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Article

Regional Electricity Interconnections for the Clean Energy Transitions in East Africa: Evidence from an Open-Source Energy System Model

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Abstract

Regional electricity interconnections are increasingly recognised as enablers of cost-effective power system expansion and deep decarbonisation in emerging economies. In East Africa, Kenya and neighbouring countries — Tanzania, Ethiopia, and Uganda — operate relatively low-carbon electricity systems; however, rapidly growing electricity demand and expanding thermal generation are placing upward pressure on grid emissions intensity, particularly in Kenya. This study examines whether planned cross-border interconnections can mitigate this trajectory using OSeMOSYS Global, an open-source least-cost capacity expansion model, comparing stand-alone national power systems against an interconnected regional grid over 2022–2050. Results show that interconnection enables access to low-cost renewable electricity and facilitates surplus generation exports, maintaining system-wide carbon intensity within climate-finance eligibility thresholds of 100 gCO₂/kWh. Outcomes are heterogeneous: Ethiopia and Kenya incur cost increases (+USD 481 million and +USD 568 million respectively) attributable to transmission capital expenditure, whereas Tanzania and Uganda achieve net cost savings (–USD 590 million and –USD 891 million) alongside substantial emissions intensity reductions of 141.9 and 280.5 gCO₂/kWh respectively. Regional emissions equity is preserved, with modest intensity increases in Ethiopia and Kenya offset by large reductions elsewhere. These findings strengthen the case for climate-financed regional transmission as a scalable and equitable mitigation strategy in East Africa.

Keywords: clean energy transition; regional electricity interconnection; climate finance; East Africa

1. Introduction

Electricity transmission infrastructure is a cornerstone of the global clean energy transition, enabling renewable integration, reducing energy poverty, and supporting sustainable development in emerging markets and developing economies (EMDEs) [1–5]. The IPCC's AR6 mitigation assessment similarly emphasizes deep power-sector decarbonisation within broader energy-system transitions that require system integration and infrastructure [6]. Complementing this, IRENA's grid-integration work highlights that high shares of variable renewables require flexibility options, explicitly including interconnections and regional markets as flexibility providers [7].

Interconnected markets allow countries to export surplus renewable electricity and import during periods of shortfall, improving market efficiency and lowering consumer electricity costs [8]. The urgency of this transformation is underscored by the scale of unmet electricity demand across

sub-Saharan Africa, where hundreds of millions of people lack reliable access to electricity and where demand is projected to grow rapidly over the coming decades [9].

There is a clear need for strong regional co-ordination as integrating variable renewables – wind, solar, and hydro – increasingly relies on robust grid interconnections and storage. Regional power links allow countries to balance complementary resources: hydro-rich neighbours can supply baseload or peaking power when solar or wind output is low. In East Africa, the Eastern Africa Power Pool (EAPP) aims to coordinate these flows among member states, with the general purpose of facilitating regional power trade through access to cheaper power from, and export of excess power to, neighbouring countries [10].

In practice, this means that Kenya can tap low-cost hydropower from Ethiopia while selling surplus geothermal and wind generation to its neighbours. Kenya's policy context also underscores the importance of regional trade. The draft National Energy Policy 2025-2034 targets universal electricity access (100% by 2030) and steers the sector toward clean, renewable-based expansion [11,12]. Recent regulations, including the Energy Act 2019 and the Energy (Net-Metering) Regulations 2024, create a conducive environment for decentralised renewables and allow consumers with systems up to 1 MW to feed excess power back to the grid [13]. Against this backdrop, expanding regional interconnections represents a potentially transformative lever for the country's electricity system.

The economic case for regional electricity cooperation is well established in the academic literature. Cross-border power trade reduces system costs by enabling countries to exploit differences in resource endowments, smooth demand variability, and avoid redundant capacity investment. A widely cited synthesis of international experience highlights that regional electricity market integration can deliver net welfare gains when supported by appropriate regulatory frameworks and governance structures, drawing on lessons from established power pools in West Africa, Southern Africa, and Central America [14]. While individual country-level energy planning studies are common, they are often not well-suited to the specific challenges faced by low- and middle-income countries[15]. Comparative regional assessments that quantify the differential impacts of interconnection across multiple countries remain scarce [16,17]. In the Eastern African context, Remy & Chattopadhyay explicitly note limited regional literature while quantifying potential gains from deeper trade within the EAPP, including reductions in reliance on expensive thermal generation and emissions [18].

This paper addresses that gap by examining the impacts of planned cross-border electricity interconnections among Kenya, Ethiopia, Uganda, and Tanzania. The study compares two configurations: a 'No Transmission' (NoTRN) scenario, in which each country plans and operates its power system independently without building any new interconnectors, and a 'Transmission' (TRN) scenario, in which the model is allowed to invest in new transmission infrastructure. Both scenarios are assessed over the period 2022 to 2050 across four dimensions: total installed capacity, annual electricity generation, system cost, and greenhouse gas emissions. The key research questions are: (i) How does the 'Transmission' scenario affect total system costs in each country relative to the 'No Transmission'? (ii) What are the emissions implications of interconnection, both nationally and regionally? (iii) How does moving from 'No Transmission' to 'Transmission' scenario reshape the generation mix and capacity portfolio? (iv) What role does cross-border electricity trade in the 'Transmission' scenario play in enabling a low-carbon transition?

The remainder of the paper is structured as follows: Section 2 describes the modelling methodology; Section 3 presents results; Section 4 discusses policy implications; and Section 5 concludes.

2. Materials and Methods

Study Region

Kenya, Ethiopia, Uganda, and Tanzania form a physically contiguous power-trading region in East Africa with existing and planned electricity interconnectors linking their national grids. These four countries have complementary generation profiles: Ethiopia possesses a large hydropower surplus providing low-cost baseload; Kenya operates a geothermal-dominated system with scope for both import and re-export; Tanzania has a mixed portfolio of natural gas and new hydro capacity; and Uganda exports surplus hydro. This complementarity creates a strong economic rationale for regional integration, as surplus low-carbon generation in one country can displace higher-cost or higher-emission generation elsewhere.

The countries are linked by existing and planned high-voltage transmission lines. The Ethiopia-Kenya line (the Suswa-Addis corridor) and the Kenya-Tanzania line (Isinya-Singida) represent the primary interconnectors, with the Kenya-Uganda corridor providing an additional link. These lines form the backbone of the EAPP's planned regional grid, and their expansion is central to the regional energy transition. Other neighbouring countries, Somalia and South Sudan, are excluded due to limited grid infrastructure and lack of integration into the regional power pool.

OSeMOSYS Global

The analysis employs OSeMOSYS Global [19], an open-source, open-data electricity system model generator built on the Open Source Energy Modelling System (OSeMOSYS) framework. OSeMOSYS Global automates the construction of country and regional electricity system models, performing least-cost capacity expansion planning to identify the optimal combination of new generation, storage, and transmission investments to meet projected electricity demand at minimum total system cost over a multi-decade planning horizon. The model simultaneously optimises capacity investment, generation dispatch, and cross-border electricity trade, enabling self-consistent evaluation of the economic and environmental value of regional interconnections. The OSeMOSYS Global codebase is publicly available at https://github.com/OSeMOSYS/osemosys_global.

For this study, the OSeMOSYS Global repository was cloned and configured for the four-country East African system. The scenario configuration files, input data, and results used in this analysis are archived in a dedicated public repository at https://github.com/jeenogeorge/Applications_OG, enabling full reproducibility of the results presented here. The scenario configuration files, input data, and results used in this analysis are archived in the `k_t_e_u_baseline_Individuals` branch.

The four countries were modelled over the period 2022 to 2050, with the analysis reported here covering 2022 to 2045 to avoid the well-documented end-of-horizon effect, whereby the absence of future periods beyond the model's terminal year causes the optimiser to systematically underinvest in long-lived assets in the final years of the planning horizon, producing results that are not representative of least-cost system behaviour [20]. The temporal resolution comprises 24 time slices per year, defined by four seasons (S1: January–February; S2: March–May; S3: June–September; S4: October–December) and six daily time segments of four hours each, capturing seasonality and diurnal variation in renewable output and electricity demand. A 10% reserve margin was applied from 2030 onwards to ensure system adequacy. Technologies excluded from new investment in all scenarios include coal, oil, open-cycle gas, nuclear, and offshore wind, reflecting the resource endowments and policy environments of the study countries.

Transmission data were integrated from the Global Transmission Database [21,22]. Technology costs, fuel prices, and operational parameters are based on the default values embedded in OSeMOSYS Global, which draw on internationally recognised sources including IRENA and the IEA. Carbon emissions are calculated using standard emissions factors for each fuel and technology type. To calibrate model outputs against observed historical generation, minimum generation constraints were applied to key technologies in the early model years, including wind generation in Kenya and hydropower in Ethiopia and Uganda, consistent with reported installed capacity and historical

dispatch data. Availability factors were further adjusted at the country and technology level to reflect known operational constraints, seasonal hydrology, and capacity utilisation patterns, particularly for hydropower, geothermal, gas, and solar technologies across the four countries.

Scenario Design

The study adopts a single electricity demand pathway, referred to hereafter as the Baseline case, consistent with each country's current development trajectory. The Baseline case assumes a continuation of prevailing trends, incorporating moderate GDP growth, ongoing population increase, and gradual electrification broadly consistent with each country's national energy targets. Electricity demand profiles in OSeMOSYS Global are generated by combining regression-based projections of annual demand – linked to GDP per capita and urbanisation rates – with historical load shapes distributed across representative time slices [19,23], providing a plausible and internally consistent demand trajectory for each country over the modelling horizon.

Within the Baseline case, two transmission configurations are evaluated. The No-Planned-Transmission scenario (hereafter NoTRN) represents a stand-alone configuration in which no new cross-border interconnector projects are constructed beyond existing infrastructure, and each country's power system is therefore optimised independently with no access to regional electricity trade beyond residual existing interconnector capacity. The Planned-Transmission scenario (hereafter TRN) allows the model to invest in new transmission infrastructure along the corridors as described in Global Transmission Database [21,22]. Within each scenario, the model endogenously determines the optimal generation mix, storage deployment, and cross-border trade pattern, choosing future investments and regional electricity flows to minimise total system cost subject to meeting demand and all technical constraints.

3. Results

This section presents the modelling results for the four-country East African system over the period 2022 to 2045. Results are organised around four dimensions: total installed generation capacity, annual electricity generation and demand, the differential impact of planned transmission on system costs and emissions, and cross-border electricity trade flows. In each case, results are compared across the No-TRN and TRN scenarios to isolate the contribution of planned regional interconnection to system outcomes in Kenya, Ethiopia, Tanzania, and Uganda.

3.1. Total Installed Capacity

Figure 1 shows the total installed generation capacity by technology and country over the period 2022 to 2045, comparing the NoTRN and TRN scenarios. Across all four countries, capacity expands substantially over the modelling horizon, driven primarily by solar photovoltaic and hydropower investments. In Kenya, solar PV becomes the dominant new technology from the late 2020s onwards, reaching approximately 22 GW by 2045 under the TRN scenario. Ethiopia exhibits the largest absolute capacity expansion, reaching approximately 32 GW by 2045, with hydropower remaining the backbone of the system throughout the period and solar PV contributing a growing share from the mid-2030s. Biomass retains a significant share of the generation mix in Tanzania alongside hydro and solar PV, while Uganda's system is predominantly hydro-based with growing solar PV additions in later years.

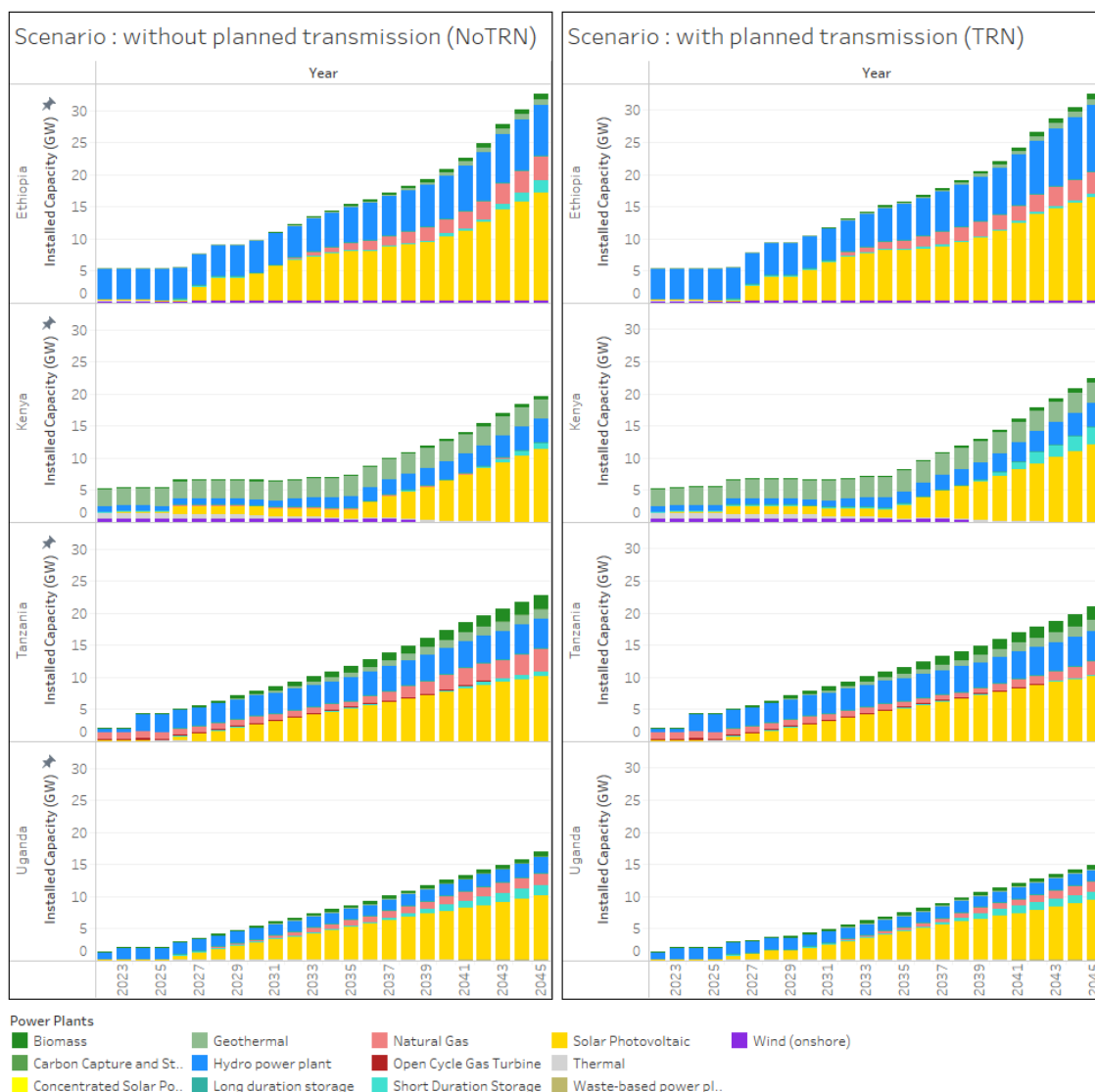


Figure 1. Total installed generation capacity (GW) by technology and country, 2022-2045, without and with planned transmission.

Kenya's total installed capacity grows from approximately 4 GW in 2022 to around 22 GW by 2045 under the TRN scenario, with solar PV accounting for the largest share of new additions, complemented by continued geothermal and hydro investment. Ethiopia's installed capacity grows from around 5 GW in 2022 to approximately 32 GW by 2045, the largest absolute expansion of the four countries, underpinned by its ambitious hydro-power programme alongside substantial solar PV deployment. Tanzania expands from approximately 2 GW to around 21 GW by 2045, with a mixed portfolio of hydro, biomass, and solar PV. Uganda's system grows from roughly 1 GW to approximately 15 GW, remaining predominantly hydro-based with increasing solar PV additions in the later years of the modelling horizon. The two scenarios show broadly similar capacity trajectories, with the TRN case exhibiting modest differences in technology composition driven by access to regional electricity trade.

3.2. Electricity Generation and Demand

Figure 2 presents total annual electricity generation disaggregated by technology and country for both the NoTRN and TRN scenarios, alongside the projected electricity demand trajectory. The grey shaded area represents the annual demand curve, which is consistent across both scenarios,

while the stacked bars show the generation mix. In all four countries, generation tracks demand closely across both scenarios, confirming that the model successfully meets electricity requirements across the planning horizon.

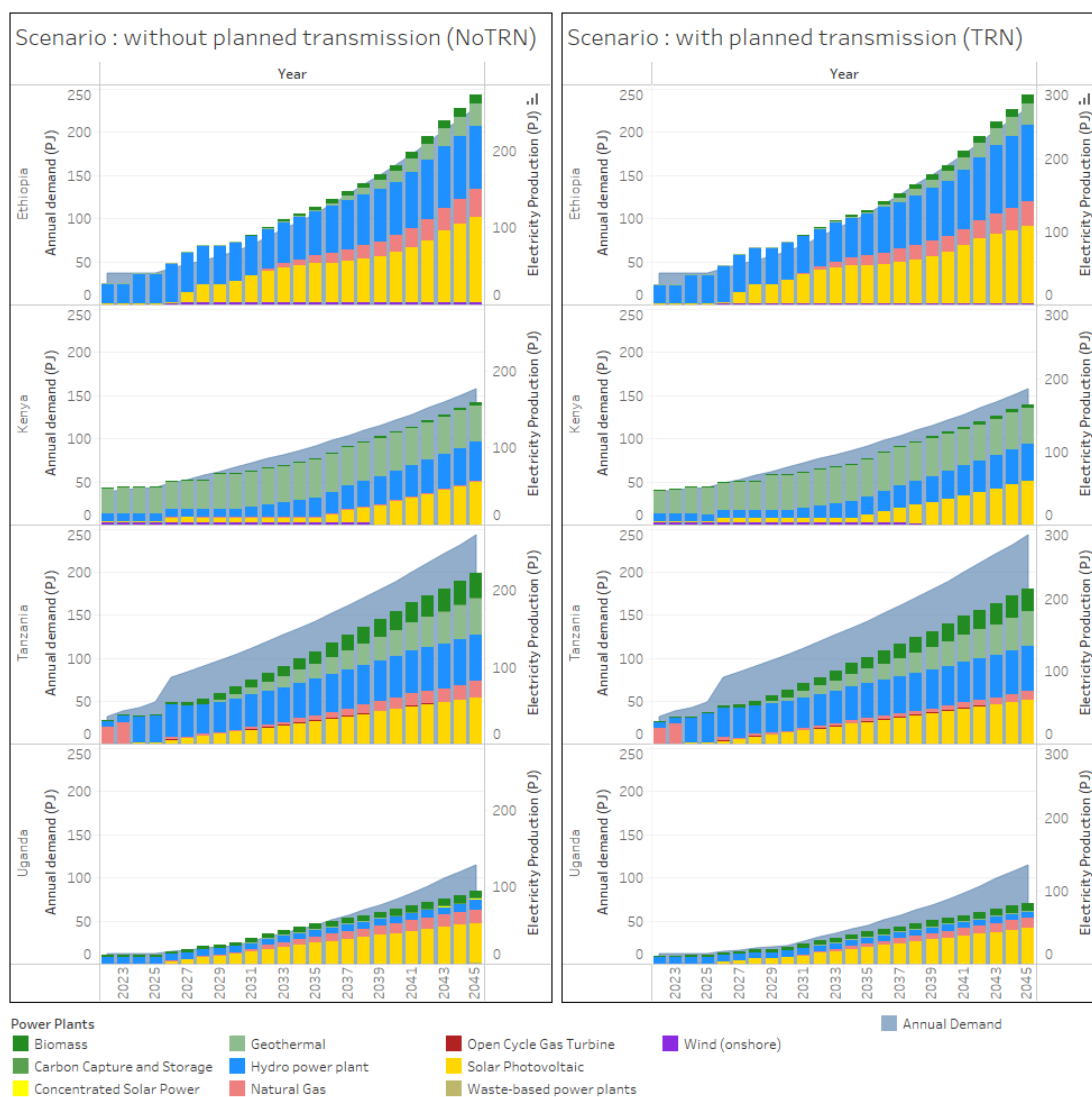


Figure 2. Annual electricity generation by technology and country compared to projected demand, 2022-2045, with planned transmission.

In Ethiopia, hydropower dominates the generation mix throughout the study period, with annual demand growing from approximately 25 PJ in 2022 to around 250 PJ by 2045, supplemented by growing contributions from solar PV and wind in later years. Kenya's demand grows more moderately from around 70 PJ to approximately 150 PJ by 2045, with its generation portfolio anchored by solar PV (PWRSPV), hydro, and geothermal (PWRGEO) contributing a stable baseload share. Tanzania's demand trajectory is notable, rising sharply from around 25 PJ in 2022 to approximately 85 PJ by 2026 before continuing to grow to around 250 PJ by 2045, with hydro, solar PV, and biomass comprising the generation mix. Uganda's demand grows from approximately 5 PJ in 2022 to around 150 PJ by 2045, with the system remaining predominantly hydro-based with growing solar additions.

3.3. Impact of Planned Transmission on System Costs, Emissions, and Capacity

Figure 3 presents the difference in total system cost, CO₂ emissions, and emission intensity between the planned transmission and no-planned-transmission scenarios (delta = With TRN minus

NoTRN) for each country. A positive value indicates that planned transmission leads to a higher outcome; a negative value indicates that interconnection reduces that outcome.

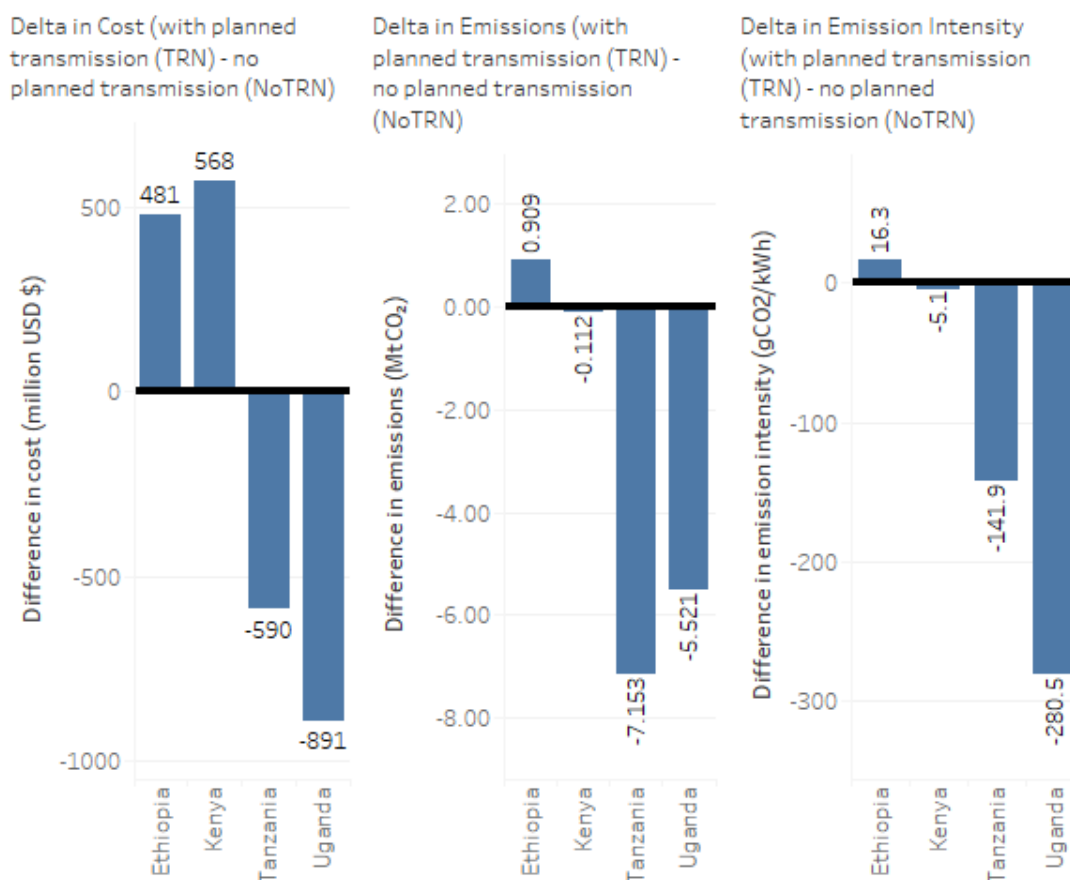


Figure 3. Difference in cumulative system cost (left), total CO₂ emissions (centre), and average emission intensity (right) between the planned transmission and no-planned-transmission scenarios by country.

The results reveal a heterogeneous pattern. Ethiopia and Kenya experience higher total system costs under planned transmission (+USD 481 million and +USD 568 million respectively), reflecting the capital expenditure associated with new cross-border transmission infrastructure. In contrast, Tanzania and Uganda realise net cost savings of approximately USD 590 million and USD 891 million respectively, arising from improved access to lower-cost generation from neighbouring countries.

The emissions pattern is similarly differentiated. Ethiopia experiences a modest increase in total CO₂ emissions (+0.91 Mt), whereas Kenya records a small reduction (-0.11 Mt). The most substantial emissions reductions occur in Tanzania (-7.15 Mt) and Uganda (-5.52 Mt), reflecting the displacement of higher-emission domestic generation by lower-carbon imports. Emission intensity changes follow a consistent pattern: Ethiopia sees a modest increase (+16.3 gCO₂/kWh) while Tanzania and Uganda record large reductions of -141.9 and -280.5 gCO₂/kWh respectively, well below typical climate-finance eligibility thresholds of 100 gCO₂/kWh [5]. Kenya's emission intensity change is negligible in absolute terms, as its power system is already near zero-carbon under the no-planned-transmission scenario (average intensity of 0.21 gCO₂/kWh), meaning interconnection has little further effect on its emissions profile.

3.4. Changes in Generation Mix and Installed Capacity

Figure 4 decomposes the delta in installed capacity (left panel) and annual electricity generation (right panel) by technology type for each country, illustrating how interconnection reshapes the domestic generation portfolio relative to the stand-alone case.

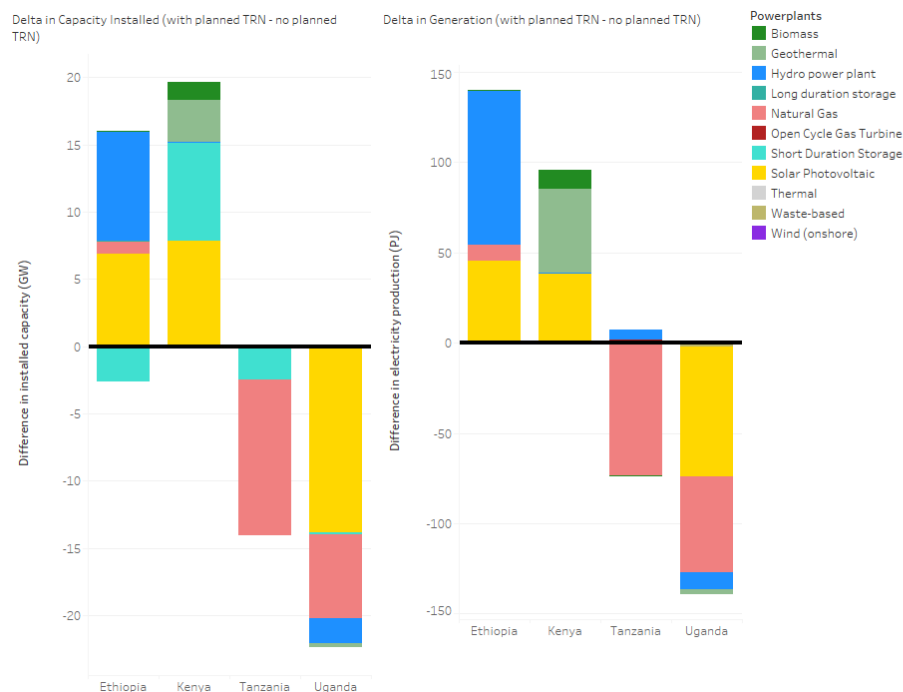


Figure 4. Difference in total installed capacity (GW, left) and annual generation (PJ, right) by technology between the planned transmission and no-planned-transmission scenarios, by country.

In Ethiopia and Kenya, interconnection leads to positive changes in both capacity and generation, driven primarily by increases in hydropower and solar PV. Both countries expand their low-carbon generation capacity under interconnection to serve regional demand in addition to domestic needs. Tanzania exhibits a notable reduction in combined cycle gas capacity and generation, as imports from neighbouring countries displace the need for domestic gas-fired generation — the primary driver of Tanzania's cost savings and emissions reductions. Uganda shows reductions in oil-based generation (PWROIL) offset by increased hydro and wind additions.

3.5. Cross-Border Trade Flows

Figures 5a-5d present the annual trade activity (PJ) for each country under the no-planned-transmission and planned-transmission scenarios over 2022 to 2045. Positive values indicate net electricity imports; negative values indicate net exports.

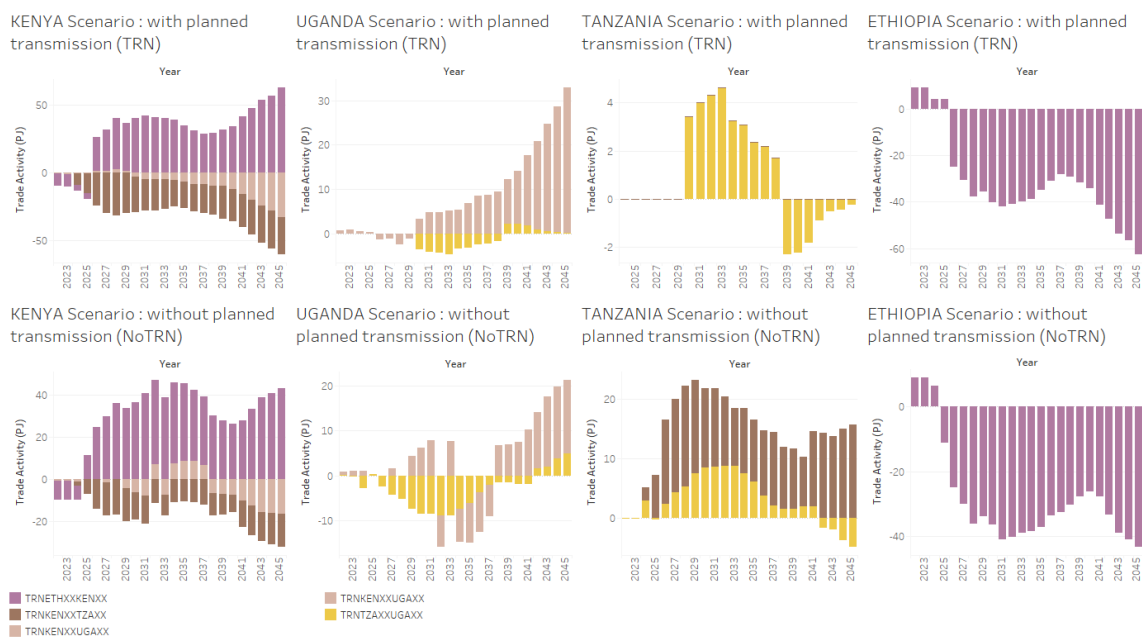


Figure 2. Annual trade activity (PJ) for Kenya, Uganda, Tanzania and Ethiopia 2022-2045 for planned and with no planned transmission scenarios.

Ethiopia is a consistent net exporter throughout the modelling period under both scenarios, as shown by the predominantly negative (below-zero) bars in the Ethiopia. Under the NoTRN scenario, Ethiopia exports primarily to Kenya via the TRNETHXXKENXX corridor, with export volumes growing steadily from around 10 PJ in the early 2020s to approximately 40 PJ by 2045 as its hydropower capacity expands. Under the TRN scenario, Ethiopia's export role intensifies further, with exports to Kenya reaching approximately 60 PJ by 2045, reflecting Ethiopia's position as the region's primary low-cost hydropower supplier. Kenya's trade profile highlights its role as a regional transit hub. Under both scenarios, Kenya simultaneously imports from Ethiopia (negative bars on the Ethiopia-Kenya corridor, appearing as positive imports in the Kenya panel) while exporting to Tanzania and Uganda (negative bars in the Kenya panel on the Kenya-Tanzania and Kenya-Uganda corridors). This import-and-re-export pattern becomes more pronounced under the TRN scenario, with Kenya's gross exports to Tanzania and Uganda growing substantially through the 2030s and 2040s. Tanzania's trade pattern differs markedly between scenarios. Under the NoTRN scenario, Tanzania records consistent positive (import) activity via the Kenya-Tanzania corridor throughout the period, reaching around 20–25 PJ by the early 2030s before declining. Under the TRN scenario, Tanzania's import volumes from Kenya increase substantially, reflecting improved access to low-cost regional generation. The Tanzania-Uganda corridor (TRNTZAXXUGAXX) shows limited activity in both scenarios. Uganda is a net importer under both scenarios, with imports arriving primarily via the Kenya-Uganda corridor (TRNKENXXUGAXX). Under the NoTRN scenario, import volumes are modest, growing from near zero to approximately 20 PJ by 2045. Under the TRN scenario, Uganda's imports grow more rapidly, reaching approximately 30 PJ by 2045, reflecting the expanding role of regional trade in meeting Uganda's growing electricity demand.

4. Discussion

The results reveal heterogeneous distribution of costs and benefits across the four countries. While Tanzania and Uganda realise net system cost savings, Ethiopia and Kenya experience cost increases associated with transmission investment. This asymmetry reflects the structure of the regional power system: countries that are well-positioned as net exporters or importers of low-cost electricity capture the largest operational savings, while those that bear the capital costs of new

transmission infrastructure may see higher near-term system costs. These distributional effects have important implications for the design of cost-sharing mechanisms and for the political economy of regional integration.

The emissions results provide strong evidence that regional interconnection can serve as an effective emissions mitigation instrument, consistent with the broader literature on cross-border power trade and decarbonisation in emerging economies [24,25]. The large reductions in emission intensity observed for Tanzania and Uganda demonstrate that access to Ethiopia's low-carbon hydropower and Kenya's geothermal generation can fundamentally transform the emission profile of neighbouring systems. These reductions are driven primarily by the displacement of gas-fired combined cycle generation in Tanzania and oil-based generation in Uganda, both replaced by lower-carbon regional imports – a structural transformation that would be substantially more costly, and in some cases technically infeasible, under stand-alone national planning.

The finding that interconnection does not compromise regional emissions equity is particularly significant in the context of climate finance. The modest increases observed for Ethiopia and Kenya are small relative to the large reductions achieved in Tanzania and Uganda, confirming that the overall regional emissions balance is favourable. This supports the case for directing climate finance toward cross-border transmission infrastructure in East Africa as a cost-effective mitigation strategy well aligned with green finance eligibility thresholds, and reinforces arguments made in the broader literature that transmission investment should be recognised as a climate mitigation asset in its own right [5,26].

The hydropower dependence of the region also introduces a climate risk dimension that strengthens the case for interconnection beyond its cost and emissions benefits. In Ethiopia and Uganda, hydropower accounts for more than 80% of electricity generation [27], while Tanzania's hydropower share, though reduced from a peak of 96% in 2003, still represented around one third of total generation in 2021, and Kenya followed a similar trajectory, declining from 77% in 1995 to around 30% in 2021 [28] – a reduction driven by geothermal and wind expansion rather than any absolute decline in hydro capacity. This heavy structural reliance on hydropower creates significant system vulnerability to climatic variability. In East Africa, more frequent heavy precipitation events and prolonged droughts are projected to increase inter-annual variability and uncertainty in hydropower generation [29]. Between October 2020 and early 2023, the region experienced five consecutive failed rainy seasons – the worst drought in 40 years – directly curtailing hydropower output and forcing costly thermal backup [30]. Even Nile Basin countries that may benefit from increased average annual hydropower output under some climate scenarios are likely to face growing inter-annual variability under higher warming trajectories [29]. Regional interconnection therefore provides not only a cost and emissions benefit but also a meaningful hedge against the climate-driven hydrological risk faced by any single country operating in isolation.

The trade flow analysis reveals that interconnection fundamentally reshapes the structure of regional electricity flows. Ethiopia emerges as the dominant net exporter throughout the modelling period under both scenarios, with its large low-cost hydropower base supplying Kenya via the Ethiopia-Kenya corridor at volumes growing from approximately 10 PJ in the early 2020s to around 60 PJ by 2045 under the TRN scenario. This confirms Ethiopia's central role as the region's primary generation surplus country and underscores the importance of the Ethiopia-Kenya interconnector as the backbone of regional trade. Kenya's position as a regional transit hub is reinforced by the trade flow results: Kenya simultaneously absorbs imports from Ethiopia while channelling electricity onward to Tanzania and Uganda via its respective corridors, optimising its domestic generation portfolio through regional trade. Tanzania and Uganda are consistent net importers throughout the modelling horizon under both scenarios, with interconnection increasing their access to lower-cost regional generation. Tanzania's import volumes from Kenya grow substantially under the TRN scenario, displacing higher-cost domestic gas-fired generation – the primary driver of Tanzania's cost savings and emissions reductions identified in Section 3.3. Uganda similarly relies on growing imports via the Kenya-Uganda corridor to meet its rapidly expanding electricity demand, with

import volumes reaching approximately 30 PJ by 2045 under the TRN scenario. These trade patterns confirm that the cost and emissions benefits accruing to Tanzania and Uganda are directly enabled by Ethiopia's exportable hydropower surplus and Kenya's transit role.

The distributional asymmetry in costs and benefits underscores the need for a robust regional cost-sharing framework. Countries that bear the capital costs of new transmission infrastructure — notably Ethiopia and Kenya — may require compensation or revenue-sharing arrangements to ensure interconnection projects deliver net national benefits. The EAPP and other regional bodies have an important role in negotiating these arrangements and providing the institutional foundation for long-term power trading agreements.

Regulatory harmonisation across East Africa will be essential to unlock the full value of interconnection. Streamlining wheeling arrangements, market access rules, and grid codes can reduce transaction costs and facilitate commercial power trade. Kenya's Energy Act 2019 and the Net-Metering Regulations 2024 represent positive steps, but further reforms — including competitive auctions, strengthened grid codes, and incentives for flexibility — will be necessary to sustain investment momentum and attract private capital into cross-border infrastructure.

Several limitations should be acknowledged when interpreting these results. The model assumes idealised market operation across borders, whereas real-world deployment faces challenges related to financing, procurement, regulatory alignment, and institutional capacity. Results are sensitive to assumed cost and demand trajectories, as well as country-specific uncertainties such as hydrological variability, geothermal development risks in Kenya, and natural gas price trajectories in Tanzania. The model relies on default OSeMOSYS Global technology cost and performance parameters, which are based on global datasets and may not fully reflect country-specific cost structures, financing conditions, or resource quality variations within each national system. Data limitations are a persistent challenge in energy system modelling for sub-Saharan Africa, where granular, up-to-date, and publicly available data on generation costs, load profiles, and transmission parameters remain scarce.

Decision making under deep uncertainty techniques [31] could help quantify the sensitivity of key results to these input uncertainties and provide policymakers with a clearer picture of the robustness of the interconnection case across a range of plausible futures. Very few studies incorporate decision making under deep uncertainty techniques in energy planning [32–34]. Future research should incorporate such techniques, drawing on stakeholder-informed scenarios developed in collaboration with national utilities and planning agencies.

Finally, the analysis is limited to four countries, whereas the Eastern Africa Power Pool encompasses thirteen member states with significant untapped interconnection potential. Extending the modelling framework to additional EAPP members — including Rwanda, Burundi, Sudan, and the Democratic Republic of Congo — would provide a more complete picture of regional integration benefits and trade-offs. Future research should also assess the role of emerging technologies, including utility-scale battery storage, pumped hydro, and green hydrogen, in complementing cross-border transmission as tools for managing variability and enabling deeper decarbonisation across the region.

5. Conclusions

Using an open-source model generator for interconnected regional electricity systems, this study evaluates the system-level costs, emissions, and structural impacts of planned regional electricity interconnections across Kenya, Ethiopia, Uganda, and Tanzania. The results demonstrate that planned interconnection delivers heterogeneous but broadly positive outcomes at the regional level. Countries that gain access to lower-cost generation from neighbours achieve meaningful reductions in both system costs and carbon emission intensity, while those bearing the capital burden of new transmission infrastructure incur near-term cost increases — yet contribute to a regional emissions balance that is clearly net negative. Critically, interconnection does not compromise emissions equity: modest intensity increases in some countries are substantially outweighed by large reductions

elsewhere, confirming that the benefits of regional integration are shared, if unevenly distributed. Cross-border trade flow analysis further reveals that interconnection activates latent low-cost renewable resources, enables structural transformation of national generation portfolios away from fossil-fuelled generation, and positions Kenya as a potential regional transit hub. Taken together, these findings strengthen the economic and environmental case for treating cross-border transmission infrastructure as a climate mitigation investment rather than merely a reliability asset, and point to the need for equitable cost-sharing mechanisms to ensure all participating countries capture a fair share of regional gains.

For policymakers, the results underscore three priorities: the timely delivery of planned interconnector projects — particularly the Kenya-Tanzania and Kenya-Ethiopia corridors — alongside fair and transparent regional cost-sharing arrangements; the alignment of national capacity planning with regional trade opportunities; and the acceleration of regulatory harmonisation across the EAPP to unlock the commercial potential of regional power trade. Realising these priorities will be essential for East Africa to achieve a secure, low-carbon, and cost-effective electricity transition.

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Data Availability Statement: The scenario configuration files, input data, and model results supporting the findings of this study are openly available in the k_t_e_u_baseline_Individuals branch of the public repository at https://github.com/jeenogeorge/Applications_OG/tree/k_t_e_u_baseline_Individuals. The OSeMOSYS Global model generator used to produce these results is publicly available at https://github.com/OSeMOSYS/osemosys_global [22].

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Abbreviations

The following abbreviations are used in this manuscript:

GW	Gigawatt
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
MW	Megawatt
NoTRN	No-Planned-Transmission scenario
OSeMOSYS	Open Source Energy Modelling System
PJ	Petajoule
PV	Photovoltaic
TRN	Planned-Transmission scenario

USD United States Dollar

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