

Electricity Market Coupling: Latin America vs. Europe

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ABSTRACT

Electricity Market Coupling is spreading all around the world; however, its potential benefits and drawbacks are still open to debate, and regions like the European Union advance quite slowly towards integration. There is no agreement in terms of what are the right policies to implement in order to acquire the benefits of integration without putting reliability at risk, and most countries continue to implement national policies without taking the interconnectors into account.

In order to contribute to the discussion, we develop a System Dynamics model that allows us to simulate the integration of two countries and test different policies. Two dissimilar cases, one in Latin America and one in Europe, are analyzed, and we obtain some insights into the aspects that deserve special attention when designing policies for interconnected countries.

Results of the simulation show that, in the long-term, the amount of investment in generation capacity, as well as the technology mix of new investments, is influenced by the degree of interconnection. Furthermore, the effect of a capacity payment mechanism depends not only on the degree of interconnection, but also on the characteristics of the integrated countries, such as the complementarities, currently installed capacity, resources, load curves, etc.

Key Words: Market Coupling, Electricity Market Integration, System Dynamics

1. INTRODUCTION

As part of the liberalization process, many countries around the world have decided to integrate their electricity systems. Motivations range from the desire to improve cohesion between countries – as is the case of the European Union, to requirements of the World Bank or IMF as a precondition for loans – as in Latin America and other developing regions (Correljé and de Vries 2008). But in terms of power supply, the objectives are quite the same in all regions: to improve reliability, to lower supply costs, to improve the use of resources, to reduce carbon emissions, etc.

The achievement of these goals depends to a large extent on an adequate expansion of generation and transmission capacities, which in liberalized systems should be addressed through market design and the regulatory framework (Jamash and Pollitt, 2008).

However, there is no agreement in terms of how much capacity is enough. Regarding transmission, some people argue that it is better to have ample capacity, while others are concerned about “gold-plating” the grid. The problem is that too little capacity will put in danger security of supply and could increase market power in generation (Brown and Sedano, 2004); but on the other hand, too much capacity will cost more than what people are willing to pay and will also affect the ability to recover fixed costs for both generation and transmission investments (Stoft 2006).

Until a couple of decades ago, electricity was supplied by publicly owned monopolies, so the expansion of the system could be planned in a coordinated way for both transmission and generation, in order to minimize costs and maximize social welfare. However, prices were high due to inefficiencies attributed to the lack of competition in the market – there were no incentives for developing better technologies or using more efficient raw materials. Furthermore, there was an incentive to over-invest, since shortages were visible while the cost of maintaining a large safety margin was invisible. As a consequence, most countries started to liberalize their electricity markets, going through privatization, de-regulation and re-regulation processes.

The result of this liberalization is that competition has been introduced at several points in the supply chain – generation and commercialization –, while transmission and distribution networks remain as monopolies. Additionally, generation and transmission activities have been unbundled, creating new challenges for expansion planning, since a high level of coordination between agents is required in order to develop a system in which generation and transmission capacities are jointly optimal.

Considering the number of variables involved in the system, such as generation availability and location, technology mix, load, etc., which are now decided by many different actors at different times, the optimal grid is probably impossible to determine; and even if it could be determined, the number of actors involved in the investment decisions and operation of the system would make it impossible to implement. The fact that a grid might take around 10 years to be built does not help; it usually has to be planned under a lot of uncertainty, and

some projects might not even materialize because of changes in the system during the approval phases.

In addition, the main goal pursued by private owners and investors is no longer reliability, as was the case before liberalization when the electricity system was a state-owned monopoly. After liberalization, cost reduction became more important, leading to cost minimization at the expense of reliability as shown in Figure 1. Guaranteeing an adequate level of security of supply is now a matter of regulation, which must provide the right signals to market participants, as they do not necessarily act in favor of the system.

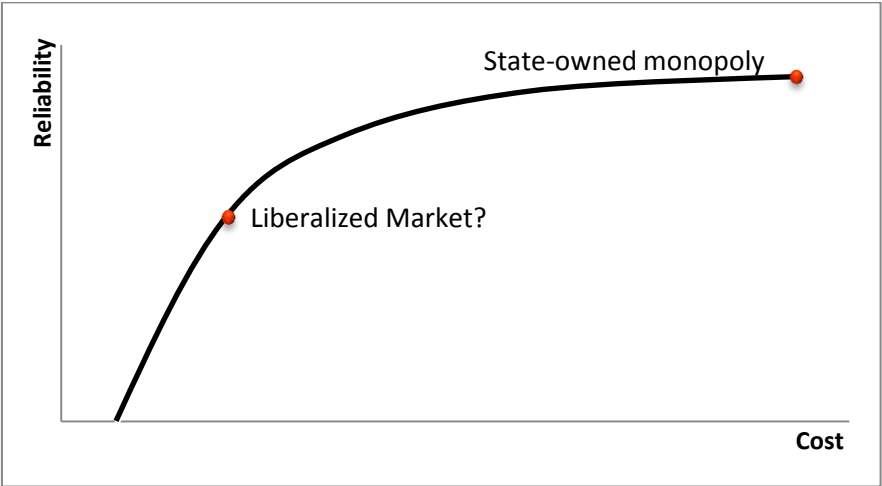


Figure 1. Liberalization

Investors might adopt strategic behaviors in order to maximize their own benefits. As an example, consider two countries connected by limited transmission capacity, as in Figure 2. Assume that country A has a lack of generation capacity and country B has a surplus of generation capacity; however, the transmission capacity from B to A is not sufficient (the line is congested) and prices are thus higher in A than in B. In such a situation we refer to A as being import constrained and to B as being export constrained.

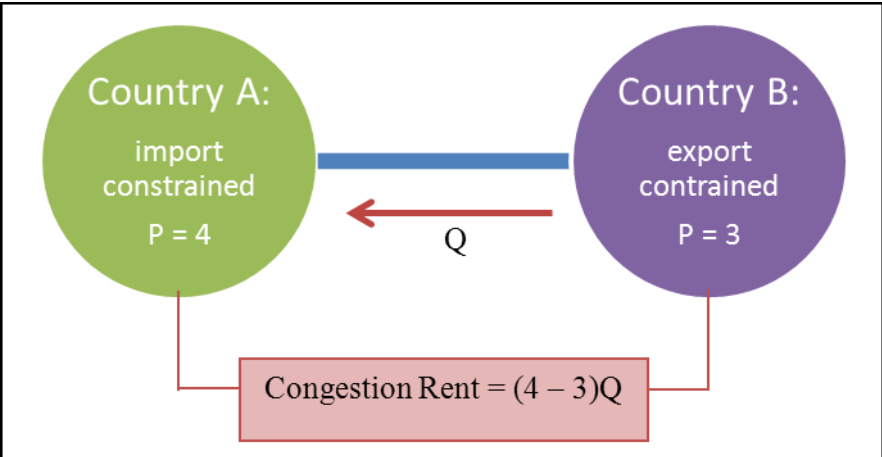


Figure 2. Limited interconnection between two countries

In such a case, an investor might have different strategies, which may not necessarily improve social welfare. He can decide to locate a generation plant in country A – an import constrained area – rather than expand the interconnection line (which would probably be more efficient for the system). The reason is that if low cost electricity cannot be imported, a generator in area A can exercise market power, increasing its offer price without risking not being dispatched, as cheaper electricity is not accessible. The investor might also decide to locate a generation plant in country B if a capacity payment mechanism (i.e. payment for being available on a stand-by basis) is in place, since that would allow him to collect those payments without actually generating electricity: the generator bids a high price in order to avoid being dispatched and earns some rents for being available.

The transmission owner might also try to limit or delay investment in grids and/or generation in order to collect higher congestion rents – created by the difference in prices when a line is congested (see Figure 2). Likewise, generators will make strategic decisions according to planned transmission and will try to block investments that are not in their interest (Stoft 2006).

Regulation and appropriate incentive mechanisms are thus required in order to avoid or limit these kinds of strategic behavior, though some authors argue that a certain degree of market power must be allowed to enable recovery of fixed costs of infrastructure (Stoft 2006); others claim this is wrong, since costs can be recovered by collecting scarcity rents and capacity payments (Borenstein and Bushnell, 2000). There is no agreement in terms of what are the right norms, policies and incentives that should be implemented in order to promote an adequate expansion of the system.

The regulatory issue gets even more complex when we consider cross-border transmission, as different market mechanisms and incentives may be adopted in each country. In this case, electricity flows and prices might be affected by these differences and a country may be adversely affected if it does not implement the right policies, since it could end up subsidizing its neighbors (Dyner et al. 2011). This effect may be intensified when investment in generation is more profitable in one country than in the other, since the former will expand its generation capacity more and thus will be a net-exporter.

As Cepeda and Finon (2011) discuss, national policies must take into account the interdependencies between neighboring countries, which may lead to unexpected and probably undesirable outcomes. Price caps, subsidies to fuels, taxes, and anything that may affect prices, are likely to have an impact on international transactions and increase the risk of free-riders.

These are just some examples of the likely behaviors of actors in an electricity market and the dangers of inappropriate regulatory policy. In the case of international electricity markets, both regional and national policies influence the development of the market and the possibility of achieving the potential benefits of regional integration.

The next section presents a description of the market coupling mechanism, which is generally considered to be the most desirable mechanism, and is currently implemented in Western-Central Europe and the Andean Community regions, among others.

2. MARKET COUPLING

From the perspective of international electricity markets, having considerable interconnection capacity between countries is essential in order to achieve the potential benefits of integration (Gilbert et al. 2004). Nonetheless, cross-border interconnection capacity is in most cases very restricted; consequently, links are highly congested and real competition among agents in different countries is not an option.

As transmission capacity is limited, especially in the case of cross-border interconnections, it is necessary to implement a *congestion management mechanism* in order to allocate the available capacity. This mechanism should give the right signals to the market actors so that they make investment decisions – as well as operational decisions – that are in the interest of the system and thus contribute to its efficiency and security of supply. Several mechanisms have been implemented for this purpose, including *Access Limitation, Priority Lists, Pro Rata, Implicit and Explicit Auctions, etc.* (for details see: ETSO, 1999).

This paper analyzes the evolution of two interconnected markets considering a *Market Coupling* mechanism, which is a particular case of *Implicit Auctions* and is currently considered to be the most desirable mechanism. Still, it cannot always be applied because of implementation problems in some regions that require using an explicit auction mechanism as a transitory stage. Market Coupling does not require, in principle, a high harmonization degree among the integrated markets – each market remains independent, with its own TSO (Transmission System Operator) and regulator; however, as the international dispatch is done in a centralized manner, some information about the supply curves must be shared.

Belpex (2012) defines the concept of Market Coupling as: “*Coupling markets involves handling their respective supply and purchase curves jointly according to the overall merit order - i.e., matching the highest purchase bids and lowest sales bids, regardless of where they have been introduced - but taking into account the available interconnection capacities. The overall aim of market coupling is to maximize the total surplus of all participants.*”

The definition of *Market Coupling* does not specify a way of allocating congestion rents, so this issue is the subject of regulation. Different options have been tried. Two examples from Latin America and Europe are: (i) the exporting and importing countries share the rents; (ii) the owners of the interconnectors keep the rents. However, the discussion about which is the best way of allocating the rents is still open. Indeed, in the case of the Andean Community, Colombia and Ecuador are currently trading according to a provisional agreement while renegotiating the initial terms, which specified that congestion rents should be collected by the exporter system. Not surprisingly, this did not convince Ecuador – usually the importing country, so they are currently sharing 50/50 congestion rents until they reach a final decision.

Allowing the transmission owner to collect the congestion rents may create an incentive to build *merchant lines* (i.e. lines built by private investors, who recover investment costs via congestion rents) when there is high congestion and thus high rents; however, there would be a strong incentive to underinvest, since congestion rents diminish as transmission capacity grows.

Transmission investment is highly dependent on the regulatory framework, but it is not an isolated issue: generation and transmission investments are interdependent, so economic signals must be sent in order to coordinate both investment decisions. As stated by Pérez-Arriaga and Olmos (2006), the interaction between transmission and generation expansion is a major unsolved problem.

Some previous work that has assessed these issues is presented in the next section.

3. BRIEF LITERATURE REVIEW

For those who are not familiar with the functioning of the electricity system, a comprehensive description and history may be found in Schewe (2007).

Literature about electricity markets is quite extensive, especially since liberalization started to take place in the 1990s, attracting the attention of the academic world. A wide variety of approaches may be found, ranging from policy-type and technical analysis (Finon and Pignon 2008; Cramton and Stoft 2005; Newbery 2002; Jamasb and Pollitt 2005) to economic models (Hunt and Shuttleworth, 1996; Joskow and Tirole, 2007) and simulation (Cramton and Stoft 2008; Rosellon 2007; Neuhoff and Newbery 2005; Ford 1999; Weidlich and Veit 2008).

Regarding cross-border transmission and market designs, the available literature is relatively recent, though still wide. In this context, Brunekreeft et al. (2005) discuss various issues related to cross-border transmission and raise several questions regarding the implications of different congestion management mechanisms, such as Locational Marginal Pricing and Market Coupling, as well as some incentive problems caused by these. They also discuss the interaction between transmission and generation expansion, stating that “the TSO may find it difficult to commit to its transmission expansion schedule regardless of generator decisions” (*page 77*).

Pérez-Arriaga and Olmos (2005) recommend a congestion management mechanism for the Internal Electricity Market of the European Union, taking into account the diversity in regulation and market mechanisms among the Member States. Two mathematical models are formulated in order to test two different mechanisms: implicit auctions and explicit auctions. The conclusion is that implicit auctions could be efficient but face important implementation difficulties, so they propose a coordinated explicit auction mechanism.

The problem of market power in a regional electricity market is assessed by Bunn and Zachmann (2009); they show analytically that under specific conditions market power becomes attractive when a player has access to a more competitive neighboring market (i.e. under regional integration).

Continuing with comparisons between implicit and explicit auctions for electricity trade and transmission, Ehrenmann and Neuhoff (2009) extend the equilibrium problem formulation introduced by Cardell et al. (1997) – a Stackelberg game – to represent the integrated market design, and the mixed complementarity problem formulation in Hobbs et al. (2003) – a Cournot game – to represent the separate market design, in the presence of market power. They show that in a simple two-node network, the integrated market design reduces the exercise of market power; however, for more complicated networks it is not possible to determine a general ranking. As an alternative, they use numerical simulation with realistic parameters to analyze the Benelux case.

Unfair treatments between the users of the network, which decrease social welfare, are pointed out by Stoilov et al. (2011), who present an analysis of the evolution of transmission charges implemented in the European internal market. They suggest the reformulation of the Inter-TSO Compensation mechanism (a regulatory mechanism created in the EU to compensate TSOs for costs incurred as a result of hosting cross-border flows), arguing that it is discriminatory since the price paid by TSOs for compensation is different from the cost incurred in each network.

Regarding the expansion of the transmission grid, Rosellón et al. (2011) present an application of a mechanism combining the merchant and regulatory approaches to attract investment in transmission capacity in the PJM market in the US, arguing that to date there is no coherent mechanism to promote adequate expansion of this system. They perform simulations and conclude that the mechanism is promising in that congestion is relieved and nodal prices converge to a lower average level, so total welfare increases. However, they do not consider expansion of generation capacity, which they indicate as a limitation of their analysis.

Cepeda & Finon (2011) assess the generation capacity adequacy problem in a regional electricity market with transmission constraints using a System Dynamics model. They consider two decentralized electricity markets – where market participants may trade electricity bilaterally – with different regulatory designs. They conclude that generation adequacy depends on the interdependency between adjacent electricity systems, but disregard the interdependency between generation and transmission adequacy, taking the interconnector capacity as “constant and perfectly reliable throughout the simulation period”, although they admit the strong link between the dynamics of generation and transmission investments.

All these studies have identified capacity adequacy in electricity systems as problematic and highly influenced by regulatory policies and market designs. There also seems to be an agreement on the fact that expansion in generation and transmission capacities are

interdependent; nevertheless, there has been little research on this subject, as one of these capacities is usually considered static and the expansion of the other is thus analyzed as an isolated problem.

The model presented in this paper helps in understanding the implications of different regulatory policies regarding capacity expansion, both in grids and generation facilities.

4. METHODOLOGY

Given the complexity of the electricity system, which involves a large number of variables and actors that interact, creating feedbacks and delays, the long-term behavior of the system is not intuitive; however, its understanding is crucial in the process of policy analysis and decision making.

Model based methodologies seem appropriate for assessing the long-term evolution of international electricity markets. Characteristics of these systems, such as the interdependencies of the elements involved, suggest an approach using behavioral simulation, which takes into account feedback processes for representing and understanding the behavior and evolution of the system.

Most of the studies related to electricity market integration have used optimization or econometrics (see: Dyner et al. 2011); however, these methodologies present limitations to assess systems away from equilibrium such as the continuously changing electricity markets. As stated by Gary and Larsen (2000), equilibrium assumptions break down in the out-of-equilibrium transition to competitive markets, and therefore these assumptions must be replaced by endogenous behavioral policies.

For this reason, we propose to tackle the problem of capacity adequacy in international electricity markets using system dynamics, which incorporates non-equilibrium assumptions, delays, and bounded rationality, and is thus more suitable for evaluating markets during transition stages.

A system dynamics model allows the *a priori* experimentation of different policies and scenarios, thus being a useful tool for policy makers in order to learn about the likely behavior of the system under different conditions (Sterman, 2000). The objective is not to forecast the system evolution but, as is frequently stated in the literature, to “visit possible futures”.

System dynamics has been used to analyze energy related issues and improve the understanding of energy policy since the 1970s (Naill 1973; Naill 1977; Ford & Bull 1989; Ford et al. 1997; Bunn & Larsen 1997), comparing favorably to other modeling approaches (Ochoa & van Ackere 2009).

Regarding the integration of electricity markets, however, there has been comparatively little written, particularly with respect to the long-term consequences of the implementation of

different policies. One exception is a recent publication by Cepeda & Finon (2011) that was discussed above in the literature review, which analyzes the generation capacity adequacy problem.

In this paper we propose a system dynamics model to assess the potential benefits and threats of regional integration of electricity markets under market coupling. This model helps in understanding the importance of designing and implementing adequate policies, both at the national and regional levels, in order to effectively improve market efficiency without putting reliability at risk.

As the characteristics of the electricity systems involved in the integration may have an impact on the achievable results, we decided to analyze two different cases: one in Latin America (Colombia – Ecuador) and one in Europe (Great Britain – France). The reasons that lead to this decision, as well as the main characteristics of these two regions are presented in the next section. Throughout the paper we use “Latin America” as shorthand for the Colombia – Ecuador case and “Europe” as shorthand for the Great Britain – France case.

5. CASE STUDIES: Latin America and Europe

Latin America and Europe have important differences in terms of resources, technology mix and even demand patterns; which may lead to different outcomes in response to the same market design and/or policies, as will be discussed in the results.

Table 1 shows the installed capacity by technology, as well as the peak demand, in each country. We can observe that Colombia and Ecuador are highly dependent on hydroelectricity, while Great Britain is more dependent on thermic generation and France on nuclear power.

	Hydro	Nuclear	Coal	Gas	Liquid Fuels	Wind	Peak Demand	Interconnector
Colombia	9.7	-	1.0	3.1	0.6	-	9.7	0.5
Ecuador	2.2	-	0.5	1.0	1.3	-	3.5	
Great Britain	4.3	10.7	34.7	33.6	-	2.7	63.2	2.0
France	25.2	63.1	6.9	14.7	-	6.7	102.1	

Table 1. Installed Capacity and Peak Demand (GW)

One of the main purposes of integration is to make a better use of the resources by taking advantage of the complementarities between the interconnected countries. In the case of Colombia and Ecuador, these complementarities are caused mainly by the hydrological patterns (Figure 3, left panel), as hydropower represents a large percentage of the total installed capacity as well as of the generation. Great Britain and France (right panel) also have

different hydrological patterns; however, the impact in this case is less significant as hydropower represents a much smaller part of the installed capacity.

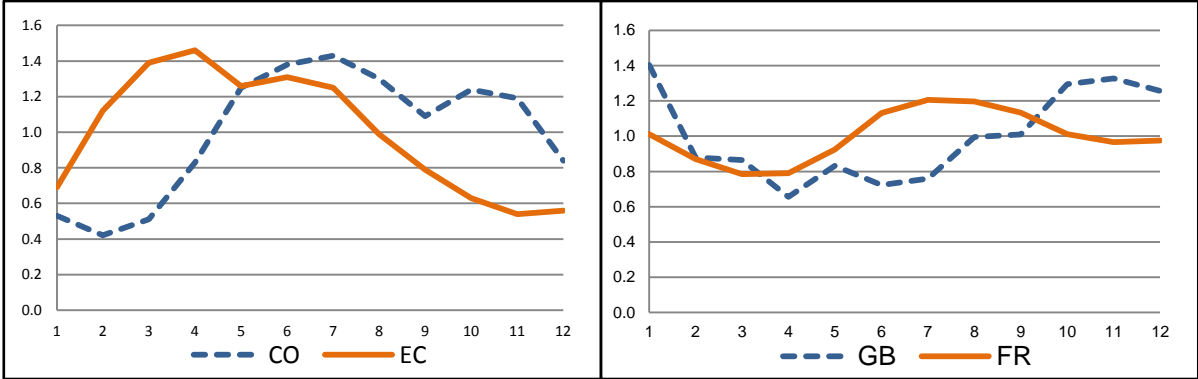


Figure 3. Hydrological Complementarities (mean monthly streamflows normalized)

From the demand side, there are also some potential benefits in the European case, since the peak hours of the two systems do not coincide, as can be observed in Figure 4 (right panel). From this point of view, the integration of Colombia and Ecuador does not have much to offer.

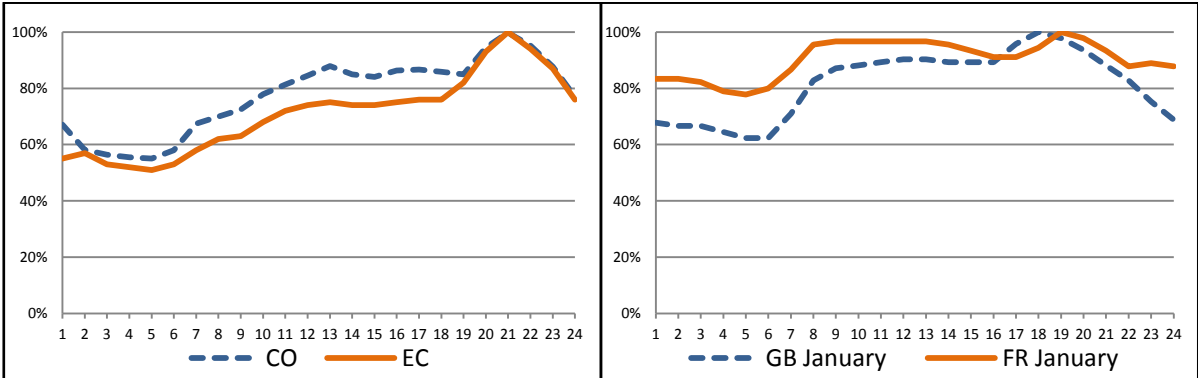


Figure 4. Typical weekday load curves (percentage of Peak Demand)

In addition to the daily load curves, it is also important to remember the fact that demand fluctuates according to the weather conditions, which means that in the case of France and Great Britain there are significant variations during the year as a result of the seasons, which does not occur in the case of Ecuador and Colombia.

The next section presents a description of the model, which was calibrated for both the European and Latin American cases in order to analyze the effect of various policies in these two dissimilar settings.

6. MODEL

We developed a System Dynamics model in order to analyze the impact of national and regional policies on the integration of two power systems. The model consists of two sub-models: a short-term dispatch model and a long-term capacity adequacy model. These allow

us to take into account the market interactions that determine electrical flows between countries and the resulting prices, which are crucial for investment decisions.

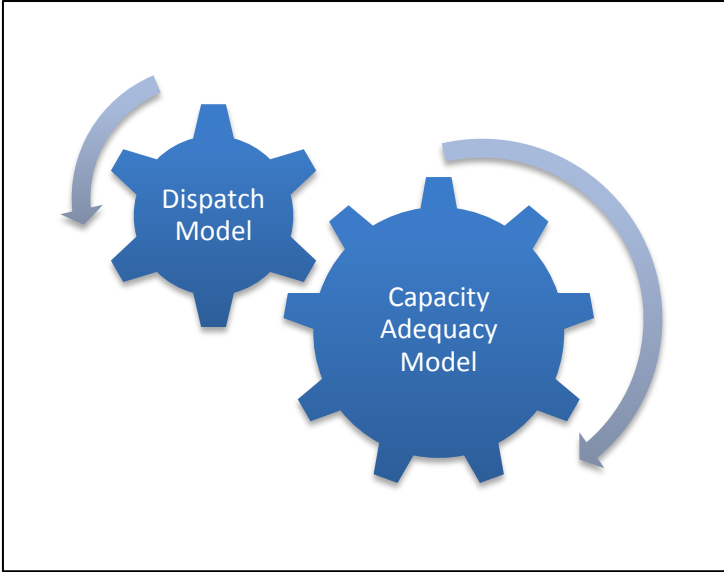


Figure 5. Mixed Model

These two models run coupled, sharing information at each step of the simulation. The Capacity Adequacy Model was developed in Vensim, and simulates the evolution of generation capacities, demand, costs, etc. in two neighboring countries. This information is passed to the short-term model, which consists of a merit order dispatch algorithm developed in Matlab that simulates the hourly dispatch under Market Coupling, and returns the generation by source in each country, prices and electricity flows to the long-term model.

In the long-term model, following de Vries and Heijnen (2008), investment decisions for the different generation technologies and grids are based on Net Present Values, which are calculated using expected load and prices for the lifetime of each project. Figure 6 presents a simplified view of the investment model structure.

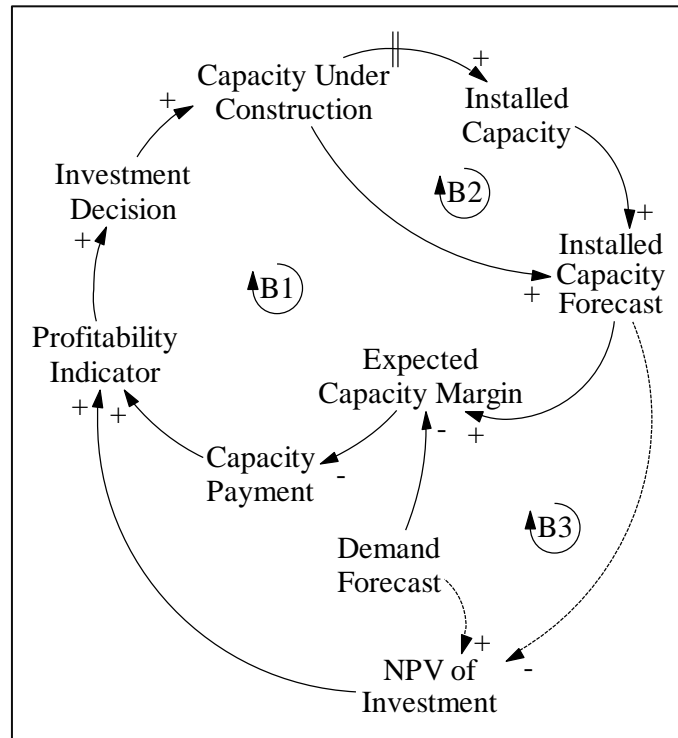


Figure 6. Causal Loop - Investment

The System Dynamics model in Vensim calculates the *Installed Capacity Forecast* for each generation technology in each country, as well as for the interconnection grid, by adding the current *Installed Capacity* and the *Capacity Under Construction*. The resulting values are passed to Matlab in order to run the dispatch algorithm, which simulates forecasts for the dispatch under Market Coupling for the life time of each investment to be evaluated, and calculates the net present value of those investments. In general, we can expect the *NPV of Investment* to decrease when *Installed Capacity* increases, and to increase as *Demand* grows.

If the *NPV of Investment* for a particular generation technology is high, the *Profitability Indicator* will be high, and more investments will be decided, which will in turn increment the *Capacity Under Construction*, and after some years, depending on the technology chosen, the *Installed Capacity*.

The countries may also decide to implement a *Capacity Payment* mechanism, which would depend on the *Expected Capacity Margin*. If this margin falls below the desired level, the *Capacity Payment* is activated, and the lower the margin, the greater the payment, in order to encourage investments to maintain an adequate level of reliability.

The model was calibrated using publicly available data, mainly from: the Colombian system operator (XM), the national electricity council of Ecuador (CONELEC), the British system operator (National Grid), the British “Department of Energy & Climate Change” (DECC), the French Transmission System Operator (RTE) and others (ELEXON; Mott MacDonald 2010; WNA; IEA; IRENA; GL Garrad Hassan 2011; ICF Consulting 2002; Eurelectric; ENTSO-E; The Royal Academy of Engineering 2004; UPME; UCTE 2009).

A complete description of the validation process of the model is out of the scope of this paper. We performed the classical SD validation tests (Barlas, 1996; Sterman, 2000). Among others, the results of the model are coherent under extreme conditions, as well as when changing different parameters. Furthermore, as the structure of the model is the same for both regions – Latin America and Europe, and only differs in the values of some state variables and parameters, the validity of the model can also be assessed through the comparison of these two cases.

The next section presents a comparative analysis of policies regarding the implementation of *Capacity Payments* and different degrees of interconnection, both in Latin America and in Europe.

7. POLICY ANALYSIS

We tested various policies regarding capacity adequacy, considering different degrees of openness to integration. In terms of the grid, we considered three degrees of interconnection: Isolated countries, Grid Expansion, and Unlimited Grid, as shown in Figure 7. Regarding generation capacity, countries may either choose to trust their neighbors and rely on the market to generate the economic signals for capacity expansion; or they may decide to implement incentives, or a capacity payment mechanism, in order to maintain a safety margin of generation capacity in their own territory, to insure that political or technical problems do not endanger their security of supply. This yields a total of 6 scenarios.

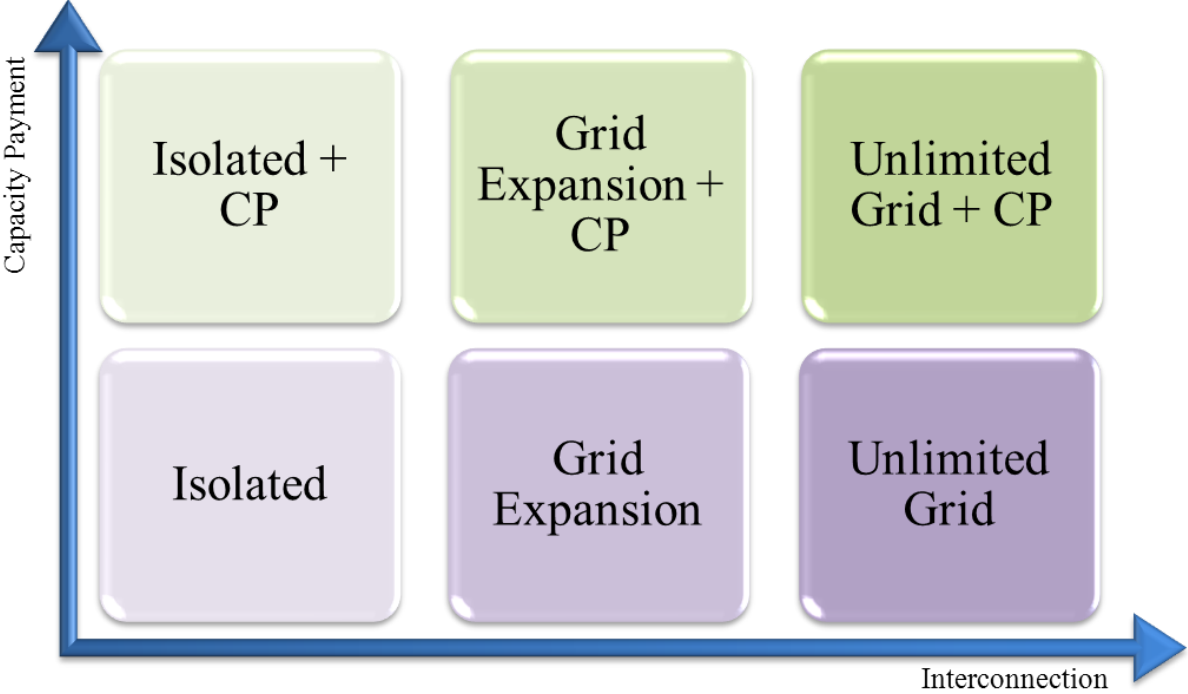


Figure 7. Scenarios to evaluate

We will first discuss the European case and then we will compare the results with the Latin American case.

7.1. EUROPE

Contrary to what might be expected, the results of the simulations, in Figure 8, show that the average price in Europe (Great Britain and France) is higher, most of the time, in the Unlimited Grid scenario compared to the Isolated case. However, its volatility is reduced.

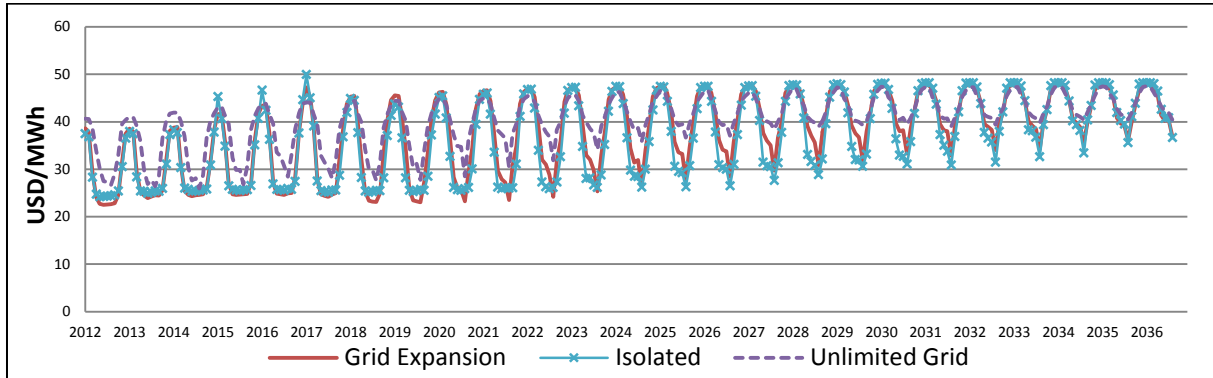


Figure 8. Average Price (Monthly) in Europe, according to the level of integration

The Grid Expansion scenario is quite similar to the Isolated case, since the current interconnector capacity between Great Britain and France represents only around 3% of Great Britain's peak demand and 2% of France's peak demand. This changes somewhat after 2018 as the interconnector is expanded, as shown in Figure 9, but remains closer to the Isolated than to the Unlimited Grid scenario.

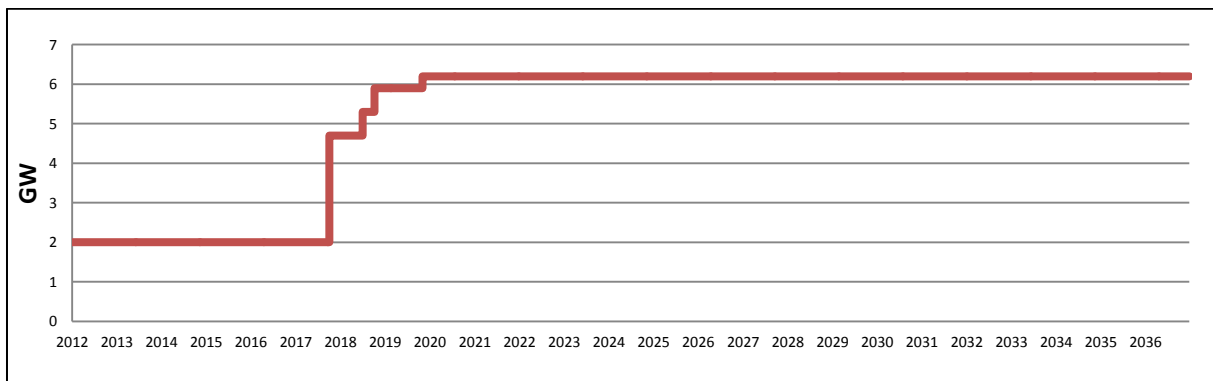


Figure 9. Great Britain – France Interconnector Capacity in the Grid Expansion scenario

Analyzing both countries separately (Figure 10), we can see that at the beginning of the simulation the Unlimited Grid scenario leads to lower prices in Great Britain and higher prices in France. This is because France will be a net exporter as it has a huge amount of nuclear capacity, which has the lowest generation cost. However, as nuclear capacity is retired, and new investments change the technology mix, the peak-price in France will increase and the possibility of importing electricity from Great Britain will cushion this effect.

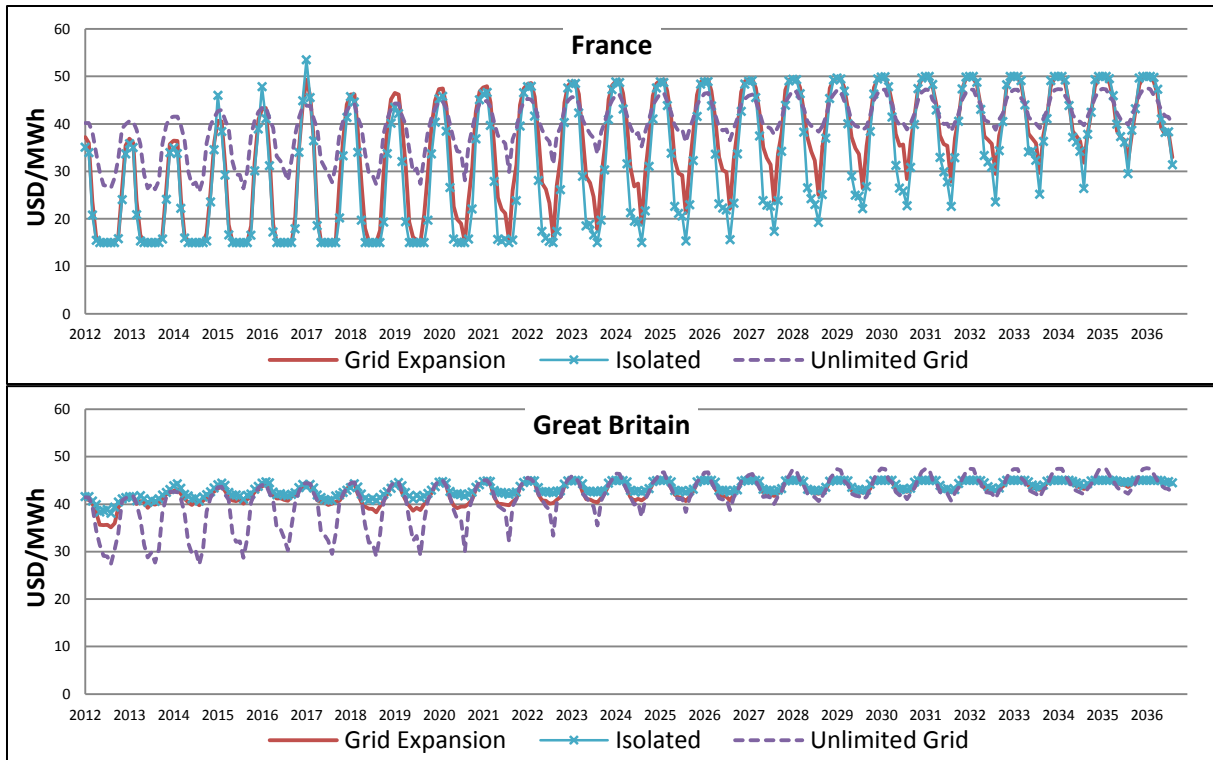


Figure 10. Average Prices (Monthly) in Great Britain and France, according to the level of integration

Figure 11 shows that indeed, at the beginning of the simulation France is a net exporter, but at the end of the simulation the direction of the flows alternates on a seasonal basis. The reason is that during summer, the total demand can mostly be met using base load technologies, which are cheaper in France; but in winter, peak plants are needed, and those in Great Britain cost less.

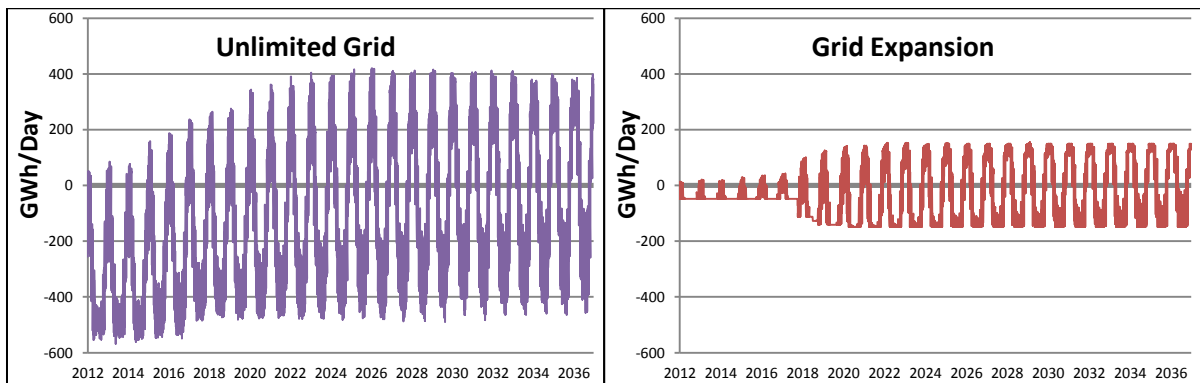


Figure 11. Net Flow Great Britain – France

In terms of reliability, the integration may bring about significant benefits when the capacity margin is low, as is observed in Figure 12. Even with a very limited interconnector capacity, as in the Grid Expansion scenario, shortages in France are significantly reduced though the capacity margin decreases as the level of interconnection increases.

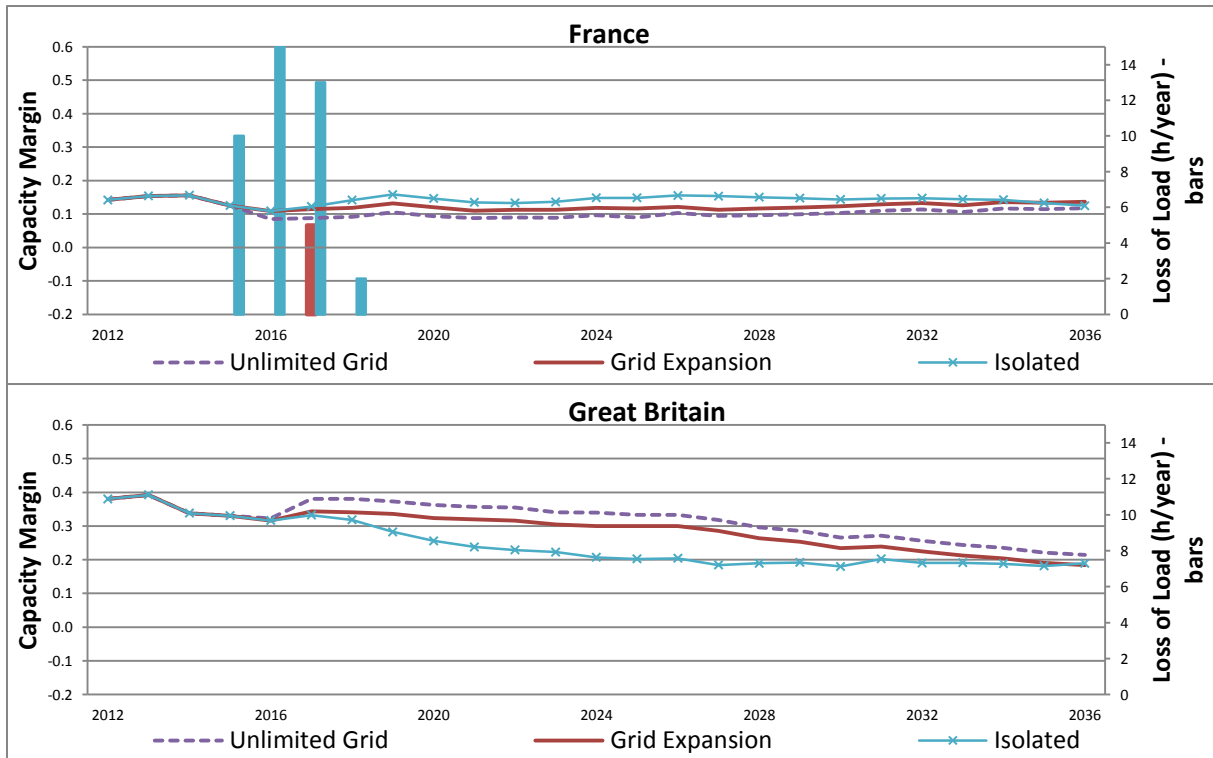


Figure 12. Capacity Margin vs. Loss of Load in Great Britain and France

Even if reliability is improved with the integration, the capacity margins are dangerously low, especially in France. So the regulator may wish to implement some kind of incentives to guarantee a safer capacity margin in case of unforeseen variations of supply or demand arise. However, the design of incentive schemes in an integrated market is very challenging, as the result will depend on the neighbor's decisions. The implementation of Capacity Payments in the Unlimited Grid scenario is analyzed in next section.

7.1.1. Capacity Payments – Unlimited Grid

In these scenarios we focus on the Unlimited Grid case and test the implementation of Capacity Payments unilaterally in each of the countries and simultaneously in both. Capacity Payments are defined as an annual payment granted to new investments during their whole lifetime, independently of their effective production. The amount of this payment depends on the expected national capacity margin in ten years.

We observe in Figure 13 that the Capacity Margin at the end of the simulation is larger when Capacity Payments are implemented in both countries compared to the case without Capacity Payments. However, when only one country decides to implement Capacity Payments, as side-effect its neighbor will invest significantly less in generation, to the point that at the end of the simulation its Capacity Margin will be negative.

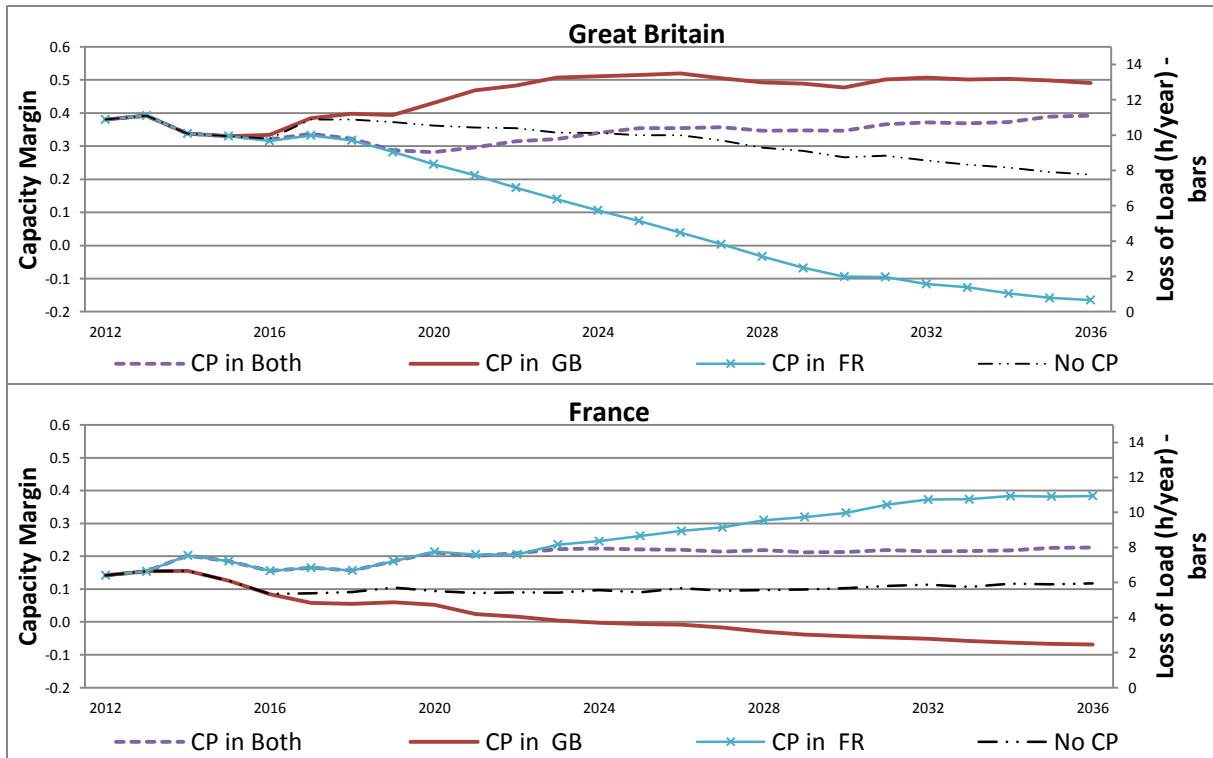


Figure 13. Capacity Margin vs. Loss of Load in Great Britain and France - Unlimited Grid with Capacity Payments.

This reduction is compensated by a larger investment in the country that implements the Capacity Payments, and leads in both cases to a reduction in average prices for both countries, as observed in Figure 14. Nevertheless, having such a low Capacity Margin implies a dependency on the neighboring country that may be undesirable, or even politically unacceptable.

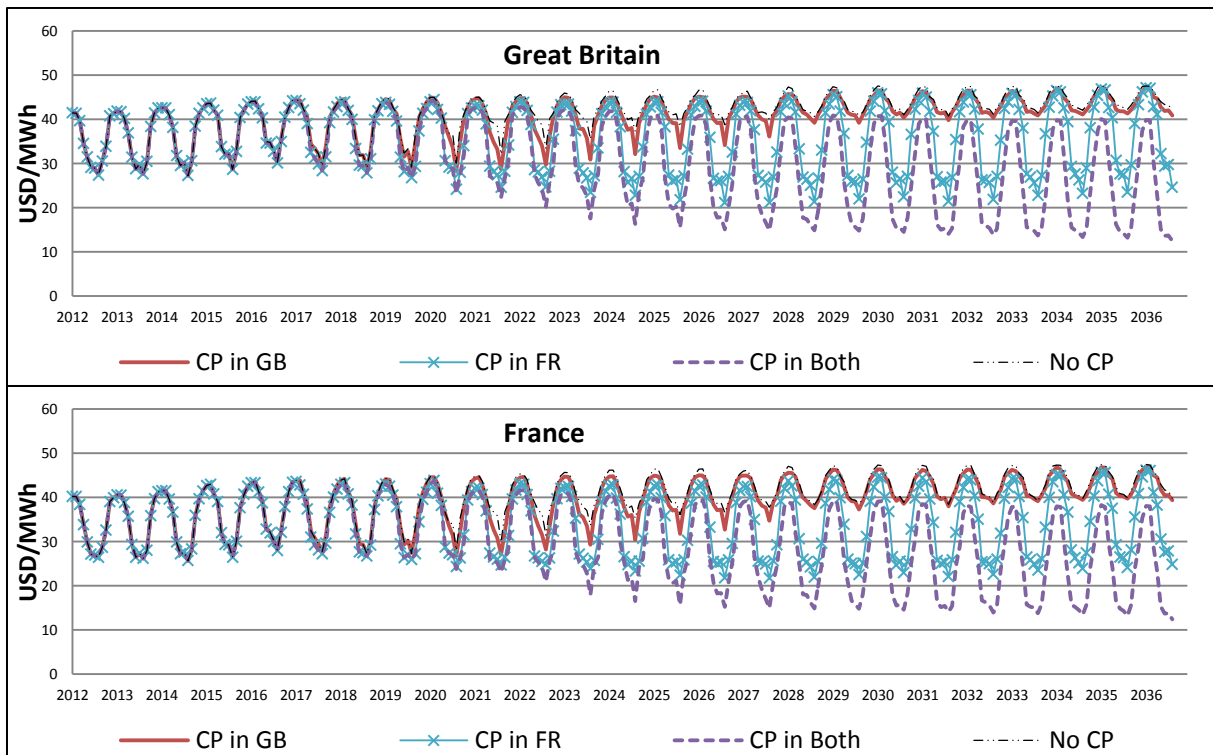


Figure 14. Average Prices (Monthly) according to the implementation of Capacity Payments – Unlimited Grid

In the case of Great Britain, it might be tempting to free-ride if France implements Capacity Payments. This leads to an important reduction in average prices in GB (and France), while the extra reduction in prices obtained by implementing Capacity Payments in both countries might not overcome the costs of this policy. But, once more, the question is whether it is appropriate for a country to lose control on a strategic service such as the electricity supply.

The next section discusses the results for the Latin American case.

7.2. LATIN AMERICA

In the Latin American case, the effect of electricity integration on the average prices is quite different from the European case. As can be observed in Figure 15, the interconnection between Colombia and Ecuador does lead, in this case, to lower average prices.

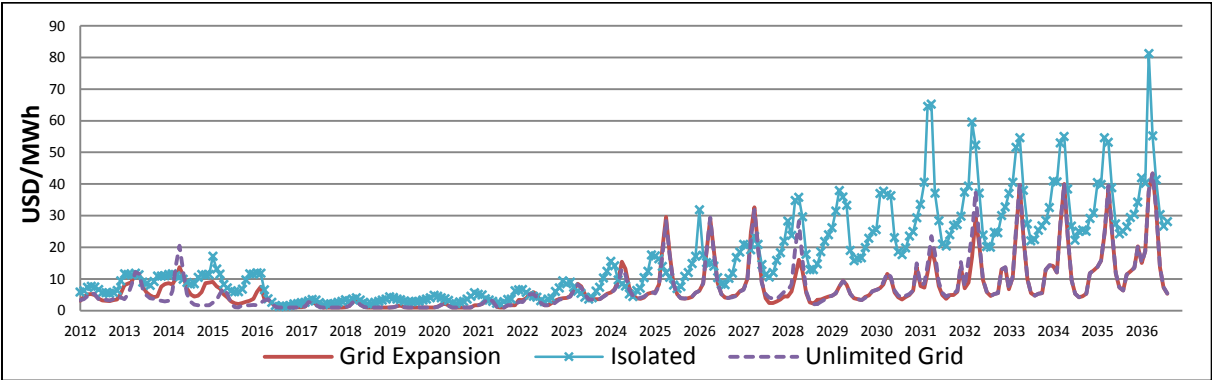


Figure 15. Average Price (Monthly) in Latin America, according to the level of integration

The Grid Expansion scenario is very similar to the Unlimited Grid (and not to the Isolated case as in Europe), since the current interconnector capacity between Colombia’s peak demand and 14% of Ecuador’s peak demand. Furthermore, the interconnector is significantly expanded, as shown in Figure 16, so at the end of the simulation it is almost equivalent to an Unlimited Grid, representing nearly 20% of Colombia’s peak demand and 45% of Ecuador’s peak demand.

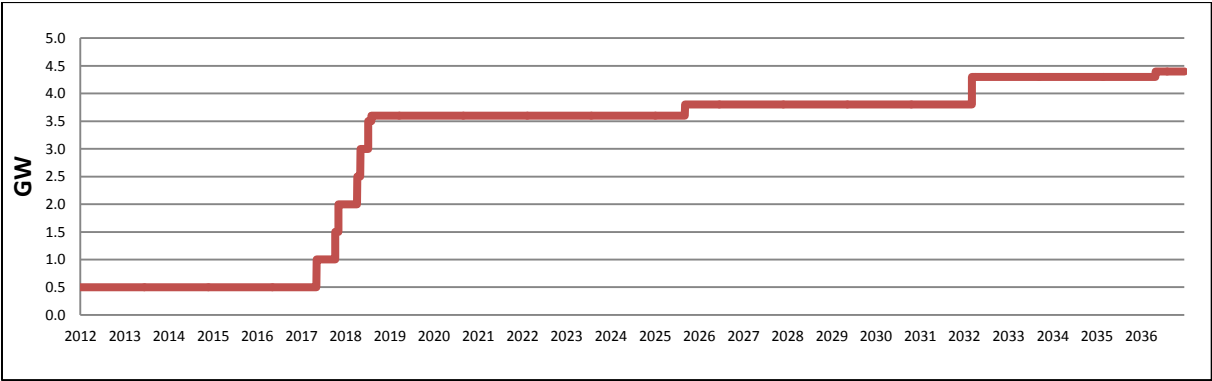


Figure 16. Colombia – Ecuador Interconnector Capacity in the Grid Expansion scenario

The attractiveness of the grid is explained by the hydrological complementarity between these countries, and the large share of hydropower in generation, which leads to tight supply in one

country when the other has low cost surplus; so there is a significant price difference due to the hydrological patterns. However, given the relative sizes of these countries, the opportunities will not be the same for Colombia and Ecuador, as we will discuss below.

Observing the average prices in each country separately (Figure 17), we can see that at the beginning of the simulation the Unlimited Grid and Grid Expansion scenarios lead to a decrease in Ecuador’s price at the expense of a slight increase in Colombia. However, after some time the generation mix will change as a result of retirement and new investment and, at the end of the simulation, both countries will benefit from lower prices compared to the Isolated scenario.

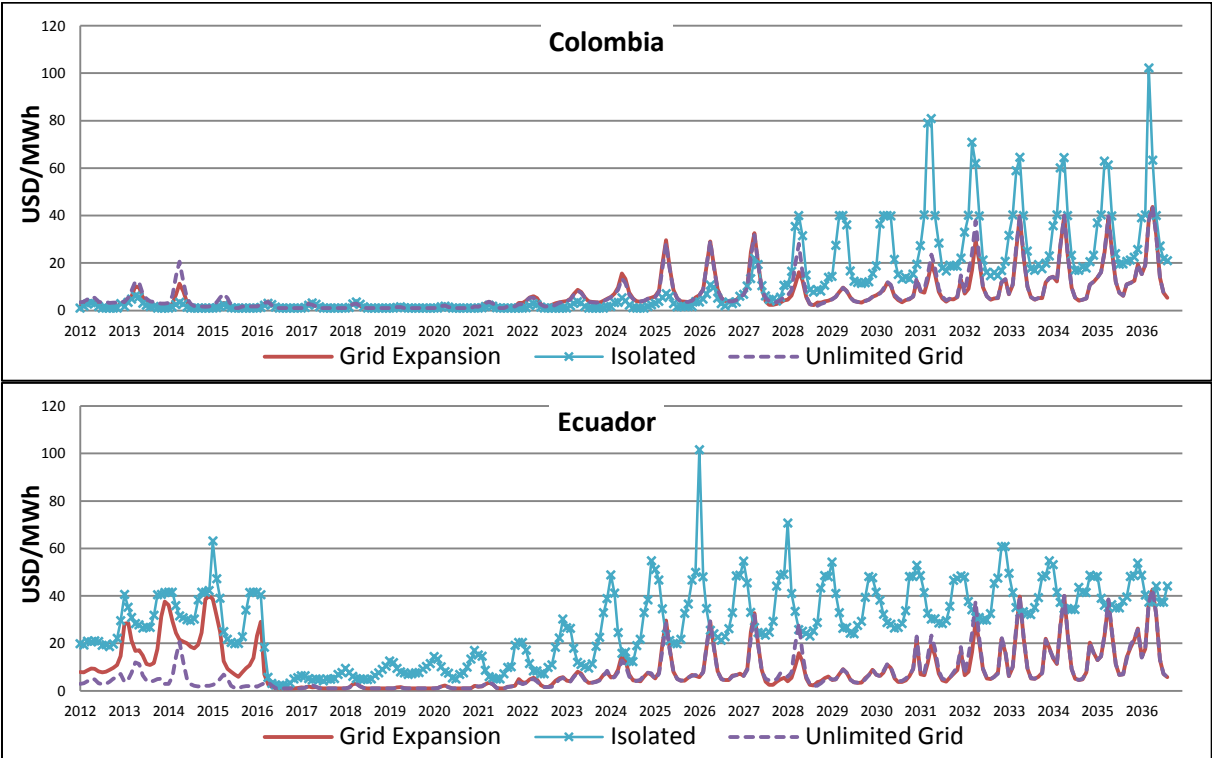


Figure 17. Average Prices (Monthly) in Colombia and Ecuador, according to the level of interconnection

As stated before, the relative sizes of the countries have an impact on the consequences of the market coupling. On the one hand, the interconnection will cause the average prices in Ecuador to fall as a result of the imports from Colombia, which reduces the possibility of recovering the fixed costs of investments. But on the other hand, since Ecuador is quite small compared to Colombia, the amount of electricity that can be imported by Colombia, as such, is not enough to significantly decrease its average price; the observed reduction is due to the increased investments in generation capacity.

If we observe the net flows, in Figure 18, we see that the flows in the sense Colombia-Ecuador are much higher than those in the sense Ecuador-Colombia, and Colombia is the net exporter most of the time.

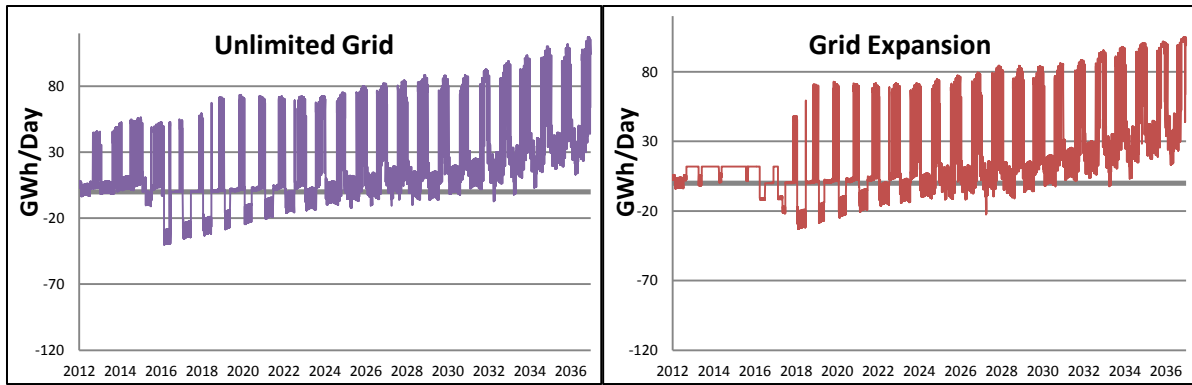


Figure 18. Net Flow Colombia – Ecuador

This is exacerbated by the fact that Ecuador will almost stop investing in generation, and will rely instead on imports from Colombia, where investment will rise compared to the Isolated case. This leads to a lower Capacity Margin in Ecuador and a slightly higher one in Colombia (Figure 19). It is important to keep in mind that the same variation in terms of installed capacity has a larger impact on the capacity margin in Ecuador than in Colombia, since Ecuador’s peak demand is much smaller than Colombia’s. Also, the fact that the Capacity Margin decreases, does not mean that there is no investment, as these countries have a relatively high rate of demand growth.

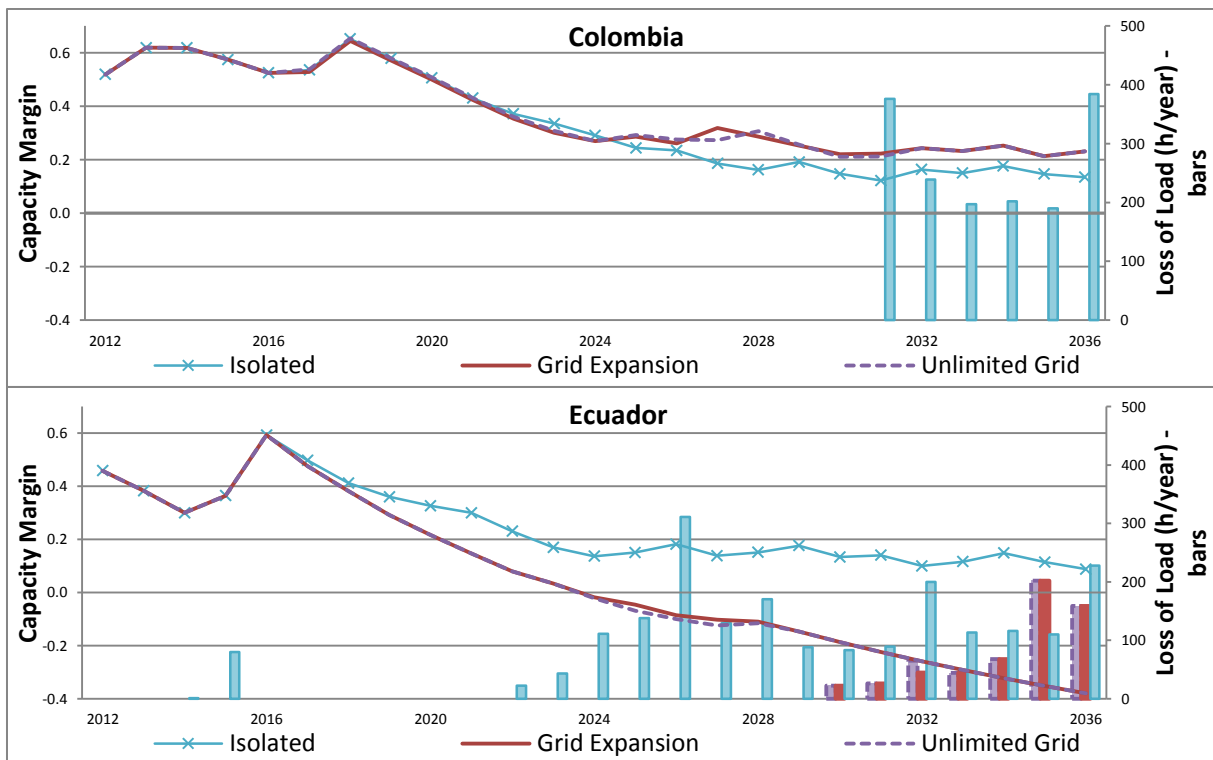


Figure 19. Capacity Margin vs. Loss of Load in Colombia and Ecuador

Figure 19 also shows that the integration (Grid Expansion or Unlimited Grid) has a positive impact on reliability, reducing (or eliminating in the case of Colombia) the occurrence of blackouts. Nevertheless, in the case of Ecuador we still observe important blackouts during the final years of the simulation. Though in the simulation Colombia does present blackouts in

the Grid Expansion and Unlimited Grid scenarios, its capacity margin is rather low, so the regulator may decide to implement Capacity Payments to encourage investments.

As discussed before in the European case, the effect of implementing capacity payments is difficult to anticipate, especially when there is an interconnection and the regulator does not control the policies implemented in its neighboring country. The next section presents an analysis of the effects of Capacity Payments in the Unlimited Grid scenario.

7.2.1. Capacity Payments – Unlimited Grid

In these scenarios the level of Capacity Payments depends on the expected Capacity Margin. If this margin is expected to be above 0.3, the Capacity Payment will be zero. Below this point, the Capacity Payment increases as the expected Capacity Margin decreases. For this reason, as shown in Figure 20, the effect of implementing a Capacity Payment mechanism is higher in Ecuador than in Colombia, since Colombia will still be close to the desired Capacity Margin when no Capacity Payments are in place.

We observe that the implementation of Capacity Payments, even when only in Colombia, eliminates the blackouts in Ecuador. However, the implementation of Capacity Payments in Ecuador, independently from their implementation in Colombia, will have a minor but negative impact on investments in Colombia. This occurs because of the reduction in exports reduces profitability, and this profitability reduction is not fully compensated by the Capacity Payments.

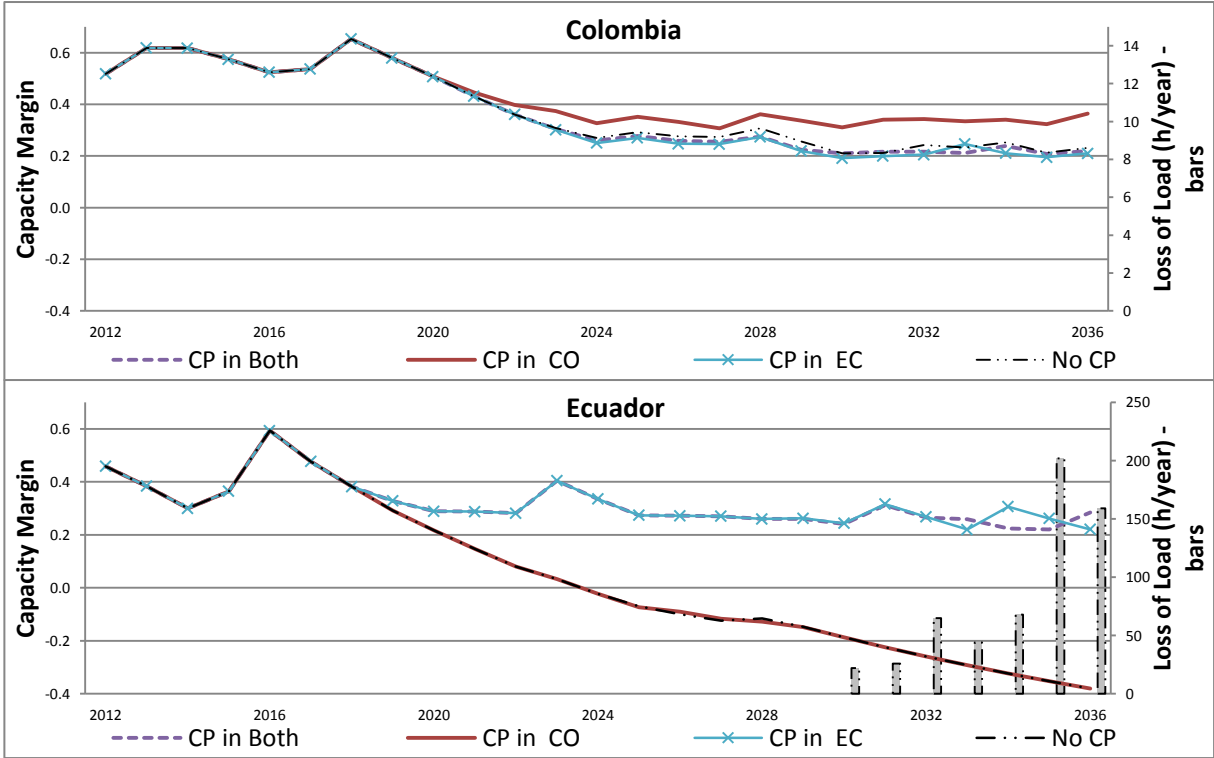


Figure 20. Capacity Margin vs. Loss of Load in Colombia and Ecuador - Unlimited Grid with Capacity Payments.

But perhaps more important is the fact that Capacity Payments may distort the market signals, resulting in a different mix of generation technologies that may lead to higher average prices, as observed in Figure 21. The implementation of Capacity Payments only in Colombia leads to the highest average prices, even higher than when there are no Capacity Payments at all. The reason is that with Capacity Payments, thermal power plants that were not profitable before, will be profitable, and the expansion of these will reduce the profitability of base-load technologies such as hydro-storage.

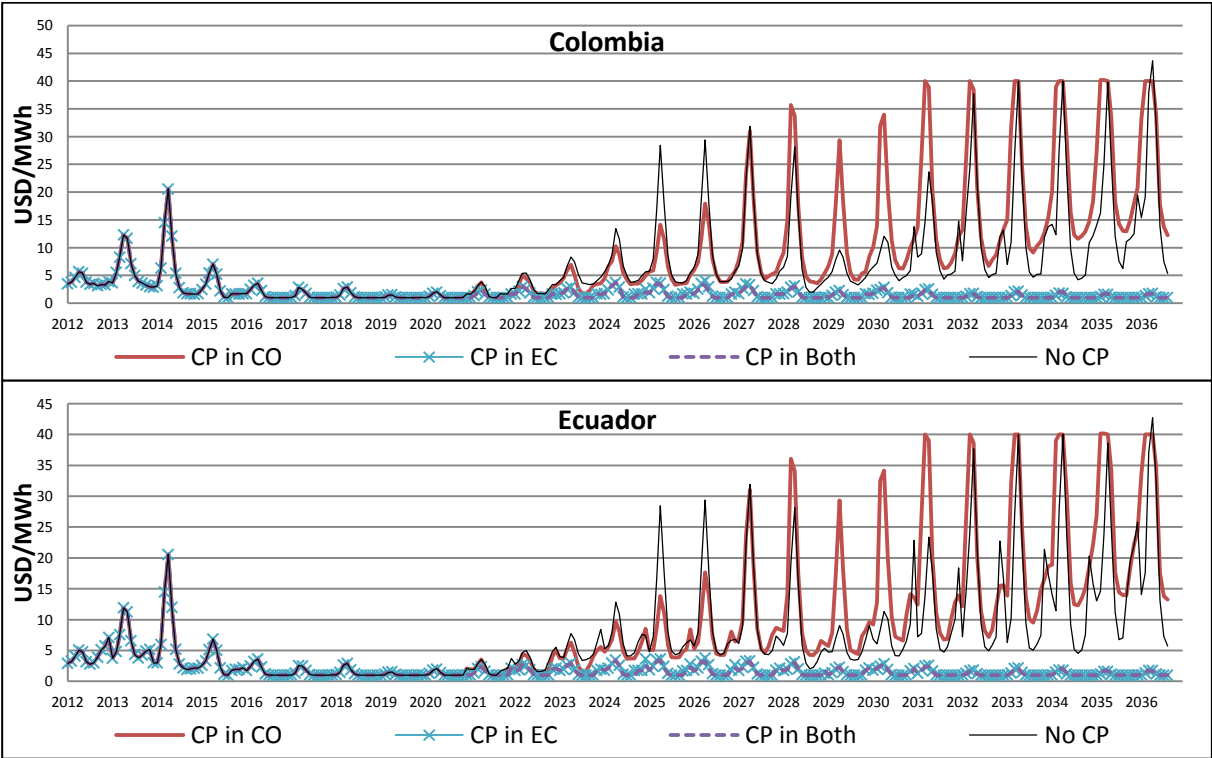


Figure 21. Average Prices (Monthly) according to the implementation of Capacity Payments – Unlimited Grid

Given these results, Colombia does not have any reason to implement Capacity Payments, as they will only result in higher costs. However, Ecuador will experience serious supply issues if it does not implement Capacity Payments and it will, additionally, depend on imports to supply its demand, as its Capacity Margin will be negative. Consequently, Ecuador does not have the choice: it must introduce Capacity Payments.

7.3. LATIN AMERICA VS. EUROPE

Comparing the results of the European and Latin American cases, we see to what extent the behavior of an integrated electricity market depends on the characteristics of the countries involved, such as the initial generation capacity, technology mix, meteorological patterns, etc. In the European case, market coupling will lead to higher average prices, while in Latin America it will lead to lower average prices. So for a consumer in Latin America the integration brings about great benefits, but for a consumer in Europe it is probably a bad idea.

However, in terms of reliability, electricity market coupling may lead to significant benefits in both regions if the right policies are in place and assuming political stability. Indeed,

integration will lead to a high level of dependency on imports, which may not be desirable in case of political tension with neighboring countries.

Also, the effect of policies, such as the implementation of Capacity Payments, is quite different in both cases. While in Europe it always leads to lower average prices, in Latin America it may lead to higher average prices when only implemented in Colombia. Thus, France and Great Britain have an interest in coordinating Capacity Payments, as they both will obtain the lowest prices when Capacity Payments are implemented simultaneously in both countries; but Colombia and Ecuador should agree to only Ecuador implementing Capacity Payments. Nevertheless, given that consumers in Colombia will also benefit from lower prices in this case, should they also contribute to those payments?

8. CONCLUSIONS

The model we developed helps us understand the potential risks and benefits of regional integration. The results show that electricity market integration may indeed bring benefits in terms of reliability, lower prices and better use of resources when the countries involved exhibit complementarities regarding resource availability or load curves, such as in the Latin American case. However, this is not always the case: in Europe integration without coordinate investment policies resulted in higher average prices.

Regulation and policies should be carefully studied, as their effects might vary significantly when applied to different regions or in different settings. As was discussed in this paper, the same policies do not have the same effects when implemented in Europe and in Latin America. It should be emphasized that exactly the same model, including the same market design, was used in both cases; the only differences are the input data for currently installed capacity, resources and demand.

The results for the Latin American case show that, in the long term, new investments in a fully integrated region may lead to a better use of resources that will translate into lower average prices for both countries with equal or even less generation capacity. While in Europe, as the main attractiveness of the integration is the large nuclear capacity currently installed in France, which will eventually decrease, the average prices will tend to converge to a higher level, though their volatility will be reduced as the number of hours where nuclear power sets the price will be limited.

In some cases, as in Ecuador, integration alone does not provide an adequate level of reliability, so capacity payments or other incentives are required to guarantee security of supply. However, prudence is recommended when designing policies for an integrated market, since the consequences of national policies are less intuitive when countries are part of an interconnected market, as they depend on the interactions with neighboring countries and the policies that those countries implement. There thus remain many open questions in terms of how to guarantee an adequate expansion of the electricity system, and what is an adequate expansion in the first place.

The risk is that, on the one hand, a country may end up subsidizing its neighbors if it implements inadequate policies, or as in the case of Capacity Payments only in Colombia, obtaining the opposite of the expected result. On the other hand, it may become highly dependent on imports, and thus vulnerable to strategic decisions by third parties, over which it has no control. But, implementing national policies aimed at maintaining self-sufficiency may be a barrier to acquiring the potential benefits of regional integration. Therefore, countries must find a satisfactory compromise to obtain reasonable benefits from integration while guaranteeing a certain level of security of supply.

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