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REFORMING THE COLOMBIAN ELECTRICITY MARKET FOR AN EFFICIENT INTEGRATION OF RENEWABLES: A PROPOSAL

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Abstract

The Colombian short-term electricity market is characterised by a single settlement and by the clearing of a single national hourly spot price for the entire grid. This price is computed ex post, based on the real-time operation of the system. In the day ahead, there is only an operational dispatch, which does not set any binding economic commitment. A deviation from such dispatch (due, for instance, to an outage), if it is informed in advance, has no economic consequence for market agents. As recognised by Colombian regulatory institutions, this design is not suitable to efficiently integrate large shares of variable renewable resources.

This paper presents a regulatory proposal for introducing, in Colombia, a multi-settlement system, consisting of a binding day-ahead market, followed by intraday sessions and a balancing market. The main discussion focuses on how to solve the complexities arising from the introduction of a multi-settlement system in a context where sessions are cleared

based on uniform pricing. The paper also analyses the interactions of the proposed design with other aspects of the Colombian power sector regulation (such as the impact of this reform on long-term contracts or on the reliability charge mechanism).

Keywords

Colombian electricity market; renewable integration; single settlement, multi settlement, binding dispatch; intraday market; uniform pricing.

1 INTRODUCTION

Renewable Energy Sources for Electricity (RES-E) are re-shaping modern power sectors. These technologies have experienced a massive growth in the last two decades and now lead global capacity additions (IEA, 2018). When they are installed in liberalised power sectors, regulation and market design often become obsolete, since both were designed to suit conventional electricity sources, in a largely more predictable environment, both in the short and in the long term. In the last decade, this situation prompted electricity market reforms around the world (Gerres et al., 2019; Henriot and Glachant, 2013). These regulatory interventions aim at adapting the regulation to assimilate efficiently these technologies. As analysed in many recent studies (MITEI, 2016; IRENA, 2017; IEA, 2016; Chao, 2011), this requires new and updated market mechanisms to generate price signals that are able to drive an efficient operation in the short term and an efficient system expansion in the long term.

Latin America is endowed with huge renewable energy resources and power systems in the region registered significant investments in these technologies in recent years (IRENA, 2016)[1]. At the beginning of this century, some concerns, mainly regarding security of supply, forced regulators to reform the original market designs and to introduce long-term auctioning mechanisms (Moreno et al., 2010; Maurer and Barroso, 2011; Mastropietro et al., 2014). Nowadays, the fast-paced penetration of renewable resources is challenging once again Latin American market designs and some authors envision a new wave of reforms (OEF, 2018).

RES-E technologies affect the time scales in which dispatch decisions have to be taken and updated. Forecasts on the availability of renewable sources become more accurate after the day-ahead market clearing (NREL, 2015); this increases the importance of the intraday time horizon. Markets need to give answers to these changing operational needs, providing accurate commitments and producing efficient price signals in these time frames. These signals are instrumental to provide RES-E resources with incentives to improve their forecasting methodologies and to reward the flexibility that they could provide to the system.

Electricity markets with large RES-E penetrations must be based on a binding dispatch in the day ahead that fixes the commercial position of the agents, an intraday market that allows to change these positions in an economically-efficient way, and a balancing market that permits to assign the costs provoked by imbalances. In the United States and Europe, multi-settlement markets are being reinforced accordingly. The situation in Latin America, however, is different (Batlle et al., 2010). At the moment of this writing, the availability of abundant hydropower resources has significantly reduced the value of flexibility services.

[1] A particularly interesting common feature in the continent is the complementary availability that non-conventional RES-E resources have with hydropower, the technology that dominates the generation mix in many Latin American countries.

As a result, many power systems in the region are based on single-settlement *ex-post* markets.

The system is usually dispatched in the day ahead based on the bids (or the audited costs) of each power plant, but this is an indicative dispatch that does not involve any commercial commitment. After the real time operation, once data on the real dispatch of the system are collected, a price is calculated based on the bid or cost of the marginal power plant. This way, no price signal is produced in the day-ahead/intraday time horizon. However, as RES-E penetration grows, the ability of hydropower resources to cope with the inherent intermittency and variability of these resources will be gradually reduced. As a consequence, the current "simplistic" market design will entail larger risks for all market agents, since the dispatch of the system will be subject to significant changes in the intraday time horizon. If renewable technologies are to be efficiently integrated, commercially-binding day-ahead, intraday and balancing markets need to be implemented.

This article focuses on the Colombian power sector. Colombia has one of the most advanced wholesale market designs in the region (Larsen et al., 2004) and the need for binding day-ahead and intraday markets has largely been discussed by the regulator, system operator and academia (CREG, 2016; XM, 2014, McRae and Wolak, 2016). A feature of the Colombian market that makes this problem particularly challenging is that, although the operational dispatch considers in detail network constraints (which are far from being negligible), the economic settlement is based on uniform pricing (a single price is cleared for the entire country).

The objective of this article is to present a detailed reform proposal for the Colombian market. The document first describes, in section 2, the Colombian power sector and the current market design, focusing on the short-term mechanism, but mentioning also other aspects of the regulation that may be affected by the reform. Section 3 presents a regulatory proposal for the introduction of a day-ahead, an intraday, and a balancing market. Section 4 concludes and highlights the main recommendations that can be drawn by the Colombian experience.

2 THE COLOMBIAN POWER SECTOR AND MARKET DESIGN

2.1 Characteristics of the Colombian power sector

Colombia has a hydro-dominated power sector. Hydropower accounts for 70% of the installed capacity (with different level of regulation capacity) and, in 2017, for 86% of the electricity generated (it must be remarked that 2017 was a very rainy year). The rest of the generation mix is currently composed by thermal power plants, running on gas, coal or fuel oil, while non-conventional RES-E technologies currently cover only 1% of the electricity demand (Figure 1).

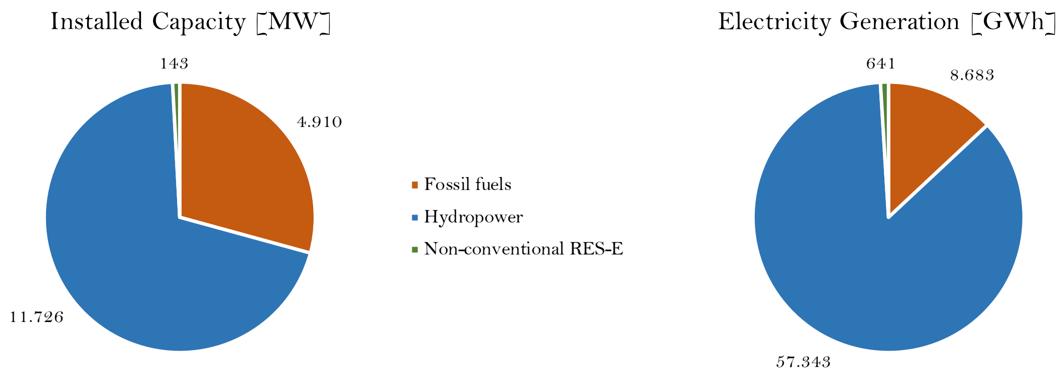

Figure 1. Installed capacity and electricity generation in Colombia in 2017; data from XM (2018)

The generation mix, however, is expected to change dramatically in the next decades (Henao et al., 2019). Colombia is endowed with abundant renewable sources[2]. According to

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[2] The Colombian power sector is also called to a wide diversification of the energy mix, since hydropower may be highly affected by climate change (Arango-Aramburo, 2019) and its further deployment may be subject to social conflicts (Martínez and Castillo, 2016).

CSMEM (2016), wind power has a theoretical potential of 30 GW. Only La Guajira region could host 18 GW of wind power, more than the current installed capacity in the system, with very high capacity factors. Many regions of the country, especially in the Atlantic coast, have excellent conditions of solar radiation. A first hint of the ongoing transition of the Colombian power sector can be obtained through an analysis of power projects currently being developed. As presented in Table i, non-conventional renewable technologies lead capacity additions that are expected in the near future. Another evidence of this transition can be found in the results of the last reliability charge auction (the Colombian capacity mechanism, see section 2.2.2 for details), held in February 2019, which registered the entrance of 1.16 GW of wind power and 0.24 GW of solar PV, expected to come on line in 2022 (XM, 2019a).

Table i. Generation projects currently registered; data from SIEL (2018)

Technology	**Projected capacity [MW]**	
Fossil fuels	3 776	6 860
Hydropower - reservoir	3 084	
Hydropower - run-of-river	3 442	11 092
Wind power	3 441	
Solar PV	4 209	

The Colombian power system is also conditioned by the complex orography of the country. Electricity demand is distributed among the inner part of the national territory and the coastal regions (while the vast Amazonian region is practically not connected to the transmission system). However, the installed capacity follows specific geographical patterns. Hydropower plants are mainly located in the Andean region, while thermal generation is concentrated in the coasts (especially in the Caribe region). The interconnections between these two macro-regions suffer frequent congestions. As already mentioned, also the RES-E potential is concentrated in the Atlantic coast.

2.2 The current Colombian market design

2.2.1 Short-term market design

The Colombian short-term market design can be schematised through the following steps:

- In the day-ahead time horizon, the independent system operator (XM) determines a nodal economic dispatch (the so-called programmed dispatch) based on bids from market agents and forecasted conditions (demand, availability of the generation facilities, etc.). No commercial commitments nor financially-binding prices are defined at this timeframe; the system operator calculates only an indicative uniform price that aims at facilitating the coordination of the short-term electricity market with the reliability charge mechanism (see subsection 2.2.2), cross-border trades, and the gas market.

- Afterwards, there may be intraday updates to the previous nodal day-ahead dispatch, which may happen whenever there is a significant change in the system conditions (e.g., availability of units or transmission lines or load forecasts). These scheduling updates, in Colombia, are referred to as "re-dispatches"[3]. As the initial dispatch, the updated dispatch (after potential re-dispatches) is indicative, and it does not produce commercial commitments nor financially-binding prices.

- The commercial and economic outcome of the market is defined completely *ex post*. The short-term market remuneration is based on the real production (the so-called real dispatch) and on a single hourly price which is uniform on the entire national grid. The

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[3] Note that the term re-dispatch is different to what is understood by re-dispatch in European markets. In Europe a re-dispatch refers to modifications to the single-node market clearing so as to comply with network constraints. The Colombian re-dispatch is a purely operational action to update the initial dispatch in case of unexpected events.

real dispatch can differ from the last programmed dispatch only for the activation of ancillary services. The uniform price is calculated based on a single-node economic dispatch, the so-called ideal dispatch, in which network constraints are disregarded, and is equal to the price bid of the marginal power plant in each hour of the day, plus a delta term to recover start-up and shut-down costs (and other fixed operational costs).

This dispatch configuration is based on some sort of separation between the operational and the commercial layer of the power sector[4] (Figure 2). From the day-ahead to the real time, all actions happen in the operational layer, where an indicative dispatch is defined and then updated, but without producing any financially-binding commitment or price. On the other hand, in the commercial layer, everything happens *ex post*, with the definition of the ideal dispatch and the calculation of a uniform national price. Since the ideal dispatch is based on a single-node representation of the network, while the programmed dispatch considers network constraints, there is the need for an additional settlement between the commercial and the operational layer. This settlement is known as "reconciliations" (expression used in the Colombian regulation) and it is presented in the following subsection.

[4] This separation is not reflected in an institutional separation, since the same entity (XM) carries out system and market operation activities.

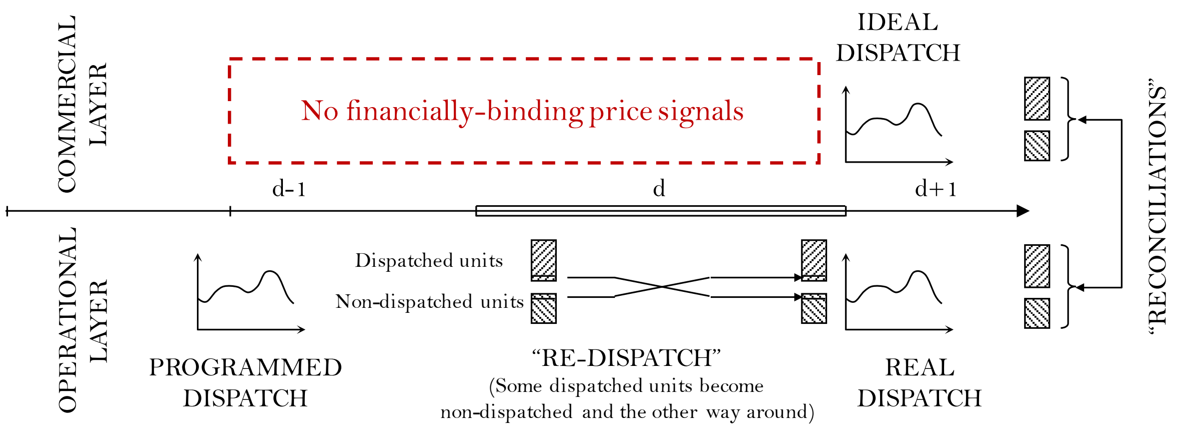


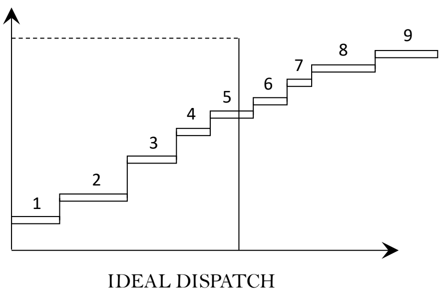
Figure 2. Time schedule of system and market operation in the short-term time horizon

The reconciliation process

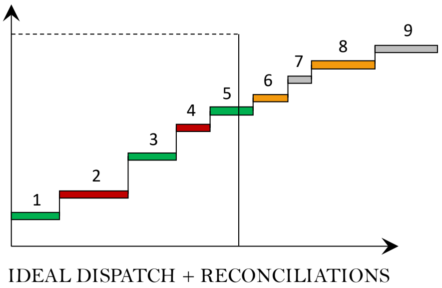
As mentioned, the ideal dispatch often does not match the real dispatch (due to the effect of network constraints). Therefore, the outcomes of the ideal dispatch (that sets economic conditions in the commercial layer) and of the real dispatch (that sets the technical conditions in the operational layer) may differ significantly, thus requiring a reconciliation process:

- When an agent is cleared in the real dispatch but not in the ideal one, the agent receives a compensation (a positive reconciliation payment).
- When an agent is cleared in the ideal dispatch but not in the real one (for example, cheap generation that could not inject electricity into the grid because of network constrains), the unit does not receive market remuneration. This situation is known as negative reconciliation (conceptually, the agent has to return the remuneration obtained in the ideal dispatch).

Figure 3 shows all possible combinations of market clearing (ideal dispatch) and operational commitment (real dispatch). The figure on the upper left shows the representation of an ideal dispatch and the table on the upper right shows whether each unit was committed in the real dispatch.



Unit number	Ideal dispatch	Real dispatch
1	Yes	Yes
2	Yes	No
3	Yes	Yes
4	Yes	No
5	Yes	Yes
6	No	Yes
7	No	No
8	No	Yes
9	No	No



Committed in the ideal dispatch / Produces in the real dispatch → Spot market remuneration

Committed in the ideal dispatch / Does not produce in the real dispatch → Negative reconciliation

Not committed in the ideal dispatch / Produces in the real dispatch → Positive reconciliation

Not committed in the ideal dispatched/ Does not produce in the real dispatch → Non-dispatched

Figure 3. Outcomes of the ideal and real dispatches and reconciliation process.

Four possible settlements (and colours, which will be used in subsequent discussions for the sake of brevity) can be, therefore, identified:

(i) The unit receives the spot market price since it is dispatched both in the ideal and the real dispatch (this case is represented with green colour),

(ii) The unit does not receive any remuneration even though it was committed in the ideal dispatch, because it did not produce in the real dispatch. The unit is subject to a so-called negative reconciliation (this case is represented with red colour).

(iii) The unit is out of the merit order of the ideal dispatch, but it was committed in the real dispatch and it is compensated with a remuneration different from the spot market price. This unit is subject to a positive reconciliation (this case is represented with orange colour). The price at which positive reconciliations are settled is different for thermal and hydropower plants. Positive reconciliations for thermal generators are priced at the highest of i) the bid from the agent (potentially increased to consider start-up and shut-down costs) and ii) a reference price defined by the system operator based on data from the agents regarding efficient fuel and maintenance costs[5]. On the other hand, hydropower plants are subject to a positive reconciliation price equal to the spot price, which can be further reduced if the plant is likely to suffer a spillage.

(iv) The unit is not dispatched in the ideal nor in the real dispatch. It is a non-dispatched unit (this case is represented with grey colour).

Figure 4 provides a graphical representation of the geographical distribution of reconciliations. The chart shows how agents in positive reconciliation are usually located in the Caribe region, while agents in negative reconciliation are mainly located in the inner part of the country.

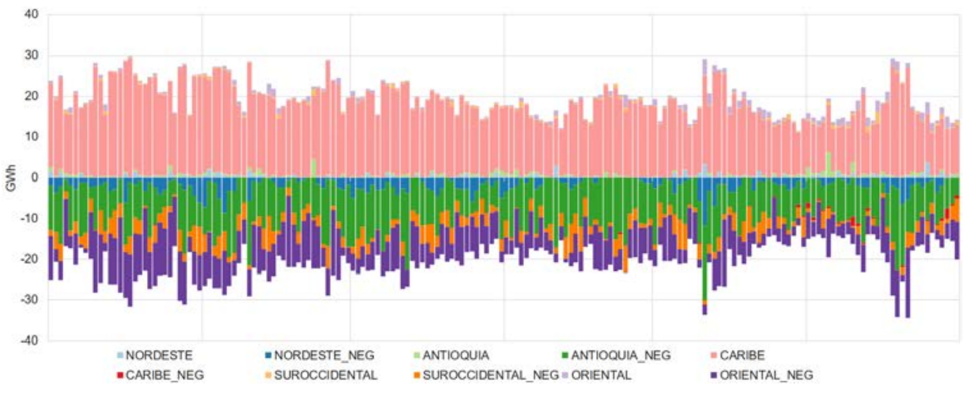


Figure 4. Positive and negative energy reconciliations by region; chart from XM (2019b)

During normal conditions, many hydropower plants from the Andean region with "cheap" bids are cleared in the ideal dispatch, but their energy cannot be transmitted to the Caribe

[5] It must be remarked that, contrary to the spot market price, the price of positive reconciliations is not uniform among resources, i.e., a price is calculated and applied to each agent (similar to what happens in a pay-as-bid market clearing).

region due to congestions in the network. Therefore, thermal generation in the Caribe region with more expensive bids are settled through the aforementioned positive reconciliation. While positive and negative reconciliations are almost symmetric in terms of energy, there is an obvious unbalance in economic terms (the remuneration for positive reconciliations is higher than the compensation from negative reconciliations) that must be covered through a specific charge in electricity tariffs, the so-called restriction charge, which is paid by the entire demand.

2.2.2 Other aspects of the regulation affected by the reform

The introduction of an *ex-ante* market sequence would have an impact also on other aspects of the power sector regulation, which are briefly described hereunder.

Long-term contracts

The contract market is a pillar of the Colombian electricity sector. Most of the transactions occur through long-term financial contracts, either procured in auctions or traded bilaterally, while the short-term market, during normal hydrologic conditions, covers only a minor share of the energy demand (XM, 2019b). These financial contracts are settled based on the *ex-post* sport market price, calculated through the ideal dispatch.

Ancillary services

The procurement of ancillary services is another aspect of Latin American power sector regulation that is being challenged by the penetration of RES-E resources. The abundance of flexible hydropower resources facilitated frequency control activities and this condition is reflected, in many cases, in simplistic market designs. In Colombia, the main ancillary service is Automatic Generation Control (AGC) for frequency regulation (Carvajal et al., 2013). The procurement of AGC is somehow embedded in the short-term market. The same daily bids from market agents are used to sequentially dispatch units to cover both the AGC and the energy demand. The Colombian market monitor highlighted more than once the potential inefficiencies that could stem from using the same price for the dispatch of two different services that are expected to have different values (CSMEM, 2015).

Cross-border trades

The Colombian power system has interconnections with Venezuela and Ecuador. Most of cross-border trades occur through the interconnection with Ecuador (Colombia is part of the Andean Electric Interconnection System, or SINEA, which fosters a regional market with Bolivia, Chile, Ecuador, and Peru; see CAN, 2017). The current market design tries to exploit efficient exchanges with neighbouring countries, but limiting the impact of the latter on the domestic market. In the day ahead of operation, the two system operators share information and calculate the expected direction and the flow through the interconnection, but no commercially-binding agreement is defined. After the operation, a different short-term price and a different delta term are calculated for and applied to national and cross-border trades registered in real time.

Reliability Charge

The reliability charge mechanism is the scheme aimed at guiding system expansion and of guaranteeing the security of supply in Colombia (Cramton and Stoft, 2007). It consists of a financial call option that obliges the contract holder to deliver its commitment (defined in terms of firm energy) to the system whenever the short-term price exceeds a strike price (the so-called scarcity price) during the course of a day and to return the difference between these two prices for the quantity associated to the contract (again, the firm energy). In exchange for this service, the contract holder receives the option premium, which is set through centralised and competitive auctions (Olaya et al., 2016). The activation of the reliability charge, therefore, depends nowadays on the evolution of the market price calculated *ex-post* through the ideal dispatch.

3 A PROPOSAL FOR MARKET REFORM

As mentioned in the introduction, the current Colombian electricity market design, which has successfully contributed to the well-functioning of the system in the last two decades, may not be able to efficiently integrate large share of variable RES-E resources (Benavides, 2018). This section presents a proposal focused on the introduction of a binding day-ahead market, followed by intraday sessions and a balancing market. This market sequence would allow to define binding commercial commitments, to update them in the intraday time horizon, when more accurate information regarding RES-E availability is produced, and to efficiently assign the cost of commercial imbalances, either between two market sessions or between the last market session and the real time.

3.1 The consideration of the network

The first decision to take in order to introduce a day-ahead and an intraday market in Colombia is related with the consideration of the network. Currently, the programmed dispatch (operational layer) considers network constraints, while the so-called ideal dispatch (commercial layer) does not.

According to economic theory, computing nodal prices in each session is the most efficient alternative (Green, 2007; Leuthold et al., 2008). Nodal prices reflect the locational value of electricity and permit an easier settlement of the intraday market. Nonetheless, their introduction would represent a change of paradigm for the Colombian electricity market, which, since the original liberalisation, has been based on uniform pricing. Similar experiences in Europe, where many electricity markets are based on a uniform price, demonstrated how this market design is more related to political decisions than to technical or economic considerations (CEW, 2017). In Colombia, it may be complex and even counterproductive[6] to introduce two major reforms (introduction of nodal prices and introduction of *ex-ante* markets) at the same time. For this reason, the rest of this section presents a proposal based on the second option, which maintains the current separation of the commercial and the operational layer.

In any case, it is worth bearing in mind that an intraday market based on uniform pricing forces the regulator to choose between guaranteeing the efficiency of the dispatch and ensuring the fulfilment of binding commercial agreements. The trade-off between these two conflicting objectives is actually the focus of this article, as discussed in detail in the following subsections.

3.2 The proposed market sequence

Figure 5 shows a graphical representation of the proposed market sequence. Each market session is composed by an ideal dispatch, which defines the price, and a programmed dispatch for the operation of the system, plus a reconciliation process that allows to identify which commercial positions set in the ideal dispatch are feasible when considering network constraints and can therefore produce binding commercial commitments.

[6] Even more significantly, it may be counterproductive to condition the introduction of *ex-ante* markets to the introduction of nodal prices, since the latter do not generate consensus among the agents of the Colombian power sector. None of the technical documents produced so far by Colombian institutions (CREG, 2016; XM, 2014) considered the switch to nodal prices.

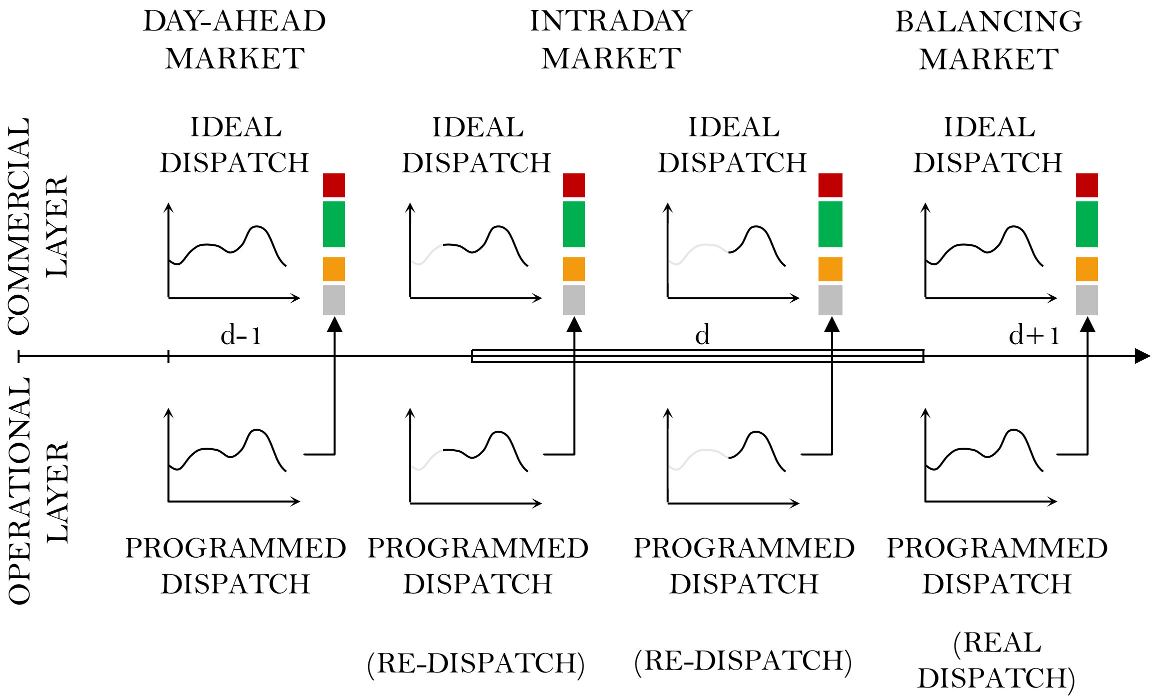


Figure 5. Proposed market sequence for the Colombian *ex-ante* electricity market (colour notation from Figure 3)

The day-ahead market may follow the same time schedule currently defined for the first programmed dispatch. Both the ideal and the programmed dispatch will be based on the following information: i) load forecasts from the system operator[7], ii) bids from the agents expressed as a price-quantity pair (the quantity represents the best estimation of the agent regarding the expected availability of the resources it controls)[8]. All the agents with an operational commitment (selected by the programmed dispatch) will have also a commercial

[7] This is true if demand, as it happens now, does not participate actively in the short-term market; see section 3.4 for possible alternatives for demand participation.

[8] The market clearing would also consider start-up and shut-down costs, but the latter should not necessarily be declared by the agents on a daily basis.

commitment; those cleared in the merit order in the ideal dispatch will be subject to the spot market price, while those cleared out of the merit order will be subject to the price of their positive reconciliation. Those agents that are cleared in the merit order of the ideal dispatch but have no operational commitment (not selected in the programmed dispatch) will have no commercial commitment either[9].

In the intraday horizon, the same procedure followed in the day ahead is repeated for the different intraday sessions. Each of them will allow trades for the remaining hours of the day of operation. Before each session, market agents will be allowed to modify their bids, in terms of both quantity and price, according to a predefined time schedule. An outage of a thermal power plant or a change in the expected availability of renewable resources can be reflected in a modification of the quantity of the bid; an unexpected change in the cost of fuels can be reflected in a modification of the price of the bid. These modifications will result in new ideal and programmed dispatches, which will be then reconciliated to update commercial commitments. Like in intraday auctions implemented in some European countries (ACER/CEER, 2018), these intraday sessions concentrate in discrete moments all the changes occurred since the previous session[10]. The regulator will have to define the number of intraday sessions. A possible solution is to introduce a few sessions (one or two)

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[9] This rule reflects what happens, for instance, in European markets based on uniform pricing, where commercial commitments are always defined after the feasibility of the market clearing has been assessed by the system operator, who may re-dispatch the system and undo some commercial position that produces the activation of a network constraint.

[10] It must be remarked that the current market design is based on a mandatory participation in the short-term market. Generators are required to submit a bid in the market, based on their expected availability. The same model would apply to the proposed market sequence. The participation to both day-ahead and intraday market sessions would be mandatory.

during a first implementation phase and to increase their number when the agents are familiarised with the mechanism and when clear benefits from the introduction of new auctions in terms of efficiency can be identified.

The clearing of the last intraday market session in which trades can be carried out for a certain hour represents the so-called gate closure for that hour. After such gate closure, commercial commitments can no longer be modified. Any change in the availability of generation resources taking place between gate closure and real time cannot be absorbed by the market and will be managed directly by the system operator (through a last operational re-dispatch or through the activation of ancillary services). The extra costs generated by these operational interventions will be allocated in an economic efficient way through a balancing market, represented by a last and ex-post calculation of the ideal and programmed dispatches. This last market session will allow to identify imbalances from market agents and to charge the extra costs to those who caused them.

3.3 A complex intraday market settlement

Contrary to the current design, the market sequence proposed in the previous section generates changes in the commercial positions of the agents. These changes need to be settled according to the prices cleared in each of the sessions, as it happens in many intraday electricity markets around the world.

After clearing each market session, under the current design, a resource with an offer bid can be in one of the four following states: i) generation cleared in the spot market, ii) generation in positive reconciliation, iii) generation in negative reconciliation, and iv) generation non-dispatched (see section 2.2.1 for details). Therefore, beyond changes in the commercial position of the agent, also "state changes" may take place (Figure 6). For instance, a resource can pass from being cleared in the spot market in one session to be non-dispatched or in negative reconciliation in the following session and the implications may be different.

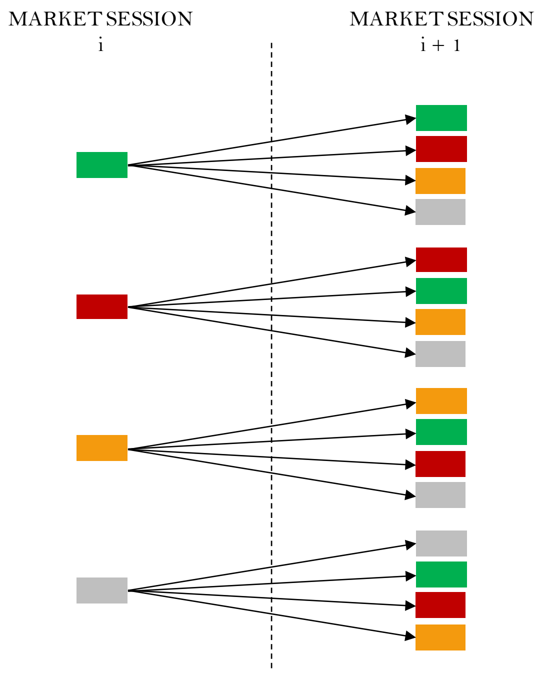

Figure 6. "State changes" between subsequent market sessions; colour notation from Figure 3

The situation depicted in Figure 6 requires the elaboration of a settlement matrix between two consecutive sessions, which specifies a settlement formula for each possible state change between two adjacent market sessions. As it will be analysed in the rest of this subsection, most of the state changes can be solved through a basic standard settlement, while few state changes will require an *ad-hoc* formula.

Table ii presents a summary of the proposed settlements. Most settlements are based on a simple formula denoted as "standard settlement", while those state changes for which the standard formula cannot be applied are highlighted in light blue. All these settlements are explained in detail in the rest of this subsection.

Table ii. Summary of proposed settlements for each possible state change; colour notation from Figure 3

q / p		Session i+1: Spot Market	Session i+1: Negative Reconciliation	Session i+1: Positive Reconciliation	Session i+1: Non dispatched
Session i	Spot Market	Standard settlement	Standard settlement only with economic gain for the agent	Standard settlement	Standard settlement
Session i	Negative Reconciliation	Standard settlement	Standard settlement	Standard settlement	Standard settlement
Session i	Positive Reconciliation	Standard settlement	Cancel previous commitments	Standard settlement	Caused extra cost (with thresholds)
Session i	Non dispatched	Standard settlement	Standard settlement	Standard settlement	Standard settlement

3.3.1 Standard settlement formula

The standard settlement in multi-settlement markets consists in compensating in the following session any shortfall or overproduction with respect to the commercial position defined in the previous session. In other words, any expected shortfall with respect to a previous commitment has to be covered through a purchase in following market sessions at the corresponding price, and any expected production larger than the one already committed has to be sold at the new price.

A possible formulation for the standard settlement that applies to most cases is as follows:

$$Standard\ settlement = p_m^i q_{pd}^i + p_m^{i+1}\left(q_{pd}^{i+1} - q_{pd}^i\right)$$

Where *p* stands for price, the subscript *m* is the market segment (either the spot market price or a positive reconciliation), *q* for quantity, the subscript *pd* stands for programmed dispatch, and the superscript *i* or *i+1* identifies the market session. The standard settlement formula can be applied to most of the state changes. Some examples are mentioned hereunder:

- A resource cleared in the spot market in the first session (green colour in the matrix) and non-dispatched in the second session (grey colour in the matrix) will sell at the price of the first session and will buy at the price of the second one. This settlement may result in an economic gain or loss for the agent, depending on the market conditions.
- A resource cleared in the spot market in the first session (green colour in the matrix) and that is cleared once again in the spot market (green colour again) or that is in positive reconciliation (orange colour) in the second session maintains its initial commitment. In fact, since the quantity cleared in the programmed dispatch is the same, the second term of the standard settlement formula is null. The same happens if the resource is in positive reconciliation in the first session.
- A resource in negative reconciliation (red colour) or non-dispatched (grey colour) in the first session will have its commercial commitment fully determined by its position in the second session and it will be remunerated accordingly.

3.3.2 Ad-hoc settlement formulas for complex state changes

While the standard settlement formula can be efficiently applied to most of the combinations presented in Table ii, there are three state changes for which the application of the standard settlement would result in counterintuitive or directly inefficient outcomes, or for which the application of this formula is impossible. These cases are analysed in this subsection.

Network constraint activation or market displacement in the intraday time horizon

A controversial application of the standard settlement may affect the state change taking place when a resource cleared in the spot market in the first session is in negative reconciliation in the second session. This state change may occur in different circumstances:

- Activation of a network constraint in the intraday time horizon (for instance, due to the sudden outage of a transmission line).
- Generation located behind a transmission line that suffers usual congestions, which is cleared in the first session and then displaced by a cheaper resource in the second session, since the generation of the two resources cannot be transmitted to the rest of the system.

In both cases, the change of conditions in the node where the resource is located is not directly reflected in the spot market price, which, being calculated as a uniform price, may grow or decrease from the first to the second session. The application of the standard formula, in this case, may result in the resource having to face an economic loss (if the price is higher in the second than in the first session) for a change in its commercial position on which it has no control and for which it is not responsible. For this reason, the settlement for this state change should apply the standard formula only if this produces an economic gain for the agent.

As pointed out above, an intraday market based on uniform pricing forces the regulator to choose between guaranteeing the efficiency of the dispatch and ensuring the fulfilment of binding commercial agreements. In the case of a generator in a constrained node that is cleared in the spot market and then displaced by a cheaper resource in its node, for instance, the proposal advanced in this article prioritises the efficiency of the dispatch (letting the cheap plant produce), even if this provokes the cancellation of a commercial agreement that is not beneficial for the agent that holds it[11]. Nodal pricing permits to achieve the two

[11] Since the intraday market is based on mandatory participation, the market monitor should also study bids from the agents in the constrained node, in order to avoid strategic behaviours from the more expensive agent, who, once it has been granted a commercial commitment in the first session, may try to elude the displacement by artificially decreasing its bid.

objectives at the same time, since the price in the constrained node of the example described above would vary depending on the resource that is generating, making the displacement beneficial for both agents. This solution cannot be achieved through uniform pricing and no market design based on a single price can avoid this intrinsic inefficiency that may increase uncertainty for market agents in constrained nodes. However, the latter is not in the same order of magnitude of the efficiency gain obtained through the introduction of a day-ahead and an intraday market, which can greatly increase the market outcome in terms of social welfare even in systems based on uniform pricing.

A very unlikely subcase of this state change happens when a generation resource in positive reconciliation in the first session ends up in negative reconciliation in the second session. This means that a generator dispatched out of the merit order to solve a network constraint suddenly enters the merit order but cannot produce due to the activation of a network constraint. In this situation, hard to be registered in real system operation, the suggested approach is to cancel the previous commitment, in order to avoid controversial economic losses for the agent.

Non-fulfilment of generation resources in positive reconciliation

A state change for which the standard settlement formula has no obvious application is the one that occurs when a generation resource in positive reconciliation in the first session is not dispatched in the second session, due, for instance, to a sudden unavailability of its assets that takes place in the intraday horizon. In this case, the system operator will have to dispatch out of the merit order another resource, whose bid is likely to be higher than the one of the first resource. In this case, it is difficult to define a price for the second session that can be applied to the standard formula, since the positive reconciliations are not remunerated at the marginal price, but in a way that can be classified as pay-as-bid.

The most economic-efficient solution is to consider the extra cost caused by the non-fulfilment of its commercial commitment by the generation resource. If a more expensive resource must be dispatched, the non-fulfilling generator should pay the difference between the price of its commercial agreement and the price of the positive reconciliation of the new resource (the resource to be considered is the one that allows to solve the same network constraints that the non-fulfilling resource was called to solve).

The main drawback of this kind of settlement consists in the large economic loss that it may cause for non-fulfilling resources. Due to network constraints, some of these resources may be replaced only by very expensive power plants. In some extreme cases, the non-fulfilment of the commercial agreement may force the system operator to cut supply to certain users; the price to be used for the settlement, in this case, would be the cost of non-served energy. There is, therefore, the possibility that generators that are likely to be dispatched out of the merit order internalise the risk of these large economic losses in their bids. An alternative to avoid this kind of dynamics is to cap the economic loss for these resources. The non-fulfilling agent may be hold responsible for the extra cost it causes, but only up to a certain threshold, above which the residual extra cost would be socialised.

3.3.3 Delta term for fixed operational costs

As mentioned in subsection 2.2.1, a delta term is currently added to the price bid of the marginal power plant to compute the *ex-post* spot price that is paid by demand. This delta term is included to recover the fixed operational costs (as start-up or shut-down costs) that may be incurred by some power plant and that are not covered by the marginal price. In a multi-settlement market, the calculation of the delta term entails, once again, a trade-off between guaranteeing the efficiency of the dispatch and ensuring the fulfilment of binding commercial agreements.

The first-best alternative would be to calculate a delta for each market session. Fixed operational costs would be recognised and included in the binding commercial commitment. These costs would be assigned to those who caused them, in the market session where they have been produced. However, although this represents the most efficient solution, this design may be unacceptable, since it may pay to a power plant some costs that it did not incur.

The second-best solution is to calculate only one *ex-post* delta term, based on the real operation of the system. With this design, there would be one single delta term for all market sessions, which would be added to the marginal price registered in each session to compute the corresponding spot price.

3.4 Participation of demand

In Colombia, demand participates in the long-term electricity market through the signature of bilateral contracts, but it does not take part in the short-term market. The latter is based on load forecasts from the system operator and demand is considered as totally inelastic. Two participation models are envisaged in this proposal, as detailed hereunder.

3.4.1 Participation through load estimation

The introduction of *ex-ante* markets requires an efficient allocation of the forecast responsibilities (as analysed in the following section, this is true also for RES-E resources). A first measure to promote demand participation in the short-term market is to hold retailers responsible for load forecasts of the demand they supply. Retailing companies should communicate to the system operator their expected demand in the day ahead, update this forecast in the intraday time horizon, and assume the economic consequences of a potential forecast error (either if the error is registered in the intraday market or in the balancing market). This cost allocation method respects the cost-causality principle and incentivises retailers to improve their forecast techniques.

3.4.2 Full participation through quantity-price bids

A most advanced alternative may consider a demand participation that is fully symmetrical to the participation of generation resources. Retailers would be required to present price-quantity bids based on their load forecasts and on their opportunity cost. As for generation resources, retailers may modify both the quantity and the price in the intraday time horizon.

This participation scheme is obviously more efficient, since it allows demand to express the value it assigns to supply. However, it would require deeper modifications to the market clearing process. The ideal dispatch, which is currently solved as a cost minimisation problem, should be reformulated as a maximisation of the net social welfare. The presence of elastic demand may also complicate the allocation of fixed operation costs on the top of the marginal price. Furthermore, if retailers participate actively in the short-term market, their bids would be subject to the reconciliation process that already affects generation bids. When an *ex-ante* market sequence is introduced, this reconciliation process would result in state changes as those analysed in section 3.3 and the settlement process may be complicated accordingly.

3.5 Participation of intermittent generation

Most of the efficiency gain associated with the introduction of a day-ahead, an intraday and a balancing market stems from a proper assignation of the risk related to the availability of generation assets and energy sources. The clearing of each market session produces commercial commitments that must be fulfilled or modified in another market session. This allows to assign efficiently the cost of imbalances between market sessions or between the last market session and the real time.

Looking at international experiences, however, not all generation resources use to face this commercial responsibility. Regulators around the world introduced exemptions for certain technologies (commonly small-sized power plants or generation assets relying on an intermittent energy source). Nonetheless, it must be remarked that these exceptions eliminate the incentive to develop advanced forecast techniques for renewable resources; for this reason, in many jurisdictions, exemptions to imbalance responsibility are being progressively eliminated.

In Colombia, power assets with an installed capacity lower than 20 MW are defined as non-centrally-dispatched. These units communicate their expected generation output for the day after, which is included in the programmed dispatch. The cost associated with any imbalance with respect to the day-ahead forecast is socialised among consumers. A similar approach may be replicated in the new market design. The generation of those resources exempted by the commercial responsibility may be directly managed, in the market sequence, by the system operator; a reference market should be defined to give a value to the energy eventually generated by these plants. The selection of which technologies and under which size should be entitled of this exemption is a regulatory decision that exceeds the scope of this article.

3.6 Interaction with other market elements

The reform of the short-term market would have an impact also on other markets and on other aspects of power sector regulation. These interactions are analysed in this section, which follows the structure of section 2.2.2.

3.6.1 Long-term contracts

After the introduction of a day-ahead, an intraday, and a balancing market, long-term contracts will have to specify a reference market for their settlement. This decision may be left to market agents signing long-term contracts or may be centrally defined by the regulator and then applied to all contracts. An element that should be considered is that a uniform definition of the reference market may be beneficial for the liquidity of long-term contracts.

3.6.2 Ancillary services

As already mentioned in section 2.2.2, the market for the procurement of ancillary service is another aspect of the Colombian regulation that will soon require a reform. Different designs are possible, both in terms of procurement process and cost allocation. In this subsection, the focus is on the interaction of these features with the short-term market design proposed in this article.

In terms of procurement process, two alternative designs can be introduced:

- Co-optimization of energy and reserves. A restriction on reserve requirements is included in the market clearing algorithm, whose dual variable represents the price for the provision of that service. The day-ahead market clearing would therefore define which resources provide reserves, which produce energy, and the price for the two products. With this design, the regulator should decide whether reserve commitment can be updated in the intraday market or not.
- Sequential procurement of energy and reserves. In this case, the day-ahead market will define initial commercial commitments for energy production; then, a specific market for reserves would be open, for those resources with residual capacity to offer this service. Such reserve market may be based on similar rules as the energy market (e.g., pay-as-cleared pricing) or have a specific design.

In terms of cost allocation, reserve costs must be clearly divided between the cost of reserving capacity prior to operation and the cost of eventually activating this capacity in the real time. The cost of capacity reserve can be socialised or assigned according to complex methodologies that pursue the fulfilment of the cost-causality principle. The cost of energy activation can be assigned through the balancing market as defined in section 3.2. This market clearing may allow to calculate a final marginal price that can be applied to the imbalances with respect to the aggregated commercial positions of market agents. This would allow to recover the energy activation costs incurred by resources providing reserves (and, potentially, also part of the capacity reserve costs, depending on the design selected for the remuneration of the reserve service).

3.6.3 Cross-border trades

The introduction of a market sequence requires to define how cross-border trades will be involved in these markets. Currently, cross-border trades are defined in the day ahead and updated in the intraday time horizon, but without establishing any *ex-ante* commercial commitment (as for the rest of transactions, the price is calculated only *ex-post*). In the future, cross-border trades could be totally equated with domestic transactions; international trades defined in the day-ahead market would produce a commercial commitment that the Colombian system will have to honour or modify in a subsequent market session, assuming the economic consequence of such modification (which could be positive or negative). Otherwise, cross-border trades may be exempted from *ex-ante* commercial commitments. The day-ahead market may define a first estimation of cross-border trades, this estimation could be updated in the intraday market, but the commercial position would be defined *ex-post*, through the last ideal dispatch (or through a dispatch specifically introduced for this scope). With this design, the trade would still be economic efficient (electricity flowing to the system with the highest price), but it would be valued at the real-time price, regardless of the market session where it was first cleared in.

3.6.4 Reliability charge

The reliability charge is a financial option based on the spot market price. With the introduction of a day-ahead, an intraday and a balancing market, the regulation will have to specify which one will be the reference market for the reliability charge, i.e., which one among these prices will drive the activation of the financial option (Figure 7). Literature on the topic (Batlle et al., 2015) suggests that the reference market of a reliability options mechanism defines the type of scarcity conditions that the regulator is trying to avoid through the introduction of such mechanism. The day-ahead market price reflects scarcity conditions related to an adequacy problem, i.e., the ability to meet peak demand with the installed capacity. If the reference market is selected closer to the real time, the corresponding price will also reflect scarcity conditions more related to a flexibility problem, i.e., the ability of the system to quickly respond to unexpected changes in the programme[12].

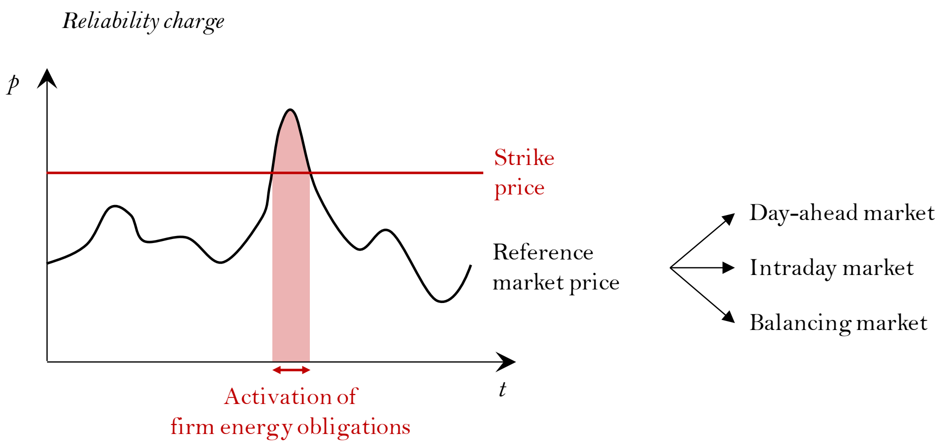

Figure 7. Graphical representation of the selection problem for the reference market of the reliability charge

[12] Some European capacity mechanisms based on reliability options have defined a reliability product with multiple reference markets; this the case of Ireland (SEM, 2015 and 2016) and Italy (Mastropietro et al., 2018).

In Colombia, scarcity conditions historically occurred during dry seasons that limited the hydropower production for long periods of time. At the same time, the large hydropower capacity provides flexible resources that can react in the very short term. Therefore, currently, scarcity conditions seem to be related with an adequacy problem and the target reference market should be the day-ahead market. Nonetheless, the reliability charge is a mechanism that aims at guiding the long-term expansion of the system and its design should target not only current scarcity conditions but also those expected to characterise the Colombian power sector in the future.

4 CONCLUSIONS AND POLICY IMPLICATIONS

The current design of the Colombian electricity market is based on a strong separation between an operational and a commercial layer of the power sector. In the day ahead, all actions take place in the operational layer, through the so-called programmed dispatch that defines operational commitments considering also network constraints. After the operation, the so-called ideal dispatch calculates a single price for the entire national territory that is used to define all commercial commitments. Therefore, as it happens in other electricity markets in the region, no price signal is produced in the time horizon that spans from the day-ahead to the real time. This design may not be suitable to efficiently integrate the large shares of renewable technologies to be installed in the system in the near future (Table i). The lack of price signals does not allow to allocate efficiently the extra costs generated by re-dispatches and imbalances, nor to take advantage of cheap resources that are made available in the intraday time horizon. The problem has been acknowledged by Colombian institutions (CREG, 2016; XM, 2014), which evidenced the need to reform the short-term market and to introduce an *ex-ante* market sequence.

This article presents a regulatory proposal for the implementation of a day-ahead, an intraday and a balancing market in the Colombian power sector. The proposed design seeks to maintain the current separation between the operational and the commercial layer of the power system (the alternative would be the introduction of nodal prices, a market clearing mechanism on which no consensus can be found, nowadays, in Colombia). Uniform pricing, which allows the calculation of a single price for the entire network, can be preserved, but this approach may complicate intraday market settlements. In some specific conditions (subsection 3.3), the regulator will have to choose between guaranteeing the efficiency of the dispatch and ensuring the fulfilment of binding commercial agreements. The proposed design prioritises the first objective, but this approach may create uncertainty for market agents. This inefficiency is intrinsic to intraday markets based on uniform pricing; however, the benefits of introducing an *ex-ante* market sequence are large enough to justify this relatively small inefficiency.

Beyond proposing an intraday settlement system capable of dealing with the above-mentioned conditions, the article also discusses possible approaches to foster the participation of demand resources and intermittent technologies in the new short-term market. Finally, the document analyses the interactions of the proposed reform with other aspects of the Colombian power sector regulation, as the long-term contract market, the market for ancillary services, cross-border trades, and the reliability charge mechanism.

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