Enabling a low-carbon electricity system for Southern Africa

AFM Kamal Chowdhury[a,b,1], Ranjit Deshmukh[a,c,1,*], Grace Wu[a], Anagha Uppal[d], Ana Mileva[e], Tiana Curry[f], Les Armstrong[g], Stefano Galelli[h], Kudakwashe Ndhlukula[i]

[a]*Environmental Studies Program, Bren Hall, University of California Santa Barbara, CA 93117, United States*
[b]*Earth System Science Interdisciplinary Center, University of Maryland, College Park, MD 20740 United States*
[c]*Bren School of Environmental Science and Management, Bren Hall, University of California Santa Barbara, CA 93117, United States*
[d]*Department of Geography, Ellison Hall, University of California Santa Barbara, CA 93117, United States*
[e]*Blue Marble Analytics, San Francisco, CA, United States*
[f]*Department of Mathematics, South Hall, University of California Santa Barbara, CA 93117, United States*
[g]*Department of Physics, Broida Hall, University of California Santa Barbara, CA 93117, United States*
[h]*Pillar of Engineering Systems and Design, Singapore University of Technology and Design, 487372 Singapore*
[i]*Southern African Development Community (SADC) Centre for Renewable Energy and Energy Efficiency, 11 Dr Agostinho Neta Road, Windhoek, Namibia*

Abstract

Southern Africa faces the dual challenge of providing affordable energy to meet rapidly growing electricity demand while limiting carbon emissions and socio-environmental impacts. To develop optimal electricity pathways for Southern Africa under varying technology and fuel cost projections and energy policies, we combined open source geospatial, hydrologic, and electricity grid-investment models that represent renewable resources in high spatio-temporal detail. We found that if technology and fuel prices continue to

*Corresponding author
Email address: `rdeshmukh@ucsb.edu` (Ranjit Deshmukh)
URL: `cetlab.es.ucsb.edu` (Ranjit Deshmukh)
[1]authors contributed equally to this work

follow current trends, wind and solar technologies can become the dominant sources of electricity in the region by 2040. Importantly, no new coal capacity was built in any scenario except when inter-regional transmission was constrained. Further, despite the abundant hydropower potential in the region, fewer than half of planned hydropower projects were cost-competitive, thus supporting river conservation efforts. Through continued build-out of renewable energy technologies and coordinated expansion of inter-regional transmission lines and electricity trade, Southern Africa could maintain its GHG emissions in 2040 at 2020 levels. Limiting coal plant lifetimes to 45 years (20 years less compared to reference) could halve emissions, but results in 13% higher total annual system costs. Alternatively, an 80% clean energy target resulted in a similar 50% reduction in annual GHG emissions by 2040 but costs only 6% or USD $3/MWh more than reference. Our study shows feasible pathways for Southern Africa to develop an affordable and low-carbon electricity system.

Keywords: wind, solar, renewable energy, electricity, Africa

Highlights

- We develop optimal 2040 electricity pathways for Southern Africa
- Wind and solar are likely to be the dominant forms of generation capacity by 2040
- No new coal capacity is required except when transmission is constrained
- Less than half of planned hydropower projects are economical
- An 80% clean energy target halves reference emissions at 6% higher costs

Context and scale

Electricity demand is projected to double in the twelve countries of conterminous Southern Africa. The challenge is to meet this growing demand while limiting carbon emissions and the socio-environmental impacts of electricity infrastructure. We developed optimal energy pathways for the region's electricity sector. If current technology and fuel cost trends continue, wind and solar dominate new capacity investments by 2040. No new coal power

plants are built, except when inter-regional transmission capacity is limited. Despite abundant hydropower potential, less than half of planned project capacity is economical, and the alternatives to hydropower appear to be a viable pathway to avoid the socio-environmental impacts of large hydropower projects. Electricity trade increases 15-30 times across scenarios, highlighting the importance of further developing the inter-regional electricity market. Lastly, meeting demand with 80% clean energy can halve emissions in 2040 compared to the reference scenario but cost only 6% more, an increase that may be subsidized by international donors.

1. Introduction

The energy transition in Southern Africa epitomizes the twin challenges facing developing regions: providing affordable energy services to meet growing demand while limiting greenhouse gas (GHG) emissions and socio- environmental impacts. This region, encompassing twelve conterminous member countries of the Southern African Power Pool (SAPP), is expecting a 60% growth in population and more than doubling in electricity demand by 2040 [1].

With large coal resources in South Africa (14th largest GHG emitter in the world and the largest in Africa), Mozambique, and Botswana, this growth in energy demand could be met by new coal capacity, thus increasing the region's GHG emissions. The large hydropower potential remaining in the region's Congo and Zambezi rivers, two of Africa's five largest rivers, could also be exploited, but at high environmental and social costs [2, 3]. At the same time, new natural gas discoveries in the region and vast amounts of high-quality renewable wind and solar resources may have the potential to create a cleaner and cost-effective future electricity system [4, 5]. Although Southern Africa, like other developing regions, has little historic responsibility for anthropogenic climate change, their energy development pathways will have profound implications for future GHG emissions, natural resource conservation, and the livelihoods of local communities. Energy planning in Southern Africa has largely relied on fossil fuels and hydropower, with minimal roles for wind and solar technologies despite their rapidly declining capital costs [1].

Previous studies of Southern Africa's electricity system have shown that alternative, more sustainable energy futures may be possible. However, these studies were carried out with analytical tools that only partially address the many complexities associated with designing large-scale power grids. For example, Wu et al. (2017) [5] estimated the regional availability of wind and solar resources and assessed the high-level impact of transmission interconnections on wind and demand variability, but without explicitly modeling the transmission investments and operations of the region's power system. Other studies have examined power sector investments and electricity trade in Southern Africa, but these either used models with low temporal and spatial resolution that do not adequately capture the variability of wind, solar, and hydropower [6, 7, 8, 9, 10] or did not optimize new transmission and/or hydropower project investments [6, 7].

Moreover, none of the aforementioned studies explicitly represented hydropower generation with spatio-temporal specificity using basin-level hydrologic modeling and project-specific energy availability. Representing hydropower generation with sufficient spatio-temporal detail is critical given the complementary roles that hydropower can serve in a high variable renewable power system and the large potential and planned capacity that exists in the region. Previous studies and current policies have focused on developing this hydropower potential, especially for exports through regional interconnections [1, 11, 12]. These studies, however, may have overlooked the opportunities that lie in coordinating the expansion of solar, wind, and hydropower resources. Most previous aforementioned studies have not explored the value of recent cost declines in wind, solar PV, and battery storage cost projections, which could potentially underestimate their role in Southern Africa's electricity futures. Other studies that have addressed these gaps did so only for South Africa [13, 14, 15]. However, given the potentially important role of regional electricity trade in enabling more renewable energy development, it is critical to model the interconnected region as a whole.

To address these gaps, we developed energy pathways for Southern Africa's electricity sector by comprehensively characterizing the cost and potential for both renewable and conventional technologies and balancing system costs with GHG emissions and socio-environmental externalities. To design these pathways, we developed a numerical modelling framework that explicitly accounts for the spatio-temporal variability of current and future generation, storage, and transmission resources across the entire region.

The framework uniquely links three open-source models that represent renewable resources with high spatio-temporal detail. First, we developed a detailed electricity system model for the twelve conterminous countries of the SAPP using high spatial and temporal resolution wind, solar, and hydropower generation data (GridPath). The GridPath platform can co-optimize generation, storage, and transmission investments and their operations across multiple investment periods under different economic and technical constraints [15, 16]. Second, to characterize the supply of renewable generation for GridPath, we developed a renewable energy resource assessment model (MapRE) [17, 5] that captures the spatial diversity and temporal variability of wind and solar resources. Third, we developed VIC-Res-Southern-Africa, a process-based hydrological-water management model simulating daily river discharge and hydropower production across all existing and planned hydropower plants [18]. We designed seven scenarios that explore the effects of technology and fuel cost trajectories and energy policies out to 2040 (Table 1)

Table 1: Core scenarios and assumptions

Scenario Names	**Renewable energy costs**	**Fossil fuel prices**	**Transmission**	**Coal retirement**	**Clean energy target**
	Declining: Renewable energy and battery capital costs decline as per NREL ATB 'low' forecasts [19] **Static**: Current costs for both renewables remain the same as in 2017 out to 2040 [1]	**Rising:** Prices for coal and natural gas increase based on SAPP's plan [1] **Static:** Fossil fuel costs remain the same out to 2040	**Optimized Tx:** Transmission (Tx) investments and operations are co-optimized with generation and storage capacity investments and operations **Existing Tx:** no new tx capacity **Planned Tx:** new tx restricted to current plans based on the SAPP Plan [20, 21]	**65 years:** normal coal lifetime **55 years and 45 years:** earlier retirements	**None:** no clean energy target **80% by 2040:** 80% clean energy (wind, solar, other renewables, hydropower, nuclear) by 2040, roughly halving the annual 2020 GHG emissions by 2040.
Reference	Declining	Rising	Optimized Tx	65 years	None
Static costs	Static	Static			
Existing Tx			Existing Tx		
Planned Tx			Planned Tx		
Coal ret. 55y				55 years	
Coal ret. 45y				45 years	
Clean 80%					80% by 2040

We developed seven core scenarios with varying combinations of capital costs of solar, wind, and battery, prices of fossil fuels, transmission (Tx) interconnections, retirement (ret.) ages of installed coal fleets, and a clean electricity target by 2040 (Table 1). The Reference scenario includes the most favorable set of assumptions for minimizing cost (extrapolation of current cost trends, optimized transmission build, longest coal power plant lifetime). Each core scenario then examines the impact of varying a key assumption (e.g., static costs) or adding an additional constraint (e.g., clean energy target). As additional sensitivities, we also examine the effects of precipitation variability on hydropower generation, limitations on natural gas capacity, and additional interactions between costs, transmission, and coal retirements. We evaluate the results in terms of optimal investments in generation, storage, and transmission infrastructure, as well as system costs and GHG emissions.

2. Results

2.1. Wind, solar, and hydropower potential

We quantified and characterized wind, solar PV, and hydropower resources in the region. For wind and solar, we spatially identified suitable candidate project sites by excluding low quality resources, protected areas, and unsuitable land-use land-cover types (e.g., forest cover, urban areas), and then quantified their installed capacity and energy generation potential (Fig. 1). We found that generation potential for both wind and solar PV exceeds future electricity demand (2040) in all countries, except Eswatini, which has lower land use and land cover suitability for large-scale solar despite relatively high solar radiation [22].

The region has large existing and potential hydropower capacity, with eight out of the twelve countries currently dependent on hydropower for more than half of their electricity generation (Fig. 1). Simulations of the VIC-Res-Southern-Africa hydrologic model show that the average hydropower generation potential exceeds future electricity demand (2040) in two countries—DRC and Mozambique—and exceeds half of the future demand in five additional countries—Angola, Lesotho, Namibia, Zambia, and Zimbabwe (Fig. 1).

2.2. New capacity and generation

Coal capacity has historically been a key generation technology for the region, but continued investments in this technology will likely be uneconomic with optimal transmission expansion. Results from the optimal, least-cost planning scenarios using the GridPath model show that no new coal capacity is required in any of the twelve countries of SAPP over the next 20 years, except when transmission capacity is constrained (Existing and Planned Tx scenarios) (Fig. 2A). In these

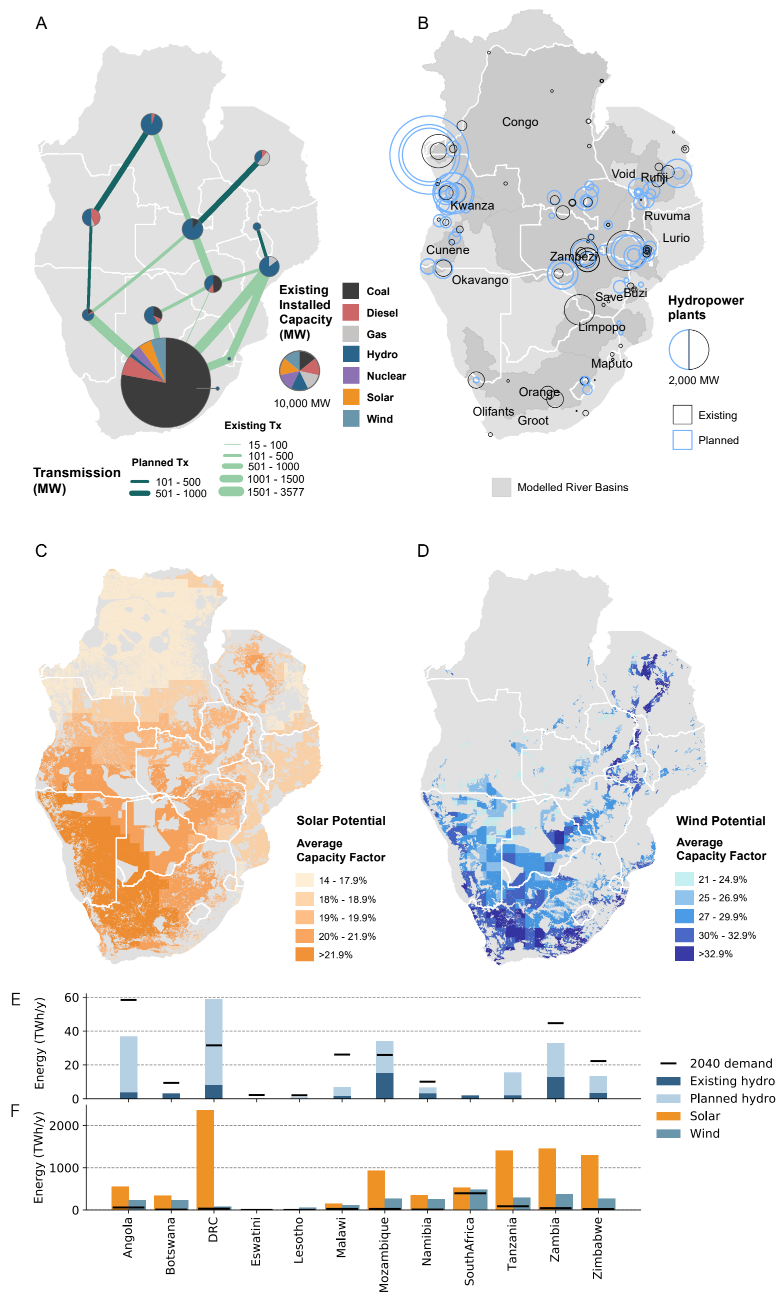

Figure 1: (A) Installed capacities (2017) and existing and planned interconnection lines, (B) Capacities of existing and planned hydropower dams, (C-D) Capacity factors of solar and wind projects, identified by MapRE analysis, (E) Average hydro-electricity availability from existing and planned dams, simulated by VIC-Res. Black segments represent the 2040 energy demands. Energy demand for South Africa and Tanzania is greater than the y-axis limit and is not shown in subfigure E, (F) Average solar and wind energy availability with 2040 energy demands.

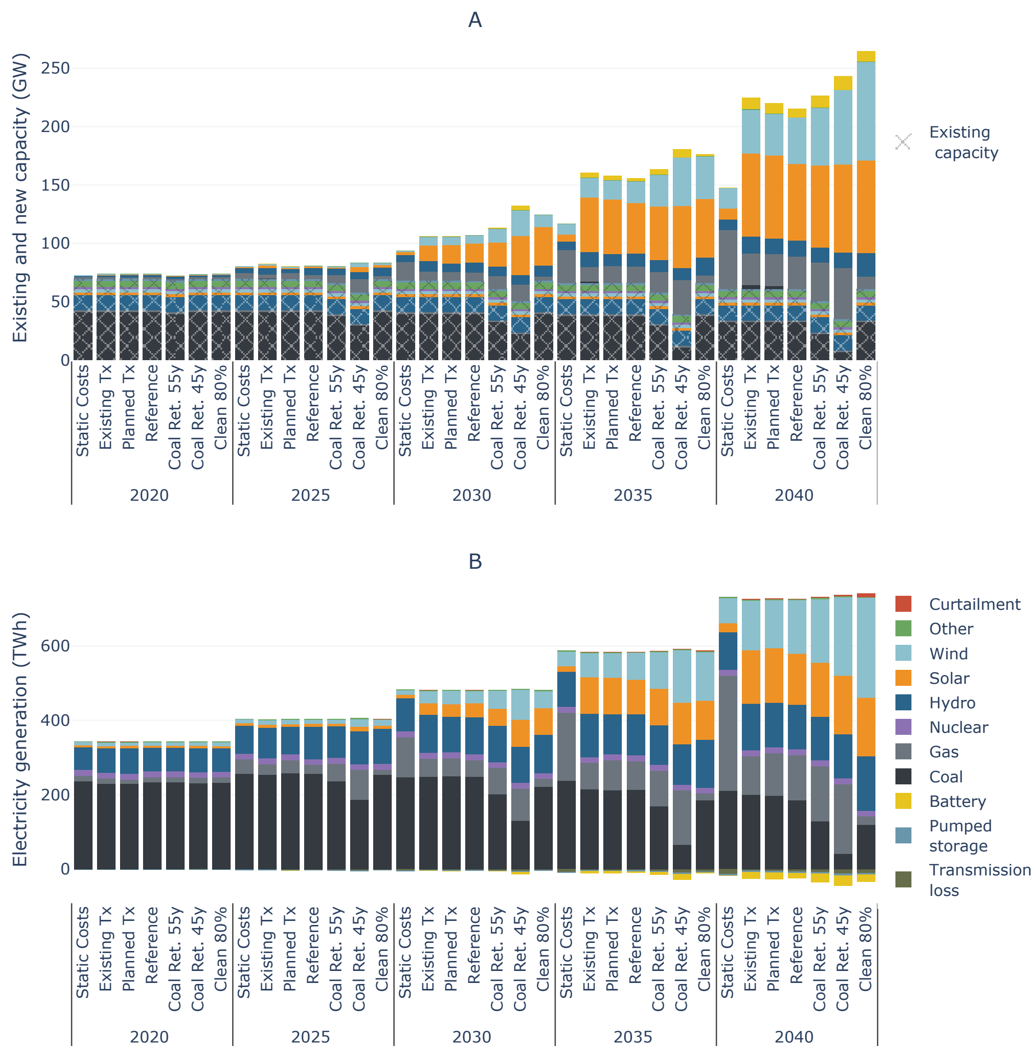

Figure 2: (A) Existing (hatched bars) and new (solid bars) generation capacities and (B) energy generation across 2020-2040 for seven core scenarios with varying renewable energy and fossil fuel costs, transmission capacity (Tx), retirement age of coal fleets, and an 80% clean energy target. Additional results for effects of limitations on natural gas capacity, additional interactions between technology and fuel costs, and hydro-climatological variability are provided in Fig. S1 and S2. Country-wise new generation capacities for the core and sensitivity scenarios are shown in Fig. S3-S8.

transmission-constrained scenarios, new coal power plants are deployed in South Africa, Malawi, and DRC because Malawi and DRC are not well connected to the rest of the SAPP, even when considering planned transmission (see Fig. S3). When transmission is constrained, new coal capacity is also required in South Africa, but only when renewable energy and fossil fuel costs remain static or when coal plants are retired 20 years early (45 year lifetime), thus replacing part of the retired capacity (Fig. S4). When GridPath is allowed to build as much new inter-regional transmission capacity as needed to minimize system costs, new coal capacity is completely avoided, even if technology costs do not change or existing coal plants are retired early. This highlights the pivotal role of additional transmission capacity along key corridors in the SAPP.

If technology and fuel costs follow anticipated trends, wind and solar technologies are likely to cost-competitively dominate future electricity generation investments in Southern Africa, and thus be the dominant source of electricity in the region by 2040. In all scenarios except Static Costs, wind and solar PV comprise the largest share of new capacity, varying from 23% to 42% and 36% to 44%, respectively, or 59% to 86% together (Fig. 2). In the Reference scenario, new solar PV and wind capacities of 66 GW and 40 GW, respectively, are deployed by 2040. To meet this requirement, the region would need to build 5 GW of variable renewable energy capacity every year until 2040, which is approximately five times the annual average installation rate from 2016 to 2020 [23, 24]. Note that capacity requirements are lower in earlier years and increase in later years—which may be enough time to develop the required human and institutional capacity. Balancing the additional variability of generation from new wind and solar capacity requires 7-12 GW of 4-6 hours of battery storage capacity. Most of the battery storage capacity is in South Africa because of its relatively inflexible coal generation fleet and its large capacity of wind and solar PV. In contrast, less than 1 GW of battery storage is required in the Static Costs scenario.

Commensurate with new capacity installations, shares of wind and solar energy together comprise the largest shares of total energy generation in 2040 across all but the Static Costs scenario. In the Static Costs scenario, share of wind and solar reaches only 12% and clean energy—which also includes nuclear, hydropower, and other renewable energy sources—meets only 29% of demand in 2040. However, in the Reference scenario, the cost-effective share of wind and solar generation more than triples to 39% and clean energy doubles to 58% in 2040 compared to the Static Costs scenario (Fig. 2). Retiring coal plants at 45 years further increases the share of clean energy to 70%, while the clean energy target policy has the highest clean energy share by meeting its explicit goal of 80%. Surprisingly, increasing inter-regional transmission capacity, which allows the region as a whole to access more lower-cost wind and natural gas resources in specific countries, does not have a significant effect on total renewable energy or clean energy shares, since there is a concomitant decline in solar and hydropower generation.

Retiring coal plants early can cut the share of coal generation by 75% in 2040. Limiting coal plants to lifetimes of 55 years and 45 years requires retiring 19 GW (49% of 40 GW installed) and 35 GW (88%), respectively, of existing coal capacity by 2040 compared to 9 GW (23%) if plants are retired after 65 years (Fig. S9). Consequently, the share of coal generation falls significantly by 2040 as coal plants retire early—18% for 55 years and 6% for 45 years, compared to 25% for 65 years.

Due to the region's significant existing and newly discovered natural gas reserves and greater flexibility of gas generators compared to coal power plants, natural gas becomes the largest source of conventional generation by 2040. In the Reference scenario, 28 GW of gas generation capacity is required by 2040. This is one-fifth of total new capacity and 18 times more than the region's existing gas installed capacity in 2020. While 13% of this capacity is built in South Africa, the rest is built in Angola, Mozambique, Namibia, and Tanzania. With more favorable costs for fossil fuels in the Static Costs scenario, natural gas becomes even more cost-competitive and its capacity almost doubles to 50 GW by 2040 compared to the Reference scenario.

2.3. Hydropower investments and generation

Despite the abundant availability of hydropower for future development (43 GW of planned capacity [1]), less than half of all planned hydropower capacity is needed in all scenarios. In the Reference scenario, only 14 GW or one-third of planned hydropower capacity is required (Fig. 2). If renewable energy and fossil fuel costs remain the same (Static costs scenario), hydropower capacity additions reduce to 9 GW or 21% of planned capacity, because fossil fuel plants outcompete the proposed hydropower projects. Even when coal plants are retired early, only a limited amount of new hydropower capacity is built. In the most favorable scenario for hydropower (Clean 80%), 20 GW or 47% of planned capacity is built. On the whole, at least 23 GW or just over half of planned hydropower capacity is uneconomic across all scenarios.

Notably, most projects planned in the DRC's Congo River basin, which has one of the highest levels of undeveloped hydropower potential in the world, are not required in any of our scenarios, including the most hydropower-favorable Clean 80% scenario (Fig. 3). These projects include the Inga dams, which are the largest proposed dams in the Southern African region [1]. Selection of hydropower projects is driven mainly by investment costs and annual capacity factors, but access to inter-regional transmission and favorable seasonal generation profiles also play a role. With increasing fossil fuel costs, more favorable costs for wind and solar (Reference scenario), and a higher clean energy target (Clean 80% scenario), more hydro projects are built, primarily those with lower capital costs and higher capacity factors (Fig. 3).

Contrary to prevailing assumptions among power system planners and investors [1, 11], new transmission interconnections, either optimally built or based on current plans, do not seem to allow or encourage more hydropower development (Fig. 2). In the Reference scenario where new transmission is built optimally, new hydropower capacity slightly decreases compared to the scenario with existing transmission capacity (See Fig. S3), and is replaced mainly by wind and natural gas capacity as explained next.

Figure 3: (A) Projected hydropower capacities built under different scenarios as a percentage (color-scale) of available planned capacities. Size of bubbles indicates planned capacities of projects aggregated by basin and country, ranging from 40 to 16,994 MW. (B) Relationship between capital costs and annual capacity factors of individual hydropower projects and their built status by scenarios. Size of bubbles indicates planned capacities of the individual projects, ranging from 30 to 7,942 MW.

2.4. Transmission interconnections and electricity trade

Transmission investments beyond planned capacity are needed to avoid new coal and expand development of low-cost wind and natural gas capacity. Across all scenarios that optimally build new transmission, inter-regional transmission capacity (defined by capacity-length or MW-km) increases by 40-130% (Fig. 4 and Table S1) compared to the existing transmission capacity in 2020. All scenarios with optimized transmission build 2-8 times more capacity along inter-regional corridors than in the Planned Tx scenario. Most of the optimally deployed transmission capacity is built after 2030, allowing sufficient lead time from present day. Importantly, more transmission capacity enables more wind capacity by providing access to better quality but geographically dispersed wind resources across the region, and provides greater access to natural gas resources in Angola, Tanzania, Mozambique, and Namibia to meet demand in the rest of the region. As a result, it avoids reliance on coal, specifically in Malawi and DRC, and some battery storage and large hydropower capacity.

Inter-regional electricity trade increases substantially in 2040 compared to 2020 across all scenarios, enabling the development of spatially heterogeneous low-cost renewable energy and natural gas resources (Fig. 4). By 2040, while electricity demand doubles, total electricity trade grows to four times the 2020 trade volume (Figs. 4G and S11) in the Reference scenario with optimal transmission and higher shares of renewables. Static Costs and early coal retirement scenarios show even greater electricity trade—about eight times the 2020 trade volume—mainly to enable greater natural gas generation exports from Angola, Mozambique, Tanzania, and Namibia. Thus, a high renewable energy system (Reference and Clean 80% scenarios) may require less transmission capacity and lower volumes of electricity trade compared to a regional system with a high natural gas generation capacity (Static costs and early coal retirement scenarios) (Fig. 4G) because of the concentration of natural gas resources in a few countries.

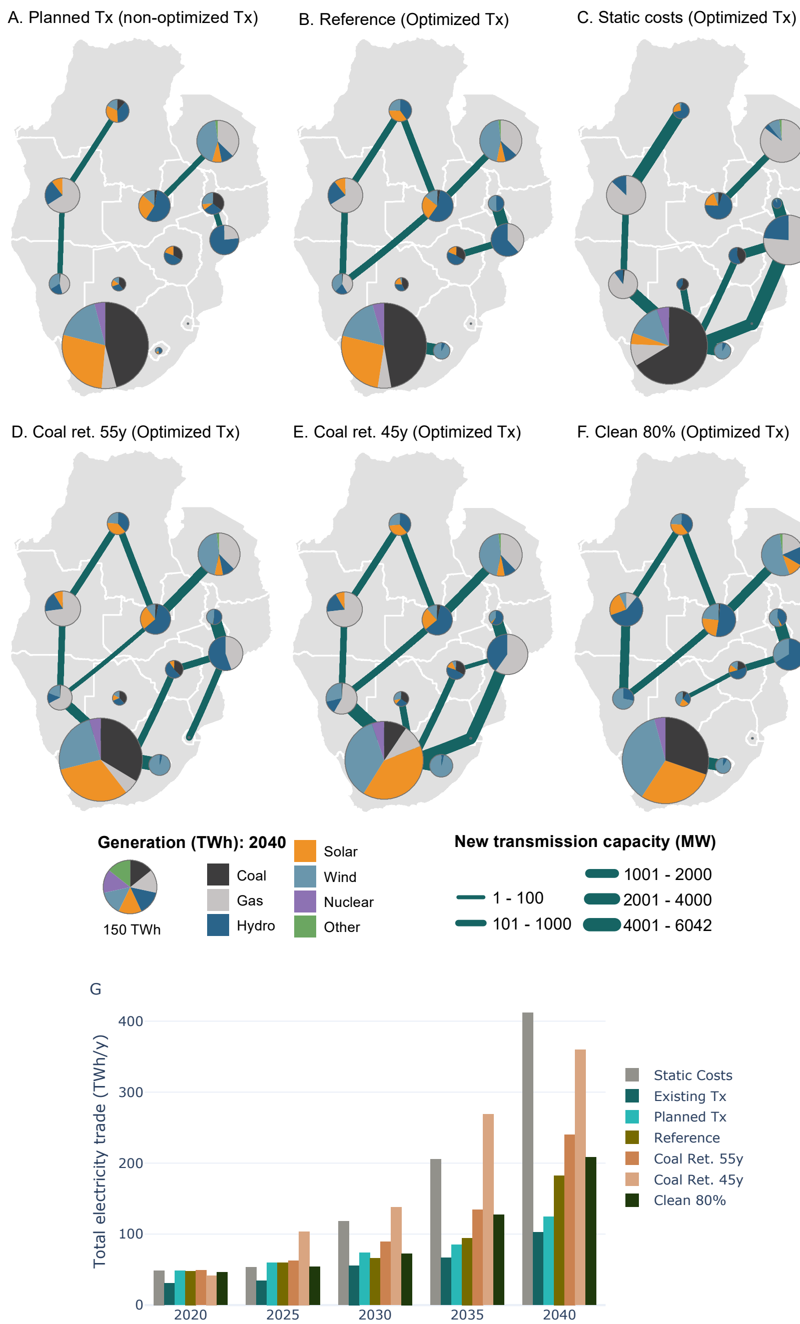

Figure 4: (A-F) New-built transmission capacity over 2020-2040, and country-wise generation mix for 2040 across six scenarios. 'Existing Tx' scenario does not consider new transmission, and thus, it is not shown. (G) Total electricity trade across SAPP over 2020-2040. New transmission capacity tabular results are provided in Tables S1 and S2.

2.5. System costs and emissions

Energy policy and market assumptions can significantly reduce GHG emissions with minor annual system costs increases, except if coal power plants are retired at 45 years. In the Reference scenario, GHG emissions in 2040 return to 2020 levels (Fig. 5). The Static Costs scenario is the upper bookend for GHG emissions—increasing nearly 50% over 2020 levels—because favorable costs encourage more fossil fuel capacity and generation. The Coal Ret 45y scenario has the lowest cumulative carbon emissions by 2040, with Clean 80% having similar annual emissions by 2040.

Early coal retirements limit GHG emissions but also result in higher system costs. Retiring coal plants 10 years earlier (55 year lifetime) results in 17% lower emissions in 2040 and only 4% higher costs compared to the Reference scenario. However, annual GHG emissions decrease by 48% when assuming 45 years lifetimes, yet costs increase by 13%.

Additional and planned transmission capacity alone only modestly increases system costs and reduces carbon emissions. This is because even in the Existing Tx scenario, electricity trade in 2040 is significantly greater than in 2020, thus capturing the benefits of utilizing existing transmission capacities for sharing resources and reducing system costs.

Adopting a high clean energy target (80%) can halve annual GHG emissions to levels comparable with a 45-year coal retirement policy in 2040, albeit with greater cumulative emissions. This higher clean energy target is cost-optimally met with an additional 14 GW (21% increase) of wind, 45 GW (110% increase) of solar, and 6 GW (46% increase) of hydropower capacity compared to the Reference scenario. Meeting the 80% clean energy target would result in annual costs that are 6% greater or 3 USD per MWh more than the reference scenario, resulting in an average carbon emission mitigation cost of 18 USD/MWh in 2040 (Fig 5). This annual cost increase in 2040 is less than half of that for the Coal Ret 45y scenario.

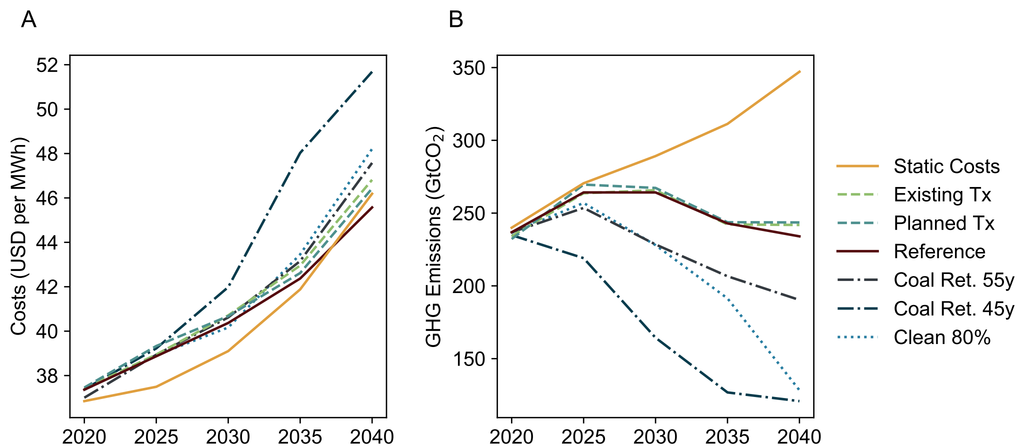

Figure 5: Annual system costs (operating and investment) and carbon emissions across 2020-2040 for the seven core scenarios. Capital costs of existing generation infrastructure are assumed to be the same and sunk across all scenarios. They are thus excluded from total systems costs. Costs depicted here all increase over time because fixed costs of existing infrastructure comprise a greater share of total costs in earlier years. This does not imply that average annual costs increase over time.

3. Discussion

3.1. ***Wind and solar will dominate if costs remain favorable***

In the absence of ambitious decarbonization policies, how renewable energy and fossil fuel costs change will be one of the most important determinants of the balance between wind, solar PV, and natural gas investments and generation. Continued reduction in wind, solar PV, and battery costs [19, 25] can cost-effectively enable Southern Africa's electricity system to limit its emissions to 2020 levels. But if costs remain static, least-cost investments would be dominated by natural gas capacity, and the region would require significant international financing and decarbonization policies to mitigate GHG emissions. Yet, historical trends and most forecasts are depicting a future with declining renewable energy and battery storage costs [26, 27] and increasing fossil fuel costs [1], thereby making a high renewable energy future much more plausible than one dominated by natural gas.

In this regard, our results are significantly different from those of previous studies, specifically the Southern African Power Pool Plan [1], which projects an electricity system dominated by coal, large hydropower, and natural gas, with wind and solar energy limited to only 2 GW, a small fraction of projected total capacity in 2040. Our results showing high shares of renewable energy are similar to those reported by recent studies that assume the latest technology cost projections but are focused only on the country of South Africa [13]. We find a more balanced share of new wind and solar capacity compared to more solar-dominated portfolios reported in other studies [10, 28].

3.2. ***Additional transmission capacity is needed to avoid new coal capacity, but early coal retirements or clean energy targets are needed to avoid coal generation***

Irrespective of cost trajectories, no new coal capacity is needed across any of the scenarios, except when new transmission is limited to current plans. This result reflects not only the large, high quality renewable resources available in the region but also the availability of cost-effective domestic natural gas resources. Yet, the share of coal generation in 2040 remains fairly high (25% in the Reference scenario and 16% in the Clean 80% scenario), unless coal plants are retired early. Early retirement results in low shares of coal generation and thus in reductions of carbon emissions as well as improved air quality and health outcomes—which have economic benefits that we did not quantify in this study [29]. However, early coal retirement have higher system costs because of the need to build replacement generation capacity.

In deciding whether and how early to retire coal capacity, policymakers and stakeholders must balance potential emissions savings with potential increases in system costs. International climate funding could not only provide the additional direct costs of retiring coal early but also finance the employment opportunities needed to ensure an equitable transition away from coal-based local economies [30]. For example, the US, UK, and EU recently committed to USD 8.5 billion to support the phaseout of coal in South Africa, the country with the most coal capacity and GHG emissions in Africa. As a comparison, we found that achieving 80% reduction in emissions from Southern Africa's electricity sector by 2040 will cost 9 billion USD more than the reference scenario, while the cost to retire coal power plants at 45 years will cost 17 billion USD more (Fig. S12). Note that these costs do not account for co-benefits or impacts including those from improved health outcomes, labor transitions, or GHG emission reductions. While the pledge to provide support for South Africa's energy transition is a commendable start, international financial commitments would benefit from being grounded in goals supported by analyses to understand how much support may be required to achieve a specific goal.

3.3. ***Most planned hydropower is uneconomic***

Hydropower has remained a cornerstone of electricity planning in the Southern African region largely due to the comprehensively-studied and inventoried hydropower potential in the region. However, large hydropower projects incur high upfront costs [31], often suffer from cost and time overruns [32, 33], have substantial environmental and social impacts [34, 35, 36, 37, 38], and are vulnerable to the impacts of climate extremes (e.g., droughts) [7, 39]. Results show that less than half of planned hydropower projects are selected irrespective of policy or cost assumptions, including an 80% clean, non-carbon target. Accounting for the risks of cost overruns and social and local environmental impacts would only further diminish the number of economic planned hydropower projects. We find that wind, solar PV, and battery storage are cost-effective and reliable alternatives to large hydropower, which is similar to findings in other developing regions, such as Southeast Asia and South America [40, 41, 42].

3.4. ***Significantly increasing electricity trade will be necessary for cost-optimal power system operations.***

Inter-regional electricity trade has declined in Southern Africa over the last decade [43]. However, if the Southern African electricity system were to operate cost-optimally, total electricity trade would need to increase by 15 times the current trade volume with Reference scenario assumptions, and 30 times with Static Costs scenario assumptions. Increasing electricity trade will require SAPP member countries to address generation supply and transmission constraints, make bilateral trades more flexible, and increase competitive market trading [44, 43]. However, increased market-based regional investments and dispatch may reduce national electricity sovereignty for some countries by relying on imports and will require institutional strength and political stability in the region to enable unhindered trade [28].

Increased transmission capacity in the absence of a clean energy target can enable cost and emissions savings but these savings are modest. However, our simplified transmission model may overestimate the limits of inter-regional electricity transfers by not capturing some technical and economic constraints other than fixed transmission losses. If existing inter-regional transfer capacities and flow limits are lower than our model assumptions, then additional transmission capacity will result in greater benefits.

In summary, the Southern African region has tangible opportunities for limiting future emissions from its electricity sector while also reducing electricity system costs. The key enabling factors are wind, solar PV, and battery storage technologies that continue to decline in cost. Importantly, all energy pathways only weakly rely on hydropower and most avoid new coal, thereby limiting GHG emissions, improving health impacts, and contributing to protect ecosystems of key global importance. Enabling these pathways would require decision-makers to critically reevaluate current power system plans that rely on new coal capacity and uneconomic planned hydropower projects. A transparent analytical planning approach with adequate representation of wind and solar potential and costs, as demonstrated in this study, would be critical in such a reevaluation.

4. Methods

4.1. Wind and solar resources

We adapted and built upon the Multi-criteria Analysis for Planning Renewable Energy (MapRE) modeling framework, which was first developed for and applied to regions in Africa [5]. MapRE is a spatial energy systems modeling framework that integrates renewable resource assessment and estimation of multiple criteria for decision making analysis [5]. Using wind and solar average resource data sets [45, 46], and applying constraints on elevation and slope [47, 48], and global and country-specific protected areas and land use land cover data sets (Table S3), we spatially identified suitable wind and solar PV sites across the twelve Southern African countries. We conducted the site-suitability analysis at a spatial resolution of 500 m, and then aggregated sites to 25 km and 100 km resolution for wind and solar PV, respectively. The higher spatial resolution for wind sites reflects the greater spatial variability in wind resources compared to solar.

Next, we developed hourly capacity factor time series for both wind and solar PV using historical weather data. We used the same year—2018—for creating the wind and solar generation profiles as the base electricity demand profile. For wind, we used hourly wind speed data from ERA5 (European Centre for Medium-Range Weather Forecasts - ECMWF - Reanalysis 5) [49]. We adjusted the coarser spatial resolution ERA5 data for each candidate site to match their annual averages to the average wind speeds at the nearest locations in the finer spatial resolution Global Wind Atlas (GWA) data [45]. Average wind speeds in the GWA data are derived from a higher temporal and spatial resolution data and are more accurate than ERA5, but GWA time series data is not publicly available. We then applied a Vestas 2 MW 90 m turbine power curve to the modified hourly wind speeds to derive hourly capacity factors using the System Advisor Model [50]. For solar PV, we used hourly global horizontal irradiance (GHI) data from the National Solar Radiation Database (NSRDB) derived from the Meteosat satellite [51]. We again used the System Advisor model [50] to covert GHI data to capacity factors for fixed tilt systems, setting the tilt equal to the latitude of each location.

To estimate levelized cost components of extending transmission interconnections and roads to new wind and solar projects, we first estimated distances of candidate projects to the nearest transmission and road infrastructure and then applied capital costs for 230 kV High Voltage Alternating

Current (HVAC) transmission lines [52] and asphalt roads to those interconnections.

4.2. Hydropower simulation

To generate energy availability data for each existing and planned hydropower project, we used a spatially-distributed hydrologic-water management model. Specifically, we established independent modelling instances for eight basins—i.e., Zambezi, Congo, Kwanza, Cunene, Rufiji, Orange, Limpopo, and Buzi—which encompass more than 90% of SAPP's total installed (∼13 GW) and projected (∼59 GW) hydropower capacity (Figure 1B). For each basin, we first used the Variable Infiltration Capacity (VIC) model (a large-scale, semi-distributed hydrological model; [53]) to simulate daily runoff, evaporation, and baseflow with a spatial resolution of 0.0625°(∼7 km × 7 km). The gridded runoff simulated by VIC is then routed through the river network by VIC-Res, a water management model that simulates daily river discharge as well as the storage and release dynamics of each reservoir [18]. In VIC-Res, each dam is represented by a cell, whereas multiple upstream cells represent the water body. The water release through turbines and spillway is determined by dam-specific rule curves accounting for the reservoir water level, inflow, storage capacity, and downstream water requirements (for irrigation and other purposes). The information on hydraulic head (H_t, calculated from storage) and release through turbines (R_t) is used with the gravitational acceleration (g), water density (ρ), and a non-dimensional turbine efficiency term (η) in equation (1) to calculate the daily (time, t) hydropower energy availability ($hydropower_t$) as:

$$hydropower_t = \eta \times \rho \times g \times R_t \times H_t. \tag{1}$$

Key inputs to VIC include a Digital Elevation Model (DEM) and data on soil, land use, land cover, precipitation, and temperature. The DEM and data on soil, land use, and land cover are adopted from [54], who used the 30-m DEM produced by the Shuttle Radar Topography Mission (SRTM) [47], the FAO Harmonized World Soil Database [55], and the USGS Global Land Cover Characterization (GLCC) dataset [56, 57]. For precipitation and temperature, we used daily-gridded data from CHIRPS [58] and NOAA Climate Prediction Center [59], respectively. To setup VIC-Res, we used the global flow direction map [60] with the same spatial resolution of VIC. The design specifications of existing and planned reservoirs are retrieved from global reservoir and dam databases [61, 62], and complemented by basin-specific studies on Zambezi [63], Congo [64], Cunene [65], Kwanza [66], Rufiji [67], and Orange [68].

We simulated daily streamflow and daily hydropower budget for the 1997–2016 period. Simulated streamflow at major dam locations closely match with the streamflow data presented in [69] (Fig. S13 A-B). Additionally, the annual and monthly average capacity factors of the dams are also validated against the capacity factors reported in [1] and [63] (Fig. S13 C-D). These validations ensure that the simulation of hydropower budget captures the hydro-climatic variability and operational constraints of the hydropower projects.

4.3. Electricity model and data

To identify cost-optimal electricity infrastructure investments in the SAPP, we used GridPath, an open-source power system modeling platform [15, 16]. Utilizing temporal and spatially-explicit demand, wind, solar, and hydro resource data along with various economic and technical constraints, GridPath's capacity-expansion functionality identifies cost-effective deployment of conventional and renewable generators, storage, and transmission lines by co-optimizing power system operations and infrastructure investments.

For this study, we developed the GridPath-SAPP model with 12 load zones, each representing a SAPP member country. These load zones are joined by transmission corridors that have existing, planned, and candidate transmission capacities. We modeled five investment periods—2020, 2025, 2030, 2035, and 2040—each representing 5 years. The model can build new infrastructure or retire existing infrastructure during an investment period. Each investment period has a discount factor—7% for this study—that is used to calculate net present value of costs incurred during that period. Within each investment period, grid infrastructure is dispatched to meet load and other constraints over 24 hours during 12 days, each representing a month, and weighted appropriately to represent a full year. Energy demand and supply is balanced in each modeled hour for each load zone. Hydropower and battery storage energy availability is constrained over each day.

The model co-optimizes investments (over each 5-year period) in new system infrastructure including generation, storage, and transmission, and hourly operating costs, while meeting country-wise hourly electricity demand, technical constraints on generators, storage, and transmission lines, and other policy constraints (e.g., clean energy targets). New generation capacities are selected linearly except for hydropower projects, which are discretely selected (binary decision). Thus, the model solves a mixed-integer linear programming problem. GridPath is written in Python and uses the Pyomo optimization language [70]. The Gurobi solver [71] was used for all simulations.

Key inputs to GridPath include projected hourly electricity demand for each investment period, installed and candidate generation capacities, hourly capacity factors of wind and solar generators, monthly energy availability of hydropower projects, and existing capacities and unit investment costs of transmission infrastructure. Other techno-economic parameters of the generators include fixed operating and maintenance (O&M) costs, variable O&M costs, heat rates, fuel costs, start-up costs, ramp rates, minimum operating levels, minimum up and down times, capital costs, plant lifetimes, emission per unit generation, storage charging and discharging efficiencies, and transmission losses. Major outputs are new-built capacities of generation, storage, and transmission, hourly electricity dispatch, curtailment, and transmission losses, exports and imports among the countries, operating and investment costs, and CO_2 emissions.

For electricity demand, we created hourly time series for each investment period based on actual 2018 data collected from the national utilities of SAPP member countries. For DRC and Botswana, because of lack of access to data, we assumed normalized demand profiles to be the same as Angola and South Africa, respectively. For each month, we first selected a representative day whose daily energy demand matched best with the average daily demand for that month. We then adjusted each country's hourly demand data to South African Standard Time and linearly extrapolated the demand across the investment periods based on annual growth rates and demand forecasts (Fig. S14) reported in [1]. Projected electricity demand profiles are shown in Fig. S15.

Existing generation capacities—mostly comprising of hydropower, coal, and natural gas, with small shares of nuclear, oil, diesel, biomass, wind and solar PV (Fig. 1A)—are adopted from [1]. Installed coal plants are assumed to retire at an age of 65 years as default according to the maximum economic lifetime of thermal plants [72], unless retired earlier in scenarios with shorter retirement ages (55 y. and 45 y.). Power plants are not retired endogenously. For new candidate generators, we considered coal projects in South Africa, Tanzania, Malawi, Zimbabwe, Mozambique, Zambia, Botswana, and

DRC, and natural gas projects in Tanzania, Mozambique, Angola, Namibia, South Africa and Zimbabwe, based on existing capacities in those countries [1]. We considered subcritical, supercritical, and integrated gasification combined cycle (IGCC) technologies for coal and open cycle gas turbine (OCGT), combined cycle gas turbine (CCGT), and internal combustion engine (ICE) technologies for natural gas generators. New coal and gas generators are assumed to utilize domestic fuels, except for the South African gas generators, which would operate on both domestic resources and higher-cost, imported liquefied natural gas (LNG). Candidate battery storage, oil, and diesel projects are considered for all countries. Small (<100 MW) biomass projects are considered only for Malawi, South Africa, Eswatini, and Tanzania [1]. Lastly, candidate wind and solar projects and their hourly capacity factor inputs are simulated using MapRE, and candidate hydropower projects adopted from [1] and their monthly energy availability inputs are determined by VIC-res. Other techno-economic parameters of the generators are from [1] and [73], while missing data are taken from global sources (Table S4). Wind, solar, and battery storage costs are from [1] and their trajectories are adopted from [19]. Coal and natural gas fuel cost projections are from [1] (Table S6). Emission factors for fuels are from [74] (Table S7).

We assumed full coordination among the SAPP countries, with only transmission losses and transfer capacities as constraints to electricity trade. Existing and planned interconnection transfer capacities (Fig. 1A and Fig. 4A) are adopted from [21, 20]. Angola, Tanzania, and Malawi do not have existing connections but have planned connections to the rest of the SAPP. In scenarios other than the Existing Tx and Planned Tx scenarios, GridPath optimally builds new transmission capacities along existing and planned transmission corridors. Lengths of the interconnectors are estimated using centroids of countries. Investment costs for new transmission lines and substations are from [75]. Annualized costs are scaled by ratios of thermal and applicable transfer limits along each corridor based on [21] (Table S5). For both existing and new lines, we assume bulk transmission losses of 1% per 100 miles [76].

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Author contributions

R.D., G.W., and K.N. conceptualized the study and acquired the funding. R.D., K.C., G.W., and A.M. developed the methodology and software. K.C., R.D., and A.U. conducted the formal analysis. K.C., R.D., A.U., T.C., and L.A. curated the data. R.D., K.C., G.W., A.M., S.G., and K.N. wrote and edited the paper. R.D. and K.N. supervised the project.

Declaration of Interest

None

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Supplemental Items

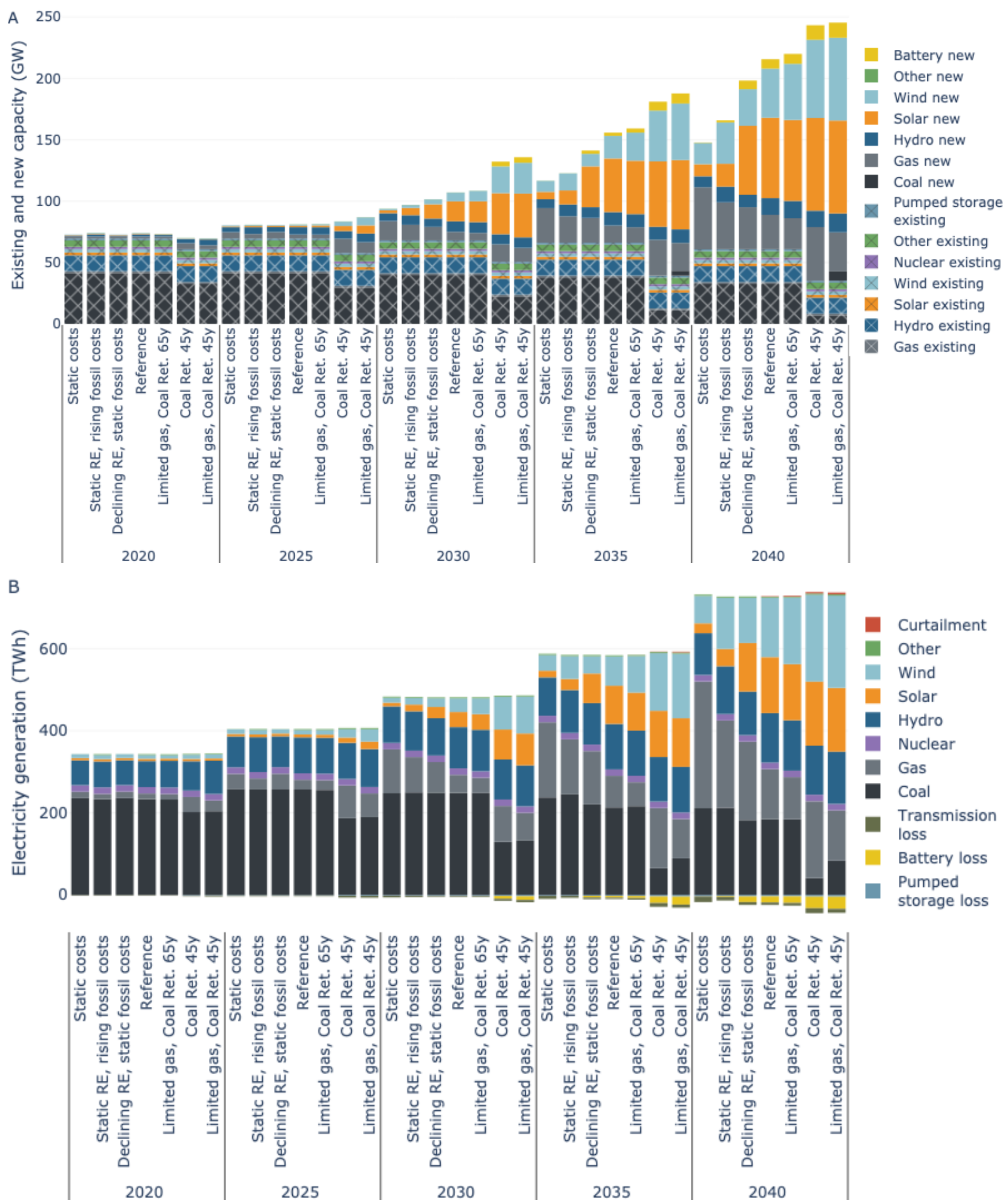

Figure S1: (A) Existing and new generation capacities and (B) energy generation across 2020-2040 for the reference and sensitivity scenarios with varying renewable energy and fossil fuel costs and limited gas with coal retirement at 65 and 45 years.

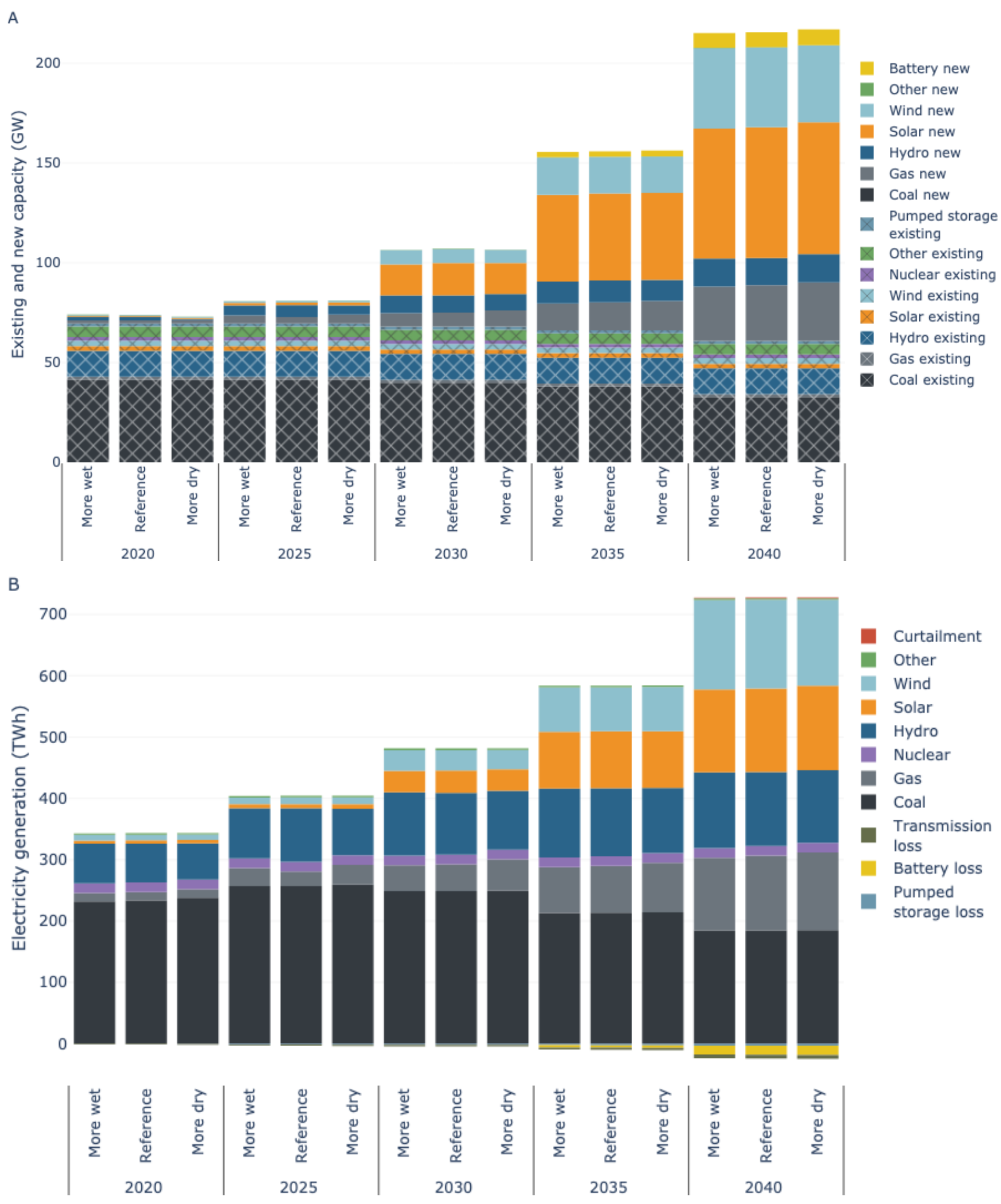

Figure S2: (A) Existing and new generation capacities and (B) energy generation across 2020-2040 for the reference and sensitivity scenarios with wet and dry climate years. Wet and dry years are chosen from historical data from 1997-2016 (see Fig. S10).

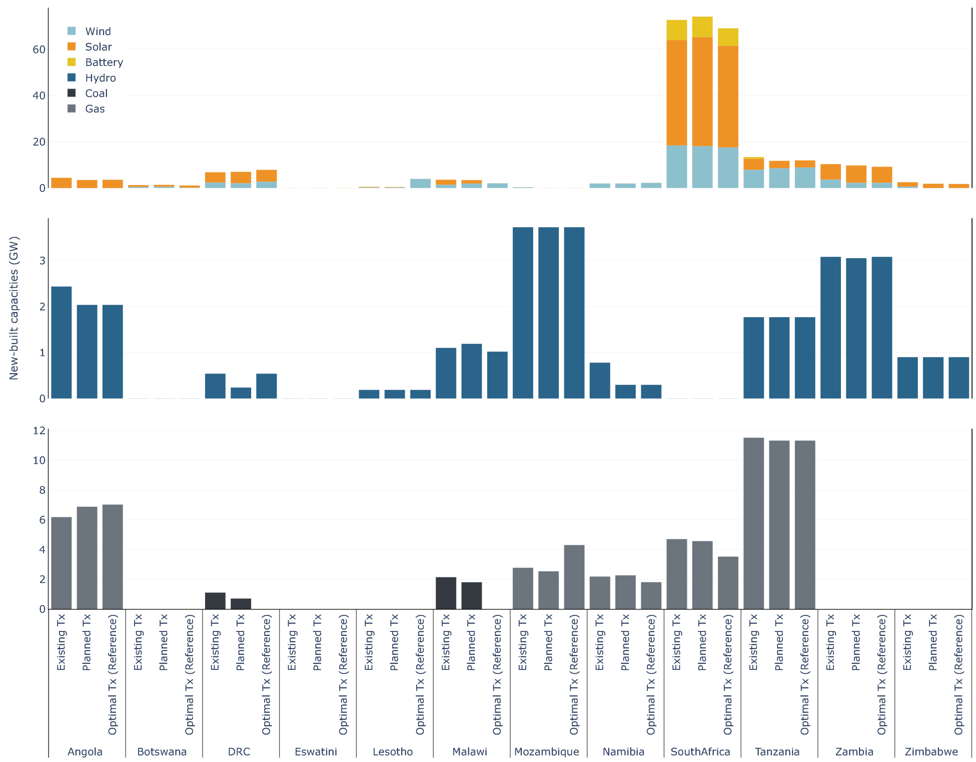

Figure S3: Country-wise new capacity across 2020-2040 for scenarios with existing, planned, and optimized transmission interconnections.

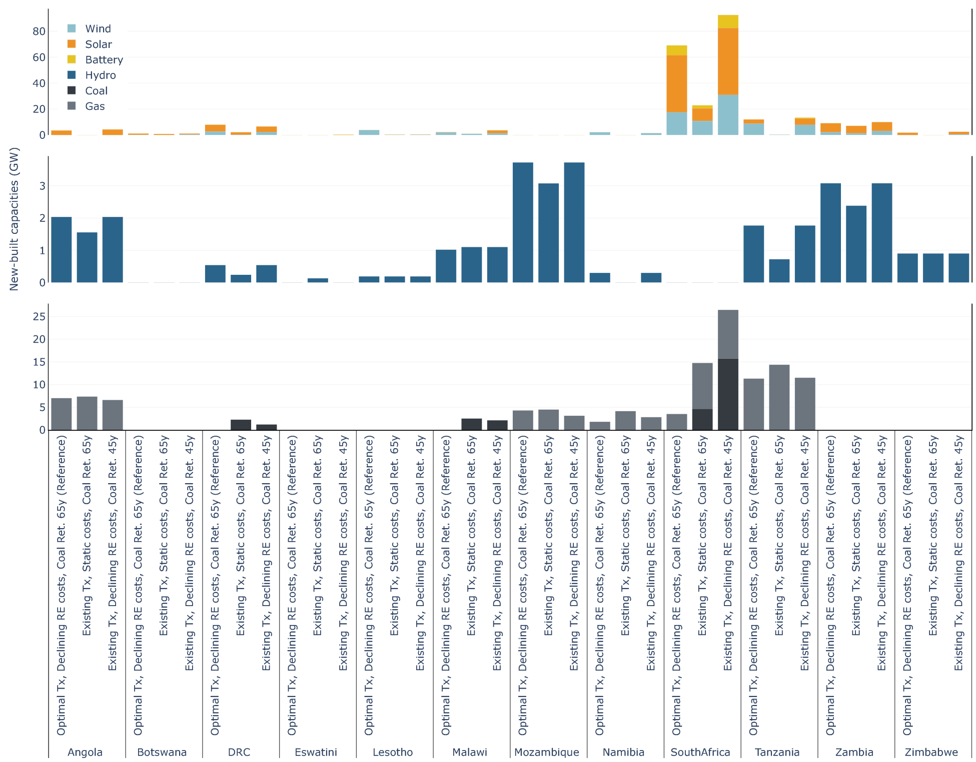

Figure S4: Country-wise new capacity across 2020-2040 for scenarios of existing transmission interconnections with static costs or coal retirement age of 45 years, compared against the reference scenario with optimal transmission, declining RE costs, and coal retirement age of 65 years.

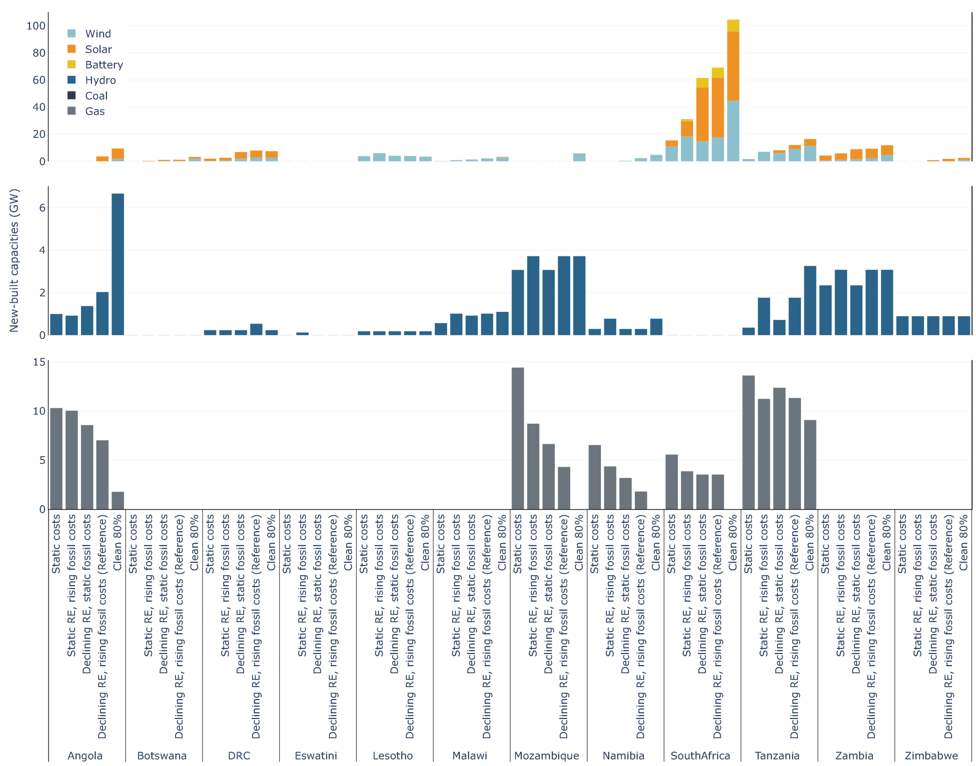

Figure S5: Country-wise new capacity across 2020-2040 for scenarios with varying renewable energy and fossil fuel costs and 80% clean energy.

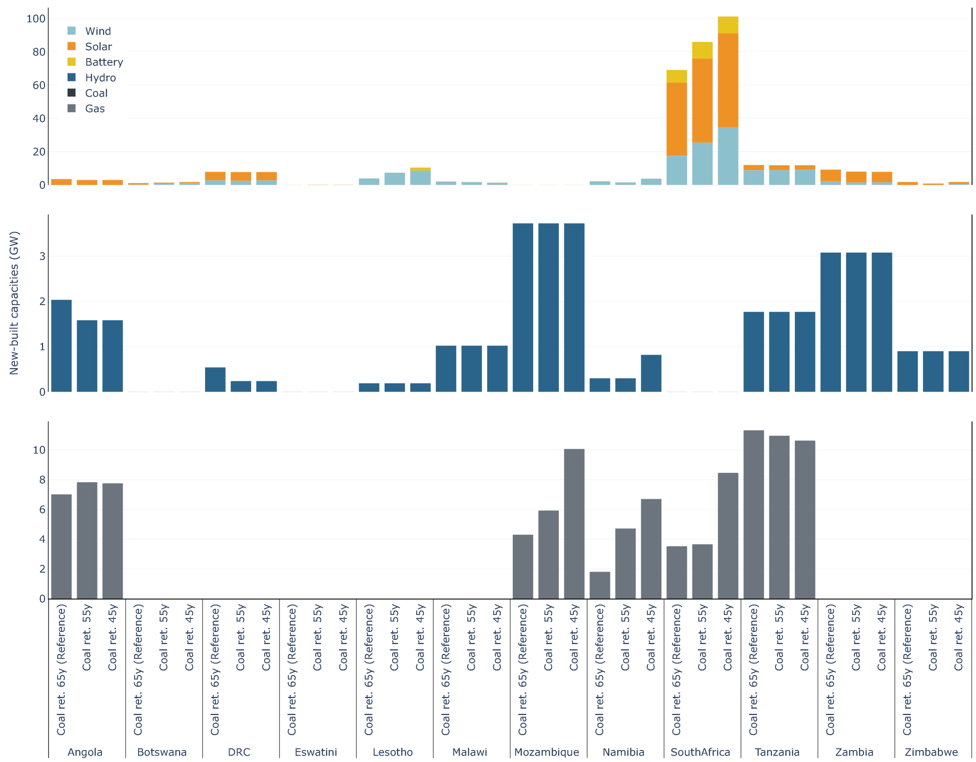

Figure S6: Country-wise new capacity across 2020-2040 for scenarios with varying coal power plant retirement ages.

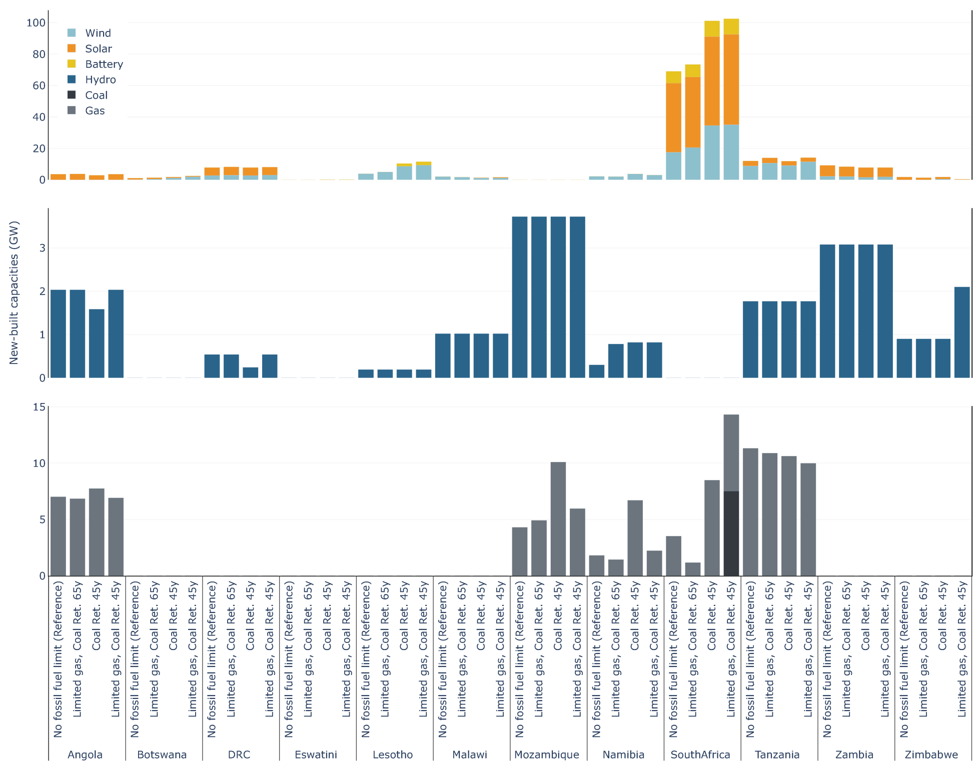

Figure S7: Country-wise new capacity across 2020-2040 for scenarios with 65 year and 45 year coal retirement ages and limited natural gas capacity.

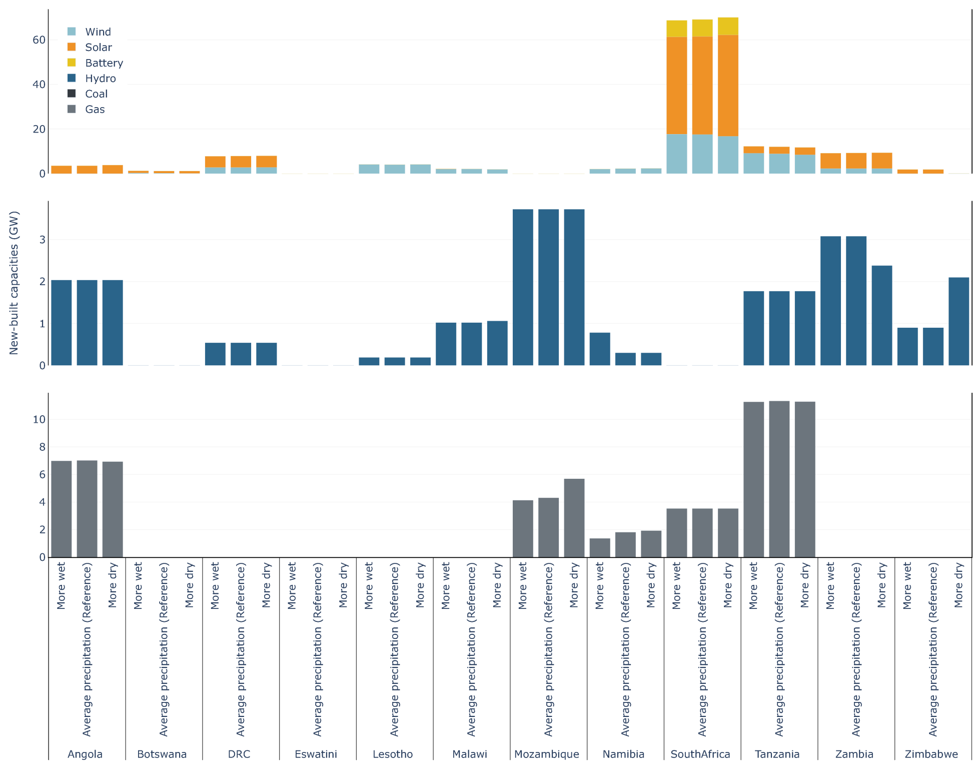

Figure S8: Country-wise new capacity across 2020-2040 for scenarios with historical dry and wet years for hydropower.

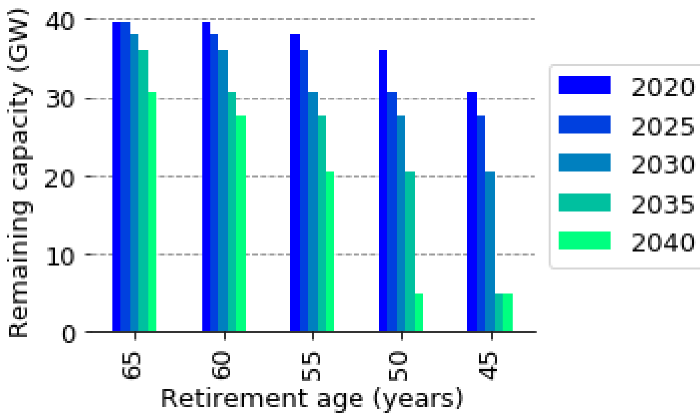

Figure S9: Total usable capacity of South Africa's coal power plants over 2020-2040 planning period at different scenarios of retirement ages.

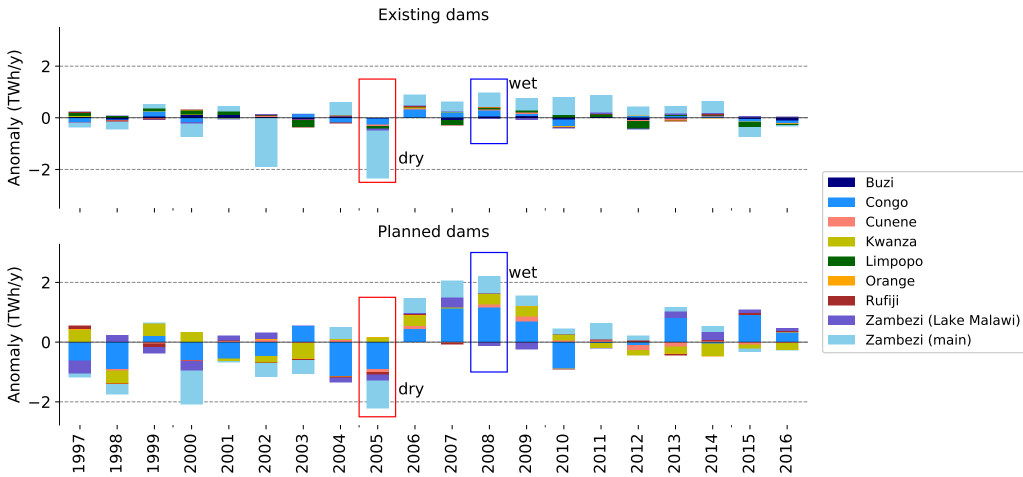

Figure S10: Anomalies of annual hydropower availability (TWh/y) at existing (upper panel) and planned (bottom panel) dams over 1997-2016. Red and blue rectangles indicate anomalies in the dry (2005) and wet (2008) years selected for sensitivity analysis.

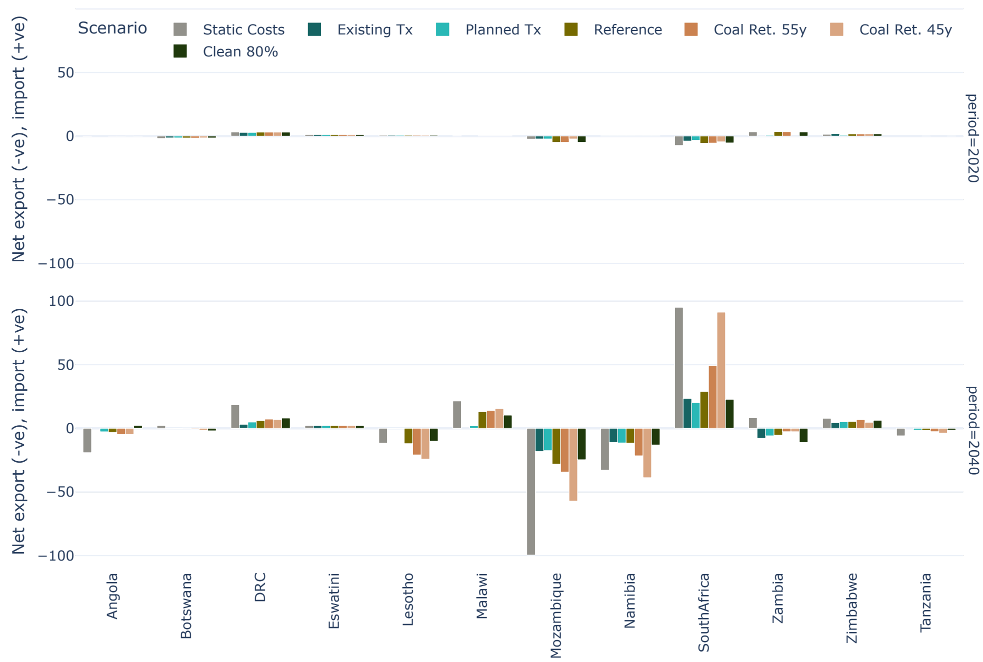

Figure S11: Net export (-ve values) and import (+ve values) of electricity (TWh/y) by each country in 2020 and 2040.

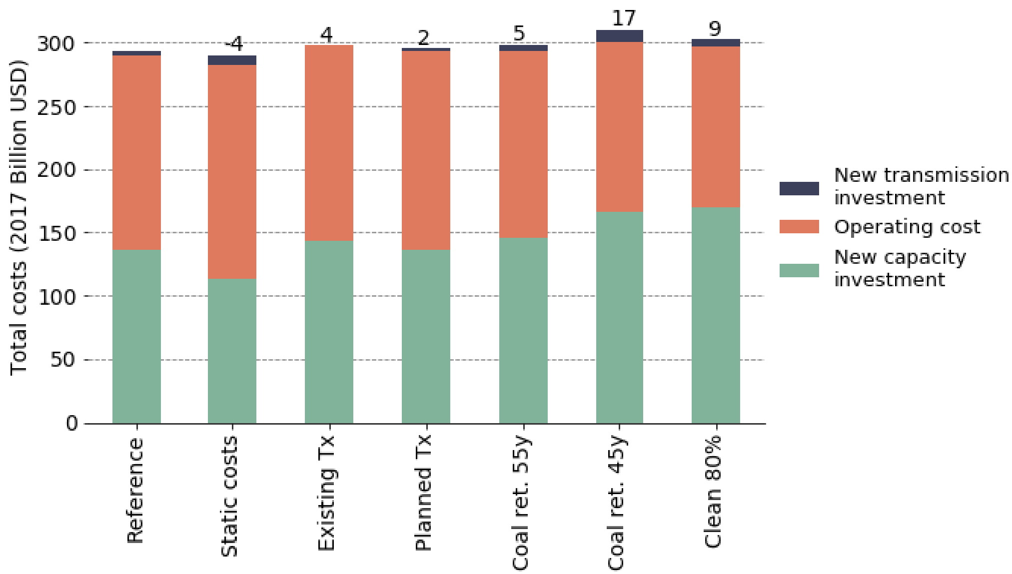

Figure S12: Net present value of total costs (new generation, storage, and transmission capacity investments and operations) from 2020 to 2045.

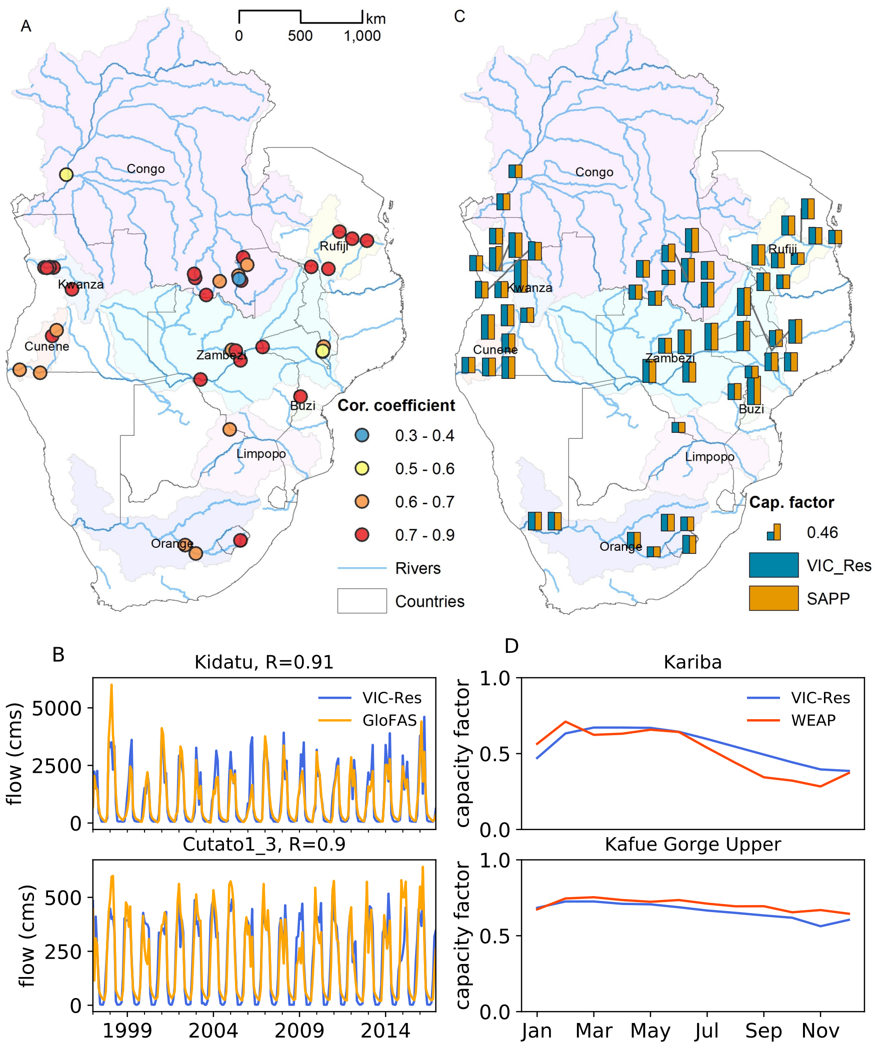

Figure S13: (A) Correlation coefficients (R) between streamflow simulated by VIC-Res (this study) vs GloFAS [69] at major dams across eight modelled basins (indicated by the shades). (B) VIC-Res vs GloFAS streamflow for 1997-2016 period at two representative dams. (C) Comparison of annual capacity factors simulated by VIC-Res vs the factors reported in [1]. (D) Comparison of monthly capacity factors simulated by VIC-Res and WEAP [63] at two dams in the Zambezi.

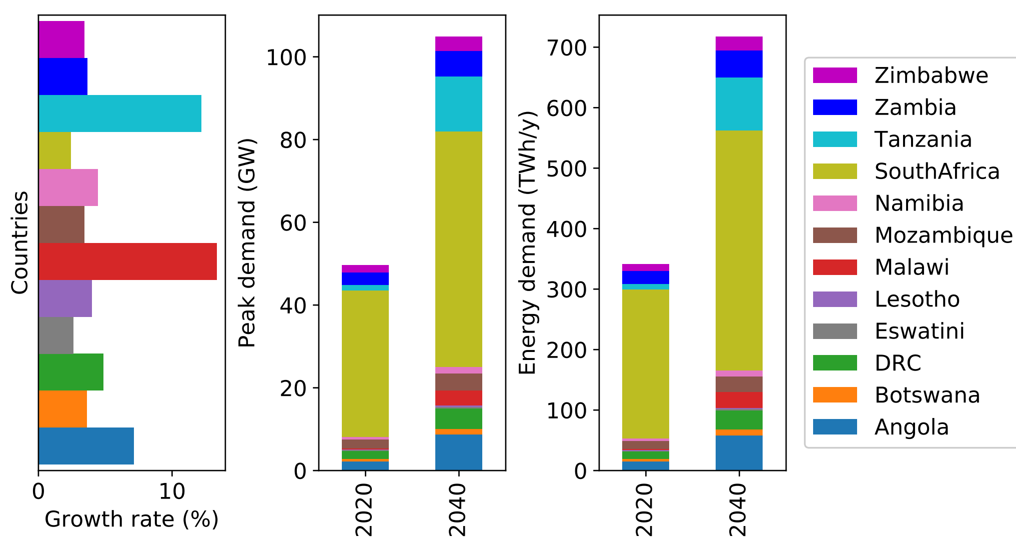

Figure S14: Electricity demand growth rate (SAPP, 2017), and estimated peak load (MW) and annual energy demand (TWh/y) for 2020 and 2040.

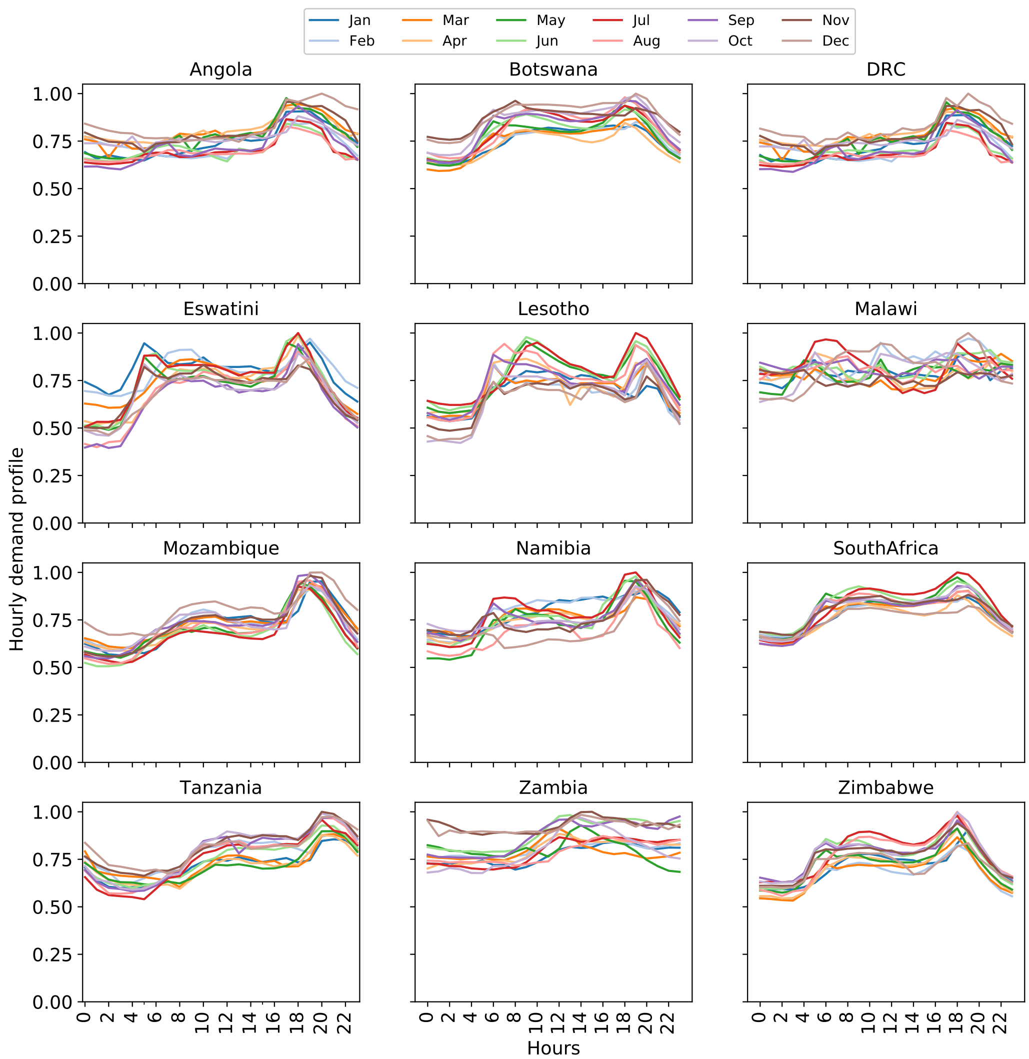

Figure S15: Hourly demand profiles for each month, estimated from hourly electricity demand (MW) data (collected from utilities) of each country for the year 2018. Time scale in x-axis is in South African Standard Time.

Table S1: Total new transmission capacity built across six core scenarios (except Existing Tx scenario in which no new capacity is built).

scenario	total capacity (MW)	total length (km)	total capacity-length (MW-km) ratio
Planned Tx	2300	3900	1
Static Costs	21100	9800	7.4
Reference	8300	7600	2.2
Coal Ret. 55y	13700	11000	3.9
Coal Ret. 45y	23600	12500	8
Clean 80%	9000	8300	2.8

Table S2: New transmission capacity (MW) built along inter-regional transmission corridors across six core scenarios (except Existing Tx scenario in which no new capacity is built).

transmission_line	Planned Tx	Static Costs	Reference	Coal Ret. 55y	Coal Ret. 45y	Clean 80%
Angola_Namibia	300	130	190	260	310	1010
DRC_Angola	600	2170	630	830	780	320
DRC_Zambia	0	0	440	370	420	900
Malawi_Mozambique	400	2860	2280	2310	2330	2140
Mozambique_Eswatini	0	4050	0	330	3340	0
Mozambique_Zimbabwe	0	1000	550	530	90	670
SouthAfrica_Botswana	0	170	0	0	100	0
SouthAfrica_Eswatini	0	3380	0	0	2780	0
SouthAfrica_Lesotho	0	3030	3020	5440	6080	2500
SouthAfrica_Mozambique	0	0	0	0	0	0
SouthAfrica_Namibia	0	2570	0	1630	4410	0
SouthAfrica_Zimbabwe	0	740	0	730	920	0
Tanzania_Zambia	1000	1000	970	1250	1500	1060
Zambia_Namibia	0	0	220	0	520	410
Zambia_Zimbabwe	0	0	0	0	0	0
Zimbabwe_Botswana	0	0	0	0	0	30

Supplemental experimental procedures

Wind and solar resource assessment

Table S3: Description and sources of input data used in MapRE.

Category	**Type**	**Data Source**	**Year**
Boundaries	Vector	GADM V3.6, URL: https://gadm.org/download_country.html	2018
Elevation, Slope	Raster	SRTM CGIAR-CGI V4.1 by CGIAR Consortium for Spatial Information (CGIAR-CSI), URL: https://cgiarcsi.community/data/srtm-90m-digital-elevation-database-v4-1/	2008
Land Use Land Cover	GeoTIFF	Land Cover CCI Climate Research Data Package (CRDP) by European Space Agency - Climate Change Initiative (ESA-CCI), URL: http://maps.elie.ucl.ac.be/CCI/viewer/download.php	2015
Water Bodies	Shapefile	Global Lakes and Wetlands Database by World Wildlife Fund (WWF), URL: https://www.worldwildlife.org/pages/global-lakes-and-wetlands-database	2004
Rivers	Shapefile	Natural Earth V4.1.0, URL: https://github.com/nvkelso/natural-earth-vector/tree/v4.1.0	2018
Population Density	Raster	LandScan Datasets by Oak Ridge National Laboratory (ORNL), URL: https://landscan.ornl.gov/landscan-datasets	2018
Protected areas	Shapefile	World Database on Protected Areas (WDPA) by United Nations Environment Programme (UNEP) and International Union for Conservation of Nature (IUCN), URL: https://www.protectedplanet.net/en/thematic-areas/wdpa?tab=WDPA	2019
Roads	Shapefile	GRIP global roads database, URL: https://www.globio.info/download-grip-dataset	2010
Transmission	Shapefile	Africa - Electricity Transmission And Distribution Grid Map by World Bank, URL: https://datacatalog.worldbank.org/search/dataset/0040465	2017
Wind	TIFF	World Bank Global Wind Atlas, URL: https://globalwindatlas.info/download/maps-country-and-region	2018
Solar	TIFF	World Bank Global Solar Atlas, URL: https://globalsolaratlas.info/download	2018

Input data assumptions for electricity system planning model

Table S4: Technical and economic parameters of generation technologies.

Technology	Capital cost[1] (USD /kW)	O&M cost[2] (USD /kW)	Fixed cost[2] (USD /MW/yr)	Variable O&M cost[2] (USD/MWh)	Heat rate (MMBtu /MWh)	Start-up cost (USD /MW)	Min. up time (hours)	Min. down time (hours)	Ramp rate (%MW/ minute)	Lifetime (years)
Bioenergy	4263	142.8	142800	5.7	13.5	129	12	12	2	30
Coal (Subcritical)	2377	79.8	79800	6.9	9.3	129	24	12	2	30
Coal (Supercritical)	3739	79.8	79800	6.9	9.3	129	24	12	2	30
Coal (IGCC)	5779	122.7	122700	6.5	9.2	129	24	12	2	30
Gas (OCGT)	835	13.8	13800	4.8	10.9	79	0	0	8	30
Gas (CCGT)	1065	14.3	14300	5.2	7	79	10	8	5	30
Gas (ICE)	1140	12.9	12900	5.6	6.9	79	10	8	10	30
Diesel	1140	13.8	13800	5.6	11.48	69	0	0	10	30
Oil	1140	13.8	13800	5.6	11.48	69	1	1	10	30
Nuclear	6137	20		3.2	10.45					40
Geothermal	3500			10						30
Hydro	varying[4]			4.5						60
Wind	varying[5]	44	52300							25
Solar PV	varying[5]	14	24400							25
Battery	varying[5]	53.3	53300							15
Pumped-storage	3500	15.6	15600							50

[1] Capital costs are from [1].
[2] O&M costs, fixed costs, variable O&M costs, heat rates, and lifetime data are from [73].
[3] Other data from different global sources including [72].
[4] Project-specific capital costs of hydropower projects varies between 788-6,510 USD/kW with an average cost of 3,410 USD/kW, adopted from [1].
[5] Capital costs of wind, solar PV, and battery varies over 2020-2040 as shown in Table S6.

Table S5: Economic parameters of transmission technologies.

Technology	Transmission capital cost (USD/MW-km)	Substation x 2 capital cost (USD/MW)
500 kV Double Circuit Line	960	22,470
230 kV Single Circuit Line	1,740	60,300

[1] Costs assumptions are from [52].

Table S6: Capital costs of wind, solar PV, and battery technologies, and fossil fuel prices.

		2017	2020	2025	2030	2035	2040
Capital costs[1]							
Wind	(USD/kW)	1720	1600	1401	1201	1120	1038
Solar PV	(USD/kW)	990	804	654	503	431	377
Battery	(USD/kWh)	668	472	292	197	178	159
Fuel prices[1]							
Coal	(USD/MMBtu)	2.6	2.7	2.8	2.9	3.1	3.2
Gas	(USD/MMBtu)	3	3.2	3.5	3.8	4	4.3
Gas (LNG)	(USD/MMBtu)	9.6	10.2	11.2	12.3	13.3	14.3
Oil	(USD/MMBtu)	8.5	9.6	11.5	13.3	15.2	17
Diesel	(USD/MMBtu)	11.3	12.8	15.2	17.6	20.1	22.5

[1] Wind, solar PV, and battery cost assumptions for 2017 are from [1]. Decline rates are from [19].

[2] Fossil fuel price assumptions for 2017 and escalation rates are from [1].

Table S7: Emission factors for fuels

Fuel	Emission factor (tCO_2/MMBtu)
Coal	0.106
Biomass	0.106
Natural gas	0.058
Oil	0.08
Diesel	0.08

[1] Costs assumptions are from [74].

Electricity System Model (GridPath) Formulation

Set	**Index**	**Description**
Π	π	Years or periods when investment decisions are made.
Δ	δ	Horizons over which storage/hydro is balanced.
$\Delta^{\pi} \subset \Delta$	δ^{π}	Horizons within an investment period π.
T	τ	Timepoints when operational decisions are made.
$T^{\pi} \subset T$	τ^{π}	Operational timepoints in investment period π.
$T^{\delta} \subset T$	τ^{δ}	Operational timepoints in a sampled day δ.
	π^{τ}	The year in which timepoint τ occurs.
	δ^{τ}	The sampled day during which timepoint τ occurs.
	hr^{τ}	Number of hours in timepoint τ.
Z	z	Load zones (or nodes).
ZF	zf	'From' load zones (or nodes) for transmission lines.
ZT	zt	'To' load zones (or nodes) for transmission lines.
BAR	bar	Balancing areas for regulation reserves.
BAS	bas	Balancing areas for spinning reserves.
RZ	rz	Renewable or clean energy target zones.
Γ	γ	All generator and storage projects.
$\Gamma^{\epsilon} \subset \Gamma$	γ^{ϵ}	Specified (including existing) generator and storage projects.
$\Gamma^{\nu} \subset \Gamma$	γ^{ν}	Candidate generator and storage projects.
$\Gamma^{\mu} \subset \Gamma$	γ^{μ}	Must-run generators (e.g. nuclear, biomass, biogas).
$\Gamma^{\phi} \subset \Gamma$	γ^{ϕ}	Dispatchable generators (e.g. CCGT, OCGT, Coal).
$\Gamma^{\omega} \subset \Gamma$	γ^{ω}	Variable generators (e.g. wind, solar).
$\Gamma^{\sigma} \subset \Gamma$	γ^{σ}	Storage projects (e.g. battery, pumped hydro).
$\Gamma^{\chi} \subset \Gamma$	γ^{χ}	Hydro projects.
$\Gamma^{z} \subset \Gamma$	γ^{z}	Projects associated with a load zone.
$\Gamma^{rz} \subset \Gamma$	γ^{rz}	Projects associated with a renewable/clean energy target zone.
Λ	λ	All transmission lines.
$\Lambda^{\epsilon} \subset \Lambda$	λ^{ϵ}	Specified (including existing) transmission lines.
$\Lambda^{\nu} \subset \Lambda$	λ^{ν}	Candidate transmission lines.

Variable	Description
$CB_{\gamma^{\nu},\pi} \geq 0$	Power capacity to install at each candidate project in each investment period.
$CE_{\gamma\subset\Gamma^{\nu}\cap\Gamma^{\sigma},\pi} \geq 0$	Energy capacity (i.e. power $\times$ duration) to install at candidate storage project in each investment period.
$B_{\gamma^{\pi}} \geq 0$	Power capacity at each project in each investment period.
$E_{\gamma\subset\Gamma^{\sigma},\pi} \geq 0$	Energy capacity (i.e. power $\times$ duration) to at each storage project in each investment period.
$U_{\gamma^{\phi},\tau} \geq 0$	Commitment level of each dispatchable generator in each timepoint.
$O_{\gamma,\tau} \geq 0$	Power output from each generator in each timepoint.
$C_{\gamma^{\sigma},\tau} \geq 0$	Charging of each storage project in each timepoint.
$D_{\gamma^{\sigma},\tau} \geq 0$	Discharging from each storage project in each timepoint.
$F_{\gamma^{\sigma},\tau} \geq 0$	Energy available in storage at the start of an timepoint.
$CUR_{\gamma\subset\Gamma^{\omega}\cap\Gamma^{\chi},\tau} \geq 0$	Output curtailment of each variable or hydro project in each timepoint.
$Reg^{up}_{\gamma\subset\Gamma^{\phi}\cap\Gamma^{\sigma}\cap\Gamma^{\chi},\tau} \geq 0$	Regulation up provision from each dispatchable, storage, or hydro project in each timepoint.
$Reg^{down}_{\gamma\subset\Gamma^{\phi}\cap\Gamma^{\sigma}\cap\Gamma^{\chi},\tau} \geq 0$	Regulation down provision from dispatchable, storage, or hydro projects in each timepoint.
$Spin_{\gamma\subset\Gamma^{\phi}\cap\Gamma^{\sigma}\cap\Gamma^{\chi},\tau} \geq 0$	Spinning reserve provision from each dispatchable, storage, or hydro project in each timepoint.
$UE_{z,\tau} \geq 0$	Unserved energy at each zone in each timepoint.
$OE_{z,\tau} \geq 0$	Overgeneration energy at each zone in each timepoint.
$CL_{\lambda^{\nu},\pi} \geq 0$	Transmission line capacity to install at each candidate transmission line in each investment period.
$T\_max\_cap_{\lambda,\tau}$	Transmission maximum capacity in each timepoint.
$T\_min\_cap_{\lambda,\tau}$	Transmission minimum capacity in each timepoint.
$O_{\lambda,\tau}$	Transmission flow on a transmission line in each timepoint.
$T\_loss_{\lambda,zf,\tau} \geq 0$	Transmission line loss at the originating (from) load zone in each timepoint.
$T\_loss_{\lambda,zt,\tau} \geq 0$	Transmission line loss at the destination (to) load zone in each timepoint.

Parameter	Description
$D_{z,\tau}$	Electricity demand or load at load zone in timepoint τ.
Π^f	First investment period.
$disc\_factor$	Discount factor derived from the discount rate to calculate net present value.
$n\_years\_rep_\pi$	Number of years represented by each investment period.
tp_weight_τ	Weight of each timepoint based on number of timepoints or hours it represents in a year.
$B\_max_{\gamma^\nu,\pi}$	Maximum cumulative power capacity installed at each candidate project in each investment period.
$E\_max_{\gamma\subset\Gamma^\nu\cap\Gamma^\sigma,\pi}$	Maximum energy capacity (i.e. power $\times$ duration) installed at candidate storage project in each investment period.
$SB_{\gamma^\epsilon,\pi}$	Specified power capacity (including existing) installed at each project in each investment period.
$SE_{\gamma\subset\Gamma^\epsilon\cap\Gamma^\sigma,\pi}$	Specified energy capacity (i.e. power $\times$ duration) installed at storage project in each investment period.
$MSL_{\gamma^\phi,\tau}$	Minimum Stable Level of each dispatchable generator in each timepoint.
$Charging\_Eff_{\gamma^\sigma}$	Charging efficiency of storage project.
$Discharging\_Eff_{\gamma^\sigma}$	Discharging efficiency of storage project.
$CL\_max_{\lambda^\nu,\pi}$	Maximum transmission capacity installed at each candidate transmission line in each investment period.
$SL\_max_{\lambda^\epsilon,\pi}$	Specified transmission maximum capacity in each investment period.
$SL\_min_{\lambda^\epsilon,\pi}$	Specified transmission minimum capacity in each investment period.
$T\_loss\_factor_\lambda$	Transmission loss factor for transmission line.

Capacity Constraints

Candidate project capacity cannot exceed pre-defined limits.

$$\sum_{\pi=\pi^f}^{\pi} CB_{\gamma,\pi} \leq CB\_max_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\nu}$$

$$\sum_{\pi=\pi^f}^{\pi} CE_{\gamma,\pi} \leq CE\_max_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\sigma} \cap \Gamma^{\nu}$$

$$\sum_{\pi=\pi^f}^{\pi} CL_{\lambda,\pi} \leq CL\_max_{\lambda,\pi} \qquad \forall \lambda \in \Lambda^{\nu}$$

Total project power and energy capacity at each project is a sum of selected candidate projects and specified projects

$$B_{\gamma,\tau^{\pi}} = \begin{cases} SB_{\gamma,\pi} & \forall \gamma \in \Gamma^{\epsilon} \\ \sum_{\pi=\pi^f}^{\pi} CB_{\gamma,\pi} & \forall \gamma \in \Gamma^{\nu} \end{cases}$$

$$E_{\gamma^{\phi},\tau^{\pi}} = \begin{cases} SE_{\gamma,\pi} & \forall \gamma \in \Gamma^{\phi} \cap \Gamma^{\epsilon} \\ \sum_{\pi=\pi^f}^{\pi} CE_{\gamma,\pi} & \forall \gamma \in \Gamma^{\phi} \cap \Gamma^{\nu} \end{cases}$$

Transmission max capacity is either specified or is the new built capacity

$$T\_max\_cap_{\lambda,\tau^{\pi}} = \begin{cases} SL\_max_{\lambda,\pi} & \forall \lambda \in \Lambda^{\epsilon} \\ \sum_{\pi=\pi^f}^{\pi} CL_{\lambda,\pi} & \forall \lambda \in \Lambda^{\nu} \end{cases}$$

Transmission min capacity is either specified or is the negative of the new built capacity

$$T\_min\_cap_{\lambda,\tau^{\pi}} = \begin{cases} SL\_min_{\lambda,\pi} & \forall \lambda \in \Lambda^{\epsilon} \\ -\sum_{\pi=\pi^f}^{\pi} CL_{\lambda,\pi} & \forall \lambda \in \Lambda^{\nu} \end{cases}$$

Generator Operational Constraints

Dispatchable generator capacity commitment cannot exceed generator capacity.

$$U_{\gamma,\tau^{\pi}} \leq B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\phi}$$

Power output plus upward reserves from dispatchable generators cannot exceed committed capacity.

$$O_{\gamma,\tau} + Reg^{up}_{\gamma,\tau} + Spin_{\gamma,\tau} \leq U_{\gamma,\tau} \qquad \forall \gamma \in \Gamma^{\phi}$$

Power output minus downward reserves from dispatchable generators must exceed or equal a minimum loading level.

$$O_{\gamma,\tau} - Reg^{down}_{\gamma,\tau} \geq U_{\gamma,\tau} \times MSL_{\gamma} \qquad \forall \gamma \in \Gamma^{\phi}$$

Startup capacity at a timepoint is the difference between committed capacity in that timepoint and the committed capacity in the previous timepoint.

$$startup\_capacity_{\gamma,\tau} \geq U_{\gamma,\tau} - U_{\gamma,\tau-1} \qquad \forall \gamma \in \Gamma^{\phi}$$

Power output of mustrun generator must equal their available capacity.

$$O_{\gamma,\tau^{\pi}} = B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\mu}$$

Power output of variable generators cannot exceed their available capacity in a timepoint.

$$O_{\gamma,\tau^{\pi}} = B_{\gamma,\pi} \times capacity\_factor_{\gamma,\tau} - CUR_{\gamma,\tau} \qquad \forall \gamma \in \Gamma^{\omega}$$

Net power output plus upward reserves from storage cannot exceed storage power capacity.

$$D_{\gamma,\tau^{\pi}} - C_{\gamma,\tau^{\pi}} + Reg^{up}_{\gamma,\tau} + Spin_{\gamma,\tau} \leq B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\sigma}$$

904 Net power output minus downward reserves from storage must exceed or equal the negative of storage power capacity.

$$D_{\gamma,\tau^\pi} - C_{\gamma,\tau^\pi} - Reg^{down}_{\gamma,\tau} \geq -B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^\sigma$$

The energy available in storage cannot exceed the installed energy capacity.

$$F_{\gamma,\tau^\pi} \leq -E_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^\sigma$$

Upward reserves from storage cannot exceed the energy available in storage in each timepoint.

$$Reg^{up}_{\gamma,\tau} + Spin_{\gamma,\tau} \leq$$
$$F_{\gamma,\tau} - D_{\gamma,\tau} \div Discharging\_Eff_\gamma + C_{\gamma,\tau} \times Charging\_Eff_\gamma \qquad \forall \gamma \in \Gamma^\sigma$$

Downward reserves from storage cannot exceed the available energy capacity in each timepoint.

905
$$Reg^{down}_{\gamma,\tau^\pi} \leq E_{\gamma,\pi} -$$
$$(F_{\gamma,\tau^\pi} - D_{\gamma,\tau^\pi} \div Discharging\_Eff_\gamma + C_{\gamma,\tau^\pi} \times Charging\_Eff_\gamma) \qquad \forall \gamma \in \Gamma^\sigma$$

The energy available in storage must equal the energy available in the previous timepoint minus the net power output from the previous timepoint. Last timepoint of each horizon is defined as the previous timepoint for timepoint 1 of that horizon.

$$F_{\gamma,\tau} =$$
$$F_{\gamma,\tau-1} - D_{\gamma,\tau-1} \div Discharging\_Eff_\gamma + C_{\gamma,\tau-1} \times Charging\_Eff_\gamma \qquad \forall \gamma \in \Gamma^\sigma$$

Power output plus upward reserves from hydro generators cannot exceed available capacity.

$$O_{\gamma,\tau^\pi} + Reg^{up}_{\gamma,\tau^\pi} + Spin_{\gamma,\tau^\pi} \leq maximum\_power\_fraction_{\gamma,\delta} \times B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^\chi$$

Power output minus downward reserves from hydro generators must exceed or equal a pre-defined fraction of available capacity. $$O_{\gamma,\tau^{\pi}} - Reg^{down}_{\gamma,\tau^{\pi}} \geq minimum\_power\_fraction_{\gamma,\delta} \times B_{\gamma,\pi} \qquad \forall \gamma \in \Gamma^{\chi}$$
Average power output from hydro projects plus curtailment during each horizon must equal the average fraction of available capacity during that horizon $$\sum_{\tau \in T^{\delta}} ((O_{\gamma,\tau} + CUR_{\gamma,\tau}) \times hr^{\tau}) = \sum_{\tau \in T^{\delta}} (average\_power\_fraction_{\gamma,\delta} \times B_{\gamma,\pi} \times hr^{\tau}) \qquad \forall \gamma \in \Gamma^{\chi}$$

Transmission Operational Constraints
Transmission flow cannot exceed transmission max capacity. $O_{\lambda,\tau} \geq T\_max\_cap_{\lambda,\tau}$
Transmission flow cannot be less than transmission min capacity. $O_{\lambda,\tau} \leq T\_min\_cap_{\lambda,\tau}$
Transmission loss for originating (from) load zone must be greater or equal to the negative of the transmission flow times loss factor. $T\_loss_{\lambda,zf,\tau} \geq -O_{\lambda,\tau} \times T\_loss\_factor_{\lambda}$
Transmission loss for destination (to) load zone must be greater or equal to the transmission flow times loss factor. $T\_loss_{\lambda,zt,\tau} \geq O_{\lambda,\tau} \times T\_loss\_factor_{\lambda}$
Transmission loss cannot exceed maximum transmission capacity. $T\_loss_{\lambda,zf,\tau} \leq T\_max\_cap_{\lambda,\tau} \times T\_loss\_factor_{\lambda}$ $T\_loss_{\lambda,zt,\tau} \leq T\_max\_cap_{\lambda,\tau} \times T\_loss\_factor_{\lambda}$

System Constraints	
$Energy\_Balance_{z,\tau}$ in zone z and in timepoint τ	
$\sum_{\gamma \in \Gamma^{\phi} \cup \Gamma^{\mu} \cup \Gamma^{\omega} \cup \Gamma^{\chi}} O_{\gamma,z,\tau}$	generator power output
$+ \sum_{\gamma \in \Gamma^{\sigma}} (D_{\gamma^{\sigma},z,\tau} - C_{\gamma^{\sigma},z,\tau})$	storage net power output
$+ \sum_{\lambda, zf=z} (O_{\lambda,zf,\tau} + T\_loss_{\lambda,zf,\tau})$	transmission flow from zone
$+ \sum_{\lambda, zt=z} (O_{\lambda,zt,\tau} - T\_loss_{\lambda,zt,\tau})$	transmission flow to zone
$+UE_{z,\tau} - OE_{z,\tau}$	unserved energy and overgeneration energy
$= D_{z,\tau}$	system load

$Regulation\_Up\_Balance_{bar,\tau}$	
$\sum_{\gamma \subset \Gamma^{\phi} \cup \Gamma^{\sigma} \cup \Gamma^{\chi}} Reg^{up}_{\gamma,bar,\tau} \geq regulation\_up\_requirement_{bar,\tau}$	regulation up provision from dispatchable generators, hydro, and storage in balancing area *bar*
$Regulation\_Down\_Balance_{bar,\tau}$	
$\sum_{\gamma \subset \Gamma^{\phi} \cup \Gamma^{\sigma} \cup \Gamma^{\chi}} Reg^{down}_{\gamma,bar,\tau} \geq regulation\_down\_requirement_{bar,\tau}$	regulation down provision from dispatchable generators, hydro, and storage in balancing area *bar*
$Spinning\_Reserves\_Balance_{bas,\tau}$	
$\sum_{\gamma \subset \Gamma^{\phi} \cup \Gamma^{\sigma} \cup \Gamma^{\chi}} Spin_{\gamma,bas,\tau} \geq spinning\_reserves\_requirement_{bas,\tau}$	spinning reserves provision from dispatchable generators, hydro, and storage in balancing area for spinning reserves in balancing area *bas*

Policy Constraints	
$Clean\_energy\_target_{rz,\pi}$ in clean zone rz and period π	
$\sum_{\tau^{\pi}} O_{\gamma \in \Gamma^{rz}, \tau^{\pi}} \geq clean\_energy\_target_{rz,\pi}$	clean generator energy output has to meet clean energy target for that investment period

Objective Function	
Generation, storage, and transmission investment costs	
$\sum_{\gamma^\nu,\pi}\Big(CB_{\gamma^\nu,\pi} \times annualized\_investment\_cost\_p\_mw_{\gamma^\nu,\pi}$	The cost of new investments in generation, storage, and transmission,
$\times n\_years\_rep_\pi \times disc\_factor_\pi\Big)$	levelized to annual payments and incurred in each investment period after a resource is built.
$+\sum_{\gamma^\nu\in\gamma^\sigma,\pi}\Big(CE_{\gamma^\nu,\pi} \times annualized\_investment\_cost\_p\_mwh_{\gamma^\nu,\pi}$	
$\times n\_years\_rep_\pi \times disc\_factor_\pi\Big)$	No endogenous retirements are modeled here.
$+\sum_{\lambda^\nu,\pi}\Big(CL_{\lambda^\nu,\pi} \times annualized\_investment\_cost\_p\_mw_{\lambda^\nu,\pi}$	
$\times n\_years\_rep_\pi \times disc\_factor_\pi\Big)$	
Operational costs	
$\sum_{\gamma,\tau}\Big(tp\_weight_\tau \times hr^\tau \times n\_years\_rep_{\pi^\tau} \times disc\_factor_{\pi^\tau}$	dispatchable and mustrun generator variable O&M cost
$\times O_{\gamma\in\Gamma^\phi\cup\Gamma^\mu,\tau} \times var\_om_{\gamma\in\Gamma^\phi\cup\Gamma^\mu}\Big)$	

$+\sum_{\gamma,\tau}\Big(tp\_weight_{\tau} \times hr^{\tau} \times n\_years\_rep_{\pi^{\tau}} \times disc\_factor_{\pi^{\tau}}$ $\times\Big(O_{\gamma\in\Gamma^{\chi}\cup\Gamma^{\omega},\tau} + CUR_{\gamma\in\Gamma^{\chi}\cup\Gamma^{\omega},\tau}\Big) \times var\_om_{\gamma\in\Gamma^{\chi}\cup\Gamma^{\omega}}\Big)$	curtailable (hydro and variable) generator variable O&M cost
$+\sum_{\gamma^{\phi},\tau^{\pi}}\Big(tp\_weight_{\tau} \times hr^{\tau} \times n\_years\_rep_{\pi^{\tau}} \times disc\_factor_{\pi^{\tau}}$ $\times O_{\gamma^{\phi},\tau} \times heat\_rate_{\gamma^{\phi}} \times fuel\_price_{\gamma^{\phi},\pi^{\tau}}\Big)$	dispatchable generator fuel cost
$+\sum_{\gamma\in\Gamma^{\mu}\cap\Gamma^{\nu},\tau^{\pi}}\Big(tp\_weight_{\tau} \times n\_years\_rep_{\pi^{\tau}}$ $\times O_{\gamma^{\mu},\tau} \times heat\_rate_{\gamma}^{\mu} \times fuel\_price_{\gamma^{\mu},\pi^{\tau}}\Big)$	candidate must-run generator fuel cost
$+\sum_{\gamma^{\sigma},\tau}\Big(tp\_weight_{\tau} \times n\_years\_rep_{\pi^{\tau}} \times disc\_factor_{\pi^{\tau}}$ $\times D_{\gamma^{\sigma},\tau} \times var\_om_{\gamma^{\sigma}}\Big)$	Storage variable O&M cost (for batteries)
$+\sum_{\gamma^{\phi},\tau}\Big(tp\_weight_{\tau} \times n\_years\_rep_{\pi^{\tau}} \times disc\_factor_{\pi^{\tau}}$ $\times startup\_capacity_{\gamma^{\phi},\tau} \times startup\_cost\_per\_unit\_capacity_{\gamma^{\phi}}\Big)$	Startup costs for dispatchable generators
$+\sum_{z,\tau}\Big(tp\_weight_{\tau}^{\delta} \times unserved\_energy\_penalty_{z}\Big)$ $+\sum_{z,\tau}\Big(tp\_weight_{\tau}^{\delta} \times overgeneration\_penalty_{z}\Big)$	Unserved energy penalties Overgeneration penalties