Supplementary Information

1 Optimization model

The optimization model minimizes the total cost of electricity supply in Latin America by jointly optimizing investments in generation, storage, and transmission, along with system operation. The model is formulated as a linear program and captures hourly operation across a full representative year. It includes multiple technology types such as solar, wind, hydropower (both run-of-river and reservoir), nuclear, and diesel generation, as well as battery energy storage systems (BESS). Investment decisions are endogenously determined for dispatchable and variable renewable generation, BESS, and transmission lines. The model ensures hourly nodal balance, enforces technical constraints on generation and transmission, and penalizes unserved energy and artificial loop flows. Additionally, hydropower generation is constrained by historical production profiles and capacity limits, while sovereignty constraints can be imposed to ensure each country maintains a minimum level of firm generation to meet its peak demand. All data inputs—including demand, capacity factors, existing infrastructure, and cost assumptions—are derived from publicly available sources and regional planning reports.

Model Sets

The optimization model is defined over the following sets:

- T: Set of time periods (typically hours in a representative year).
- N: Set of nodes or countries.
- L: Set of transmission lines.
- G: Set of dispatchable generators.
- S: Set of solar generators.
- E: Set of wind generators.
- HE: Set of reservoir-based hydropower plants.
- HP: Set of run-of-river hydropower plants.
- NU: Set of nuclear generators.
- G_n: Subset of dispatchable generators located at node n.
- S_n: Subset of solar generators located at node n.
- E_n: Subset of wind generators located at node n.
- L_n^{from}: Set of lines originating at node n.
- L_n^{to}: Set of lines ending at node n.

Decision Variables

The optimization model includes the following decision variables:

- $P_{g,t}$: Generation from dispatchable generator g at hour t [MW].
- $S_{s,t}$: Generation from solar generator s at hour t [MW].
- $E_{e,t}$: Generation from wind generator e at hour t [MW].
- $C_{n,t}^{BESS}$: Charging power of battery storage in node n at hour t [MW].

- $D_{n,t}^{BESS}$: Discharging power of battery storage in node n at hour t [MW].
- $E_{n,t}^{BESS}$: Energy stored in battery in node n at hour t [MWh].
- $\Delta_{n,t}$: Energy not supplied (ENS) in node n at hour t [MW].
- $F_{l,t}$: Power flow on line l at hour t [MW].
- $F_{l,t}^{LOOP}$: Loop flow penalization term for line l at hour t [MW].
- PI_g: New investment in dispatchable generator g [MW].
- SI_s: New investment in solar generator s [MW].
- EI_e: New investment in wind generator e [MW].
- PI_n^{BESS}: New investment in BESS power capacity at node n [MW].
- FI_l: New investment in transmission line l [MW].
- $E_{h,t}^{HE}$: Energy stored in reservoir hh at time t, used to model intertemporal water balance for hydropower plants.

Model Parameters

The optimization model uses the following parameters:

- CV_g: Operating cost of dispatchable generator g [USD/MWh].
- CI_g: Investment cost per MW of dispatchable generator g [USD/MW].
- CI^{BESS}: Investment cost per MW of battery power capacity [USD/MW].
- CI^{TX}: Investment cost per MW of transmission capacity [USD/MW].
- $VOLL$: Value of Lost Load; cost penalty per unit of unmet demand [USD/MWh].
- $P_s^{S\max}$: Existing capacity of solar generator s [MW].
- $P_e^{E\max}$: Existing capacity of wind generator e [MW].
- $S_{s,t}^{\text{profile}}$: Hourly solar availability profile for generator s at hour t].
- $E_{e,t}^{\text{profile}}$: Hourly wind availability profile for generator e at hour t.
- $D_{n,t}$: Electricity demand at node n at hour t [MW].
- $F_l^{\max}$: Existing transmission capacity of line l [MW].
- Hr: Duration of battery storage in hours.
- η_c: Charging efficiency of BESS.
- η_d: Discharging efficiency of BESS.
- α_g: Firm capacity contribution factor of generator g (used in sovereignty constraint).
- $\text{Inflow}_{h,t}$: Estimated inflow to reservoir h at hour t.
- Prod_h^{HP}: Historical annual generation of run-of-river plant h.
- Prod_h^{HE}: Historical annual generation of reservoir plant h.
- $HE_{h,t}^{profile}$: Normalized hourly generation profile for reservoir hydropower plant h at time t.
- $E_{h,\text{init}}^{HE}$: Initial stored energy in reservoir h.

Objective Function

The objective is to minimize the total system cost, which includes operating costs, investment costs, and penalties. Formally:

$$\min \left(\text{OPEX} + \text{CAPEX}^{GX} + \text{CAPEX}^{TX} + \text{CAPEX}^{BESS} + \text{ENS} + \text{LOOP} \right) \tag{1}$$

Where:

- **Operating Cost (OPEX):**

$$\text{OPEX} = \sum_{t \in T} \sum_{g \in G} P_{g,t} \cdot CV_g \tag{2}$$

- **Generation Investment Cost ($\mathbf{CAPEX^{GX}}$):**

$$\text{CAPEX}^{GX} = \sum_{g \in G} PI_g \cdot CI_g \tag{3}$$

- **Transmission Investment Cost ($\mathbf{CAPEX^{TX}}$):**

$$\text{CAPEX}^{TX} = \sum_{l \in L} FI_l \cdot CI^{TX} \tag{4}$$

- **Storage Investment Cost ($\mathbf{CAPEX^{BESS}}$):**

$$\text{CAPEX}^{BESS} = \sum_{n \in N} PI_n^{BESS} \cdot CI^{BESS} \cdot Hr \tag{5}$$

- **Unserved Energy Penalty (ENS):**

$$\text{ENS} = \sum_{t \in T} \sum_{n \in N} \Delta_{n,t} \cdot VOLL \tag{6}$$

- **Loop Flow Penalty (LOOP):**

$$\text{LOOP} = \sum_{t \in T} \sum_{l \in L} F_{l,t}^{LOOP} \cdot \lambda \tag{7}$$

Where λ is a small penalty factor (e.g., 0.001) used to discourage artificial loop flows.

Model Constraints

1. Nodal Power Balance

For each node $n \in N$ and time $t \in T$, the sum of generation, imports, and discharges must match demand, exports, and storage charging:

$$\begin{aligned}&\sum_{g \in G_n} P_{g,t} + \sum_{s \in S_n} S_{s,t} + \sum_{e \in E_n} E_{e,t} + HP_{n,t} + HE_{n,t} + NU_{n,t} \\ &\quad + P_{n,t}^{BESS} + \Delta_{n,t} = D_{n,t} + \sum_{l \in L_n^{\text{to}}} F_{l,t} - \sum_{l \in L_n^{\text{from}}} F_{l,t}\end{aligned} \tag{8}$$

2. Generation Limits

$$P_{g,t} \leq P_g^{\max} + PI_g \qquad \forall g, t \tag{9}$$

$$S_{s,t} \leq (P_s^{S\max} + SI_s) \cdot S_{s,t}^{\text{profile}} \qquad \forall s, t \tag{10}$$

$$E_{e,t} \leq (P_e^{E\max} + EI_e) \cdot E_{e,t}^{\text{profile}} \qquad \forall e, t \tag{11}$$

3. Transmission Capacity Limits

$$F_{l,t} \leq F_l^{\max} + FI_l \qquad \forall l, t \tag{12}$$

$$F_{l,t} \geq -(F_l^{\max} + FI_l) \qquad \forall l, t \tag{13}$$

4. Battery Operation

$$D_{n,t}^{BESS} - C_{n,t}^{BESS} = P_{n,t}^{BESS} \qquad \forall n, t \tag{14}$$

$$P_{n,t}^{BESS} \leq PI_n^{BESS} \qquad \forall n, t \tag{15}$$

$$P_{n,t}^{BESS} \geq -PI_n^{BESS} \qquad \forall n, t \tag{16}$$

$$E_{n,t}^{BESS} = E_{n,t-1}^{BESS} + \eta_c \cdot C_{n,t}^{BESS} - \frac{1}{\eta_d} \cdot D_{n,t}^{BESS} \qquad \forall n, t \tag{17}$$

$$E_{n,t}^{BESS} \leq PI_n^{BESS} \cdot Hr \qquad \forall n, t \tag{18}$$

5. Unserved Energy and Loop Flow Penalties

$$\Delta_{n,t} \leq D_{n,t} \qquad \forall n, t \tag{19}$$

$$F_{l,t}^{LOOP} \geq -F_{l,t} \qquad \forall l, t \tag{20}$$

$$F_{l,t}^{LOOP} \leq F_{l,t} \qquad \forall l, t \tag{21}$$

6. Run-of-River Plants

$$HP_{h,t} \leq HP_h^{\max} \cdot \left(\frac{\text{Prod}_h^{HP}}{HP_h^{\max} \cdot 8760} \right) \qquad \forall h \in HP,\ \forall t \in T \tag{22}$$

7. Reservoir Plants (without profile)

$$\sum_{t \in T} HE_{h,t} \leq HE_h^{\max} \cdot T \cdot \left(\frac{\text{Prod}_h^{HE}}{HE_h^{\max} \cdot 8760} \right) \qquad \forall h \in HE \tag{23}$$

$$HE_{h,t} \leq HE_h^{\max} \qquad \forall h \in HE,\ \forall t \in T \tag{24}$$

8. Reservoir Plants (with profile)

$$E_{h,t}^{HE} = E_{h,t-1}^{HE} + \text{Inflow}_{h,t} - HE_{h,t} \qquad \forall h \in HE,\ t > 1 \tag{25}$$

$$E_{h,0}^{HE} = E_{h,\text{init}}^{HE} \quad \text{(e.g., average monthly value)} \tag{26}$$

$$\text{Inflow}_{h,t} = \text{Prod}_h^{HE} \cdot HE_{h,t}^{profile} \qquad \forall h \in HE,\ \forall t \in T \tag{27}$$

$$E_{h,t}^{HE} \leq \text{Prod}_h^{HE} \qquad \forall h \in HE,\ \forall t \in T \tag{28}$$

9. Energy Sovereignty Constraint

$$\sum_{g \in G_n^{\text{firm}}} \left(P_g^{\max} + PI_g\right) \cdot \alpha_g \geq \max_{t \in T}(D_{n,t}) \quad \forall n \in N \tag{29}$$

2 Formulation of Geopolitical Costs and Losses from Trusting/Not Trusting

This section details the mathematical formulation of the political costs associated with regional energy integration in Latin America. Specifically, we operationalize and quantify three core metrics presented in the main text: (1) the **Geopolitical Cost** of sovereignty preferences, (2) the **Economic Loss from Trusting**, and (3) the **Economic Loss from Not Trusting**. These constructs enable the translation of political dynamics—such as fragmentation, distrust, and risk aversion—into quantifiable economic impacts across scenarios with and without sovereignty constraints (SE).

2.1 Geopolitical Cost (GC)

The Geopolitical Cost captures the economic inefficiency that arises when sovereignty constraints prevent optimal regional coordination. It is defined as the difference in system costs between two scenarios: one that imposes national self-sufficiency requirements (with SE) and one that allows for full regional cooperation (without SE).

$$\Delta\text{OPEX} = \text{OPEX}_{\text{SSE}} - \text{OPEX}_{\text{CSE}} \tag{30}$$

$$\Delta\text{CAPEX} = \text{CAPEX}_{\text{CSE}} - \text{CAPEX}_{\text{SSE}} \tag{31}$$

$$\text{GC} = \Delta\text{CAPEX} - \Delta\text{OPEX} \tag{32}$$

Where: SSE = scenario without sovereignty constraints; CSE = scenario with sovereignty constraints.

The resulting GC value quantifies the annual economic penalty from underutilizing regional synergies due to sovereignty-driven planning. As shown in Fig. 4 of the main article, this cost can reach up to \$7.9 billion annually by 2045, depending on hydrological conditions.

2.2 Economic Loss from Trusting (ELT)

This metric captures the risk exposure of a country that opts to rely on regional integration—reducing local backup investments—under the assumption that the integrated system will perform reliably. If this trust is unmet due to underperformance or lack of coordination, countries may face energy shortages and costly emergency responses.

2.2.1 Power Deficit (DP)

$$DP_i = P_{CT,i}^{\text{GX\&BESS}} - P_{ST,i}^{\text{GX\&BESS}} \tag{33}$$

This expression measures the reduction in local capacity investments (generation and storage) due to reliance on regional imports.

2.2.2 Energy Deficit (DE)

$$DE_i = (\text{IMP}_{CT} - \text{IMP}_{ST}) + (\text{EXP}_{ST} - \text{EXP}_{CT}) \tag{34}$$

DE_i captures the net change in electricity imports IMP and exports EXP for country i between scenarios with (ST) and without (CT) regional optimization.

2.2.3 Loss from Trusting (ELT)

$$ELT_i = DE_i \cdot C_{\text{oil}} + \text{CAPEX}_{\text{oil}}^{\text{GX}}(DP) - \left(\text{CAPEX}_{ST,i}^{\text{GX\&BESS}} - \text{CAPEX}_{CT,i}^{\text{GX\&BESS}}\right) \tag{35}$$

Where:

- C_{oil}: operating cost of emergency diesel generation,
- $\text{CAPEX}_{\text{oil}}^{\text{GX}}(DP)$: investment cost in diesel capacity equivalent to DP_i,
- CT: coordinated transmission scenario (regional optimization),
- ST: status quo scenario (limited or no regional coordination).

This formulation reflects the backup cost borne by a country if regional support fails. Countries with smaller internal systems (e.g., Uruguay, Bolivia) are particularly vulnerable, as illustrated in Fig. 5 of the article.

Note: Calculations assume no sovereignty constraints (SE) and exclude transmission investments.

2.3 Economic Loss from Not Trusting (ELNT)

This metric represents the opportunity cost of maintaining national self-reliance and rejecting regional integration. It measures the excess cost of building and operating standalone systems compared to scenarios that leverage regional cooperation.

$$ELNT_i = \left(\text{CAPEX}_{CSE,i}^{\text{GX\&BESS}} - \text{CAPEX}_{SSE,i}^{\text{GX\&BESS}}\right) + (\text{OPEX}_{CSE,i} - \text{OPEX}_{SSE,i}) \tag{36}$$

$ELNT_i$ quantifies the additional capital and operating costs incurred due to lack of integration. These costs are highest for large, hydro-reliant systems that stand to gain the most from regional diversity (e.g., Brazil, Colombia, Paraguay), as evidenced in Fig. 6 of the main text.

Note: All scenarios exclude future transmission investments in Latin America.

Together, these formulations provide the mathematical backbone for interpreting political fragmentation as a measurable economic burden. By mapping trust dynamics to cost metrics, they offer a structured framework to guide policy design, coalition building, and institutional reform in support of regional energy integration.

3 Cost Assumptions and Emission Factors

The model incorporates technology-specific assumptions for variable costs, annualized investment costs, and carbon emission factors. Table 1 presents the operating costs for thermal power plants. Table 2 summarizes the annual investment costs per megawatt of installed capacity, and Table 3 lists the CO_2 emission factors for thermal technologies. All cost data are expressed in 2025 USD.

Table 1: Variable Operating Costs of Thermal Generators

Technology	Variable Cost	Unit
Coal	46	USD/MWh
Diesel	200	USD/MWh
Gas	91	USD/MWh

Table 2: Annualized Investment Costs by Technology

Technology	Investment Cost	Unit
Gas	113000	USD/MW·year
Diesel	62000	USD/MW·year
Solar PV	80700	USD/MW·year
Wind	115100	USD/MW·year
Battery Storage	30000	USD/MWh·year
Transmission*	30000	USD/MW·year

Note: * 300 km assumed

Table 3: CO_2 Emission Factors for Thermal Technologies

Technology	Emission Factor	Unit
Coal	0.949	ton CO_2/MWh
Gas	0.436	ton CO_2/MWh
Diesel	0.779	ton CO_2/MWh

Table 4 presents the set of international transmission lines considered in the model, distinguishing between existing infrastructure and candidate projects. Existing lines represent the current cross-border interconnections with reported transfer capacities (Fmax), based on regional planning documents and system operator data. Candidate lines are hypothetical interconnections with no predefined capacity, representing strategic opportunities for future regional integration. These candidate links are incorporated into the optimization model as potential investment options and can be selected endogenously depending on their economic and operational relevance. All transmission capacities are expressed in megawatts (MW), and line directions are nominal and assumed bidirectional.

Table 4: Existing and Candidate Transmission Lines

From	To	Type	Fmax (MW)
Costa Rica	Panama	Existing	300
Brazil	Uruguay	Existing	570
Brazil	Argentina	Existing	2250
Paraguay	Argentina	Existing	3200
Paraguay	Brazil	Existing	6300
Uruguay	Argentina	Existing	3990
Argentina	Chile	Existing	200
Argentina	Bolivia	Existing	120
Peru	Ecuador	Existing	100
Ecuador	Colombia	Existing	613
Colombia	Venezuela	Existing	13.5
Mexico	Guatemala	Existing	200
Honduras	Nicaragua	Existing	300
El Salvador	Honduras	Existing	300
Nicaragua	Costa Rica	Existing	300
Guatemala	El Salvador	Existing	300
Panama	Colombia	Candidate	–
Brazil	Paraguay	Candidate	–
Brazil	Bolivia	Candidate	–
Venezuela	Brazil	Candidate	–
French Guiana	Brazil	Candidate	–
Brazil	Guyana	Candidate	–
Paraguay	Bolivia	Candidate	–
Peru	Chile	Candidate	–
Peru	Bolivia	Candidate	–
Chile	Bolivia	Candidate	–
Suriname	French Guiana	Candidate	–
Guyana	Suriname	Candidate	–

4 Hydrological Resource Patterns in Latin America

Hydropower plays a central role in Latin America's electricity systems. However, the seasonal and interannual variability of water inflows differs substantially across countries due to geographic and climatic diversity. Understanding these temporal patterns is essential for regional planning, particularly when designing transmission interconnections and evaluating complementarities between hydro-dominated systems.

4.1 Normalized Hydro Generation Profiles

Figure 1 presents the normalized hourly hydro generation profiles used in the model, grouped by region and country. Each curve corresponds to the median historical series for a given country, and all profiles have been scaled such that the sum of their hourly values over the full year (8,760 hours) equals 1. This normalization allows for a consistent comparison of seasonal and diurnal patterns across countries and regions, independently of their absolute generation levels. The Southern Cone and Andean regions are shown separately, including high and low scenarios for selected countries (e.g., Brazil, Paraguay, Colombia, and Ecuador) to reflect interannual hydrological variability.

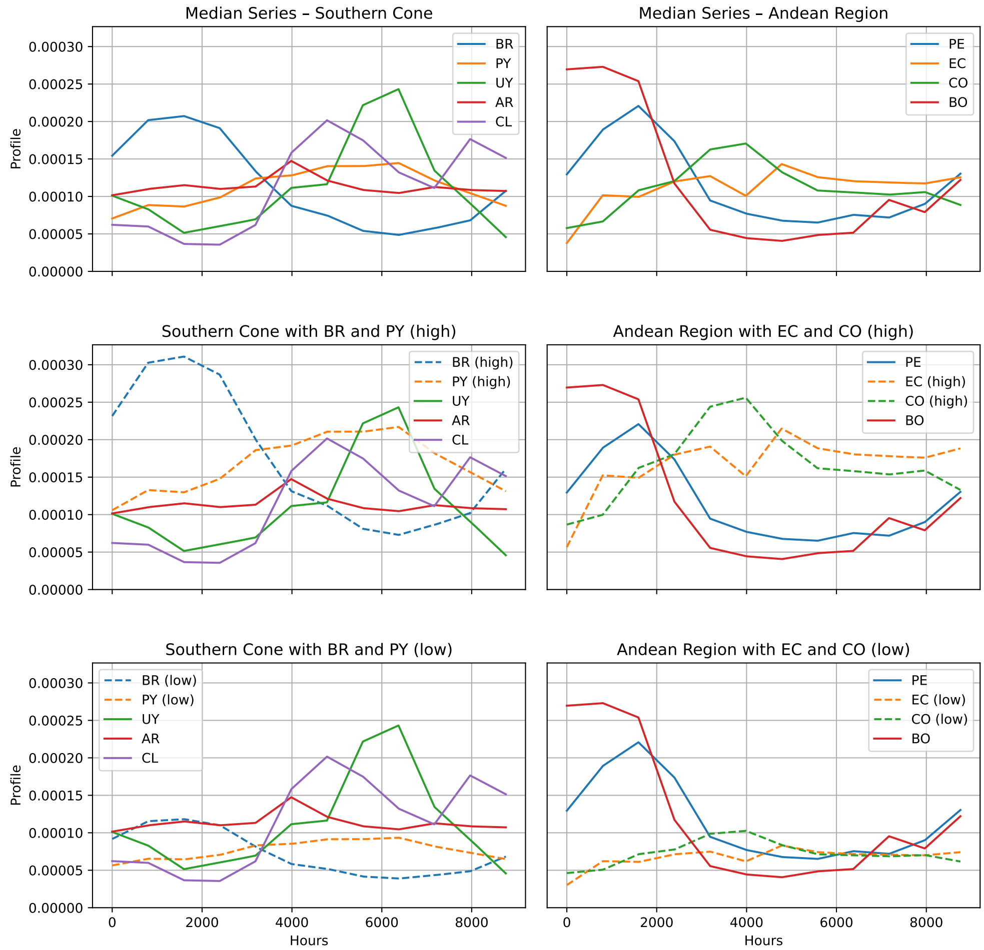

Fig. 1: Normalized hourly hydro generation profiles for selected Latin American countries.

4.2 Hydrological Profile Correlation Analysis

To evaluate the synchronicity and complementarity of hydroelectric production profiles across South American countries, we computed a weighted correlation matrix based on normalized monthly profiles. Each correlation value reflects not only the temporal similarity (positive or negative correlation) between countries but also accounts for the relative magnitude of their expected production. This allows us to identify regions with aligned seasonal behavior as well as those with inverse or offset patterns, which can inform regional integration and diversification strategies.

The matrix reveals several important regional patterns:

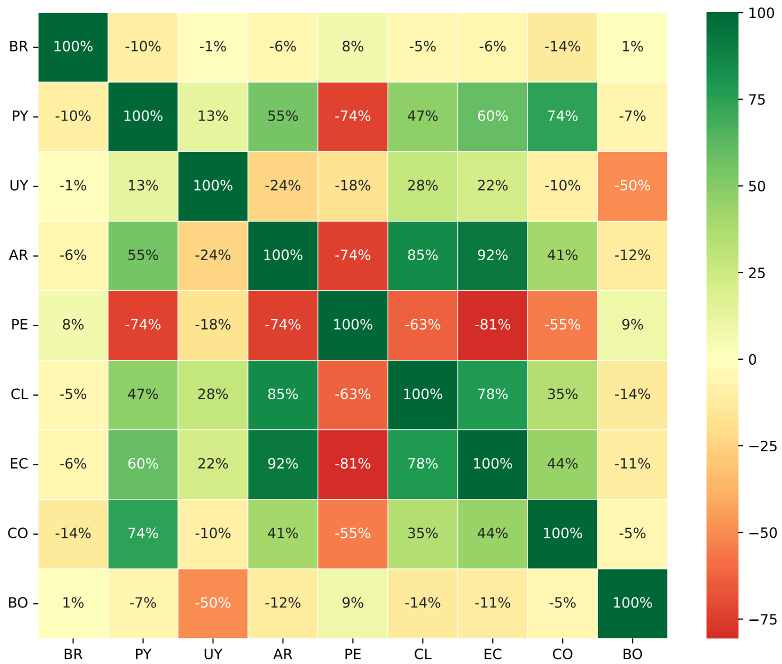

Fig. 2: Signed percentage correlation matrix based on monthly hydro production profiles and their annual expected output.

- **High positive correlations** are observed among Argentina, Chile, and Ecuador (e.g., AR–CL: +85%, AR–EC: +92%), indicating synchronous hydrological behavior. These countries experience similar seasonal patterns, which may limit the benefits of seasonal balancing but could enable shared reserve strategies.
- **Strong negative correlations** emerge between Peru and other countries, notably Argentina (–74%) and Ecuador (–81%). This reflects a high degree of seasonal complementarity and suggests that power exchange between the Andean and Southern Cone regions could enhance system flexibility.
- **Paraguay shows intermediate alignment** with Colombia (+74%), Ecuador (+60%), and Argentina (+55%), pointing to a moderately synchronous but potentially flexible role in regional integration.
- **Brazil and Bolivia exhibit low correlation** with most other countries (e.g., BR–UY: –1%, BO–AR: –12%), suggesting hydrological independence or divergent seasonality.

These insights highlight potential opportunities for regional interconnection strategies, particularly between hydrologically complementary areas such as Peru and the Southern Cone, or Colombia and Argentina.

5 Long-Term Evolution of Cross-Border Transmission in Latin America

Figures 3, 4, and 5 detail the existing interconnections in 2025 and the planned transmission expansions by 2035 and 2045 under the scenario without energy sovereignty. Between 2025 and 2045, the region's cross-border transmission capacity grows exponentially — transitioning from a limited set of links mostly under 4,000 MW in 2025, to a significantly more robust grid by 2035, with multiple corridors exceeding 15,000 MW. Examples include Colombia–Panama (15,533 MW) and Venezuela–Colombia (20,482 MW). By 2045, some links reach and surpass 30,000 MW, such as Venezuela–Colombia (32,618 MW) and Venezuela–Brazil (36,788 MW).

This expansion reflects a strategic shift from a fragmented and bilateral system toward a fully meshed, resilient regional grid designed to enable the large-scale exchange of renewable electricity, enhance energy security, and reduce the geopolitical costs of sovereignty-based constraints. Notably, investment costs for interconnections in this scenario amount to approximately 6.51 billion USD by 2035, increasing by 2 billion USD by 2045.

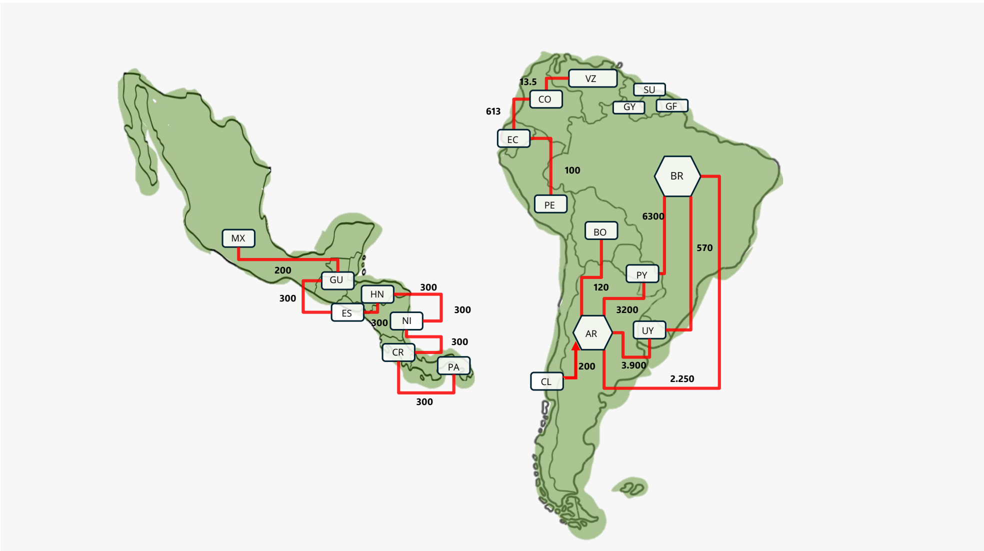

Fig. 3: Existing cross-border interconnections in Latin America by 2025 (base case, without sovereignty constraints).

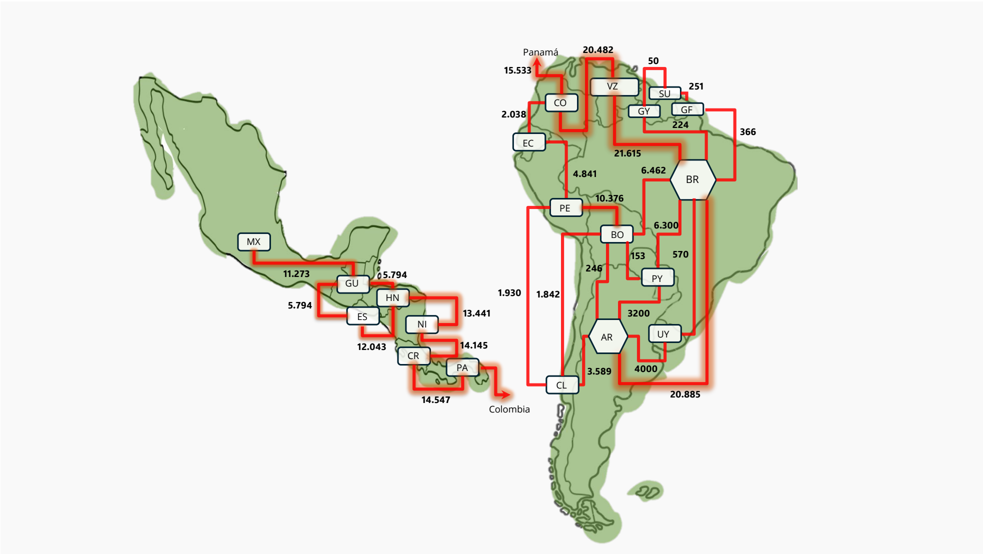

Fig. 4: Planned transmission interconnections and capacity expansions by 2035 (no sovereignty scenario).

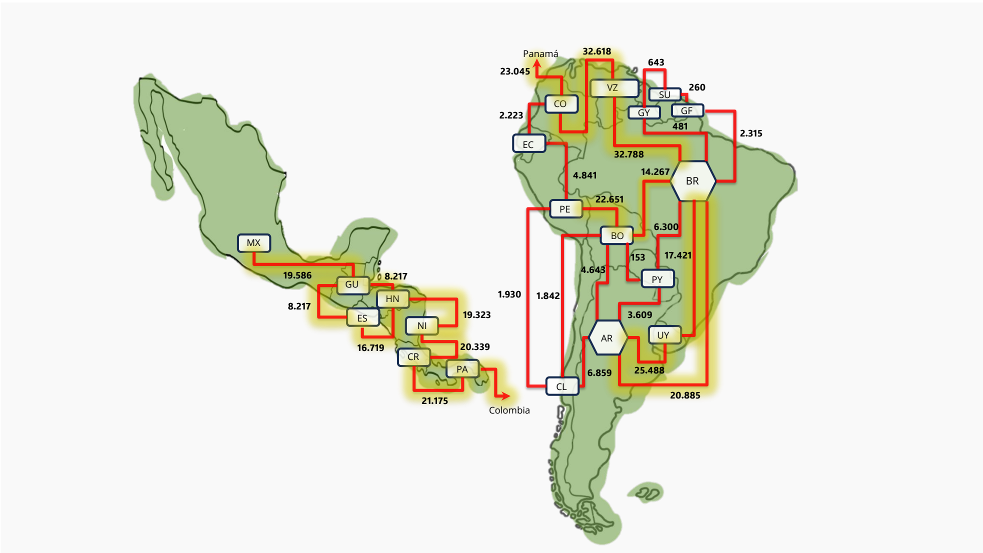

Fig. 5: Planned transmission interconnections and capacity expansions by 2045 (no sovereignty scenario).

On the other hand, Figures 6 and 7 present the same interconnection developments for 2035 and 2045 under the scenario with national sovereignty constraints.

In this case, the overall regional transmission capacity also grows exponentially between 2025 and 2045. Starting from a relatively limited network in 2025, the region achieves stronger interconnections by 2035, with several corridors exceeding 15,000 MW — for example, Colombia–Panama (18,317 MW) and Venezuela–Colombia (19,429 MW). By 2045, these links reach even higher levels, including Venezuela–Colombia (30,307 MW) and Uruguay–Brazil (31,768 MW).

This evolution reflects a coordinated transition toward a resilient and strategically interconnected grid, capable of supporting cross-border renewable integration, enhancing energy security, and mitigating the geopolitical cost of sovereignty. Investment costs for 2035 are estimated at approximately 6.24 billion USD, rising by an additional 3 billion USD by 2045.

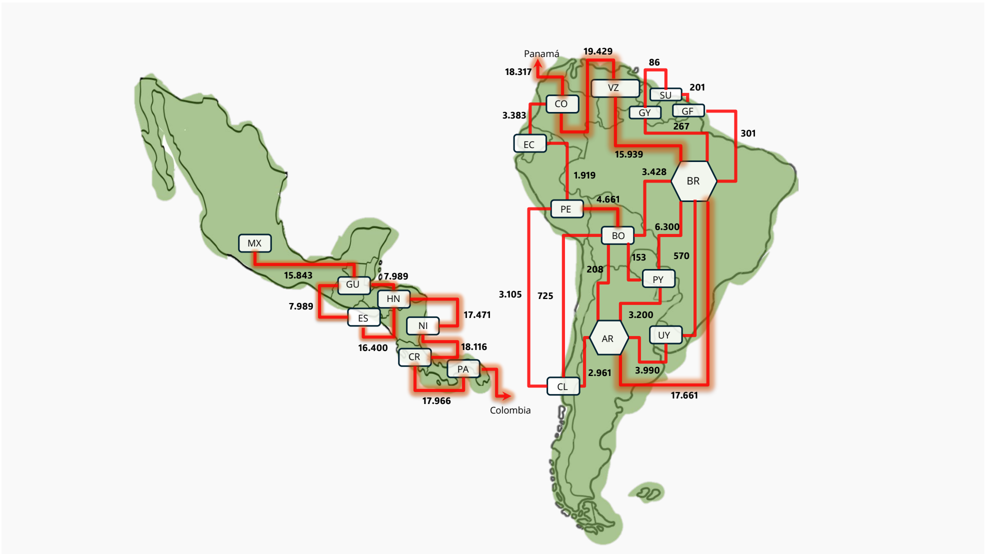

Fig. 6: Planned transmission interconnections and capacity expansions by 2035 (sovereignty scenario).

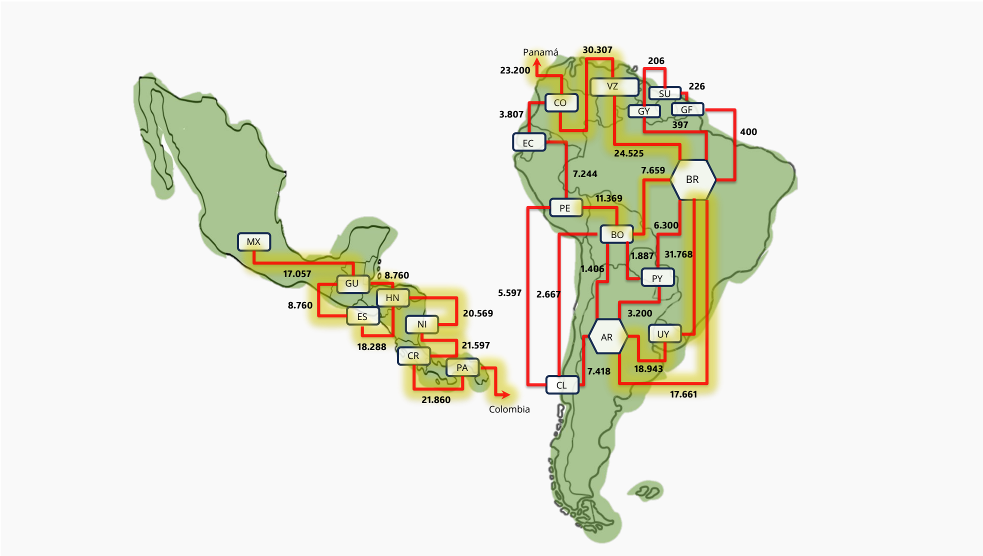

Fig. 7: Planned transmission interconnections and capacity expansions by 2045 (sovereignty scenario).