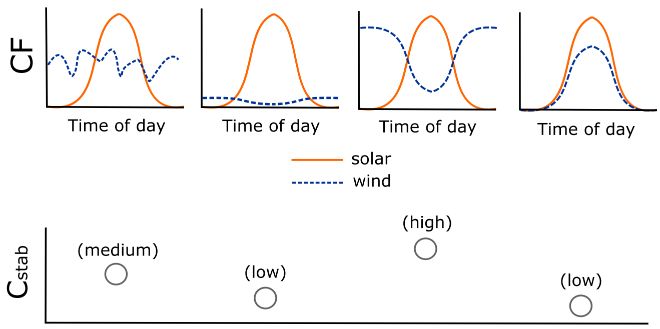

Figure 2. Schematic representation showing how the stability coefficient C_{stab} represents the reduction in hybrid power output variability, as compared to a solar PV-only system.

Here, $CF_{\mathrm{mix}} = (CF_s + CF_w)/2$, an overlined $\overline{CF}$ denotes a daily average, t is the time step (sub-daily), and subscripts s, w, mix denote solar, wind and hybrid mix, respectively. By definition, $C_{\mathrm{stab}} \leqslant 1$, with $C_{\mathrm{stab}} = 0$ meaning that a hybrid solar/wind system does not improve balancing relative to solar-only (wind and solar output having the same relative shape) and $C_{\mathrm{stab}} = 1$ meaning the sum of solar and wind power output is constant over time (perfect synergy). We note that, for a more general solar-wind capacity ratio of n:m, one should use the expression $CF_{\mathrm{mix}} = (nCF_s + mCF_w)/(n + m)$.

C_{stab} addresses the limitations of correlations-based approaches, because it takes the CF of hypothetically installed solar panels and wind turbines into account. This is not the case when calculating solar-wind correlation coefficients, which can give similar values for solar with strong wind as for solar with weak wind, i.e. independent of CF, as long as the strong and weak wind have similar normalised cycles. In contrast, high complementarity only results in high values of C_{stab} when the average resource strength is reasonable, while low complementarity does not necessarily result in low values of C_{stab} if the resource strength is high enough. This is shown schematically in figure 2: low complementarity does not preclude usefulness in a hybrid system (first panel from the left); high complementarity does not automatically mean usefulness in a hybrid system (second panel), but only if resource strength is sufficient (third panel); the latter, however, does not imply usefulness if complementarity is low (fourth panel).

To our knowledge, this study is the first time a hybrid metric like C_{stab}, combining information on complementarity and on CF, has been benchmarked against using average CF maps. The coefficient of variation itself [43–45, 49], on which C_{stab} is based, or alternative fluctuation indices [64] have been used before to quantify resource complementarities, but none of these works studied the implications of combining such metrics with information on CFs. The mathematical hybrid index for synergies presented by [65] goes in this direction, but it works optimally only if power output shapes are sinusoids, and its implications for RE potential estimation vis-à-vis using average CF maps were not studied. The latter topic, however, has been touched upon by [66], who noted that compromises in solar PV CF may be beneficial for synergies with other power sources.

Criteria like C_{stab} can also be used on seasonal scales to assess the stability of a hybrid solar/wind/hydropower mix [49]; the only difference may then be choosing a different baseline than solar power variability, since this may be smaller on seasonal timescales (e.g. in WA, see figure 3(b)) than that of wind and hydropower potential; in WA it is the latter two that would necessitate seasonal balancing. However, since large-scale hydropower is dispatchable, and solar and wind could conceivably be used during the dry season for e.g. water pumping to fill reservoirs [24, 67], this is not only a question of weather and climate, but also of system operation.

In this study, we calculate C_{stab} for solar and wind capacity installed in the same spatial location, but it could also be applied to analyse synergies between spatially separated power stations if transmission is taken into account; see section 4 for a discussion.

3. Results

Here, we first discuss hybrid solar/wind systems for one example location (Taïba Ndiaye, Senegal; see supplementary material figure 4), before scaling up the analysis across WA.

3.1. Case study: Taïba Ndiaye

Figure 3(a) shows hourly solar and wind CF by month for 2017 in (the ERA5 grid cell containing) Taïba Ndiaye. Figure 3(b) visualises the corresponding monthly average CF. These plots reveal that (i) the impact of the monsoon on solar power production is reflected mostly by changing power output variability (larger interquartile range), not so much its average; (ii) the impact of the monsoon on wind power production is pronounced, with the strongest wind resources in and after the Harmattan period (November/December–April), and a substantial drop in

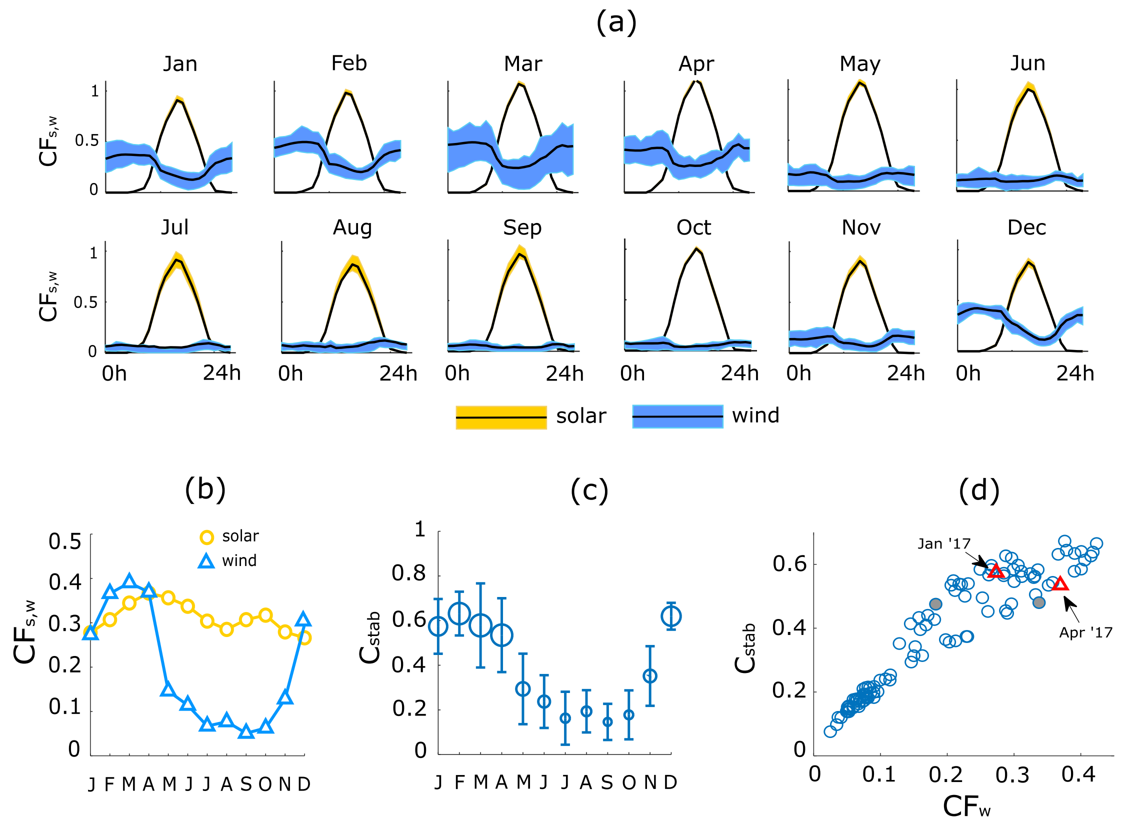

Figure 3. (a) Daily average cycles by month from 2017 ERA5 data for the capacity factors (*CF*) of the type of solar panels and wind turbines considered in this study, in the grid cell containing Taïba Ndiaye, Senegal. Shaded areas are interquartile ranges. All times in UTC. (b) Corresponding monthly average *CF* in the same location. (c) Monthly average C_{stab} for 1:1 hybrid solar-wind systems in the same location. The bars represent standard deviations, the size of the markers is proportional to CF_w from (b). (d) Scatterplot of CF_w versus C_{stab} for all months in the period 2009–2017 (108 values) in the same location. The two filled circles show that a similar reduction in power output variability would have been achieved in different months with wind turbines running at very different *CF*.

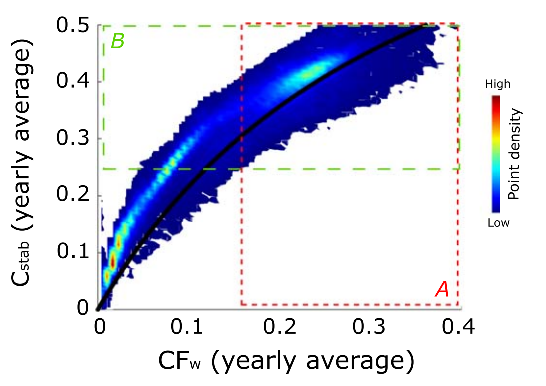

Figure 4. Contourplot of the annual average values for C_{stab} versus CF_w for all land grid cells in the West African domain considered in this study. The black line represents a hypothetical, constant wind power output on daily scales, i.e. a situation where $CF_w(t) = \overline{CF_w}$, which gives the expression $C_{stab} = \overline{CF_w}/(\overline{CF_s} + \overline{CF_w})$. Box *A* indicates all cells meeting $CF_w \geqslant 0.15$; Box *B* indicates all cells meeting $C_{stab} \gtrsim 0.25$ (see text). Note that the extent of the axes has been limited for clarity; a limited amount of cells falls outside of this domain, with very high average CF_w and C_{stab}.

resources during the monsoon from May–October/November; and (iii) the potential wind power production may indeed have an opposite diurnal cycle as compared to the solar cycle in many months.

To further investigate the possible solar-wind interplay in a hybrid system in Taïba Ndiaye, the monthly average C_{stab} is plotted in figure 3(c). In this figure, the marker size is proportional to the monthly CF_w. Overall, C_{stab} broadly follows the pattern of CF_w, which is as expected: since CF_s varies much less by season than CF_w, it is the latter that controls the seasonal shape of C_{stab}. A stronger wind resource results in better hybrid output balancing, especially when the strongest winds blow during the night.

The figure also reveals the added value of the parameter C_{stab} to the individual $CF_{s,w}$. Compare, for instance, the values in January and April: these months have nearly the same C_{stab}, but figure 3(b) shows that the difference in wind power production between them would be nearly ten percentage points. Thus, despite a substantially stronger wind resource in April than in January, the potential of this extra wind for balancing solar power production is limited. Figure 3(a) reveals why: the difference between wind power output in January and April consists mainly of the *daytime* wind resource being weaker in January than in April. For a hybrid system, in which solar power would be the main power source during daytime, this is no substantial disadvantage.

This can be more clearly visualised with a scatterplot of C_{stab} versus CF_w, as in figure 3(d), revealing different regimes of influence of the wind resource on hybrid power balance. This plot includes all monthly average CF_w and C_{stab} values from the years 2009–2017. For $CF_w \lesssim 0.12$, C_{stab} scales more or less linearly with CF_w, so in a hybrid system, the shape of the wind cycle matters little if CF_w is very low, and the only contribution of the wind is then to (sometimes) provide (low) power during nighttime. However, as $CF_w \gtrsim 0.15$, the points scatter, i.e. beyond a certain threshold, the wind cycle plays a more significant role in the added value of using wind in a hybrid solar/wind system than the *CF* itself. The points representing January and April 2017 have been highlighted for clarity. There are more extreme examples (filled circles in figure 3(d)): in one of the months, wind turbines running at $CF_w = 0.34$ would have led to an average reduction of nearly 50% in daily power output variability in a 1:1 solar/wind system, but in another month, the same would already have been possible with wind turbines running at a much lower $CF_w = 0.18$.

3.2. Scaling up to regional level

We now turn from temporal to spatial scales. Figure 4 shows a contourplot of the annual average C_{stab} versus annual average CF_w for all land grid cells in our domain, from the ERA5 years 2009–2017 (the plot thus contains nine points for each land grid cell in the domain). This is the 'spatial' analogue of figure 3(d), which showed C_{stab} against CF_w for different *months* in a single location. The black line represents 'constant wind power': the hypothetical situation where CF_w (not V, since CF_w does not scale linearly with V) has the same diurnal average, but no diurnal cycle, e.g. $CF_w(t) = \overline{CF_w}$. One can then analytically derive the expression $C_{stab} = \overline{CF_w}/(\overline{CF_s} + \overline{CF_w})$ from equation (1). Since $\overline{CF_w}$ and $\overline{CF_s}$ differ by day and location, the black line is this expression's spatio-temporal average across all days and land grid cells. (One could instead also construct another contourplot from values of annual averages per grid cell, which would be clustered very close to the black line.) It is clear that C_{stab} values are mainly concentrated above this line. In practical terms, this means that the added value of wind in balancing power output in tandem with solar PV power is 'better than its average' in WA: the diurnal wind power potential cycle is, on average, complementary to the solar cycle.

Figure 4 can highlight the consequences of considering only average values of $CF_{s,w}$ (figure 1) in selecting locations for RE production. The plot contains two dashed squares, denoted A and B. Square A represents $CF_w \geqslant 0.15$. A map indicating suitability of locations for wind power on the basis of $CF_w \geqslant 0.15$ would sample all cells within that square—essentially, all cells in the north of the region in figure 1(b). However, since the scatter cloud is concave, sampling square A leaves out many cells where comparable balancing would be achieved, despite not meeting $CF_w \geqslant 0.15$. Sampling all cells whose C_{stab} falls within the same range as that of the cells meeting $CF_w \geqslant 0.15$ corresponds to square B, representing $C_{stab} \gtrsim 0.25$. Thus, if *usefulness of wind in reducing hybrid power output variability* were the criterion, instead of *usefulness of wind as standalone*, one could find substantially (here, 30%) more cells meeting this criterion. It is also to be noted that nearly all cells sampled additionally by square B lie *above* the constant wind power line (many more, relatively, than in square A), which confirms what was referenced in section 2.2: with high solar-wind synergies, there are many locations that may be interesting for hybrid systems even if wind as standalone source would not be classified as viable there.

Figure 5 shows a map indicating (i) which locations would be 'suitable' for standalone wind power with the criterion $CF_w \geqslant 0.15$ (in gray), and (ii) all *additional* locations that would be 'suitable' for hybrid solar/wind power with the criterion $C_{stab} \gtrsim 0.25$ (in colours). For the latter, the blue to red shades indicate for how many years the criterion is met in the period 2009–2017 (signal robustness). Blue colours indicate that this location is (i) instead classified as marginally suitable for standalone wind in some years (near $CF_w = 0.15$ in square A), or (ii) instead classified as unsuitable for hybrid systems in some years (near $C_{stab} = 0.25$ in square B).

The main 'hotspots' of additional locations are a band stretching across the Soudano-Sahelian zone [68] and covering large parts of Senegal, The Gambia, southern Mali, Burkina Faso, southern Niger, northern Nigeria, the Benue basin, and small areas in the very northeast of Guiné-Bissau, northwest of Guinée-Conakry and north of Benin; plus offshore locations close to Ghana, Togo, Benin and Nigeria. (Note that offshore cells were not included in figure 4 for purposes of clarity—these locations tend to have much higher average CF_w than onshore cells and would have basically added a separate 'cluster' in that figure.) These zones are much closer to hotspots of population density, and much closer to existing transmission grid lines [25], than the northern areas where the criterion $CF_w \geqslant 0.15$ is met. Despite not appearing on typical wind power suitability maps [1, 25, 27, 28, 30, 69], they may thus be important to consider for energy policymakers, power system planners and other stakeholders, especially since most countries containing such zones have included wind power targets in their NDCs or energy policies (see table 1). While such an approach can be applied anywhere worldwide, it may be particularly relevant for WA, since it is not known as a region of particularly high wind resources, and by looking at wind power as standalone, one would indeed tend to conclude that its potential in the region is rather limited.

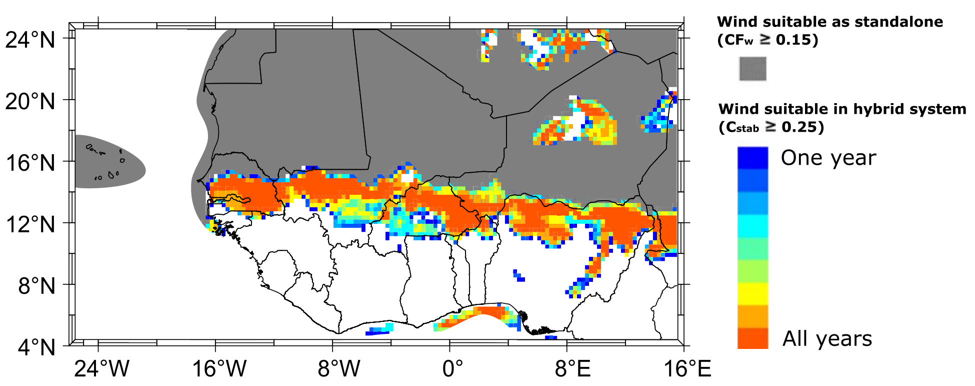

Figure 5. Map of our domain, showing the difference between considering only the average capacity factor of wind turbines CF_w as criterion for viable locations (gray) and considering the usefulness of wind turbines for balancing out solar panel output on diurnal timescales, expressed with C_{stab} (colours indicating the amount of years in the period 2009–2017 in which this signal is found from ERA5 data). Clearly, the first method underestimates the extent of suitable locations as compared to the second.

Table 1. List of countries in WA containing (parts of) the coloured area in figure 5 with policy targets pertaining to renewable energy (mixes) including solar, wind and hydropower.

Country	Energy policy targets for solar/wind/hydro	Source
Niger	250 MW RE by 2030, of which 130 MW hydro and 20 MW wind	[3]
Mali	More than 100 MW of renewable power capacity installed by 2020, mainly solar, wind, small hydro and biomass, to attain a 10% share of RE in the 'electricity mix'	[4]
Nigeria	Ensure 10% of hydro in power production by 2030 and 6% of solar; no quantified wind power target, but 'developing wind energy as an alternative renewable energy resource' to 'integrate this with other energy resources into a balanced energy and electricity mix' is mentioned as key objective.	[5]
Gambia	44 MW hydro, 50 MW solar, 20 MW wind installed capacity by 2030	[6]
Guiné-Bissau	72 MW of RE capacity installed by 2030, of which 53 MW hydro, 15 MW solar and 2 MW wind power	[7]
Guinée-Conakry	30% of electricity production from renewable sources by 2030 (excl. biomass); 50 MW installed capacity of wind and solar and 1650 MW of hydropower	[8]
Ghana	RE penetration of 10% by 2030, with 150–250 MW utility-scale solar power, 50–150 MW utility-scale wind power, 150–300 MW small/medium hydropower	[11]
Togo	67.5 MW of solar, 24 MW of wind, 115 MW of medium/large hydro, and 70 MW of small hydropower capacity by 2030	[12]
Senegal	Achieve rate of energy independence of at least 15% by 2025 from using renewable sources (without biomass); solar, wind and hydropower all mentioned as candidates	[15]
Burkina Faso	50% of RE in 'energy mix' by 2025; wind energy potential 'worthwhile to evaluate'	[16]

4. Discussion

Here we highlight several notes of caution and provide recommendations for future studies. First, focusing on smoothing power output does *not* imply that a flat power output is the desired outcome. This is (i) practically impossible with fluctuating renewables, and (ii) unnecessary, since demand profiles are not flat either. We use a hypothetical solar/wind hybrid system with equal capacity for solar PV and wind (1:1 capacity ratio) for demonstration; this ratio could be 'tuned' to better match demand. For instance, if demand has a strong diurnal shape, with higher demand during daytime, a higher share of solar capacity than of wind could be considered. The highlighted areas in figure 5 would expand, contract, and/or shift somewhat if the ratio were changed. However, this does not affect the generality of our conclusion, that considering hybrid systems from the start provides information that separate assessments of solar and wind cannot. Considering demand profiles in this study would have caused large uncertainties; load profile estimations are available for specific locations in WA, see e.g. [70], but subject to high uncertainty, as is widely the case in rural settings in developing economies [71], and poised to undergo substantial changes as energy demand rises across WA. Further, demand management by shifting certain flexible loads to specific times can also be an option [56]. We therefore believe that this supply-side view may be a useful starting point.

Second, this approach is an *indication* of what can be added to RE potential assessments, not a final product. Several factors influence the precise outcome, such as (i) stricter criteria on CF_w and C_{stab} for 'feasibility' (tending to shrink and/or move the zones in figure 5 northwards), (ii) wind turbine type [72], and (iii) data product. Therefore we do not claim that the best possible assumptions have been used: this remains to be seen through comparison of data products and observations. It has been mentioned, for instance, that reanalyses may not be the best available products for solar irradiation [47]. However, using a satellite-based data product for calculating CF_s is unlikely to change our broad conclusions, since the main constraint that solar potential puts on this analysis is the diurnal solar cycle itself, not the uncertainty therein due to cloud cover.

Third, the lack of measurements at 100 m height constitutes a barrier towards validating ERA5 data. While ERA5 near-surface wind speeds have been compared to available measurement data (see supplementary material C–D) and no principal objections to using these was found, this could not be done for 100 m wind speeds. Data at comparably high altitudes from radiosondes in the AMMA campaign have previously been assimilated into ECMWF reanalysis [73, 74]; and data from wind profilers and radiosondes in newer campaigns such as DACCIWA [32] could conceivably be used for evaluation in the future; such campaigns, however, typically focus on monsoon months, when winds are weakest and thus of least value for energy applications.

Fourth, the ERA5 spatial resolution, while finer than previous reanalyses, is still not sufficient to discern local corridors where wind speed may be high. This is especially relevant in regions with pronounced orography, such as the Fouta Djallon mountains in Guinée-Conakry. It also means that coastal regions may be suboptimally represented: coastal grid cells may represent averages of land and sea conditions.

Fifth, uncertainty ranges of wind (and sometimes solar) power output can be rather broad (see section 3.1). Options for reducing the risks posed by day-to-day variability must still be explored in systems with excellent solar/wind(/hydro) synergies, for example through storage technologies and export/import between countries/regions [24, 26, 75]. Storage technologies are set to play a substantial role in power systems with high shares of renewables in the future; while synergies between solar PV and wind power can be exploited to reduce storage needs and costs, as can demand management options, that does not mean the need for storage can be eliminated. Storage technologies such as thermal storage and pumped hydropower play an important role in near-term high-RE scenarios for sub-Saharan Africa [24, 56]. The methods presented here could thus contribute to estimating such storage needs for WA. Spatially distributing power-generating stations and trading power between regions can also smooth out volatility and thus reduce shocks in power production [76]. The expanded Sahelian area which was suggested as suitable for hybrid solar-wind exploitation in this study (figure 5) already hosts existing grids [25] (as opposed to the more northern territories, where the wind is strongest), and therefore this analysis may also be of interest to West African power pool planning. We therefore intend to focus future research on the potential for balancing RE generation in WA through storage and transmission.

Sixth, given the potential for CSP as alternative way to harness the Sun's energy [35], one may wonder what our findings imply for future CSP deployment in WA. The EREP, in fact, targets similar amounts of grid-connected capacity to be installed for solar PV, CSP, and wind power by 2030 in WA—about 1 GW for each. All three of solar PV, CSP, and wind power are thus to be viewed as important components of future WA power systems. Due to this matching of scales, the synergies between solar PV and wind power may be quite relevant on the near- to medium-term planning for CSP in WA, since they will codetermine the future needs for storage capacity in CSP installations. Good synergies will reduce balancing and storage needs, and therefore future CSP costs [36], which are currently the bottleneck for CSP deployment according to the EREP [17]. An assessment of possible complementarities between CSP with storage on one hand, and solar PV and wind power on the other, will strongly depend on the amount of assumed storage capacity and time [36, 77–81], and therefore goes beyond the scope of the current work. However, such an assessment should be undertaken as part of our intended future research into the roles of storage and transmission. (NB: we have checked that, if one would replace solar PV by CSP *without* storage in this study using the parameterisation of [82], conclusions on solar-wind synergies would be very similar, as C_{stab} does not differ substantially with the choice of solar PV or CSP in the absence of storage.)

Seventh, the results in figure 4 pertain to annual averages of CF_w and C_{stab}. One may be interested in other parameters than averages: maxima, for instance, if the wind resource were only used during part of the year (in Harmattan conditions), and replaced by hydropower during the monsoon. Averages are then less interesting, since the additional locations in square B could theoretically be locations where C_{stab} is above threshold owing to higher averages during the monsoon, when wind power would not be crucial anyway. We have checked that taking *maximum* annual CF_w and C_{stab} (i.e. selecting the best month for hybrid solar/wind) leads to the same conclusions presented in section 3.2. This seems logical, given that NLLJs show their strongest signature during Harmattan season [19].

Eighth, analyses like this one are meant to *contribute* to decisionmaking and target-setting in energy policy, not *determine* it. Local circumstances—topographical, socio-economical, legal—should be considered when selecting optimal power plant locations. Several studies have looked at relevant criteria besides resource strength, such as maximum population coverage [83, 84], or exclusion of zones with high agricultural activity, protected/prohibited areas, steep slopes, legal constraints, etc [27]. Studies like this can help pinpoint locations where such criteria should be further investigated.

Last, hybrid RE systems may be susceptible to compound (e.g. low solar plus low wind) events [67, 85]; the methods developed here may be helpful in assessing these in the future.

5. Conclusion

In this study, the ERA5 reanalysis product was used to assess the synergies of solar PV and wind power in WA down to hourly scales. Both of these sources play an important role in many West African countries' energy policy and projected power mixes. We demonstrate that, even though the average wind power potential is not very high across WA, being concentrated in the sparsely-populated north, wind could still be a useful resource in hybrid power systems in a much more extended area, close to centers of population and existing grids in the Soudano-Sahelian zone. This is because at hub heights of large wind turbines, winds blow stronger during nighttime than daytime, especially during the dry season. Wind power could thus provide diurnal stability to hybrid power systems with a substantial solar PV component and limited hydropower resources. To quantify this, the stability coefficient C_{stab} was introduced to show the suitability of combining solar and wind into a hybrid system. We argue, using a case study and regional upscaling, that consideration of hybrid systems should happen right from the start of RE resource assessments, through a parameter such as C_{stab}, not as second step after establishing individual resource strengths.

This research can help inform policymakers in WA about their countries' RE potential, and allay fears of a spatial mismatch between renewable resources on one hand, and population and existing grids on another [86]. It can also help provide a framework for generating high-resolution input for energy models for WA (countries) to assist power systems planning [87]. The methods and datasets used in our research are globally applicable, and could hopefully contribute to enhancing climate services for sub-Saharan Africa, which are in short supply [88, 89].

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☐	☒	A description of all covariates tested
☐	☒	A description of any assumptions or corrections, such as tests of normality and adjustment for multiple comparisons
☐	☒	A full description of the statistical parameters including central tendency (e.g. means) or other basic estimates (e.g. regression coefficient) AND variation (e.g. standard deviation) or associated estimates of uncertainty (e.g. confidence intervals)
☒	☐	For null hypothesis testing, the test statistic (e.g. *F*, *t*, *r*) with confidence intervals, effect sizes, degrees of freedom and *P* value noted *Give P values as exact values whenever suitable.*
☒	☐	For Bayesian analysis, information on the choice of priors and Markov chain Monte Carlo settings
☒	☐	For hierarchical and complex designs, identification of the appropriate level for tests and full reporting of outcomes
☒	☐	Estimates of effect sizes (e.g. Cohen's *d*, Pearson's *r*), indicating how they were calculated

Our web collection on statistics for biologists contains articles on many of the points above.

Software and code

Policy information about availability of computer code

Data collection	Data collection was done without specific software, except for the use of Python scripts used to download climate data from the Climate Data Store, whose principle is described on https://cds.climate.copernicus.eu/api-how-to, and the SWAT+ hydrological model, which can be downloaded through https://swat.tamu.edu/software/plus/. A large part of the collected data has been summarised in a spreadsheet-based and fully referenced database by the authors; this database is provided as Supplementary Data along with the paper.
Data analysis	The data analysis in this study was performed using a purpose-built tool called REVUB, whose code is available on GitHub: https://github.com/VUB-HYDR/REVUB and whose full mathematical description is available in the Supplementary Information. Certain pre- and post-processing calculations to prepare inputs into REVUB and process output from REVUB was done using Excel-based spreadsheets.

For manuscripts utilizing custom algorithms or software that are central to the research but not yet described in published literature, software must be made available to editors/reviewers. We strongly encourage code deposition in a community repository (e.g. GitHub). See the Nature Research guidelines for submitting code & software for further information.

Data

Policy information about availability of data

All manuscripts must include a data availability statement. This statement should provide the following information, where applicable:

- Accession codes, unique identifiers, or web links for publicly available datasets
- A list of figures that have associated raw data
- A description of any restrictions on data availability

The ERA5 reanalysis data was downloaded via the Climate Data Store at https://cds.climate.copernicus.eu/. Data from the CORDEX-Africa framework is available at http://cordex.org/data-access/esgf. EWEMBI forcing data can be accessed via http://doi.org/10.5880/pik.2019.004. ECOWREX data and shapefiles are available at http://www.ecowrex.org/mapView/. Grid load data from Ghana is available at http://ghanagrid.com/index.php/loadprofile. Grid load data from Burkina Faso is available upon request, as is the data on the LCOE of existing and future hydropower plants in West Africa. LCOE data for solar and wind power in West Africa is available in the IRENA report referenced under the Methods section "Analysis: Levelised cost of electricity". The SWAT+ simulation results are available via https://

doi.org/10.5281/zenodo.3580663. All other plant-level data used in the simulations is available and fully referenced in the WARPD database, provided as Supplementary Data to this paper.

Field-specific reporting

Please select the one below that is the best fit for your research. If you are not sure, read the appropriate sections before making your selection.

☐ Life sciences ☐ Behavioural & social sciences ☒ Ecological, evolutionary & environmental sciences

For a reference copy of the document with all sections, see nature.com/documents/nr-reporting-summary-flat.pdf

Ecological, evolutionary & environmental sciences study design

All studies must disclose on these points even when the disclosure is negative.

Study description	The study focuses on modelling smart management strategies of present and future hydropower plants in West Africa to support substantial grid integration of solar and wind power and thus limit natural gas consumption, while avoiding ecologically unsustainable effects of hydropower (over)exploitation. The modelling is done from point to subcontinental and hourly to decadal scales.
Research sample	The research sample consisted of all existing, planned and potential hydropower plants in West Africa, as well as all existing and planned, plus a representative set of assumed potential, solar and wind power plants in West Africa.
Sampling strategy	The sample size was equal to the full set of hydro, solar and wind power plants in West Africa which either already exist or which could be constructed in the coming decades according to current plans and/or assessments of overall resource potential. The details are fully explained in Methods and a complete overview of the sampled plants is given in Supplementary Data.
Data collection	The input data for the modelling was collected by the team of authors, led by Sebastian Sterl, in the period between July 2018 and November 2019, largely through internet-based literature and data collection. Meteorological data from the ERA5 reanalysis were obtained from the Climate Data Store via https://cds.climate.754 copernicus.eu/. Hydrological data were obtained from SWAT+ model simulations and bias-corrected to ECOWREX data available via http://www.ecowrex.org/756 mapView/. EWEMBI forcing data were obtained via http://doi.org/10.5880/pik.2019.004. Grid load data from Ghana was obtained from http://ghanagrid.com/ index.php/loadprofile. Grid load data from Burkina Faso was obtained from SONABEL, Burkina Faso's national electricity company, in preparation for a workshop (https://cireg.pik-potsdam.de/en/cireg/project-diary/workshop-energy-and-water-modelling/) organised by the CIREG project in which several authors participate (see Acknowledgements) that took place in Ouagadougou from 18 to 22 March 2019 (this data is available upon request). LCOE data for hydro, solar and wind power in West Africa were obtained from a recent IRENA report (https://www.irena.org/publications/2018/Nov/Planning-and-prospects-for-renewable-power), and some of the underlying data of that report was provided by its authors (this data is available upon request).
Timing and spatial scale	The data collection happened according to the authors' personal schedules in the period between July 2018 and November 2019, with continuous updating of older data in case newer data was found during the process.
Data exclusions	No data were excluded from the analysis a priori, e.g. the full set of collected data is available in Supplementary Data. However, certain hydropower plants were not included in the quantification according to the following criteria (as explained in Methods): if their rated capacity was under 10 MW; or if they were to be located on the main river section upstream of the Inner Niger Delta because of the extreme ecological impacts dam construction would have there.
Reproducibility	The results from the analysis are fully reproducible using the code (provided open-access) and the referenced datasets used by the researchers. The GitHub entry contains data files for a minimal working example, which can be used to reproduce a representative part of the results and several of the Figures in the manuscript and the Supplementary Information. The SWAT+ simulation results used as input for the simulations are available via https://doi.org/10.5281/zenodo.3580663. The reanalysis data from the ERA5 dataset used as input for the simulations can be obtained free of charge by any user from the Climate Data Store. The WARPD database, containing power plant-level data needed as input for the simulations, is given as Supplementary Data along with the paper. Any data that is not included in these repositories and/or available open-access via the references provided in the paper, can be obtained from the authors upon request.
Randomization	Given that the different scenarios that were assessed were simulated according to fully deterministic conditions (modelled with provided code and with fully documented and referenced input data), and based on the exact same set of hydropower generation plants with the same technical characteristics and the same set of locations for solar and wind power generation, no biases based on "study groups" could occur. Therefore, no randomization procedures were necessary.
Blinding	Given that the simulated scenarios are fully deterministic (modelled with provided code and with fully documented and referenced input data), and no observer-expectancy effects are possible in the given study setup, no blinding procedures were necessary.

Did the study involve field work? ☐ Yes ☒ No

Reporting for specific materials, systems and methods

We require information from authors about some types of materials, experimental systems and methods used in many studies. Here, indicate whether each material, system or method listed is relevant to your study. If you are not sure if a list item applies to your research, read the appropriate section before selecting a response.

Materials & experimental systems

n/a	Involved in the study
☒	☐ Antibodies
☒	☐ Eukaryotic cell lines
☒	☐ Palaeontology
☒	☐ Animals and other organisms
☒	☐ Human research participants
☒	☐ Clinical data

Methods

n/a	Involved in the study
☒	☐ ChIP-seq
☒	☐ Flow cytometry
☒	☐ MRI-based neuroimaging

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Turbines of the Caribbean: Decarbonising Suriname's electricity mix through hydro-supported integration of wind power

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ABSTRACT

The Caribbean nation of Suriname has historically depended on a mix of hydropower and oil-based fossil fuels for meeting electricity needs. Continued reliance on fossil fuels poses challenges both for climate change mitigation and for energy security. This paper explores the potential for increasing the share of renewables in Suriname's electricity mix, with a special focus on the complementary role of existing hydropower and future wind power infrastructure. We show that these resources have great synergetic potential for displacing fossil fuel-based power generation. Flexible operation of the Afobaka hydropower plant, newly in full possession of Suriname, allows significant wind power integration without violating grid stability and associated power quality requirements. Considering the trade-off between displacing expensive fossil fuels and limiting wind power curtailment on Suriname's island-like grid, our results suggest that integrating wind power in the Surinamese electricity mix is economically advantageous up to a share of 20–30%, independently of near-term demand growth. These results have wider relevance for climate policy in various Caribbean countries and other island states with existing hydropower infrastructure and substantial wind/solar power potential, for which this study fills an important literature gap.

1. Introduction

Worldwide, many countries are planning to increase the share of renewables in their electricity mix, steering away from fossil fuels both to support global emission reductions [1] and to ensure energy security [2]. Recently, wind and solar power technologies have been becoming more cost-competitive every year compared to fossil fuels [3], leading to substantial interest in their grid integration. The variable nature of wind and solar power is a major constraint in this regard, especially in the context of relatively weak, low-inertia grids, the limiting factor being violations of grid stability requirements and associated power quality issues at high penetration of variable renewable energy (VRE) [2].

Particular challenges may exist for states with isolated grids such as the Caribbean islands [4–9], for which neither spatial resource spreading [10] nor cross-border interconnections [11] are realistic ways of improving grid stability prospects. An obvious solution would be having sufficient dispatchable backup and/or storage capacity, but dispatchable generation is often fossil-fuel based [12], and battery storage costs - although declining - are still high [2,13]. Yet, there is general consensus in the Caribbean region and among other Small Island and Developing States that shifting towards VRE is desirable for sustainable development [2,14].

The Caribbean country of Suriname, although not an island state, is island-like in the sense that its largest grid system EPAR (Electricity PARamaribo, covering 90% of Suriname's electrical load) serves a relatively small area and has no interconnections to other grids (Fig. 1).

Abbreviations: CapEx, Capital Expenses; ELCC, Effective Load Carrying Capability; EPAR, Electricity PARamaribo; HPP, Hydropower plant; IRRP, Integrated Resource and Resilience Planning; ITCZ, Inter-Tropical Convergence Zone; LCOE, Levelised Cost of Electricity; NDC, Nationally Determined Contribution; OpEx, Operational and Maintenance Expenses; PV, Photovoltaics; REVUB, Renewable Electricity Variability Upscaling and Balancing; RLDC, Residual Load Duration Curve; VRE, Variable Renewable Energy.

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Despite this, its inertia is relatively high owing to the substantial contribution to the electricity mix by the 189-MW Afobaka hydropower plant (72% of total installed capacity on the EPAR grid [15]), turbining water from the Brokopondo reservoir. Built in the 1960s, Afobaka was originally conceived to benefit a foreign commercial firm active in the aluminium industry; at the turn of the century, as industrial activity declined, the firm instead started selling hydroelectricity to Suriname through a Power Purchase Agreement [16]. Since then, hydropower has provided nearly 60% of Suriname's electricity needs on average, with thermal (diesel and heavy fuel oil) power providing the rest [17]. With the firm's recent full withdrawal from the country, the Afobaka plant was handed over to Suriname on 31 December 2019 [18].

Given the dispatchability of reservoir hydropower plants such as Afobaka [10,20–23], hydro-supported integration of VRE could be a promising avenue for Suriname to displace fossil fuel-based power generation. This could carry substantial benefits both in terms of emissions mitigation [1] and of avoiding fuel costs of oil-based commodities on volatile world markets [2]. In recent years, a solid literature base on hydro-VRE complementarity has emerged, consisting of roughly four categories. However, as we argue in the following, all of these leave an important literature gap for applications of hydropower flexibility on islands and in island-like countries, such as Suriname.

Studies in the first category assess spatial and temporal hydro-solar-wind complementarities by applying mathematical indicators, typically correlation-based, to hydrometeorological variables [24]. Examples include an investigation of two-way complementarity between wind speeds and precipitation [25] and wind speeds and streamflow [26] in Brazil; and of three-way complementarity between wind speeds, solar radiation and streamflow in Brazil [27] and Europe [28]. While valuable as initial assessments, such studies neglect the role of operational schemes of hydropower plants, and are thus mostly applicable to non-dispatchable run-of-river projects, not reservoir-based hydropower.

Studies in the second category address the operational aspect of reservoir hydropower alongside VRE by investigating synergies at individual power plant level, such as e.g. joint operation of hypothetical hydro and wind power plants in Mexico [29], strategies for cascaded hydropower, small hydropower and pumped hydropower with solar and wind in southwestern China [30–32], day-ahead scheduling of hydro-solar-wind-thermal power generation in northwestern China [33], or the operation of China's Longyangxia hydro-PV plant, the world's largest hydro-VRE complex [34–39]. These have been highly valuable in uncovering the potential for hydropower to support VRE integration. However, a common element across these studies is that each tends to concentrate on certain temporal scales, lacking an integrated framework to simultaneously account for hourly-to-multiannual trends, as is recommended [20,40].

Studies in the third category do integrate these timescales, but typically focus on larger areas with less detail on individual hydropower plants; examples include e.g. regional integration of hydropower in the Zambezi basin with wind power in South Africa [41], impacts of hydro-wind integration on reservoir operation in the Southeastern US [42], hydropower mitigating spot-market value drops of wind power in Sweden at high penetration [43], or the role of hydropower in high-VRE scenarios for the Nordic countries [44].

The fourth category of studies takes this even further, focusing on large-scale interconnected grids for entire continents, but lacking results on individual hydro and VRE power plant level [11,45–47]. An exception to this is a recent study on integrated hydro-solar-wind planning and its synergies with regional power pooling in West Africa [20], which integrated hourly-to-multiannual and plant-to-regional trends. However, like other studies focused on spanning large geographical areas, it concentrated heavily on the potential for regional power trade to increase VRE penetration. There exists thus a clear gap in literature for strategies adapted to island states and isolated regions, for whom electricity exchange with neighbouring territories is no option to leverage solar and/or wind power.

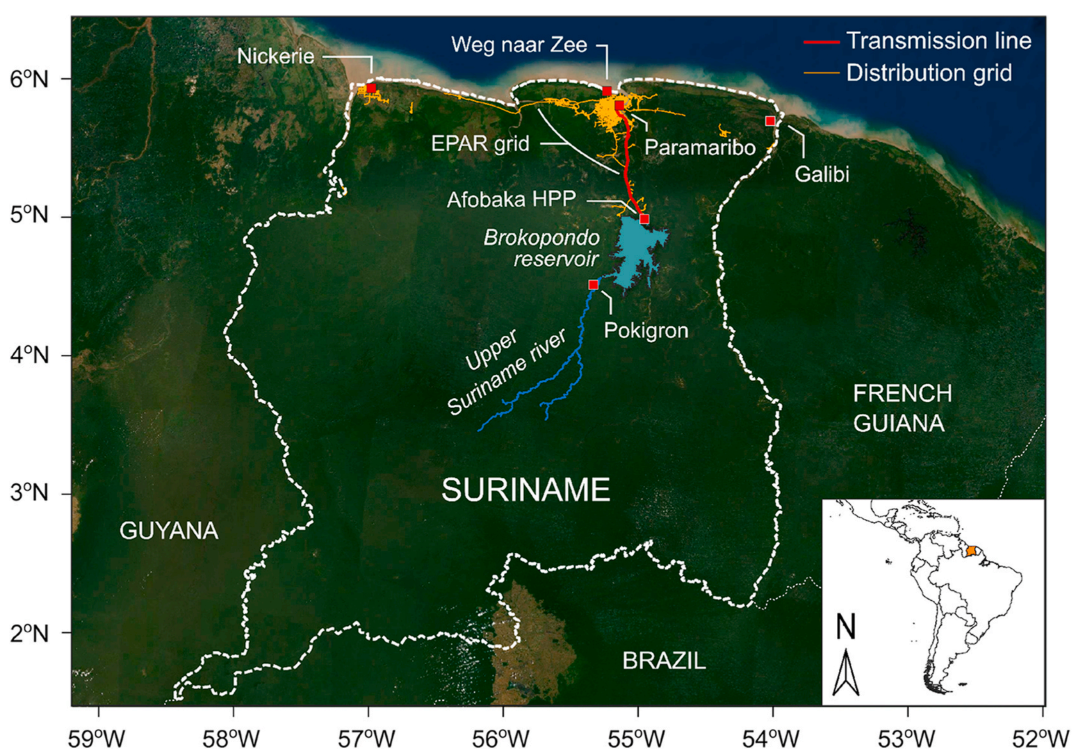

Fig. 1. Overview of the study area. Map of Suriname, indicating the Afobaka hydropower plant (HPP) and Brokopondo reservoir, the measurement station at Pokigron, the high-voltage (161 kV) transmission line from Afobaka to the capital Paramaribo, the EPAR grid serving Paramaribo and its surroundings, and the windy coastal locations Galibi, Nickerie and Weg naar Zee. Background: Esri's World Imagery [19] (see Acknowledgements). Inset: Suriname's location along the South American Caribbean coast.

To summarise, most studies on hydro-supported VRE integration do not cover all the relevant temporal scales, and those that do so either lack the spatial detail necessary for assessing island (-like) grids, or focus explicitly on strategies that are no option for islands and territories with isolated grids. The present study has been elaborated to address this literature gap.

This paper discusses the potential of hydro-supported wind power integration in Suriname, exploring hourly-to-multiannual resource complementarities and pathways towards high wind power penetration to displace thermal (diesel and heavy fuel oil) sources from the electricity mix of Suriname's isolated EPAR grid. The paper also discusses the potential for solar power, the role of transmission, implications for energy/climate policy in other Caribbean countries and island states, and the Paris Agreement context. In the following sections, the model framework (section 2), data and assumptions (section 3), and the principal results (section 4) are described, before discussion points (section 5) and conclusions (section 6) are summarised.

2. Hydro-wind complementarity

This section discusses the climatic context behind Suriname's hydro-wind complementarity (2.1), the model framework used to conduct this study (2.2), and the principal trade-off to be investigated for high renewable infeed on island (-like) grids (2.3).

2.1. Climatic context

From a climatic perspective, Suriname's wind power and hydropower potential are roughly anti-correlated because wind speed and rainfall show opposing seasonal cycles. The climate of Suriname is characterised by a short (December–January) and a long (April–August) rainy season. The highest wind speeds occur around the short rainy season, when the Inter-Tropical Convergence Zone (ITCZ) is at its southernmost location and strong northeasterly Atlantic trade winds reach the coastline; the lowest wind speeds occur during the long rainy season, when the ITCZ has moved north and prevents trade winds from reaching the coast (Fig. 2a) [48]. Correspondingly, the yearly refilling of the Brokopondo reservoir by the Suriname river mainly takes place during the low wind season (Fig. 2b).

From an electricity mix perspective, therefore, hydropower and wind power could be highly complementary in Suriname, with (i) hydropower dominating during one part of the year and wind power during another, (ii) the high flexibility of dispatch of the Afobaka hydropower plant helping to compensate the year-round hour-to-hour variability of wind power generation, and (iii) the multi-year storage capacity of the Brokopondo reservoir helping to compensate for potential interannual variability in both hydropower and wind power potential. As such, a hydro-wind mix [10,29,41,43,49] could be effective in displacing substantial amounts of thermal power generation - responsible for the bulk of Suriname's energy-related greenhouse gas emissions - from the power mix, without wind power variability becoming a problematic issue for grid stability.

2.2. Model framework

To estimate the wind power generation (and corresponding installed capacity) whose power mix integration could be supported by the Afobaka hydropower plant, a methodology is needed to explicitly couple hydropower, wind power and electricity demand at hourly resolution over long time periods. Such a model should consider various limiting factors on hydropower flexibility: (i) standard constraints such as maximum power output and maximum ramp rates; (ii) minimum stable reservoir outflow needed for grid inertia and environmental purposes; and (iii) the sustainability of Brokopondo lake levels which should be guaranteed on multi-annual time scales (based on the reservoir rule curve), even with flexible hydropower operation in function of wind speeds.

Scientific literature has made important progress in modelling hydro-wind-solar integration in recent years [29–39, 41–43, but often (i) relied on closed-source software, and/or (ii) focused on subsets of the relevant temporal scales, e.g. only on daily timescales, a certain season, or a single year, although interannual variability is of prime importance for renewables' integration studies [20,40]. The recently developed Renewable Electricity Variability, Upscaling and Balancing (REVUB) model (https://github.com/VUB-HYDR/REVUB), an open-source software originally used to assess the potential of hydro-wind-solar power mixes in West Africa from hourly to decadal scale [20], is well-suited to address the above challenges. Full details on the technical characteristics of the model are given in Ref. [20]. We provide a brief summary of the model below.

The REVUB model derives hydropower reservoir operation rules as based on certain needs for flexibility determined by the hourly variations in VRE generation and electricity demand. This is done while ensuring compliance with minimum outflow or minimum stable output constraints of hydropower plants, and ensuring that reservoir rule curves are followed as closely as possible. Starting from an initial state of reservoir filling, the model marches forward in time by dispatching hydropower as necessary to follow a certain target load together with VRE. It recalculates the reservoir state at each next time step depending on the water released (turbined and/or spilled) in the previous time step, the water received from upstream, and net gains/losses on the lake surface. After a simulation, which should preferably span multiple years to take the full effects of seasonality and interannual variability of reservoir operation into account, the model verifies whether lake level stability (according to the rule curve) can be guaranteed under the simulated operation. If this is the case, the model resimulates for a higher target load, iterating until the highest target load is identified with which lake level criteria can be adhered to. In the following, this

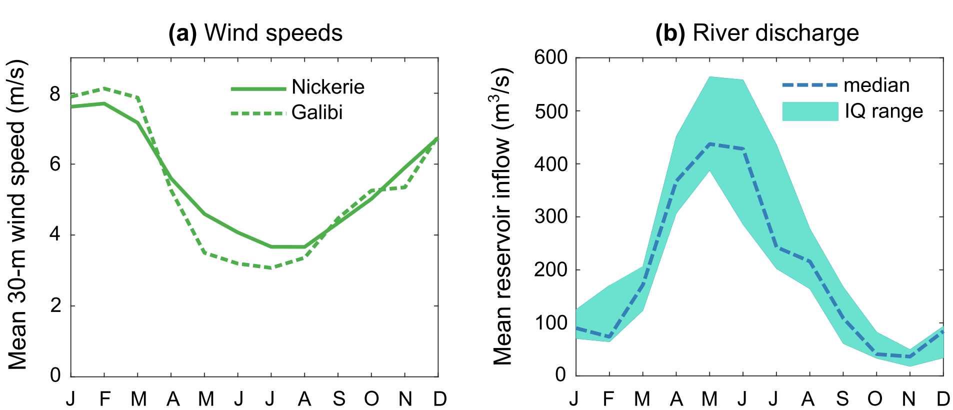

Fig. 2. Seasonal wind-hydro complementarity in Suriname. (a) Mean monthly wind speed in the coastal locations Nickerie and Galibi (Fig. 1), from measurements at 10-min resolution in the period 08/11/2009–08/11/2010 (see Section 3.2); (b) median and interquartile range of average monthly inflow from the Suriname river into the Brokopondo lake, from measurements at daily resolution at Pokigron during the period 01/01/1975–29/12/1983 (see Section 3.1). See Acknowledgements for data sources.

highest possible target load is denoted the “Effective Load Carrying Capability” (ELCC) of hydro-plus-VRE.

The REVUB model has already been used and validated for numerous large reservoirs in West African countries situated in similar climate zones as Suriname, and with similar power generation profiles dominated by thermal power and hydropower, such as Ghana and Côte d'Ivoire [20]. This validation was done by comparing modelled lake levels to remotely sensed lake level elevations, as well as by comparing modelled hydropower generation to historically recorded values, yielding promising results. Given the similarities in latitude, seasonality of rainfall, and power mix characteristics between various West African countries and Suriname, the model is deemed appropriate for application to the Surinamese context of this study.

Based on multiannual time series of lake inflow, evaporation, wind power potential, reservoir dynamics, and electricity demand at hourly resolution, the REVUB model is used here to calculate the share of electricity demand that could be followed - hour by hour, season by season and year by year - by a combination of flexible hydropower from Afobaka and variable wind power generated along Suriname's coastline, taking into account all above-mentioned constraints. The ELCC here thus corresponds to the fraction of total load that is guaranteed to be reliably met by hydropower and wind power for every hour on a multiannual time scale. This translates to the level of wind power generation that could be integrated in Suriname's power mix through hydro-driven flexibility, and the amount of thermal power that could be consistently displaced from the mix.

Since Suriname's island-like grid cannot export excess power, these results are sensitive to the extent to which wind power curtailment would be deemed acceptable during periods of very high wind speeds and/or low demand [50,51]. This is described in more detail in the next subsection.

2.3. Overproduction and curtailment

The term “overproduction” is used here to denote wind power exceeding the ELCC in moments when hydropower has already ramped down to its minimum (stable) level. During such moments, thermal power must additionally ramp down to allow further wind power penetration, and if this is no option, wind power must be curtailed to safeguard grid stability. In other words, overproduction denotes wind power generation beyond a level which can be supported by complementary hydro-wind operation. In this context, three possible situations can be distinguished, depicted schematically in Fig. 3 for an example 24-h period of hydro-wind-thermal power generation in Suriname: (a) no overproduction, (b) overproduction without curtailment, and (c) overproduction with curtailment.

If overproduction would not be allowed (Fig. 3a), wind power variability would always have to be fully compensated by increasing or reducing hydropower output. Thermal plants would then have to cycle up and down following the residual load (total load minus renewable generation), equalling a constant fraction of the instantaneous total load (Fig. 3d). Clearly, not allowing any overproduction would place a stringent upper limit on the achievable wind power penetration.

Relaxing this constraint would allow increased wind power penetration (Fig. 3b). Thermal power plants would then have to ramp up and down more frequently to ensure grid stability, as the hydro-plus-wind profile would no longer always represent the same fraction of the total load, and the residual load would therefore exhibit an extended range (Fig. 3d). (For the purposes of this analysis, the thermal plants in Suriname are assumed to be technically capable of following such residual loads [52,53].)

At high allowed rates of overproduction, it is possible that total hydropower and wind power generation would sometimes exceed the total electricity demand (Fig. 3c). During such periods, wind power generation would need to be partially curtailed and thermal plants would have to remain idle (negative values in Fig. 3d) to ensure grid stability.

The important question, especially for island (-like) grids, is to what extent accepting curtailment can be a cost-effective option of displacing high amounts of thermal power from the mix [50,51]. Elucidating this trade-off is one of the principal goals of our analysis.

3. Data and assumptions

REVUB simulations were set up using high-resolution (i) river inflow and evaporation data for the Brokopondo reservoir and detailed technical/design characteristics of the Afobaka plant (3.1), (ii) wind speed data representing conditions along Suriname's coastline (3.2), and (iii) electricity demand data for the EPAR grid (3.3).

3.1. Hydropower

The water budget of the Brokopondo reservoir was modelled using

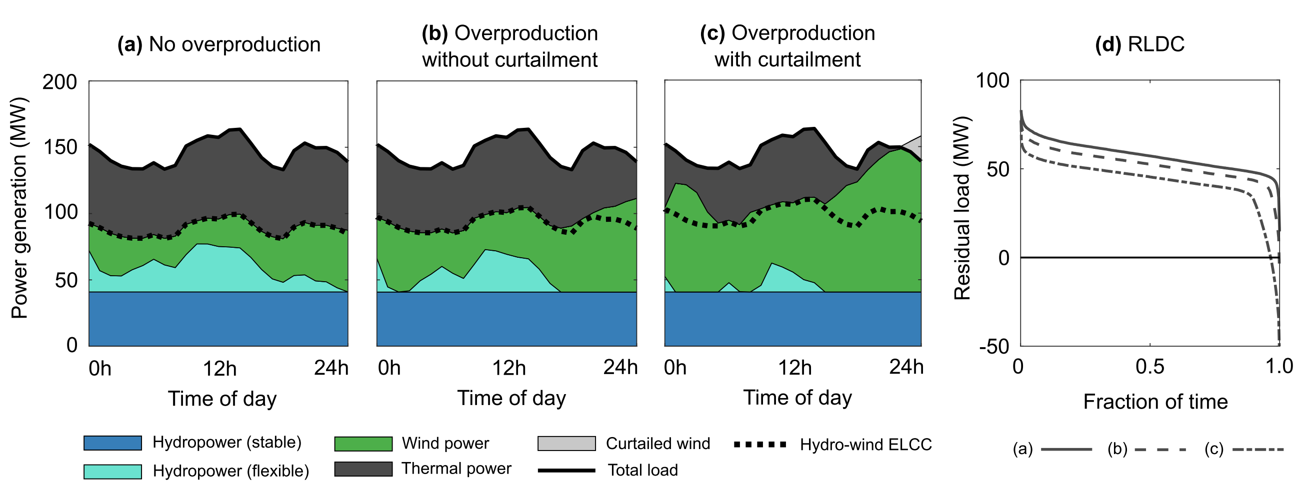

Fig. 3. Hydro-wind-thermal operation under different wind power penetration rates. Schematic of the three stages of overproduction, showing the same single day (February 9 in year 5) from a simulation of Suriname's electricity mix with hydro, wind and thermal power, covering nine years at hourly resolution and run with three different overproduction constraints (and otherwise the same simulation settings as in Fig. 5; see section 3 for data sources). In the first stage (a), the hydro-wind ELCC (Effective Load Carrying Capability) must be exactly equal to the sum of hydropower and wind power, i.e. zero overproduction. In the second stage (b), this constraint is relaxed, allowing higher wind power penetration. In the third stage (c), the constraint is relaxed further, leading to a situation in which wind power must sometimes be curtailed. The residual load duration curve (RLDC), reflecting the load that thermal power plants must follow, is shown in (d) for all three cases (based on hourly data from the entire nine-year simulated time series) against the fraction of total time spanned by the simulation time series.

time series of river discharge and reference evapotranspiration recorded at Pokigron (Fig. 1) at daily resolution during the period 1975–1983. Inflow into the reservoir was based directly on the measured river discharge; evaporation from the lake surface was estimated by correcting the measured evapotranspiration with a pan evaporation factor of 0.6 [54], assumed to include the compensating effect of rainfall on the lake surface. It is to be noted that, while a rainfall time series was also available from the same station, such local rainfall measurements tend not to reflect the total rainfall over lakes as large as Brokopondo very well, as they usually modify the local climate [55].

It was assumed that 60% of the water budget available for turbination in the Afobaka plant should be released at a constant rate, even under flexible operational rules designed to compensate for the variability of wind power. The purpose of stable outflow is to generate baseload power and ensure sufficient grid inertia, since any hydro-supported wind power takeup will displace thermal power from the mix and thus reduce the amount of synchronous spinning generation on the grid. Such a stable outflow additionally benefits environmental purposes [20,56]. The stable outflow was thus fixed at 60% of the long-term average outflow; the latter was taken to be 135 m^3/s, i.e. the median value of multiannual reservoir inflow, based on previous studies on the Afobaka plant [57] (cf. Fig. 2b).

Various technical and design characteristics of the hydropower plant as implemented in the simulations are shown in Table 1. The bathymetric (head-volume) relationship of the Brokopondo reservoir is shown in Fig. 4a, and its lake level rule curve in Fig. 4b. The latter represents a near-sinusoid oscillating between 51.13 m hydraulic head in April and 53.27 m in September. In this range, the bathymetric relationship is linear by approximation (cf. Fig. 4).

To validate the assumption that the inflow and evaporation from 1975 to 1983 are valid for present-day simulations of hydropower generation, the average hydropower output resulting from our REVUB simulations was compared to the amount which Suriname used to buy on a yearly basis from the commercial company exploiting the dam before it entered Suriname's possession at the end of 2019. The Power Purchase Agreement between the two parties obliged Suriname to buy 700.8 GWh/year, corresponding to an average power output of 80 MW [58]; our simulations suggest an average electricity generation of 707.4 GWh/year, a difference of less than 1%. This supports the notion that the historical data can be taken as representative for present-day conditions for our purposes.

3.2. Wind power

To calculate wind power potential, the hourly-resolution 10-m wind speed in the period 1980–2018 was extracted from the ERA5 reanalysis [59] in the two grid cells containing Galibi and Nickerie (Fig. 1) and the 16 grid cells directly adjacent to those. Galibi and Nickerie were chosen because (i) their wind climate is representative for the general conditions along the coast, and (ii) in-situ onshore wind speed measurements at 10-min resolution in the period 8/11/2009–8/11/2010 are available for both locations, which allowed for a statistical downscaling and bias-correction of the reanalysis data as documented in previous work [48]. After bias-correcting the data, the results were extrapolated to turbine hub height based on typical onshore roughness length values of 0.01 m along the coast.

All calculations pertaining to the conversion of wind speed to wind power generation were done on the basis of the power curve of Vestas V100-1.8 onshore wind turbines with a hub height of 95 m and cut-in, rated, and cut-out wind speed of respectively 3, 12 and 20 m/s [60] (see Acknowledgements). In all simulations, it was assumed that half of all wind power capacity would be deployed in (a location with similar conditions as) Galibi, and the other half in (a location with similar conditions as) Nickerie, to reflect generalised wind conditions along the coastline.

It is to be noted that limits on data availability meant that non-overlapping periods for the hydrological time series (section 3.1) and the wind speed time series had to be used. This implies that the effect of any potential covariance of hydrological and meteorological parameters cannot be discerned in our analysis. However, given the large storage potential of the Brokopondo lake, any such effects (e.g. simultaneous occurrence of high/low inland rainfall with high/low coastal wind speeds) presumably make no significant difference for joint hydro-wind operation.

This is, to the author's knowledge, the first application of the ERA5 reanalysis to Suriname. However, ERA5 data have already been applied to and validated for various other regions in assessments of wind power potential, notably for Sweden [61] and West Africa [62]. Our work thus adds to the burgeoning literature on ERA5 applications for renewable resource assessments [63].

Table 1
Technical hydropower plant data. List of characteristics of the Afobaka hydropower plant and the Brokopondo reservoir lake used in the simulations. * = Corrected for efficiency losses under part-load operation. The actual installed capacity is 189 MW; three of the units are fixed blades/adjustable gates (30 MW) while the three others are adjustable blades/adjustable gates (33 MW), which have broader discharge-peak efficiency ranges.

Quantity	Value	Unit
Rated capacity*	180	MW
Number of turbines	6	–
Reservoir volume	2.10×10^{10}	m^3
Lake area	1.56×10^9	m^2
Maximum head	55.6	m
Maximum ramp rate	36	MW/min
Power factor	0.95	–
Initial filling level	80%	–

3.3. Electricity demand

Electricity demand on the EPAR grid at hourly resolution was obtained from Suriname's utility company (EBS) for the period 2014–2018. Notably, nearly no net change occurred in total load during 2014–2018, with a mean of 1323 GWh/year and a standard deviation of ± 47 GWh/year, and no discernible increasing or decreasing trend. This near-zero change can be attributed to a gradual tariff raise in the rate schedule for electricity by the Surinamese government in 2015–2016, in conjunction with efforts to stimulate demand-side energy efficiency. This stabilised total grid load, which had been growing at 6% before this period. Nevertheless, Surinamese power demand may still grow substantially in the future, with growth rate projections of back up to 6%/year cited in literature [57]. This is further discussed in section 4.3.

4. Results

This section discusses simulation results pertaining to the power mix characteristics from hourly-to-multiannual time scales with joint hydro-wind operation (4.1), the economic advantages of wind power penetration through fossil-fuel displacement (4.2), and various sensitivity tests (4.3).

4.1. Power mix analysis

Fig. 5 shows results at hourly, seasonal and multiannual time scale from two example simulations, based on wind speeds from 2010 to 2018 (full time series) and the load profile from 2018 (assumed invariant from year to year). The outcomes were analysed for a very low acceptance of curtailment (1%, Fig. 5a–c) and a resulting deployed wind power capacity of 100 MW, and compared to the results under a higher acceptance rate of curtailment (13%, Fig. 5d–f) and a deployed wind power capacity of 200 MW.

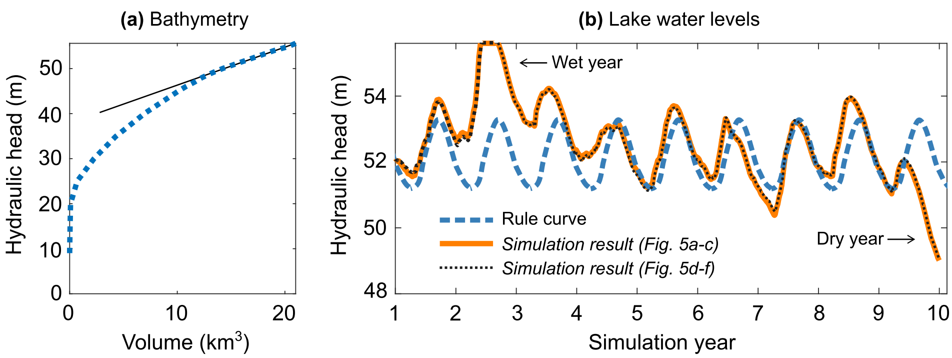

Fig. 4. Reservoir lake bathymetry and rule curve. (a) The bathymetric relationship between hydraulic head (the lake level elevation relative to the turbines in the powerhouse) and water volume in the Brokopondo reservoir. The solid line indicates the linear relationship by which the curve can be approximated ([head in m] $\approx 0.9096 \times$ [volume in km^3] $+$ 36.715; $R^2 =$ 0.992) in the volume range spanned by the rule curve. (b) The rule curve of Brokopondo lake levels, to be followed as closely as possible in the simulations, shown for a nine-year period (dashed line). For comparison, the actual lake levels resulting from simulated joint hydro-wind operation (solid line and dotted line, corresponding respectively to the simulation settings in Fig. 5a–f) are also shown. The simulations ensure that the rule curve is followed to the extent possible, despite the occurrence of anomalously wet and dry years as indicated.

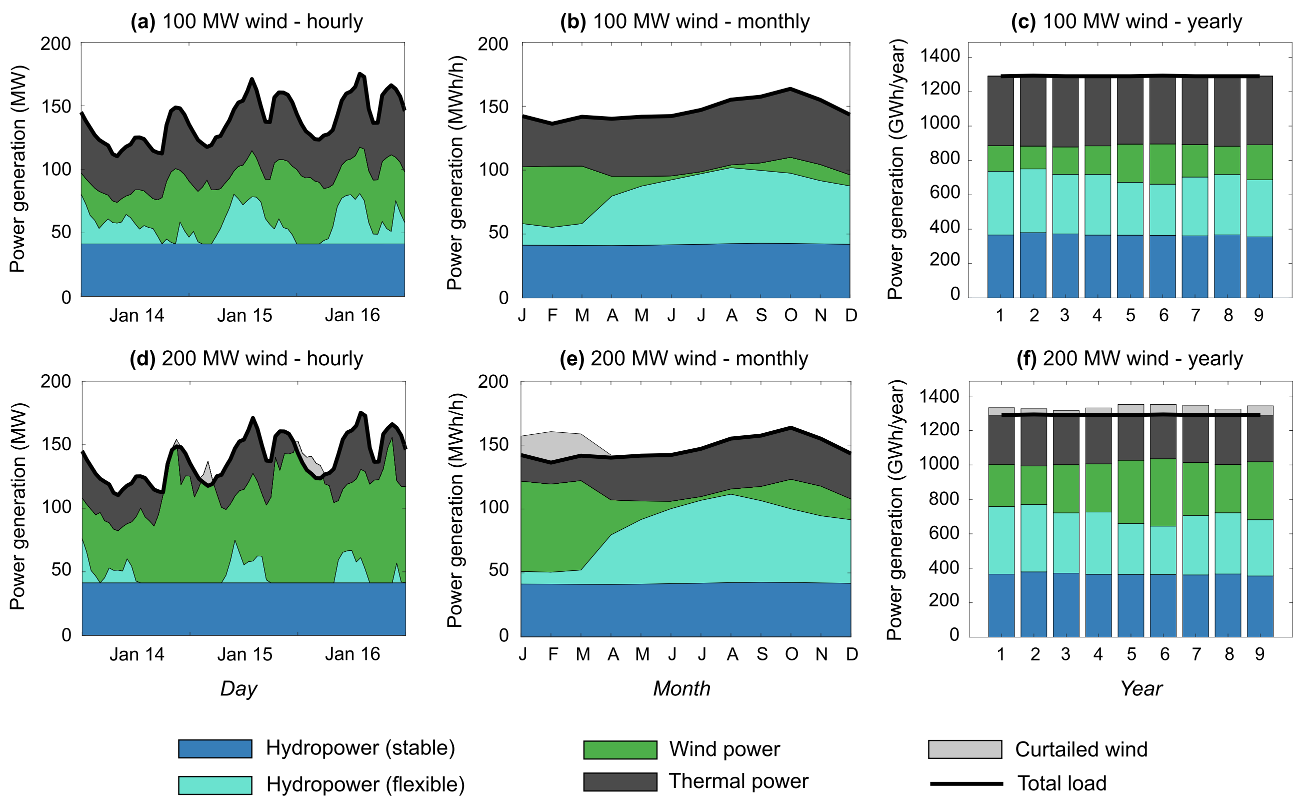

Fig. 5. Simulated hourly, seasonal and multiannual hydro-wind-thermal profiles. Total electricity generation mix as simulated based on 2018 load and 2010–2018 wind data, at hourly (left column; data from the first simulation year), aggregated seasonal (middle column; first simulation year) and multiannual (right column) resolution for two cases: with 100 MW (top row) and 200 MW (bottom row) wind capacity deployment. These optimised levels of wind power deployment are the result of the constraints on overproduction on the model, with near-zero curtailment in the former and 13% in the latter case. Categories are stacked from bottom to top in the following order: hydropower (stable), hydropower (flexible), wind power, thermal power, curtailed power.

The hour-to-hour power generation for an example time slice of the simulation (January 14–17 in simulation year 1; Fig. 5a,d) for both cases shows to what extent an increase in installed wind power capacity ensures better displacement of thermal power from the mix. The ramification of higher wind power feed-in is that more ramping from thermal power plants and more wind power curtailment will be needed to ensure grid stability (cf. the discussion from section 2.3), even though the hydropower plant already compensates for wind power variability to the extent possible.

The seasonal power generation profiles for both cases (Fig. 5b,e) highlight that accepting some curtailment can be an effective lever towards consistently displacing thermal power, principally during the good wind season when the wind blows strongly but not always at the "right" times. Moving to the higher curtailment acceptance rate increases the wind power penetration in the months January to March from roughly 30% (Figure 5b) to 50% (Fig. 5e). During the long rainy season, wind speeds are too low to push substantial thermal generation from the power mix in either configuration. However, the more wind power infeed during the good wind season, the higher the hydropower potential will be during the long rainy season (since less water will have been used for flexible dispatch during the good wind season), and thus the more thermal generation can also be avoided in those months in the second case.

At interannual time scales (Fig. 5c,f), the acceptance of higher rates of curtailment helps to carry the average wind power share in electricity generation from roughly 14% (Figure 5c) to 24% (Fig. 5f). Moreover, the flexible operational rules for hydropower ensure that the interannual variability of wind power generation is well-compensated by hydropower in both cases, despite interannual variability in the reservoir inflow itself (Fig. 4).

4.2. Economic implications

Following these two cases, the important question is how much thermal power can be displaced by wind power as a function of wind turbine deployment and accepted wind curtailment, and to what extent this would be economically advantageous. The latter can be inferred by considering the costs and gains involved, as follows. Wind turbine deployment, involving capital and operational expenditures but zero fuel costs, would displace a certain amount of power generation from existing thermal plants, and wind power overproduction/curtailment increase this displacement. However, wind power overproduction would not substantially reduce capacity requirements from thermal power due to the low capacity credit [64] of "overproduced" wind power (Fig. 3b). Accepting wind power curtailment to increase wind penetration thus primarily avoids "per-MWh" costs for thermal plants (fuel costs), but not "per-MW" costs (e.g. fixed operational/maintenance costs). An appropriate comparison to find the optimal level of wind curtailment is thus to weigh the curtailment-adjusted LCOE of wind power [65], which measures all costs of producing electricity from wind turbines including the cost of financing and operating the plant, against the avoided fuel costs for thermal plants [2]. Simulations spanning a wide range of curtailment rates (Fig. 6a) were therefore performed, and the corresponding displacement of thermal power (Fig. 6b), the curtailment-adjusted wind turbine capacity factor (Fig. 6c), and the curtailment-adjusted wind power LCOE (Fig. 6d) calculated, in function of wind capacity deployment.

For joint hydro-wind operation with up to nearly 50 MW of installed wind power capacity, hydropower can perfectly compensate for all variability in wind power generation and no overproduction occurs (Fig. 6a, left vertical line; cf. Fig. 3a). Up to ~70 MW wind power capacity, some overproduction occurs but no curtailment is necessary for supply-demand balancing (Fig. 6a, right vertical line; cf. Fig. 3b). Beyond 100 MW, the curtailment rate increases at roughly 0.13% points per MW of deployed wind capacity.

As a consequence of this curtailment, the increase in the share of wind power in the electricity mix is not a linear function of installed wind capacity, but flattens off for higher wind deployment (Fig. 6b): while the first 100 MW of wind capacity can bring the share of wind in the power mix up by 15% points (i.e. from 0% to 15%), another 100 MW would increase the share by only 10% points (from 15% to 25%) due to necessary curtailment. The decrease in thermal power is proportional to the increase in wind power, thus dropping from the current average share of 47% at zero wind turbine deployment to 22% at 200 MW wind turbine deployment.

The annual average capacity factor of wind power in the assessed locations is around 21% according to the 2010–2018 wind speeds and with the assumed wind turbine type. However, beyond 100 MW of wind deployment, the curtailment-adjusted capacity factor drops roughly linearly at a rate of 0.03% points per deployed MW of wind capacity (Fig. 6c). This affects the expected LCOE of wind power, since the same investment and operational costs per MW will lead to fewer GWh fed into the grid per MW deployed. The LCOE of onshore wind power in Suriname was estimated based on the assumptions in Table 2, and the curtailment-adjusted LCOE was correspondingly calculated (Fig. 6d).

Comparing the latter to the historical fuel cost range for thermal power in Suriname (between 14.6 $ct/kWh and 17.6 $ct/kWh; see Acknowledgements), it can be observed that displacing thermal generation

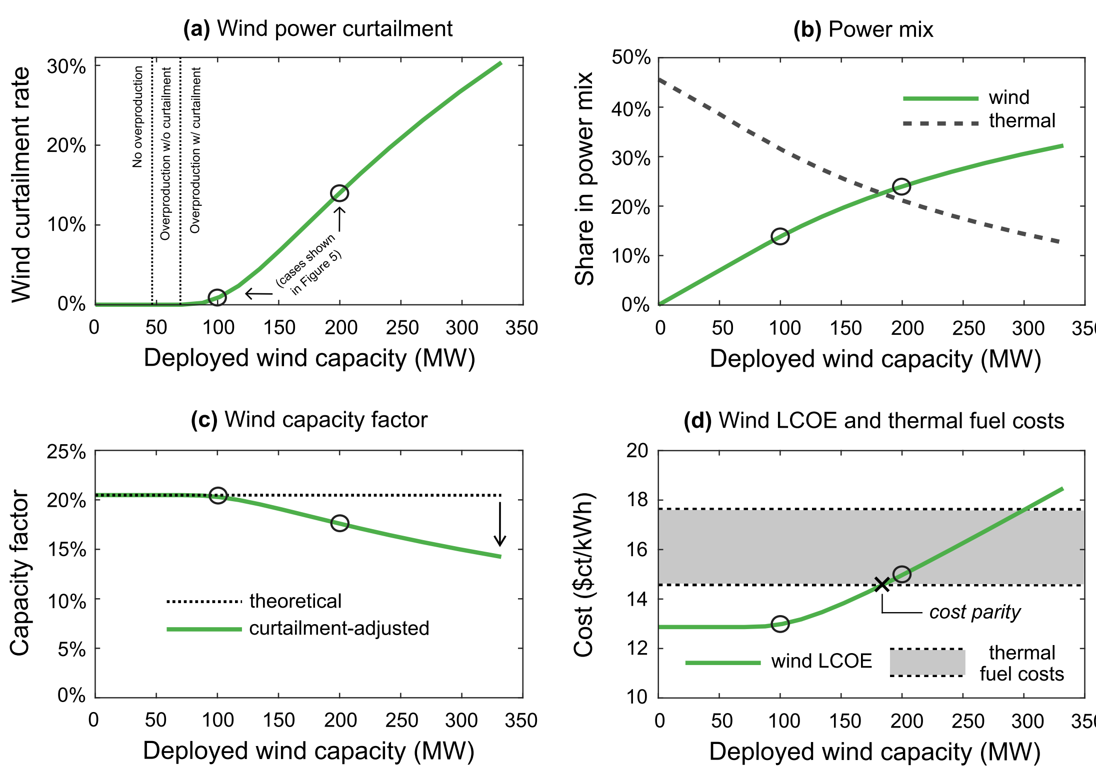

Fig. 6. The effects of increasing wind power curtailment acceptance. The amount of curtailed wind power (a), the share of wind power and thermal power in the electricity mix (b), the curtailment-adjusted capacity factor of wind power (c), and the curtailment-adjusted LCOE (Levelised Cost of Electricity) of wind power compared to the fuel costs of thermal power (d), all as a function of total wind capacity deployment. In (a), the ranges corresponding to situations (a)–(c) in Fig. 3 are indicated by vertical dotted lines.

Table 2
Assumptions used in the calculation of onshore wind power LCOE. CapEx = Capital Expenses; OpEx = Operational and Maintenance Expenses. *: Based on Brazil, the only neighbouring country for which data was available.**: Typical lifetimes for onshore wind turbines are around 20 years [68]. Given that the turbines proposed in this study would be located along Suriname's vulnerable coastal zone, whose infrastructures are susceptible to substantial risk of damages occurring due to flooding and coastal erosion [69], a more conservative 15-year lifetime was chosen.

Quantity	Value	Unit	Source
CapEx	1610	USD/kW	[66]
OpEx	43.6	USD/kW	[66]
Discount rate	10%	–	[67]*
Project lifetime	15	years	[68]**

with wind power would be economically advantageous up to at least 180 MW of wind turbine deployment, meaning that the avoided fuel costs would exceed the cost of curtailment [51]. This point, where the curtailment-adjusted wind power LCOE crosses the lower bound of historical fuel costs, is hereafter denoted "at cost parity" (Fig. 6d). Given the wide range observed for fuel costs and the relatively conservative assumptions (in terms of cost of capital and infrastructure lifetime; cf. Table 2) on wind power costs, this point represents a conservative estimate. At cost parity, wind curtailment rates would be around 10%, and wind would achieve a share of around 23% in the power mix, with a corresponding amount of thermal power being successfully displaced. A penetration of at least 23% of wind power in the electricity mix would therefore be technically feasible and economically advantageous for Suriname under the above assumptions, even without demand response and storage measures.

4.3. Sensitivity analysis

How sensitive is the above conclusion to assumptions regarding the load profile, selected wind period, and overall demand level? Load profiles may change from year to year depending on economic and climatic conditions; average wind speeds may shift on decadal time scales; and higher overall demand means lower need for curtailment at equal wind power deployment. The above analysis was therefore repeated for several cases: (i) using the load profile from each of the years in the period 2014–17 instead of 2018; (ii) using the wind speeds from each 9-year period preceding 2010–2018 (i.e. 1983-1991, 1992–2000, and 2001–2009); and (iii) using an adjusted overall demand level, assuming a growth rate of overall electricity demand between 0%/year and 8%/year over a 10-year period (thus representing possible demand levels around the year 2030).

Fig. 7 shows the sensitivity of wind power's (a) installed capacity and (b) power mix share at cost parity to the chosen load year and the chosen wind period. Clearly, the choice of load year has a relatively limited effect on the conclusions, reflecting the low change in power demand and typical hourly profiles observed in recent years. Contrarily, results are more sensitive to the chosen meteorological period for wind speeds: the average capacity factor of wind power based on the weather of the period 1983–1991, for instance, is around two percentage points higher than for 2010–2018, leading to higher yield per turbine, lower expected LCOE, and a wind power share of 30% at cost parity. This highlights the importance to undertake studies on potential future shifts in wind strength in Suriname as a result of natural variability and climate change; for instance, previous work has indicated that climate change may benefit wind power strength in Suriname [48].

Lastly, the effect of demand growth is shown in Fig. 8. While the wind turbine capacity deployable before reaching cost parity logically increases in line with the demand growth (assuming that the fuel costs for thermal power generation would not change, and that thermal power would remain the only alternative source next to hydro and wind), the corresponding share of wind power in the electricity mix is not very sensitive to this growth, at least when compared to the sensitivities to wind regime shown in Fig. 7. Assuming the demand growth estimate of around 6% cited in literature [48] would apply to the entire decade 2020–2030, wind power could be competitive with thermal power up to nearly 400 MW deployment by 2030 (achieving a 27% share in the mix), even assuming zero decrease in capital and/or operational and

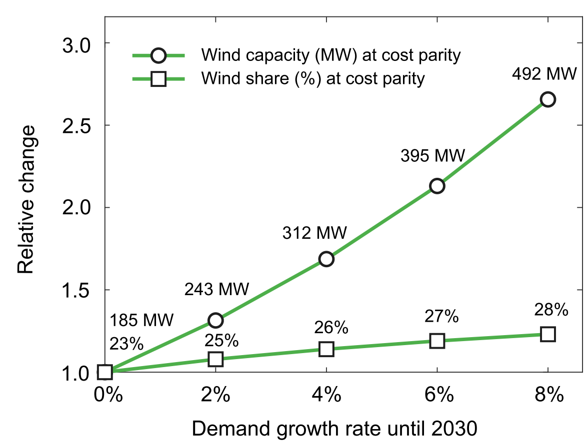

Fig. 8. Results of sensitivity tests for overall demand. Sensitivity of the installed capacity and power mix share of wind at cost parity to the demand level resulting from different growth rates over a 10-year period (i.e. from the present day until 2030).

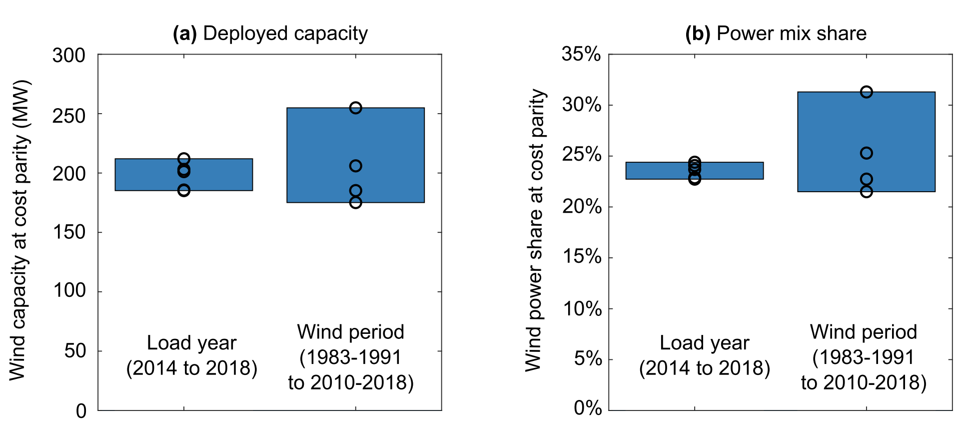

Fig. 7. Results of sensitivity tests for wind and load periods. Sensitivity of the installed capacity (a) and power mix share (b) of wind at cost parity with the cheapest thermal power to the choice of load year (left bars) and wind period (right bars) used in the simulations. The circles indicate the outcomes from individual sensitivity experiments; the bars the range spanned by these.

maintenance expenses until then, which is highly unlikely [3].

Based on this sensitivity analysis, it can be asserted that a penetration of 20–30% of wind power in Suriname's electricity mix would be technically feasible and economically advantageous even without advanced flexibility measures such as demand response and/or battery deployment. Given that costs of wind power have been decreasing worldwide for many years and this trend is still ongoing [70], it appears certain that the above conclusions are conservative. As potential wind turbine deployment in Suriname would presumably happen in stages, the costs for each consecutive project could realistically be lower than for preceding projects as technology progresses and wind turbines with higher hubs (reaching higher capacity factors) become cheaper, allowing for penetration rates potentially beyond 30%. As more capacity for VRE is installed and experience gained in operating the grid, batteries and other forms of storage may become more relevant as a further backup source, allowing even more VRE penetration and providing additional grid ancillary services (see also section 5.3).

5. Discussion

This section discusses hydroturbine use (5.1), transmission infrastructure (5.2), and solar photovoltaic (PV) power (5.3). It also provides recommendations for future research, based on implications for other Caribbean countries and island states (5.4) and the Paris Agreement's long-term goals (5.5).

5.1. Hydroturbine usage

The more wind power is integrated into the power mix, the more ramping will be required from the hydropower plant (and from its thermal counterparts). The Afobaka hydro plant is equipped with six turbines of ~30 MW capacity (see Table 1). On average, the power output of the plant is around 80 MW [57] (see section 3.1); therefore, on average, three out of six turbines will be active. However, the ramping up and down in function of wind speed means that the number of instances with fewer or more active turbines will increase with wind turbine deployment, as shown in Fig. 9 (corresponding to the simulations in Fig. 5).

At 100 MW of installed wind power capacity (Fig. 9a), a majority of time (41.2%) would still be spent with three active turbines. However, at 200 MW of wind power (Fig. 9b), the amount of time spent with two (30.2%) or four (33.9%) active turbines would exceed the time with three active turbines (26.5%), reflecting the higher variability in wind power feed-in requiring more frequent up- and down-ramping of the hydro plant.

The high inactivity of half of Afobaka's turbines under current operation has recently been mentioned as a possible argument for diverting further rivers into the Brokopondo lake to increase the water budget and avoid underutilisation of the available infrastructure [18]. As this study shows, joint hydro-wind management would be an alternative way of increasing the utilization rate of currently idle turbines, an effect that would become more pronounced the more wind turbines would be feeding into the grid. It could thus be argued that joint hydro-wind operation presents an avenue to avoid potential ecological damage of river-diverting interventions: it would increase the spread of turbine usage without changing the average water budget. While this would not increase the average power output of the plant, the wind power integration enabled by this flexible operation would compensate for the lack of increased hydropower output that further river diversions could have brought. Hydro-wind integration can therefore synergise well with ecological sustainability objectives [20].

Another option to increase hydroturbine usage while avoiding upstream river diversions would be to create a smaller second artificial lake downstream and retrofit the Afobaka plant with a wind- or solar-powered pumping station, converting the plant to a pumped-hydro "battery". During periods of high VRE generation, part of the power could be used to pump water from the smaller reservoir back into the Brokopondo lake, effectively storing the electricity as increased hydropower potential [71,72]. Whether such a project would be infrastructurally feasible, and what the technical/design characteristics would have to be (lower lake size, pumping power, etc.), could be the subject of future studies. The REVUB model, which has a pumped-storage module, could then be used to estimate the corresponding increase in potential for fossil fuel displacement [20].

5.2. Role of transmission capacity

The wind speed time series used in this study can be seen as representative of wind conditions all along the Surinamese coast. To cost-effectively deploy substantial wind capacity in Suriname, locations as close to the existing grid as possible should be preferred to avoid high upfront transmission line costs. A suitable potential location for initial projects could be Weg naar Zee, a coastal locality around 20 km from the center of the Surinamese capital Paramaribo (Fig. 1) where the EPAR grid is already present.

As our results have shown, with the current island-like configuration of the EPAR grid, some wind power curtailment will likely have to be accepted if high wind power penetration is to be reached in the absence of storage. However, in the future, overland transmission lines connecting Suriname to neighbouring countries/regions, notably Guyana, French Guiana, and the Brazilian states of Roraima and Amapá [73], could be a lever towards avoiding curtailment, allowing to export any renewable power not needed in Suriname. It could also help create a business case for Suriname around flexible export of hydroelectricity to

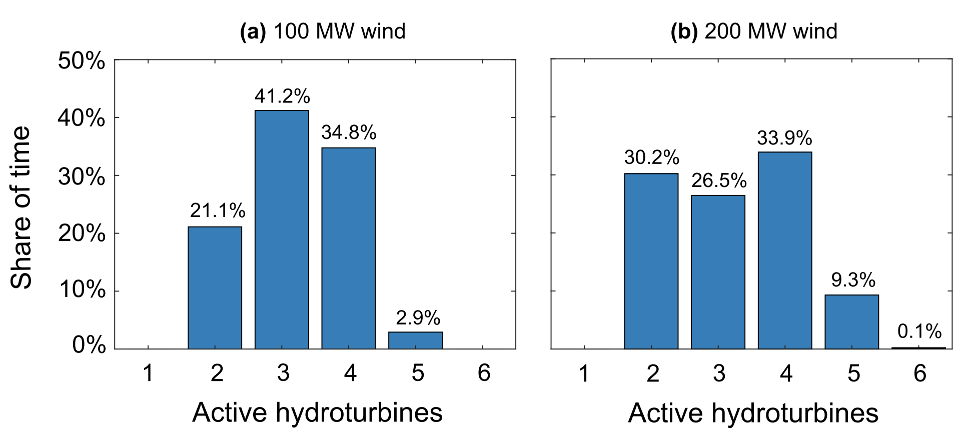

Fig. 9. Hydroturbine use. Hydroturbine utilization rate for the same two cases of wind power infeed shown in Fig. 5: (a) with 100 MW wind capacity; (b) with 200 MW wind capacity.

other regions dealing with temporary generation shortfalls [11,20,73].

5.3. Role of solar PV

Next to wind power, solar PV has also been suggested as an important technology for decarbonising Suriname's power mix in the future [11,15,45]. The LCOE of solar PV power has experienced very sharp downward trends, globally as well as in South America, in the recent past that show no signs of abating [11,70]. However, two factors lead us to conclude that in Suriname's specific case, wind power is a more obvious candidate to be supported by hydro-driven flexibility than solar power. Firstly, there is no real seasonal hydro-solar complementarity in Suriname, with a year-round cloudy climate and minimum irradiation levels occurring in the period December–April (below 5 sunshine hours/day) [74], coinciding with the period of decreasing water levels in Brokopondo. Secondly, the cloud- and thunderstorm-driven minute-to-minute intermittence of solar irradiation in Suriname is very high and present year-round; this would put substantial strains on hydropower dispatch on very short (sub-minute) time scales [2], which would be further compounded by the fact that irradiation variability is highest in the same period December–April when average irradiation is lowest [74] and when the lake water level drops to its minimum.

Nevertheless, it is clear that solar PV should be part of Suriname's long-term energy policy [11,15,45]. The deployment of solar home systems and off-grid solutions could be promising, especially for Suriname's interior areas. On a larger scale, battery storage, pumped-hydro storage, and demand response (e.g. through sectoral coupling) could be feasible candidates to facilitate electricity mix integration of solar power. In particular, battery storage systems may become an important future asset for providing frequency support at high solar penetration once their costs have sufficiently declined, owing to their superior (millisecond-to-second) response times when compared to conventional spinning generation [2]. More research on solar PV potential and its use cases in Suriname in combination with battery storage is therefore recommended.

5.4. Implications for other Caribbean countries and island states

Hydro-supported integration of VRE could be interesting for various other Caribbean countries and territories. Substantial hydropower capacity is currently available in the Dominican Republic, Jamaica, Haïti, Belize and Guadeloupe, while there is large unexploited hydropower potential in Guyana [75]. Although river discharge, reservoir areas and water budgets for hydropower on the Caribbean island countries are clearly of a smaller scale than for Brokopondo in Suriname's interior, rugged island geography often allows for much higher-head sites than Afobaka. All these Caribbean regions, whether island or continental, could therefore likely make smart use of hydropower's contributions to grid inertia and flexibility to support increased penetration of renewable resources such as wind and solar power, potentially in combination with pumped-storage solutions.

Wind power potential is high along the coastlines of most Caribbean island countries, and typically follows comparable seasonal (trade wind) patterns to Suriname [76]. Solar power potential is also widespread, with most Caribbean countries, including the Dominican Republic, Jamaica, and Haïti, having lower cloudiness and lower irradiation intermittence than Suriname. For instance, Jamaica is already exploiting both wind and solar power, for which research on grid integration is ongoing [2]. We therefore recommend comparable studies on hydro-driven flexibility to be undertaken for at least the Dominican Republic, Jamaica, Haïti, Belize, Guadeloupe and Guyana. Depending on each country's nationally available resources, these could focus on hydro-wind [29,41–43], hydro-solar [34–39], or hydro-wind-solar synergies [20,30–33].

Outside of the Caribbean region, various Small Island and Developing States and other island territories could also benefit from such complementarities. We mention Fiji, Samoa, the Solomon Islands, Papua New Guinea, New Caledonia, Madagascar and Greenland as potentially interesting case studies with existing and/or potential hydropower capacity [75] and without the option of large-scale interconnected grids as lever for high VRE takeup.

5.5. Outlook for climate policy and recommendations

Energy systems worldwide must have largely decarbonised by mid-century if the goals of the Paris Agreement are to be met [1,45]. Which are the most important options for Suriname to reach "100% renewables" in the long term (beyond the 2030 horizon of the present study), fully pushing thermal generation from the mix while also decarbonising other sectors? Firstly, there remains unexploited hydropower potential in Suriname, mostly in the Kabalebo river basin where power generating capacities of a similar order as Afobaka would be feasible [77]. Exploiting this potential would also enable further hydro-supported takeup of VRE, which could thus function as the backbone of long-term climate policy strategies even under rising power demand. Secondly, future drives for electrification, coupling the transport, buildings and industry sectors to the power sector alongside storage technology deployment, could help decarbonise those sectors while increasing VRE potential by widening the scope for demand response [78]. The authors of this paper are currently planning a follow-up study for Suriname to investigate the potential of these options.

However, future climate change may itself affect the availability of renewable resources. For instance, under continued trends of global warming, the hydropower potential of the Afobaka plant may be negatively affected [57], but wind regimes along the Surinamese coast may increase in strength [48]. Climate change-related changes in solar irradiation [79] and hourly load profiles [80] can be expected as well. We therefore recommend studies on the climate change impact on hydro, wind, solar, and load to accompany any study on renewables' integration potential to support integrated resource and resilience planning (IRRP). The aforementioned follow-up study on Suriname will include such investigations.

Lastly, such follow-up work could also consider the potential economic implications of increased VRE deployment in more detail. As discussed, substantial oil-based fossil fuels can be cost-effectively displaced from Suriname's power mix by a combination of existing hydropower infrastructure and near-grid wind power. However, future VRE growth and new hydropower development may necessitate transmission grid expansion, e.g. merging the EPAR grid with Suriname's various smaller grids [15], entailing substantial costs. Further, an eventual regional integration with power grids of neighbouring states may need to explicitly take into account remunerations for flexibility services delivered by hydropower, such that hydropower exports could constitute a business case for Suriname [11,73]. Trade-offs between upfront costs to support VRE expansion and avoided fossil fuel costs could then be assessed in a regionally integrated manner.

6. Conclusion

Based on high-resolution data regarding reservoir inflow, evaporation, wind speed, and electricity demand in Suriname, this study leads to several conclusions. Firstly, the Afobaka hydropower plant, newly in Suriname's full possession, can support the power mix integration of substantial amounts of wind power, thanks to its flexibility of dispatch and the strongly present seasonal hydro-wind complementarity. Secondly, accepting limited amounts of curtailment during the good wind season can be an effective lever to increase wind power penetration. Given conservative cost estimates for wind power and historically observed fuel costs for thermal power, displacing thermal with wind would remain economically advantageous up to wind curtailment levels of around 10%. Thirdly, taking into account interannual-to-decadal variability in wind speeds, this corresponds to a deployed wind power capacity in the range 175–250 MW and wind power generation of 300–460 GWh/year given present-day demand. The resulting share of wind power in Suriname's power mix would lie in the 20%–30% range. Fourthly, the latter number is relatively insensitive to future demand growth rates.

Such a level of wind power penetration would represent a considerable displacement of thermal power from the power mix and a corresponding decrease in greenhouse gas emissions. It would also guarantee Suriname to well overshoot its Nationally Determined Contribution (NDC) target of 35% renewable electricity generation by 2030. We therefore conclude that planning for the deployment of coastal onshore wind power, with up to at least ~200 MW of total capacity given current demand levels, represents a no-regret option for Suriname.

Given the island-like nature of Suriname's main grid, these methods and results also provide starting points for investigating comparable synergetic hydro-wind-solar planning in several other Caribbean countries and island states.

CreDiT Statement

Sebastian Sterl: Conceptualisation, Methodology, Writing - original draft, Data curation, Formal analysis, Investigation, Project administration, Software. Peter Donk: Conceptualisation, Methodology, Data curation, Investigation. Patrick Willems: Writing - review & editing. Wim Thiery: Writing - review & editing; Fund Acquisition.

Data and code availability

The REVUB code application used for this study, and the data used as input, are available via https://github.com/VUB-HYDR/2020_Sterl_etal_RSER. The code and manual for the REVUB model itself are available via https://github.com/VUB-HYDR/REVUB.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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A Grid for all Seasons: Enhancing the Integration of Variable Solar and Wind Power in Electricity Systems Across Africa

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Abstract

Purpose of review This review paper assesses recent scientific findings around the integration of variable renewable electricity (VRE) sources, mostly solar PV and wind power, on power grids across Africa, in the context of expanding electricity access while ensuring low costs and reducing fossil fuel emissions.

Recent findings In this context, significant research attention has been given to increased cross-border transmission infrastructure between African countries to harness the spatiotemporal complementarities between renewable electricity resources, as well as to storage options, such as battery storage and power-to-gas.

Summary Much of the recent, model-based literature suggests that a combination of increased interconnections in and between Africa's power pools, leveraging spatiotemporal complementarities between solar PV, wind and hydropower, as well as a large-scale deployment of storage options could help African countries meet their burgeoning power demand with largely decarbonized electricity supply.

Keywords Variable renewables · Solar power · Wind power · Hydropower · Grid flexibility · Storage

Introduction

Worldwide, an unprecedented expansion of electricity supply using modern renewable electricity (RE) sources is underway. Most of this expansion is driven by solar photovoltaic (PV) and wind power [1], underscored by these technologies' rapidly declining costs [2, 3••] and a desire to decarbonize power supply in the context of the Paris Agreement [4]. Solar PV and wind power are characterized as variable renewable electricity (VRE) sources: driven by meteorology (e.g. irradiation, temperature, wind speed), they vary on all timescales from sub-hourly to interannual [5]. As the share of grid-connected VRE grows, power systems will have to adapt to the new reality of short, medium- and long-term weather-driven variabilities to ensure reliable power supply without endangering grid stability [6].

This has vastly different implications across the world. For instance, Europe and North America have benefitted for decades from large-scale, interconnected, adequate grids. Here, the main challenge now lies in integrating VRE into existing grid infrastructure, which will require a certain level of technological adaptation to increase grid flexibility [7]. On the other hand, developing regions with low levels of electricity access and rapidly growing power demand, such as sub-Saharan Africa [8, 9, 10•], face a different challenge altogether: growing VRE *while growing the grid* [11•, 12, 13], simultaneously responding to the dual challenge of currently inadequate electricity access and the need to decarbonize electricity supply.

As such, many developing countries are "greenfields" for developing power systems with high VRE shares, and their power systems planning will need to focus on VRE integration from the outset—which could be an opportunity that Europe and North America never had. In this context,

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this review paper assesses recent findings on modelling the energy transition at various scales in Africa, with a focus on the specific recommendations for increasing flexibility and VRE shares in Africa's burgeoning power systems. The focus here lies on technical challenges and solutions available to African countries to successfully achieve high shares of VRE in the electricity mix. While there are undoubtedly a multitude of non-technical (e.g. political, financial) challenges to successful VRE deployment as well [14••], these fall outside the scope of this paper.

Getting VRE on the grid

The spatiotemporal variability of VRE sources will require increased grid flexibility to safeguard the supply–demand balance. It is generally helpful to break down the different flexibility measures into three categories: generation-driven, storage-driven and demand-driven [6, 15, 16], as indicated schematically in Fig. 1 where several prime examples of each category are provided. In the following, each of these categories and examples will be discussed in the context of VRE integration on the African continent. The focus will be on generation-driven flexibility, but attention will be given to storage-driven and demand-driven approaches as well.

Generation-driven flexibility

Flexibility to meet peak demands is currently mostly provided by natural gas and, where available, hydropower plants; in the future, concentrated solar power (CSP) with thermal storage, as well as biomass plants, could also play an important role. Logically, the flexibility of existing and planned gas, hydropower, CSP and biomass plants in Africa thus constitutes an obvious case to support VRE uptake.

Both natural gas reserves and hydropower potential in Africa are spatially very unevenly divided. While many countries make substantial use of domestic natural gas in their electricity mixes (e.g. Nigeria), other countries need to import natural gas from abroad (e.g. Benin) [18, 19]. As far as hydropower is concerned, some countries already today have large enough hydropower fleets to potentially support a massive uptake of VRE (e.g. Ghana, Ethiopia) [20, 21•], but others have either yet to substantially exploit their hydropower potential (e.g. Burundi, Central African Republic, South Sudan), or do not have potential to speak of [22].

For this reason, discussions on natural gas- and hydropower-driven flexibility for VRE uptake in Africa are often strongly linked to plans on cross-border transmission infrastructure and regional integration of power systems [11•, 18], especially for hydropower. For example, in the same way that Norway's hydropower provides much-needed flexibility to continental Europe's power system [23], there are several countries across Africa that could find themselves in comparable positions in a VRE-rich future, including Guinea in West Africa [11•, 18] and Ethiopia in East Africa [21•, 24, 25]. In this context, it is important to note that various older hydropower plants in Africa may need refurbishment to be able to provide better flexibility services to aid VRE integration in the future [26, 27].

Given that natural gas is an important emitter of carbon dioxide, it will eventually have to be phased out along with other fossil fuels to retain chances of meeting the long-term temperature goals of the Paris Agreement [4]. While natural

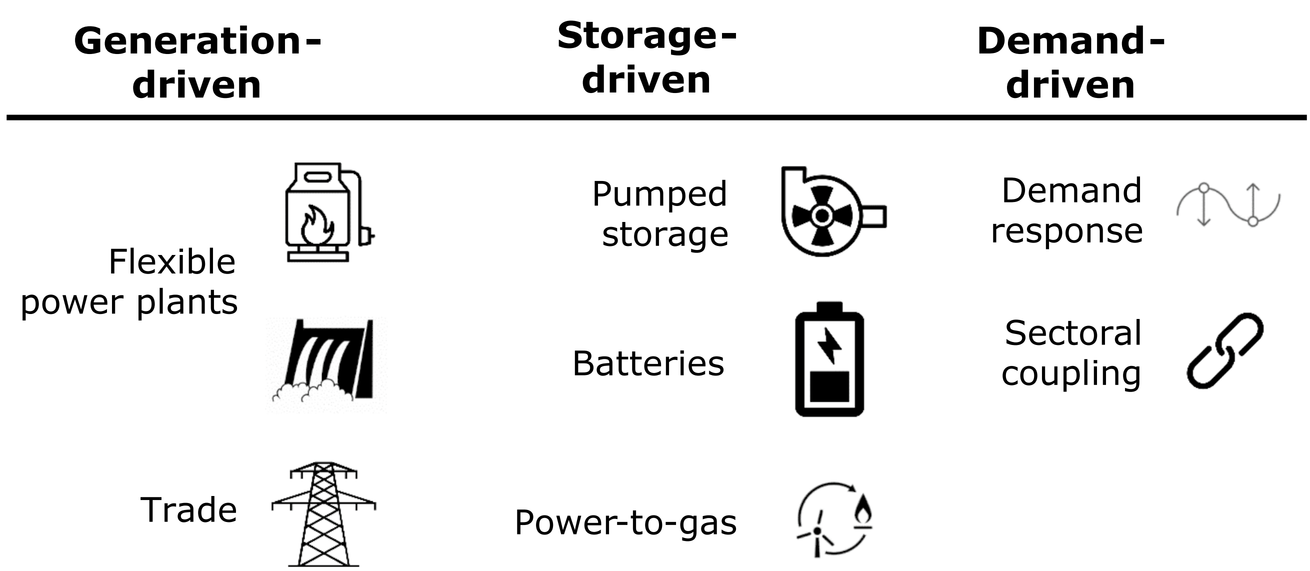

Fig. 1 Various categories of flexibility and prime examples of flexibility measures in each of these categories to enhance VRE penetration. Inspired by ref [17].

gas can therefore help in the near-term to support increased VRE penetration, especially for important natural gas producers like Nigeria (and its neighbours) [18], it cannot be considered a solution in the very long term, and significant expansion of natural gas to increase VRE penetration would be partially defeating the purpose of VRE. Therefore, in the context of generation-driven flexibility, it is desirable that where available, hydropower (provided that it meets environmental sustainability requirements) [28], CSP, and biomass, contribute strongly to generation-driven flexibility in the years to come.

The buildout of power pools across Africa would not only add value for hydro-rich countries seeking to export electricity to hydro-poor ones. In fact, significant spatial synergies exist in Africa between hydropower on the one hand and VRE on the other. Water-rich, rainy regions tend to have relatively low irradiation and wind speeds as compared to drier regions; the latter therefore have stronger (and thus cheaper) solar PV and wind power generation potential. Such spatial complementarities have been shown to exist between country pairs both across West Africa (e.g. Guinea and Senegal or Ghana and Burkina Faso) [11•, 18], East Africa (e.g. Ethiopia and Sudan) [21•, 24, 25, 29•] and Southern Africa (e.g. Zambia/Zimbabwe and South Africa) [30]. Reinforced grid interconnections may thus add value to VRE resources from hydro-poor countries by allowing them to complement hydropower from wetter regions [11•, 21•].

Some studies have even suggested that a smart deployment of VRE on interconnected regional grids may help reduce future investment needs for additional hydropower in water-rich countries, thus lowering sustainability concerns around environmental impacts of hydropower plants [11•, 31, 32•, 33, 34] as well as lessening competition for water resources amidst the water-energy nexus [35]. This is an important finding given the various barriers and controversies that surround the potential development of some of Africa's major unexploited hydropower resources, such as population displacement, disputed water rights, cost overruns and long lead times [34]. In the same vein, a diversification towards more VRE to reduce hydropower-dependency may reduce future power system shocks related to the impact of climate change on water resources [33, 36].

Next to hydropower's flexibility of dispatch to support VRE on (sub-)hourly timescales, hydropower and VRE exhibit pronounced seasonal synergies in many regions in Africa, with VRE tending to be highest during the dry season(s). For instance, such synergies have been documented for West Africa [11•, 37•], North-East Africa [21•] and South Africa [30]. In the context of regionally integrated power systems, this marks a strong case for seasonal patterns in imports and exports between countries to achieve more cost-favourable systems overall. These may even change prevailing patterns of trade between countries, with current importers of electricity potentially becoming strong exporters in the future [11•, 25, 37•, 38]. An example is Niger, which is currently importing most of its electricity from Nigeria, but could leverage its strong solar PV and wind resources to become a net exporter of electricity in the future [11•, 37•].

It has further been suggested that synergetic operation of hydropower with VRE may re-introduce natural seasonalities in the outflow of large, multi-year storage reservoirs, due to the increased need to dispatch hydropower during the low-VRE (i.e. rainy) seasons, which would have positive ramifications for river ecology [28]. A recent study suggested this concept as a potential way to mitigate an ongoing political conflict between Ethiopia, Sudan and Egypt on the Grand Ethiopian Renaissance Dam, while at the same time providing an opportunity to support enhanced VRE uptake across the region, including in other neighbouring countries such as Djibouti and South Sudan [21•].

In all the above contexts, much research attention has been given to five separate so-called "African Power Pools" (West, Eastern, Central, Southern and North) and their potential for achieving lower-cost electricity generation and lower emissions. Most covered in scientific and gray literature appear to be the West African Power Pool (WAPP) [10•, 11•, 18, 31, 37•, 38, 39] and the Eastern Africa Power Pool (EAPP) [21•, 25, 29•, 32•, 40], followed by the Southern Africa Power Pool (SAPP) [29•, 30, 41]. All of these cover a wide range of climate zones, ranging from wet and orographic highlands to dry, sunny and often windy flatlands, and could thus harness substantial hydro-solar-wind synergies leveraged by increased interconnections between countries dominated by different climates.

On the other hand, literature on the Central African Power Pool (CAPP) is relatively scarce. The available material mostly paints a picture of a region to remain dominated by hydropower in the foreseeable future [8, 42]. The latter is not unsurprising given that it is climatologically the most homogeneous of the African power pools, with most of its members being typical "hydrocountries", like DR Congo, Gabon, and Cameroon. However, it has also been suggested that the CAPP could become a substantial feeder to the SAPP whose electricity demand is much higher, mostly because of South Africa, currently Africa's second largest electricity consumer after Egypt [43].

Lastly, the North African Power Pool (NAPP) is an extreme at the other end: its hydropower potential is very low, and where it exists, it has largely already been exploited. Here, it is rather the potential for dispatchable Concentrated Solar Power (CSP) with thermal storage that is promising, thanks to extremely favourable direct normal irradiation (DNI) levels, with Morocco showcasing this in several large-scale projects. For this reason, CSP with thermal storage has been suggested as a strong candidate for investment to help support solar PV uptake in North Africa's future [44–46]. North Africa may also benefit from improved interconnections to the European mainland for electricity imports and exports [45, 47].

Such options related to electricity trade are not available for the various island states that are considered part of Africa. While a large island state like Madagascar could likely still make good use of spatiotemporal hydro-solar-wind complementarity by expanding power grids within its borders [48], small African island states (Comoros, Seychelles, Mauritius, São Tomé and Príncipe and Cabo Verde) will largely require other solutions to integrate VRE in their power mix [49, 50], such as storage technologies.

Notably, next to existing and future hydropower, planned biomass plants may also play important roles in flexibility provision in the future [37•]. Some countries with relatively high (unexploited) biomass potential, like Côte d'Ivoire, even foresee a more important role in the power mix for biomass (agricultural residues and wastes) than for solar PV by 2030, where it would be the third-largest contributor to the mix behind natural gas and hydropower according to current policy [51]—despite the much stronger expected cost reductions of solar PV [2]. Overall, however, the potential for biomass power generation in Africa is estimated to be substantially below that of hydro and VRE [52, 53], and it is thus likely to play more of a complementary role rather than a dominant one.

In the context of renewable resource complementarities in Africa, the somewhat less obvious ones should not be forgotten. For instance, despite their inherent lack of flexibility, solar PV and wind can mutually support each other thanks to temporal complementarities e.g. on diurnal scales [54]. Furthermore, next to its general flexibility of dispatch, biomass-based power may exhibit seasonal synergies with run-of-river hydropower in cases where the main cropping season falls outside the rainy season [24]. Geothermal power, on the other hand, for which the potential is mostly concentrated in African Rift countries (i.e. in the Eastern African Power Pool), may be more likely to be used for providing baseload power, contributing relatively little to flexibility [24].

Storage-driven flexibility

Generation-driven flexibility cannot support VRE indefinitely, primarily because natural gas plants are not compatible with the Paris Agreement, hydropower potential has clear upper limits, and biomass plants depend on agricultural output which is a seasonally limited resource. Thus, it will be of imperative importance that storage technologies are deployed at large scale across Africa to assist in VRE integration.

Worldwide, the most-used storage technology of the present-day is pumped-storage hydropower [55]. However, in Africa, only South Africa and Morocco have made use of this technology to date [56, 57] and current policy plans do not suggest that this is about to change, despite available potential [58]. In particular, pumped-storage hydropower may hold promise for small island states which cannot benefit from regional interconnections, such as Cabo Verde [59] and Mauritius [60], which both have pronounced orography (permitting high-head pumped-storage schemes) and high solar PV and wind power potential.

Thanks to the recent, unprecedented decreases in costs of battery storage [61], it appears more and more likely that a large-scale deployment of battery storage solutions to complement solar PV and, to a lesser extent, wind power generation, may play a substantial role in Africa's energy future. Recent studies on the West African [37•] and North African regions [62•] and on South Africa [63•], as well as on sub-Saharan Africa as a whole [3••], have suggested solar PV-plus-batteries as the most attractive future backbone of power systems on the basis of least-cost optimization—allowing to lower costs and CO_2 emissions while increasing employment opportunities (as compared to business-as-usual pathways without strong drives to increase VRE penetration).

Although the grid-scale battery storage sector is nascent on a worldwide scale and the above-cited studies remain projections for the time being, first steps are already being taken on the African continent. South Africa appears to be a frontrunner as of 2021, with its utility having issued a request for bids in 2020 for a large-scale storage facility to complement a local wind farm and provide ancillary services [64]. In coal-dependent and relatively hydro-poor South Africa, such projects are likely to be considerable assets for increasing VRE penetration while reducing the reliance on fossil fuels [63•].

Battery storage will, by nature, mostly be a lever to reduce intra-daily variability of electricity supply. For seasonal storage, it has been suggested that power-to-gas technologies could play important roles—not only for the power sector, but also to increase sectoral coupling and aid the decarbonization of e.g. industry [37•, 62•]. The relative importance of storage technologies will be strongly contingent upon the region [3••]. For instance, regions with substantial reservoir hydropower schemes (like West and East Africa) may leverage this to provide seasonal balancing and thus reduce the future need for power-to-gas technology [37•], which will not be the case for North Africa [62•].

Last, Concentrated Solar Power (CSP) with thermal (molten salt-based) storage has been successfully implemented in Morocco and South Africa. Further expansions of CSP capacity could further support VRE uptake in the years to come, potentially through explicit tendering of hybrid CSP/PV plants [46]. Such projects will be most attractive in the geographical regions benefitting from the highest DNI levels, e.g. North Africa and Southwest Africa [65].

Demand-driven flexibility

In addition to generation-driven and storage-driven flexibility measures, various levers for increasing VRE penetration while safeguarding a balanced power mix are to be found on the demand-side. Clearly, demand response measures within the power sector to shift loads to better match VRE infeed could be helpful; however, with electricity demands still strongly on the rise across Africa [8] and electricity access lagging behind [66], this is clearly not yet of prime concern and literature on the topic is scarce. What appears much more pressing at the moment in terms of demand is the need to reduce losses in transmission and distribution [67], such that unnecessary demand growth related to these losses can be tempered.

Looking at demand-side flexibility from a broader perspective, the topic of sectoral coupling could mark a strong case for supporting VRE penetration in the longer-term future. Various studies on cost-optimised power systems in Africa [37•, 62•, 63•, 68, 69] showed that sectoral coupling can lead to more cost-effective systems overall, across diverse regions of the continent with different resources and storage needs. For instance, power-to-gas technologies can contribute to sectoral coupling of electricity and non-electricity sectors across Africa if the produced gas is consumed in the industrial sector, instead of being used within the electricity sector as storage option [3••].

Conclusions and the way forward

The African continent has a unique opportunity to plan its future electricity (and energy) systems from the outset with a high VRE penetration as one of the targets. Many African countries are practically "greenfields" for VRE deployment, where even comparatively small capacity additions of VRE could have important ramifications for power system operation. It is therefore of high importance that all currently available technologies (notably flexible hydropower and gas plants, as well as interconnections and power pooling) are used to support an initial push for increased VRE penetration. At the same time, research and development efforts to further the prospects for near-term deployment of battery and other storage technologies, and those for longer-term demand response and sectoral coupling approaches, will be indispensable in going beyond what generation-driven flexibility can provide in terms of VRE support.

Various studies have shown that increasing VRE penetration across Africa could be cost-competitive as compared to continued fossil fuel- and hydro-dominance, and carry various climate and other environmental benefits, thus helping to achieve the goals of the Paris Agreement. Recently, however, the carbon lock-in risks for Africa have been estimated as high, with the share of non-hydro renewables projected to remain below 10% by 2030 unless a rapid shift to modern VRE and other renewable resources is undertaken [14••]. It is therefore urgent that all solutions mentioned above are leveraged to the extent possible to facilitate the transition to low-carbon electricity supply across Africa, while at the same time growing power grids and increasing electricity supply to larger shares of the population.

Next to the technological and economical aspects, governmental support for VRE will be imperative if such a transition is to succeed. This support can come in various forms; examples include explicit policy support for renewables [67], the creation of dedicated governmental agencies for renewables [70, 71], and training and capacity building of national stakeholders in all matters concerning long-term power systems planning with high VRE shares [16, 72].

In this context, the author of this review paper has recently been involved in the planning and organization of capacity building workshops on power system modelling with high VRE penetration with energy sector stakeholders in various African countries, including Côte d'Ivoire, Gabon, Niger, Mali and Cameroon. The objective of these workshops has been to support these countries' revisions of their Nationally Determined Contributions (NDCs) in the run-up to the COP26 in Glasgow. In the author's view, national VRE strategies and targets, as communicated e.g. in power sector masterplans and NDCs, can be prime opportunities for countries to showcase their desire to enhance VRE integration on a worldwide stage. Such visibility, in turn, may act as a catalyst for enhanced research efforts to chart pathways appropriate for each country's specific circumstances to attain power sector decarbonization — something which today is still lacking, with many studies having an important region-wide focus but falling short of providing tailored advice for policymakers in individual countries.

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Compliance with Ethical Standards

Conflict of Interest The authors declare that they have no conflicts of interest.

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•• Of major importance

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DATA NOTE

A spatiotemporal atlas of hydropower in Africa for energy modelling purposes

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Abstract
The modelling of electricity systems with substantial shares of renewable resources, such as solar power, wind power and hydropower, requires datasets on renewable resource profiles with high spatiotemporal resolution to be made available to the energy modelling community. Whereas such resources exist for solar power and wind power profiles on diurnal and seasonal scales across all continents, this is not yet the case for hydropower. Here, we present a newly developed open-access African hydropower atlas, containing seasonal hydropower generation profiles for nearly all existing and several hundred future hydropower plants on the African continent. The atlas builds on continental-scale hydrological modelling in combination with detailed technical databases of hydropower plant characteristics and can facilitate modelling of power systems across Africa.

Keywords
Hydropower, energy modelling, Africa, resource profiles, renewables, decarbonization

Open Peer Review

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Any reports and responses or comments on the article can be found at the end of the article.

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Plain language summary

Hydropower plants rely on river flow to generate electricity. Since river flows change between different seasons, electricity from hydropower plants will also change from season to season. In this paper, we present a new database that contains calculated profiles of electricity generation from season to season for hundreds of hydropower plants in Africa, both existing and future ones. This database will be helpful to scientists doing research on electricity generation in different African countries.

1. Introduction

To achieve the long-term objectives of the Paris Agreement, it is well-established that electricity supply worldwide will have to decarbonise by mid-century[1]. In this context, it is imperative that the shares of low-carbon resources in power systems increase. Low-carbon resources include solar photovoltaics (PV), concentrated solar power (CSP), wind power, hydropower, geothermal power, ocean power, bioenergy and nuclear power. Among these, the strongest growth rates over the past decade, and the highest drops in price, have been recorded by solar PV and wind power[2], which are thus seen more and more as potential backbones of future power systems[3].

Given the dependence of solar PV and wind power generation on meteorological variables, these are classified as "variable renewables", or VRE[4]. Because of this variability in generation from short (sub-hourly) to long (seasonal and interannual) timescales, increasing the share of VRE in electricity systems will require increased flexibility and storage to solve issues related to mismatches between VRE supply and electricity demand, which must be considered in modelling exercises[5].

Although solar and wind power have recorded the highest rates of growth among renewable resources in recent years, the most-used renewable electricity resource worldwide is currently still hydropower[2]. This comprises run-of-river hydropower without storage, which is essentially another form of VRE[6]; reservoir hydropower, which can be dispatched flexibly to aid VRE grid integration[4,7–11]; and pumped-storage hydropower, which can be used as a "battery" to avoid curtailment of surplus VRE[12].

To inform long-term planning and modelling of renewable power capacity expansion, it is crucial that reliable resource profiles of VRE and hydropower are available to the modelling community[13]. The inclusion of such resource profiles at high spatiotemporal resolution, from hourly to seasonal and interannual timescales and across geospatial zones of different resource strengths, is crucial to accurately represent modern renewable technologies in energy system models. For this reason, dedicated spatiotemporal databases on solar and wind resource strength and availability have been developed, such as the Global Solar Atlas[14] and the Global Wind Atlas[15] or the reanalysis-based web interface "*renewables.ninja*"[16]. Such resources typically allow the user to select locations on the world map and extract representative resource profiles for VRE from hourly to seasonal and interannual timescales, which can then be used in energy modelling exercises.

The picture is different for hydropower. Comprehensive and integrated databases of hydropower resources are currently unavailable to the modelling community at the required level of detail[17]. This is a consequence of the challenge of accurately modelling river flows across a wide range of river basins with different hydrometeorological conditions within a single model framework[18], as well as the wide disparity in individual hydropower plants' technical characteristics[19]. A consequence of this comparative disparity vis-à-vis solar and wind power, and the resulting lack of comprehensive hydropower databases, is that hydropower plants – which are more and more considered to be an important lever to support VRE uptake thanks to their flexibility of dispatch (for reservoir plants) and potential seasonal synergy with VRE (for run-of-river plants) – are often represented coarsely and without the warranted spatiotemporal detail in energy models[9]. For instance, many studies lump hydropower plants in a region together as one single technology without detail on individual plants (e.g. 3,20), do not consider interannual variability of river flows (e.g. 21), or do not contain information on seasonally constrained availabilities of hydropower (e.g. 22).

This data gap is especially problematic for regions where (i) hydropower forms an important backbone of many power systems, (ii) substantial expansions of hydropower generation are still planned, and (iii) precipitation patterns are highly variable on seasonal timescales. All of these apply to the African continent[23–25], for which science-based services for the renewable energy sector are in short supply[26]. To close the data gap and improve the resources available for energy modelling on Africa, we present here a new spatiotemporal data atlas for nearly all existing and several hundred future hydropower plants across the African continent, containing (i) geospatial references, (ii) technical characteristics, and (iii) seasonal power plant availability profiles, including uncertainty ranges reflecting interannual hydrological variability. The seasonal availability profiles in the atlas include the effect of reservoir sizes on operational possibilities to shift seasonal availabilities of hydropower dispatch, and of current and future configurations of hydropower plants in a cascade. This African hydropower atlas is hereafter abbreviated by "AHA".

2. Materials and methods

The AHA, which is herewith made freely available to the research community, is designed to be a comprehensive resource containing technical, spatial, and temporal data on existing and future hydropower plants across Africa. It covers all continental African countries which together constitute the major African Power Pools (respectively the North, West, Central, Eastern, and Southern African Power Pool), as well as the island nation of Madagascar.

The AHA is collated into a single spreadsheet-based file which contains both inputs and results of the calculations carried out to establish the atlas. An overview of the calculation flow performed to obtain the full dataset is provided in Figure 1. Each of the elements of this workflow are described in a separate subsection hereafter.

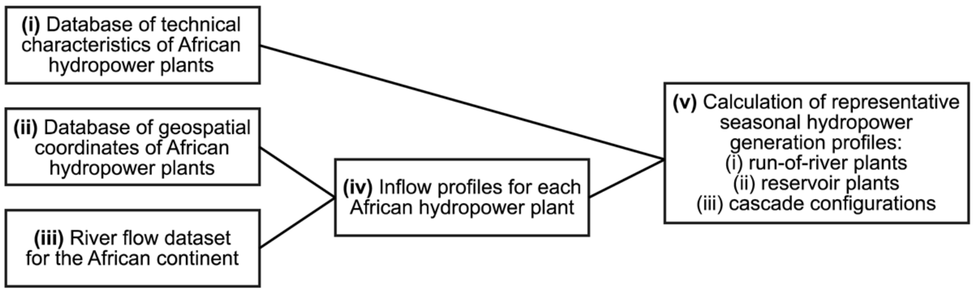

Figure 1. Schematic overview of the various inputs, intermediate results, and outputs of the calculations performed to create the African Hydropower Atlas.

2.1 Database of technical characteristics of African hydropower plants

The technical information for each hydropower plant includes the rated capacity (in MW), the reservoir size (in million m^3 wherever applicable), the multiannual mean discharge of the river section upon which the plant is located (in m^3/s), the design discharge wherever known (in m^3/s), the earliest expected year of entry into service, and the multiannual average capacity factor of the plant wherever known from previous research (in %). In cases where the latter value was unknown, it was assumed to be 50% based on typical values observed for hydropower plants around the world[2].

This data was collated from a wide array of available information. Globally, the data sources can be divided into three categories: (i) existing hydro databases, such as the Global Reservoir and Dam (GRanD) database[27], the FAO's Dams in Africa dataset[28], and the West African Renewable Power Database (WARPD)[9]; (ii) bespoke information, pertaining to individual hydropower projects, from technical project overview sheets, environmental impact assessments, white papers, scientific papers, and other technical modelling studies; and (iii) online news articles on hydropower projects. The consultation and selection of data sources happened strictly according to the hierarchy (i)-(ii)-(iii), with sources from category (i) forming the default, being supplemented by categories (ii) and (iii) wherever necessary. All used data sources are referenced in the AHA. The processing of this data to calculate temporal hydropower availability profiles is explained further below, in section 2.5.

The database includes both existing (active) hydropower plants, as well as future plants. The term "future" is relatively broad and may encompass, for example, projects under construction or in the pipeline, projects in need of financing, or projects in the pre-feasibility phase. In many cases, distinguishing between these categories is not straightforward. Based on the above-mentioned data sources, the AHA distinguishes between three categories of future projects in descending order of concreteness: committed, planned, and candidate. For any future plant where no specific information was identified regarding its status (as of the writing of this paper), the categorization was set to "candidate" by default. In those cases, the "first year" parameter was left empty. Projects in this category may either be currently unlikely to obtain financing, have been shelved, or have never gone beyond pre-feasibility studies.

We note that we constrained the entries to the current version of the atlas by the criterion that the data should be available in publicly consultable sources. Thus, the atlas could be improved if presently undisclosed information available in, for example, internal documents of planning agencies were to be made publicly available. We therefore eagerly invite all relevant stakeholders to review and submit corrections and/or missing data to the author team, since the goal is for the database to be regularly updated. This particularly concerns the list of future projects, which can likely be expanded much beyond its current state and of which we do not claim full comprehensiveness.

Currently, the AHA contains a total of 633 entries on hydropower plants, of which 266 are existing, 60 committed, 44 planned and 263 candidates. Their total capacity amounts to 132 GW, of which 24% is existing (approximately 32 GW, lining up well with other statistics on existing plants[29]), 19% committed, 6% planned, and the remaining 51% candidate. The division of the total capacity by category and by country is shown in Figure 2.

We note that hydropower plants have been allocated to the country of their coordinates, notwithstanding that, in some cases, a part of the produced electricity would be allocated for exports (e.g. hydropower plants in some river basins are shared among all riparian countries). In the cases of hydropower plants located on rivers forming country borders (11 cases in total in the AHA), their capacity was allocated equally among the countries in question, thus forming separate entries in the database.

2.2 Database of geospatial coordinates of African hydropower plants

The geo-referencing of hydropower plants was done according to a hierarchy of data choices, depending on the status of each plant. Firstly, all existing plants were georeferenced

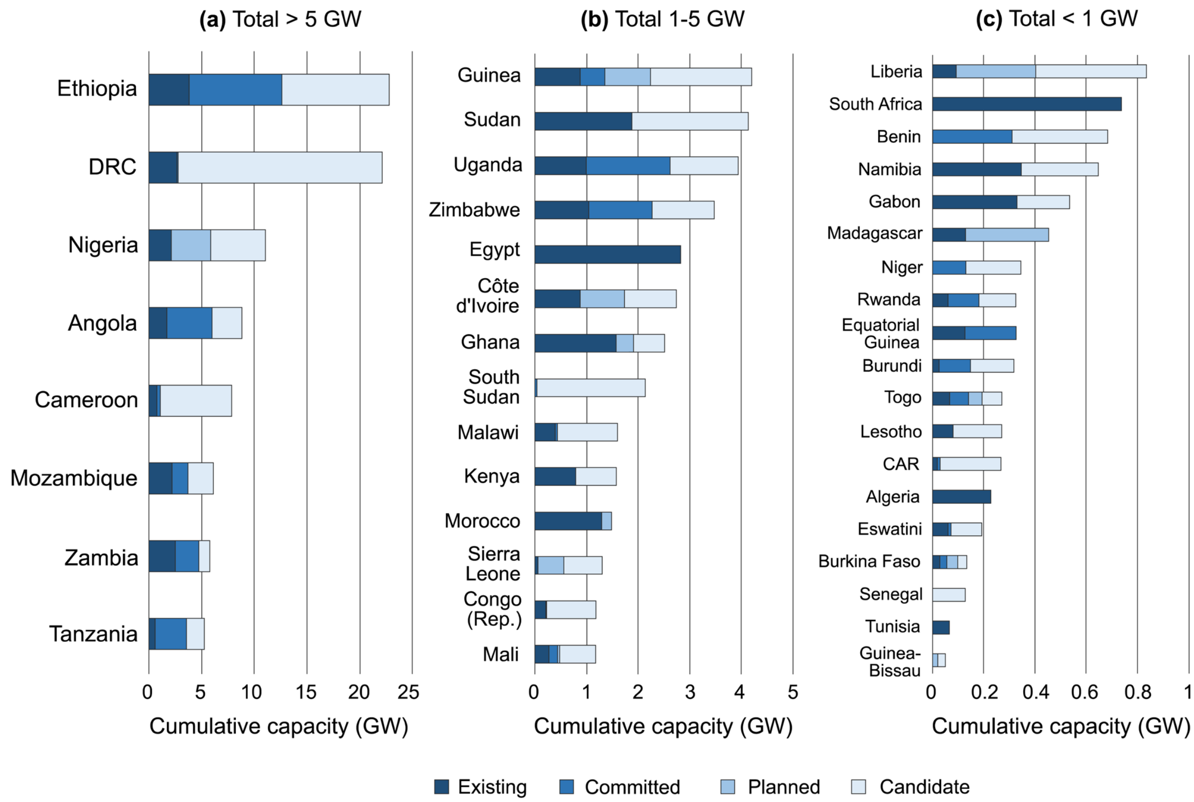

Figure 2. Overview of total capacity of existing, committed, planned, and candidate hydropower plants across Africa as collected in the AHA, for countries where this capacity totals (**a**) > 5 GW, (**b**) 1–5 GW, and (**c**) < 1 GW. DRC = Democratic Republic of the Congo; Congo (Rep.) = Republic of the Congo; CAR = Central African Republic.

using satellite imagery; the coordinates given in the AHA correspond to the location of the dam and/or powerhouse as identifiable via Google Maps. Secondly, all hydropower plants that are not yet servicing the grid but are clearly identifiable as being under construction on satellite imagery, were similarly georeferenced. Thirdly, the locations of all other committed, planned and candidate hydropower plants were identified as best possible from specific project information available in any of the consulted sources.

This last category of data could take on a variety of specificity: in some cases, georeferenced coordinates of the intended location of the planned plant were provided in the consulted document(s) as referenced in the AHA; in others, the information remained less precise (e.g. "*the plant will be constructed about 50 km downstream of location A, about 100 km west of city B*"). In the latter case, satellite imagery was consulted to roughly identify the river section corresponding to the description, and a "best guess" location (e.g. where whitewater reveals the presence of rapids, showing a relatively steep head drop) was selected on the river section. We note that, as long as the river section is identifiable at the spatial resolution of the river flow data that is used (see section 2.3), this approximation is unproblematic for the analysis.

A spatial overview of the hydropower plants collected in the AHA is shown in Figure 3.

2.3 River flow dataset for the African continent

To estimate hydropower generation profiles for each of the identified locations under the given technical plant characteristics, estimations of river flow at monthly resolution on the African continent were obtained from dedicated simulations with SWAT+ (Soil and Water Assessment Tool[30]). A previous version of this dataset has been used for hydropower potential assessment in West Africa before (refs. 9,31); the updated version used for this paper is available through the repository in ref. 32. Detailed descriptions of the characteristics of the simulations are provided in refs. 9,33,34; performance metrics of the simulations in comparison to observed data from the Global Runoff Data Centre (GRDC) are described in ref. 34. The most important points from these publications are repeated below.

In SWAT+, watersheds are delineated into sub-basins from which hydrologic response units (HRUs, which are distinct areas of a sub-basin with a unique combination of land use, soil type and slope class) are defined. For the SWAT+ model used for the AHA, sub-basins were delineated using 3,500 km^2 as

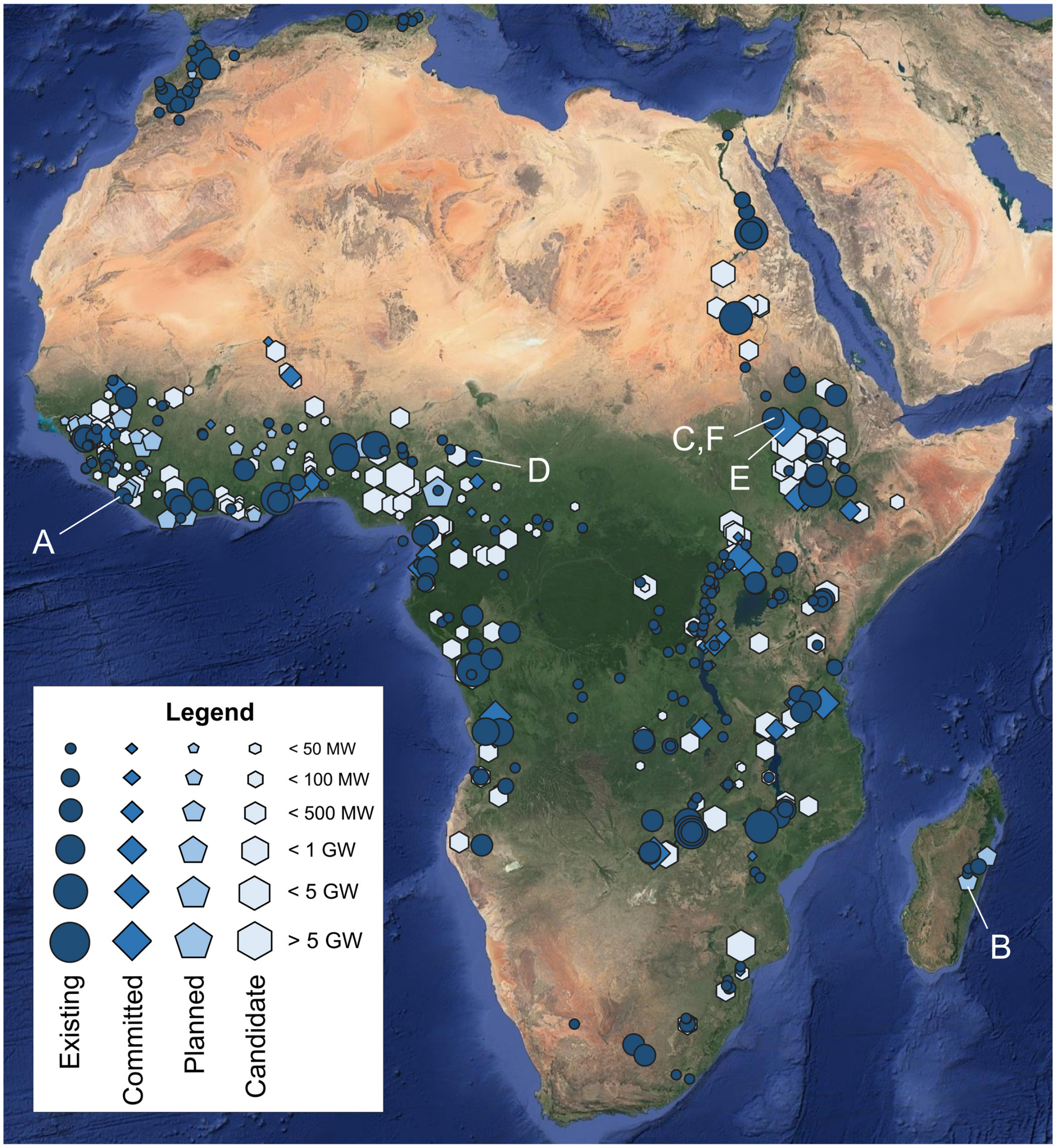

Figure 3. An overview of the georeferenced African hydropower plants by category (existing, committed, planned, candidate). Sizes of icons reflect installed capacity as per the legend. The characters (**A**)–(**F**) refer to the plants whose temporal power generation profiles are shown in Figure 4. Background: Esri's World Imagery[44] (see Acknowledgements).

threshold, yielding 5,700 sub-basins and 461,829 HRUs across the African continent. Input data was obtained from the following sources:

- Digital elevation: A 90 x 90 m Digital Elevation Model (DEM) acquired from the Shuttle Radar Topography Mission[35];
- Land use: Data from the Land Use Harmonization (LUH2) dataset[36] at 0.25° x 0.25° resolution;
- Soil: Data from the Africa Soil Information Service (AfSIS) dataset[37] resampled at 0.25° x 0.25°;
- Meteorological forcing: Data from the EWEMBI dataset[38] at 0.5° × 0.5°.

Further, the following methodologies were employed to estimate evapotranspiration and surface runoff and perform flow routing:

- ➢ Evapotranspiration: Using the Penman–Monteith method;
- ➢ Surface runoff: Using the Soil Conservation Service curve number method;
- ➢ Flow routing: Using the variable storage routing method.

Temporally, the simulations were carried out at daily resolution across the 37-year period 1980–2016. For the reposited dataset, results were averaged to monthly timescales to reduce file size. The first eight years of the simulation were considered as spin-up time and left out of the analysis. Spatially, each river section of the modelled river network is designated by a unique identifier (ID) as provided in the reposited dataset, to which hydropower plant coordinates could be mapped (see next section).

2.4 Inflow profiles for each African hydropower plant

The geospatial information described in section 2.2 and the river flow information described in section 2.3 were combined as follows to obtain the river inflow feeding each hydropower plant.

First, the geospatial hydropower plant information (coordinates) was mapped to the river network of the SWAT+ simulations (river sections), such that monthly river flow across the 37-year simulation period could be extracted separately for each hydropower plant. This "snapping" was straightforward in 74% of cases, with hydropower plant coordinates being precisely covered by the SWAT+ river network. In the other 26% of cases, the river stretch most representative for the hydropower plant coordinates was selected according to the following hierarchy. First, if the hydropower plant coordinates were so close to the river source that the modelled SWAT+ network did not extend sufficiently far upstream, the most upstream river section in the modelled network (downstream of the plant coordinates) was selected. Second, if the hydropower plant was located on an affluent not covered by the SWAT+ network at all, the geographically nearest river section in the same river basin (draining into the same main river) was selected. Third, in the extremely rare cases where the entire river basin of the hydropower plant was not covered by the SWAT+ network, but a nearby river basin with the same prevalent precipitation seasonality was covered, the geographically nearest river section of that basin was selected. Note that in all these cases, the objective of this snapping was to infer a reasonable estimate of river flow seasonality and interannual variability for each hydropower plant. The AHA includes the selected SWAT+ river section ID for each identified set of hydropower plant coordinates.

Second, a typical range of years of different "wetness", spanning the range from very dry to very wet years, was selected as follows. First, the flow profile for a "normal year" was defined as the monthly median of the dataset. Subsequently, the flow profile for "very dry" and "very wet" years was taken to be the "normal year" profile multiplied by a corrective factor, calculated as the ratio of the 5th (very dry) and 95th (very wet) percentile value of average annual flow to the multiannual average flow. To account for the fact that some few hydropower plants with very large reservoirs are capable of buffering water on interannual timescales and thus mitigate interannual variability, an exception in the calculation was made for those plants with a typical filling time[9] of more than one full year. For these plants, instead of the 5th and 95th percentiles, the 10th and 90th percentiles were taken to account for this mitigation of dry and wet extremes on interannual timescales.

Third, the seasonality of river flow for these three types of years (very dry, normal, and very wet, each characterized as a time series of twelve values representing the months of the year) was calculated by dividing each time series by the multiannual average flow. In this way, the (normalized) seasonality was obtained for each plant in the AHA for which a match of geospatial coordinates with SWAT+ simulated river stretches could be performed.

Fourth, wherever possible, the three resulting time series of river inflow to each hydropower plant were additionally bias-corrected (using the simple scaling technique[39]) to the multiannual mean river discharge value collected from existing databases and literature (see section 2.1). This last step could be performed for 59% of cases (457 out of 633 plants).

2.5 Calculation of representative seasonal hydropower availability profiles for energy modelling

The final step in the calculations was to convert the typical river inflow datasets (whether bias-corrected or not) for each reservoir to typical power output profiles. A distinction was made between (i) run-of-river hydropower plants, (ii) reservoir hydropower plants, and (iii) hydropower plants in a cascade. For each of these, typical profiles of outflow (e.g. of turbined water) were calculated from inflow profiles as described below, before these were further converted to typical seasonal capacity factors.

2.5.1 Run-of-river hydropower plants. For run-of-river hydropower plants, the turbined outflow profiles were taken equal to the inflow profiles. Power generation was assumed to be a linear function of the turbined outflow profile, with the exception that maximum power output was assumed to be reached when outflow was equal to or higher than the design discharge (reflecting the fact that run-of-river hydropower plants are typically designed to produce at full capacity during several months of the year, not only during the single wettest month).

Typical seasonal capacity factors were thus calculated according to:

$$\langle CF_{hydro} \rangle_m^{n,d,w} = \min\left(\frac{\langle Q(t) \rangle_m^{n,d,w}}{Q_{design}}, 1 \right), \quad (1)$$

where $\langle CF_{hydro} \rangle_m^{n,d,w}$ is the average capacity factor of the hydropower plant in month m during a normal (n), very dry (d) or very wet (w) year; $\langle Q(t) \rangle_m^{n,d,w}$ is the average turbined outflow in that month; and Q_{design} is the design discharge.

In cases where the design discharge was not known, it was estimated by dividing the multiannual mean river discharge value (used for bias-correction of SWAT+ data) by the multiannual average capacity factor recorded in the AHA (assumed to be 50% unless known otherwise, as mentioned in section 2.1). Thus, for instance, the design discharge of a hydropower plant with an average capacity factor of 50% was assumed to be twice the average discharge. For such cases, the capacity factor was thus calculated according to:

$$\langle CF_{hydro} \rangle_m^{n,d,w} = \min\left(\frac{\langle Q(t)_m^{n,d,w} \rangle}{Q_{mean}} \times CF_{hydro}^{mean}, 1 \right), \quad (2)$$

where CF_{hydro}^{mean} is the assumed multiannual average capacity factor, and Q_{mean} the multiannual average river discharge.

In those cases where neither the design discharge Q_{design} nor the multiannual mean river discharge Q_{mean} were available (the latter meaning that no bias-correction could be performed), it was assumed that the design discharge corresponded to 50% of the maximum flow in a "normal" year. The (non-bias corrected) monthly profiles were then divided by that (non-bias corrected) value, thus obtaining an estimate of typical monthly average capacity factors:

$$\langle CF_{hydro} \rangle_m^{n,d,w} = \min\left(\frac{\langle q(t) \rangle_m^{n,d,w}}{0.5 \times \max\limits_{m}[\langle q(t) \rangle_m^{n}]}, 1 \right), \quad (3)$$

where $q(t)$ represents the flow time series before bias-correction.

All above calculations were performed separately for the months of a normal, very dry, and very wet year. An example of a capacity factor profile calculated for a run-of-river hydropower plant is shown in Figure 4(a).

2.5.2 Reservoir hydropower plants. For all reservoir-based plants, the reservoir inflow was separated into a "storable" and a "non-storable" component, based on the typical "filling time" of the reservoir (the time it would take for the average inflow to fill the reservoir). This approach is described in detail in the Supplementary Material of ref. 9 and briefly summarized here.

Essentially, the "storable" component corresponds to the percentage of inflow that, if cumulated across the year, would be precisely enough to fill the reservoir's live storage volume; this component is assumed to be stored by the reservoir and redistributed equally over the different seasons (see section 3 for a discussion of this assumption). The "non-storable" component, on the other hand, corresponds to the remainder of the inflow which hence cannot be stored (as this would lead to spilling, which is to be minimized in normal reservoir operation schemes); it is therefore assumed to be directly turbined. For reservoirs with a filling time of more than one year, the non-storable component is equal to zero. Note that the filling time can differ between dry and wet years; thus, a reservoir's non-storable component may be zero during very dry years (resulting in an unseasonal outflow profile) but finite during very wet years (bringing a seasonal peak into the outflow profile)[9]. We assumed live storage volume to be 70% of total reservoir volume in all cases.

The total outflow of the reservoir-based plants was then calculated as the sum of the redistributed "storable" and "non-storable" flow components. Subsequently, the conversion of these outflow profiles to typical monthly average capacity factor profiles was done as described by Equation (1)–Equation (3) in section 2.5.1.

Four examples of capacity factor profiles for reservoir hydropower plants are shown in Figure 4(b)–(e), of which two with less-than-a-year (b–c) and two with more-than-a-year filling time (d–e).

2.5.3 Cascade configurations. For the development of the AHA, the definition of a "cascade" was taken to refer to any one or more run-of-river plants, or plants with relatively small reservoirs, being located downstream of larger reservoir plants on the same river stretch. In such cases, the inflow profile of the first downstream run-of-river plant was taken equal to the calculated outflow profile of the upstream reservoir plant; the inflow profile of the second downstream plant was taken equal to the outflow profile of the first downstream plant; and so forth. Finally, the outflow profiles of each plant were converted to typical monthly average capacity factor profiles as described by Equation (1)–Equation (3) in section 2.5.1.

Since cascade configurations can be time-dependent – for instance, a reservoir plant may be planned or under construction upstream of an existing run-of-river plant – the outcomes of this calculation depend on the year for which the calculations are performed, and whether this is before or after the planned reservoir plant comes online. To differentiate between these cases, the AHA contains results sheets for different example years: 2020, 2030, and "All", the former two reflecting the hydro fleets of 2020 (present-day) and 2030, respectively, and the latter reflecting the hypothetical case where all hydropower plants, including "candidate" plants, are constructed.

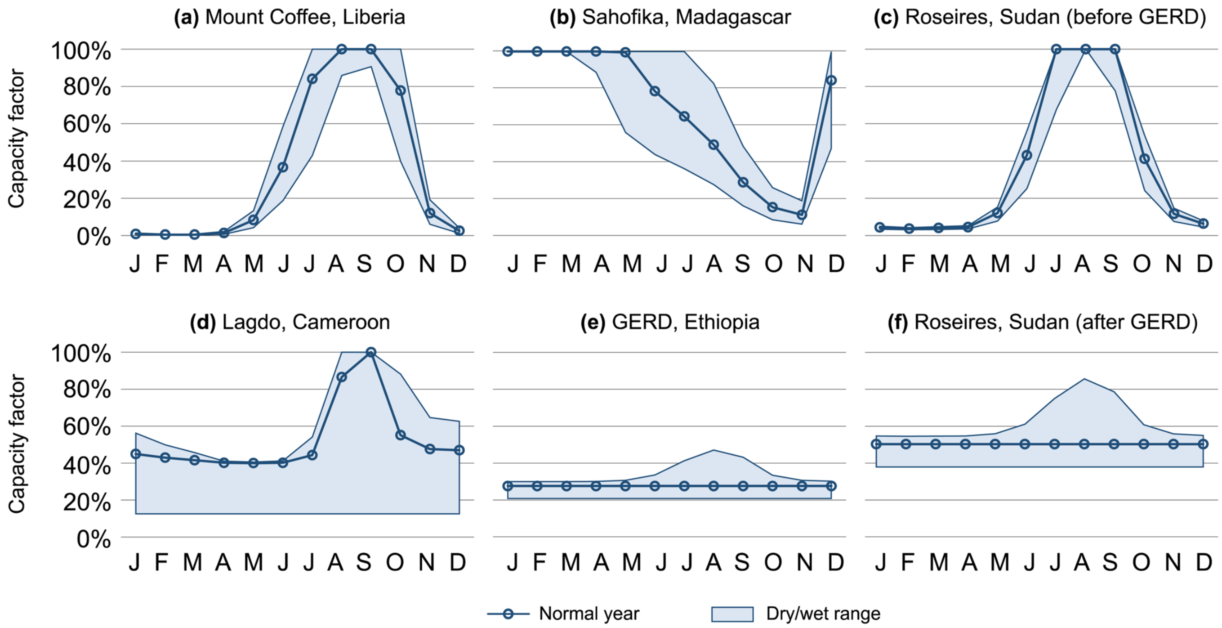

Figure 4. Six demonstrations of the monthly typical capacity factor profiles in the AHA (normal years as well as very dry and very wet years). Showcased are a run-of-river plant (**a**), two reservoir plants with less-than-a-year storage capacity (**b**–**c**), and two reservoir plants with more-than-a-year storage capacity (**d**–**e**). Further, the plant in (**c**) will form part of a cascade with (**e**) in the future, resulting in profile (**f**). GERD = Grand Ethiopian Renaissance Dam.

An example of capacity factor profiles for a hydropower plant that is currently not part of a cascade system, but will become so in the future due to upstream construction of a large reservoir plant, is provided in Figure 4(c) & (f).

2.5.4 Data coverage. With these procedures, seasonal availability profiles could be calculated for 550 out of 633 hydropower plant entries in the AHA (87%). For the remaining 83 entries – mostly small existing plants for which the snapping to the simulated river network could not be performed with confidence (see section 2.4), and "candidates" with unclear locations – the profiles could not be calculated from the present version of the AHA. Future iterations of the database and the simulations may make it possible to further close this gap.

3. Use and limitations of AHA data in energy modelling

The data provided in the AHA is aimed at servicing the energy modelling community to enable better representation of seasonal constraints of hydropower availability at a plant-by-plant level. The best way to import these profiles into any model will depend on the specific software used.

However, the general principle of importing and applying the profiles in energy models is as follows. For run-of-river plants, the AHA profiles can be used as-is (i.e. considered fixed), as these plants are not considered to be dispatchable, and cannot ramp up or down in function, for example, of the day-night cycle of solar PV or power demand. These profiles are thus to be used in the same way as would solar PV or wind resource profiles.

For reservoir plants, the profiles denote seasonal availability constraints rather than a fixed curve of power output. Such plants can be dispatched flexibly up to a certain extent, for example, to follow demand or to aid VRE integration[9], constrained by typical (sub)-hourly ramping rates which are different from case to case. In such cases, the modelling should be set up in such a way as to ensure that the power plants are represented as dispatchable technologies but constrained by average seasonal availability profiles as given by the AHA.

It is important to note that the AHA represents a first attempt at providing a comprehensive, continent-wide spatiotemporal dataset for Africa. As such, it is subject to various limitations which must be considered. The most important limitations are summarised below.

First, the river flow profiles were obtained from simulations representing a historical period. Thus, any potential effects of future climate change on river flow, which may be substantial, have not been taken into account[40]. However, this has been planned for future iterations of the AHA based on SWAT+ simulations forced by relevant data from climate change scenarios.

Second, for the same reason, the capacity factor calculations were purely based on simulated reservoir inflow and did not consider evaporation and precipitation effects on the reservoir surfaces of future reservoirs which do not form part of the hydrological network as simulated. However, the effects of this omission are expected to be relatively minor since inflow is normally by far the dominant component of reservoir water budgets. (A notable exception to this rule is Lake Victoria, a natural lake that was later dammed for hydropower generation at its outlet.)

Third, the calculations did not explicitly model reservoir dynamics and thus do not include the effect of seasonal hydraulic head variations on seasonal capacity factors. While this effect exists, it is typically minor except for reservoir plants with very low heads[9].

Fourth, the calculations took a strong supply-side view in assuming that the purpose of hydropower reservoirs is to (partly) remove the seasonality and variability of river inflow such as to stabilize power output on seasonal timescales. However, in cases where power demand itself has a strong seasonality, or in cases where other sources in the electricity mix, like solar and wind power, exhibit extremely pronounced seasonalities and these have a major effect on the supply-demand balance, reservoir hydropower may be required to follow these seasonalities rather than fully flattening the "storable" component of river flow. If the load profiles that hydropower should follow are known, corresponding calculations could be straightforwardly carried out by adapting the methodology described in section 2.5.2. However, we note that this is mostly of importance for reservoirs with more-than-a-year storage capacity (7% of entries in the AHA). For such cases, we recommend that specific case studies be undertaken on the hydropower plants in question to elucidate the potential re-introduction of seasonalities under integrated hydro-VRE operation, such as ref. 41.

Fifth, for all hydropower plants, there may be additional constraints not included in the AHA that impact their inclusion in energy modelling exercises. For example, there may be certain environmental outflow constraints that put further limits on monthly hydropower generation[42], or certain hydropower plants where power generation needs to be co-optimised with irrigation or other secondary purposes[43].

Sixth, in its current form, the AHA covers the African mainland and Madagascar. However, there is potential for small hydropower plants on other, small African island nations such as São Tomé & Príncipe and the Comoros. These are currently not covered by the hydrological simulations used for the AHA. However, these countries will be integrated into the AHA in the future, contingent upon more exhaustive river flow data becoming available.

4. Conclusions and outlook

This paper describes a new African Hydropower Atlas, which marks the first, continent-wide spatiotemporal database of hydropower generation profiles for existing and future hydropower plants. The aim of the AHA is to provide estimates of monthly constraints on capacity factors of hydropower plants to the energy modelling community at a plant-by-plant resolution, taking the differences between moderately dry, normal, and moderately wet years into account. The data set is made freely available in a spreadsheet-based format; in the future, it may be integrated into a web-based interface to allow interactive visualization of the results and promote more widespread diffusion of the resource.

By helping energy modellers to better represent hydropower plants' contribution to electricity mixes across Africa, the AHA may support more informed prioritisation of future hydropower projects to be developed. This is important both from a financial and an environmental point of view. On the financial side, using AHA data in energy modelling may help elucidate which hydropower plants would be most suitable to contribute to a cost-optimised configuration of future power mixes, taking into account the seasonal variability of the hydro resource. On the environmental side, we note that it is undesirable that Africa's full hydropower potential be exploited, such that excessive ecological impacts of river-damming interventions may be avoided[19]; using AHA data, priority could be allocated to hydropower plants whose contribution to diversified electricity mixes would be most conducive towards low costs and high VRE penetration, allowing to deprioritize and/or shelve plans for other hydropower plants and avoid lock-in to hydro-dependency[23].

The main contribution of this work to the existing literature is the collation of large amounts of data and their processing into a single final product. This is not to say that the data sources that have been used are necessarily the best ones available. In the future, we hope that new iterations of hydrological simulations, new knowledge on the effects of climate change, and new knowledge on existing and upcoming hydropower plants as communicated by public documents and stakeholder feedback can be integrated into the AHA to improve its quality.

Data availability

HydroShare: Online repository of materials for an all-Africa hydropower atlas (v1.0). https://doi.org/10.4211/hs.acff23a8fcde4703a7f1f8a3a75b68bd[32].

This project contains the following underlying data:

- The AHA provided as a spreadsheet (.XLSX), containing the geospatial references of the hydropower plants and their technical characteristics used in the calculations, as well as their typical monthly capacity factor profiles for normal, dry and wet years
- SWAT+ simulation results used to extract river flow profiles provided as text files (.TXT).
- GIS shapefile of the river sections covered in the SWAT+ simulation.

Data are available under the terms of the Creative Commons Attribution 4.0 International license (CC-BY 4.0).

Code availability

Analysis code available from: https://github.com/VUB-HYDR/2021_Sterl_etal_AHA

Archived analysis code at time of publication: https://doi.org/10.5281/zenodo.4612483[45].

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POLICY BRIEF

Smart mixes of solar, wind and hydropower in West Africa

A new study shows the high potential of a regionally integrated power system in West Africa to increase solar and wind power penetration and avoid hydropower overexploitation.

WASCAL West African Science Service Centre on Climate Change and Adapted Land Use

Combating Climate Change. Improving Livelihoods

CIREG Climate Information for Integrated Renewable Electricity Generation

SPONSORED BY THE Federal Ministry of Education and Research

West Africa's electricity sector is at a crossroads. Population and industrial growth put strong pressures on planners to ensure power system adequacy in the years to come. Electricity in West Africa has historically been generated from thermal fuels (natural gas or diesel) and hydropower. Yet, as everywhere in the world, solar and wind power are emerging thanks to their ever-dropping costs.

Plans to integrate national electricity grids into a unified regional electricity market, the West African Power Pool (WAPP), have been high on the political agenda recently. A power pool could serve to lower the overall cost of electricity, helping countries to share their power-generating potential with their neighbours.

However, until today, the master plans of the power sector, of most West African countries, still envisage a strong expansion of natural gas and hydropower capacities, with less importance accorded to solar and wind power. Many grid operators are wary of the technical risks that solar and wind power may pose for grid stability, due to their variable and intermittent nature.

In the fight against climate change, however, it is important that countries become less dependent on gas infrastructure (since fossil fuel use will worsen climate impacts) and hydropower (since climate impacts may increase pressures on water resources). Instead, they could choose a path that leads to high and diverse penetration of renewable energy sources, thereby aligning policies with the Paris Agreement.

This requires power systems to be highly flexible to compensate for the hourly, seasonal, and multi-year variability of solar and wind power. A new study conducted by the CIREG project in which WASCAL is a scientific partner (Sterl et al. 2020), has looked at the synergies between the WAPP initiative, the operating rules of hydropower plants, and the emergence of solar and wind power. Using high-resolution hydrometeorological data to assess hydro, solar, and wind power potential across West Africa, the team of scientists investigated the mutual synergies between these three resources.

This study concludes that the WAPP can be an extremely important lever to support renewable power generation in West Africa. This is because a power pool would connect regions with highly divergent hydro, solar, and wind power potentials, allowing three synergies to be exploited: spatial, diurnal and seasonal.

SPATIAL

Solar power potential is omnipresent throughout West Africa. Hydropower potential can be found mostly in southern West Africa (e.g. Ghana, Nigeria, Côte d'Ivoire, Guinea), and wind power potential in northern West Africa (e.g. Senegal, Mali, Niger). These resources can only be shared with better interconnected grids.

DIURNAL

Solar power can only be generated during daytime when the sun shines, whereas hydropower can be operated to peak in the evenings and nights, and this is also when the wind blows hardest in the northern West African countries during the Harmattan (see Sterl et al. 2018). The three resources thus support each other in delivering reliable electricity day and night.

SEASONAL

Solar and wind power potential are both at their highest during the dry season. In a hydro-solar-wind mix, hydropower plant dispatch will therefore be reduced during the dry season and increased during the wet season, when reservoirs receive most inflow anyway. This means hydropower reserves can be more easily safeguarded throughout the dry months.

Without a regional power pool, these synergies cannot be fully valorized as individual countries lack the natural resources to exploit them simultaneously. With a power pool in place, this could be solved. Each country could then contribute to the power pool to the best of its capabilities.

We estimate that around 60% of West Africa's current electricity demand could be met with existing and planned hydro, solar, and wind power plants if they were efficiently combined in a regionally integrated grid. This is illustrated in Figure 1.

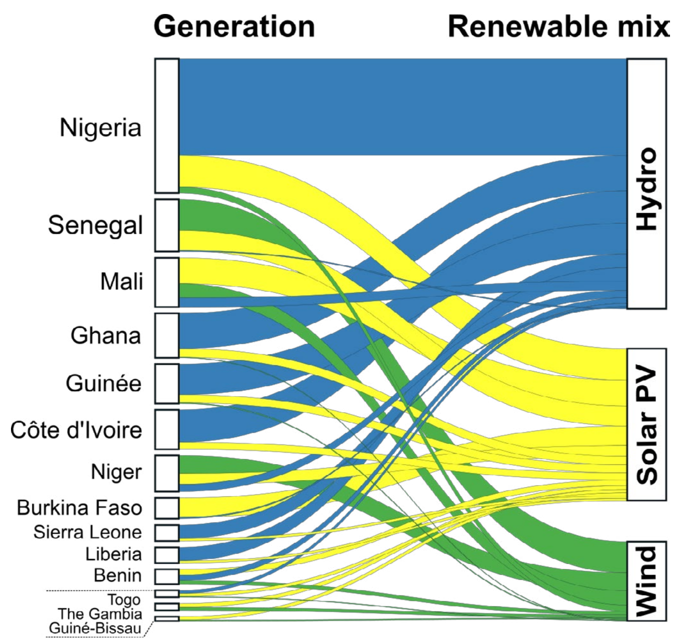
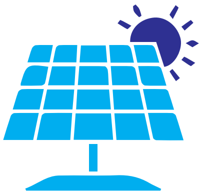
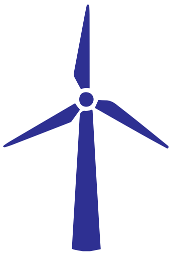


Figure 1: A regional power pool in West Africa could help all countries benefit from the renewable resource potential, which is spatially very unevenly distributed.

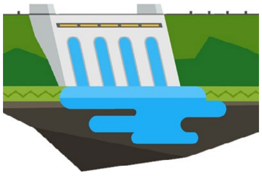
Each West African country could then center its renewable electricity policy plans around the needs that would best serve the regional power pool. This means, very concretely, that countries could emphasize the rollout of renewable resources in policy planning as follows:



Solar PV power in all West African countries, irrespective of climate regime and monsoon intensity, as the resource is strong and omnipresent in the region.



Wind power mostly in the dry Sahelian regions of Mali and Niger and along Senegal's Atlantic coastline, with additional possibilities in northern Nigeria.



New hydropower mostly in the wet, highland regions of Nigeria, Guinea and Sierra Leone, with additional possibilities notably in Ghana, Côte d'Ivoire and Liberia.

This implies a shift away from today's renewable energy policy, often dominated by plans for hydropower expansion. The difference between resource prioritization in current policy and the proposed "power pool scenario" is shown in Figure 2.

In addition to these national efforts, expanded cross-border transmission infrastructure to connect high-potential areas with high-consumption centers will be of high importance. Existing and planned hydropower plants would also have to be operated with the highest possible flexibility to enable effective grid integration of solar PV and wind power. This will help countries to avoid the use of fossil fuels and diversifying the renewable power portfolio, which reduces hydro-dependency. West African countries will thus benefit threefold:

- Reducing countries' dependencies on extractive resources, such as natural gas and diesel, and avoiding fuel costs.

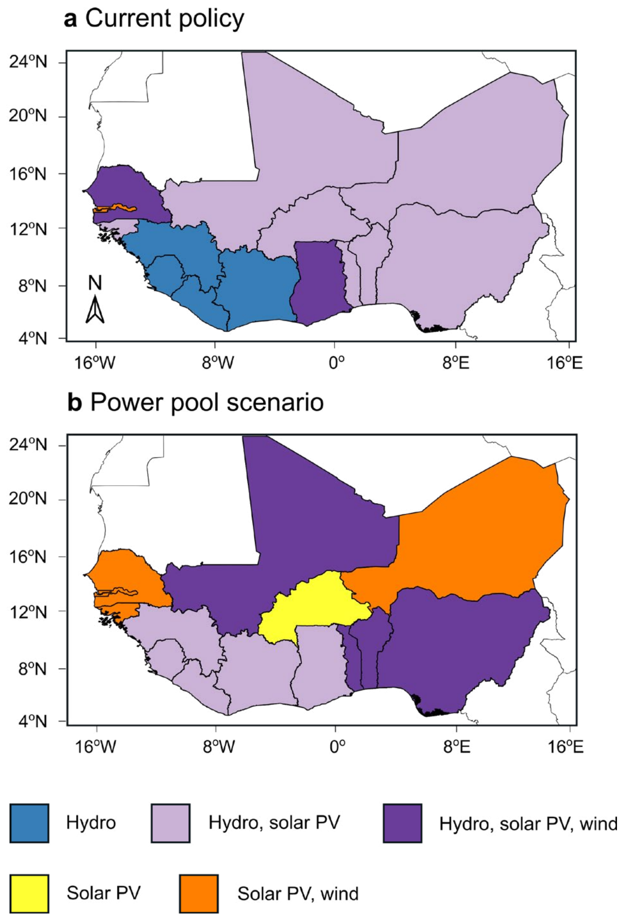


Figure 2: In order to best contribute to the West African Power Pool while supporting renewable electricity generation, West African countries could revise their resource priorities according to regional hydro-solar-wind synergies.

- Setting countries on a path towards dominance of modern renewable technologies, which are getting cheaper and cheaper, while increasing energy security.
- Avoiding future ecologically damaging river-damming interventions by implementing only those hydropower projects that are best suited to support solar and wind power.

In the future, modern storage technologies are expected to become affordable as well, which will further benefit solar PV and wind power integration. The proposed development of solar PV across West Africa, and of wind power in selected countries, is thus fully in line with preparing for such developments in the longer term.

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ALONGSIDE SOLAR AND WIND POWER, *GERD* IS NOT A ZERO-SUM GAME

OPERATING *GERD* IN SYNERGY WITH OTHER RENEWABLES LEADS TO WIN-WIN SITUATIONS FOR ETHIOPIA, SUDAN, AND EGYPT

Policy Brief

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Date

March 2021

VRIJE UNIVERSITEIT BRUSSEL

KU LEUVEN

POTSDAM INSTITUTE FOR CLIMATE IMPACT RESEARCH

A new study shows that several disagreements between Ethiopia, Sudan and Egypt around Africa's largest hydropower plant, the new Grand Ethiopian Renaissance Dam (GERD), could be alleviated by massively expanding solar and wind power across the region. Adapting GERD operation to support grid integration of solar and wind power would provide tangible energy and water benefits to all involved countries, creating regional win-win situations.

For several years, political tensions between Ethiopia, Sudan and Egypt have been escalating in a conflict surrounding the nearly complete Grand Ethiopian Renaissance Dam (GERD) on the Blue Nile. Ethiopia says it needs GERD's electricity to help lift millions of citizens out of poverty. But Egypt is concerned by GERD's consequences for its agriculture, which depends completely on Nile water. Sudan, meanwhile, sees both potential benefits and risks related to GERD. Ongoing mediation to agree on long-term operation of the dam has so far yielded little result.

Why is GERD so contentious? After all, nobody denies Ethiopia its right to development and to provide its citizens with reliable electricity. The problem lies not in the domain of energy, but of water. The Blue Nile is a very seasonal river, and the GERD's reservoir will be large enough to fully remove the flow seasonality, because its storage capacity corresponds to 1.6 years of mean annual Blue Nile flow. This would allow Ethiopia to use GERD for producing year-round hydroelectricity. However, such an operational scheme would overhaul the natural timing of the water reaching Sudan and Egypt, with consequences for downstream areas not fully known. Behind many disagreements around GERD lies the question of who, if anyone, should be allowed to exert such control over the Nile river.

ENERGY AND WATER

New research from the Vrije Universiteit Brussel (VUB) and KU Leuven in Belgium, in collaboration with the Potsdam Institute for Climate Impact Research (PIK) in Germany, now shows that there are potential ways out of this controversy. By adopting a holistic viewpoint, integrating the domains of energy and water, the study demonstrates that mutual win-win situations between Ethiopia, Sudan, Egypt, and potentially other East African neighbours can be found for the long-term operation of GERD.

Concretely, the study proposes that Ethiopia and its neighbours deploy large-scale solar and wind farms, work towards a regionally integrated power grid, and then agree on Ethiopia operating GERD in synergy with solar and wind power. This would mean turbining less water on sunny and windy days, and more water during cloudy, windless conditions and at night, to "firm up" the variable solar and wind power.

Concretely, the study proposes that Ethiopia and its neighbours deploy large-scale solar and wind farms, work towards a regionally integrated power grid, and then agree on Ethiopia operating GERD in synergy with solar and wind power.

REINTRODUCING SEASONALITY

The key point is that sunshine and wind in many regions of Ethiopia, Sudan and their eastern African neighbours have strong seasonal profiles that are opposite to the Blue Nile flow. In these places, the sun shines brightest, and the winds blow strongest, during the dry season. This means that a synergetic hydro-solar-wind operation will automatically re-introduce a certain seasonality into GERD outflow, which will mimic the natural flow to a certain extent (Figure 1). In other words, hydropower, solar power, and wind power can fit together like pieces of a puzzle – thanks to the complementary natural patterns of these resources.

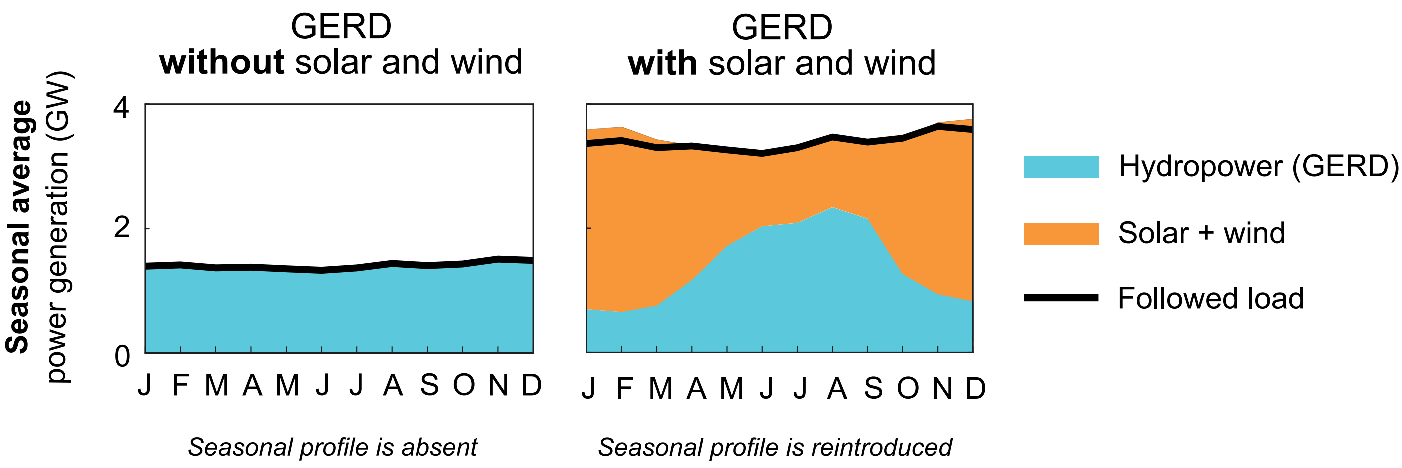

Figure 1: By operating GERD in synergy with solar and wind power, which have opposite seasonal profiles to the Blue Nile river flow, a seasonality would be reintroduced into the water flowing out of the GERD, towards Sudan and Egypt. Ethiopia will nevertheless retain the full power generation benefits of GERD.

This synergetic operation would automatically mean producing less hydropower during the dry season, and more during the wet season, but without affecting GERD's annual average power output. Essentially, Ethiopia would have all the benefits expected from a big dam – but for Sudan and Egypt, it would look as if Ethiopia only built a modest, relatively small reservoir. There are already many such reservoirs on the Nile whose presence is uncontested.

Essentially, Ethiopia would have all the benefits expected from a big dam – but for Sudan and Egypt, it would look as if Ethiopia only built a modest, relatively small reservoir.

REGIONAL WIN-WIN SITUATION

By reconciling parties around common energy and water objectives, the study identifies multiple concrete benefits of such integrated hydro-solar-wind planning, which could be reaped by Ethiopia, Sudan and Egypt once GERD is fully in service. This shows that GERD does not have to be a zero-sum game, and benefits for one country can translate into benefits for its neighbours as well (see Table 1).

<table>
<tr><th>COUNTRY ➔
SECTOR ⬇</th><th>ETHIOPIA</th><th>SUDAN</th><th>EGYPT</th></tr>
<tr><td rowspan="3">ENERGY</td><td>Reliable, year-round clean power supply at low cost</td><td>Displacement of fossil fuels with clean solar and wind power, supported by GERD</td><td rowspan="3"></td></tr>
<tr><td>Strategic exports in East African Power Pool</td><td rowspan="2">Roseires Dam automatically operating in seasonal synergy with solar and wind power</td></tr>
<tr><td>Full use of GERD infrastructure</td></tr>
<tr><td rowspan="2">WATER</td><td rowspan="2"></td><td>River ecology safeguarded</td><td>High Aswan Dam/Lake Nasser filling schedule not overhauled</td></tr>
<tr><td>Protection from floods/ droughts</td><td>Assurances of Ethiopia not hoarding water with GERD</td></tr>
</table>

Table 1: Overview of benefits of synergetic GERD-solar-wind operation for Ethiopia, Sudan and Egypt.

For instance, Ethiopia could remain a regional powerhouse in electricity exports, while lowering its electricity generation costs on the long term thanks to solar and wind power. Ethiopia would make more efficient use of GERD's more than a dozen turbines by frequently producing at peak power whenever solar and wind would be unavailable, thus better valorising the dam's infrastructure.

The seasonal power generation profile of Sudan's own Roseires dam would also automatically become complementary to solar and wind power developed in Sudan. Consumption of polluting fossil fuels in Sudan (and other eastern African countries) could be substantially displaced by solar and wind, backed up by hydropower from Ethiopia and from Sudan itself. Nile river ecology across Sudan would be less affected by the new dam since flow seasonality is an important component of rivers' ecological sustainability.

The proposed solutions work better if solar and wind power is deployed on a common Eastern African Power Pool, instead of in Ethiopia alone.

Both Sudan and Egypt could receive more water during dry years than before. Egypt would also not need to change the operation of its own High Aswan Dam (HAD). Periods in which GERD fills up while Lake Nasser is still emptying would be reduced to a minimum, thanks to the retention of a Blue Nile flow seasonality (Figure 2).

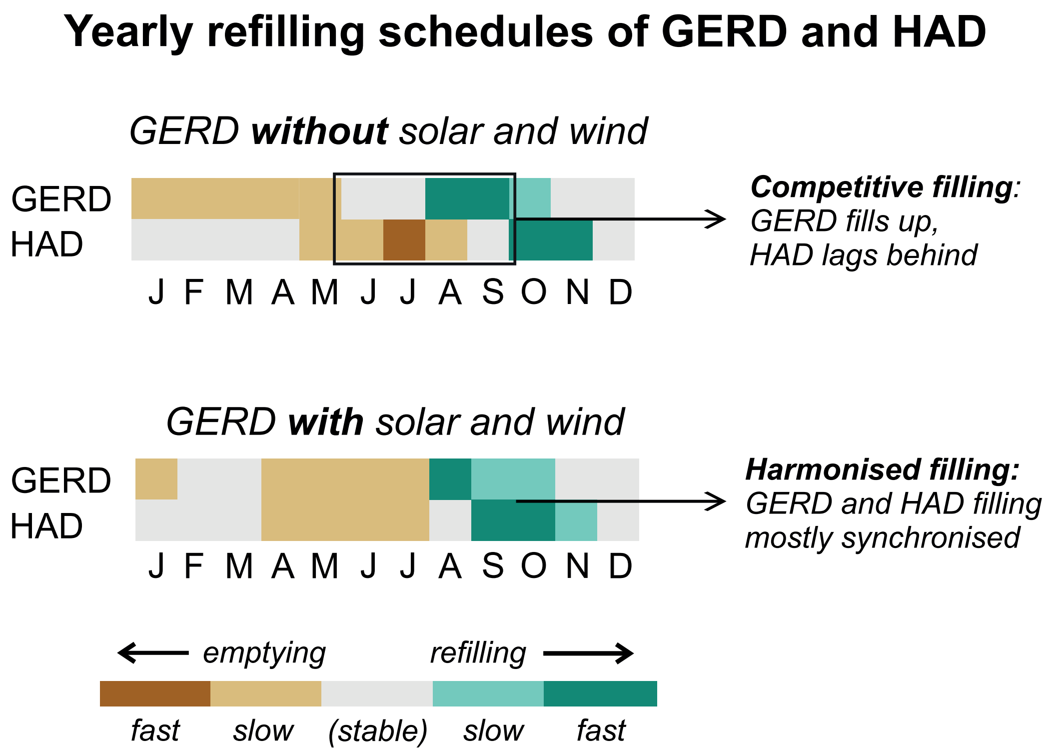

Figure 2: Thanks to synergetic operation of GERD with solar and wind power, the yearly refilling schedules of GERD and the High Aswan Dam (HAD) can be harmonised such as to reduce potential contentious periods around reservoir filling.

The entire eastern African region would stand to contribute. The proposed solutions work better if solar and wind power is deployed on a common Eastern African Power Pool, instead of in Ethiopia alone. Regionally integrated renewable electricity generation would allow for better synergies and reduce the overall costs of renewable power generation.

INVESTMENT NEEDS

This proposed solution would need substantial investment shifts towards solar and wind power, away from new hydropower and fossil fuel plants. The order of magnitude of new capacity needed for solar and wind power is comparable to that of GERD, and so are the investment costs needed.

Luckily, solar and wind power are currently breaking all expectations in terms of cost reductions; investing in these resources therefore appears a future-proof choice. Within 10 years, solar and wind power in Ethiopia (and its neighbours) are expected to be cheaper than hydropower from GERD on a levelized-cost basis (Figure 3).
Simultaneously, massive hydropower projects are falling out of favour with international donors, and the Paris Agreement strongly discourages new fossil fuel investments. Integrated hydro-solar-wind planning provides a way forward with common objectives and shared interests for Ethiopia, Sudan, and Egypt.

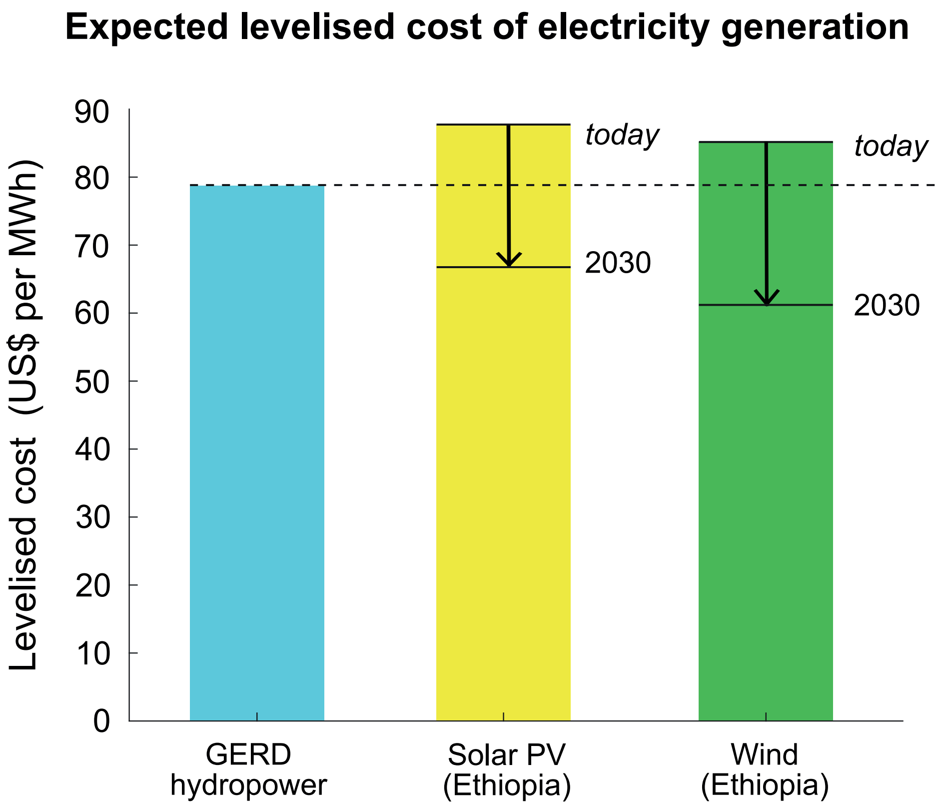

Figure 3: The levelized cost of electricity for solar and wind power is expected to continue to fall substantially in the next years, meaning that hydropower may no longer be the cheapest renewable electricity source ten years from now.

FURTHER READING

The full study is entitled “Linking solar and wind power with operation of the Grand Ethiopian Renaissance Dam” (Sterl et al. 2021) and has appeared in the scientific journal Nature Energy. (https://doi.org/10.1038/s41560-021-00799-5)

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