RESEARCH ARTICLE SUMMARY

RENEWABLE ENERGY

Declining cost of renewables and climate change curb the need for African hydropower expansion

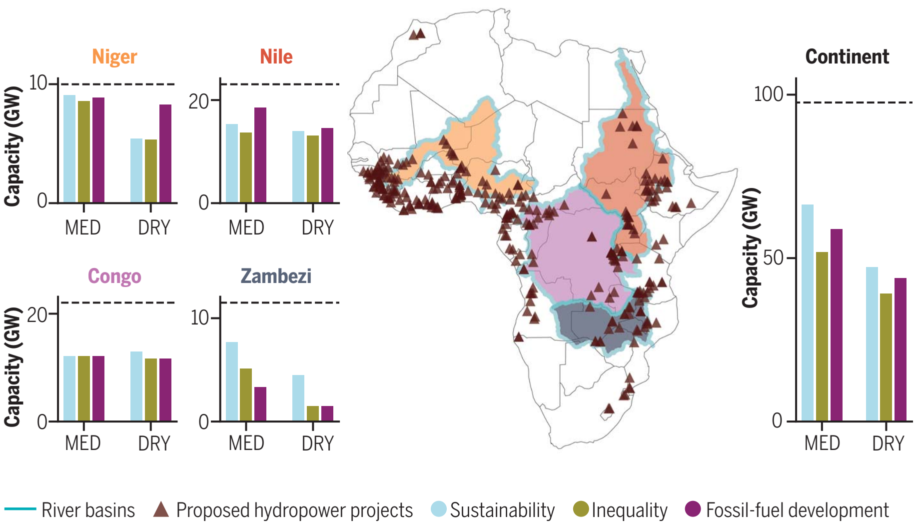
Angelo Carlino, Matthias Wildemeersch, Celray James Chawanda, Matteo Giuliani, Sebastian Sterl, Wim Thiery, Ann van Griensven, Andrea Castelletti*

INTRODUCTION: Driven by population growth and the goal of improving living standards, especially in the least-developed regions, many African countries plan to expand their power generation capacities to meet future energy demand. Indeed, total electricity demand is expected to grow by 5 to 6% per year until 2050, mainly in sub-Saharan Africa. Yet the future of African energy systems will not only be driven by the additional energy demand but also by the need to mitigate and adapt to anthropogenic climate change. Hydropower is an important component of African power systems, especially in sub-Saharan countries. It provides around 20% of total electricity generation, but its full potential has not been exploited yet. Traditionally considered a cheap source of low-carbon electricity, more than 300 hydropower plants, corresponding to an additional 100-GW power capacity, are under consideration across the continent.

RATIONALE: Although an apparently effective strategy, the long-term planning of hydropower systems is complex. First, as the cost of renewables continues to decline, solar and wind power are becoming more competitive and potentially cheaper alternatives. Second, in recent years, hydroclimatic variability has negatively affected hydropower generation in major river basins. Climate change will alter the spatiotemporal distribution of water availability, exacerbating the impacts of extreme events and reducing the predictability of future power generation. Finally, future energy demands and climate policies depend on evolving socioeconomic conditions that are fundamentally uncertain. In this work, we investigated the power capacity expansion across the African continent over the next 30 years and elucidated the cost-optimal sequencing of hydropower projects. We built an integrated modeling framework that captures individual power project characteristics within an energy system model that simulates three socioeconomic scenarios that harmonize land-use change, climate impacts on water availability, final energy demands, and climate policy options. Our model relies on a combination of the Shared Socioeconomic Pathways (SSPs) and Representative Concentration Pathways, namely SSP1-2.6, SSP4 and SSP5-8.5. SSP1-2.6 describes a sustainable development scenario that aims to maintain the global mean temperature below 2°C, whereas the other two scenarios result in higher levels of warming and are characterized by rising inequalities and fossil-fueled development, respectively. We considered median (MED) and very dry (DRY) water availability scenarios to capture hydroclimatic variability reflecting a risk-neutral and risk-averse planning perspective.

RESULTS: Our results show that between 32 and 60% of the proposed hydropower capacity is not cost-optimal. Moreover, our analysis suggests that hardly any new hydropower will be built after 2030, meaning that its role in terms of installed capacity and generation will gradually decrease in favor of solar and wind power. Across the scenarios, hydropower expansion is robust in the Nile, Congo, and Niger river basins, whereas it remains uncertain in the Zambezi and smaller river basins. These findings emphasize the importance of connecting hydropower planning with capacity expansion models, because cost-optimality cannot be determined solely based on each project's technical characteristics. Finally, we discover that an increase in annual capital investment between 1 and 4% at the continental level can ensure the reliability of the power system against hydroclimatic variability. Yet the required increase in capital investments and the observed reductions in vulnerability do not necessarily overlap at the country level. As local interests conflict and diverge from system-wide ones, we underline the importance of electricity exchanges between countries and cooperation for power system reliability.

CONCLUSION: Traditional planning of hydropower facilities is challenged by the dynamics of technological innovation, climate impacts on water availability, and uncertainty in long-term socioeconomic projections that affect energy demands and climate policies. Using a multisectoral modeling framework, we designed capacity expansion plans that avoid commitments to cost-inefficient hydropower infrastructures that are often associated with substantial impacts on the local communities and environment. Yet, in the short term, especially in the transition to a net-zero emissions energy system, hydropower represents a cheap alternative to displace fossil fuels, especially coal. ■



Cost-optimal hydropower expansion. Proposed (dashed line) and cost-optimal (bars) capacity expansion for continental Africa and its major river basins under the scenarios considered. In total, 32 to 60% of the proposed capacity is not cost-optimal. More than half of the capacity proposed for the Nile, Congo, and Niger basins is always cost-optimal, whereas the expansion in the Zambezi River basin depends on the considered scenario. The colors of the shaded areas in the map correspond to the river basins represented by each graph.

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RESEARCH ARTICLE

RENEWABLE ENERGY

Declining cost of renewables and climate change curb the need for African hydropower expansion

Angelo Carlino[1,2]†, Matthias Wildemeersch[2]‡, Celray James Chawanda[3], Matteo Giuliani[1], Sebastian Sterl[3,4], Wim Thiery[3], Ann van Griensven[3], Andrea Castelletti[1]*

Across continental Africa, more than 300 new hydropower projects are under consideration to meet the future energy demand that is expected based on the growing population and increasing energy access. Yet large uncertainties associated with hydroclimatic and socioeconomic changes challenge hydropower planning. In this work, we show that only 40 to 68% of the candidate hydropower capacity in Africa is economically attractive. By analyzing the African energy systems' development from 2020 to 2050 for different scenarios of energy demand, land-use change, and climate impacts on water availability, we find that wind and solar outcompete hydropower by 2030. An additional 1.8 to 4% increase in annual continental investment ensures reliability against future hydroclimatic variability. However, cooperation between countries is needed to overcome the divergent spatial distribution of investment costs and potential energy deficits.

Over the next few decades, African energy systems are expected to undergo profound changes. The total electricity demand is predicted to increase by 5 to 6% per year over the next 10 years until 2050 (*1*–*3*), an increase that is driven by sustained population growth, mainly in sub-Saharan Africa (*4*), and the continuous infrastructural investments aimed at improving energy access and living standards, especially in the least-developed areas (*5*, *6*). This increasing demand, together with the need to mitigate and adapt to anthropogenic climate change (*7*), will shape the future development of African energy systems. The use of low-carbon energy sources (*3*, *8*, *9*) will gradually lessen the historical dependency on fossil fuels, which are abundant across the continent (*10*). In the short term, annual investments of US$190 billion are required to ensure such a successful energy transition, with more than two-thirds of this financial investment allocated to clean-energy sources (*3*). Among these, hydropower has historically been favored as a low-cost source of baseload power (*11*), and policies that are in place now imply a substantial infrastructural expansion (*12*). Moreover, hydropower is an attractive component of the future African power system owing to its ability to balance grid load in support of intermittent renewable electricity sources (*13*–*15*) and because the remaining untapped potential across the continent is relatively large (*11*). According to plans of national and regional agencies, more than 300 new hydropower projects are, at present, committed, planned, or under consideration across the African continent (*16*). These projects amount to a total of around 100 GW of additional hydropower capacity, with 168 large (≥100-MW) projects accounting for almost 90 GW (*16*).

Nevertheless, climate change makes future hydropower generation uncertain (*17*) and increases the risk of cascading power system failures across countries and power pools (*18*), likely jeopardizing its potential to foster resilience (*19*). Moreover, capacity expansion projections are linked to future energy demand, technology costs, and climate policy, which are fundamentally uncertain factors (*20*, *21*). The excessive reliance on hydropower in many sub-Saharan countries is presently a source of concern and a reason for caution in additional hydropower investment (*22*). Further doubts are cast on hydropower capacity expansion (*23*) when socioeconomic and environmental impacts of hydropower are analyzed, such as population displacement (*24*), reduced sediment connectivity (*25*), loss of biodiversity (*26*), and competition with other water uses, most importantly with agriculture (*21*).

Given the scale of future infrastructure development, the socioeconomic and environmental impacts of hydropower expansion, and the need to bridge continental as well as regional power system development, it is crucial to identify the hydropower projects that should be prioritized and the ones that should be discarded based on the cost-optimal power system capacity expansion. Indeed, the selection and sequencing of the required hydropower infrastructure, given energy, socioeconomic, and technological development, is a critical first step. Further research should evaluate the ensuing social, climatic, and environmental impacts on the alternatives of interest to support final planning decisions. To what extent do the planned hydropower expansion and its spatial distribution over the main river basins change depending on socioeconomic, land-use, and climatic uncertainties? What are the costs of climate-proofing the energy system, and how are these costs spatially distributed compared with power deficits driven by hydroclimatic variability?

In this work, we build an integrated modeling framework to examine the role of hydropower in a sustainable energy transition that is cognizant of hydroclimatic and land-use change, socioeconomic projections, and climate policy options. Although previous studies on strategic dam planning (*27*–*30*) rarely included the power system and rarely went beyond the basin scale (*31*, *32*), our analysis examines the full energy portfolio at the continental scale. Specifically, we consider cross-basin interactions across the power grid (*33*), hydropower projects proposed at the river basin and national scales, and socioeconomic and land-use projections. By doing so, we limit undesirable outcomes that result from the integration of national, regional, and continental policies across multiple sectors and scales (*34*).

Our results show that hydropower will have lost its dominant role in Africa's renewable electricity mix by 2050, with solar and wind power representing at least 29 to 38% and 8 to 12% of generation, respectively, and hydropower's share shrinking to 7 to 14% under all considered scenarios. Between 40 and 68% of the proposed new hydropower capacity or, in other words, between 120 and 251 of the 367 proposed projects could potentially be cost-optimal, and nearly no new hydropower plants are recommended to be built after 2030. Although the viability of hydropower expansion in the Zambezi River basin is dependent on the scenario that is considered, many of the proposed projects for the Nile, Congo, and Niger remain economically viable under all considered scenarios. Finally, guaranteeing the reliability of the energy system against hydroclimatic risks only requires reallocating some of the investments in hydropower toward other sources, especially solar power and firming technologies, with a small increase in annual capital investments. Yet the need for additional investment and the risk of shortages are often located in different regions. As a consequence, we highlight the importance of transnational governance measures to guarantee climate-resilient energy systems.

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Sequencing hydropower projects within power capacity expansion

To obtain plans for hydropower project sequencing and associated power capacity expansion, we set up a multiscale, multisector modeling approach (fig. S1). We combined input data from three main datasets. First, we used the Shared Socioeconomic Pathways (SSPs) database (*35*) to obtain projected energy demands. Second, we relied on the African Hydropower Atlas (*16*) to characterize each hydropower project in the OSeMOSYS-TEMBA model (*36*). Third, to coherently account for the coevolution of the climatic and the socioeconomic system, we used the Inter-Sectoral Impact Model Intercomparison Project (ISIMIP2b) scenarios (*37*) to represent the future hydrological regime that will result from changes in the climate system and the land-use sector. Natural climate variability was considered using a median and a very dry hydrological scenario. These correspond to the 50th and 5th percentiles of the distribution of simulated annual average generation, which is obtained by simulating a distributed hydrological model under an ensemble of climate projections from 2020 to 2050 (see materials and methods).

We used this model to study the expansion trajectory of the African energy systems over the period from 2020 to 2050 at the continental scale assuming centralized decision-making. We considered three socioeconomic scenarios that aggregate socioeconomic, land-use, and climatic assumptions: (i) a sustainable development scenario, using a carbon emission constraint compatible with a 2°C long-term warming, according to SSP1-2.6; (ii) a scenario designed to focus on heterogeneous economic development among regions not associated with climate policy efforts, according to SSP4-6.0; and (iii) a fossil-fueled economic growth scenario associated with high greenhouse gas emissions, according to SSP5-8.5. For each socioeconomic scenario, we consider the median (MED) and very dry (DRY) hydrological scenarios. We use the first to represent traditional hydropower planning and the second to stress-test the power system under worst-case hydroclimatic conditions. Indeed, these two scenarios can be seen as describing different risk-preparedness targets (risk–neutral and risk-averse, respectively) with respect to the uncertainty associated with hydroclimatic variability. For each considered scenario, we optimized the power capacity expansion for each energy source and the sequencing of the proposed (i.e., planned, committed, and candidate) hydropower projects collected in the African Hydropower Atlas. Moreover, we examined the cost-reliability trade-off at different spatial scales, which would otherwise remain hidden behind the large-scale formulation of the least-cost capacity expansion problem.

Cost-effectiveness of solar energy avoids the need for long-term hydropower expansion

Our model results show that at least one-third of the new hydropower capacity proposed at the regional and country levels is not cost-optimal across continental Africa, and this result holds under all considered scenarios (Fig. 1). Under ensemble median hydrologic change (i.e., under the MED scenarios), new hydropower installed capacity ranges from 52 GW under SSP4-6.0 to 66 GW under SSP1-2.6, whereas these values drop to between 39 GW (SSP4-6.0) 47 GW (SSP1-2.6) when considering dry hydrology conditions under the risk-averse approach (i.e., under the DRY scenarios), meaning that more than half of the proposed capacity is not economically viable at the continental scale. In all these plans, two large projects are responsible for more than 17 GW of viable capacity: the soon to be completed 6.4-GW Grand Ethiopian Renaissance Dam and the 11.0-GW Inga 3 candidate project in the Democratic Republic of the Congo. In general, the SSP1-2.6 scenario consistent with a warming of 2°C at the global level requires more hydropower than other scenarios owing to the reduced reliance on fossil fuels. To isolate the impact of climate change on hydropower expansion, we examined capacity expansion strategies by considering hydropower generation based on observations from 1986 to 2005. We see that climate change is particularly affecting the scenarios with the largest hydropower expansion and is responsible for a reduction of 9 GW (SSP1-2.6) and 8 GW (SSP5-8.5) (fig. S2). As we consider the salvage value of infrastructure at the end of the planning horizon that corresponds with the remaining operational life, our results remain consistent when we extend the horizon until 2070 (fig. S3).

Under all socioeconomic and hydrological scenarios, at least half of the additional hydropower capacity is installed in the period from 2020 to 2030 (Fig. 1, A to C), with the window in which hydropower can still compete economically with solar photovoltaics (PV) rapidly closing. Beyond 2030, the share of new investments in solar power increases substantially, and further development of hydropower in Africa is unlikely to be cost-effective (Fig. 2). Although hydropower could still be competitive with solar PV until the end of this decade, the often-witnessed build time and cost overruns for hydropower projects (*38*) may even preclude large-scale hydropower expansion before that time, paving the way for further solar PV deployment. In addition, all capacity investments are expected to grow rapidly in the decades after 2030, thus further diminishing the role of hydropower in the future energy portfolio (*39*). Similarly, given the large expansion of the power system in the next few decades, the decline of hydropower is also substantial in the total capacity share (fig. S4). The gap is even more pronounced for the DRY scenarios in which more than half of the

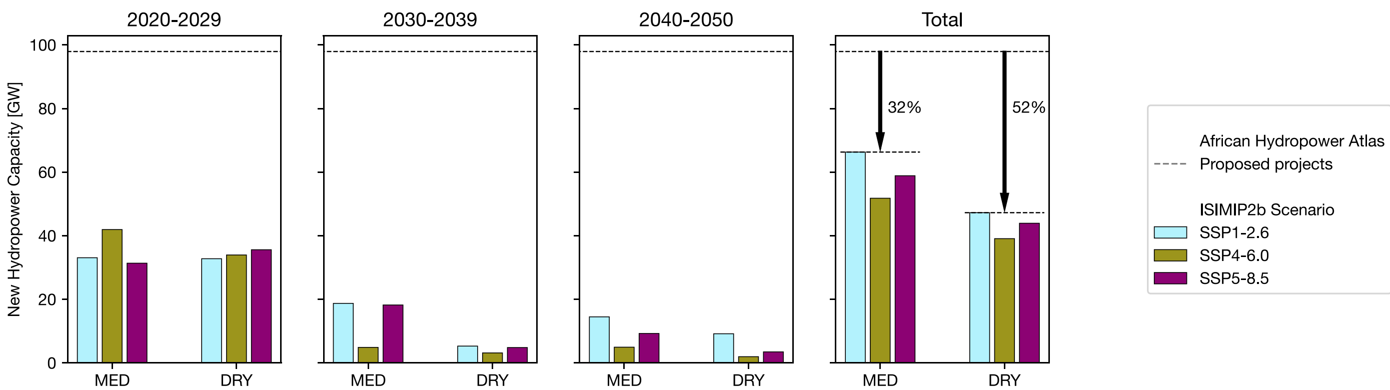

Fig. 1. Decadal and total hydropower capacity expansion under the considered scenarios. The dashed line indicates the capacity of proposed projects reported in the African Hydropower Atlas. The colors of the bars are associated with the considered SSP scenarios, which coherently capture socioeconomic, land-use, and hydroclimatic change. For each decade and for the total, the bars on the left report the capacity expansion plan designed under ensemble median hydrology (MED), and the bars on the right correspond to the capacity expansion plan designed under dry hydrology (DRY). The arrows indicate the fraction of proposed capacity, which is not cost-optimal under the two different risk-preparedness targets.

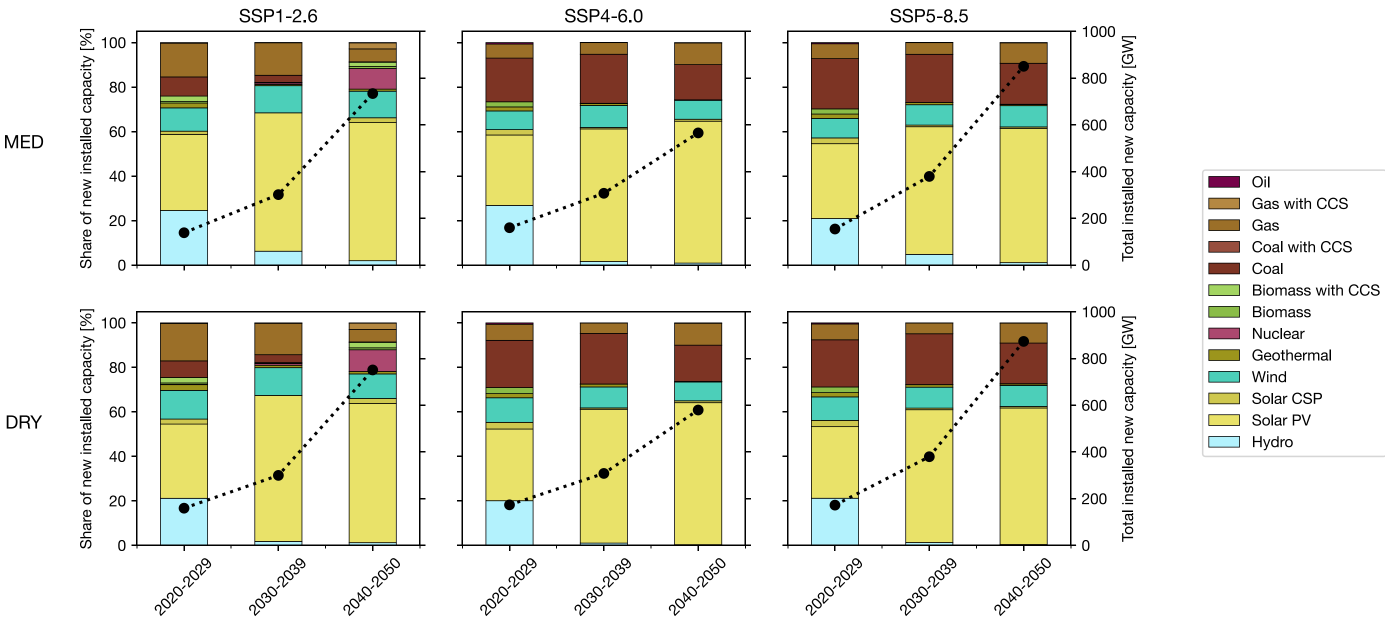

Fig. 2. Power capacity expansion at the continental level. The share of new installed capacity for each power source (left *y* axis) and the new installed capacity (right *y* axis) are reported against the three decades examined. The top row reports the share of each power source in new capacity under median hydrology (MED scenarios), and the bottom row reports the capacity expansion plans designed under dry hydrology (DRY scenarios). Each column represents the different SSP scenarios. Each power source is described in the legend, the order of which, from top to bottom, follows the order of the stacked bars from top to bottom. CCS, carbon capture and storage; CSP, concentrating solar power.

proposed capacity is not economically optimal, resulting in higher investments in solar power (bottom row in Fig. 2). Solar power becomes a option, displacing hydropower projects whose generation changes the most from median to very dry hydrology. In SSP1-2.6, an important role is played by nuclear power by mid-century, which is used to further reduce investment in fossil fuel power sources and represents an important share of energy generation in 2050 (fig. S5). Contrary to SSP1-2.6, where coal becomes almost absent, under SSP4-6.0 and SSP5-8.5, it still contributes around 40% of the energy generation mix by mid-century, with more than 2000 terawatt-hours under SSP5-8.5 (fig. S5). With respect to the flexibility required in the power system to balance the reduced output of solar plants at night, hydropower comes after biomass and fossil fuels, and wind has a complementary diurnal profile to solar as well (fig. S6). Consequently, our results do not suggest that hydropower will still be a major provider of firm generation and flexibility by mid-century.

Location and drivers of hydropower expansion

Most of the planned African hydropower projects concentrate in four major river basins—Nile, Congo, Zambezi, and Niger—which account for around 66% of the total proposed additional hydropower capacity (*16*). Across the socioeconomic and risk-preparedness scenarios, the cost-optimal dam portfolio varies substantially, even though some projects are consistently selected (fig. S7). A robust finding over the considered scenarios and river basins is that less hydropower is installed in the DRY capacity expansion scenarios and under SSP4-6.0 and SSP5-8.5 (Fig. 3). The Congo River basin is consistently cost-optimal for around half of its potential through the Inga 3 Dam, accounting for 11 GW in the Democratic Republic of the Congo and built in all the scenarios. Half of the proposed potential for the Nile River basin is always cost-optimal, mainly in Ethiopia and Uganda, up to 80% in SSP5-8.5 with MED capacity expansion. The hydropower expansion in the Zambezi River basin is instead very uncertain and strongly dependent upon the considered scenario, ranging from 30% (SSP5-8.5) to 70% (SSP1-2.6) of the proposed capacity in the MED scenarios and between 13% (SSP4-6.0 and SSP5-8.5) and 39% (SSP1-2.6) in the DRY scenarios. Finally, the cost-optimal hydropower potential in the Niger River basin is between 86% (SSP4-6.0) and 91% (SSP1-2.6) of the proposed capacity for the MED scenarios, and it is reduced to between 53% (SSP4-6.0) and 83% (SSP5-8.5) in the DRY scenarios. These projects are located mainly in Nigeria, a potential hotspot of hydropower development. For what concerns the remaining smaller basins, the development of projects varies considerably from 38% (SSP4-6.0) to 71% (SSP1-2.6) of their total capacity in the MED capacity expansion scenarios and between 24% (SSP4-6.0) and 32% (SSP1-2.6) for the DRY capacity expansion scenarios.

Given these results, we can partially trace the cost-optimal power expansion decisions back to the characteristics of the proposed hydropower projects. High average capacity factors and high capacity are usually good indicators of cost-optimality (Fig. 4). Indeed, the higher the capacity, the lower the capital cost of new hydropower (*40*), even though the probabilities of delays and cost overruns increase as well (*41*). Furthermore, the higher the average capacity factor, the higher the annual generation of a power plant. The construction of new hydropower projects is not sensitive to the interannual variability in the capacity factor. Then again, spatial and temporal energy system constraints, such as transmission line capacity and proximity to more economically favorable hydropower projects, enable a full understanding of the cost-optimal power system development. This is, for example, the case for projects in the Zambezi basin in Zambia, a region well connected to the Democratic Republic of the Congo. The development of the Inga 3 Dam in the latter allows for substantial cheap electricity exports to neighboring countries, reducing the viability of domestic hydropower expansion in Zambia.

The regional distribution of costs and deficits requires cooperation

It is presently unclear how the magnitude of drought-induced power deficits compares with the size of additional investment costs that are required to climate-proof the energy system

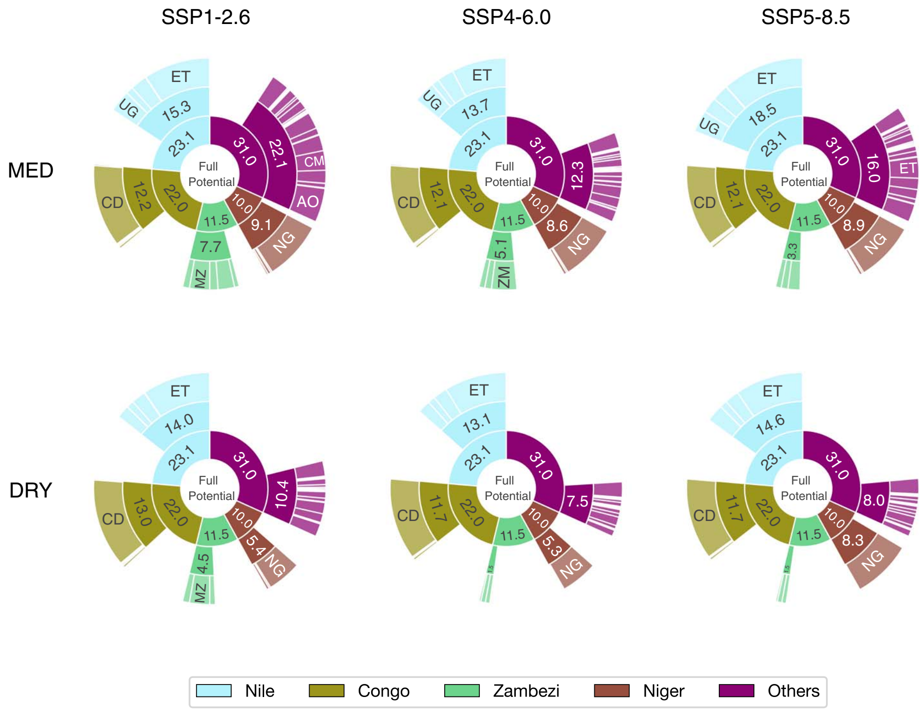

Fig. 3. Basin- and country-level hydropower capacity expansion. The full capacity of proposed projects is reported by river basin in the inner ring. The cost-optimal capacity in each river basin is reported in the middle ring and is assigned to the corresponding countries in the outer ring. All values are reported in GW units. The columns correspond to the SSP scenarios examined. The top and bottom rows report results from the MED and DRY capacity expansion scenarios, respectively. For each scenario, only countries that are building more than 2.5 GW of new hydropower are labeled, namely Angola (AO), Democratic Republic of the Congo (CD), Cameroon (CM), Ethiopia (ET), Mozambique (MZ), Nigeria (NG), Uganda (UG), and Zambia (ZM).

(i.e., to guarantee demand satisfaction under dry hydrological conditions). For this reason, we stress-test the MED capacity expansion plans, obtained under median hydrology, by simulating it under dry hydrology to estimate the potential deficit that can occur. The observed generation deficits should be understood as the result of planning the power capacity expansions for each source, not only for hydropower, without explicitly accounting for hydroclimatic variability. The reported deficits present a worst-case scenario because safety mechanisms such as reserve margins are supposed to be in place to reduce the probability of occurrence and the magnitude of these events. The DRY capacity expansion plans can remove this risk with a capital cost increase between 1.8% (SSP5-8.5) and 4% (SSP1-2.6) in annual capital investments at the continental level under all the socioeconomic scenarios. Yet at the country level, the cost increase and potential deficit are unevenly distributed and vary widely across the scenarios (Fig. 5).

Generally, reduced hydropower generation requires backing up with existing, mainly fossil fuel–based technologies or with additional capacity. This additional capacity is typically solar PV under cost-optimal expansion scenarios, especially under SSP1-2.6, in which the reliance on fossil fuels for power generation is constrained. Consequently, spatial planning of the deployment of renewable power plants will be affected as well.

For many regions that are not dependent on hydropower, there is no difference between the two plans because they are not affected by power deficits or additional costs induced by hydrological variability (Northern Africa and South Africa). Nonetheless, power pools strongly dependent on hydropower, such as the Southern African, Eastern Africa, and West African Power Pools, are more subject to cost increase and power deficit. Under SSP1-2.6, West Africa is affected by generation deficit events that require substantial capital investments to ensure reliability (e.g., Senegal, Guinea-Bissau, Ghana, and Togo). Conversely, the power deficits in Nigeria and Burkina Faso require a modest increase in annual capital cost. In the other scenarios, the power deficit affects mostly Mali, Niger, and Benin, but the costs to achieve reliability remain low in all the power pool.

With respect to the Eastern Africa Power Pool, Ethiopia, Tanzania, Uganda, Rwanda, and South Sudan are most at risk of power outages induced by hydroclimatic variability. All of these countries require substantial investments to reduce this risk, and additional economic efforts will be required from Egypt, Sudan, and Kenya, especially in the case of SSP1-2.6. With respect to the Southern African Power Pool and scenario SSP1-2.6, Zambia, Namibia, and Mozambique remain most vulnerable to droughts. Zambia is particularly at risk because the power deficit would be around 13%, which could be mitigated with an 11% increase in annual capital investment. In addition to the above-mentioned countries, in the Central African Power Pool, Angola, Zimbabwe, and the neighboring Democratic Republic of the Congo are also required to increase their investments to climate-proof their energy systems to a substantial extent. Under the other scenarios, Zambia always remains exposed to drought-related power outage risk, together with Namibia, whose cost to ensure reliability remains lower. In all scenarios, a generation deficit is observed if power trade is not allowed between countries, underscoring the importance of cooperation and political stability in the region (fig. S8).

Discussion

As African power demand grows, especially in sub-Saharan Africa, the remaining untapped hydropower potential represents a cheap, clean energy source, which explains the large number of infrastructural projects that are presently under consideration. However, as costs associated with solar and wind power generation continue to decline, the historical reliance on hydropower of many sub-Saharan African countries might come to an end. Solar and wind power are expected to become the primary power sources in 2050, representing 50% of the electricity mix of the continent in the sustainable development scenario compatible with a 2°C long-term warming (SSP1-2.6) and always representing at least 50% of new installed capacity in the next three decades under all scenarios considered. Even under the SSP1-2.6 scenario, which pushes for extensive renewable capacity expansion, no more than 67% of proposed hydropower capacity is cost-optimal, and this percentage shrinks to 48% under the assumption of aversion to hydroclimatic risk. Project delays and cost overruns might further favor solar and wind projects, making hydropower development even less competitive from an economic perspective (42). Yet in the short term, especially in the transition to a final net-zero configuration, hydropower represents a cheap alternative to avoid the high costs of installing solar and wind at the present level of technological maturity and to displace fossil fuels, mainly coal. The Nile, Congo, and Niger River basins provide reliable hydropower generation. Yet the development of projects in these regions needs to be accompanied by investment in grid capacity in order to reap all the benefits of large hydropower. Climate-proofing the energy system against hydroclimatic variability requires reducing investment in hydropower

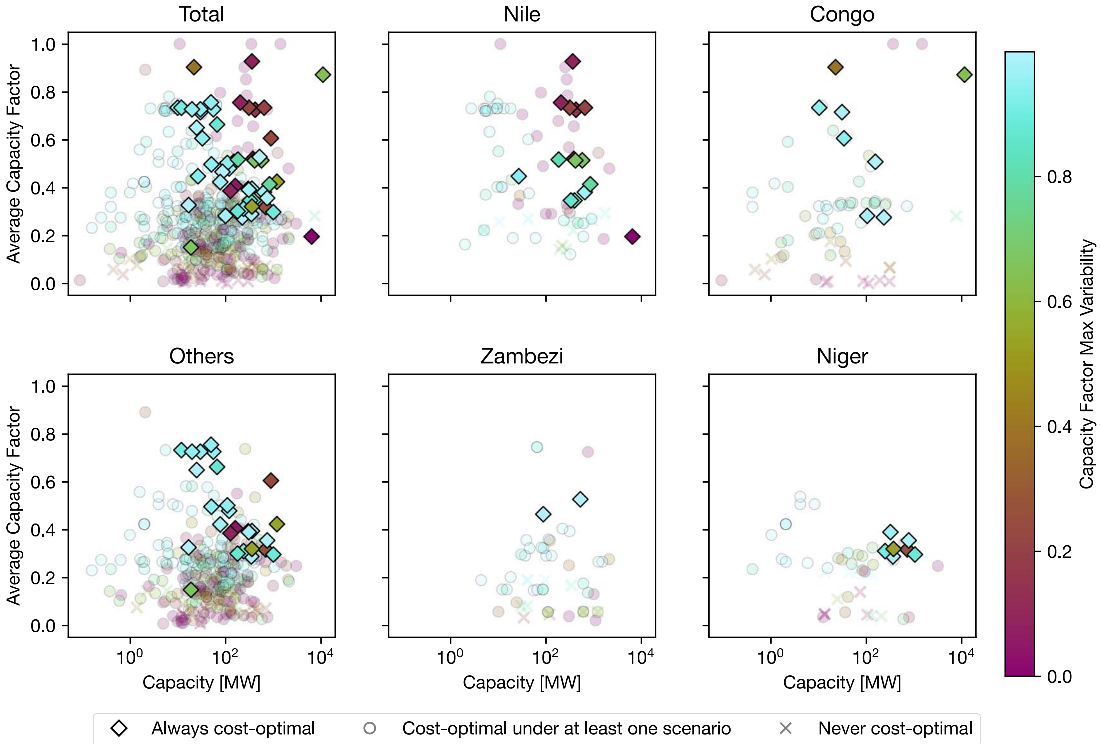

Fig. 4. Main characteristics of projects and their role in least-cost capacity expansion. Capacity, average capacity factor under very dry hydrology, and maximum interannual capacity factor variability under very dry hydrology of the examined hydropower projects are reported on the *x* axis, the *y* axis, and with different colors, respectively. The diamond marker indicates a project that is always cost-optimal. The circles correspond to projects that are cost-optimal at least once, whereas the crosses correspond to the projects that are never built. The always–cost-optimal projects correlate with the average capacity factor (point biserial correlation coefficient = 0.37; $p = 2 \times 10^{-19}$) and capacity (point biserial correlation coefficient = 0.18; $p = 3 \times 10^{-5}$). Their correlation with capacity factor's variability is weaker (point biserial correlation coefficient = 0.09; $p = 0.03$).

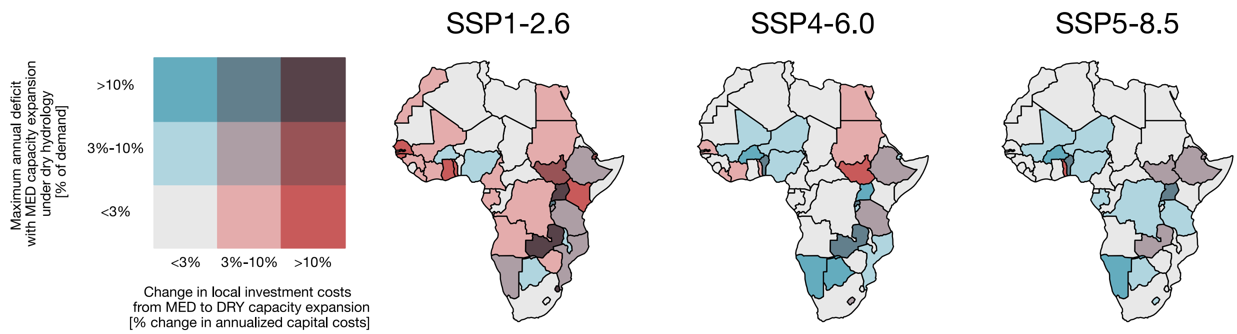

Fig. 5. Country-level cost-deficit trade-offs. Maximum annual power deficit as a percentage of demand over the period from 2020 to 2050 obtained from simulation of the MED capacity expansion plan under dry hydrology. The additional cost of eliminating the power deficits is derived as the percentage increase obtained from the annualized capital costs of the MED and the DRY capacity expansion plans. Their joint value is reported for each country in the maps by the bidimensional color scale that is visible in the legend, and each map corresponds to a different SSP scenario.

and investing in additional solar, wind, and firming capacity, particularly in the scenarios where emissions are constrained. These additional costs are not necessarily distributed uniformly or fairly across the countries, highlighting the need for coordination and incentive mechanisms to support capacity expansion plans, which are robust to climate change impacts.

Through the reduction in economically viable hydropower capacity associated with the declining cost of wind and solar, technological innovation helps reduce pressure on riverine ecosystems and small communities in the proximity of proposed impoundments and further downstream as far as the impacts of these changes propagate (*43*). Indeed, previous research on hydropower's social and environmental trade-offs (*25*, *27*, *30*) and the effects of environmental risks on the financial performance of this infrastructure (*44*) has suggested caution in construction of new projects. Introducing these factors into our modeling framework is likely to further reduce the space for hydropower in future energy systems. Analyses at the river-basin level remain complementary to our study and might be better tailored to address such concerns. However, additional research and development of new methods are needed to connect local, regional, and continental scales for a robust planning of water and energy systems (*34*). Similarly, greenhouse gas emissions from reservoirs (*30*, *45*–*47*) are a deterrent for hydropower capacity expansion, particularly in tropical areas where life-cycle emissions associated with new dams might be comparable to those of fossil fuel power sources (*48*, *49*). Accounting for this factor will likely further promote the expansion of wind, solar, and other carbon-neutral technologies.

Additionally, we are not able to fully capture the contribution of hydropower projects to ancillary services such as frequency regulation and improved renewable integration associated with the rapid ramp-up of power output. Although these services are rarely considered in hydropower planning, their importance will rise as more wind power and solar power are added to the grid, potentially affecting our results. Moreover, electricity generation is not always the main purpose for which water reservoirs are built. If some of the reservoir hydropower projects were to be associated with other needs (e.g., agriculture, flood control, drinking water supply), cross-sectoral interactions could improve their economic performance and make them attractive investments. In this case, reservoir greenhouse gas emissions should not be attributed to electricity generation only, but the exact attribution of greenhouse gas emissions to the different sectors remains a complex issue.

Governance and political stability are key to ensuring sustainable exploitation of the economically viable hydropower potential, particularly in transboundary river basins (*50*). The Nile and the Niger River basins, identified as hotspots of hydropower development, are high-risk areas because of their transboundary nature in regions of political instability and presence of armed conflict (*51*). Implementation of cooperation schemes is crucial to reduce tensions and provide water and energy security in these areas (*13*, *15*, *52*–*54*).

In a broader sense, cooperation and governance are fundamental to allow all African countries to switch their focus from energy independence to energy security (*55*). In this regard, establishing power pools and the Africa Clean Energy Corridor has been crucial for energy governance. These mechanisms and investments paved the way for increased energy security across the continent (*56*). To prepare for the impacts of dry years, investment in alternative power sources is required, even in locations that might not be directly affected by generation deficits. Understanding the consequences of interconnected power systems can therefore promote the design of agreements and policy interventions that foster energy security and resilience in the face of hydroclimatic change. Growing evidence motivates concerns about the increased risk of conflict and instability associated with the growing impacts of climate change (*57*). Governments and power pools must prepare for stressful contexts where local strategies do not match large-scale cost-optimal development. To confront the friction between coordinated and decentralized decision-making levels, mechanisms building on incentive schemes and side payments need to be designed. In this conundrum, our results can inform future research to ensure multiscale coordination for energy security and sustainable hydropower development within the African continent.

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SUPPLEMENTARY MATERIALS

science.org/doi/10.1126/science.adf5848
Materials and Methods
Supplementary Text
Figs. S1 to S8
Table S1
References (*59*–*82*)

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Declining cost of renewables and climate change curb the need for African hydropower expansion

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Editor's summary
A growing population and increasing energy demand have spurred investments in hydropower generation in Africa. At the same time, the cost of power from other types of renewable sources has continued to drop. Carlino *et al*. explored the ramifications of this trend on the economics of hydropower. They analyzed the African energy landscape from 2020 to 2050, and predicted that the declining cost of wind and solar power will make a large fraction of the current hydropower candidate installations economically uncompetitive over that period. Cooperation between countries could help to overcome the regionally unequal distribution of investment costs and potential energy deficits. —H. Jesse Smith