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AN AGENT-BASED SIMULATION MODEL FOR EVALUATING FINANCIAL TRANSMISSION RIGHTS IN THE COLOMBIAN ELECTRICITY MARKET

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ABSTRACT

Congestion of transmission and the need to allocate congested capacity is one of the problems that arise in the operation of power transmission grids. Congestion can be managed with mechanisms based on rules and also with market mechanisms such as financial transmission rights. In this paper we present a simulation model for evaluating options for managing transmission capacity in the Colombian electricity system. The model combines agent-based simulation with optimization in order to examine if financial transmission rights can improve capacity allocation in the Colombian market. The main contribution of this research is to provide a simple model that combines the physical features of the interconnected system and the economic features of the Colombian power market, allowing decision makers to better evaluate regulatory alternatives. Our results suggest that a market approach is effective in managing transmission congestion, although it increases the complexity of market rules.

1 INTRODUCTION

Deregulated electricity markets need to adequately remunerate and allocate transmission capacity in order to schedule power generation and manage network congestion. The literature reports a variety of regulatory and market approaches for remunerating and allocating transmission capacity; the most commonly discussed approaches are: postage stamp (Lima, Padilha-Feltrin, and Contreras 2009), contract path (Hogan 1992), MW-mile (Pan, Teklu, Rahman, and Jun 2000), congestion rents with zonal or nodal prices (Hogan 1992), physical and financial transmission rights(Joskow and Tirole 2000, Kristiansen 2004), and flowgate rights (Ruff 2001). The performance any of these mechanisms depends on the structure of the market and the physical structure of the power system (Zambrano 2013) and the efficiency gains of implementing any mechanism should be weighted against its costs.

Colombia has an uninodal system in which there is a single price for electricity, regardless of transmission constraints. Transmission prices are regulated using postage stamp charges and scarce transmission capacity is allocated via prorate and priority rules. The two components of postage stamp charges are usage charges and compensations. Usage charges depend on transmission assets and AO&M expenses and are set by the Regulatory Commission, whereas compensations depend on the quality of transmission services (CREG 2009). Although the Colombian system has operated adequately under the current rules, some issues need further study and improvement. According to the planning unit (UPME 2009), there is a need for increasing the quality of available information and transmission capacity as well as for sending signals for expanding generation and regional transmission systems. Other studies also identify substantial transmission constraints (Gallego Vega and Duarte Velasco 2010) and a need for congestion management by sending signals for

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demand, or by creating an adjustment market or near real-time market (Barrera Rey and García Morales 2010).

Studies for the electricity market in Colombia usually focus on the competition among power generators and do not consider transmission constraints. (Mesa Palacio 2012) proposes remuneration schemes for the Colombia-Panama interconnection, and evaluates such schemes using simulation results from MPODE, a stochastic dual program for hydro scheduling which is based on (Pereira and Pinto 1991). (Gallego Vega and Duarte Velasco 2010) build a simulation model for the optimal dispatch of the Colombian market. This model finds the optimal flows that minimize total operating cost in the system while satisfying generation, transmission and active power balance. Using real data from the system, (Gallego Vega and Duarte Velasco 2010) calculate nodal prices and find the distribution of congestion costs. We extend the approach of (Gallego Vega and Duarte Velasco 2010) in two ways: first, we add market for financial transmission rigths, FTRs, in order to reduce the risk of nodal prices and second, we create a simulation tool using free software, that includes network constraints and that can represent the competitive behavior of agents in the wholesale market. Although the model has been built and calibrated for the Colombian system, its structure can be modified to accommodate to other market structures.

2 LITERATURE REVIEW OF FINANCIAL TRANSMISSION RIGHTS

Financial transmission rights (FTRs) give their holders the right to collect congestion rents, or the opportunity costs of transmission constraints, without having actual control of transmission capacity (Bushnell 1999, Lyons, Fraser, and Parmesano 2000). These rights hedge price risks in nodal pricing markets (Kristiansen 2004) and help to efficiency in the use of congested transmission assets (Lyons, Fraser, and Parmesano 2000, Kristiansen 2004). The FTR specifies a receipt and delivery points; for the periods in which there is congestion between the receipt and delivery points, the holder of the FTR receives part of the congestion rents collected in these periods; if a generator does not hold a FTR and the line is congested, then it must pay congestion charges (Joskow and Tirole 2000). FTRs, along with access charges and other complementary charges, help to recover investments in transmission (Kristiansen 2004)(Deb, Hsue, Albert, and Christian 2001). According to (Kristiansen 2004), FTRs provide economic signals for location of demand and supply when the FTRs' markets are liquid and FTRs' prices are efficient.

The evaluation and design of transmission rights markets is complex because it needs to consider the physical constraints of transmission grids and because it is difficult to predict how market agents are going to behave. According to (North and Macal 2007), p. 112, power markets are adaptive complex systems. The uniqueness of power markets arises from the diversity of technologies and regulation, the competition between agents, the complexity of regulation and the technical and physical features of transmission networks (Weidlich and Veit 2008).

Agent based simulation has proved useful to address such complexity. Among the issues that have been studied with Agent-Based simulation models are power market, design of markets, modeling agent decisions, and the links between operation and planning (see (Sensub, Genoese, Ragwitz, and Most 2007) for a review of applications in these areas). Among the most known ABS models for power markets are SEPIA (Harp, Brignone, Wollenberg, and Samad 2000), EMCAS (North and Macal 2007), and NEMSIM (Grozev, Batten, Anderson, Lewis, Mo, and Katzfey 2005). The Electricity Market Complex Adaptive System is a software tool developed by the Center for Energy, Environmental and Economic Systems Analysis at Argonne National Lab, which allows to simulate the behavior of an electricity market. This model is particularly relevant because it includes the economic and physical features of electricity markets, while allowing for a diversity of agent behavior, including strategic behavior, and learning (Zhou, Chan, and Chow 2007).

In this paper we apply agent-based simulation to investigate if a market mechanism can improve the current scheme for remunerating and and allocating transmission in Colombia. Based on an extensive review of the literature and the comparison of different remuneration schemes, we propose an approach similar to the one applied in PJM, which is based on nodal prices and a market for financial transmission rights (FTRs).

PJM (Pennsylvania - New Jersey - Maryland) is one of the most studied markets with FTRs (Kristiansen 2004). The PJM market has a deregulated centralized structure, based on nodal pricing and regulated transmission income. FTRs in PJM are purely financial products, periodically auctioned. There are different types of FTRs corresponding to different periods for which risk hedging is needed (on-peak and off-peak); both generators and load service entities can buy FTRs, and while there are hourly FTRs, annual and monthly FTRs are sold for only a subset of transmission lines. The day-ahead dispatch is used for collecting congestion rents and for liquidating FTRs (PJM 2012). In addition to the FTR auction, there is a secondary market in which market agents can trade FTRs, and auctions for revenue rights in which the revenues from the annual FTR auction are allocated.

The proposed FTRs have hourly resolution and are sold as obligations in monthly sealed-bid auctions of one-round. As shown in Figure 2, in this scheme, the sellers are the system operator and transmitters, while the buyers are large consumers and distribution companies. The system operator acts as the auctioneer. Besides the monthly auctions, FTRs also may be assigned to transmission companies investing in new transmission capacity. The proposed mechanism adds a variable charge to the transmission income. This charge is linked to the congestion rents and seeks to represent the operating conditions of the system. This approach helps to control the transmission revenues, since the variable charge is zero if there is not congestion.

3 AUCTION DESCRIPTION

For this paper we propose annual and monthly auctions for Financial Transmission Rights, FTRs. Other possible auctions designs are discussed by (Cadena Sarmiento and Serna Suárez 2008), but the proposed auction is based on the structure of the FTR market in PJM. There is an annual FTR auction with four rounds in which a 25% of the transmission capacity is auctioned, and there are monthly FTR auctions, in which already allocated FTRs can be reconfigured (see Figure 1).

Table 1: Proposed financial transmission rights auction for Colombia.

	Annual FTR auction	**Monthly FTR auction**
Auctioned capacity	Total transmission capacity	Residual capacity after assigning FTRs
Auction format	Several rounds	one round
FTRs' type	Obligations	Obligations
FTRs' period	24 hours	24 hours
FTRs' duration	one year	one month

Table 1 summarizes the main characteristics of these auctions. Each annual auction has 4 rounds, while there is a single round for monthly auctions. In each round,

- Participants make buy or sell bids. Each bid has a receipt and delivery point a power amount (MW) and a price ($/MW) for each of the hours in the day
- There is a clearing process in which the market operator determines which bids satisfy feasibility constraints while maximizing revenues. For this process, the network topology as well as its technical characteristics are considered. Previoulsy assigned FTRs are modeled as constraints.
- The assigned FTRs are published, and each FTR has a one-year duration. These allocations are inputs for next rounds, and for the monthly auctions.

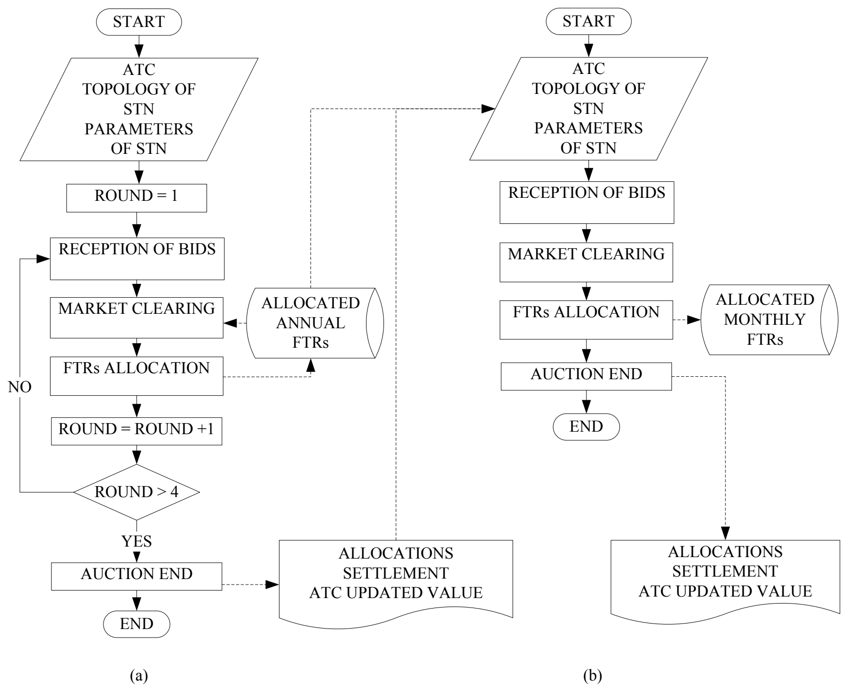

Figure 1: Processes in annual and monthly auctions.

Source: modified from (PJM 2009) and (PJM 2012).

Figure 1 summarizes the process for trading annual and monthly FTRs. Monthly auctions are similar to a closed-envelope auction with discriminatory price. Unlike the annual auction, there is a single round for the monthly auction and the length of the assigned FTRs is one month.

The main objective of the auctions depicted above is to allocate the financial transmission rights to the agents that value them most which, in a competitive and liquid market, also ensures revenue maximization. Note that the auctions are complemented by a secondary market. In the next sections we discuss the implementation of these auctions in the market model.

4 MODEL

We develop our model based on the methodology in (North and Macal 2007, Macal and North 2011) which involves four stages: analysis, design, implementation, and verification and validation. Thus, we define the model's purpose, the appropriate scope and level of aggregation, as well as the model's assumptions, attributes, behaviors and interactions of agents. For implementation and validation, we define the modeling platform and establish a set of verification and validation tests for the model structure and behavior.

Our model aims to investigate questions such as:

1. Would nodal prices improve the operation of Colombia's power system?
2. Would nodal prices improve investment signals for regulators and agents?
3. Can nodal prices and FTRs improve the current transmission remuneration scheme for the Colombian market?
4. Is transmission capacity allocation more efficient under the current scheme than under a nodal pricing-FTRs scheme?

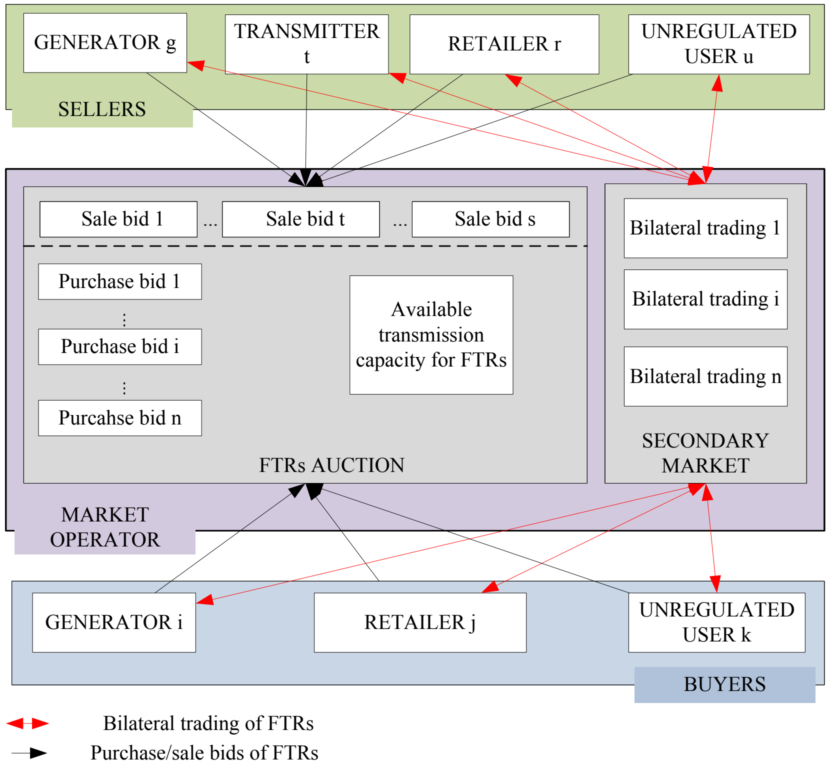

Figure 2: Structure of the proposed market for Financial Transmission Rights.

In order to answer these questions, a simulation model was built with the current uni-nodal structure of the Colombian market, and it was later modified to allow for nodal pricing and a market for financial transmission rights. Both models have modules for the wholesale power market with an energy contract market, a day-ahead energy market and a settlement system. They differ on how transmission capacity is allocated and its use remunerated. Among the assumptions and simplifications made for this analysis are:

- A simplified version of the national transmission system is used that does not include all of the lines.
- Nodes in the transmission system correspond to the operative areas of the national interconnected system. Ecuador and Venezuela are modeled as nodes.
- Generators can manage several plants in the network but it is assumed that a single agent attends all of the demand in an given node.
- Generation plants with capacity lower than 10 MW were treated as a single unit.
- Strategic decisions are modeled by varying the risk hedging level and bid prices from buyers.
- 2010 and 2011 are base years for calibration and validation. To evaluate policies, projections for 2020 are used.

In its current version, the model only simulates monthly auctions, and we expect to add the annual auctions and secondary market modules in future work. Figure 3 shows the activities diagram of monthly auction process.

This process starts when the auctioneer, represented by the system operator, opens the receiving period of both buy and sell bids for FTRs. After receiving the bids, the auctioneer performs a simultaneous-feasibility test to determine which FTRs can be dispatched and which not. Then, the auctioneer publishes the allocations and proceeds with the settlement on which distributes the auction income between sellers

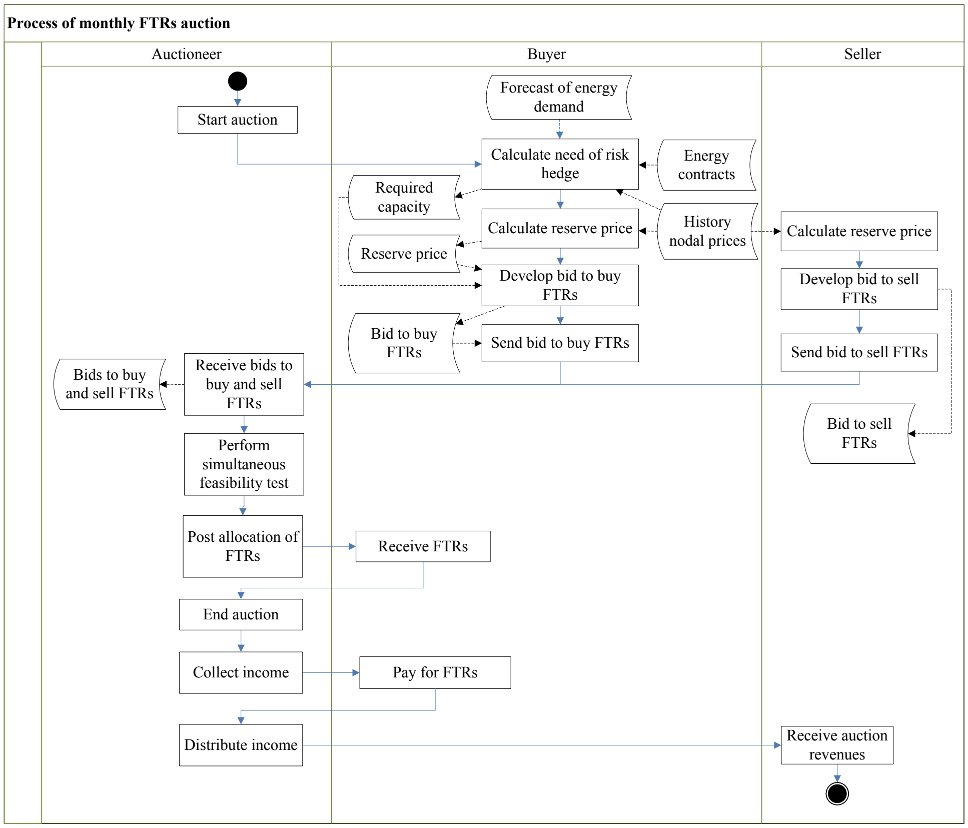

Figure 3: Activities diagram of monthly FTRs auction process.

and during the duration period of assigned FTRs, collects and distributes the congestion rents between the holders of such FTRs according to their capacity and nodal price differences.

FTRs sellers are the grid owners. They send to system operator a reserve price. Retailers are the buyers. They define the FTRs bids consisting of an energy amount and a reserve price for each hour of the day, which are defined from an energy demand forecast, a risk hedging level based on your energy contracts, and the nodal prices history.

The simulation models are built using Repast (http://repast.sourceforge.net/), a JAVA-based platform that allows the integration of different computational tools such as optimization software, database software and other programming languages, among other features. Figure 4 presents the basic structure of the models; only the model with nodal prices has a module for auctioning FTRs.

The information with the different contracts, supply, and demand for each node, as well as the network information is stored in an Excel database. As this is a prototype, all modules are located in the same computer, and managed interactively by Repast. In both models, the computational model simulates the operation of an energy market with a daily dispatch determined using an optimal power flow formulation. In the model for the current structure of the Colombian energy market, we store the hourly spot prices and the settlement of bilateral market and the exchange energy market. In addition, in the nodal prices-FTRs market model, we store the hourly nodal prices, congestion rents, and the variables of the monthly FTR auctions such as FTRs settlement and the final settlements of market agents. Energy spot prices and transmission income are the main variables used to compare these models under different demand scenarios.Furthermore, as shown in Figure 4, there are several instances for each of the agents, except for the system operator, which administers the wholesale market, and it also has roles as auctioneer in the transmission market.

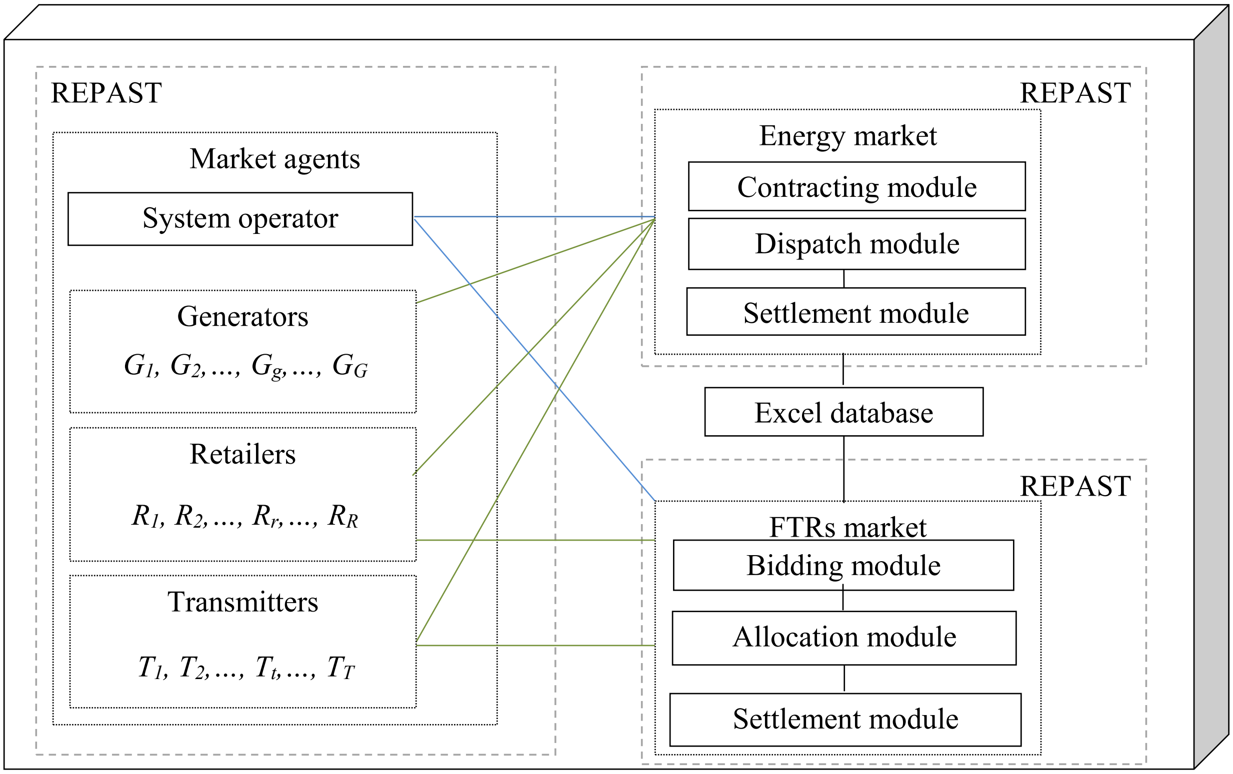

Figure 4: Model structure.

Finally, for the verification and validation of the model, a subset of the validation techniques mentioned by (Sargent 2010), such as: animation and operational plots, degeneration tests, and extreme conditions test was used. Tests of dimensional consistency and the validation of structure were applied too. These tests were applied using, among other things, the model graphic interface that shows in real time the evolution of hourly spot prices, the transmission constraints and the energy dispatch information.

5 RESULTS AND DISCUSSION

To compare the performance of the current and proposed mechanisms, we make simulation runs using historical information for 2010 and 2011. We find that, consistent with (Gallego Vega and Duarte Velasco 2010), energy prices under the current scheme do not reflect actual transmission constraints in the flowgates that interconnect the center regions (where most of the hydraulic generation is located) with the north and southwest of the country. These congestion costs are internalized by means of nodal prices in the proposed mechanism.

When nodal prices and a FTRs market are implemented, the market value of the FTRs is linked to the congestion levels the buyers observe, and therefore depends on the historical behavior of energy supply, demand and prices. As a result, this proposed scheme is more sensitive than the current scheme to speculative behavior from generators, specially in periods of low hydrology. Simulation results show that the main buyers of FTRs are located in the northern regions and the interconnection links; these agents need to cover for the risk associated with buying energy from the generators in the center of the country. Buyers located in the center of the country, by contrast, only buy FTRs for peak hours and during periods of low rain fall.

Figure 5 shows the behavior of the different sources of income for transmission companies. Results in Figure 5 suggest that revenues from transmission under the FTR scheme are more efficient than in the current scheme because the transmission companies recover all costs, including congestion costs. The proposed model introduces a variable source of income for transmission, which is linked to congestion rents and represents the operating conditions of the system.

The gray line in Figure 5a is the average transmission income. This average income increases during the second half of 2011 because in this period loads to the network are higher. As Figure 6 shows, during the day transmission income tends to be higher in periods of peak demand. Results in Figure 5a also suggest that a purely nodal market (without FTRs), that addresses congestion costs, can also improve average transmission income with respect to the current uninodal scheme (red) in periods where demand increases (mid to late 2011 in Figure 5. Note that there is a difference between the transmission income with and without FTRs because the share of the transmitters in the FTR model is calculated on the balance after settlement of the FTRs, and not on all of the congestion rents collected from market. These results suggest that a nodal pricing scheme along with an FTR market to hedge price risks has positive impacts on the operation of the Colombian system, compared to the current scheme. The analysis of capacity constraints indicate that the proposed scheme sends location and investment signals and that a variable congestion charge improves the structure of transmission revenues. Since the 2011 scenario only includes current capacity, we run a 2020 scenario in order to examine whether the proposed scheme is able to remunerate new capacity investments.

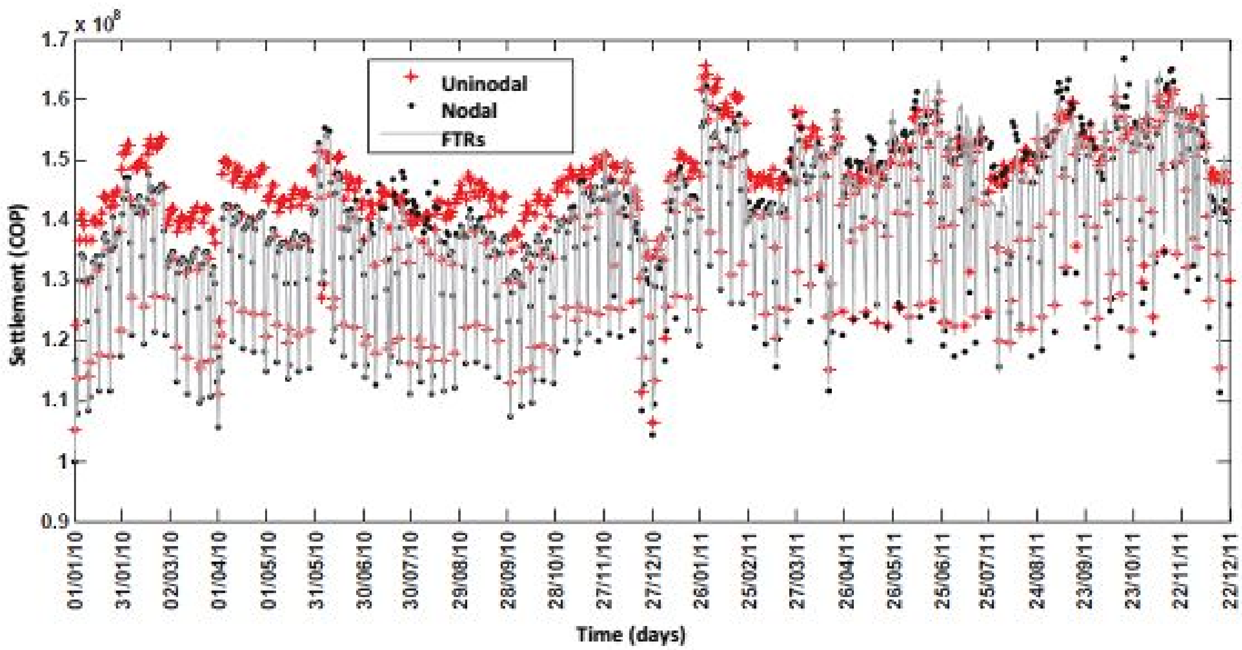

Figure 5: Market settlement: average daily transmission revenues

5.1 Performance Of FTRs Under Planned System Expansion

To evaluate how FTRs perform under the currently planned generation and transmission expansion plan, we make simulation runs using demand projections developed by UPME to 2020, and including all of the planned expansions for generation and transmission capacity.

The simulation results show that, even with planned generation and transmission expansion, transmission constraints are present in low, medium and high demand scenarios. The new hydraulic plants congest some interfaces in the center of the country, and the flowgates to other regions still register high levels of load. This happens because the current expansion plans respond more to the need for reliability than to market

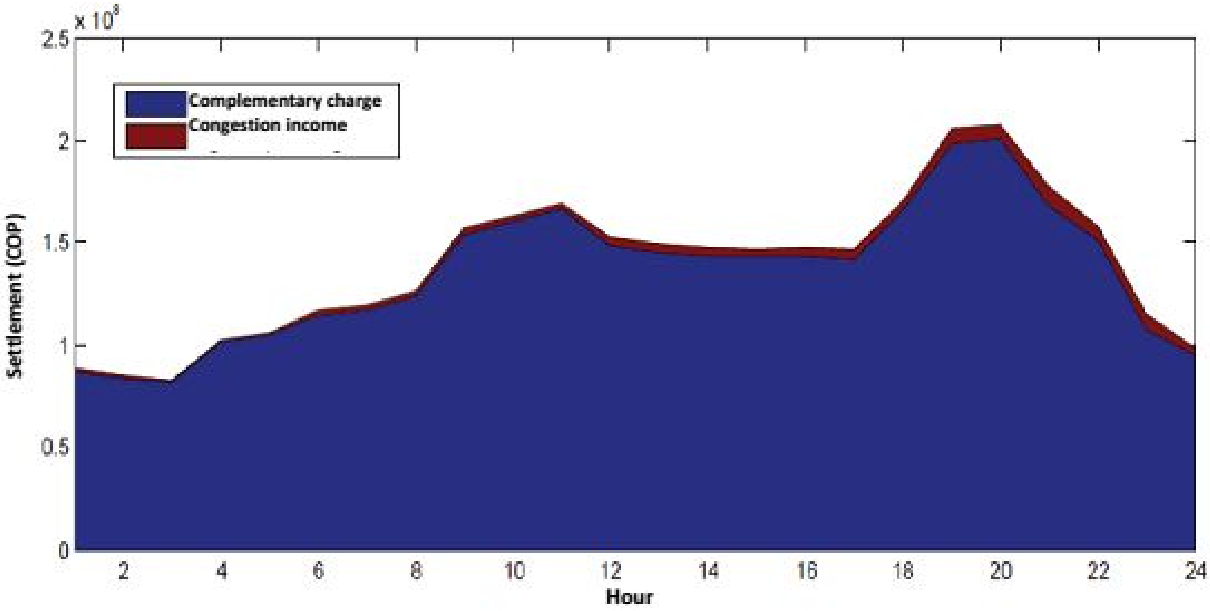

Figure 6: Market settlement: hourly revenues from congestion and complementary charges

opportunities. If congestion is managed via nodal pricing with FTRs, then expansion plans should seek to minimize congestion, taking into account the location signals provided by the market value of FTRs. The FTRs are also an incentive for expanding transmission capacity because transmission companies receive FTRs when they add new capacity and these FTRs provide additional revenues when demand growth causes congestion in the network. Note that in the proposed scheme, regulators planners and the system operator maintain their current roles in coordinating the expansion of transmission and generation. The proposed changes aim to take advantage of market signals in order to improve the efficiency of expansion planning, control market power, and improve the availability of information.

As Figure 7 shows, revenues generated by the FTRs for new investments are considerable when compared to the congestion rents collected in each scenario. Figure 7a, shows that even when additions are small compared to the existing capacity, revenues from the corresponding FTRs can be higher than 10% of the congestion rents collected for the whole system. This results not only from the demand level, but from the final network configuration after expansions. It is possible for a new line to alleviate congestion locally while negatively affecting other system's interfaces and nodal prices.

Finally, regarding transmission income, simulations indicate that, even when congestion persists in the system, such income remains controlled. In Figures 7b, 7c and 7d presents the average hourly income of transmitters for the demand scenarios HIGH, MEDIUM and LOW respectively. Note that revenues under the proposed model are similar to those obtained in the Colombian scheme (MC model). Transmission income follows the trend of demand and except for peak hours where congestion is higher, the total income remains below the regulated income. This is quite important because even if congestion were maintained or even increased after the expansions made, the proposed scheme does remunerate transmission capacity in excess, but it maintains the incentives for transmission companies and potential investors to participate in the market.

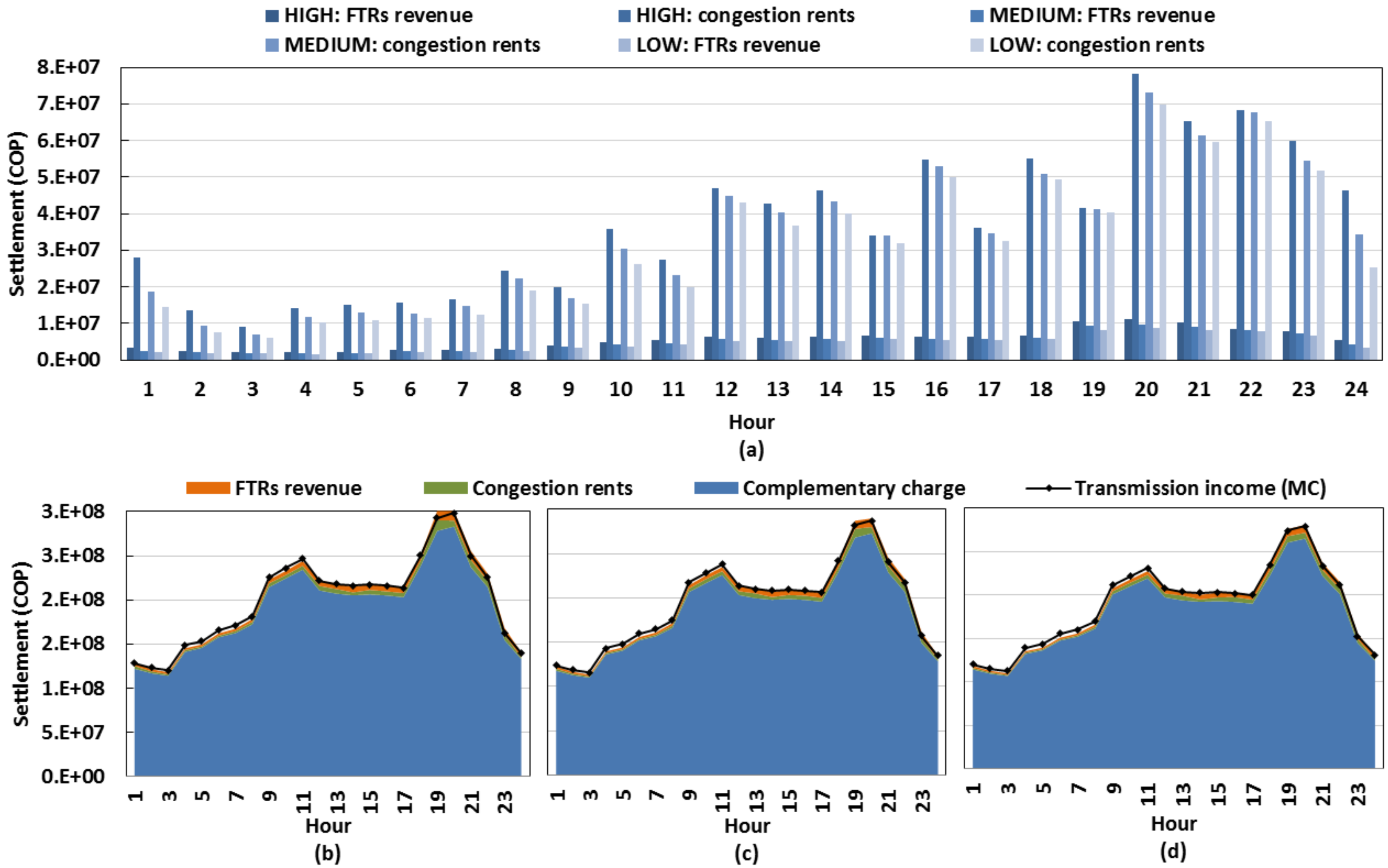

Figure 7: Transmission revenues for 2020: average FTR revenue for new investments (a), average transmission revenues for HIGH (b), MEDIUM (c) and LOW (d) scenarios.

6 CONCLUSIONS

The Colombian electricity system requires timely and sufficient investment in transmission capacity to satisfy a growing demand for energy. Economic incentives can contribute to achieving such goal. In this paper we investigate whether a change from an uninodal market with stamp charges to a nodal market with financial transmission rights improves the performance of the system. In order to evaluate this, we propose and build a simulation model that combines agent-based simulation for the market with an optimization model for Colombian transmission network. The model extends previous research in Colombia by combining physical and economic features of the Colombian power system, and it allows decision makers to evaluate how their decisions affect prices and allocation of capacity under different conditions. We find that a nodal market combined with a market for financial transmission rights improves current signals for investment and location of both generation and transmission assets, while lowering energy prices in some regions. In addition, a market scheme can decrease transmission costs provided that the planner considers reduced congestion as a measure of social benefit and as a decision criterion in the expansion planning. Despite the possible contributions of financial transmission rights to the performance of the Colombian power system, additional analyses are required to better assess the strengths and to correct the weaknesses of alternative schemes. Specifically, a cost-benefit analysis of the implementation of FTRs and nodal pricing is needed. Extensions and future work could address the long-term response of the market to financial transmission rights incentives, and the security of power supply under events such as terrorist attacks on the electricity infrastructure, or hydrological events. These are left as future work.

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