Renewable energy alternatives to mega hydropower: a case study of Inga 3 for Southern Africa

R Deshmukh1,3, A Mileva2 and G C Wu1
1 Energy and Resources Group, University of California at Berkeley, 310 Barrows Hall, Berkeley, CA 94702, United States of America
2 Blue Marble Analytics, San Francisco, CA, United States of America
3 Author to whom any correspondence should be addressed.

E-mail: ranjit.deshmukh@berkeley.edu

Keywords: hydro, renewable energy, dam, Inga, Congo, South Africa

Abstract
We assess the feasibility and cost-effectiveness of renewable energy alternatives to Inga 3, a 4.8-GW hydropower project on the Congo River, to serve the energy needs of the host country, the Democratic Republic of Congo (DRC), and the main buyer, South Africa. To account for a key uncertainty in the literature regarding the additional economic impacts of managing variable wind and solar electricity, we built a spatially and temporally detailed power system investment model for South Africa. We find that a mix of wind, solar photovoltaics, and some natural gas is more cost-effective than Inga 3 to meet future demand except in scenarios with pessimistic assumptions about wind technology performance. If a low load growth forecast is used, including Inga 3 in the power mix results in higher system cost across all sensitivities. In our scenarios, the effect of Inga 3 deployment on South African power system cost ranges from an increase of ZAR 4300 (US$ 330) million annually to savings of ZAR 1600 (US$ 120) million annually by 2035. A cost overrun as low as 20% makes the Inga 3 scenarios more expensive in all sensitivity cases. Including time and cost overruns and losses in transmission from DRC to South Africa make Inga 3 an even less attractive investment. For DRC, through analysis of spatial datasets representing technical, physical, and environmental constraints, we find abundant renewable energy potential: 60 GW of solar photovoltaic and 0.6–2.3 GW of wind located close to transmission infrastructure have levelized costs less than US$ 0.07 per kWh, or the anticipated cost of Inga 3 to residential consumers.

1. Introduction
Large hydropower has long been a key technology for increasing electricity generation in regions with abundant hydro resources. Globally, 700 GW of hydropower projects are either planned or under construction (Zarfl et al 2014). Proponents of hydropower highlight its relatively low economic costs and low greenhouse gas (GHG) emissions. However, large hydropower projects require high upfront financial commitments (World Commission on Dams 2000), often suffer from cost and time overruns (Ansar et al 2014, Sovacool et al 2014a), and can have substantial environmental and social impacts (McCully 1996, Stone 2011, Ziv et al 2012, Richter et al 2010, Sovacool and Bulan 2012). Given these shortcomings, developing countries with persistent energy supply shortages and limited access to capital should consider and thoroughly weigh alternatives to the hydropower-expansion paradigm, particularly with regards to economic risk. Recent cost declines for solar photovoltaic (PV) and wind generation technologies (Bischof-Niemz 2015, Wiser and Bolinger 2016) may make these resources economically competitive with new hydropower generation. In this study, we investigate, from a systems perspective, whether wind and solar PV can be cost-effective low-carbon alternatives to new large hydropower projects. Specifically, we examine the case of the 4800 MW Inga 3 hydropower project proposed in the Democratic Republic of Congo (DRC).

The DRC has among the lowest per capita GDP in the world, and only 13.5% of its population has
access to electricity (World Bank 2016). To increase both energy access and income through energy exports, DRC and international partners have focused on developing the 40,000 MW of hydropower potential at the Inga site on the Congo River (World Bank 2014b). The Inga 3 project is the first phase of the 40,000 MW Grand Inga dam complex, and would be the third dam installed at the site. Inga 3 is meant to meet three key goals: (1) export 2500 MW of low-cost, low-carbon power to South Africa’s coal-dominated grid; (2) supply 1300 MW for mining activities in DRC’s southeastern Katanga province; and (3) provide the remaining 1000 MW to DRC’s utility Société Nationale d’Électricité (SNEL) for increasing reliable electricity access in and around the capital, Kinshasa (World Bank 2014b). However, major risks and uncertainties affect the development and viability of Inga 3.

First, the projected cost of US$ 14–16.5 billion for Inga 3 (World Bank 2014b, Wright et al 2017) is more than 30% of DRC’s 2015 annual GDP. Empirical evidence showing systematic cost overruns for large hydropower projects (Ansar et al 2014, Sovacool et al 2014b) suggests that Inga 3, one of the largest proposed dams in the world, may be a significant economic risk to the DRC and South Africa. Second, precipitation over the Congo Basin, a key determinant of its financial viability, has declined over the last three decades (Zhou et al 2014), adding uncertainty to its energy potential. Third, Inga 3 would likely have large social and environmental impacts, including displacement of 10,000 people, threats to endemic freshwater biodiversity and mangrove islands, and reduced carbon sequestration through reduced organic sediment flow to the ocean (World Bank 2014a, World Bank 2014b, USAID 2015). Despite these risks and uncertainties, the DRC continues to support the Inga 3 and South Africa assumes that its 2500 MW share will come online by 2033 (Department of Energy 2016).

The key questions in our study are as follows: Is it possible to achieve Inga 3’s three energy goals with wind and solar PV in South Africa and the DRC? If so, what are the system-wide cost impacts of wind and solar options compared to Inga 3? Previous studies have made arguments in favor (Tshombe et al 2007, Taliotis et al 2014, Gottschalk 2016) and against Inga 3’s development (Showers 2009, Green et al 2015). However, none of these studies has systematically examined and compared the technical feasibility and economics of supply alternatives to the Inga 3. While Jones (2017) analyzes the likely technical and financial performance of Inga 3, its economic analysis of generation alternatives is restricted to a comparison of levelized costs, which does not capture the electricity system-wide cost impacts of adding variable wind and solar generation to the grid nor does it consider the availability and quality of these alternative resources in each country. A key gap of these studies comparing variable renewable energy with conventional technologies is whether wind and solar PV can still be economically competitive even after considering the variability in their generation, which imposes additional costs on the electricity system as a whole. Such a system-wide cost comparison requires a different, high resolution energy simulation modeling approach.

In the present study, to accurately compare the costs of Inga 3 and its alternatives in South Africa’s future electricity system, we used spatially-modeled wind and solar resource areas within the country in a high spatial and temporal resolution power system capacity-expansion model, GridPath. This model explicitly accounts for wind and solar variability, a key concern for South Africa’s coal-heavy inflexible grid. Recent studies have used power system planning models to examine the technical feasibility and cost-effectiveness of energy alternatives to large and controversial hydropower development, specifically in Malaysian Borneo (Shirley and Kammen 2015) and Brazil (de Faria and Jaramillo 2017). Our analysis extends these other studies by employing a higher spatial and temporal resolution power system capacity-expansion model and detailed renewable resource potential assessment. Unlike other studies, we assume no subsidies for renewable energy to assess whether renewables can economically compete without incentives. For DRC’s energy needs, we quantify and economically value solar PV and wind potential within the country through a spatial analysis of multiple power plant siting needs and constraints. Such high resolution spatial analysis allows for accurate assessment of resource availability and generation costs of wind and solar technologies.

We present our analysis in two parts. To address the first of Inga 3’s goals, we develop least-cost electricity generation investment plans for South Africa to examine whether Inga 3 would be a cost-effective investment from South Africa’s perspective. Next, we address the second and third of Inga 3’s planned goals by identifying and economically assessing wind and solar PV potential in the DRC, focusing on resources located close to existing and planned transmission infrastructure and within DRC’s mining areas. The site suitability analysis builds on previous work (Wu et al 2015, Wu et al 2017) using additional and more accurate solar radiation, land cover and land use (LULC), conservation, and transmission infrastructure datasets specific to the DRC.

2. Methods

2.1. Electricity generation capacity investments for South Africa

To explore alternative scenarios for South Africa’s electricity future, we develop a power system capacity-expansion optimization model, using a subset of features from the GridPath platform, to determine the least-cost investments in conventional and renewable generation and storage through 2035. For a detailed
description and assumptions of the capacity-expansion model, see supplementary information section A available at stacks.iop.org/ERL/13/064020/mmedia. We simulate South Africa’s electricity system as a single node, ignoring transmission constraints, and model four investment periods (2020, 2025, 2030, 2035) each represented by 12 days, one per month, with each day weighted by the number of days per month to represent a full year. Power system operations on each day are modeled hourly. The model optimizes investment in new conventional and renewable generation capacity and grid operations to meet demand and other operational constraints with the lowest capital and operational costs.

2.1.1. Load and existing generation assumptions
For load forecasts, we use the 2016 IRP ‘High Growth Less Energy Intensive’ and ‘Low Demand’ annual demand forecasts (Department of Energy 2016) and develop several load profile sensitivities (SI A.4). Based on the 2016 draft IRP, we assume 43 547 MW of existing and planned generation capacity to be available by 2035 in all scenarios and use the study’s operating parameter assumptions (e.g. heat rates, minimum stable levels) for all generators (Department of Energy 2016).

2.1.2. Hydropower assumptions
Based on the IRP study, we assume South Africa’s share of 2500 MW of Inga 3 will come online by 2033. For Inga 3, we assume a capacity factor of 70% and also run sensitivity analyses with capacity factors of 60% and 80%. We use precipitation patterns for the Congo Basin to derive an annual distribution of available hydropower for Inga 3. The model dispatches hydropower plants subject to monthly energy, maximum rated power, and minimum generation level constraints. For detailed assumptions about Inga 3 and other hydropower plants, see SI A.9.3.

2.1.3. Candidate resource assumptions
For the additional capacity needed to meet South Africa’s demand through 2035, we model several candidate resource technologies, including pulverized coal, fluidized bed coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), wind, solar PV, and battery storage. The model chooses among the candidate resources based on their capital and operational (fuel and variable operations and maintenance) costs as well as operating constraints (e.g. heat rates for conventional generation, generation profiles for wind and solar, maximum monthly available energy for hydro) in order to minimize total power system cost through 2035.

For hourly renewable resource data, we use wind speeds at 80 m hub height from Vaisala and solar irradiation data from reanalysis of the MERRA-2 dataset (Pfenninger and Staffell 2016, Rienecker et al. 2011) modeled for 2013. We adopted suitable areas of wind and solar PV resources from previous studies, which used the multi-criteria analysis and planning for renewable energy (MapRE) methodology to exclude low quality resources, protected areas, and unsuitable LULC types (Wu et al. 2017, Department of Environmental Affairs and Council for Scientific and Industrial Research 2014). Renewable energy cost assumptions are based on South Africa’s 2016 auction prices (Wright et al. 2017). See SI A.9.4 for details.

Actual monitored annual wind capacity factors of South Africa’s existing fleet are about 20%–25% lower than our simulated data (National Energy Regulator of South Africa 2016). This is likely because simulated data represent the highest-quality resource, but existing projects may have been sited not only on resource quality, but also on land availability and transmission interconnections not captured in our analysis. To account for simulated data discrepancies, we run sensitivity cases with 25% lower capacity factors for wind.

2.1.4. Scenarios and sensitivity cases
We construct several sensitivity cases using combinations of assumptions for the following key areas of uncertainty (table 1): Inga 3 capacity factor, Inga 3 capital costs, Inga 3 cost overruns, capacity factors for wind sites in South Africa, and load forecasts and shapes. For each sensitivity case, we run two scenarios—one with Inga 3 in the generation mix and one without. We then (1) compare the new generation capacity mixes and (2) estimate the differences in total system cost in 2035 (the annualized investment costs plus annual operational costs) between the cases with and without Inga 3. We assume South Africa’s share to be 53% of the total Inga 3 capital cost, proportional to its capacity allocation.

2.2. Quantifying potential and costs of solar PV and wind in the DRC
We use the MapRE methodology (Wu et al. 2017) to analyze wind and solar PV potential in the DRC.

| Table 1. Sensitivity assumptions for modeling South Africa’s electricity capacity mix. |
|-----------------------------------------------|
| **Sensitivities** | **Assumptions (least optimistic <—> most optimistic for Inga 3)** |
| Inga 3 annual capacity factor | 60%; 70%; 80% |
| Inga 3 cost overruns | 100%; 80%; 60%; 40%; 20%; 0%; ~20% |
| Wind hourly capacity factors | Vaisala simulated; scaled down (reduced by 25%) |
| Load forecast | High growth less energy intensive (base case scenario); Low growth |
| Load shape | Modified load shapes of base case load forecast scenario—climate warming; climate extreme warming; daily peak increase |
3. Results

3.1. Future generation capacity investments for South Africa

3.1.1. Least-cost electricity generation mix for South Africa with and without Inga 3

We develop a capacity-expansion model to determine new capacity needed above the existing and planned capacity of 43,547 MW by minimizing new investment capital costs and variable costs (see existing and new generation capacity in 2035 in figure 1(a)). In all sensitivity cases, both with and without Inga 3 and for all load projections, all new investments are in wind, solar PV, and natural gas (combined cycle and open cycle; figure 1(a) and supplementary information C.4).

No new coal plants are built in any of the sensitivity cases or scenarios. In the cases without Inga 3, all Inga 3 capacity is replaced by a combination of wind, solar PV, and natural gas. Investment in conventional generation capacity is needed to meet peak load and help balance the grid with high shares of wind and solar. Our model results indicate that the additional conventional generation capacity will have low capacity factors. While natural gas plants in South Africa will need to rely on imported expensive liquefied natural gas (Department of Energy 2016), and thus have higher variable costs per unit of energy generation than coal plants, their lower capital costs combined with the low expected capacity factors make them a more cost-effective choice than coal for infrequent use.

Annual energy generation from all natural gas plants does not exceed 2.5% across all scenarios (including all load forecasts and load profile sensitivities) (figure 1 and supplementary information C.4).

3.1.2. Expected costs or savings of including Inga 3 in South Africa’s electricity future

To evaluate the benefit or cost of Inga 3 to the South African power system, we compare annual system costs (annualized capital costs of new capacity plus total variable costs) from the 2035 investment period in the cases with and without Inga 3 (figure 2).

Using the CSIR cost estimate for the dam, Inga 3 is more cost-effective than the renewable energy alternatives under the higher load (base case) scenarios across all load profiles when wind capacity factors are adjusted downward and annual capacity factor of Inga 3 is 70% or 80%; if wind capacity factors are not adjusted downward or the Inga 3 capacity factor is 60%, the Inga 3 scenarios are costlier across all load sensitivities (figure 2). If the lower load forecast is used, perhaps more realistic given recent slowdown in South Africa’s economic growth, the Inga 3 scenarios are more expensive than the alternative across all sensitivities. Cost differences range from ZAR 4300 to −1600 million (US$ 330 to −120 million) annually in 2035.
Figure 1. (a) Existing and planned, and least-cost new generation capacity investments and (b) annual energy generation mix for South Africa with and without Inga 3 in 2035 for base case load projection. Existing and planned generation capacity of 43,547 MW, assumed from South Africa's IRP 2016, is fixed across all scenarios (rightmost stacked bar). New generation capacity is chosen by the least-cost capacity-expansion optimization model. New chosen capacity categories are shown in legend enclosed in the box. Annual capacity factors for Inga 3 are varied from 60%–80%. Monthly energy budgets for Inga 3 are assumed to vary by season based on precipitation patterns. Capacity factors for wind are estimated from Vaisala wind speed data and then scaled 25% down to be similar to existing wind power plant generation in South Africa. Inclusion or exclusion of Inga 3 is forced (exogenous). OCGT is open cycle gas turbine; CCGT is combined cycle gas turbine.

3.1.3. Estimating implications of potential cost overruns of Inga 3

Two recent empirical studies show that large hydropower projects experience systematic cost overruns (on average 96% higher in Ansar et al. 2014 and 71% higher in Sovacool et al. 2014a). To assess the effect of Inga 3 cost overruns on South Africa’s system costs, we increase the CSIR capital cost estimate for Inga 3 from 0% to 100% (no cost overruns to double the capital costs) in 20% increments. We also include a cost overrun of −20%, which would result in a lower Inga 3 cost similar to the World Bank estimate of US$ 14 billion. Figure 3 shows South Africa’s 2035 system cost differences of scenarios with Inga 3 over scenarios without Inga 3 (i.e., system costs with Inga 3 minus costs without Inga 3) across six sensitivities varying the Inga 3 capacity factor (60%, 70%, and 80%) and wind capacity factor (simulated and scaled down 25%).

If Inga 3 cost is 20% lower than the CSIR estimate, the dam is more cost-effective than the renewable energy alternatives if wind capacity factors are scaled down. A cost overrun as low as 20% over the CSIR cost estimate makes the scenario with Inga 3 more expensive than the corresponding scenario without Inga 3 across all cases, with differences ranging between ZAR 900 and 5300 million (US$ 70–410 million) per year. With a 100% cost overrun, the cases with Inga 3 would cost between ZAR 8400 and 12 900 million (US$ 640–990 million) more per year than those without Inga 3 depending on the scenario. Whether South Africa or DRC bears these additional costs, cost overruns are a serious risk for the economic viability of Inga 3.
3.1.4. Expected annual greenhouse gas emissions from South Africa’s electricity sector

Although no new coal plants are built, we find that total emissions from electricity generation in South Africa can be either higher or lower if Inga 3 is included in the power mix across the scenarios we tested (figure 4). A key determinant of the direction of GHG emissions change is the assumed load projection. At lower load levels, coal output is increased in order to compensate for the reduced energy availability resulting from removing Inga 3 from the mix. The higher annual coal load factor results in an increase in emissions over the case with Inga.

However, at higher load levels, coal is already running near maximum capacity (even with Inga in the mix) during the peak net load hours; removing Inga 3 is compensated for by more wind, not by ramping up coal power output. At the same time, the increase in wind generation requires that coal output be reduced in the off-peak hours in order to accommodate the
wind energy and avoid curtailment. The coal load factor is therefore reduced relative to the case with Inga 3 and GHG emissions are lower. At the higher load forecast, all but one scenarios with Inga 3 have annual GHG emissions greater than those without Inga 3. We have included two sample dispatch plots showing this dynamic in supplementary information C.1.

Our analysis is for electricity system direct emissions only. We do not account for other GHG emissions from Inga 3, such as potential methane emissions or emissions from construction materials, and hence cannot quantify the overall lifecycle balance of GHG emissions.

3.2. Meeting energy needs in the DRC with wind and solar PV

3.2.1. Wind and solar PV potential near DRC’s transmission infrastructure

We find that using our land use and land cover assumptions, the potential capacity for wind energy is 11 GW within 25 km of existing transmission lines (figure 5) and 17 GW within 25 km of existing and planned grid infrastructure (figure 5). Of the 17 GW of highly accessible potential, 0.64 GW of wind resources have estimated levelized costs of electricity (the sum of the annualized costs of generation, transmission and road extensions) less than US$ 0.07 per kWh and 1.0 GW of wind potential less than US$ 0.08 per kWh within 25 km of existing or planned transmission lines. Removing the high-voltage DC (HVDC) transmission line connecting Inga 1 and 2 and Kolwezi from consideration reduces the 17 GW potential by only 500 MW. Most high-quality wind is located along the eastern border of the DRC, with several scattered potential project areas in the southeastern Katanga province (figure 5).

The potential for solar PV is greater than that for wind in the DRC. We identified 82 GW of potential solar PV capacity, of which approximately 1 GW is estimated to have total LCOE less than US$ 0.06 per kWh, nearly 60 GW with total LCOE less than US$ 0.07 per kWh, and nearly all potential with LCOE less than US$ 0.08 per kWh (figure 6). Potential within 25 km of existing transmission lines is still vast (62 GW; figure 6). Like wind, most lowest cost project locations for solar PV are in eastern and southeastern DRC, particularly in the Katanga province (figure 6). However, we identified 6.6 GW of solar PV potential with an average total LCOE of US$ 0.07 per kWh about only 100 km southwest of Kinshasa, one of the main beneficiaries of Inga 3. The solar potential within 25 km of existing and planned transmission infrastructure vastly exceeds the total capacity of Inga 3 and matches that of the Grand Inga. Removing the Inga-Kolwezi HVDC line from consideration reduces the total potential by only 2–3 GW or 2%–5%. Because we heavily discounted the potential installed capacity per unit area of land (90% and 75% for solar PV and wind technologies, respectively), some areas may have even greater potential for renewable energy development.

3.2.2. Wind and solar PV potential within DRC’s mining areas

To assess the potential for wind and solar PV to meet the energy needs of the mining industry, we identified wind and solar potential within areas with existing or potential mining activity. Removing only the land...
Figure 5. Wind potential project areas. (a) All wind potential project areas are colored using each project area’s levelized cost of electricity (LCOE). (b) LCOE for project areas within 25 km of existing transmission lines. (c) LCOE for project areas within 25 km of existing and proposed transmission lines. Capacity factors vary from 15%–45%. For reference, DRC had a total installed generation capacity of 2.5 GW in 2013. Two transmission line datasets are shown—AICD (Africa Infrastructure Country Diagnosis) and SNEL (Société Nationale d’Electricité; see table D.1 in supplementary information section D for data sources).

Figure 6. Solar PV potential project areas. (a) All solar PV potential project areas are colored using each project area’s total levelized cost of electricity (LCOE). (b) LCOE for project areas within 25 km of existing transmission lines. (c) LCOE for project areas within 25 km of existing and proposed transmission lines. Capacity factors vary from 16%–20%. For reference, DRC had a total installed generation capacity of 2.5 GW in 2013. Two transmission line datasets are shown—AICD (Africa Infrastructure Country Diagnosis) and SNEL (Société Nationale d’Electricité); see table D.1 in supplementary information section D for data sources.

use and land cover constraint, we identified potential wind and solar PV project areas within areas with active permits for mining exploration and exploitation. We find that approximately 52% of such areas have solar PV potential with generation-only LCOE less than US$ 0.07 per kWh and 10% have wind potential with generation LCOE less than US$0.15 per kWh (figure 7). At these costs, the potential installed capacity within mining areas is more than 2400 GW of solar PV and 130 GW of wind (figures 7(b) and (d)). Costs of all
Figure 7. Wind (a) and solar PV (c) potential project areas within areas with active mining permits for exploitation and exploration. Grey areas show mining permitted areas without suitable sites for ground-mounted wind or solar power. Supply curves for wind (b) and solar (d) show the range of generation LCOE for all potential projects.

4. Discussion

4.1. Sensitivity analyses show high economic risk of Inga 3 for South Africa

4.1.1. Cost-effectiveness of wind, solar PV, and gas generation compared to Inga 3

Our study examines whether Inga 3 is an economically competitive electricity generator in South Africa’s energy supply under various sets of technical and economic assumptions. We find that it can be more cost-effective to procure Inga 3 over domestic renewable energy alternatives only in scenarios with a combination of pessimistic assumptions about wind technology performance, optimistic assumptions of mid or high energy availability from Inga 3, and no overrun in Inga 3’s capital costs. In scenarios with lower load levels, which could result from slower economic growth, Inga 3 is less cost-effective than the alternatives across all sensitivities tested. Even a 20% cost overrun makes all cases with Inga 3 more expensive than their corresponding cases without it regardless of load level or wind technology performance, and not accounting for additional potential costs discussed below.

4.1.2. Long construction lead times result in additional interest costs

Projects with longer lead times increase financing costs because of additional interest payments (US Energy Information Administration 2016). In the sensitivity cases, we use CSIR overnight capital costs that do not include accumulation of interest during construction. However, including CSIR estimates for interest...
costs accrued during eight years of construction, the total capital cost of Inga 3 would increase by 48% to US$ 24.6 billion. Consequently, South Africa’s share of annual costs will increase by 48% or US$ 350 million (ZAR 4500 million) per year. World Bank cost estimates also do not include interest accrued during construction. Wind projects take 1–3 years to construct and most solar PV projects take a year, incurring lower additional interest costs.

4.1.3. Cost increases due to transmission losses
The length of the transmission line from Inga 3 to Kolwezi (DRC-Zambia border) is 1850 km (USAID 2015), and 1500 km more to the South African border. We did not include transmission losses on this line in our economic analysis because of uncertainty about which country bears the cost of transmission losses from Inga 3 to the South African border. However, even with a low-loss 800 kV HVDC line, the transmission losses from Inga 3 to the South African border will be at least 10% (Siemens 2012). In order to secure 2500 MW of supply, South Africa may bear the cost of 2800 MW or 58% of Inga 3 capacity, 10% more than that assumed in our analysis. Lower voltage or alternating current (AC) transmission lines would increase losses. Wind and solar PV resources can be located within South Africa, incurring relatively lower transmission losses. Renewable resources close to high voltage transmission infrastructure can be prioritized for development, minimizing losses (Wu et al. 2017).

4.1.4. Other economic risks
The management of the Congo Basin watershed, which spans six countries, can affect flow and sedimentation rates on the Congo River, and thus the performance of the Inga 3. Development plans that are most risky for the Inga 3 include other hydropower projects on the tributaries of the Congo River and potential diversion of the Oubangui River, a major tributary of the Congo River, to relieve the loss of water in Lake Chad (USAID 2015). The cumulative effects of these developments on the hydrology of the Congo River have not been studied, despite potentially large impacts on the viability of the Inga 3. Climate change may magnify the effect of these development projects. A recent study reported widespread decline of vegetative ‘greenness’ within the Congo Basin, which is consistent with observed trends of declining rainfall and rising temperatures in the basin (Zhou et al. 2014).

4.2. Wind and solar can enable energy security and energy access in the DRC
4.2.1. Abundant, low-cost, and accessible wind and solar PV resources in the DRC
The World Bank estimated electricity price for Inga 3 is 7–8 US cents/kWh for DRC customers and South Africa and is as high as 12 US cents/kWh for mining companies based on their willingness to pay (World Bank 2014b). These estimates are based on assumptions of no cost overruns and a capacity factor of about 86%. We find that wind and solar PV resources within the DRC can be cost-competitive even with this optimistic cost forecast for Inga 3 and are sufficiently abundant to serve as alternatives to energy supplied by Inga 3.

Solar PV potential greatly exceeds wind potential in the DRC, with the majority of the lowest-cost solar PV resources near existing transmission lines located in the mining province of Katanga. Results of our solar potential assessment are aligned with the only other resource assessment available (ICF 2017). For utility-scale solar PV projects, land cover and land use may prove to be the most constraining siting criteria. From the systems perspective, the temporal variability of wind and solar resources can be challenging for grid management. However, countries with high shares of renewable energy have already tested and adopted several effective strategies for managing variability, such as increasing flexibility in system operations, conventional generation, and demand; implementing innovative market mechanisms; and deploying grid-scale battery storage (Cochran et al. 2012, Wu et al. 2017, Enernex Corporation 2011, GE Energy 2010, Schaber et al. 2012, Trade Wind 2009). International experiences with deploying these strategies can enable the DRC to manage the variability and uncertainty of wind and solar generation.

4.2.2. Serving mining energy needs through wind and solar
The mining sector’s energy needs can be met by abundant renewable resources—with over 50% of all mining permitted areas having low-cost solar PV potential. Developing distributed power plants close to where the electricity is consumed reduces the need to upgrade long transmission lines and avoids transmission losses. Wind and solar generation can supplement mining companies’ existing large and new small hydropower generation as well as displace expensive diesel generation. With rapidly declining costs of battery storage, standalone applications of solar plus storage are becoming increasingly cost-effective in replacing standalone diesel generators (IRENA 2017).

4.2.3. Decentralized solutions for energy access
More than 90% of DRC residents lack access to electricity. Although we show that the allocation of 1000 MW from Inga 3 to domestic residential and non-mining commercial consumption (limited to the Kinshasa region) can be substituted with accessible
grid-connected wind and solar PV, the availability of 1000 MW is inadequate to address their energy access needs. While the dominant strategy to provide electricity access is to construct large generation projects and extend the grid, the often sparse population in sub-Saharan Africa makes grid extension and individual connections prohibitively expensive (Morrissey 2017). Decentralized energy options such as distributed solar PV and mini-hydro mini-grids are cost-competitive alternatives to grid extension, and could rapidly advance the DRC’s universal energy access goals (Szabó et al. (2016), Mentis et al. (2017)).

5. Conclusions

Our study economically evaluates alternatives to the Inga 3 mega-dam project from the perspective of each of the dam’s key electricity consumer groups. We employ a capacity-expansion model with higher spatial and temporal resolution than previous analyses, thus better accounting for the variability—and thus, grid integration requirements—of wind and solar. Despite the potential system-cost impacts of managing their variable supply, results show the economic competitiveness of a mix of wind, solar PV, and natural gas compared to Inga 3 for South Africa. For DRC, through analysis of spatial datasets representing technical, physical, and environmental constraints, we find abundant renewable energy potential located close to transmission infrastructure have levelized costs less than the anticipated cost of Inga 3 to residential consumers. With Inga 3 as a case example, this study also demonstrates the value of combining spatial resource assessment analysis with energy capacity expansion modeling for systematically determining the cost-competitiveness of proposed generation projects. Through this electricity modeling framework, our results show that wind and solar PV can be cost-competitive alternatives to large hydropower projects, even without considering externality costs of conventional generation pollution or subsidies for renewable energy.

Acknowledgments

We would like to thank Crescent Mushwana, Elisabeth Caesens, Jarrad Wright, Rudo Sanyanga, Joshua Klemm, and Ange Asanzi for valuable comments. A.M. and G.C.W. would like to acknowledge International Rivers for financial support. R.D. would like to thank the ITRI-Rosenfeld postdoctoral fellowship. Publication made possible in part by support from the Berkeley Research Impact Initiative (BRH) sponsored by the UC Berkeley Library.

ORCID iDs

R. Deshmukh https://orcid.org/0000-0002-5593-675X

References

Ansar A, Flyvbjerg B, Budzier A and Lunn D 2014 Should we build more large dams? The actual costs of hydropower megaproject development SSRN Scholarly paper ID 2406852 (Rochester, NY: Social Science Research Network)

Bischof-Niemz T 2015 Financial costs and benefits of renewables in South Africa in 2014 Technical Report CSIR/02400/RD Core/IR/2015/0001/B Council for Scientific and Industrial Research (CSIR), South Africa

Black & Veatch Corp. and NREL 2009 Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report Technical Report NREL/5-6A2–46877 Western Governor’s Association

Black & Veatch Corp. and RETI Coordinating Committee 2009 Renewable Energy Transmission Initiative (RETI) Phase Ib Final Report Technical Report RETI-1000–2008-003-P (www.energy.ca.gov/reти/documents/index.html)

Cochran J, Bird L, Heeter J and Arent D 2012 Integrating Variable Renewable Energy on the Electric Power Markets: Best Practices from International Experience Technical Report National Renewable Energy Laboratory

CPUC 2017 Proposed Reference System Plan Technical Report California Public Utilities Commission (ftp://ftp.cpuc.ca.gov/resources/electric/erp/resolverse/)

de Faria F A M and Jaramillo P 2017 The future of power generation in Brazil: an analysis of alternatives to Amazonian hydropower development Energy Sustain. Dev. 41 24–35

Department of Energy SA 2016 Integrated Resource Plan Update: Assumptions, Base Case Results, and Observations Technical Report Revision 1 Department of Energy, Republic of South Africa

Department of Environmental Affairs and Council for Scientific and Industrial Research 2014 Renewable Energy Development Zones Technical Report

Enernex Corporation 2011 Eastern Wind Integration and Transmission Study Technical Report National Renewable Energy Laboratory

GE Energy 2010 Western Wind and Solar Integration Study Technical Report National Renewable Energy Laboratory

Gottschalk K 2016 Hydro-politics and hydro-power: the century-long saga of the Inga project Can. J. Afr. Stud. 50 279–94

Green N, Sovacool B K and Hancock K 2015 Grand designs: assessing the African energy security implications of the Grand Inga Dam Afr. Stud. Rev. 38 133–58

ICF 2017 Conceptual Plan for Enhancing Transmission Infrastructure to Expand Electricity Access in the Democratic Republic of the Congo (DRC) Technical Report United States Agency for International Development

IRENA 2017 Electricity Storage and Renewables: Costs and Markets to 2030 Technical Report International Renewable Energy Agency

Jones T 2017 The Economic Costs of the Inga III Dam Technical Report International Rivers

McCully P 1996 Silenced rivers: the ecology and politics of large Dams (www.caibdirect.org/caibdirect/abstract/19971801995)

Mentis D et al 2017 Lighting up the World: The first application of an open source, spatial electrification tool (ONSET) on Sub-Saharan Africa Environ. Res. Lett. 12 085003

Morrissey J 2017 The energy challenge in sub-Saharan Africa: a guide for advocates and policy makers Part 2: Addressing energy poverty Technical Report Oxfam

National Energy Regulator of South Africa 2016 Monitoring of Renewable Energy Performance Technical Report Issue 7

Pfenninger S and Staffell I 2016 Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data Energy 114 1251–65

Richter B D, Postel S, Revenga C, Sadowa J, Lehner B, Churchill A and Chow M 2010 Lost in development’s shadow: the downstream human consequences of dams Water Altern. 3 14
Environ. Res. Lett. 13 (2018) 064020

Rienecker M M, Suarez M J, Gelaro R, Todling R, Bacmeister J, Liu E, Bosilovich M G, Schubert S D, Takacs L and Kim G-K 2011 MERRA: NASA’s modern-era retrospective analysis for research and applications J. Clim. 24 3624–48

Schaber K, Steinke F, Mühlich P and Hamacher T 2012 Parametric study of variable renewable energy integration in Europe: advantages and costs of transmission grid extensions Energy Policy 42 498–508

Shirley R and Kammen D 2015 Energy planning and development in Malaysian Borneo: assessing the benefits of distributed technologies versus large scale energy mega-projects Energy Strat. Rev. 8 15–29

Showers K 2009 Congo River’s grand inga hydroelectricity scheme: linking environmental history, policy, and impact Water History 1 31–58

Siemens 2012 Fact Sheet-High-voltage direct current transmission (HVDC) Technical Report (www.siemens.com/press/pool/de/events/2012/energy/2012-07-w-ismar/factsheet-hvdc-e.pdf)

Sovacool B K and Bulan L C 2012 Energy security and hydropower development in Malaysia: The drivers and challenges facing the Sarawak Corridor of Renewable Energy (SCORE) Renew. Energy 40 113–29

Sovacool B K, Gilbert A and Nugent D 2014a An international comparative assessment of construction cost overruns for electricity infrastructure Energy Res. Soc. Sci. 3 152–60

Sovacool B K, Gilbert A and Nugent D 2014b Risk, innovation, electricity infrastructure and construction cost overruns: testing six hypotheses Energy 74 906–17

Stone R 2011 Hydropower. The legacy of the three Gorges Dam Science 333 817

Szabo S, Moner-Girona M, Kougias I, Ballis R and Bódis K 2016 Identification of advantageous electricity generation options in sub-Saharan Africa integrating existing resources Nat. Energy 1 2016140

Taliotis C, Bazilian M, Welsch M, Gielen D and Howells M 2014 Grand Inga to power Africa: hydropower development scenarios to 2035 Energy Strat. Rev. 4 1–10

Trade Wind 2009 Integrating Wind: Developing Europe’s Power Market for the Large Scale Integration of Wind Power Technical Report European Wind Energy Association

Tshombe I M, Ferreira I W and Uken E 2007 NEPAD vision and Trade Wind 2009 Integrating Wind: Developing Europe

Taliotis C, Bazilian M, Welsch M, Gielen D and Howells M 2014

US Energy Information Administration 2016 Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016 Technical Report

USAID 2015 Affirmative Investigation for DRC - Inga 3 B C. Hydropower Project Technical Report United States Agency for International Development

Wiser R and Bolinger M 2016 2015 Wind Technologies Market Report Technical Report Lawrence Berkeley National Laboratory

World Bank 2014a Africa’s Growth Set to Reach 5.2 Percent in 2014 With Strong Investment Growth and Household Spending The World Bank (www.worldbank.org/en/news/press-release/2014/04/07/africas-growth-set-to-reach-52-percent-in-2014-with-strong-investment-growth-and-household-spending)

World Bank 2014b International Development Association Project Appraisal Document on a Proposed Grant in the Amount of SDR 47.7 million (US$ 73.1 million equivalent) to the Democratic Republic of Congo for an Inga 3 Basse Chute and Mid-size Hydropower Development Technical Assistance Project Technical Report 77420 Z R Sustainable Development Department, Africa Region, World Bank

World Bank 2016 Data Technical Report The World Bank Group (data.worldbank.org)

World Commission on Dams 2000 Dams and Development: A New Framework for Decision-Making: The Report of the World Commission on Dams (London and Sterling, VA: Earthscan)

Wright J, Bischof-Niemeyer J, Calitz J, Mushwana C, van Heerden R and Senalala M 2017 Formal Comments on the Integration Resource Plan Update: Assumptions, Base Case Results, and Observations 2016 Technical Report 20170331 C SIR-EC-ESPO-REP-DOE-1.1A Rev 1.1. CSIR (www.csir.co.za/sites/default/files/Documents/20170331CSIR_EC_DOE.pdf)

Wu G C, Deshmukh R, Ndhlukula K, Radiojic T and Reilly J 2015 Renewable energy zones for the Africa clean energy corridor LBNL#187271 (Abu Dhabi: International Renewable Energy Agency and Berkeley, CA: Lawrence Berkeley National Laboratory)

Wu G C, Deshmukh R, Ndhlukula K, Radiojic T, Reilly-Moman J, Phadke A, Kammen D M and Callaway D S 2017 Strategic siting and regional grid interconnections key to low-carbon futures in African countries Proc. Natl Acad. Sci. 114 E3004–12

Jaral C, Lumsdon A E, Berlekamp J, Tydecks L and Tockner K 2014 A global boom in hydropower dam construction Aquat. Sci. 77 161–70

Zhou L et al 2014 Widespread decline of Congo rainforest greenness in the past decade Nature 509 86–90

Ziv G, Baran E, Nam S, Rodriguez-Iturbe I and Levin S A 2012 Trading-off fish biodiversity, food security, and hydropower in the Mekong River Basin Proc. Natl Acad. Sci. 109 5609–14