Policy Research Working Paper 9692

How Much Does Latin America Gain from Enhanced Cross-Border Electricity Trade in the Short Run?

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WORLD BANK GROUP
Development Economics
Development Research Group
June 2021

Abstract

Regional or cross-border trade of electricity would be beneficial for all trading partners for multiple reasons. However, cross-border electricity trade in Latin America is limited, and the potential benefits have been forfeited. This study estimates the potential savings on electricity supply costs if 20 Latin American countries allowed unrestricted trade of electricity between the borders without expanding their current electricity generation capacity. Two hypothetical electricity trade scenarios—unconstrained trade of electricity between the countries within the Andean, Central, and Mercosur subregions and full regional trade involving all 20 countries are simulated using a power system model. The study shows that the volume of cross-border electricity trade would increase by 13 and 29 percent under the subregional and regional scenarios, respectively. The region would gain US$1.5 billion annually under the subregional scenario and almost US$2 billion under the full regional scenario. More than half of this gain would be realized by the Andean subregion under both scenarios. These are short-term benefits without expanding the current electricity generation capacities. In the future, when countries add more generation capacity to meet their increasing demand, the potential benefits of electricity trade would be higher. A further study is needed to measure the increased benefits in the long run.

This paper is a product of the Development Research Group, Development Economics. It is part of a larger effort by the World Bank to provide open access to its research and make a contribution to development policy discussions around the world. Policy Research Working Papers are also posted on the Web at http://www.worldbank.org/prwp. The authors may be contacted at gtimilsina@worldbank.org.

Produced by the Research Support Team

How Much Does Latin America Gain from Enhanced Cross-Border Electricity Trade in the Short Run? [1]

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Key Words: Regional electricity cooperation, Cross-border electricity trade, Latin America, Electricity planning

JEL Classification: Q40, Q50

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[1] The authors would like to thank Virgilio Galdo and Martin Rama for their comments and suggestions, and Remi Gigoux for data collection. Financial support is provided by the Regional Chief Economist's Office for World Bank's Latin America and Caribbean Regional Vice Presidency and Energy Sector Management Assistant Program. The views and interpretations are of authors and should not be attributed to the World Bank Group.

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How Much Does Latin America Gain from Enhanced Cross-Border Electricity Trade in the Short Run?

1. Introduction

Regional or cross-border electricity trade entails several economic and environmental benefits to the participating countries. These include: (i) optimum use of natural resources for electricity generation across the participating countries; (ii) reduction in the total costs of electricity supply in the region as it avoids investment for installing capacities to meet the peak load in a country, instead it imports electricity from a neighboring country at a lower cost; (iii) it avoids additional investments in reserve capacity by pooling together and sharing the reserve margins; (iv) it allows inframarginal trade of electricity thereby increasing the utilization of existing capacities; (v) it reduces reliance on fossil fuel and facilitates introduction of scale-efficient renewable energy resources (e.g., hydro, wind, solar) which would be unexploited otherwise; (vi) trade will improve the supply reliability of the overall system as each sub-system can rely on all other sub-systems during contingency events such as generator outages; and (vii) it facilitates exchange of renewable or clean electricity between the countries that help reduce greenhouse gases (GHGs) and local air pollutants. Total benefits of the trade, including short-term fuel and operational cost savings, long-term capacity savings, reliability, and avoided emissions, can be substantial that far outweigh the cost of building the necessary infrastructure and institutions (e.g., Rogers and Rowse, 1989; Bowen et al., 1999; Yu, 2003; Pineau et al., 2004; Gnansounou et al., 2007; ESMAP, 2010; Timilsina and Toman, 2016; Timilsina and Toman, 2018; Timilsina and Curiel, 2020). Timilsina and Toman (2016) estimate that the South Asia region would save US$100 billion (2015 price) through unrestricted electricity trade in South Asia between 2020 and 2040. It would reduce 8% of the power sector CO_2 emissions during the same time frame (Timilsina and Toman, 2018). Timilsina and Curiel (2020) find that the Middle East and North Africa (MENA) region would benefit US$111 billion (2018 price) during the 2018-2035 period if regional electricity trade is facilitated utilizing the existing cross-border transmission links and also removal of natural gas subsidies.

Regional electricity trade has been exercised in many regions around the world. It has been in practice in North America (Canada and the United States) and Europe for more than 100 years.

The markets for electricity in both regions are highly interconnected. Regional electricity trade has also been initiated in other areas, such as in different parts of Africa, in the Middle East, and in certain parts of Southeast Asia. In Latin America, there exists limited electricity trade regionally in Central America (SIEPAC)[3] and multilaterally or bilaterally in other parts of Latin America, such as Brazil-Uruguay-Argentina. Almost every neighboring country has limited bilateral cross-border transmission interconnections (Del Campo, 2017) in Latin America. However, with the exception of a few (e.g., Argentina-Chile and Brazil-Paraguay), the power flow capacities of these interconnections are small. In fact, the volume of cross-border electricity trade in the region accounts for less than 5% of the total regional generation. Furthermore, about 90% of the trade is Paraguay hydro exported to Brazil and Argentina (IEA, 2020). If this export is excluded, total cross-border electricity trade in the region accounts for less than 0.5% of the regional generation.

One of the key impediments to the regional electricity trade is the lack of regulatory/institutional reforms in the power sector to facilitate the trade. Countries in Latin America are characterized by serious distortions in their electricity market. Some are run by inefficient vertically integrated utilities (Costa Rica), while others have dominant private players with market power (Colombia or Honduras). Argentina, which used to be cited as an exemplary model for reform in terms of unbundling, has completely backtracked, and Uruguay, with an efficient integrated utility, uses electricity as a source of fiscal revenue. Existing regulations often discourage cross-border electricity trade even if cross-border transmission infrastructure exists. Absent necessary reforms in the power sector, investors, mainly the private sector, would not be ready to invest in export-oriented electricity generation and transmission assets. It also hinders the power traders from playing a role to enhance cross-border power trade that helps to benefit trading partners by exploiting the price gaps between them and also better utilizing the existing generation resources. In Europe, significant benefits, in terms of power system reliability, utilization of natural resources, and economic efficiency, were reported when the European Network of Transmission

[3] SIEPAC stands for Sistema de Interconexión Eléctrica de los Países de América Central. The system interconnects electricity grids of six Central American countries: Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and Panama. This 230kV, 300 MW transmission interconnection line is 1,790 km long, extends from Guatemala to Panama, and has been operational since 2013.

System Operators for Electricity was created by linking system operators of various countries (IEA, 2014).

However, a key question is: What would be the size of the foregone benefits due to the lack of cross-border electricity trade that could be retrieved if sectoral reforms facilitate the trade? If benefits are large, it could serve as an additional justification that policy makers could use to rationalize their power sector reforms and facilitate investment in the transmission and other enabling infrastructure. Note that unless policy makers realize the tangible benefits through rigorous quantitative analysis, neither they get motivated to move forward with this agenda, nor the other stakeholders, particularly development partners, have the necessary justification to support such initiatives.

The objective of this study is to estimate the gains from sub-regional and regional electricity trade in Latin America. The Electricity Planning Model (EPM) developed by the World Bank (Chattopadhyay et al. 2017) is employed for the analysis. The focus of this study is the short-term benefits that can be realized through infra-marginal trade (day-ahead, intra-day, and balancing services) if the electricity system interconnections are facilitated in LAC through power system reforms. Newberry et al. (2016) show that the short-term electricity trade in Europe would have benefitted the region by about 3.4 billion euros per year. There exist a few studies analyzing the short-term benefits of bilateral electricity trade between countries in LAC (Agostini et al. 2018), but no such study exists from a regional perspective.

The paper is organized as follows: Section 2 highlights the rationale behind the increased cross-border electricity in LAC. Section 3 briefly presents the methodology, data, and scenarios analyzed. Results of the model simulations are discussed in Section 4. Key conclusions are drawn in Section 5.

2. Rationales for Cross-Border Electricity Trade in LAC

As indicated in the introduction section above, there are several benefits of cross-border electricity trade. In this section, we provide evidence or quantitative indicators of the potential benefits the cross-border trade in the LAC region. We highlight three strong reasons that indicate LAC countries should enhance their cross-border interconnection and trade. The first indicator of potential enhanced cross-border trade is the existing reserve capacities or the capacities in excess of peak loads that sit idle in the absence of cross-border interconnection and trading facilities. Countries can utilize these capacities, which have already been built, and their capacity costs are already sunk. They can benefit by utilizing these unused capacities. Second, sharing peak load capacities can reduce the volume of 'reserve capacity' that would otherwise be needed in individual countries. Different countries have peak loads in different periods in a day and different months in a year. The capacities sit unutilized in other periods. Cross-border interconnections provide an opportunity to utilize these capacities because of differences in profiles of loads (hourly as well as daily or monthly) across the countries. Countries do not trade unless there is a win-win situation for trading parties. A country gains if importing electricity would be cheaper than producing at home to meet the demand in a given hour, keeping all other factors such as geopolitical factors aside. The difference in electricity production costs (marginal and average costs) between the countries is another driver of cross-border electricity trade. Below we present the evidence of these factors or potential drivers.

2.1 Installed capacity in excess of peak load

2.1.1 Gross installed capacity in excess of peak load

A typical characteristic of a power system or grid is that it should have a much higher installed capacity than the maximum load (peak load). There are two reasons for this. First, a power plant, especially hydro and other renewables, is not available to run at its full or rated capacity because input energy carriers (i.e., water for hydro, sun irradiation for solar) may not be available at the time when peak load occurs. This situation arises in dry seasons for hydro and at night for solar. Therefore, a much higher capacity is needed to install to meet the peak load if the system is hydro dominant.[4] Conversely, during the wet season, a hydro-dominated system may have excess energy that can be exported to reduce expensive thermal generation, especially liquid fuel like diesel or heavy fuel oil-based generation, in a neighboring system. Secondly, power plants which are not constrained by their input energy carriers (i.e., fuel supply) are also not available throughout a year because of scheduled and unscheduled outages. Therefore, power systems must have ready

[4] Normally, rated capacity of a hydro power plant is available to generate electricity between 40% to 60% of the total time (8,760 hours) in a year. For solar, the capacity is available 18% to 25% of the time (Timilsina, 2020).

to run or spinning reserve capacity on top of the generation capacity needed to meet the peak load so that these reserve capacities can guaranty uninterruptible power supply even when some power plants are out of operations in a given hour (especially during the peak load). If two power systems (grids) are interconnected, they can share these spinning reserve capacities. They can save investment from adding reserve capacities. Figures 1a and 1b indicate the potential of savings in reserve capacities.[5] Figure 1a shows the installed capacity in access to peak load. Most of the countries in LAC (Bolivia, Brazil, Bolivia, Chile, Costa Rica, Ecuador, El Salvador, Guatemala, Nicaragua, Paraguay, Peru, Uruguay, and the República Bolivariana de Venezuela) have installed capacities almost equal to two times or higher than their peak loads (please see line graph in Figure 1a).

Figure 1a: Installed (gross) capacity in excess of peak load

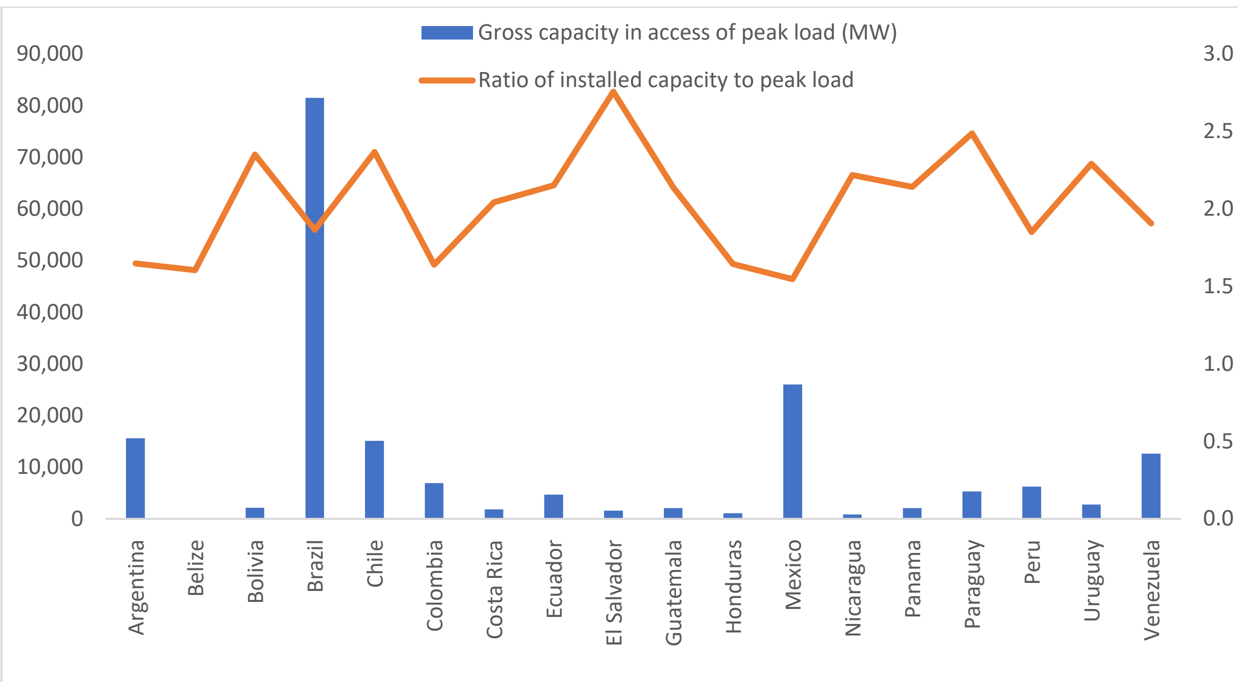
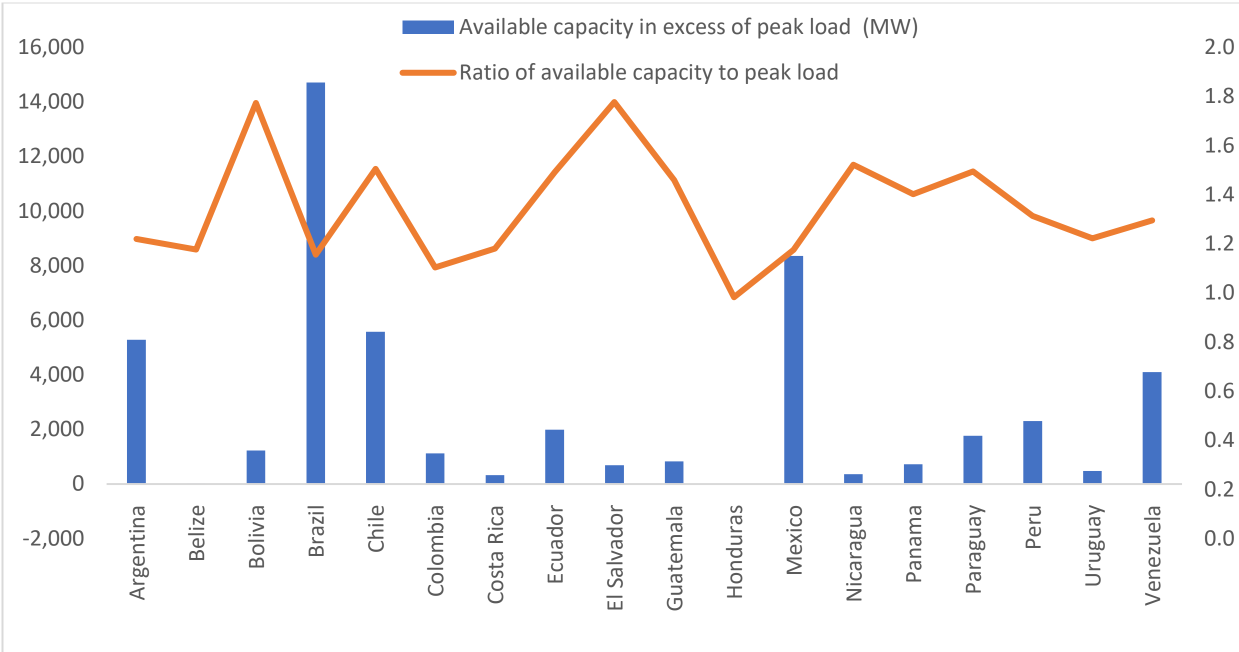


Figure 1b: Adjusted installed (net or available) capacity in excess of peak load

[5] The savings would be more than the reserve capacities because interconnection also allow capacities to meet the peak loads, especially when peak loads occur in different time periods. This will be explained in the next section.



The total installed capacity above peak load is not a good indicator of showing potential cross-border trade because not all installed capacity is available to operate in a given time for the reason explained above. We adjusted the installed capacity with its availability factor and reproduced Figure 1b. Even after the adjustment with the availability factors, some countries, such as Bolivia, El Salvador, have a net capacity 80% higher than their peak loads. If these countries' power systems were interconnected with that of their neighbors, they could have saved much of these excess capacities. These excess capacities provide a good indication of cross-border electricity trading potential in the future.

2.2 Difference in hourly and seasonal daily load profiles

2.2.1 Hourly load profiles

One of the key indicators to demonstrate the potential of cross-border trade is the difference in load curves among the countries. The load curves between the countries are different in a given day, thereby showing the potential for daily trading between them. They are also different across the seasons or months, indicating the potential for seasonal electricity trade among the countries.

Figures 2a to 2c show the daily load curves for every month in the Andean, Central and Mercosur regions of Latin America. More detailed load profiles are provided in Appendix A.

In the Andean region, Bolivia, Colombia and Ecuador have evening peaks, whereas Peru has day peaks. This implies that Bolivia, Colombia and Ecuador can sell electricity to Peru during the day, whereas reverse trade could happen during the evening thereby, all countries benefit from the daily trading. The figures also indicate that hourly peak loads during the weekends and holidays are about 7% smaller than that on the weekdays in Colombia and Ecuador and about 5% smaller in Peru.

In the Central region, all countries have evening peaks; however, Nicaragua and Mexico's afternoon peak loads (3 PM to 5 PM) are not much different from their evening peak loads (7:30 PM to 9 PM). On the other hand, Guatemala's peak loads during the daytime (11 AM to 12:30 PM) are 80% lower than its evening peak loads (5 PM to 6 PM). The difference in these hourly load curves indicates the hourly cross-border trade of electricity among these countries. As illustrated in Figure 2b, hourly peak loads during the weekends and holidays are about 10% smaller than that on the weekdays in Costa Rica and Mexico and 5%-7% smaller in El Salvador, Guatemala and Nicaragua. Interestingly, the shapes of weekends/holidays hourly load curves are different from that of weekdays hourly load curves. Mexico's weekends/holidays hourly load curves are relatively flat during the day and evening time, whereas that is not the case in other Central American countries. The evening peaks in Guatemala and Nicaragua are much higher than their daytime peaks. Moreover, the holidays (except weekends) in these countries may fall on different dates, thereby providing further opportunities for cross-border electricity trades in these countries.

Unlike Andean and Central American countries, Mercosur countries have day peaks instead of the evening peak. This suggests hourly trade potential between the Mercosur region and other regions. The Mercosur countries can export electricity to other regions during the evening time and import it during the daytime. Within the Mercosur region, the shapes of hourly load curves are different between the countries. The difference in load shapes also indicates daily trading opportunities. The load curves are also different across the months, which implies hourly cross-border trading opportunities in some months, if not all.

Figure 2a: Hourly load curves by month in the Andean region

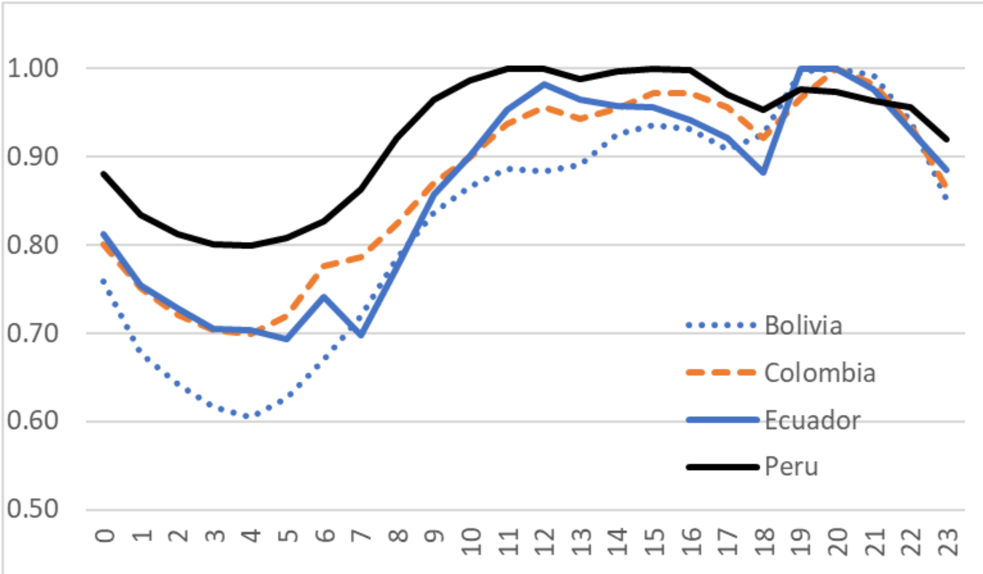


Figure 2b: Hourly load curves by month in the Central region

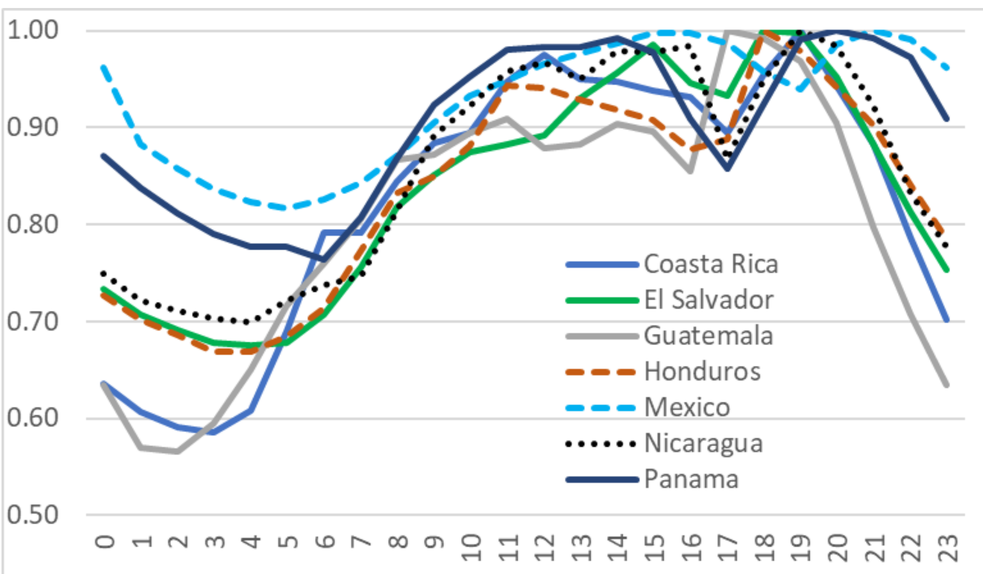
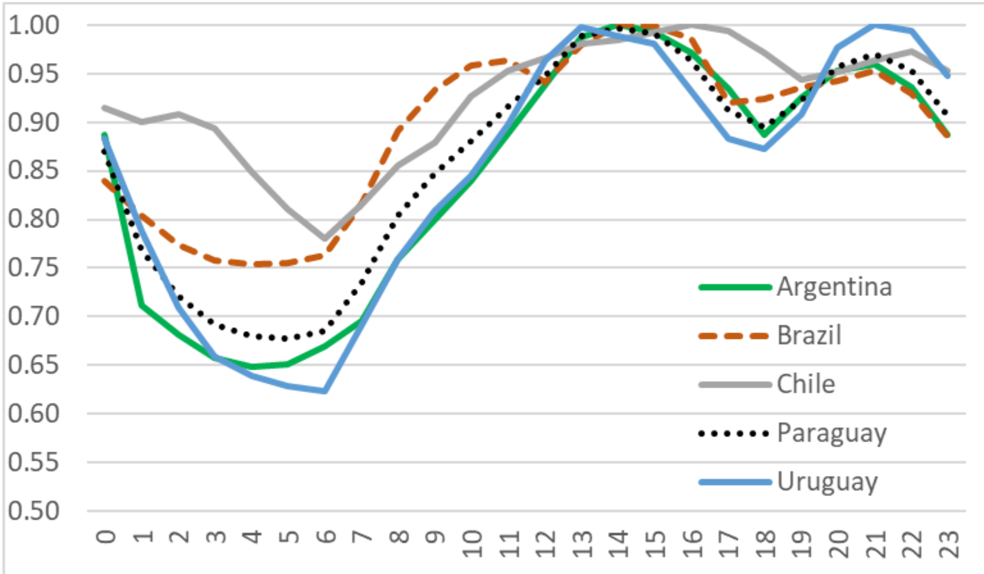


Figure 2c: Hourly load curves by month in the Mercosur region



2.2.2 Seasonal load profiles

Cross-border electricity trade opportunity also occurs due to seasonal or monthly difference in loads between the countries. Figure 3a to 3c presents monthly variations of peak loads between countries in different regions. The seasonal variations of loads provide bigger opportunities for electricity trade between the regions than countries within a region. This is because countries within a region fall in the same climatic zone and therefore do not show significant variations of peak loads or hydro energy availability across the months. For example, peak load occurs during February- March in all Andean countries (Figure 3a). Similarly, April and May exhibit the lowest electricity demand in all Andean countries. In the Central America region, El Salvador, Guatemala and Mexico exhibit peak loads from August to October. They have the lowest demand in the May-June season. It would be interesting to see the hourly and seasonal cross-border electricity trade between the countries in Andean, Central and Mercosur regions and also between these seasons.

Figure 3a. Monthly variations of peak loads in the Andean region

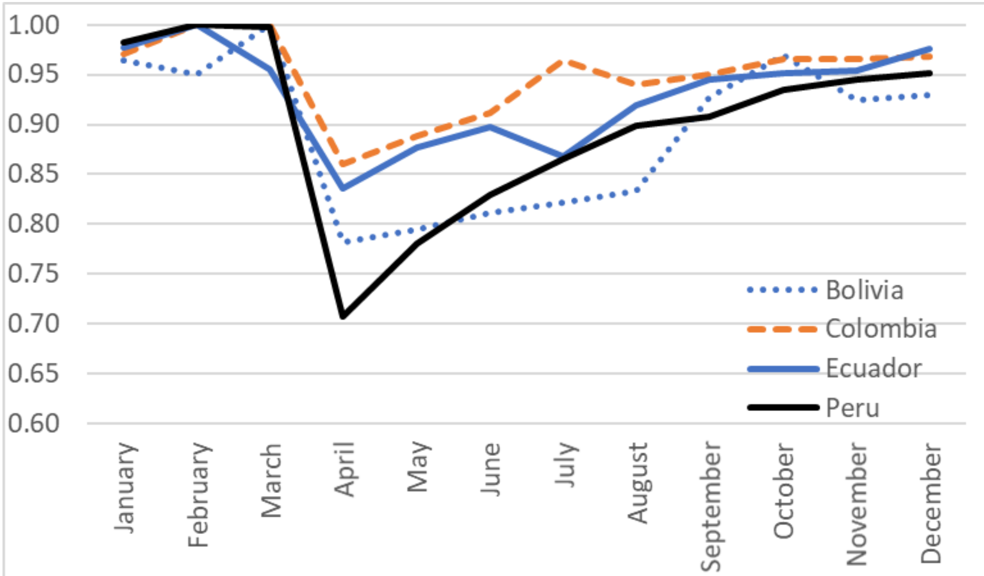


Figure 3b. Monthly variations of peak loads in the Central region

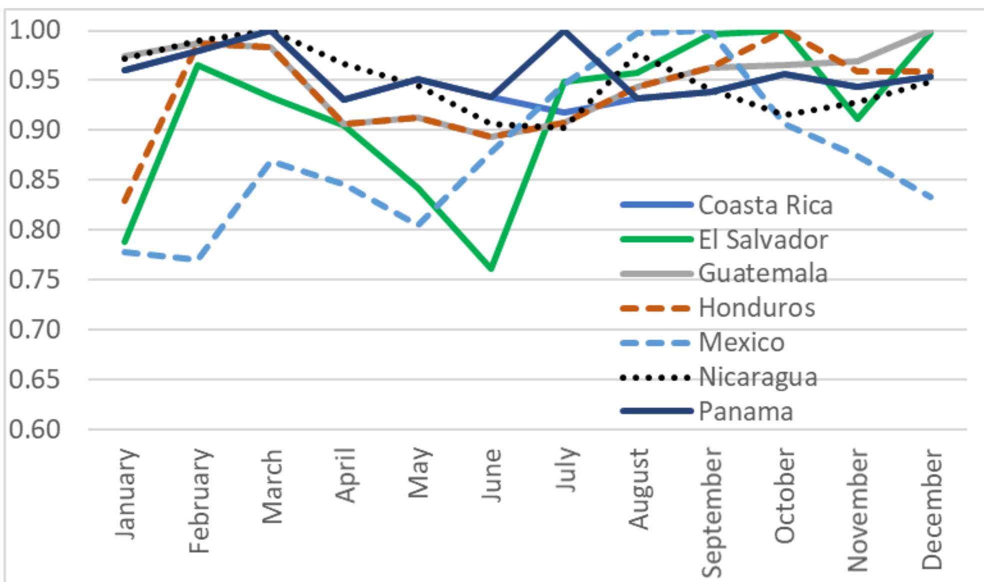
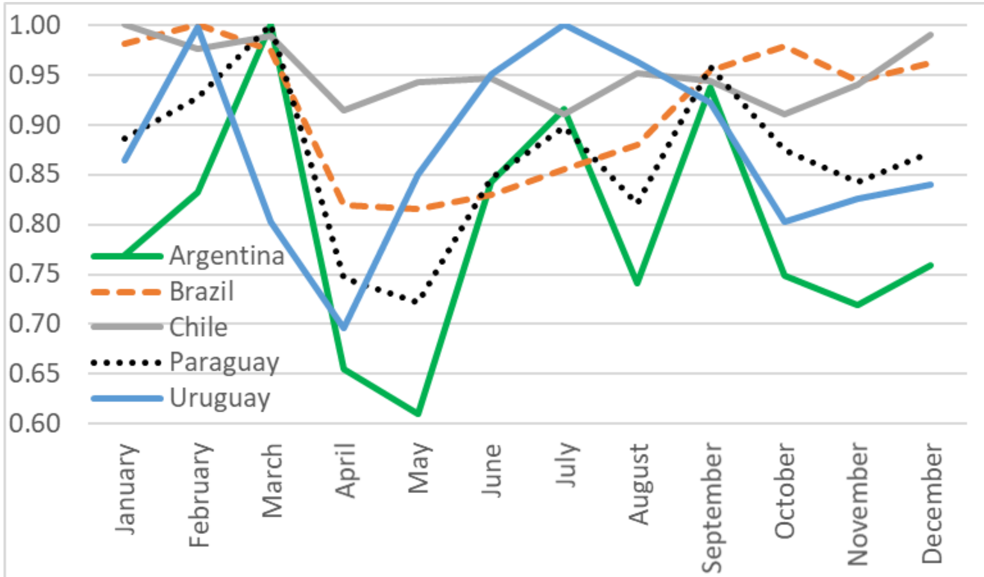


Figure 3c. Monthly variations of peak loads in the Mercosur region



2.3 Difference in electricity generation costs

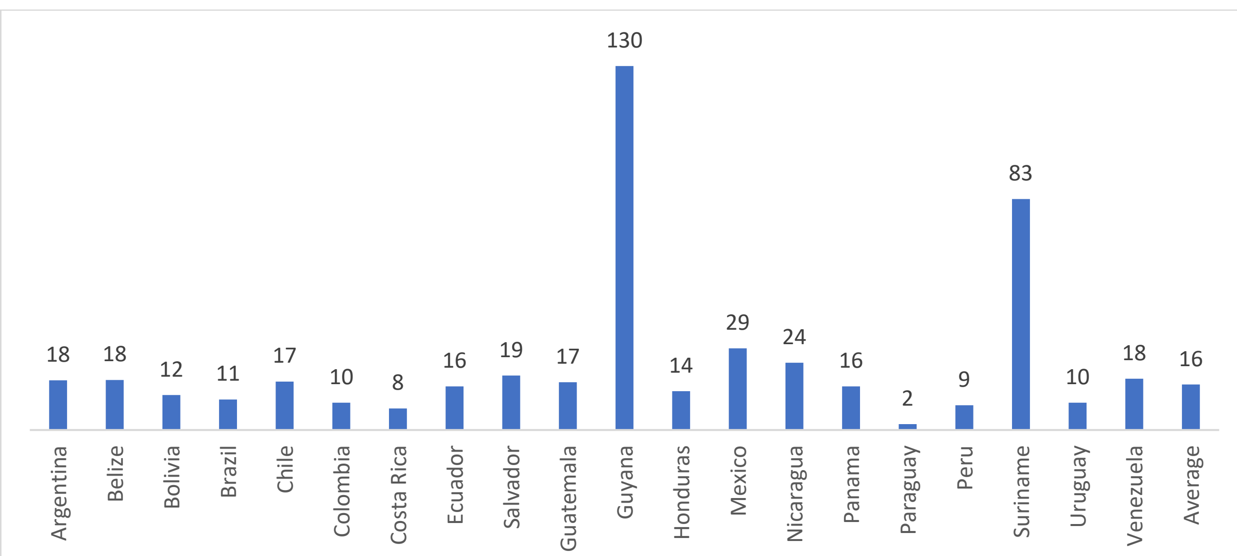
Countries can benefit from cross-border electricity trade when electricity generation costs vary between them. If surplus electricity is available across the border much cheaper than producing at home, it would be beneficial to import. However, this benefit is not realized for several reasons, including geopolitical reasons, which are beyond the scope of the study. Other reasons include lack of cross-border transmission interconnections, different rules and regulations governing electricity across the countries. For example, if electricity plants enjoy subsidized fuels (e.g., natural gas), a country may not have the interest to export its subsidized electricity unless the export price it receives is higher than its electricity costs net of subsidies. There may also be restrictions on cross-border trade from a power system security perspective that goes beyond transfer capability. For example, if one of the systems has a weak transmission system and inadequate spinning reserve capability, it may suffer from significant frequency and voltage excursions. In an interconnected system, a weak power system prone to such frequency/voltage excursions may cascade from it to other systems and bring down the entire interconnected grid. There may also be other policy-driven restrictions, including energy security, that might prevent a country from being overly reliant on imports to meet its electricity needs, even if it makes sense otherwise.

2.3.1 Difference in average costs of electricity production

Figure 4 presents a comparative picture of average electricity generation costs in Latin American countries. Guyana and Surinam exhibit the highest costs of power generation because their electricity systems are mainly diesel-based. Diesel is the most expensive fuel for power generation. Paraguay has the lowest cost of electricity generation because its entire power generation system is hydro-based. Since hydropower plants do not have fuel costs and other O&M costs are also relatively low, electricity generation from already built hydropower plants would be the cheapest. Other countries where hydro is the predominant source of electricity generation (e.g., Brazil, Costa Rica) also enjoy a relatively lower variable cost of electricity generation. Although natural gas accounts for 40% of the electricity generation mix in Peru (the remaining is mostly hydro), its electricity generation costs are also low because of lower natural gas prices in Peru as compared to other Latin American countries (except in Bolivia). However, if opportunity costs of natural gas (i.e. export price) are used instead of the actual price, the cost of electricity generation would be higher. We will highlight it in the sensitivity analysis later. If we keep aside Guyana and Surinam, the small countries with the predominantly diesel-based generation, the average cost of electricity generation is the highest in Mexico because of the high price of natural gas that accounts for more than 60% of total electricity generation.

Figure 4. Short-run average costs of electricity generation in Latin American countries

(US$/MWh, 2020 price)



Note: The costs do not include capital costs as the capital costs are sunk costs

2.3.2 Difference in marginal costs of electricity production

While the difference in average costs broadly indicates the incentive for cross-border trading, it is the marginal costs that provide a clear signal for cross-border trade. If two countries have different load profiles (e.g., hour, month) and if their hourly and monthly marginal costs are different, the incentives or benefits of cross-border trading would be higher. In other words, the difference in marginal costs is a better indicator of cross-border trading than the difference in average costs. Table 1 presents monthly representative marginal costs for LAC countries.

The variations of marginal costs depend on the generation mix in a country. If marginal plant type is the same across the hours and months, marginal costs do not vary unless the country trades electricity with other countries which have different types of generation mix. In Argentina, for example, marginal costs of electricity generation would be the highest in March, July and October. These are the same months electricity demand would be the highest in the country. In Paraguay, the cost of electricity production is virtually zero in some months when demand is small and the excess electricity is sold to Brazil and Argentina. On the other hand, marginal costs would be the highest when Paraguay imports electricity from Brazil as Paraguay's marginal costs during the importing time are the marginal cost of the imported electricity.

Table 1. Monthly marginal costs of electricity generation

Country	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Range
Argentina	19	19	24	19	19	19	24	19	24	19	19	19	19 - 24
Belize	31	31	31	30	30	44	50	66	67	51	30	31	
Bolivia	11	11	11	11	11	11	11	11	11	11	11	11	11 - 11
Brazil	12	36	24	0	0	0	0	0	12	12	12	12	0 - 36
Chile	23	23	23	23	23	23	23	23	23	23	23	23	23 -23
Colombia	52	56	56	19	41	43	43	43	43	52	47	52	19 - 56
Costa Rica	19	25	31	12	31	12	31	31	31	31	31	31	12 -31
Ecuador	90	90	59	19	42	45	45	45	48	54	48	54	19 - 90
El Salvador	19	26	32	12	32	12	32	30	32	32	32	32	12 - 32
Guatemala	19	25	25	12	25	12	25	25	25	25	25	25	12 - 25
Honduras	20	26	34	13	34	13	34	31	43	97	41	42	13 - 97
Mexico	32	32	32	32	32	47	54	71	71	54	32	32	32 -71
Nicaragua	19	26	32	12	32	12	32	32	38	90	37	38	12 - 90
Panama	19	26	32	19	32	19	32	32	32	32	32	32	19 -32
Paraguay	11	34	23	0	0	0	0	0	11	11	11	11	0 - 34
Peru	19	24	19	14	14	14	14	14	14	14	14	14	14 - 19
Uruguay	12	20	12	0	0	12	12	12	12	11	11	12	0 - 20
Venezuela, RB	54	54	54	42	42	45	45	45	45	54	54	54	42 -54

3. Analytical Model, Assumptions, Scenarios, and Data

3.1 The model

The study uses the EPM developed by the World Bank (Chattopadhyay et al. 2017; Chattopadhyay et al. 2018). A detailed description of the model is provided in Appendix B. The conceptual foundation of the model is also available in Timilsina and Toman (2016) and Timilsina and Curiel (2020). EPM is a long-term planning model that determines both capacity expansion decisions, including the selection of power plants and transmission lines across the zones/countries, as well as dispatch (or operational) decisions on when and how much to use both existing and newly built plants and lines. It is an inter-temporal or dynamic optimization model that determines a sequence of investment decisions over the years to build new power generation capacities while optimizing the least-cost option to meet the projected load satisfying the resource, technological, environmental, policy, and any other constraints. The long-term investment planning and the short-term economic dispatching are part of a single joint optimization process as opposed to two separate stages. However, for this analysis, we used only the short-term dispatching component (module) of the model wherein the capacity decisions are already made and restricted to existing plants and lines only.

In short-run mode, the model minimizes the total costs of electricity production from already installed capacities. It includes fixed operation and maintenance (O&M) costs together with fuel costs, variable O&M costs, and cost of reliability (cost of energy not served) in all zones (or grids). It does not account for capital cost because it is a sunk cost. The cost minimization problem is subject to several physical constraints, such as total energy demand equals the sum of generation, import and non-served energy, less export; power generation does not exceed the maximum and minimum output limits of a unit; power generation is constrained by ramping rates or limits; reserves are committed every hour to compensate forecasting errors; renewable generation is constrained by their resource profile (i.e., the hourly rate of availability). There are capacity limits on generating units and also inter-temporal daily/seasonal limits on some energy plants such as hydro generators. In addition, flows across countries/zones are limited by the transfer capacity limits that are also exogenously fixed in the current analysis to the level of existing capacity.

One critical factor of sizing a generator is its minimum load requirement. It is the parameters either specified by the manufacturer or calculated as the minimum load required for a generating unit to produce energy economically. In a power system model, it is approximated through a simple dispatch model for representative hours of the year. This constraint forces that all generating units should serve at least their minimum loading levels for specific days in the year.

Renewable generation differs from conventional units because it is intermittent, meaning generation resources (e.g., solar, wind) are not available at certain hours in a day or may disappear all of a sudden (overcast sky). This means the power outputs of a renewable generator are beyond the control of producers. Based on the forecasts of resource profile (e.g., weather forecast), the electricity generation profiles are approximated for each renewable energy technology in terms of the hourly capacity factor for a year for a plant of a given type (e.g., solar, wind) at a specified location.

The marginal cost of supply: The model produces the marginal cost of electricity for each block considered in the model. The marginal cost for a particular hour in a country/zone reflects the additional cost that the *system* will incur if an additional MWh needs to be supplied. The presence of inter-temporal constraints like hydro that may span across the day and possibly months means that the marginal cost, or shadow price of the demand constraint in the optimization model, is "linked" across the hours. This is because an MWh demanded in an hour has implications for how the supply will be met in all other hours of the day/month/season. For instance, if a hydro generator is on the margin to meet the extra MWh, there is an opportunity cost of that unit that could be used in another hour of the day/month/season. In a hydro-dominated system like several of the LAC countries, marginal costs tend to be uniformly spread across the hours for this reason, i.e., they tend to be very close to each other if not identical, reflecting the economically optimal outcome. This is typical of prices in a hydro-dominated market that tend to demonstrate a "smoother" price duration curve compared to a thermal system with a greater degree of variability across hourly prices as the marginal generator changes, say from coal to gas or liquid fuel. On the other hand, marginal costs in a hydro-dominated system like LAC may exhibit greater seasonal and interannual variability to reflect significant variation in the hydro energy availability over these timescales. The marginal cost of one system will also be linked across the zones/countries. If the transfer limit across two countries is not reached, i.e., the marginal unit of supply for an importing country could come from another country. The marginal cost for the importing country would then reflect that of the exporting country separated by transmission losses on the interconnector. If the transfers reach the limit on the interconnector, this link is "broken," and each country will have its marginal generator that sets the price. As the discussion above alludes to, if we look at some hydro-dominated systems that are highly interconnected – as we assume in some of the trading scenarios – marginal costs will converge both in space and time that is entirely consistent with the underlying economically optimal dispatch.

Price convergence is, in fact, what *should* also happen in a wholesale regional electricity market. Marginal costs are the prices of electricity in a competitive market in the absence of any distortions in the market (i.e., absence of subsidies, taxes). As discussed earlier, the difference in the marginal costs of electricity is the main driver of cross-border electricity trade. A country with higher marginal costs of electricity production tends to import electricity from the one with lower marginal costs of electricity production, subject to generation and transmission capacity constraints. In the process, the marginal costs of the two systems will come closer, raising the price for the exporting country and reducing it for the importing country, albeit they will always be differentiated by transmission loss factor. The model produces an optimal mix of electricity generation in each country for both domestic consumption and export, including the level of exploitation of renewable energy resources for electricity generation. If the generation is not enough in a given time slot, it imports or pays the penalty for not being able to meet the demand. Based on the model results, cost savings due to the cross-border electricity trading are calculated by subtracting the total costs of electricity supply in the baseline from the total costs of electricity supply under the trading scenarios.

3.2 Key assumptions

The least-cost planning/dispatch model implicitly assumes a perfect or purely competitive market. It means all participants behave in a perfectly competitive manner (the power plant owners submit their true costs as bids). This is an optimistic assumption but a standard assumption in economic analysis.

The model assumes merit-order load dispatching. It means a power plant with the lowest operational cost is dispatched in a given time slot to meet the demand. In practice, it is not necessary that merit-based dispatching is always followed.

The study considers unconstrained electricity trade in the trading scenarios. The word 'unconstrained' needs some attention here. It is a purely hypothetical or ideal case. It may not be realized from a practical perspective but is deliberately created to get an understanding of the absolute maximum level of (gross) benefits that may be realized. However, it is necessary to assess the maximum (upper ceiling) benefits that countries can be realized in an ideal situation, namely, a perfectly competitive market with unlimited transfer capacity. The actual benefits from trade could be lower than this situation as market imperfections and transfer capacity limitations are introduced.

The model does not account for transmission and distribution costs. There are three key reasons for this: (a) the primary objective of this analysis is to develop a first-cut upper bound estimate of gross benefits only so that policy makers can form a view on an unconstrained view of trade benefits; (b) the analysis has been cast as a retrospective one looking at "foregone" benefits that could have been realized and as such the model has been set in dispatch mode without allowing for capacity expansion of transmission; [6] and (c) transmission costs can be estimated and compared with the gross benefits to undertake a cost-benefit analysis exogenous to the model. It should also be mentioned that a proper account for transmission would require a load flow analysis of the entire regional power system covering thousands of substations and lines that spread across the region. It is quite complicated even for a single country analysis due to a lack of data on spatial electricity demand and transmission and distribution assets. In this study, we include 20 countries. We could use the costs of transmission interconnections, however considering costs of generation and transmission facilities makes sense only in the long-run analysis, not in a short-term (one year) analysis like this one. We will expand the study for a long-term analysis in the next phase.

3.3 Scenarios

[6] It should be noted that EPM does perform a co-optimization of interconnectors at a high level (i.e., across the countries and zones but ignoring the detailed transmission network within each country/zone), i.e., endogenously determine if one or more cross-border interconnector should be included in the optimal capacity plan.

The study considers three scenarios: baseline scenario, sub-regional trading scenario and full-regional trading scenario. Their definitions are as follows:

- **Baseline**: In the baseline, each country dispatches its power plants following the merit-order rule and meets its demand in **2020**. It accounts for existing cross-border electricity trading facilities.
- **Sub-regional trading scenario**: This scenario considers a hypothetical situation where countries within the sub-region would have traded electricity without any constraint in 2020. There are three sub-regions: Andean, Central, Mercosur. The Andean sub-region includes Bolivia, Colombia, Ecuador, Guyana, Peru, Suriname and the República Bolivariana de Venezuela. The Central sub-region includes Belize, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua and Panama. The Mercosur sub-region includes Argentina, Brazil, Chile, Paraguay and Uruguay.
- **Regional trading scenario**: This scenario also considers a hypothetical situation where countries within the entire LAC region would have traded electricity without any constraint in 2020.

3.4 Data

A large amount of data has been collected for the study. The main data collected are:

(i) Inventory of electricity generation capacities for 10 types of power plants: gas combined cycle, gas simple cycle (or gas turbine), coal (steam turbine), diesel (internal combustion), hydro (reservoir, run of river and pumped storage), nuclear, solar (PV and solar thermal), coal, geothermal, wind and biomass. The installed capacities of these technologies are provided in Table 2.

Table 2. Installed capacity for power generation by plant type in 2020 (MW)

	Biomass	Gas CC	Gas GT	Hydro	Diesel	Nuclear	Solar	Coal	Geothermal	Wind	Total
Argentina	46	11,267	7,387	11,310	1,663	1,755	439	4,153	-	1,609	39,629
Belize	53	-	20	54	43	-	-	-	-	-	169
Bolivia	151	1,180	1,168	759	336	-	121	-	-	27	3,741
Brazil	14,064	11,048	5,097	104,603	4,297	1,990	2,074	5,856	-	1,487	150,516
Chile	472	3,438	3,478	6,949	1,404	-	3,258	4,600	40	2,507	26,145
Colombia	150	2,487	853	11,922	141	-	118	1,973	-	18	17,662
Costa Rica	71	-	156	2,418	318	-	5	-	262	421	3,652
Ecuador	152	-	922	5,091	2,026	-	28	462	-	21	8,701

El Salvador	252	378	82	548	612	-	474	63	-	50	2,459
Guatemala	1,036	-	128	1,577	413	-	93	471	49	107	3,874
Guyana	40	-	-	5	320	-	6	-	-	0	370
Honduras	221	-	15	753	912	-	511	90	35	234	2,771
Mexico	1,011	28,443	5,728	12,642	1,964	-	214	18,509	926	4,203	73,640
Nicaragua	217	-	65	156	688	-	14	74	155	186	1,553
Panama	8	381	268	1,791	775	-	199	167	-	270	3,860
Paraguay	22	-	-	8,810	25	-	-	-	-	-	8,857
Peru	72	3,365	3,634	5,232	452	-	285	211	-	375	13,625
Suriname	2	-	-	189	301	-	7	-	-	-	499
Uruguay	425	-	1,106	1,538	84	-	256	-	-	1,514	4,922
Venezuela, RB	50	3,630	3,380	17,115	-	-	1	2,206	-	125	26,508
Total	18,512	65,617	33,487	193,462	16,773	3,745	8,101	38,834	1,466	13,155	393,153

Source: See Appendix C.

(ii) Peak load and annual generation. Please see these data in Table 3.

Table 3. Peak load and annual energy demand in 2020

	Peak Load (MW)	Annual energy demand (GWh)
Argentina	24,038	135,244
Belize	105	637
Bolivia	1,591	9,169
Brazil	94,182	620,720
Chile	11,044	75,931
Colombia	10,764	72,935
Costa Rica	1,787	10,405
Ecuador	4,041	26,276
El Salvador	892	6,714
Guatemala	1,810	11,363
Guyana	133	1,205
Honduras	1,685	9,266
Mexico	47,604	334,398
Nicaragua	700	4,661
Panama	1,802	11,210
Paraguay	3,560	18,227
Peru	7,360	52,713
Suriname	272	2,006
Uruguay	2,149	11,767
Venezuela, RB	13900	109,401

(iii) Fuel prices: Fuel prices data collected from numerous sources are provided in Table 4.

Table 4. Fuel prices data

Country	Coal	Diesel	Natural Gas
	US$/metric ton	US$/Liter	US$/MMBTU
Argentina	68.9	0.77	2.46
Bolivia	54.5	0.54	1.21
Brazil	68.0	0.70	5.00
Chile	75.8	0.60	2.37
Colombia	52.9	0.47	6.20
Costa Rica	54.5	0.80	4.52

Ecuador	54.5	0.36	3.92
El Salvador	54.5	0.67	4.52
Guatemala	72.0	0.50	3.00
Honduras	54.1	0.49	3.36
Mexico	54.5	0.85	4.52
Nicaragua	54.5	0.75	4.52
Panama	52.9	0.60	4.52
Paraguay	54.5	0.66	4.52
Peru	52.0	0.87	1.64
Suriname	54.5	0.70	4.52
Uruguay	54.5	0.53	6.81
Venezuela, RB	54.5	0.54	1.64

Sources: Various; please see Appendix C.

(iv) Hourly load (8784 hours in 2020, as this is a leap year) for all countries with some exceptions (e.g., the República Bolivariana de Venezuela, Paraguay). These data were used to create load hourly and monthly load profiles. Load profiles were developed for weekdays and weekends/separately. Detailed load profiles are discussed in Section 2 above and also in Appendix A.

(v) Existing transmission capacity for cross-border trade: The existing bilateral cross-border transmission interconnection capacities are provided in Table 5.

Table 5. Existing cross-border interconnection capacity (MW)

		TO																	
		Argentina	Belize	Bolivia	Brazil	Chile	Colombia	Costa Rica	Ecuador	El Salvador	Guatemala	Honduras	Mexico	Nicaragua	Panama	Paraguay	Peru	Uruguay	Venezuela, RB
FROM	Argentina				90	1										1		231	
	Belize																		
	Bolivia																		
	Brazil	1150																570	
	Chile	5																	
	Colombia								28										
	Costa Rica													110	14				
	Ecuador						149										3		
	El Salvador										300	300							
	Guatemala									300			300						
	Honduras									300				300					
	Mexico		30								300								
	Nicaragua							23				300							
	Panama							72											
	Paraguay	60			6300														
	Peru								38										
	Uruguay	275			200														
	Venezuela, RB				200		380												

Source: See Appendix C.

4. Results from Model Simulations

This section presents key results from the model simulations. We ran three scenarios: (a) **baseline** scenarios, (b) **sub-regional electricity trade** scenario and (c) full **regional electricity trade** scenario. The baseline scenario assumes that each country dispatches its power plants following the merit-order rule to meet its demand while also utilizing the existing cross-border electricity trading facilities. In the sub-regional trading scenario, countries in each of three sub-regions (Andean, Central, Mercosur) are assumed to trade electricity without any constraints while meeting their sub-regional demand. This represents hypothetical sub-regional power pools, including the possibility of heavy imports and also wheeling of power through a country. Any existing electricity trade between the sub-regions is allowed. The regional electricity trade scenario assumes a hypothetical regional power pool in Latin America. Although the sub-regional and regional scenarios represent highly optimistic scenarios from a practical perspective, the results indicate how much the sub-regions and the region would have gained if there were no physical (i.e., lack of cross-border transmission interconnections) and regulatory constraints to limit cross-border trade in Latin America. In the following sub-sections, we present the results corresponding to cross-border electricity trade, sub-regional/regional electricity supply costs, and electricity generation mix under the three scenarios considered.

4.1 Effects on cross-border trade

In the baseline, Latin American countries trade about 4% of their total generation. More than 85% of the total electricity trade in the region (i.e., 3.4% of total regional generation) occur in the Mercosur region in the baseline. The volume of cross-border electricity trade increases by more than 3 times under the sub-regional trading scenario and more than 7 times under the regional trading scenario. The traded volume of electricity accounts for 13% and 29% of the total generation under the sub-regional and regional scenarios, respectively (Figure 5). However, it should be noted that the increase in trade also includes a very significant share of wheeling of power through several countries that are between an exporter and the final importer country.[7]

[7] For instance, if there are five countries A-E and a MWh is being exported from A to E but going through A→B→C→D→E, there are three pure wheeling transactions and trade volume will be counted as 4 MWh. Given the size, generation mix and current connectivity which remain fixed.

Figure 5. The volume of total electricity trade under alternative scenarios in LAC

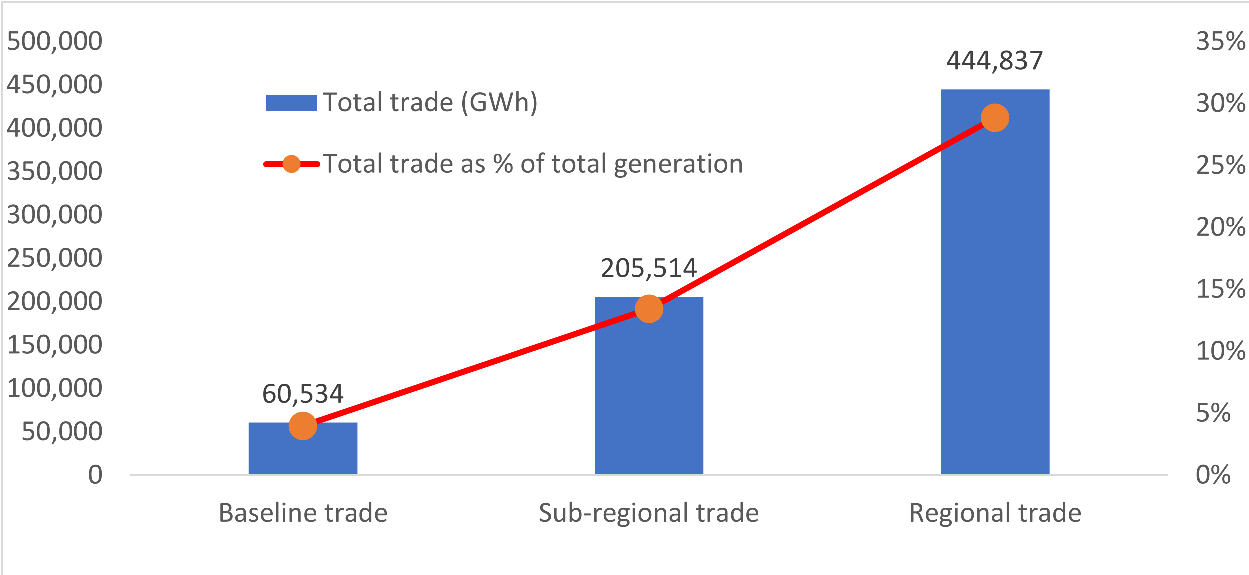


Figure 6 provides the sub-regional breakdown of electricity trade under the alternative scenarios. In the Andean sub-region, electricity trade increases by 158 times from 576 GWh (i.e., practically non-existing trade) to 91,099 GWh under the sub-regional electricity trading scenario. This high volume of trade could be caused due the counting of transition electricity or wheeling electricity. For example, if a country exports electricity to a third country through a neighboring country, the neighboring country's trade artificially increases as the electricity wheeled through it is also accounted as its own trade. The trade volume increases further in the full-regional electricity trading scenario – The Andean sub-regions exports and imports increase by 186 and 218 times from the baseline. The Central region benefits more under the full regional trading scenario because they already have sub-regional trading in the baseline through existing cross-border transmission systems, including the Central American cross-border electricity transmission network, SIEPAC. Compared to the volume of electricity trade under the sub-regional electricity trading scenario, electricity trade in Central America under the full regional trading scenario would be around 12 times higher. Mercosur region already enjoys a large-scale electricity trade in the baseline. Its trade increases by around 2 times under the sub-regional electricity trading scenario. Electricity exports in the sub-region increase further (by almost two times) under the full regional electricity trading scenario as compared to the sub-regional electricity trading scenario.

Figure 6. The volume of total electricity flow under alternative scenarios

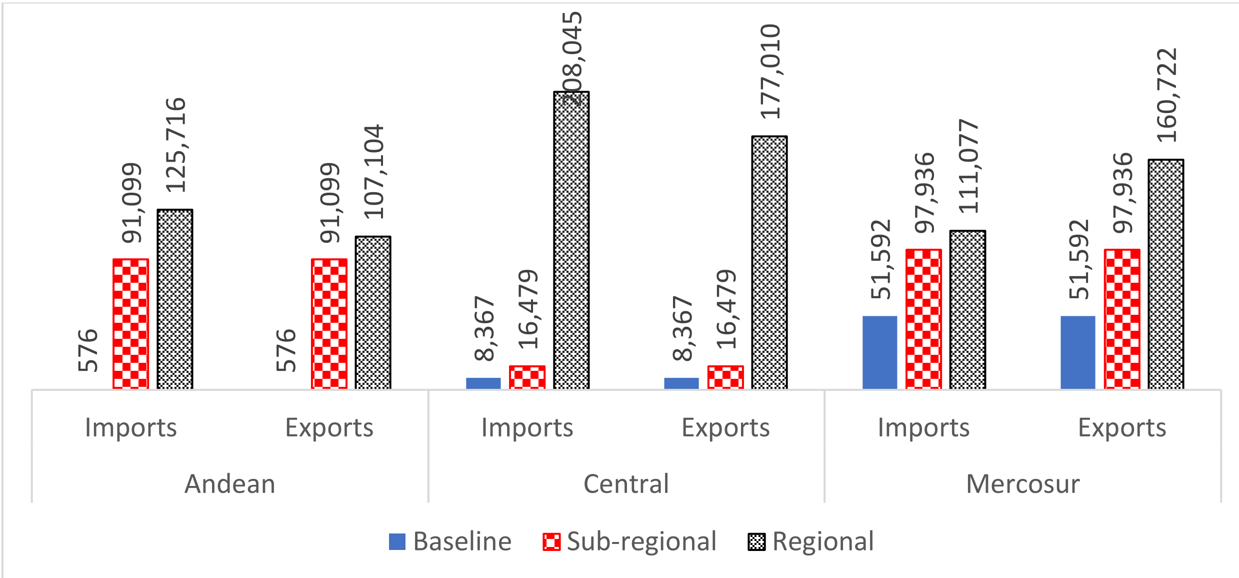
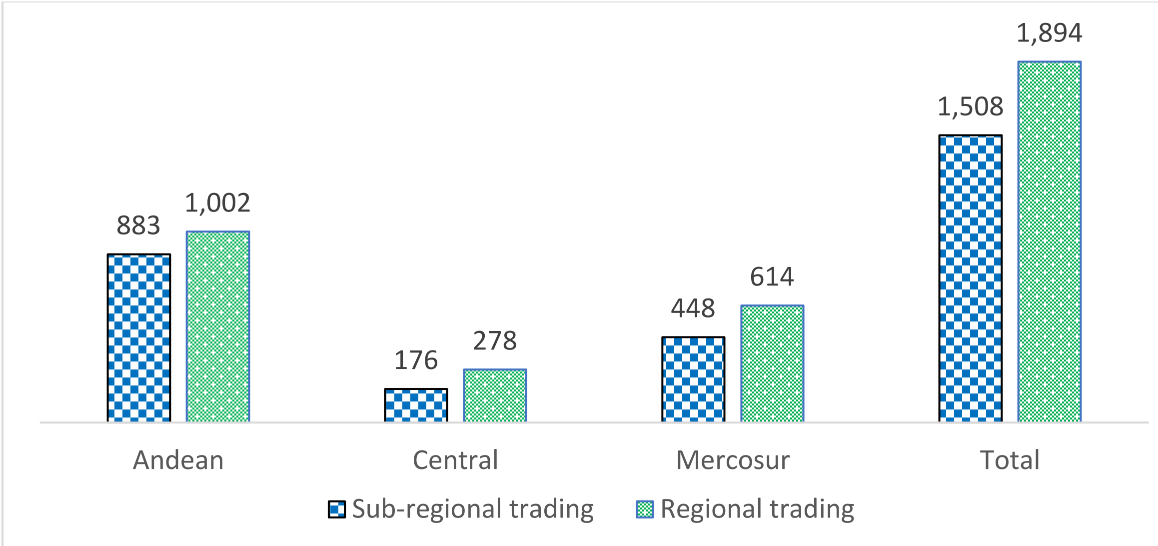


Figure 7 presents the dollar value of gross annual benefits from cross-border electricity trade in LAC. As mentioned above, the Andean sub-region benefits the most from the trade, whether it occurs at the sub-regional level or the full regional level. At the sub-regional level, its benefit would be 28% of its total electricity supply costs.[8] If the trade occurs at the regional level, the benefit increases to 33%. The central region's gain represents 1.7% and 2.7% of its total electricity supply costs under the sub-regional and full-regional trading scenarios, respectively. Mercosur region's gains would be 4.6% and 6.4% of their generation costs under sub-regional and regional trading scenarios, respectively. In overall, the gains from the trade would be 6.4% and 8.2% under the sub-regional and full-regional trading scenarios, respectively. In absolute terms, an annual gross benefit of $1.89 billion is quite substantial, albeit the underlying assumption of unconstrained trade would also require a potentially massive expansion of the regional grid. Nevertheless, we note that $1.5 billion, or nearly 80% of the gains of trade, may be realized through sub-regional trade. These estimates lay the foundation of a cost-benefit analysis of trade similar to the economic test used in Europe by the European Network of Transmission System Operators (ENTSO-E, 2018) for the expansion of cross-border trade.

Figure 7. Annual benefits from cross-border trade in Latin America (Million US$)

[8] Electricity supply costs = Costs of own generation + value of imports – value of exports.



4.2 Effects on electricity supply costs

The cross-border electricity trade would reduce the overall costs of the electricity supply. The savings in electricity supply costs amount to US$1.5 billion and US$1.9 billion a year under the sub-regional and regional trading scenario, respectively (see Figure 8). These represent *gross* benefits of trade for the year that could have been realized. This is a significant drop in systemwide generation cost, especially when we note the fact that this mostly fuel and variable O&M cost reduction in a region that is dominated by hydro and renewable. As we have discussed before, there are other major benefits of the trade, including avoided generation capacity, reserve capacity and the potential decrease in unserved energy over future years.

One issue is that the model does not account for the investment needed for strengthening existing cross-border transmission interconnections and adding new interconnections.[9] Estimation of new transmission investments needed not only for the new cross-border interconnectors but also upgrades to the rest of the national grid that they entail is a significant task. To have a more precise estimation of transmission interconnection costs, we need a detailed assessment of transmission corridors, detailed survey, and load-flow analysis to understand the exact flows and grid upgrades

[9] In other words, the dispatch/planning model can only calculate the gross benefits of trade rather than net benefits. This is a standard protocol in most regulatory standards including the ENTSOE Cost Benefit Analysis framework noted before, as well as regulatory tests in Australia, the United States, Canada, and other countries.

needed, that are well beyond the scope of this study. However, we made some rough estimations of investments needed on transmission interconnections to realize the cross-border electricity trade indicated by our model.[10] Our estimates show that the region will need to invest US3.9 billion and US$6.4 billion on regional transmission corridors under the sub-regional and regional trade scenario, respectively. In annualized terms (including fixed O&M costs of transmission), these translate into US$248 million pa and US$407 million per year, respectively, using a 6% discount rate and 50 years life of these assets. Compared to the annual benefits from the trade, these investments are relatively small. The ratios between the annual benefits from the cross-border trade and annualized investment required to realize it are, respectively, 6.1 and 4.7 under the sub-regional and regional trading scenario.

Figure 8 presents the average costs of electricity generation (left axis) and Figure 9 presents the percentage savings in electricity supply costs in the region as a whole under the sub-regional and regional trading scenarios as compared to that in the baseline. In the baseline, the average cost of electricity generation in Latin America was $16.3/MWh; it drops by 6.4% and 8.5% under the sub-regional and regional electricity scenarios, respectively. The Andean sub-region realizes the highest level of savings from cross-border trading because of a large drop in electricity generation costs due to the trade. Its savings in electricity generation costs would be 23.4% and 33.4% under the sub-regional and full-regional trading scenarios.

Figure 8. Average costs of electricity generation ($/MWh) under alternative scenarios

[10] These cost estimates are developed for eight key corridors (Argentina-Brazil, Chile-Argentina, Panama-Costa Rica-Nicaragua-Honduras - El Salvador, Guatemala-Mexico, República Bolivariana de Venezuela-Colombia, Colombia-Panama, Bolivia-Peru, Peru-Ecuador-Colombia) that account for majority of the trade in both scenarios accounting for multiple wheeling transactions that the unconstrained flow regime entails. The interconnector lengths are approximated between major generation and load centers (capitals). Interconnector capacity is calculated assuming these corridors will be highly utilized at 80% to arrive at the transfer capability (MW) figures. A voltage class and number of circuits (single/double/triple/quad) are associated with the transfer capability requirement. Lumpsum unit costs on a per km basis for each interconnector type are sourced from CERC India, WECC USA and a World Bank Report prepared for Africa.

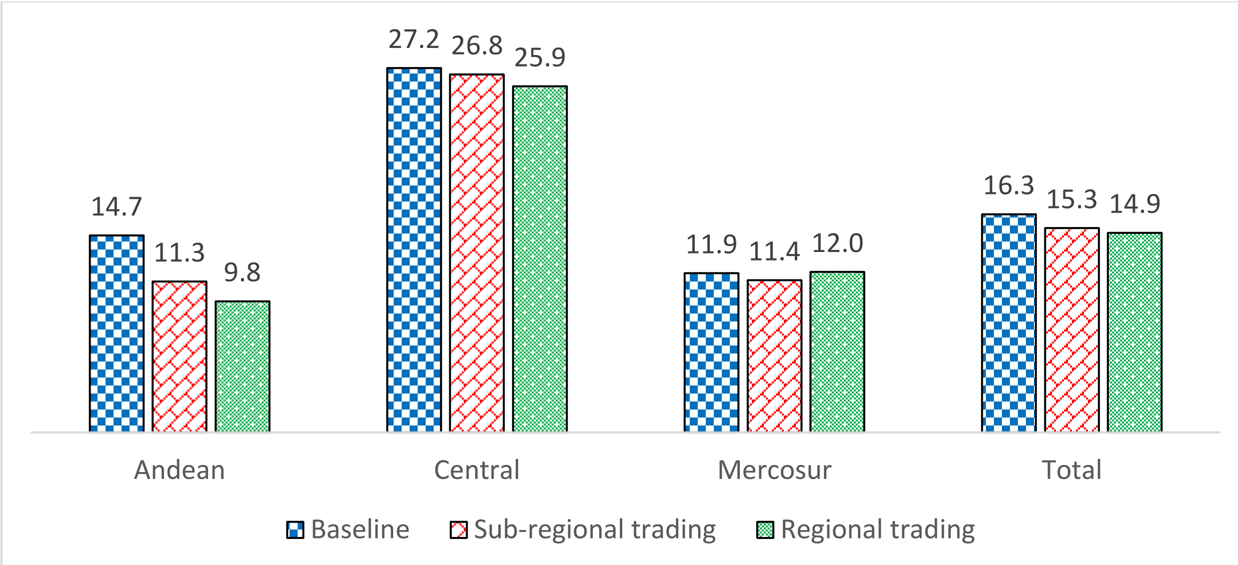
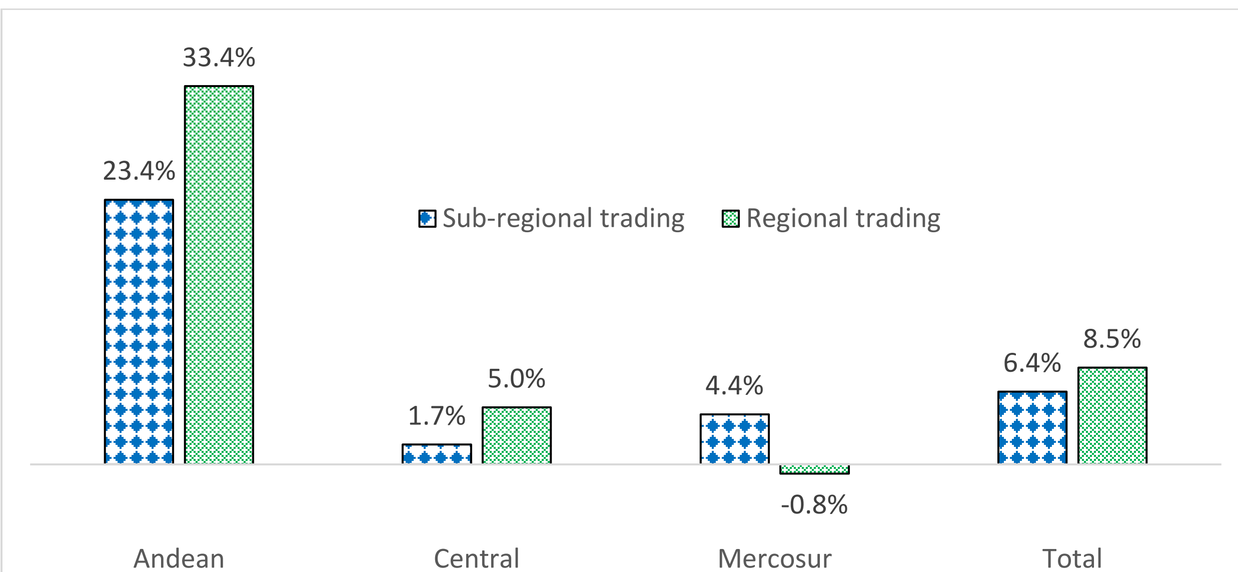


Figure 9. Savings in electricity generation costs from the baseline (%)



4.3 Impacts on the generation mix

Cross-border trade affects the operation of existing electricity generation plants and hence the generation mix. Electricity plants in a country with lower operational costs are utilized more because it could sell excess electricity to other countries. In the absence of trade, these plants would have stayed idle in a given hour when countries' own demand is lower (e.g., partial peak hours).

At a regional level, the generation mix is unlikely to change significantly because the chances are that low/zero cost hydro and renewables that are available in the region as a whole will be used up, even if the opportunity cost of such generation is greater and hence the trading scenarios will find a different allocation among the countries. Therefore, the generation mix of individual countries changes more across the scenarios than the sub-regional/regional mix. Figure 10 compares the generation mix from various types of power plants under the alternative scenarios. In the Andean sub-region, the share of gas-based generation increases from 22.4% in the baseline to 26.4% in the sub-regional scenario. It drops to 23.1% in the regional trade scenario. The share of hydro slightly decreases under the sub-regional trading scenario, whereas it increases in the regional trade scenario. The dynamics of the generation mix are better explained later with the help of Table 6. In the Central sub-region, hydro and coal are found to replace natural gas-based generation. Coal and renewables are substituting hydro and gas-based generation in the Mercosur sub-region. For Latin America as a whole, coal and renewables are replacing hydro and natural gas-based electricity generation.

Figure 10. Electricity generation mix by sub-region and by scenario (%)

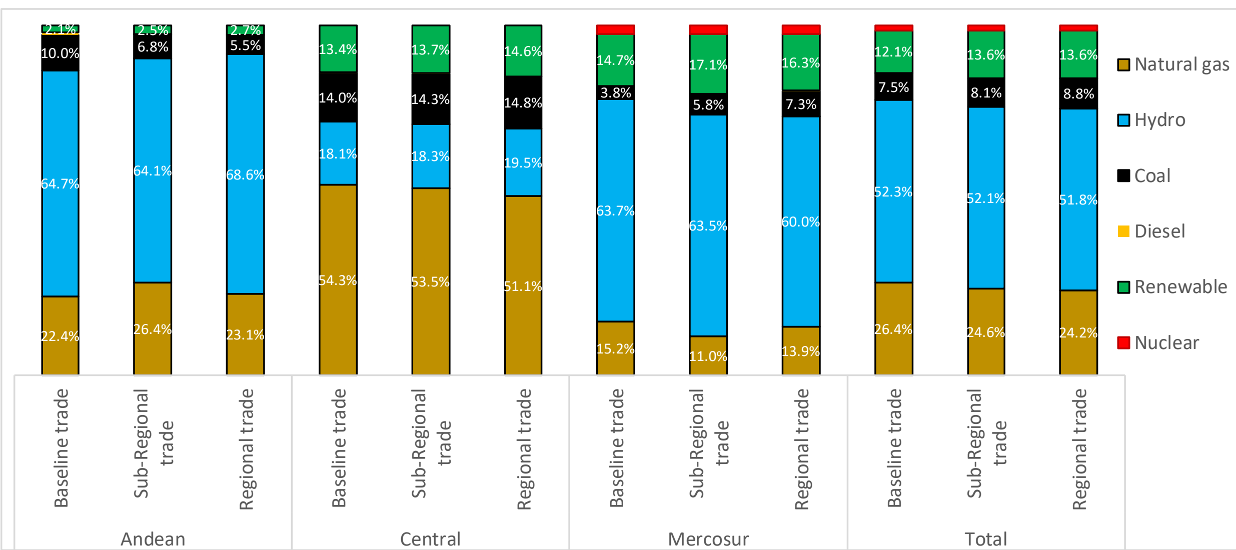


Table 6 illustrates how the sub-regional and full regional electricity trade affect electricity generation in various countries. A large change in electricity generation can be observed in Bolivia, Guyana and Surinam. Bolivia does not have an electricity interconnection with any other countries at present. Its total installed capacity is more than two times its peak load (see Figure 1). If Bolivia is interconnected with other Andean countries (sub-regional trading), the electricity generation capacity would be utilized to sell the electricity to its neighboring countries. Therefore, its total generation increases by 2.3 times in the sub-regional trading scenario and 2.5% in the full regional trading scenario (Figure 11). It will export electricity to Peru in the sub-regional trading scenario and Peru and Paraguay under the full regional trading scenario (see Table 5). Guyana and Surinam are the two countries with the highest costs of electricity generation because their electricity systems are predominantly diesel-based (see Figure 4). Cross-border electricity interconnection would allow these countries to import cheaper electricity. While Guyana would decrease its electricity generation by 72%, Surinam would decrease by 54%. Instead, they import electricity from neighboring countries (Figure 11).

Other countries with a significant increase in the total generation are Peru and Guatemala. In Peru, natural gas accounts for 40% of electricity generation; it could avoid expensive gas-based generation by importing cheaper hydro generation from neighboring countries. Guatemala would do the same to replace its biomass-based electricity generation. Although Costa Rica uses mostly renewables (hydro and geothermal), it can replace some of these generations when they find cheaper imports in some time slots.

Figure 11. Change in total electricity generation from the baseline due to trade (%)

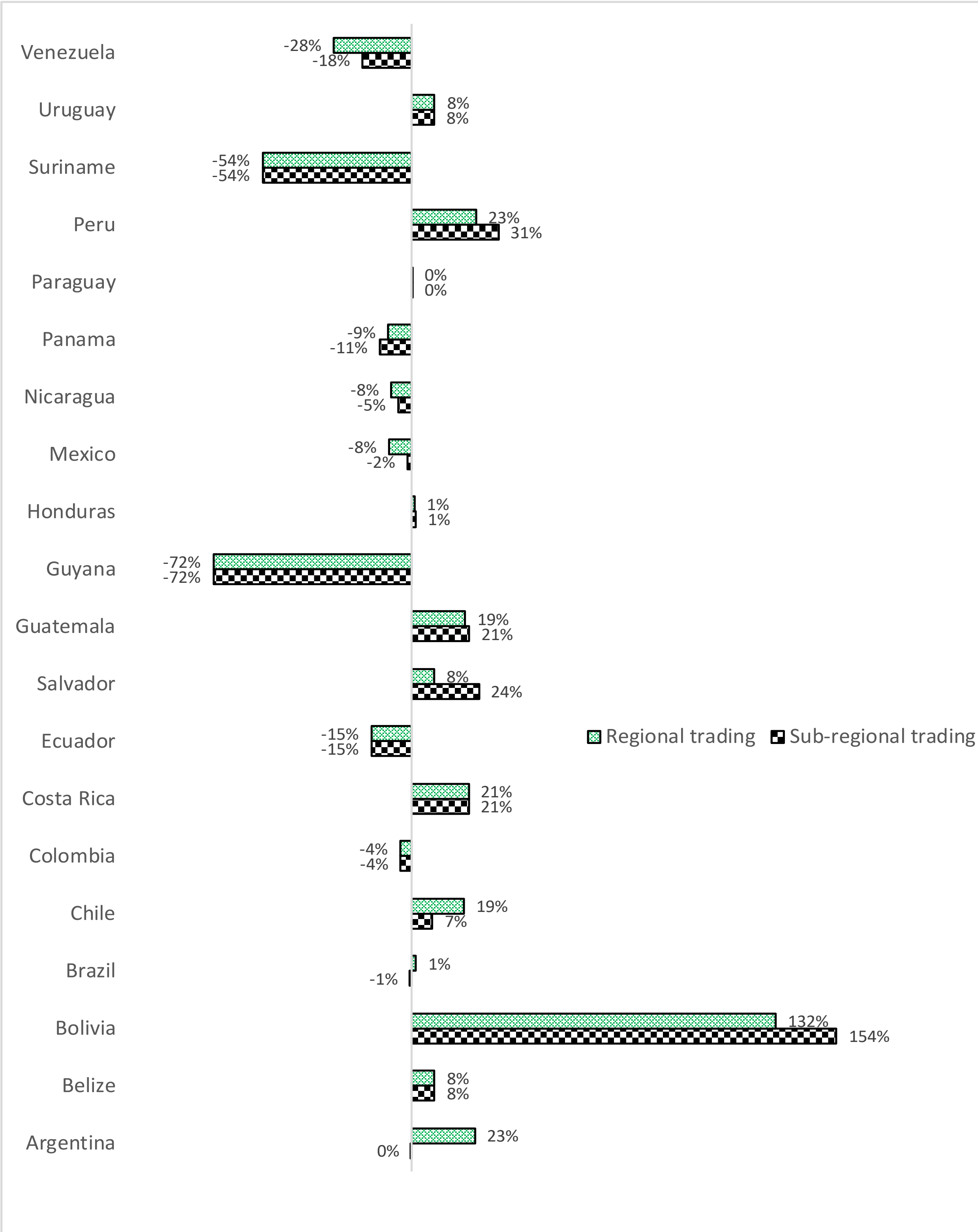


Table 6. Electricity Generation mix under the alternative scenario (%)

	Biomass	Gas CC	Gas GT	Hydro	Diesel	Nuclear	Solar	Coal	Geoth.	Wind
Baseline										
Argentina	0.3%	55.9%	0.1%	30.4%	0.0%	5.3%	0.6%	3.5%	0.0%	3.9%
Belize	57.0%	0.0%	0.0%	43.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Bolivia	0.0%	57.7%	0.0%	38.6%	0.0%	0.0%	2.9%	0.0%	0.0%	0.8%
Brazil	15.4%	5.4%	0.0%	72.2%	0.0%	2.7%	0.6%	2.9%	0.0%	0.8%
Chile	4.9%	35.7%	0.0%	28.9%	0.0%	0.0%	9.6%	15.4%	0.5%	5.1%
Colombia	1.6%	5.5%	0.0%	75.7%	0.0%	0.0%	0.3%	16.8%	0.0%	0.2%
Costa Rica	0.0%	0.0%	0.0%	80.5%	0.0%	0.0%	0.1%	0.0%	12.6%	6.8%
Ecuador	4.6%	0.0%	7.7%	80.4%	0.5%	0.0%	0.2%	6.5%	0.0%	0.1%
El Salvador	34.1%	17.5%	0.0%	34.6%	0.0%	0.0%	13.1%	0.0%	0.0%	0.6%
Guatemala	49.5%	0.0%	0.0%	42.0%	0.0%	0.0%	0.9%	4.4%	2.6%	0.6%
Guyana	26.2%	0.0%	0.0%	1.0%	72.1%	0.0%	0.7%	0.0%	0.0%	0.0%
Honduras	24.0%	0.0%	0.6%	48.3%	0.2%	0.0%	12.2%	8.2%	4.2%	2.2%
Mexico	2.4%	60.1%	2.5%	12.4%	0.3%	0.0%	0.1%	15.5%	2.4%	4.2%
Nicaragua	38.8%	0.0%	2.9%	12.4%	3.2%	0.0%	0.5%	1.6%	30.6%	9.9%
Panama	0.6%	20.5%	0.0%	59.4%	1.8%	0.0%	2.5%	11.9%	0.0%	3.4%
Paraguay	0.2%	0.0%	0.0%	99.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Peru	1.1%	38.9%	0.0%	57.9%	0.0%	0.0%	1.1%	0.1%	0.0%	0.9%
Suriname	0.6%	0.0%	0.0%	44.6%	54.3%	0.0%	0.6%	0.0%	0.0%	0.0%
Uruguay	14.2%	0.0%	0.0%	48.8%	0.0%	0.0%	3.0%	0.0%	0.0%	34.0%
Venezuela, RB	0.4%	22.8%	4.0%	60.3%	0.0%	0.0%	0.0%	12.3%	0.0%	0.3%
All	7.9%	25.4%	1.0%	52.3%	0.2%	1.5%	1.0%	7.5%	0.8%	2.3%
Sub-regional trading scenario										
Argentina	0.3%	49.1%	0.0%	30.4%	0.1%	5.3%	0.6%	10.4%	0.0%	3.9%
Belize	60.3%	0.0%	0.0%	39.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Bolivia	5.1%	39.9%	38.4%	15.2%	0.0%	0.0%	1.1%	0.0%	0.0%	0.3%
Brazil	18.9%	1.3%	0.0%	72.7%	0.0%	2.7%	0.7%	2.9%	0.0%	0.8%
Chile	4.6%	30.4%	0.0%	26.9%	0.1%	0.0%	8.9%	23.9%	0.4%	4.8%
Colombia	1.7%	0.2%	0.0%	78.9%	0.0%	0.0%	0.3%	18.8%	0.0%	0.2%
Costa Rica	4.0%	0.0%	0.0%	73.9%	0.0%	0.0%	0.1%	0.0%	16.4%	5.7%
Ecuador	5.4%	0.0%	0.0%	94.3%	0.0%	0.0%	0.2%	0.0%	0.0%	0.1%
El Salvador	27.5%	33.6%	0.0%	27.9%	0.0%	0.0%	10.6%	0.0%	0.0%	0.5%
Guatemala	41.1%	0.0%	2.1%	34.8%	0.0%	0.0%	0.8%	18.7%	2.1%	0.5%
Guyana	93.9%	0.0%	0.0%	3.5%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%
Honduras	23.7%	0.0%	0.5%	47.7%	0.0%	0.0%	12.1%	9.7%	4.1%	2.2%
Mexico	2.4%	60.3%	2.2%	12.6%	0.2%	0.0%	0.1%	15.3%	2.5%	4.3%
Nicaragua	41.1%	0.0%	2.6%	13.1%	0.0%	0.0%	0.6%	0.0%	32.2%	10.4%
Panama	0.7%	12.2%	0.0%	67.1%	0.0%	0.0%	2.8%	13.4%	0.0%	3.9%
Paraguay	0.3%	0.0%	0.0%	99.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Peru	0.8%	38.0%	13.6%	44.0%	0.4%	0.0%	0.9%	1.5%	0.0%	0.7%
Suriname	1.3%	0.0%	0.0%	97.5%	0.0%	0.0%	1.2%	0.0%	0.0%	0.0%
Uruguay	20.6%	0.0%	0.0%	45.1%	0.0%	0.0%	2.8%	0.0%	0.0%	31.5%
Venezuela, RB	0.4%	20.7%	0.0%	73.4%	0.0%	0.0%	0.0%	5.0%	0.0%	0.4%
All	9.4%	22.9%	1.7%	52.1%	0.1%	1.5%	1.0%	8.1%	0.8%	2.3%
Full-regional trading scenario										

Argentina	0.2%	54.7%	0.0%	24.7%	0.1%	4.3%	0.5%	12.3%	0.0%	3.1%
Belize	60.3%	0.0%	0.0%	39.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Bolivia	5.6%	43.7%	32.5%	16.6%	0.0%	0.0%	1.3%	0.0%	0.0%	0.3%
Brazil	18.8%	2.2%	0.0%	71.2%	0.0%	2.7%	0.6%	3.7%	0.0%	0.8%
Chile	4.1%	30.0%	0.0%	24.2%	0.2%	0.0%	8.0%	28.8%	0.4%	4.3%
Colombia	1.7%	0.0%	0.0%	79.1%	0.0%	0.0%	0.3%	18.8%	0.0%	0.2%
Costa Rica	4.0%	0.0%	0.0%	73.9%	0.0%	0.0%	0.1%	0.0%	16.4%	5.7%
Ecuador	5.4%	0.0%	0.0%	94.3%	0.0%	0.0%	0.2%	0.0%	0.0%	0.1%
El Salvador	31.6%	23.6%	0.0%	32.1%	0.0%	0.0%	12.2%	0.0%	0.0%	0.6%
Guatemala	41.6%	0.0%	0.9%	35.2%	0.0%	0.0%	0.8%	18.9%	2.2%	0.5%
Guyana	93.9%	0.0%	0.0%	3.5%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%
Honduras	23.8%	0.0%	0.1%	47.9%	0.0%	0.0%	12.1%	9.7%	4.1%	2.2%
Mexico	2.6%	60.4%	0.0%	13.6%	0.1%	0.0%	0.1%	15.9%	2.6%	4.6%
Nicaragua	42.2%	0.0%	0.0%	13.5%	0.0%	0.0%	0.6%	0.0%	33.1%	10.7%
Panama	0.6%	14.8%	0.0%	65.1%	0.0%	0.0%	2.7%	13.0%	0.0%	3.7%
Paraguay	0.3%	0.0%	0.0%	99.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Peru	0.9%	40.5%	8.0%	46.9%	0.4%	0.0%	0.9%	1.6%	0.0%	0.7%
Suriname	1.3%	0.0%	0.0%	97.5%	0.0%	0.0%	1.2%	0.0%	0.0%	0.0%
Uruguay	20.7%	0.0%	0.0%	45.1%	0.0%	0.0%	2.8%	0.0%	0.0%	31.4%
Venezuela, RB	0.5%	15.0%	0.0%	84.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
All	9.5%	23.4%	0.8%	51.8%	0.0%	1.5%	1.0%	8.8%	0.8%	2.3%

5. Conclusions

This study measures the short-run potential economic benefits and power sector implications of hypothetical cases of enhancing cross-border electricity trade in Latin America involving 20 countries. Two scenarios are examined – unconstrained cross-border electricity trade between the countries within three sub-regions (Andean, Central and Mercosur) and full regional trade involving all 20 countries in the region. The benefits are measured in the short run with the question at hand: how much the LAC region would benefit if unconstrained trade is facilitated across the border at present (say in 2020) by optimally utilizing the existing capacities (i.e., without adding new capacities).

The study first illustrates why the LAC countries should enhance their cross-border electricity trade by providing numerical evidence to support the trading argument. These include the following. (a) Higher ratios between the installed capacities and peak loads (evidence of benefitting by sharing reserve margins and increased utilization of already built generation assets). Several countries in LAC have installed capacity more than two times as high as their peak loads. (b) Differing load profiles across the countries (evidence of sharing hourly and seasonal peak loads). (c) Differences in average as we as marginal costs across the countries (evidence of cost efficiency to be gained through the trade).

Our study finds that the existing volume of electricity trade (baseline scenario) in LAC is approximately 4% of the regional generation. It would increase to 13% and 29% under the sub-regional and regional scenarios, respectively. The Andean region realizes the highest increase in electricity trade volume; the traded volume of electricity in this sub-region accounts for 0.2% and 33% of the total sub-regional generation in the baseline and sub-regional scenario, respectively. The ratio of traded electricity to total generation would almost double from the baseline scenario to the sub-regional scenario in the Central and Mercosur sub-regions. In terms of trade value, the region as a whole would gain US$1.5 billion annually under the sub-regional scenario and almost US$2 billion under the full regional scenario. More than half of this gain would be realized by the Andean sub-region under both scenarios. About one-third of the total regional gains would go to the Mercosur sub-region. The Central region would gain 12% and15% of the total regional gains under the sub-regional and full regional scenarios.

These are short-term benefits. If we consider a long period, the size of the total benefits would be much larger, although the size of the annual benefits may not change much. Since the analysis is for the short run, it does not include the costs of constructing cross-border transmission interconnections. A long-run, 30-40 years' time horizon study would be necessary to analyze cross-border electricity trade and cooperation economics. It will be a natural extension of the study.

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APPENDIX A

Figure A1: Hourly load curves by month in the Andean region

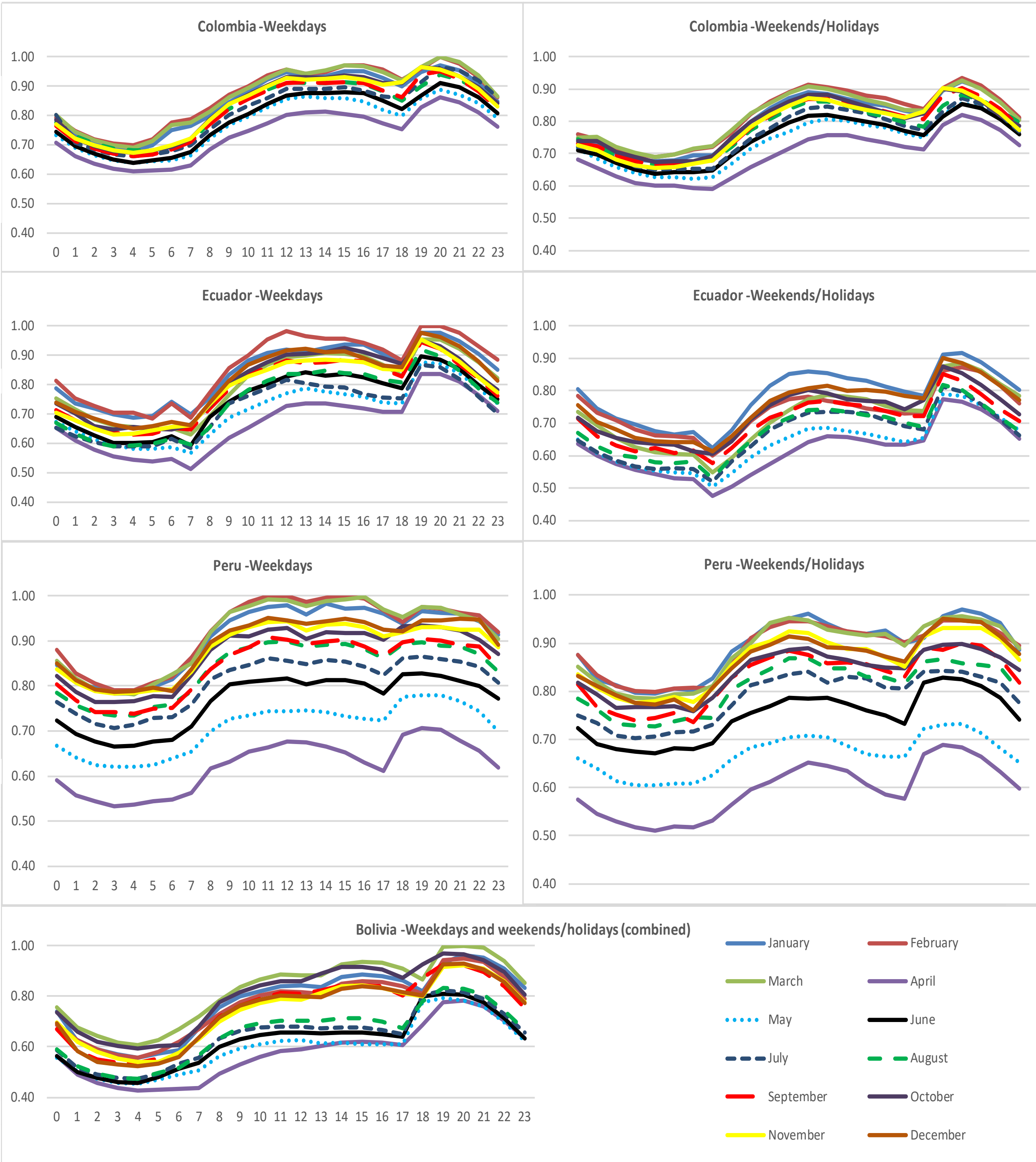


Figure A2: Hourly load curves by month in the Central region

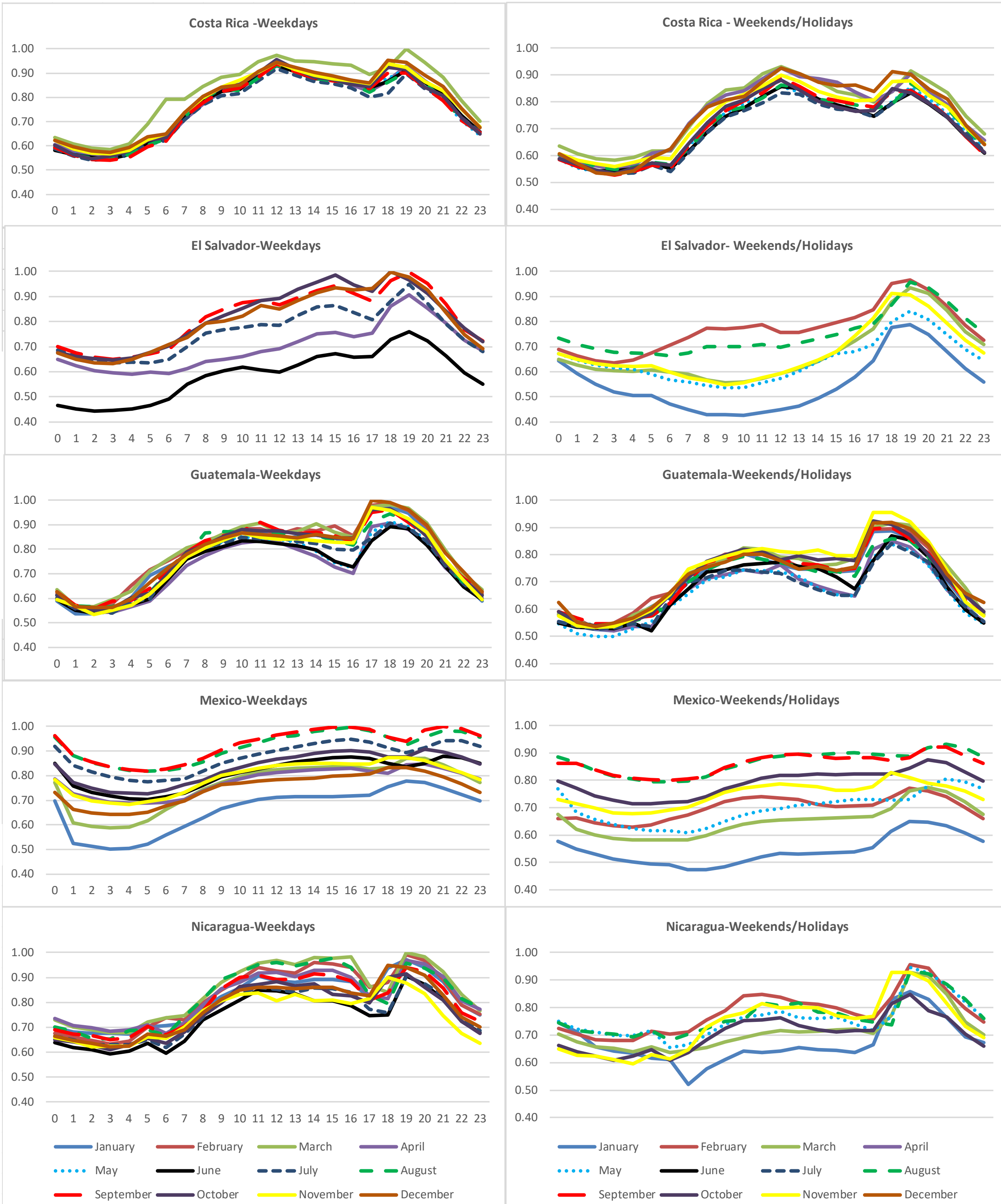


Figure A3: Hourly load curves by month in the Mercosur region

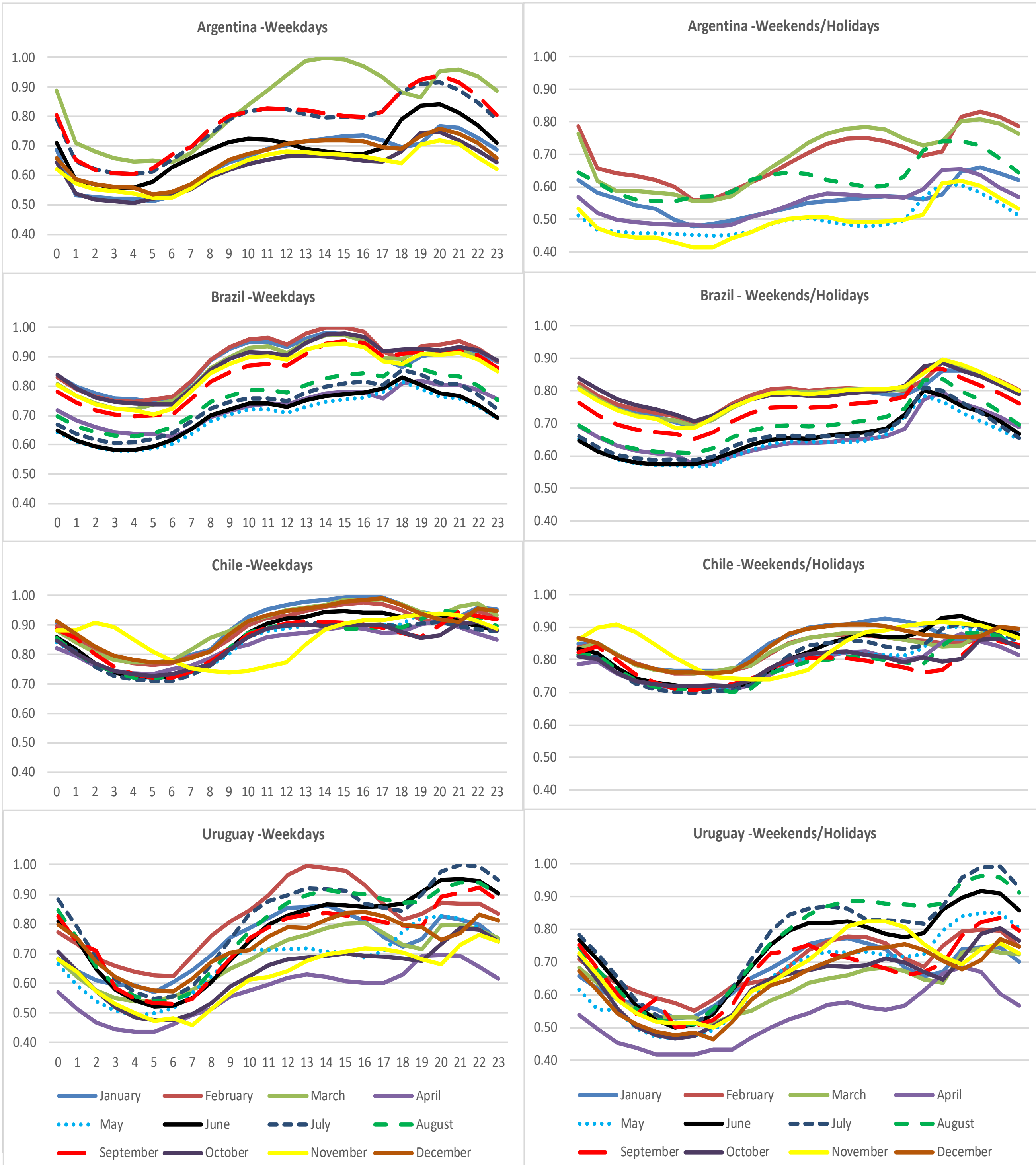


Figure A4. Monthly variations of peak loads in the Andean region

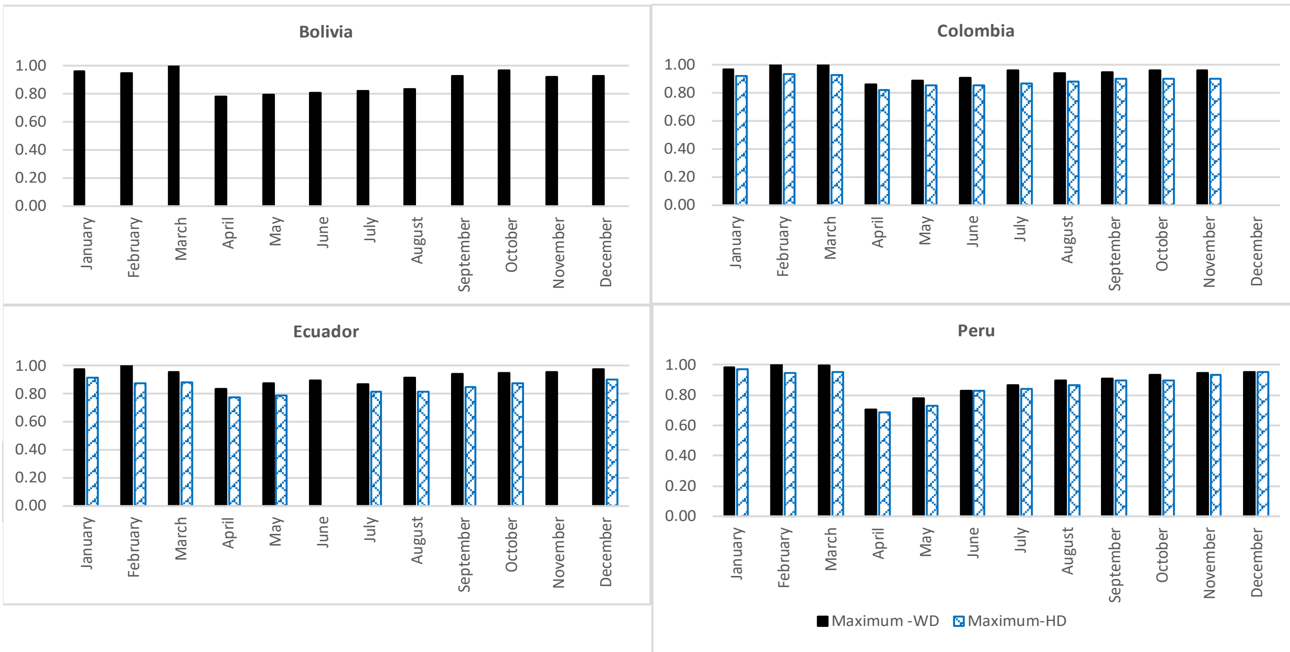


Figure A5. Monthly variations of peak loads in the Mercosur region

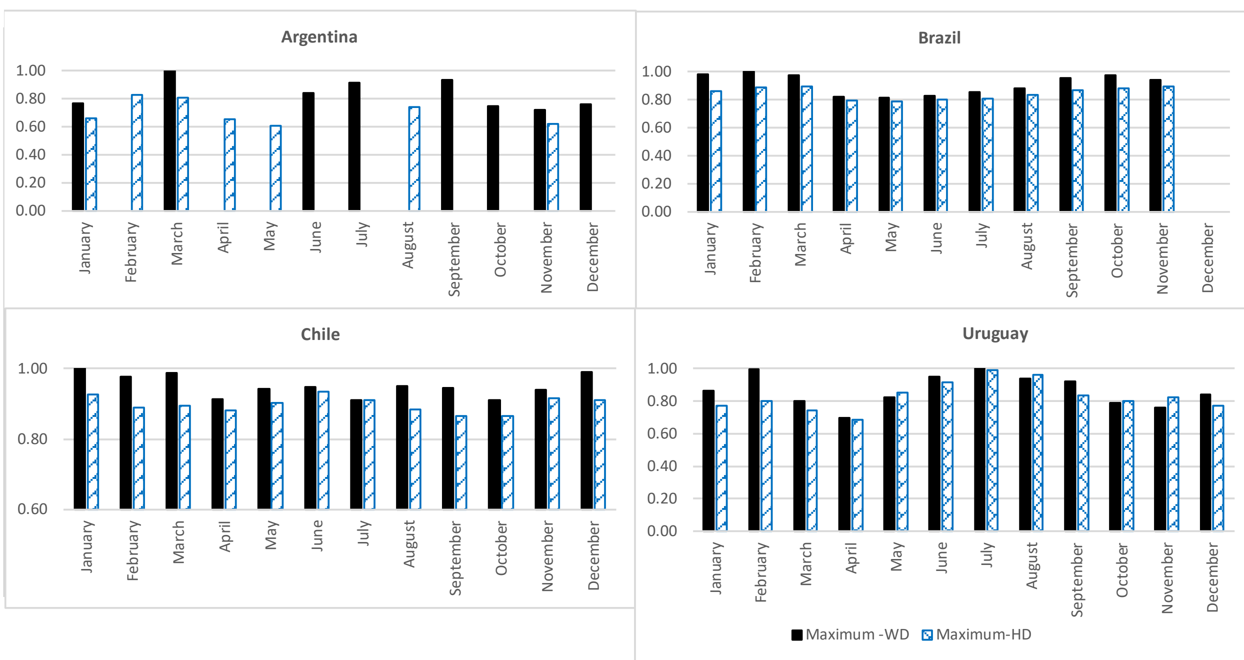
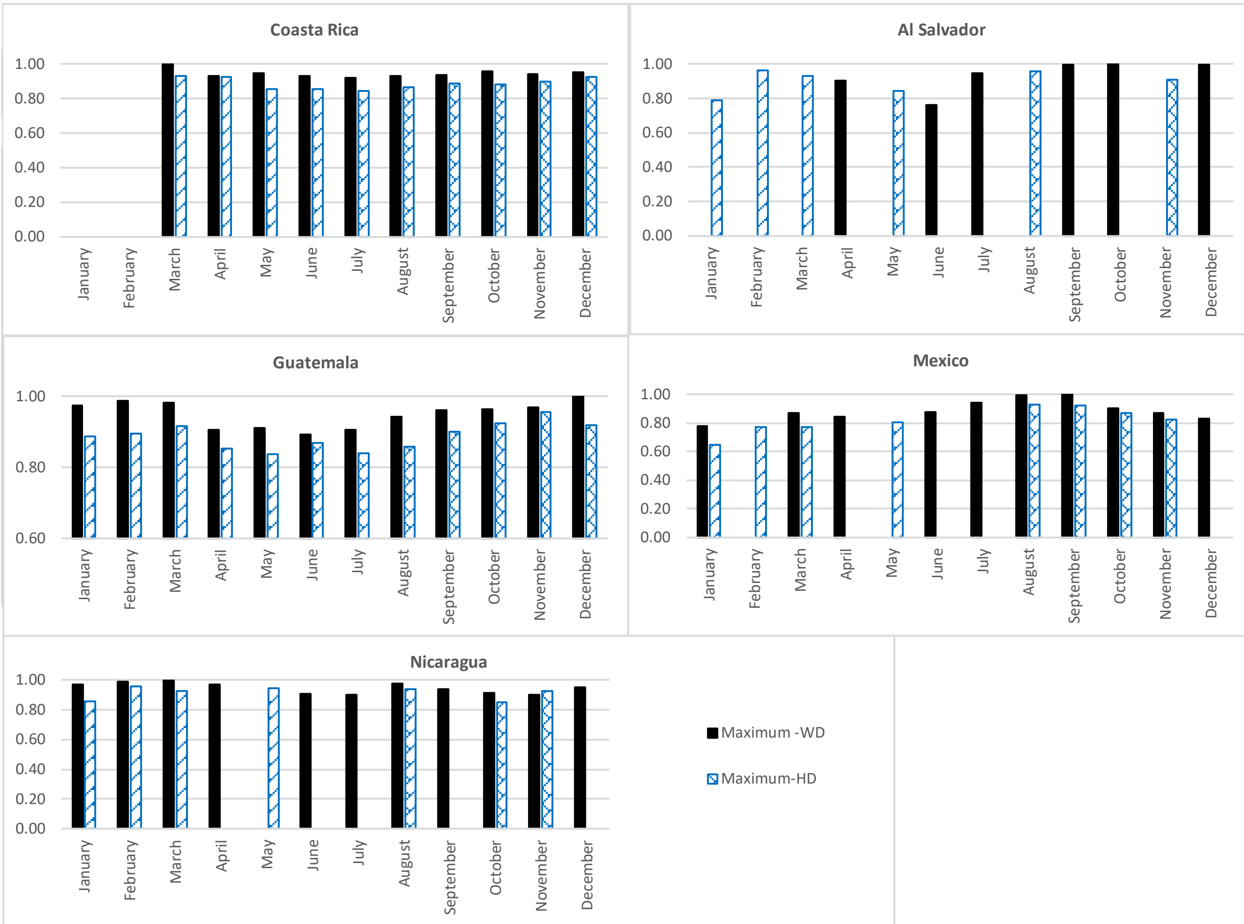


Figure A6. Monthly variations of peak loads in the Central region



Appendix B

Detailed Description of the Model

Nomenclature

Sets	
$d \in D$	D is the set of types of days or weeks
$f \in F$	F is the set of fuels
$g \in G$	G is the set of generation type
$q \in Q$	Q is the set of seasons or quarters
$t \in T$	T is the set of hours considered per day (usually 24)
$y \in Y$	Y is the set of years considered in the planning model
$z, z2 \in Z$	Z is the set of grids/zones/regions modeled
$sc \in S$	S is the set of flags and penalties used to include/exclude certain features of the model
Subsets considered	
$EG, NG \in G$	EG contains generators existing at the starting year of the planning horizon and NG contains candidate generators[11]
$MD \in D$	MD is a subset of days the planner expects the minimum load levels to be binding
$PT, OPT \in T$	PT and OPT are peak and off-peak hours
$RE \in F$	RE is renewable technology according to regulator's criteria[12]
$RG \in G$	MD is a subset of days with binding minimum load levels
$map_{g,f}$	includes valid combinations of fuels and generators; subset of the set $G \times F$
Non-negative decision variables	
$build_{g,y}$	Investment in MW
$cap_{g,y}$	Capacity available at year y in MW
$emissions_{z,y}$	Emissions of carbon dioxide in tons
$emissions\_Zo_{z,y}$	Emissions of carbon dioxide in tons per zone z
$fuel_{z,f,y}$	Fuel consumption in MMBTU
$gen_{g,f,q,d,t,y}$	Generator output in MW
$genCSP_{g,z,q,d,t,y}$	Power output of the solar panel in MW

[11] The generators already planned are included in any of the two sets depending on criteria such as their capacity, status of their construction process etc.

[12] Type of resources considered as renewables might be different from country to country or state to state. For example, some states do not include hydropower towards their renewable targets (e.g. California does not count large hydropower towards the RPS (Renewable portfolio standard) while others such as Oregon do [13].

$retire_{g,y}$	Capacity in MW retired
$reserve_{g,q,d,t,y}$	Spinning reserve requirement met in MW
$storage_{z,q,d,t,y}$	Level of energy in MWh stored at zone z
$storage\_inj_{z,q,d,t,y}$	Power level in MW at which the storage unit g is charged during hour (q,d,t)
$storage\_out_{z,q,d,t,y}$	Power level in MW at which the storage unit g is discharged during hour (q,d,t)
$storageCSP_{g,z,q,d,t,y}$	Level of energy in MWh stored in CSP unit at zone z
$storageCSPinj_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is charged during hour (q,d,t)
$storageCSPout_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is discharged during hour (q,d,t)
$trans_{z,z2,q,d,t,y}$	Active power in MW flowing from z to $z2$
$unmetDem_{z,q,d,t,y}$	Unmet demand in MW (or equivalently violation of the load balance constraint)
$unmetRes_{z,y}$	Violation of the planning reserve constraint in MW
$unmetSResZo_{z,q,d,t,y}$	Violation of the zonal/regional spinning reserve constraint in MW
$unmetSResSY_{q,d,t,y}$	Violation of the system-level spinning reserve constraint in MW
Variables for modeling objective function	
$carboncost_{z,y}$	Carbon tax payments by generators
$fixedcost_{z,y}$	Fixed Operation and Maintenance Cost along with capital payments in constant prices
$npvcost$	Net present value of power system cost over the whole planning horizon; objective function that optimization model tries to minimize
$reservecost_{z,y}$	Cost to procure spinning reserves
$totalcost_{z,y}$	Annual system cost in constant prices
$usecost_{z,y}$	Damage/economic loss in constant prices because of unmet demand
$usrcost_{z,y}$	Penalty in constant prices for unmet spinning reserve requirements
$variablecost_{z,y}$	Variable cost including fuel and variable operation and maintenance cost in constant prices
Parameters	
$Availability_{g,q}$	Availability of unit g to generate power in quarter q
$Annual\_built\_limit_{y}$	Maximum amount of MW allowed to be built per year
$CapCost_{NG,y}$	Capital cost in USD \$ or other monetary unit per MW
$Carbon\_emission_{f}$	Equivalent tons of CO_2 emitted per MMBTU of fuel consumed
$Carbon\_tax_{y}$	Carbon price in USD\$ per equivalent tons of CO_2
$Commission\_year_{g}$	Earliest commission year for generators

CRF_{NG}	Capital Recovery factor[13]
$CSP\_storage$	CSP storage capacity in hours
$Demand_{z,q,d,t,y}$	Hourly load level in MW in hour t, day d, quarter q and year y
$DRate_{y}$	Discount rate; real or nominal if cost parameters in real or nominal terms respectively
$Duration_{q,d,t,y}$	Duration of each time slice (block) in hours
$FieldEfficiency_{CSP}$	Efficiency of the CSP solar field
$FixedOM_{g,y}$	Fixed Operation and Maintenance Cost in USD $ or other monetary unit per MW
$FuelPrice_{f,y,z}$	Fuel price in USD $/MMBTU
$GenCost_{g,f,y}$	Generation variable cost (fuel and VOM) in USD $ or other monetary unit per MWh
Gen_zone_{g}	Contains the zone index of the zone the generator belongs to
$HeatRate_{g,f}$	Heat Rate in BTU/MWh
$Life_{NG}$	Operating life for new generators
$LossFactor_{z,z2,y}$	"Linearized" loss factor in % of active power flowing on transmission line
$MaxCapital$	Maximum amount of annualized capital payments in USD$ billion over the horizon
$MaxFuelOff_{f,y}$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$MaxNewCap_{NG}$	Maximum capacity to be built over the horizon in MW
$MinCapFac_{g}$	Minimum capacity factor (to reflect minimum load requirements)
$OverLoadFactor_{g}$	Overload factor of generator *g*, as %, of capacity
$PlantCap_{EG}$	Existing capacity at initial year in MW
PRM_{z}	Planning reserve margin per zone z
$RampDn_{g}$	Ramp-down capability of generator *g*, as %, of capacity installed[14]
$RampUp_{g}$	Ramp-up capability of generator *g,* as %, of capacity installed
$ResCost_{g}$	Cost to provide reserves in USD $ or other monetary unit per MWh
$ResOffer_{g}$	Percentage of the generator's unit qualify as a reserve offer
$RESVoLL$	Violation penalty of planning reserve requirement in $/other monetary unit per MW
$Retirement\_year_{EG}$	Latest retirement year for existing generators
$ReturnRate_{y}$	Discount factor at the starting year of stage ending at year y

[13] $CRF_{NG} = \frac{WACC}{1-\frac{1}{(1+WACC)^{Life_{NG}}}}$

[14] Note that ramping capabilities of generator are usually expressed in MW/min and then based on the minutes the operating reserve requirement is defined, we can estimate the capability in MW and subsequently expressed it in % of installed capacity. In the United States, 10 min is a typical time for operating reserves and 5 min for regulation reserves.

$RPprofile_{g,RE,q,d,y,t}$	Renewable generation profile in % of installed (rated) capacity
$SolarMultipleCSP$	CSP output to solar field ratio
$SResSY_y$	System-level spinning reserve constraint in MW
$SResZo_{z,y}$	Zonal/regional spinning reserve constraint in MW
$StageDuration_y$	Duration of a stage represented by year y in years
$StartYear$	First year of the horizon
$Storage\_capacity_{z,y}$	Capacity of storage unit
$Storage\_efficiency_{z,y}$	Efficiency of storage (per charging cycle)
$Storage\_energy_{z,y}$	Energy capability of storage unit
$Sy\_emission\_cap_y$	Cap on CO_2 emissions within the system at year y in equivalent tons
$Topology_{z,z2}$	Network topology: contains 0 for non-existing lines and 1 or -1 to define the direction of positive flow over the line
$TransLimit_{z,z2,q,y}$	Transmission limits by quarter q and year y
$TurbineEfficiency_{CSP}$	Efficiency of the CSP power block
$VarOM_{g,y}$	Variable Operation and Maintenance Cost in USD $ or other monetary unit per MWh
$VOLL$	Penalty/Economic loss consider per MWh of unmet demand
$WACC$	Weighted Average Cost of Capital
$WeightYear_y$	Weight on years
$Zo\_emission\_cap_{y,z}$	Cap on CO_2 emissions within zone z and year y in equivalent tons
$zone\_index_z$	Index of zone z, unique number assigned to zone z

Equations

Objective function and its components

$$npvcost = \sum_{z,y} ReturnRate_y * WeightYear_y * totalcost_{z,y} \quad (1)$$

$$totalcost_{z,y} = fixedcost_{z,y} + variablecost_{z,y} + reservecost_{z,y} + usecost_{z,y} + usrcost_{z,y} + carboncost_{z,y} \quad (2)$$

$$fixedcost_{z,y} = \sum_{g \in NG} CRF_{NG} * CapCost_{NG,y} * cap_{g,y} * + \sum_{g} FixedOM_{g,y} * cap_{g,y} \quad (3)$$

$$variablecost_{z,y} = \sum_{g \in Z,f,q,d,t} GenCost_{g,f,y} * Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \quad (4)$$

$$reservecost_{z,y} = \sum_{g \in Z,q,d,t} ResCost_g * Duration_{q,d,t,y} * reserve_{g,q,d,t,y} \quad (5)$$

$$usecost_{z,y} = \sum_{q,d,t} VOLL * Duration_{q,d,t,y} * unmetDem_{z,q,d,t,y} \quad (6)$$

$$usrcost_{z,y} = \sum_{q,d,t} RESVoLL * unmetRes_{z,y} + \sum_{z,q,d,t,y} Duration_{q,d,t,y} * SRESVoLL * unmetSResZo_{z,q,d,t,y} + \sum_{q,d,t} Duration_{q,d,t,y} * SRESVoLL * unmetSResSY_{q,d,t,y} \quad (7)$$

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * carbon_{emission_f} * gen_{g,f,q,d,t,y} \quad (8)$$

Note: This study does not consider long-term capacity expansion; it optimizes the existing systems. Therefore, the first component in the right hand side of Equation (3) becomes zero as no new capacity will be added in this analysis.

Transmission network constraints

$$\sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} \left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y} + storage_{out_{z,q,d,t,y}} - storage_{inj_{z,q,d,t,y}} + unmetDem_{z,q,d,t,y} = Demand_{z,q,d,t,y} \quad (9)$$

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \quad (10)$$

System requirements

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_y \quad (11)$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2} \left(TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}\right) \geq SResZo_{z,y} \quad \forall\, z,q,d,t,y \quad (12)$$

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_z) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall\, z,y \quad (13)$$

Generation constraints

$$\sum_{f} gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq \left(1 + OverLoadFactor_g\right) * cap_{g,y} \quad (14)$$

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_g \quad (15)$$

$$\sum_{f} gen_{g,f,q,d,t-1,y} - \sum_{f} gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_g \quad \forall\, t > 1 \quad (16)$$

$$\sum_{f} gen_{g,f,q,d,t,y} - \sum_{f} gen_{g,f,q,d,t-1,y} \le cap_{g,y} * RampUp_g \quad \forall\, t > 1 \tag{17}$$

$$\sum_{f} gen_{g,f,q,d,t,y} \ge MinCapFac_g * cap_{g,y} \qquad \forall d \in M \tag{18}$$

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \le Availability_{g,q} * \sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \tag{19}$$

Renewable generation

$$gen_{g,f,q,d,t,y} \le RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \qquad \forall\, RE \notin CSP \tag{20}$$

Concentrated Solar Power (CSP) Generation

$$storageCSP_{g,z,q,d,t,y} \le cap_{g,y} * CSP\_storage \qquad \forall\, map(g, CSP) \tag{21}$$

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \tag{22}$$

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \le cap_{g,y} \tag{23}$$

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t.y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \quad \forall\, g, z, q, d, t, y \tag{24}$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \tag{25}$$

Time consistency of power system additions and retirements

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \qquad \forall\, ord(y) > 1 \tag{26}$$

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \qquad \forall\, ord(y) > 1 \tag{27}$$

$$cap_{g \in NG,y} = PlantCap_{EG} \qquad ord(y) = 1 \tag{28}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g)\text{: } (ord(y) - 1) * StageDuration_y + StartYear < Commission\_year_g \tag{29}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g \in EG)\text{: } (ord(y) - 1) * StageDuration_y + StartYear > Retirement\_year_{EG} \tag{30}$$

Storage constraints

$$storage_{z,q,d=1,t=1,y} = 0 \tag{31}$$

$$storage_{z,q,d,t>1,y} = storage_{z,q,d,t-1,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d,t-1,y} - storage\ out_{z,q,d,t-1,y} \quad (32)$$

$$storage_{z,q,d,t=1,y} = storage_{z,q,d-1,t=241,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d-1,t=24,y} - storage\ out_{z,q,d-1,t=24,y} \quad (33)$$

$$\sum_{t \in PT} storage\ out_{z,q,d,t,y} \leq Storage_{efficiency_{z,y}} * \sum_{t \in OPT} storage\_inj_{z,q,d,t,y} \quad (34)$$

$$storage\ inj_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (35)$$

$$storage\ out_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (36)$$

$$storage_{z,q,d,t,y} \leq Storage\ energy_{z,y} \quad (37)$$

$$storage\ out_{z,q,d,t,y} \leq storage_{z,q,d,t,y} \quad (38)$$

$$storage\ inj_{z,q,d,t,y} \leq Storage\ energy_{z,y} - storage_{z,q,d,t,y} \quad (39)$$

Investment constraints

$$\sum_{y} build_{g \in NG,y} \leq MaxNewCap_{NG} \quad (40)$$

$$build_{g \in NG,y} \leq Annual\ built\ limit_{y} * WeightYear_{y} \quad (41)$$

$$fuel_{z,f,y} \leq MaxFuelOff_{f,y} \quad (42)$$

$$fuel_{z,f,y} = \sum_{g \in Z,q,d,t} Duration_{q,d,t,y} * HeatRate_{g,f} * gen_{g,f,q,d,t,y} \quad (43)$$

$$\sum_{y,g \in NG} ReturnRate_{y} * pweight_{y} * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \leq MaxCapital \quad (44)$$

Environmental policy

$$emissions\_Zo_{z,y} = \sum_{g \in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_{f}} * Duration_{q,d,t,y} \quad (45)$$

$$emissions\_Zo_{z,y} \leq Zo\_emission\_cap_{y,z} \quad (46)$$

$$emissions_{z,y} = \sum_{g,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_{f}} * Duration_{q,d,t,y} \quad (47)$$

$$emissions_{z,y} \leq Sy\_emission\_cap_{y} \quad (48)$$

Appendix C

Data Sources

Argentina

The Secretariat of Energy of the Ministry of Energy and Mines (MINEM) has an online open data website that contains a comprehensive dataset on existing power plants used for electricity generation (Ministerio de Energía y Minería, Secretaría de Gobierno de Energía, 2020). More specific information on the nuclear power plants is available from the Nucleoeléctrica Argentina company principally owned by the Argentinian government (Nucleoeléctrica Argentina S.A., 2020). The Argentine Wholesale Electricity Market Administrative Company - CAMMESA (Compañía Administradora del Mercado Mayorista Eléctrico S.A) publishes a dataset on imports/exports of electricity on their data portal (CAMMESA, 2020). CAMMESA also tracks real-time or hourly demand and publishes it in the "Daily Demand Programming" (CAMMESA, 2021). CAMMESA also publishes Annual Reports that contain annual historical data on fuel consumption and fuel costs for electricity generation, which are supplemented with another official sources (Comisión Nacional de Energía Atómica, CNEA, 2019). The Ministerio de Energía y Minería, Secretaría de Planeamiento Energético Estratégico, (2019) presents energy demand forecasts.

Belize

The Belize Electricity Limited (BEL) is the main electricity authority in Belize. It buys electricity from independent power producers (IPP) it also imports electricity from Mexico. BEL also operates a gas turbine plant as a standby plant for energy security and reliability. As of 2019, 58% of electrical production was renewable, 5% was non-renewable, and 37% was imported (Belize Electricity Limited, 2020). Details on the various Power Purchase Agreements (PPAs) in place in Belize to feed electricity to the national grid by private companies are published by the Public Utilities Commission (Public Utilities Commission of Belize, 2020). Belize does not publish or make available any hourly data on demand and daily load curve.

Bolivia

The National Commission of Power Dispatch (CNDC, Comité Nacional de Despacho de Carga) publishes extensive data on power generation and dispatch for the Bolivian national grid (SIN) (CNDC, Comité Nacional de Despacho de Carga, 2020). We got the hourly load curve data ("Despacho de carga realizado" and "Curva de carga") from this source. Please note that hourly load curve data for Bolivia corresponds to one day of data per month: the day with the highest recorded demand in MW in that month. We have reconstructed an annual hourly load curve data with the highest demand day for each month (CNDC, Comite Nacional de Despacho de Carga, 2021). Bolivia mostly uses natural gas for power generation. Consolidated prices for natural gas in 2020 are compiled from CNDC of Bolivia (CNDC, Comite Nacional de Despacho de Carga, 2020)(CNDC, Comite Nacional de Despacho de Carga, 2020) (CNDC, Comite Nacional de Despacho de Carga, 2020). Bolivia does not have transmission interconnection with neighboring countries, although plans have been made and a memorandum has been signed with Argentina. The Electricity and Nuclear Technology Supervisory Authority (AETN) publishes the Annual Statistical report, which is also an extensive source of data on the electricity sector in Bolivia (AETN, 2020).

Brazil

The Power Trade Chamber of Commerce of Brazil (CCEE, Câmara de Comercialização de Energia Elétrica) publishes detailed datasets relevant to the power sector in Brazil. We use this source for installed capacity and power generation for individual plants (Câmara de Comercialização de Energia Elétrica, 2020). The National Operator of the Electricity System (ONS) also presents extensive information and data for the electricity sector in Brazil (Operador Nacional do Sistema Elétrico, 2020). We use its online data portal (Curva de Carga Horária) for hourly load curve data. ONS also publishes monthly reports on the cross-border trade of electricity with Argentina and Uruguay (ONS, 2020). Electricity demand projections are from EPE (Empresa de Pesquisa Energetica) and ONS (EPE, ONS, Ministério de Minas e Energia, 2019).

Chile

The Energía Abierta initiative of the Chilean National Energy Commission (CNE, Comisión Nacional de Energía) makes various dataset relevant to the electricity sector in Chile available to the public (Energía Abierta, Comisión Nacional de Energía, 2020). Data on installed capacity, plant-level monthly and annual fuel consumption and electricity generation are from this source (Comisión Nacional de Energía, 2020). Real-time and hourly load data are from the Chilean Coordinator Eléctrico National website (Coordinador Eléctrico Nacional, 2020). CNE also publishes projections for energy demand every year and for a time horizon of 20 years (CNE, 2020). Chile has an interconnection with Argentina but there has been no flow of electricity over the last two years between the two countries. Discussions are in progress to open an interconnection with Peru in the near future. Data for electricity trade is available from the Argentinian online data portal (CAMMESA, 2020).

Colombia

The Mining and Energy Planning Unit (UPME) of Colombia, part of the Ministry of Mines and Energy, has an online information system on the electricity sector (SIEL – Sistema de Informacion Eléctrico Colombiano) containing extensive electricity data including installed capacity and generation, electricity trade from interconnections with Ecuador and the República Bolivariana de Venezuela (UPME- Sistema de Informacion Eléctrico Colombiano, 2020). Additional data on certain technical parameters of the national grid (SIN, National Interconnected System), can also be obtained from the Paratec website (XM, Paratec, 2020). XM Colombia is a company that is operating the National Interconnected System (SIN) and manage the Wholesale Energy Market (MEM), for which we perform the functions of the National Dispatch Center -CND-, Administrator of the Commercial Exchange System -ASIC- and Account Clearer of Accounts of charges for Use of the networks of the National Interconnected System - LAC. In addition, XM manages the short-term International Electricity Transactions -TIE- with Ecuador. XM Colombia publishes a lot of useful information on the operation of the electricity sector in Colombia, such as daily and hourly data on power generation and electricity demand at the national level (XM, 2021).

The Mining and Energy Planning Unit (UPME) publishes energy demand projections on the SIEL data portal, last revised projections were made in June 2020 (UPME, 2020). It also publishes extensive data on prices for all fuels used for power generation.

Costa Rica

The CENCE (Centro Nacional de Control de Energia), which is part of the Costa Rica Institute of Electricity (ICE) is the repository of data relevant to the electricity sector in Costa Rica. Data on installed capacity for power generation in Costa Rica are taken from the November 2020 Monthly Report on the state of the SEN National Electricity System (CENCE, Centro Nacional de Control de Energía), 2020). Real energy demand in the SEN in Costa Rica (in MW) for 2019 and 2020 for the periods March to December are also made available to the public by CENCE, as it is possible have access to real-time operation and load curve. (CENCE, 2020). CENCE also publishes fuel prices for power generation in their report Estudio de Planeamiento Operativo Energetico Para el Periodo 2020-2024 (CENCE, 2020), as well as energy demand forecasts in their report Electricity Generation Expansion Plan for 2018-2034 (PEG2018) (CENCE, 2018).

Ecuador

The Energy and Natural Resources Regulation and Control Agency developed a data portal named SISDAT that contains all data on power plants in Ecuador (Agencia de Regulación y Control de Energía y Recursos Naturales No Renovables, 2021). National Electricity Operator of Ecuador (CENACE) is responsible for operating the national grid and provides data and information for real-time operation of the grid and statistics on the grid system. This data is available partly on their website (CENACE Ecuador, 2020). The Electricity Regulation and Control National Agency (ARCONEL) publishes Annual Statistics of the Electricity Sector in Ecuador, which contains useful data on the entire status of the electricity sector, available for 2018 at (ARCONEL, Agencia de Regulación y Control de Electricidad, 2018). More generally, ARCONEL is a complete source of data on the electricity sector (ARCONEL, 2020). Information on fuel costs for power generation and electricity trade data for Ecuador at their interconnections with Colombia and Peru are collected from ARCONEL in their Annual Report on the Electricity Sector (ARCONEL, Agencia de Regulación y Control de Electricidad, 2018).

El Salvador

The National Energy Council of El Salvador (CNE, Consejo Nacional de Energía) is the main source of information. Its Annual and Monthly Statistical yearbook, as well as online system provides data installed capacity and generation (CNE, 2021). The Transactions Unit (UT, Unidad de Transacciones), the agency responsible for the operation and control of the national grid, publishes extensive data on the grid system including hourly load curves, fuel prices, imports and exports of electricity at the international interconnections (UT, Unidad de Transacciones, 2020). Energy and power demand projections to 2028 are under the responsibility of the CNE which has released them to the public in their report: "Plan Indicativo de Expansion de la Generacion 2019-2028", that includes several scenarios for growth up to 2028 (CNE, Consejo Nacional de Energía, 2019).

Guatemala

Administrador del Mercado Mayorista (AMM), the wholesale electricity market administrator of Guatemala, has an online data portal that provides information on installed capacity data, power generation, hourly load profiles, electricity trade with Mexico (AMM, 2020, 2021). Data on electricity imports and exports are also available from the AMM online data portal (AMM - Administrador del Mercado Mayorista, 2021). The Ministry of Energy and Mines of Guatemala (UPEM, Unidad de Planeación Energético Minero) provides data on fuels prices.

Guyana

The state-owned Guyana Power and Light Inc. (GPL) used to publish electricity information, but they stopped releasing their Annual Reports since 2012. GPL is also responsible for developing the programs for expansion of the electricity sector in Guyana; however, the last update was the 2016-2020 Development and Expansion Programme published in 2016 (Guyana Power and Light Inc., 2020). The Guyana Energy Agency (GEA) publishes some information on electricity, particularly renewable energy (Guyana Energy Agency, 2020). Data and information on Guyana's electricity sector are very scarce, and finding updated information is challenging. Some data are from IRENA's Statistical Profile on Guyana (IRENA, 2018). Information on energy demand forecasts are from Inter-American Development Bank (IADB, 2018). No hourly load curve data is available for Guyana.

Honduras

The Empresa Nacional de Energía Eléctrica (ENEE), the state-owned power company is the source of main data in Honduras (ENEE, 2020). The Operator of the National Grid System (ODS, Operador del Sistema) publishes monthly reports on the national grid containing various information such as power plant capacities and generation, capital and fuel costs, demand forecasts. We use the 'Plan Indicativo de Expansión de la Generación del SIN 2020 – 2029' for these data (ODS, Operador del Sistema, 2019). Data for the hourly load curve in Honduras is taken from electricity dispatch reports made available by ODS on their platform. However, only pre-dispatch hourly energy demand in MW ("Predespacho Final") for the last 4 months are available to the public (ODS, 2021).

Mexico

Mexico's Energy Secretariat (SENER) issues the National Electricity System Development Program (PRODESEN), containing information on power generation, transmission, and distribution activities. The last edition of the PRODESEN was published in 2018 and includes the Development Program for 2018-2032. It has detailed information on the current National Electricity System and the various power plants in operation at the plant level (SENER, Secretaría de Energía, 2018). Energy demand projections up to the year 2032 are also available in the PRODESEN 2018-2032. SENER has also developed a publicly available Energy Information System (SIE) which contains various datasets on the electricity market and power sector in Mexico (SENER, 2020). The CENACE (Centro Nacional de Control de Energía) is in charge of monitoring the SEN (National Grid) and provides hourly load curves (CENACE, 2021).

Nicaragua

The National Electricity Dispatch Center of Nicaragua (CNDC) provides real-time and historical data on the National Electricity grid of Nicaragua. The CNDC releases daily post-dispatch reports to the public which includes hourly generation and demand (in MW) for each power plants (CNDC, Centro Nacional de Despacho de Carga, 2021). However, these data is only accessible at the moment on a day-by-day basis, as a result data is available for the first three days of each month. The Instituto Nicaragüense de Energía (INE, Nicaraguan Energy Institute) is also a source of comprehensive data and statistics on the electricity sector in Nicaragua (INE, Instituto Nicaragüense de Energía, 2020). The Ministry of Energy and Mines released in 2018 a plan for expansion of the power sector of Nicaragua including scenarios for medium-demand projections for the national grid (SIN) up to 2033 (Ministerio de Energía y Minas, 2018), which was the source of data such as fuel costs.

Panama

The National Electricity Transmission Company (ETESA, Empresa de Transmision Electrica, S.A.), is responsible for electricity dispatch in Panama and the source of data on the status of the grid, generation, interconnections (Centro Nacional de Despacho, Empresa de Transmisión Eléctrica, S.A., 2021). Energy demand projections are from the Expansion Plan of the National Interconnected System Grid 2020-2034, published by ETESA in April 2020 (ETESA, Empresa de Transmisión Eléctrica, S.A. , 2020). It also provides information and data on fuel costs and electricity trade at interconnectors with neighboring countries. The National Authority of Public Services (ASEP) also has an online data portal where monthly data on power generation and average generation costs are available (ASEP, 2021).The Centro Nacional de Despacho (ETESA), provided hourly load profile data for the month of July 2020 under 'Comportamiento del Sistema' (Centro Nacional de Despacho, Empresa de Transmisión Eléctrica, S.A., 2021).

Paraguay

The national electricity grid, Administración Nacional de Electricidad (ANDE) provides data on installed capacity and power generation (ANDE, 2020). Energy balances published by the Vice-ministry of Energy and Mines also provide some electricity data (Viceministerio de Minas y Energía, 2020). Paraguay has also developed an online Energy Information System (SIEN) that also includes some relevant data on the electricity sector, albeit not necessarily up to date (Viceministerio de Minas y Energía, 2020). Data on hydropower and hydroelectricity production, as well as monthly exports and diesel prices, are coming from the SIEN. Paraguay does not publish or make available hourly load curves.

Peru

Peru's Ministry of Energy and Mines (MINEM) publishes the 'Annual Report on Generation of Electricity' ('Capitulo 3 – Generacion de Energia Electrica') that provides various data on the electricity sector, including power plant-level data (MINEM, Ministerio de Energía y

Minas, 2018). The National Interconnected System Financial Operation Committee (COES), a private Peruvian nonprofit organization, also has an online portal containing real-time and summary statistics of the national Peruvian electricity grid and the operating power plants (COES, 2021). COES also makes available the fuel costs for several power plants in Peru using various fuel types (COES, 2021). Real-time operation of the national grid including hourly load curve and past real demand in MW can also be accessed through the information released publicly by COES (COES, 2021). The Organismo Supervisor de la Inversión en Energía y Minería (OSINERGMIN, Supervisory Agency for Investment in Energy and Mining of Peru) publishes the Annual Statistics Report (OSINERGMIN, 2019) which contains a variety of economic data and information on the electricity sector.

Suriname

The main source of data in Surinam is the state-owned energy company EBS EnergieBedrijven Suriname (EBS, EnergieBedrijven Suriname , 2020). The Government of Suriname has published a plan including energy demand forecasts in 2017 (Republiek of Suriname, 2017). Suriname currently has no interconnections with neighboring countries. It also does not publish hourly load curves.

Uruguay

The website of the National Administration of Power Plants and Electrical Transmissions (Administración Nacional de Usinas y Trasmisiones Eléctricas), better known as UTE, provides most data needed for this study (UTE, 2021). Its publication “Balance de Gestión y Futuro del Sector Eléctrico” presents electricity forecasts until 2030 (UTE, 2019). The Statistical series (Estadísticas de energía eléctrica) published by the Ministry of Industry, Energy and Mines provides data on power plant capacity (MIEM, 2020). The Administration of the Electricity Market of Uruguay (ADME, ADMINISTRACIÓN DEL MERCADO ELÉCTRICO) publishes hourly data on generation and electricity trade at interconnections with Brazil and Argentina. Historical hourly generation data are from ADME (2021) and (ADME, 2021). Fuel costs for power generation are also compiled and discussed by ADME (ADME, 2020).

República Bolivariana de Venezuela

CORPOELEC (Corporación Eléctrica Nacional, SA), the state-owned electricity authority, is responsible for electricity statistics in the República Bolivariana de Venezuela. Installed capacity and generation data are from the Asociación Venezolana de Ingeniería Eléctrica, Mecánica y carreras afines (AVIEM, 2020). Energy price data are from Global Petrol Prices (2021) and Bloomberg (2020). The República Bolivariana de Venezuela does not publish daily or hourly load curves. Electricity demand forecasts are from Inter-American Development Bank (IADB, 2018).

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