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Mission of energy transformation and modernization of the electricity industry: roadmap for the energy of the future

Focus No. 1 - Competition, participation and structure of the electricity market

Final Paper

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Executive Summary

The objective of Focus No. 1 is to develop recommendations on competition, participation and structure of the electricity markets in Colombia. This executive summary reflects both responses to the research agenda identified by Cadena and Alvarez (2019)[1], as well as other topics and perspectives introduced by team members.

Design of short-term markets

Well-designed short-term markets for energy and ancillary services are essential foundations for efficiency, competition and innovation. Weaknesses of the current short term market design include the following: (i) the Day-ahead dispatch (D-1) is not binding; (ii) there is only a secondary regulation auxiliary service and it is not co-optimized with the energy market; (iii) there is generator market power in congested local areas; (iv) there is no local price signal; (v) there are insufficient mechanisms to efficiently correct agents´ positions the day of operation, including the lack of real-time hourly pricing signals, and finally, (vi) lack of participation of the demand side.

To begin to address these weaknesses, the regulator is currently undertaking initiatives to implement binding dispatch, intraday markets and balancing mechanisms as well as to co-optimize ancillary services with energy. The team believes the *end-state* for these reforms should contain certain key elements, including a day-ahead market and a real-time market with three-part bidding and automated market power mitigation, nodal pricing (also called locational marginal pricing or LMP), co-optimization of energy and reserves, and binding financial settlements in each market.[2] This end-state design reflects the experiences of multiple markets around the world.

The team has reviewed two pathways for market design reforms towards this end-state: (1) "phased reforms", which include other design components such as intra-day markets, and (2) "accelerated reforms" which focus on this transition directly.

The team concluded that since CREG has an advanced design for short-term market modernization, which is expected to improve efficiency and price formation, a reasonable approach to short-term market improvement is to begin with the CREG design, but that in parallel, in 2020 the design of the "end-state" design with LMP also begins, with a target for

[1] Given limitations of time, this report does not address in detail every topic raised by Cadena and Alvarez (2019), but also emphasizes other topics which were considered high priority.
[2] Sometimes called a "two-settlement system."

completion by end of 2021 and methods identified for a transition from the existing design as needed. Also, from this date the LMP model could be run in parallel to the binding dispatch model and intraday markets, in such a way that the decision of the application of nodal prices is made with the necessary adjustments detected in the LMP simulations, as a means to solve the congestion management inefficiencies and improve the transparency of the market, efficiency and price formation.[3] This proposal would facilitate the introduction of new generation technologies at the central and distributed level by giving locational price signals. Figure ES-1 illustrates the proposed roadmap. While this approach is reasonable, some members of the team continue to believe that the more direct, accelerated reform pathway (without interim reforms) may ultimately provide a smoother transition, and are willing to participate in any subsequent consultations on this approach. [4]

Figure ES-1 – Proposed roadmap for short-term market design reforms

In many regions, there is a growing need for operational flexibility to support integration of variable energy resources (wind and solar). These needs include increases in primary frequency response requirements, wider inter-hour and intra-hour ramping ranges and ramping reserves,

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[3] Appendix 1 reviews the empirical results from three US ISOs which made similar transitions and were able to measure these benefits. Appendix B discusses locational market power mitigation methods which should be implemented with LMP.

[4] Some members of the team believe that due to the incremental approach, the design could foster continued "unintended consequences", which require ongoing remedies. While the team has not conducted a detailed "stress test" of the proposed current design reforms, many of which are still in development, types of unintended consequences observed elsewhere could include continued opportunities for generation market power and continued inefficiency in dispatch and scheduling between day-ahead and real-time requiring persistent manual operator adjustments.

and potential increases in other operating reserves and frequency regulation. This flexibility can be provided by conventional resources and hydro, but is also being met increasingly by the participation of battery and flywheel energy storage and other types of new resources, such as demand response and the variable energy resources themselves. Because energy storage can provide a range of potential services simultaneously, further changes in the market design should take into account the specific requirements of these technologies, including smaller minimum sizes, control signals which maximize utilization (such as the energy neutral frequency regulation control signals offered by several ISOs in other countries), performance payments, and offering sufficient bidding parameters for state of charge management, to limit depth of charge and discharge, and address other operational constraint. In addition, because energy storage may need to obtain multiple revenue streams from a range of services, such projects will benefit highly from clarity about the timing of changes to market design and system operations.

Improvements to design of contracts and bilateral markets

Organized, transparent and liquid markets for medium and long-term electricity contracts will play a key role in the transformation. Future expansion would rely on the strength of these markets. The team believes recent activity by the CREG (114-2018 and 079-2019) points in a promising direction for the development of these organized exchanges. However, further attention should be paid to the credit robustness in these markets (for example through requirements to the confidence level used to design guarantee schemes) to avoid systemic events. The purpose of regulation should be to optimize the final result for the end consumer. Therefore, it is imperative that the regulatory design seeks to align incentives between retailers and final users to benefit all Colombian consumers.

Long-term Resource Adequacy Mechanism

There is agreement among the members of Foco 1 that Colombia must have a long-term resource adequacy mechanism. This mechanism ensures that the Colombian electricity supply industry is able to serve system demand during all possible future system conditions, including El Niño events.

The current reliability charge mechanism (CxC) has three primary weaknesses:

1. It enhances the incentive for large suppliers to exercise unilateral market power in the short-term market for energy when critical system conditions arise.
2. It has led to higher costs to consumers and lower average water levels, particularly during El Niño periods. Therefore, it does not appear to be an effective mechanism to balance system reliability and market efficiency.

3. The certainty of income provided by the reliability charge mechanism reduces the incentive of suppliers to sell fixed-price long-term contracts for energy and buy and sell other hedging instruments. This can reduce liquidity and the volumes traded in these markets.

Several economic principles guide our analysis of long-term resource adequacy mechanisms and form the basis for our recommendations. First, long-term resource adequacy implies uninterrupted energy production during all possible future system conditions, including El Niño events. Second, there should be an efficient price formation in the short and long term markets for energy. The long-term resource adequacy mechanism should promote transparency, liquidity, and reduce credit risks in the short-term and long-term markets for energy. Third, the long-term resource adequacy mechanism should encourage retailers and large consumers to hedge their short-term price and quantity risk. Fourth, the long-term resource adequacy mechanism should limit the incentive of large suppliers to exercise market power in the short-term market during stressed system conditions, particularly those leading up to El Niño events. Fifth, the long-term resource adequacy mechanism should encourage efficient and effective risk-sharing mechanisms between electricity suppliers employing different technologies to supply energy, thereby reducing the aggregate uncertainty in electricity supply.

Two approaches have been recommended by members of the Foco 1 team.

Some members of the Foco 1 team favor modifying the existing reliability charge mechanism, separating reliability and energy products, separating the auctions for new and for existing plants, and allowing efficient thermal plants to participate as strategic reserve resources. This approach would allow firm energy quantities to be set for the wet season and dry season separately.

The second approach to long-term resource adequacy favored by other members of the Foco 1 team ensures that there is adequate energy to meet the hourly demand in Colombia throughout the year under all possible future system conditions. This energy is purchased through standardized quarterly fixed-price and fixed-quantity forward contracts shaped to the hourly demand for energy within the quarter of the year. Each quarterly contract is purchased far enough in advance of delivery to allow new entrants to compete with existing generation units to supply this energy. Like the existing long-term resource adequacy mechanism, these standardized fixed-price forward contract purchases are mandatory for retailers and free consumers.

Regardless of the long-term resource adequacy mechanism chosen, the Foco 1 team members agree that all existing firm energy obligations should be honored. This implies a transition period that consists of a hybrid system of the existing and new reliability mechanism with three stages.

The first stage covers the period 2019-2023. Sufficient firm energy obligations have been purchased to cover the target demand defined by CREG over this time period. This gives CREG and the Ministry sufficient time to develop the details of the new long-term resource adequacy mechanism. Given the uncertainty of HidroItuango it may be necessary to make additional firm energy purchases under the existing reliability charge mechanism with short durations during this timeframe.

The second stage covering the period 2023-2026, would continue the existing reliability charge mechanism. Before the beginning of 2023, the first auctions for either firm energy under the new reliability scheme or standardized contracts for energy under the second scheme would take place. These contracts would begin making deliveries in the 2026 to ensure that new entrants can compete in the auctions held before the end of 2023.

The third stage would continue the process of holding auctions for the new reliability charge or standardized energy contact long-term resource adequacy products to replace the firm energy obligations that expire. This process would continue until all existing firm energy obligations have expired and been replaced by the new long-term resource adequacy mechanism. Staggering the procurement of products for the new long-term resource adequacy would guarantee security of supply during the transition. An important component of this transition is design and implementation of a clearinghouse and an enhanced system of guarantees to consistent with international best practice to ensure that suppliers, retailers, and free consumers fulfill their obligations under the chosen long-term resource adequacy product.

Other topics

The report provides preliminary recommendations on several other key topics identified by Cadena and Alvarez (2019), including reforms to transmission planning, development of distributed energy resources and retail customer participation in the markets, improvement in international interconnections and the establishment of an independent Market Monitoring Unit (MMU). Some of these recommendations are briefly summarized here:

- The definition of the national transmission system (STN) including the STR should be expanded. This will improve competence in developing the new projects of the Regional Transmission System (STR) and reduce barriers to new renewable, distributed energy resources and storage systems.
- The resource interconnection process requires revisions to reduce barriers to entry caused by speculative positions in the queue, impediments by some network operators, and regulatory restrictions on sharing the same interconnection.
- New types of transmission expansion projects should be considered in addition to the current project categories.

- A more flexible framework for proposing types of expansion projects for the STN, including transmission alternatives, is required to improve cost-effectiveness and energy market efficiency.
- Resource interconnection and transmission planning should allow greater participation by third-parties and generator owners.
- Rules for multiple uses of energy storage projects in transmission and distribution planning should be advanced, including whether and how such projects can obtain both cost-of-service and market-based revenues, rules for prioritization of services to ensure reliability, and identification of allowable contractual structures with sufficient time for project development; the economic value of such projects, which are at an early stage in many countries, will be partly contingent on the market design reforms discussed above. Appendix 3 provides some details on this topic from the U.S. markets.
- As installed costs of distributed energy resources decline, and new methods for customer participation (e.g., prosumer) become feasible, opportunities for third-party and retail participation in power system operations and direct or indirect participation in wholesale markets are increasing.
- Even at low levels of penetration, it is desirable to begin forecasting potential growth in DER on individual distribution circuits (hosting capacity analysis) and their impact on wholesale markets, reliability and high-voltage transmission planning. The wholesale market design reforms will also facilitate improvements in valuation of locational net benefits for distributed resources.
- Finally, an independent Market Monitoring Unit (MMU) should be established, with functions including monitoring wholesale market issues and performance, as well as actions by the operator and manager of the market and the future DSO, focusing on market efficiency and results. The MMU should be in operations prior to the recommended major market design reforms.

Introduction

Focus No. 1 (Foco 1) was formed to develop recommendations on competition, participation and structure of the electricity markets in Colombia. This final report reflects both responses to the research agenda for Foco 1 identified by Cadena and Alvarez (2019),[5] as well as other topics and perspectives introduced by team members. The report reflects some prioritization of what were considered to be foundational reforms to wholesale market design. In particular, certain key changes in wholesale market design could facilitate many of the government's future objectives, including improvements in economic efficiency, transparency, reliability and introduction of new types of supply and demand resources.

Foco 1 team members also prepared several short and long papers to reflect their views; this final report incorporates some of that material, but other papers which provided input remain separate and can also be reviewed (e.g., Wolak 2019c). Some topics reviewed include preliminary "roadmaps" with timelines, several of which could be further developed.

Organization of report

The report is organized to focus on two primary topics: the end-state for the design of the short-term markets for energy and ancillary services (Section A), and the design of a revised resource adequacy mechanism (Section C). Whether and how these designs are implemented is considered foundational to the further reform of the wholesale markets. In addition, there are several other topics addressed, including bilateral contracts (Section B), transmission planning (Section D), selected issues related to retail customer participation and distribution network planning (Section E), international interconnections (Section F), and establishment of a market monitoring unit (Section G).

There are three appendices which offer further international perspective on selected topics, including the experience of U.S. ISOs which made the transition from a single system or zonal pricing method to nodal pricing, local market power mitigation methods, and a review of some recent developments on energy storage with multiple uses.

[5] Some topics recommended by Cadena and Alvarez (2019) are considered in several sections of this report, rather than as stand-alone sections, notably transparent data and storage and aggregators.

A. Design of short-term markets

The short-term markets for energy and ancillary services in Colombia require substantial modification to improve economic efficiency, reduce the impact of market power, improve price formation, improve planning and valuation of new generation and transmission projects, and support the integration of new resource types, including Non-Conventional Renewable Energy Sources (NCRES), demand response, energy storage, and distributed energy resources. Many such reforms have already been established by CREG, or are under evaluation, and the study team assumes them in this report, but does not necessary jointly agree about implementation priorities. Cadena and Alvarez (2019, pgs. 11-12) reviewed a number of studies which evaluated nodal pricing and generally found benefits for the Colombian market, and requested that Foco 1 identify a roadmap and assess other implementation requirements.

A key observation of the Foco 1 team is that given the current market design, there is a risk that a series of incremental design reforms will be implemented, motivated by multiple desirable objectives, but without a guiding vision of the end-state design. Some members of the team believe that such an incremental approach can result in "unintended consequences," in which objectives are not achieved and continuous redesigns are needed, due primarily to the *lack* of a foundational design which incorporates sufficient locational and intertemporal constraints and provides incentives for efficient operations and investment. We thus begin with a brief description of an end-state, which we believe will be adaptable to future operational needs and introduction of new technologies.

1. The future design of the energy and ancillary service markets

In many regions, certain core design features of the short-term energy and ancillary service markets have been fairly stable once implemented, and provide the framework for other elements – such as new market products or pricing mechanisms – which can be modified as system conditions change and new technologies are introduced.

The study team jointly supports several core design elements for the *end-state* of the Colombian market (and allowing for many further improvements to this core design). These include the following:

- A day-ahead market with binding (first) financial settlement.
- A balancing or real-time market with binding (second) financial settlement. All deviations from the day-ahead schedules are re-settled at real-time market prices.

- Three-part bidding for all supply, demand and storage resources, which includes start-up costs, minimum load costs and energy offer curve.
- Additional bidding components to reflect resource characteristics as needed for operational efficiency, including operational parameters, combinatorial options for multi-stage resources, and unique features of newer technologies such as state-of-charge management for energy storage.
- Security-constrained unit commitment and security-constrained economic dispatch, with use of a full network model in each market iteration.
- Automated local market power mitigation in each market.
- Co-optimization of energy and bid-based ancillary services in each market.
- Nodal pricing (or locational marginal pricing, LMP) of energy in each market, with the nodal price used to settle supply and demand resources, and an integrated zonal price based on the nodal prices used to settle inelastic demand. The nodal price includes both marginal energy and marginal congestion components, and could also include a marginal loss component.
- Hourly market pricing in the day-ahead market, with sub-hourly pricing (e.g., 5 minute) in the real-time market.
- Make-whole payments to ensure that no resource which bids into, and is selected in the auction markets, can subsequently lose money based on following XM instructions.

This end-state design does not include all design elements which may be considered desirable, but is compatible with them. For example, these additional elements subsequently introduced could include financial transmission rights to hedge congestion costs, scarcity pricing, and financial or virtual trading within the day-ahead energy market.

As discussed further below, the study team does not agree on the benefit of introducing intra-day markets before the full implementation of the core market design elements. However, the team has concluded that since CREG has an advanced design for short-term market modernization, which is expected to improve efficiency and price formation, the viable alternative for short-term market improvement is to continue development of that design. However, at the same time, the design of a locational marginal pricing (LMP) model (or nodal pricing) should begin in 2020, with the objective of completion in 2021, and subsequently run in parallel with the binding dispatch model and intraday markets. This would be done so that the resulting nodal prices can be used on a preliminary basis to improve congestion management as well as the transparency of the market and price formation. This approach would also begin to facilitate the introduction of new generation technologies at the central and distributed level by giving location signals.

Two pathways to achieving market design objectives

Implementation of new or revised short-term market designs is a multi-year process, which requires investment of time and resources as well as concurrent adjustments by market participants and bilateral contractual mechanisms and exchanges. As such, the team has different initial views on the costs and benefits of alternative implementation pathways for achieving the end-state design.

As a starting point, the team has identified two basic pathways to market design implementation, which we have called "phased reforms" and "accelerated reforms."

<u>Phased reforms pathway</u>

The *phased reforms pathway* assumes that this full transition should take a longer period (around 5 years) to implement, so as to preserve the stability and simplicity of current energy pricing and contracting, and due also to other factors.

This approach, which reflects current perspectives at CREG and XM, would continue the single system price method in the energy market but also introduce three-part bidding and automated local market power mitigation into the day-ahead market, and the implementation of intra-day markets and real-time balancing markets using the same pricing method.

- The major foreseen advantage of this pathway is its incremental approach to market design improvements.
- The major disadvantage of this pathway is that it will not provide locational price signals or remove reconciliation charge payments for many years. It will also inhibit improvements to price formation.
- In the view of some members of the team, another important disadvantage of a phased approach combining incremental reforms in several aspects of the design (e.g., also beginning to include new ancillary service products), based on the experience of other market transitions in the US and around the world, is the "unintended consequences" of incompletely specified market designs, which could require ongoing remedies. [6]

<u>Accelerated reforms pathway</u>

The *accelerated reforms pathway* would refocus market design reforms for the next 2-3 years on the transition to an integrated design which includes all the core elements of the end-state design

[6] While the team has not conducted a detailed "stress test" of the proposed current design reforms, many of which are still in development, types of unintended consequences observed elsewhere could include continued opportunities for generation market power (e.g., in intra-day markets) and continued inefficiency in dispatch and scheduling between day-ahead and real-time requiring persistent manual operator adjustments.

listed above. In particular, this would begin the implementation of nodal pricing much earlier than the phased reform pathway as a means to resolve the inefficiencies in congestion management and improve price formation.

- The major advantage for this pathway is that it can rapidly improve market transparency, efficiency, and price formation, using tested designs and software, as well as facilitate the introduction of new technologies. Appendix 1 reviews some of the immediate benefits measured in the US markets which undertook similar reforms, including transitions from zonal to nodal pricing.
- Due to the need to focus on the core design elements, this pathway would delay the introduction of intra-day markets until there is sufficient experience with the other key elements of the end-state design.
- If Colombia pursues the accelerated reforms pathway, decisionmakers can draw from the experiences of regulatory entities and ISOs in other countries which have made this transition, particularly those in the United States and Mexico. There is always a risk of implementation difficulties and cost overruns if these transitions are not managed carefully, but at the same time, there is now extensive experience with such transitions, including several which were completed at low cost and on 2-3 year time-frames.[7]
- A further potential disadvantage is that it would require a complete focus on the full set of end-state market design elements simultaneously. It may also create more near-term market impacts to the valuation of existing generation and bilateral contracts, as well as shifts in costs to load, although mitigating measures are readily available for some of these impacts, such as use of aggregated nodal pricing points for load financial settlement and trading hubs.

The next sections discuss elements of these implementation pathways in more detail.

[7] In the United States, ISOs made the transition to the basic "end-state" design above from very different starting points. For example, PJM and New York ISO implemented these designs in one step or in stages from the prior cost-based tight power pools in those regions, which had several decades of joint operating experience. MISO and SPP implemented those designs in large, multi-state regions which had not previously operated on a coordinated basis in real-time. CAISO, ISO-New England and ERCOT began with different zonal pricing designs (with ISO-New England making the transition from a tight power pool), and then subsequently made the transition to an "end-state" design (see Appendix A). Of these latter three, ISO-New England implemented the revised market design in 2-3 years at very low cost, while ERCOT took many more years and experienced significant cost overruns. CAISO was somewhere in the middle of these two. There is extensive documentation on these market design and software transitions which can be reviewed by the Colombian government.

Comments on selected market design elements

This section provides additional comments on selected market design elements discussed above. As will be discussed, there is substantial agreement among the study team regarding many of these elements.

Multi-part bidding

The Colombian market design has already included more complex three-part bid structures for its ex post market price calculation, but the method of price determination encourages exercise of market power; the study team agrees that the market design should be modified to allow these bid components in the determination of market prices directly, which (along with automated market power mitigation) will improve incentives for submitting bids which reflect actual marginal opportunity costs. This approach is compatible with both pathways for design reforms reviewed by the team.

Market optimization

XM has made notable improvements in the use of optimization as a component of the energy market design, for ex post analysis. The team agrees with the general design reform of conducting security-constrained unit commitment (SCUC) in the day-ahead market and within the operating day, followed by security-constrained economic dispatch (SCED) in the real-time market using market bids to minimize total procurement costs.

The Foco 1 team find that some of this potential efficiency improvement will be offset by continuation of the single system price congestion management method. Alternatively, If SCUC/SCED is used to establish nodal prices, then there will be more improvements in price formation, including market price transparency.

Market pricing

The Colombian market design calculates both a single system energy price hourly and individualized reconciliation payments to resources which are re-dispatched up. The *phased reform* pathway would continue this approach when adding additional intra-day and balancing markets. In contrast, with the nodal pricing we envision as the end-state design there will be a single market-clearing price for each pricing location (which may include one or more generating units). However, for purposes of settling loads or facilitating forward trading, all markets with nodal pricing utilize aggregations which provide averaged nodal prices over larger regions. Aggregated nodal pricing is a fully consistent method to create single prices in utility zones or preferred generator delivery areas, which can be used to reduce shifts in wholesale costs to load or as mechanisms to simplify bilateral contracting for sellers and buyers.

Market power mitigation

The team agrees that automated local market power mitigation methods should be implemented which conduct market power mitigation directly on bids prior to auction market clearing. This design attempts to minimize *ex post* interventions for purposes of market power mitigation. This design for market power mitigation is considered compatible with any market structure, and could be used in any further design reforms. Appendix 2 reviews the methods used in several U.S. ISOs.

Intra-day markets

As noted above, the study team diverges on the benefits provided by intra-day markets using the current single system price congestion management system. Some study team members support this implementation as a component of the *phased reform* approach. Other team members believe that implementation of such intra-day markets should follow the completion of the *accelerated reforms*, which could provide more immediate benefits. The reason for recommending a delay of implementation is because the U.S. wholesale markets which currently operate with the "end-state" design described above have not found that such intra-day markets would be sufficiently liquid or improve market efficiency.[8] Hence, it appears to those who support the accelerated reforms approach, that the benefits of those reforms should be measured on their own before consideration of new intra-day markets.

However, we note that in order to reduce the possible lack of liquidity the CREG has developed a method to require "total arbitrage." That is, in each session of the intraday markets all generators must submit offers and declaration of availability.

Financial settlement

The current design conducts one financial settlement per hour of day, as determined by the pricing in the ex post process. The intra-day dispatch market proposed for the *phased reforms* would have additional hourly settlements based on the set of hours in each iteration. In the alternative, the two-settlement system design proposed for *accelerated reforms* generally has two settlements for all hours of the day, day-ahead and real-time, although additional real-time settlements have been implemented.[9] The two-settlement system design is also compatible with

[8] Team members point out, based on economic research from intra-day markets in Europe, that there is a concern that such markets would not be sufficiently liquid and will be primarily used by large players to exercise unilateral market power. However, all team members agree that intra-day markets could be compatible in principle with any of the market designs reviewed.

[9] For example, California ISO has a Fifteen Minute Market (FMM) in real-time, as well as a 5-minute market, with a financial settlement in both periods. The 15-minute market clears first, with the 5-minute market used to perform additional dispatches within the 15-minute periods. All the other U.S. ISOs only conduct 5-minute settlement.

an intra-day design for multiple hour market re-settlements, if market participants request such a design.

Price formation

The current market design establishes an ex post simulation of the prior day of operations. The study team agrees that this method doesn't provide the appropriate incentives for price formation, and that shifting to a SCUC with three part bidding and automated market power mitigation, along with an accurate representation of the network model for the full sequence of day-ahead to real-time market solutions, will improve price formation. This includes efforts to reduce operator actions in both market processes (see also FERC 2014b).

As with other design improvements discussed above, members of the study team find that some of this potential efficiency improvement will be offset by continuation of the single system price congestion management method. If SCUC is used alternatively to establish nodal prices, then there will be more transparent improvements in price formation.

2. Energy market design

While the core energy market design features were discussed above, this section examines some additional design details which are relevant to the Colombian energy market.

The study team agrees that the energy market prices used for financial settlement should reflect operational constraints on resources as well as transmission network constraints. Table 1 compares some of the attributes of the primary energy pricing methods under consideration. This table includes zonal pricing, although the team does not recommend a transition to zonal pricing as an incremental reform to the energy market.[10]

As noted, the study team agrees that nodal pricing should be considered the end-state design for market design. The combination of nodal pricing and the other features of the market design

[10] Starting from the current market design, an incremental reform would establish a zonal pricing design (which was already tried in Colombia, and is discussed here for completeness); zonal pricing typically follows similar procedures to the current market design to establish the prices in each zone. We do not recommend zonal pricing as the next reform of the market design for the following reasons: (i) zonal pricing will provide more transparent information about the economic costs of one or more major inter-zonal transmission constraints, but not about any other transmission constraints within the zones; (ii) zonal pricing still has reconciliation costs which are not reflected in market prices; and (iii) Continuous modification of pricing zones to reflect changes in actual congestion have not proven to be an effective design solution; nodal pricing adjusts directly to any change in the transmission network topology.

discussed above, create a more complete framework for economic efficiency and improved price formation while addressing transmission and operational constraints.

- Nodal pricing instantaneously conducts least cost congestion management at all stages of the market sequence; there is generally no need for additional dispatch adjustments (see further discussion below). XM currently performs the physical dispatch of the plants considering their technical characteristics and the effect of network restrictions, thus optimizing to reflect network congestion. However, decoupling this optimization from price formation does not yield an efficient price signal; moreover, local market operations are carried out after the physical dispatch.
- Nodal pricing can include both marginal congestion and marginal losses.
- Nodal prices can be aggregated to provide load with a single, averaged wholesale price and at generator trading hubs if useful to simplify bilateral contracting between buyers and sellers. This may also be useful for transitioning existing long-term contracts which currently reference the single system price.
- Nodal pricing adjusts to all changes in transmission network topology which are captured daily in the market model; there is no need to establish fixed zones.
- While there can be many nodal prices, individual generators only need to know the price at their node; the prices at other nodes generally do not affect their bidding incentives (unless there is locational market power, which needs to be mitigated).
- Nodal pricing will eliminate uplift under the current market design due to the congestion component of reconciliation payments; nodal pricing does not eliminate the uplift due to the start-up costs for individual generators (see also FERC 2014a).
- Under the two-settlement system design with nodal pricing, the factors affecting price formation become more transparent; XM and CREG can evaluate further design and operational reforms to ensure that market prices accurately reflect marginal opportunity costs.

Participation in the energy market for new technologies

Modifications of the energy market design should facilitate the entry and efficient operations of new types of resources, including NCRES, demand response and energy storage.

As a general matter, experiences in other market regions have clarified that market design and advances in optimization methods have a significant impact on the participation of new technologies. A day-ahead market with binding financial settlements will facilitate participation of both demand response, to allow for preparation for load reductions in real-time, as well as energy storage, which can develop an optimal schedule for charging and discharging based on less volatile day-ahead prices before potentially offering into the real-time market. The energy market design should allow for explicit consideration of operational constraints – notably ramp rates and other intertemporal constraints – so that market prices reflect the impact of these constraints. Locational pricing sends the correct signals for location of resources which are intended to address peaking needs, such as demand response and energy storage.

Clearly specified market participation models for new types of resources should be introduced for the energy market (e.g., FERC 2018). These models should allow for representation of the following:

- Minimum resource sizes, minimum bid increments, minimum continuous energy for the different market intervals (day-ahead, real-time), and other relevant operational requirements.
- For energy storage, the options for managing state-of-charge (SoC) by the storage operator or system operator and any additional operational constraints needed for efficient operations of such devices (particularly batteries with limitations on cycling), including maximum and minimum SoC, maximum charge limit, maximum discharge limit, maximum and minimum charge time, maximum and minimum run time, minimum charge and discharge limits, and charge and discharge ramp rates.

Table 1 – Attributes of single system price versus zonal or locational pricing

	Single system price	Multiple zone pricing	Nodal pricing
Number of energy market prices	One.	Two or more prices reflecting frequently congested subregions.	Hundreds.
Market price to generators	Single system price considering only generation restrictions (ramps, technical minimums, etc.), as-bid (redispatch).	Zonal price; as-bid inter-zonal redispatch; as-bid intra-zonal redispatch.	Nodal price.
Market price to loads	System price.	Zonal price.	Load aggregation prices.
Market price components	Energy and average losses only.	Energy only.	Energy, marginal congestion, and marginal losses.
Trading points	System.	Zones (fixed for defined periods).	Generator nodes, generator trading hubs (nodal aggregations), load aggregation points.

	Single system price	Multiple zone pricing	Nodal pricing
Sources of uplift – (1) redispatch due to congestion	Real-time only: Adjustment bids; payments to generators dispatched up.	Method can vary. CAISO prior method: Day-ahead: Adjustment bids used to clear inter-zonal congestion; payments to generators dispatched up (Bid minus zonal price); Real-time: adjustment bids for intra-zonal congestion.	None.
Sources of uplift – (2) multi-part bidding	Bid sufficiency guarantee for all resources selected in auctions.	Bid sufficiency guarantee for all resources selected in auctions.	Bid sufficiency guarantee for all resources selected in auctions.
Bid mitigation method – system	Bid cap.	Bid cap.	Bid cap; may include conduct-impact test (e.g. NYISO).
Bid mitigation methods - local	Automatic mitigation of bids to cost-based bid or prior average bid in congested locations (based on shift factor threshold on congested elements).	Automatic mitigation of bids to cost-based bid or prior average bid in congested locations (based on shift factor threshold on congested elements).	Automatic mitigation of bids to cost-based bid or prior average bid in congested locations (based on shift factor threshold on congested elements).
Do bids mitigated due to congestion set market prices?	No, all adjustment bids, whether mitigated or not mitigated, are settled through separate payments.	No, all adjustment bids, whether mitigated or not mitigated, are settled through separate payments.	Yes.
Examples of current or former markets	Colombia, Australia, Alberta; Previous: ISO-New England.	Previous: CAISO, ERCOT.	All U.S. ISOs.

Box 1 – Experiences with the transition from zonal to nodal pricing in the United States

Of the seven ISOs in the United States, four made a transition from zonal to nodal pricing after beginning market operations: PJM (transition in 1998), ISO-New England (2003), California ISO (2009), and ERCOT (2010). Of these transitions, all were accompanied by significant market participant engagement, and in some cases, concerns regarding a more complex market design. As we reviewed these experiences for the Foco 1 report, we found that in all cases, despite some proposals to undertake interim measures (e.g., additional pricing zones to improve congestion management), each of these markets made the transition to nodal pricing in one step. In addition, both internal and external market monitors provided empirical evidence of immediate short-term efficiency improvements, and there are also some research studies making this finding (e.g., Wolak 2011b). ISO-New England had an energy market design very similar to the Colombian market from 1998-2003, with a single system price calculated using basically the same method as done by XM. The details of how ISO-New England transitioned to nodal pricing over about 2-3 years may thus be of particular interest to Colombian regulators. Other lessons can be drawn from the other markets. Appendix 1 details these findings.

3. Ancillary services and market mechanisms

The Colombian market design is currently undergoing a reform to its short market that includes development of a binding dispatch in the day-ahead time-frame, followed by intraday markets and a balancing market, which will support co-optimizing the centralized procurement of energy and bid-based ancillary services in each of these markets. This paper will not review the full set of possible new ancillary services and market designs for those services, but will focus on general principles for market design and additional recommendations.

- Where appropriate, primarily for frequency regulation and operating reserves, bid-based market mechanisms should be used to procure ancillary services.
- Co-optimizing the centralized procurement of energy and bid-based ancillary services in the day-ahead and real-time markets could yield significant cost savings to Colombian consumers.
- Locational pricing of operating reserves for improved reliability can be developed as an extension of the market design.

Demand response and energy storage are playing a much greater role in the provision of ancillary services in many countries, with NCRES and distributed energy resources also increasing their participation. Box 2 provides some notable recent international experiences with such participation.

Table 2 summarizes existing barriers to participation of these types of resources in the Colombian market. Box 2 reviews some recent experiences with high levels of penetration of these resources in U.S. ancillary service markets, and there are also examples from other countries.

Integration of these new types of resources into the ancillary service markets has been facilitated by new types of design features:

- Performance payments for fast response capabilities and accuracy of response (in the United States, required under FERC Order 755 (2011) for FERC jurisdictional ISOs).
- Reductions in minimum resource sizes: the participation, in addition to generators, of demand directly for large UNR (greater than 1 MW, which was recently reduced from 5 MW and could be potentially reduced further in the future) and/or through marketers and/or demand aggregators and agents who are enabled to provide complementary services through storage technologies [PC]; to facilitate participation of aggregated DER, smaller participation sizes and bid increments can be helpful; the smallest such sizes observed in other countries is 100 kW minimum size.
- Large scale NCRES with advanced inverters are offering a full range of ancillary services in other country markets (wind, solar pilots).
- Improvements to market participation models (e.g., FERC 2018). For example, storage models should accommodate resource and bid parameters and constraints discussed above in the energy market section.

Table 2 – Current barriers to wholesale market participation by energy storage and DER

Service	Market or procurement description	Current barriers to ESS/DER participation
Energy arbitrage	Energy market time-shift by charging in low cost hours and discharging in high cost hours.	Ex post calculation of energy prices reduces opportunities for efficient operations by energy storage; lack of locational energy price signal.
Primary frequency response	Generator head room requirement, no market product, penalties for non-compliance.	No market product, so energy storage cannot be directly valued; only as avoided penalties by conventional generation.
Frequency Regulation/AGC	Market product which provides energy market price for units on AGC.	Market design developed for generation; adaptation to energy storage will require consideration of additional rules and mechanisms, such as energy neutrality of AGC signal, performance payments, and other design elements.

Box 2 – Participation by new types of resources in ancillary service markets

ISOs around the world have experienced different degrees of ancillary service market participation by new types of resources, including demand response, energy storage, NCRES and dispatchable DER. Of particular interest are cases where these resources have already achieved a high degree of participation. In the United States, demand response was the first type of new resource to demonstrate significant participation in ancillary services, primarily contingency reserves. For example, in 2018, demand response provided 24.5% of PJM's Tier 2 Synchronized Reserves (only combustion turbines provided more), and 2% of PJM's Regulation (which includes load control technologies as well as behind-the-meter batteries). In ERCOT, load resources are allowed to provide up to 60% of responsive reserves, and now offer supply of over 5 GW against an hourly procurement requirement of around 3 GW. Possibly the most unique US case-study to date is the rapid expansion of lithium-ion batteries in the PJM Regulation market. In 2012, PJM implemented a number of reforms to its Regulation market design to facilitate the entry of newer technologies (and to respond to FERC directives to introduce performance payments). These reforms included creating a new "fast" AGC control signal (called RegD) along with continuing the "slow" AGC signal (RegA), a substitution method by which RegD could replace RegA while capturing the additional control benefits of RegD (meaning that 1 MW of RegD was credited initially with displacing more than 1 MW of RegA, as a function of the quantity of RegD selected), creating a 15-minute energy neutral control signal for RegD to facilitate utilization of short-duration batteries, and adding a performance payment. The result was to facilitate the rapid entry of batteries over the next few years, most of which were merchant projects (that is, took full market risk). There were no batteries in the market prior to these design reforms. By 2016, almost 300 MW of new short-duration batteries accounted on average for over 40% of PJM's Regulation supply, as shown in the table below. This entry primarily backed coal plants out of the Regulation market, with a lesser effect on natural gas and hydro participation. Over 2015-2016, a number of operational and market design issues began to emerge, which led to declines in battery supply. Notably, PJM system operations found that it could not operate a large amount of batteries while maintaining 15-minute energy neutrality without at times adversely affecting area control error (ACE). In addition, high prices experienced in the market over 2014-2015 had induced a high battery entry, leading to a decline in market prices. There were other problems. These led PJM in 2017 to cap RegD procurement and seek changes to the market rules, including shifting to a 30-minute RegD control signal cycle. These proposed reforms were controversial with the storage plant owners and the case is at FERC for settlement. Battery share of the market declined over 2017-18 as some projects exited and others added more constraints on their operations to reduce throughput. Nevertheless, the market result is one of the more dramatic demonstrations of the potential for new technologies in ancillary services.

Table – Battery revenues and market share in the PJM Regulation market, 2014-18

Year	Battery share of market (%)	Avg. battery revenue ($/MW of Regulation provided)
2014	16	36.78
2015	27.6	27.07
2016	41	15.39
2017	30	28.25
2018	21.2	33.21

Sources: Monitoring Analytics, PJM State of the Market reports, 2015-2018.

4. Market power mitigation

Market power mitigation in the short-term energy and ancillary service markets takes place through several primary mechanisms:

- structural changes to ownership of market resources to improve market competition;
- reducing barriers to entry for new resources; and
- bidding restrictions in market operations to reflect the impacts of transmission network constraints and peak demand conditions.

There are many variants on how market power mitigation is implemented around the world. Based on our review, CREG should modify its market power mitigation mechanisms to better reflect the opportunities for market power due to local transmission network constraints. However, we have not provided specific recommendations. At a general level, a local market power mitigation (LMPM) mechanism is a pre-specified administrative procedure (written into the market rules) that determines: (1) when a supplier has local market power worthy of mitigation, (2) what the mitigated supplier will be paid, and (3) how the amount the supplier is paid will impact the payments received by other market participants. Ideally, the LMPM mechanism is automated and applied sufficiently to reduce exercise of market power but not excessively dampen market prices. Appendix 2 surveys the methods of LMPM in different ISOs.

5. Additional market design features

Colombia should anticipate further adaptations to the short-term markets when considering the types of designs to adopt and the timing of the implementation. Some of those features were discussed above, such as additional optimization mechanisms for energy storage. Other features which have been implemented in other markets include the following.

Virtual transactions

Virtual transactions – offers and bids submitted by financial entities at allowed pricing locations – can be introduced into the day-ahead market to improve the efficiency of the day-ahead to real-time market sequence. Virtual transactions can be introduced simultaneously with the implementation of the day-ahead market with locational pricing, or after some period of market operations. Market design choices can include the types of transactions allowed (supply, demand, spreads), the locations used for transactions (internal nodes, aggregations of nodes, external nodes), and the allocation of uplift to such transactions.

Scarcity pricing

Scarcity pricing can also be introduced to improve alignment of high energy and ancillary service prices with system conditions during periods of shortage without requiring submission of high market bids; this will in turn improve the responsiveness of existing resources, facilitate entry of demand response, and provide indicators of operational needs, such as ramp constraints. Optional designs include nested ancillary service scarcity penalty factors or an operating reserve demand curve.

6. Roadmap

Figure 1 represents a reasonable roadmap which incorporates the perspectives of team members.

The team concluded that since CREG has an advanced design for short-term market modernization, which is expected to improve efficiency and price formation, the viable alternative for short-term market improvement is to begin with the CREG design, but that in parallel, in 2020 the design of the "end-state" design with multinodal pricing model (LMP) also begins, with a target for completion by end of 2021 and methods identified for a transition from the existing design as needed.

Also, from this date the LMP model could be run in parallel to the binding dispatch model and intraday markets, in such a way that the decision of the application of nodal prices is made with the necessary adjustments detected in the LMP simulations, as a means to solve the congestion management inefficiencies and improve the transparency of the market, efficiency and price formation. This proposal would facilitate the introduction of new generation technologies at the central and distributed level by giving locational price signals.

While this approach is reasonable, some members of the team also believe that the more direct, accelerated reform pathway would also be feasible, and are willing to participate in any subsequent consultations on this pathway.

Focus No. 1 - Competition, participation and structure of the electricity market

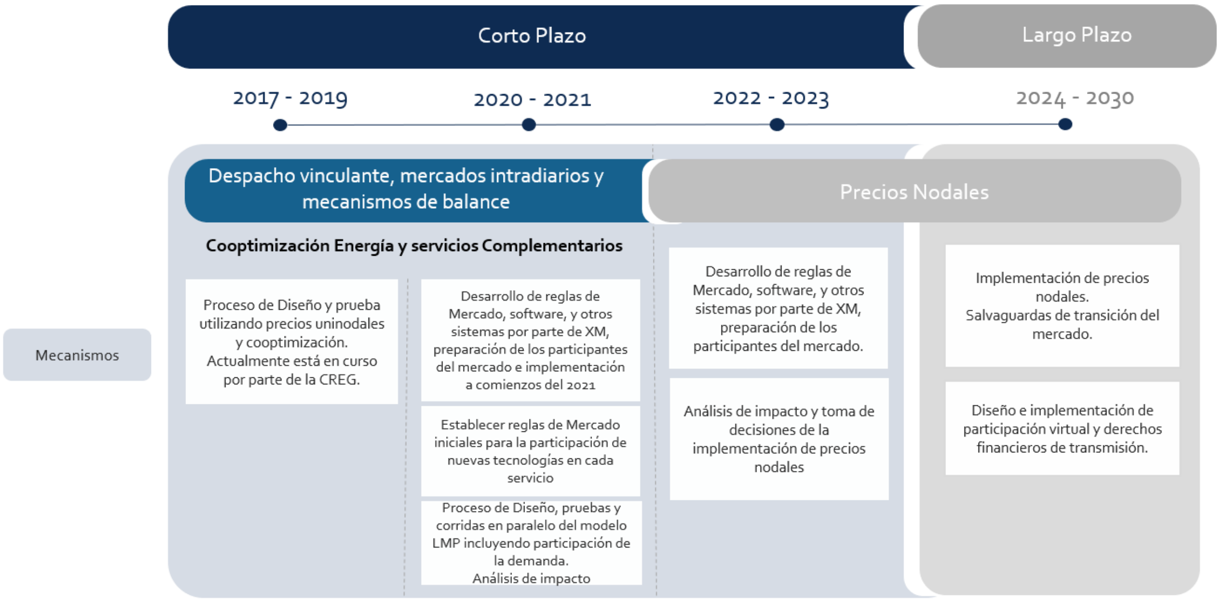

Figure 1 – Proposed roadmap for short-term market design reforms

B. Improvements to design of contracts and bilateral markets

General Observations

New plants typically require fixed-price or indexed long term forward contracts for a significant share of the expected output of the plant in order obtain the necessary up-front financing to construct the plant. Existing plants sign fixed-price or indexed forward contracts to reduce their exposure to short-term prices and reduce the volatility of their financial results. These contracts supplement the revenues earned from the existing reliability charge mechanism. Generation unit owners and retailers also participate in the bilateral over-the-counter (OTC) market to hedge their medium-term price risk, typically 2 to 3 years into the future.

The OTC market in Colombia, which represents the only viable alternative to government sponsored auctions,[11] suffers from the following weaknesses:

- Negotiated prices are not available to the public. This situation favors large and integrated incumbents, who enjoy the benefits of this partial market information. This creates a barrier entry of capacity from new market participants that do not have access to this information.
- Prices for the unregulated demand in Colombia are typically well below prices for the regulated demand.
- There is a lack of anonymity, because bilateral contract price depends on the counterparty. This implies that contract prices mix pure commodity risk and credit risk.
- There an extreme diversity of types of contracts traded. This lack of standardization can create an obstacle for the eventual use of this data to construct a credible forward curve for energy.
- Non-vertically integrated retailers and generation unit owners and small participants have limited access to bilateral contracts.
- Opaque counterparty risk management makes it difficult to determine if the bilateral forward market is adequately protected against default.

[11] The NCRES auction in October 2019 represents a rare exception where a government-sponsored auction resulted in bilateral contracts.

A liquid, transparent and standardized market for hedging at time horizons necessary for new entry to compete supply the energy is essential to promote competition in the short-term market and facilitate the entry of new generation capacity.

Regulated sector retailers are typically able to pass-on the portion of unhedged short-term price increases in their monthly retail price. The generation cost component of the regulated retail tariff is a weighted average of (i) the bilateral contract prices in the previous month for the retailer, (ii) the bilateral contract prices observed for the whole market, and (iii) the short-term wholesale market purchases of the retailer.[12] This retail pricing mechanism provides a limited incentive for regulated retailers to purchase bilateral contracts to hedge their short-term market price risk.

A vertically-integrated supplier is indifferent to the short-term energy price to the extent it can pass it on to its consumers. However, its generation unit naturally prefers higher prices. The current structure places in an unfair position non-integrated participants; furthermore, a larger amount of final demand served by vertically-integrated suppliers from their own generation units tends to reduce liquidity in the market for fixed-price forward contracts.

CREG 131 of 1998 (Article 4) states that every unregulated user must operate with a single retailer. This allows free consumers to switch providers, but makes it more difficult for free consumers to create a portfolio of contracts with different suppliers, which can reduce the extent of competition in the market for bilateral contracts for energy for free consumers.

Anonymous and Standardized Contracts

CREG 114 (2018) opens the door for the market itself to propose Anonymized and Standardized Markets (MAEs, for their Spanish initials). CREG has propose to form this market (MOR) for over a decade. MAEs would solve the problems of the lack of transparency, lack of anonymity, lack of standardization of contracts. These MAEs would also require standardized mechanisms for resolving counterparty risk such as clearinghouse.

CREG 079 (2019) seeks to align the bilateral market with general principles of organized markets, specifically avoiding the possibility that market participants arbitrage different market environments. In particular, it posits that:

- Price transfer (from retailer to regulated consumer) is feasible only through (i) contracts that are registered through formal auctions organized by retailers, (ii) spot market purchases, or (iii) contracts registered through licensed MAEs (standardized and anonymized markets, defined in CREG 114).

[12] See page 8 of CREG Resolution 119 of 2007 for a description of this price-setting process.

- Formal auctions organized by retailers should define standardized fixed-price contracts (that could be indexed to official government price indices) for fixed (or pre-determined patterns) hourly quantities of energy.
- Purchases through formal auctions organized by a retailer to an integrated generator are limited (with limits decreasing from 50% of its regulated demand in 2020 to 10% in 2025).
- Auction results (average prices) should be made available to the public.

Recommendations

- The regulation should incentivize participants to create markets that are in the best interest of a well-functioning Wholesale Energy Market.
- MAEs should be a good starting point for creating liquid forward or future markets. However further scrutiny should be focused on retail design:
  - A limit should be placed on the percentage of the counterparty risk costs that retailers are able transfer to users (percentage of the total, or up to a certain amount in pesos).
  - Strengthen the audit process for transferring these costs. Because these costs area paid in full or in part by users, there should be absolute transparency in calculating these costs.
  - Require MAEs to define minimum standards of credit safety in its guarantee scheme. For example, require risk models to obey minimum levels of confidence (95%, say).
    - To define the limit of the cost that can be transferred to the user, the calculation can be made with a given level of confidence (it can be the same 95%) above which it is the retailer who must bear the cost of the guarantees. This puts pressure on retailers to develop mechanisms to balance credit security against market development.
  - Force retailers to report to CREG all contracts made with related parties (names of related parties, price, volume, date). Keeping this information hidden is a safe-conduct for related parties not to manage their conflict of interest.
  - All forward market transactions (particularly those among related parties) must be carried out at market prices. This can be supervised by the SSPD or by a self-regulatory entity that must have access to all information from the markets.
  - Moreover, this information on transactions in these bilateral markets must be made available (without names of buyers and sellers or other confidential information) to the public in an accessible manner.
- It is imperative to design regulation that aligns the interests of the retailers of the regulated sector with those of the consumers. This same situation should be sought for retailers.
  - Eventually, a transparent and modern market would allow users to switch retailers efficiently, incentivizing retailers to respond to users´ risks and objectives. This situation should be a long term goal.

    - A direct way to achieve incentives alignment is to avoid a pass-through of 100% of the spot market purchases. Using the market average of contracts that expire in a given period as shown in CREG Resolution 119 of 2007 exposes the retailers to the risk of the short-term market price, which motivates them to participate in the fixed-price forward contracts market.
- The unregulated demand should be able to negotiate independently and directly with generators. The existence of framework contracts ("contratos marco") for widespread use across the industry can facilitate these transactions in the OTC market. Now, if retailers are to be kept as intermediaries for the unregulated demand, the latter should be able to establish simultaneous relations with as many retailers as desired.

Roadmap

Table 3 – Roadmap for reforms to contracts and bilateral market mechanisms

Recommendations	**2020-2021**	**2022-2023**	**2024-2030**
Parametrization of incentives for agents to participate in MAE.	Definition of MAE principles of pass-through (prices and costs) to regulated demand. Definition of MAE principles of credit requirements.		
Alignment between MAEs and other markets.	Resolution of credit aspects of private auctions. Transparency of private auctions.		
Alignment of incentives between retailers and regulated users.	Align exposure to spot prices and risks.	Promote more competition from retailers. Allow users to know prices of basic services from different retailers.	Develop ample transparency and facilitate switching providers for final users.
Unregulated demand hedging dynamics.	Allow demand to sustain relationships with as many retailers as desired.		

C. Long-term Resource Adequacy mechanism

There is general agreement among the team members that a long-term resource adequacy mechanism is required for the Colombian wholesale electricity market. A finite offer cap on the short-term energy market, the limited deployment of interval metering technology, and the inability to curtail only those customers that fail to purchase sufficient energy in the forward market for delivery during system scarcity conditions implies the existence of a "reliability externality." This externality arises because no individual retailer or large consumer bears the full cost of failing to purchase sufficient energy to meet demand under extreme system conditions. This outcome justifies the need for a regulator-mandated mechanism to ensure that there will sufficient energy available to meet demand during El Niño and other system scarcity conditions.[13]

Given this starting point, there are still several different possible regulatory and/or market designs which could achieve long-term resource adequacy, and Foco 1 team members have different views on which of these would result in a least cost mechanism for Colombian consumers. The team has evaluated two approaches which differ in terms of the product used to ensure long-term resource adequacy. The first approach would maintain the current firm energy concept and the second approach would focus instead on an aggregate energy concept.

- The first approach would maintain and attempt to eliminate the defects in the current firm energy-based Cargo por Confiabilidad (CxC) revealed during the most recent El Niño event. These defects are described in McRae and Wolak (2016 and 2019).
- The second approach would transition to a regulator-mandated standardized energy contracting approach that ensures that all retailers and free consumers have purchased sufficient energy in the forward market at various horizons to delivery to cover future system demand during all hours of the year.

Members of the Foco 1 disagree over which these two approaches should be pursued as well as over specific details of the design of each of these two approaches. This section first summarizes the defects in the existing reliability charge mechanism and relevance of several historical rationales for this mechanism. This is followed by a discussion of the economic principles governing the analysis. Finally, there is a description of a proposed long-term resource adequacy mechanism.

[13] See Wolak (2019) for a discussion of the logic underlying that "reliability externality" that justifies the need for a regulator-imposed long-term resource adequacy mechanism.

Analysis of the Reliability Charge mechanism

There are three shortcomings in current reliability charge mechanism:

1. As demonstrated in McRae and Wolak (2019) it enhances the incentive for large suppliers to exercise unilateral market power in the short-term market for energy when critical system conditions arise.
2. The results in McRae and Wolak (2019) show that it led to higher costs to consumers and lower average water levels, particularly during expected El Niño periods. Therefore, it does not appear to be an effective mechanism to balance system reliability and market efficiency.
3. The certainty of income of provided by reliability charge mechanism dulls the incentive of suppliers to sell fixed-price long-term contracts for energy and buy and sell other hedging instruments. This can reduce liquidity and the volumes traded in these markets.

Several of the challenges that motivated the introduction of the current reliability charge are significantly less relevant today. Technological change and recent government policy decisions have also introduced a number of new reliability challenges for a long-term resource adequacy mechanism. These considerations should motivate a fundamental review of alternative designs.

(1) The reliability charge was originally designed to ensure that the hydroelectric-energy dominated system in Colombia was backed up with sufficient thermal generation capacity to meet system demand during low water conditions. The Colombian government has recently taken actions to increase the amount intermittent wind and solar generation capacity. These intermittent generation technologies are poorly suited to participate in the existing reliability charge mechanism.[14]

(2) The poor performance of some generation units (the most egregious example being Termocandelaria) during the most recent El Niño event has revealed shortcomings in the compensation and penalty mechanisms designed to ensure firm energy sold under the reliability mechanism will provide this firm energy during El Niño events.

(3) Historically, the reliability charge mechanism has played a key role in driving the expansion of the generation capacity in Colombia. Forward reliability charge auctions clear based on price and quantity offers of new generation capacity, with existing plants participating as price-takers in these auctions. Therefore, forward capacity prices should

[14] The firm energy of a generation unit is defined as amount of energy the unit can provide under extreme system conditions. Because solar and wind generation units produce when the underlying resource is available, defining the firm capacity of these resources is far less straightforward that determining the firm energy of a thermal resource or even a hydroelectric resource.

cover the expected cost of investing in new generation capacity net of expected energy and ancillary services revenues. This logic implies that long-term resource adequacy mechanisms should be judged in large part based on the economic signals they provide for investments to achieve the least cost mix of new generation capacity to serve demand under all possible future system conditions.

(4) The existing reliability charge mechanism has made commitments to generation unit owners up to 2043. Changing these commitments is likely to be an extremely costly and time-consuming process. Therefore, any changes in the existing reliability charge mechanism should attempt to honor these existing commitments.

(5) Finally, the Foco 1 team believes in the importance of developing a liquid forward market for energy and at time horizons to delivery that allow new entrants to compete with existing firms to supply this energy. Consequently, an important feature of any proposed long-term resource adequacy mechanism is the extent to which it provides strong incentives for the development of an active forward market for energy.

Guidelines and options for mechanism reforms

Several economic principles guide our analysis of long-term resource adequacy mechanisms and form the basis for our recommendations. First, long-term resource adequacy implies uninterrupted energy production during all possible future system conditions, including El Niño events. Second, there should be an efficient price formation in the short and long term markets for energy. The long-term resource adequacy mechanism should promote transparency, liquidity, and reduce credit risks in the short-term and long-term markets for energy. Third, the long-term resource adequacy mechanism should encourage retailers and large consumers to hedge their short-term price and quantity risk. Fourth, the long-term resource adequacy mechanism should limit the incentive of large suppliers to exercise market power in the short-term market during stressed system conditions, particularly those leading up to El Niño events. Fifth, the long-term resource adequacy mechanism should encourage efficient and effective risk-sharing mechanisms between electricity suppliers employing different technologies to supply energy, thereby reducing the aggregate uncertainty in electricity supply. (This will limit the impact of the uncertainty of completion of specific generation projects such as Ituango)

The long-term resource adequacy mechanism should encourage the least cost mix of generation resources to meet demand under all possible future system conditions. This means that the mechanism should encourage efficient use of water resources from existing hydroelectric generation capacity. Thermal generation units should be encouraged to offer capacity into the short-term market with the most competitive price offers and with the highest possible level of availability. Finally, the long-term resource adequacy mechanism should recognize and reward the unique attributes of different technologies that enhance system reliability.

It is important to emphasize that the current conditions in the Colombian wholesale electricity market described give rise to the "reliability externality" described earlier, so any long-term resource adequacy mechanism must be mandatory. This logic is also why it is mandatory for all retailers and free consumers to participate in the existing reliability charge mechanism in Colombia. All retailers and free consumers would prefer to "free ride" on the firm energy purchases of other market participants (that ensure a reliable supply of electricity), rather than purchase their own firm energy obligation. Nevertheless, an important goal for the design of any long-term resource mechanism is to limit the need for regulatory intervention into the operation of the long-term resource adequacy mechanism and instead rely on market signals to the extent possible.

Options for Reform of Long-Term Resource Adequacy Mechanism

This section describes the two long-term resource adequacy mechanisms for Colombia recommended by the Foco 1 team. The first is a capacity-based long-term resource adequacy mechanism that modifies the existing reliability charge. The second is a standardized forward contract for energy-based long-term resource adequacy.

The rights and responsibilities acquired in past reliability charge auctions must be honored under either recommended long-term resource adequacy mechanism. The results of the firm energy auctions in the years 2008, 2011-2012, and 2019 should be respected. These obligations include

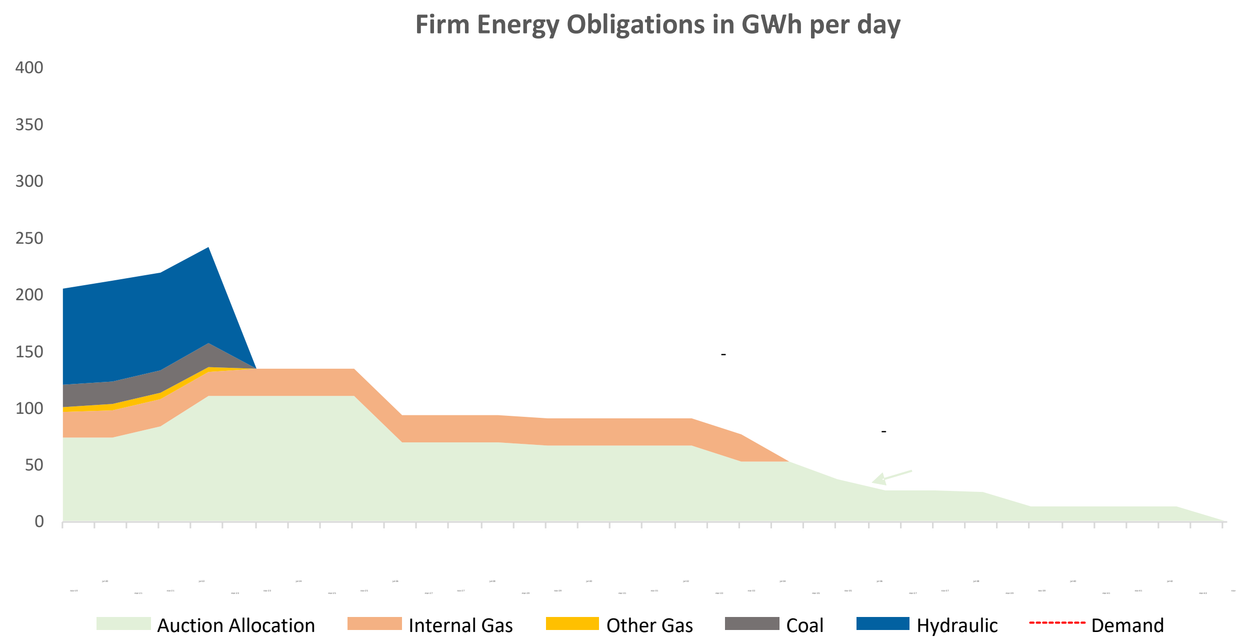

Figure 1: Existing Firm Energy Obligations

the natural gas plants located near in the Atlantic coast with access to the regasification plant with firm energy obligations from 2016-2026. Also included are plants built before 2008 with firm energy obligations expiring as late as 2023. Figure 1 shows the time path of Firm Energy Obligations (OEFs) assigned in these reliability charge auctions.

Modification of Existing Reliability Charge

Several members of the Foco 1 team support retaining a modified version of the existing reliability charge mechanism. These modifications include defining additional firm energy products that distinguish between existing versus new generation capacity and distinguish between capacity based on the value of the generation unit's annual average capacity factor. The firm energy products would also allow to be distinguished by season of the year to address the seasonal nature of the supply of hydroelectric energy.

This modification of the existing reliability charge would create three separate products: i) firm energy from new generation capacity that have not begun construction or is under construction at the time of the firm energy auction, ii) firm energy from existing plants with annual average capacity factors less than 20% without an existing Firm Energy Obligation, and iii) firm energy from other existing plants. This modification is designed to increase the ability of the reliability charge to achieve a desired mix of generation capacity and compensate each type of generation capacity for the unique reliability services it provides.

Firm Energy Obligation auctions will sell products distinguished by season of the year in which delivery takes place. The creation of seasonal products is designed to allow specific energy sources to sell seasonal quantities of firm energy close to amount of firm energy the resource is able to provide in that season of the year.

The objective demand for each of the three firm energy products would be set by UPME. The demand for firm energy from generation units with annual average capacity factors less than 20% would be determined by the demand for strategic reserve, which depends on the uncertainty in system demand and the likelihood of the loss of generation units with large firm energy obligations. The demand for firm energy from existing generation units with no prior firm energy obligation would equal the total demand for firm energy minus the demand for firm energy from new generation units and strategic generation units. The auction for all of these firm energy obligations would take place three years prior to the beginning of the obligation period through sealed bid auctions. These auctions should allow the sale of firm energy obligations that deliver only in the rainy season and firm energy obligations that only deliver during the dry season each year. Annual periods would be auctioned for existing plants while longer reliability periods should be defined for new plants.

The Strike Price for these firm energy obligations should be set higher than the strike price of existing firm energy obligations. One possible strike price would be the first level of the blackout price, as defined by UPME. The payment to the purchaser of these obligations would continue to be the positive difference between the short-term market price and the Strike Price times the amount firm capacity sold by the generation unit. Each generation unit could only sell new firm energy obligations equal to the total firm energy of the unit less the amount of existing firm energy obligations sold by the unit.

The mechanisms for ensuring that the generation unit owners selling firm energy obligations make the firm energy of their generation units available during stressed system conditions must be strengthened. Financial guarantees to deliver firm energy should be marked to changing market conditions to ensure that suppliers of firm energy always find it in their interest to meet their contractual obligations.

Standardized Energy Contracting Approach to Long-Term Resource Adequacy

The second approach to long-term resource adequacy favored by some members of the Foco 1 team ensures that there is adequate energy to meet the hourly system demand in Colombia throughout the year under all possible future system conditions. This energy would be purchased through quarterly standardized fixed-price and fixed-quantity forward contracts shaped to the hourly demand for energy within the quarter of the year. Each quarterly contract auction will be held far enough in advance of delivery to allow new entrants to compete with existing generation units to supply this energy. Like the existing long-term resource adequacy mechanism, these standardized fixed-price forward contract purchases are mandatory for retailers and free consumers.

All retailers and free consumers would be required to purchase and hold to delivery these standardized fixed-price long-term contracts for energy equal to pre-specified percentages of their annual demand for energy at various horizons to delivery in the future. For example, the retailer or free consumer might be required to hold 100% of its actual demand in this standardized product one year in advance, 95% two years in advance, 90% three years in advance and 90% four years in advance. These percentages would be set by CREG in consultation with XM and UPME to ensure that the hourly demand for energy will be met throughout the coming year, regardless supply conditions, including an El Nino event.

These standardized contracts would be quarterly products that shaped to the hourly pattern of system demand during the quarter. Let Q_h equal system demand during hour h of the quarter and $Q_T = \sum_{h=1}^{H} Q_h$, is the quarterly system demand for energy, where H is the total number of hours in the quarter. Set $w_h = \frac{Q_h}{Q_T}$ equal to the share of quarterly demand in hour h of the quarter. Under these standardized contracts for energy, if 10,000 MWh of quarterly energy is sold under this contract, then w_h×10,000 MWh is the seller's forward contract quantity obligation during hour h of the quarter for all hours during the quarter. Note that because $\sum_{h=1}^{H} w_h = 1$ for each quarter, 10,000 MWh of energy purchased is fully allocated to all hours of the quarter.

Free consumers or retailers that fail to meet these standardized contract purchase requirements would be penalized on $/MWh basis for the extent to which they fail to comply with the requirement. For example if the retailer's actual annual load is 10,000 MWh and the contracting requirement for the year in question is 90 percent of actual load, then the standardized contract holdings for the retailer for this delivery year must be a least 9,000 MWh in order to avoid these non-compliance penalties.

This long-term resource adequacy requirement implies that if all retailers and free consumers have purchased required amount of this standardized long-term resource adequacy contract, then the mandated percentage of final demand is hedged against short-term price fluctuations, even though individual loads and generation units would still face residual short-term price risk to the extent their hourly generation or load shapes differ from the hourly system load shape. This is an important feature of this standardized fixed-price forward energy contracting based approach to long-term resource adequacy. It only ensures that there is adequate energy purchased in the forward market at a fixed price to ensure that system-wide demand is fully hedged. Individual generators and retailers are free to engage in bilateral contracting to hedge their own production and consumption of energy.

The duration of contracting requirement into the future and fraction of final demand that is mandated to be covered at each horizon to delivery will be determined by CREG. Compliance will be verified and penalties assessed by the XM and CREG. Recommendations for these magnitudes are provided in Section 4 of Wolak (2019c).

These standardized contracts would be sold through periodic auctions run by XM, similar to the current reliability charge mechanism. Because they are standardized products, a simple auction mechanism could be used by retailers and large consumers to purchase this standardized product. Specifically, because retailers and free consumers are purchasing a fixed quantity of quarterly energy shaped to the hourly pattern of system demand within the quarter, a declining clock auction could be used. The market-clearing price for each quarterly product would equal the lowest price where the aggregate amount demanded is equal to amount supplied.

These contracts would clear against the hourly short-term price by XM, with a counterparty risk management mechanism set by CREG. A clearinghouse should be established between large suppliers and retailers to manage counterparty risk between all parties. This mechanism would ensure that those suppliers and retailers with larger repayment risk post larger guarantees for each MWh of energy purchased in these contracts than more credit-worthy generators, retailers, and free consumers. There is significant international experience with the design and operation of clearinghouses for forward financial products that could guide the design and operation of this counterparty risk management mechanism.

It is important to emphasize that there would be no restrictions on other kinds of contracts that generation unit owners and retailers and large consumers can enter into once they have satisfied long-term resource adequacy compliance requirements of holding the required quantity of the standardized forward contracts for energy at each pre-specified horizon to delivery. Retailers must hold any contracts used for compliance until the delivery date, but they are free to sell these contracts if they lose load or buy contracts it they gain load. Market participants would also be free to enter into other forward contracts to hedge their short-term price risk.

Besides ensuring adequate energy to meet the hourly system demand under stressed future supply and demand conditions such as an El Niño event, the major goal of this long-term resource adequacy mechanism is to foster an active forward market for energy at delivery horizons long enough for new entrants to compete to supply this energy. There are two reasons why this is likely to occur. First, retailers are likely to gain and lose load over time, which implies that the entities that gains load will need to purchase this standardized contract and the entities that lose load will want to sell their contracts. Second, these standardized contracts still leave generation unit owners and retailers with residual short-term price risk to the extent their load shapes differ from the system load shape. This creates an additional demand for hedging instruments.

This mechanism provides a strong incentive for cross-hedging agreements to form between intermittent generation unit owners and thermal resource owners. Hydro and other intermittent renewable generation unit owners that sell the standardized long-term resource adequacy energy contracts will want insurance against the quantity risk they face by selling these standardized contracts. They can purchase this from a dispatchable thermal resources, which provides an additional revenue stream to thermal resource owners. Moreover, this cross-hedging by hydro suppliers will ensure that early in an El Niño event, thermal suppliers will displace hydro suppliers to ensure there is adequate water to serve system demand throughout the entire El Niño event period.

An important feature of this fixed-price standardized long-term contract approach to long-term resource adequacy is that it provides strong incentives for thermal resource owners to make their capacity available to the short-term market during each hour of the quarter. A thermal generation unit owner with an hourly standardized long-term contract obligation can meet this forward energy obligation two ways: (1) buy producing the energy from its generation unit, or (2) purchasing this energy from the short-term market. If the short-term price is at or above the unit's marginal cost, then it is profit-maximizing for the unit owner to produce this energy. If the short-term price is below the unit's marginal cost, this it is profit-maximizing to purchase this energy from the short-term market. The most straightforward way to ensure the generation unit owner makes the efficient "make versus buy" decision on an hourly basis is for it to submit an offer price into the short-term market at its unit's marginal cost of producing energy. This ensures that the owner will produce energy when that is most profitable and buy energy from the short-term market when that is most profitable. Moreover, by failing to submit an offer into the short-term market, the supplier risks losing profits by failing to make the efficient "make versus buy" decision. With all thermal resources submitting offers into the short-term market during as many hours of the year as possible, system demand throughout the year will be met at least cost.

The logic of previous paragraph implies that the this long-term resource adequacy mechanism provides strong incentives for suppliers to find the least cost mix of generation resources, storage and active demand-side participation to meet the hourly demand throughout the year. Because suppliers have sold these standardized fixed-price forward contracts under this scheme far enough in advance of delivery to allow new entrants to compete to supply this energy, once these contracts have been sold, all suppliers have a collective interest achieving the lowest possible cost of serving system demand. That is because the total revenues associated with serving system demand have been determined from the sales of these standardized fixed-price forward contracts, and by minimizing the cost of serving system demand these suppliers can maximize the profits they earn from their standardized forward contract sales.

To the extent there are concerns that suppliers may sell more energy in these standardized forward contracts than they are able to supply from their units, the firm energy concept from the existing reliability payment mechanism could be used to limit the amount quarterly energy each existing generation unit owner sells. For example, if a supplier is found to have 100 MWh of firm energy than the maximum amount of quarterly energy the supplier could sell is equal to 100 MWh×H, where H is the number of hours in the quarter. Because thermal suppliers typically have firm energy quantities greater than the amount of energy they produce each hour and hydroelectric suppliers typically have firm energy quantities less than the amount of energy they produce each hour, this restriction on quarterly energy sales will ensure that there will be adequate energy to serve system demand even during El Nino conditions.

New generation units could be included in this scheme by selling in the quarterly auctions delivering energy at least three years in the future. These new generation projects would be required to have a firm energy quantity sufficient to meet their quarterly energy sales by certain dates in advance of delivery or face the prospect their standardized energy contracts being liquidated. For example, if a new entrant sold 10,000 MWh in quarterly energy, this implies new firm energy capacity equal to 10,000 MWh/H must be built before the compliance date. If the seller of this quarterly energy quantity fails to construct or purchase (from an existing generation resource not already sold as quarterly energy) the necessary firm energy by the compliance date, this 10,000 MWh quarterly energy contract would be liquidated.

Possible Approach to Eliminating Mandatory Purchase of Standardized Contracts

Some members of Foco 1 would prefer not to mandate that retailers and free consumers purchase long-term contracts to hedge their energy demands. However, without certain pre-conditions, this approach may not lead to the quantity of fixed-price long-term forward contracts necessary to achieve long-term resource adequacy because of the existence of the "reliability externality" described earlier. However, as noted in Wolak (2019c), this reliability externality no longer exists if CREG is willing to leave the short-term energy market uncapped and is also willing to commit to allow short-term energy prices to rise to the level necessary to make the hourly demand equal to the hourly supply during all possible system conditions. This regulatory reform may cause short-term prices to rise to extremely high levels during El Niño periods. Consumers are also likely to face extremely high retail prices during these time periods in order to reduce their demand to meet the available supply. Nevertheless, such a reform could provide sufficiently strong incentives for retailers and large consumers to purchase large enough quantity of hedges against short-term price risk to ensure long-term resource adequacy.

Transition Period to Long-Term Resource Adequacy Mechanism

Under either scheme for long-term resource adequacy there will be a transition period. The first stage covers the period 2019-2023, where the Firm Energy Obligations have already been assigned to cover the target demand defined by CREG. Given the uncertainty of Hidro-Ituango it may be necessary to have auctions for new firm energy obligations to cover the period 2024-2025.

The second stage of the transition, covering the period 2023-2026, would present the opportunity to have the new long-term resource adequacy mechanism begin to operate. The existing reliability payment mechanism would be used to replace existing firm energy obligations expiring between 2023 and 2026. By late 2023, the first auctions for the new reliability charge or the first auctions for the new standardized forward contracts for energy could be run. These contracts would begin delivery in 2026 to allow new entrants to compete to provide these products.

Third stage would continue to replace all existing reliability charge contracts expiring after 2026 with new long-term resource adequacy products—either the new reliability charge contracts or the standardized contracts for energy. The third stage would be complete when all existing firm energy contracts under the existing reliability charge have been replaced.

Box 3 – A Simplified Standardized Energy Contract Long-Resource Adequacy Mechanism

Instead of placing the requirement to purchase the standardized quarterly fixed-price forward contracts for energy on retailers and free consumers, CREG could purchase these contracts through the auctions and assign these obligations based on the share of system demand that each retailer and free consumer withdraws during the quarter. This would make compliance with the mechanism straightforward. CREG would simply purchase the quantity of the standardized quarterly contract equal to its estimate system demand for the quarter. Then each retailer or free consumer would be assigned a quarterly standardized fixed price forward contract obligation equal to its share of demand in that quarter. This would eliminate the need to monitor compliance with the contracting mandate by each retailer or free consumer. The aggregate obligation is purchased by CREG and shares of this obligations are assigned to each retailer and free consumer based on their total withdrawals of energy during the quarter.

Take the example of a market with two retailers, one of which has a quarterly demand of 20,000 MWh and the other with a quarterly demand of 30,000 MWh, which makes a quarterly system demand of 50,000 MWh. In this case CREG would purchase 50,000 MWh of the quarterly product and the hourly obligations of the first retailer would be $w_h \times 20{,}000$ MWh and hourly obligations of the second retailer would be $w_h \times 30{,}000$. The hourly clearing of these contracts would be based on the difference between the hourly short-term price minus the market-clearing price from the auction for the quarterly product times the hourly quarterly forward contract obligation.

Having CREG purchase these quarterly standardized contracts and assign them to each retailer and free consumer would also make it more straightforward for mid-stream adjustment in the quantities of these products purchased as demand conditions change. If demand grows unexpected, then CREG could purchase addition MWhs of these contracts to ensure that it meets the percentage requirement for covering system demand at the specified delivery horizon.

This simplified approach would make it more straightforward for CREG to manage the transition from the existing reliability charge mechanism to the new standardized energy contracting approach to long-term resource adequacy. CREG could simply identify the aggregate need for quarterly energy and make this purchase and assign these obligations to retailers and large consumers based of the quantity of firm energy obligations that have expired for each retailer and free consumer.

Finally, this approach would also facilitate the formation of clearinghouse to manage counterparty risk because CREG and XM would know the quantity of obligations and the market price for all outstanding quarterly contracts for all market participants. This would provide greater visibility into the risk that each party will fail to fulfill its contractual obligations to supply or pay for this energy obligation implied by these quarterly contracts.

D. Improvements to transmission planning and expansion

Cadena and Alvarez (2019) highlighted that reforms to congestion management and energy pricing should be linked to transmission planning and expansion. They also discussed topics such as reductions in administrative burdens and delays for generation interconnection and transmission projects, and competition for transmission projects. The Foco 1 team has provided some review of potential reforms, and also experiences in other countries. Most of these topics can receive further examination; for example, the topic of how competition for transmission projects with regulated rates of return in the United States has evolved over the past decade is complicated, with several variants of planning procedures and mechanisms for competition which require detailed analysis.[15] Another topic which is currently at the forefront in many regions is the development of viable assessment of "non-wires alternatives" to conventional projects, which is discussed briefly below and in Appendix 3. This section provides the team's general observations (for additional observations, see also PHC 2018).

Key Findings

- The introduction of locational energy pricing (and flowgate shadow pricing) and improved ancillary service markets in the short-term markets will improve the information available for cost-benefit analysis of transmission expansion decisions, and in particular for evaluation of alternatives to transmission.
- The resource interconnection process requires revisions to reduce barriers to entry caused by speculative positions in the queue, impediments by some network operators, and regulatory restrictions on sharing the same interconnection. This is discussed further below.

[15] For example, U.S. ISOs and RTOs have adopted two basic approaches to competitive transmission development processes, although there are features which are better characterized as "hybrids" in some cases. The first approach is generically called the "competitive bidding" model: the ISO or utility identifies eligible competitive transmission projects through its transmission planning processes, and entities compete to construct the projects. However, in some processes market participants also have opportunities to submit project proposals before the final ISO transmission plan, which may result in selected projects. The second approach is generically called the "sponsorship model": the ISO or utility identifies transmission needs and allows for eligible entities to propose competitive transmission projects through its transmission planning processes. Winning submissions then have the right to construct the projects. A detailed review of how these methods have evolved and the attributes and experiences with each approach is beyond the scope of this report.

- In addition to costs, transmission project evaluation needs more detailed consideration of the factors identified in the existing regulations, as well as new considerations such as contribution to resilience.
- A more flexible framework for proposing types of expansion projects for the STN, including transmission alternatives, is required to improve cost-effectiveness and energy market efficiency.
- Resource interconnection and transmission planning should allow greater participation by third-parties and generator owners.
- With clarification of the rules, multiple use energy storage projects can play a greater role in transmission and distribution planning; the economic value of such projects, which are at an early stage in many countries, will be contingent on the market design reforms discussed above.

Recommendations

<u>Definition of the National Transmission System (STN)</u>

Expand the definition of the national transmission system (STN) including the STR. The integration of options like photovoltaic solar generation, small and medium hydropower plants, energy storage and network bidirectionality due to prosumers, makes the Regional Transmission System (STR) a key factor in ensuring competition, participation of new entrants and intelligence of networks, changing then its function because it will no longer be for a few users but for the entire market. This means that if this classification of regional and national is not modified such classification will remain a greater barrier to entry.

<u>Resource interconnection process</u>

While the Foco 1 team did not collectively examine improvements to the resource interconnection process, we do agree that such improvements are necessary and that there are lessons learned from other regions to facilitate flexibility and timeliness of these processes. In particular, several U.S. regions have had to adapt procedures in recent years to the very rapid growth in renewable projects, many of which are small and located in remote areas. The recommendations summarized here are presented as a starting point for further reforms.

- Allow some generation projects to share the same connection, achieving greater economic efficiency and less social and environmental impact.
- Create a single window managed by UPME to grant free access to the network to generation projects greater than 5 MW for interested parties to submit their connection requests.

- Once the application is filed, the UPME must submit, within a term not exceeding 10 business days, the Terms of Reference (Términos de Referencia, TDR) for the connection study, with the database and the necessary information for the study to comply with the TDRs to grant free access to the network.
- The interested party must submit the connection studies in a period not exceeding 6 months, after which the information would expire and would have to restart the process.
- The UPME must give its concept in a timely fashion (some team members recommend no more than four months). If it determines that the applicant must provide guarantees, the maximum term to provide such guarantees is one month after informing the applicant. Failure in submitting the guarantees will be ground for rejection of the connection request. The UPME may request its concept to OR or to the conveyor, without this concept being binding or implying extension of the term of four months. Any clarification requested will not imply extension of the terms.
- The priority of the connection will be given according to the submit date of connection study and the date of connection commissioning will not have a slack of more than one year.
- The validity of the concept of connection will not have more than twelve months, time in which it must inform the UPME on the signing of the connection and registration thereof.
- UPME will keep updated and public on its website the information about approved, rejected and expired connections.

<u>Transmission planning evaluation criteria</u>

UPME should evaluate the full set of criteria for transmission expansion projects, including least cost, resilience and recovery.

<u>Additional types of transmission expansion projects</u>

New types of transmission expansion projects should be considered in addition to the current project categories. Some general types of new projects include the following:

Transmission capacity extensions, which could be done by repowering, utilization of energy storage systems, digitalization, FACTS, or other measures.

- They will be requested by any carrier agent or third party and their approval will be done automatically by the CREG prior technical approval by UPME and if the MW price offered is less than a reference value regulated by the CREG.
- The remuneration will be liquidated and collected by the LAC (*Liquidación y Administración de Cuentas*, a public entity) in equal monthly payments for ten years

calculated with the WACC approved for the transport business, once the expansion is put into commercial operation.

- The operation and maintenance of these extensions must be carried out by a transporter as extension's owner or on behalf of the third party.

Projects at-risk. This type of projects will be requested by any conveyor agent or third party and their remuneration will be agreed freely between the conveyor and beneficiaries who agreed with the conveyor for developing the project.

- Once in operation, the project must guarantee it meets the network´s code and all rules that apply.
- Likewise, it is an obligation to allow free access to these types of assets. They will not be part of the assets of any conveyor and therefore their remuneration will not be in charge of the demand.

Deep connections. Any generation connection or load that requires a reinforcement to the network and that is not approved by the UPME, because it does not benefit the demand, can be executed by the generator or the demand, at its expense, through a conveyor.

- Once in operation, the project must guarantee it meets the networks code and all the rules that apply.
- Likewise, it is an obligation to allow free access to these types of assets. They will not be part of the assets of any conveyor and therefore their remuneration will not be in charge of the demand.

<u>Multiple use energy storage projects (T&D and market services)</u>

A recent topic for transmission planners and wholesale market design is the use of energy storage (and also distributed energy resources) to defer conventional transmission and distribution (T&D) upgrades, and in some cases avoid them entirely. These projects are typically categorized by whether (1) they are being implemented only for purposes of T&D deferral (with operations restricted to those uses), or (2) they are also going to provide other market and reliability services, which can be called "multiple-uses" (FERC 2017). The Foco 1 team saw its role as primarily on topic (2). A general finding in research studies is that multiple use projects are more likely to be cost-effective, but they may also combine regulated and market-based revenues and thus have more complicated contractual structures and at sufficient scale may impact energy market prices. This section provides some general recommendations, followed by the summary box and more extensive discussion in Appendix 3.

The experience in other regions highlights that all regulatory, market design and planning entities need to be engaged in developing the rules for T&D projects which incorporate energy storage in multiple uses. CREG and XM should advance in the development of rules for multiple uses of energy storage projects in transmission and distribution planning, including:

- Rules for authorization of storage as transmission assets to receive either or both cost-of-service and market-based revenues, in particular to prevent "double counting" when providing multiple uses; this includes storage as a transmission asset only and storage which will provide transmission and market services.
- Rules are required to establish prioritization of services provided by multiple-use storage as transmission assets; generally, services provided as a transmission asset will take priority over market services, and market services which contribute reliability will take priority over those which are not needed for reliability.
- Contractual structures allowed for storage in multiple uses should be identified with sufficient time for project development.

Appendix 3 provides some additional perspective.

Box 4 – Energy storage as a transmission asset and wholesale market participant

Energy storage has substantial potential to provide alternatives to conventional transmission and distribution upgrades by altering loadings on congested network elements, as well as to potentially provide wholesale market and other services with the capability on the device not otherwise utilized. To fully exploit this potential is requiring both policy and market design rule development, which is taking different forms in different regions.

In the United States, FERC (2017) issued a policy statement which provided substantial latitude to its jurisdictional ISOs (which excludes ERCOT) to begin to develop rules for what it called storage providing "multiple services". Of note, FERC will allow for such projects to combine ISO cost of service rates for the transmission services provided, and wholesale market revenues for other uses, as long as there is no "double counting" of the resulting project revenues. There could be many potential contractual methods for ensuring such an outcome. FERC notes that even if operated only as transmission assets, these projects will have an impact on energy market prices, but leaves it to each ISO to determine how this impact will affect project development. Both the California ISO (CAISO) and the Midcontinent ISO (MISO) have begun stakeholder processes to develop such rules (CAISO has approved two storage projects within its transmission plan to date).

In contrast, the Public Utilities Commission of Texas (PUCT) has taken a less supportive view of such projects. First, the PUCT has to date rejected proposals for energy storage located on the transmission or distribution networks to provide multiple services. Second, the PUCT has expressed concern that even energy storage providing transmission or distribution only services would undermine energy price formation and thus has placed limitations on the capacity (MW) of such projects that utilities can develop. This topic will continue to require research and market design reforms for several years. For Colombia, clearly clarity about the reforms to the energy and ancillary service markets will facilitate decisions on any projects intended to provide multiple uses.

Appendix 3 provides a more detailed review of these rules as they currently stand.

E. Retail customer participation, distribution network planning, siting and operations

This topic overlaps with the work of Foco 3 and Foco 5, and hence we will focus more on the market aspects of these topics. This section provides some preliminary observations and recommendations to be followed by more detailed review, including international experiences, in the final report.

As installed costs of distributed energy resources decline, and new methods for customer participation (e.g., "prosumers") become feasible, opportunities for third-party and retail participation in power system operations and direct or indirect participation in wholesale markets are increasing. Colombia can also draw on a growing catalog of policies and projects in other countries (and in cases, particular states in those countries), to develop its own pathways to efficient investment and expansion of market participation.

Preliminary Recommendations

<u>General recommendations</u>

- Valuation of distributed energy resources using locational energy and reliability benefits, as well as resilience contributions, should be developed as a basis for policy development, resource planning and customer participation.
- Even at low levels of penetration, it is desirable to begin forecasting potential growth in DER on individual distribution circuits (i.e., hosting capacity analysis) and their impact on wholesale markets, reliability and high-voltage transmission planning.
- The development of "non-wires alternatives" to transmission and distribution expansion should consider energy market and reliability benefits, as well as contractual options for wholesale market participation (as discussed in Section D and Appendix 3).

<u>Retail customer participation and trading platforms</u>

- Lower the threshold for UNR from 100 kW to 50 kW starting 2020 and eliminate the threshold by 2025.
- Enable, starting 2020, the aggregation by retailers of regulated users.
- Regulate, no later than 2020, the binomial power and energy tariff scheme at the hourly level and, once the binding dispatch and intraday markets enter into operation, publish in real time the short-term market prices.

- Enable, starting 2020, that UNRs can have more than one supplier for each commercial frontier allowing to contract with as many retailers as they want and defining the dispatch priority of each supplier.
- Allow, starting in 2023, that the individual or aggregate demand exceeding 1 MW actively participate in the short-term market, in the reliability markets and in the long-term contracts directly or through a retailers. By this date there will be enough experience with the short-term market modernization that CREG is designing.
- Regulate, before 2022, the trading platforms between consumers.
- Regulate the role of Distribution System Operators (DSO) in such a way that transparency in information is guaranteed and will no produce barriers for retail transactions.

Roadmap

- This roadmap contains selected elements of reforms to distribution planning and market mechanisms.

Table 4 – Roadmap for reforms to distribution planning and market mechanisms

Recommendations	**2020-2021**	**2022-2023**	**2024-2030**
Lower the threshold for UNR	From 100 kW to 50 kW		From 50 kW to 0
Demand aggregation	Aggregation by retailers of regulated users Create new agent UNRs can have more than one supplier for each commercial frontier allowing to contract with as many retailers		
Tariffs	Binomial power and energy tariff scheme at the hourly level		
Active participation of demand		Regulate the trading platforms between consumers Participate in the short-term market	

F. International interconnections

International interconnections are a very attractive option to increase market size, facilitate the creation of an Energy Hub to export renewable energy, increase competition and contribute to reliability. Moreover, these interconnections provide greater operational flexibility needed to address the integration of NCRES at large-scale, and small-scale, and promote the distributed generation. Some general recommendations are provided here, which can be developed further.

Recommendations

- Define as energy policy the creation of an Energy Hub to trade energy.
- Develop regulatory harmonization schemes.
- Create the figure of International Agent that can freely negotiate in the different markets of Colombia with energy produced in Colombia and/or in countries where there is integration.
- Develop a contract market that is liquid and guarantees the formation of low-risk portfolios for the parties.
- Allow free access to interconnections.
- Include in the expansion works of the network those interconnections with large social benefit and that are agreed with the national or regional neighboring markets in such a way that their cost is assigned to the demand.
- Allow to develop at-risk interconnections.

G. Market monitoring unit and functions

The Foco 1 team agrees that an independent Market Monitoring Unit ((MMU) should be established, with a broad purview over the market and planning functions which we reviewed in this report. In the United States, the evolution of independent MMUs has a long history with some relevant regulatory orders which can be examined in more detail. However, our recommendations here focus only on some key features.

The main objectives of the MMU, would be:

- **Identification of design problems and failures in the operation.** The MMU must also monitor the work of the operator and manager of the market and the future of the DSO, focusing on market efficiency and results.
- **Monitoring market performance.** The MMU must identify trends that lead to corrective action before significant market failures can occur. Tests must be carried out on a permanent basis. Some members of the Foco 1 team have recommended a quarterly review under which the following market participants would be evaluated:
    - Those whose quarterly participation in the short- term market exceeds 25% of the energy dispatch.
    - Those whose quarterly participation in the contract market exceeds 25% of total quarterly transactions.
    - Those who set the price in the short-term market for a number of time periods greater than 25% of the total quarterly periods.

Other methods could be developed with reference to the experiences of existing MMUs.

- **Market power mitigation.** The MMU may conclude that a certain behavior has violated market rules or is an anticompetitive behavior. The case, then, may be transferred to the SIC or the SSPD, as appropriate.
- **Internal and External Market Monitors.** A further decision in the development of Market Monitoring Units is whether to have either an internal unit or an external unit, or both (see table below). While the rules may differ between regions, generally both types of units are intended to be independent, while the internal units report to the ISO management and possibly also the Board, and the external units report only to the Board or to the regulators. As shown in Table 5, many North American markets have both, which are not required to reach a consensus on their assessments.

Table 5 – Internal and external MMUs at North American ISOs/RTOs

	PJM	ISO-NE	NYISO	MISO	SPP	ERCOT	CAISO	AESO	IESO	CENACE
Internal Market Monitor (IMM)		✓	✓		✓		✓		✓	
External Market Monitor (EMM)	✓	✓	✓	✓		✓		✓	✓	✓

Preliminary Recommendations

- An independent Market Monitoring Unit (MMU) should be established to evaluate market issues and performance.
- The first step should be an external MMU; consideration of an internal MMU can follow.
- To preserve independence, the external MMU should be financed by market participants rather than by the system operator.

Roadmap

The MMU should be established before any major market design transitions, so that it can bring its oversight to those transitions

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Focus No. 1 - Competition, participation and structure of the electricity market

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Appendix 1 – U.S. case studies of economic benefits from the transition from zonal to nodal pricing

In the United States, all the ISOs have now implemented locational marginal pricing (LMP) of energy (or nodal pricing), along with several other common elements of market design: both day-ahead and real-time markets, security-constrained unit commitment (SCUC) with three-part offers, and co-optimization of energy and reserves. (In Section 1 of this paper, we described this design as the "end-state" which Colombia should target in coming years). Of these ISOs, PJM,[16] NYISO, MISO and SPP began market operations with nodal pricing. However, ISO-New England, California ISO and ERCOT operated for several years with variants on single zone or multiple zone energy pricing before making the transition to LMP and these other design elements.[17] In each of these US regions, the ISOs and market participants needed to be convinced of the desirability of these market design reforms, and each offers different perspectives on how the transition took place and how the resulting benefits were measured. Case-studies of these transitions thus have relevance to Colombia's evaluation of a similar market redesign.

This brief review summarizes some major themes and reported results in each of these ISOs, as well as references which could be used for further examination. The focus is on the immediate impact of the transition, as most of the ISO market monitors conducted interim evaluations in the months after it, and in the annual reviews for the year of the transition. However, such comparisons to the performance of the prior zonal market designs were not continued in subsequent years. Moreover, in all cases, there remained many other market design and operational issues which were not addressed by the initial market design revision, but which were not caused by those revisions. This review mentions but does not track all the subsequent enhancements intended to further improve market performance. In a few cases, there were market design issues which arose specifically due to the transition[18] but which were resolved subsequently.

[16] While PJM operated using a zonal system for a few months in 1998, this was rapidly suspended and does not offer a useful case-study.

[17] In addition, in North America, the Independent Energy System Operator (IESO) of Ontario (Canada) has operated with a single system price energy market since 2002, but is now making the transition to an LMP market. Since that market has not yet started, there is no empirical evidence of the benefits, but simulated benefits can be reviewed on the IESO website.

[18] For example, there was increased real-time price volatility in CAISO in the months after the implementation, which was later addressed.

As observed in the concluding comments, the general finding is that each ISO observed, and in some cases, measured the improvements in congestion management and energy pricing, as well as in other aspects of the market redesign, such as more efficient procurement of ancillary services. In a few cases, researchers also estimated the economic benefits of these transitions (e.g., Wolak 2011).

ISO-New England

ISO-New England was the first U.S. ISO to undertake the transition from zonal to nodal pricing. From April 1999 – February 2003, ISO-New England operated its energy markets very similarly to the current Colombian market. For each hour of the day, the ISO calculated a single system hourly real-time energy price using a two-pass method: the first pass cleared the market without transmission constraints, and calculated the unconstrained system price, which was to become the market clearing price; the second pass cleared the market with transmission constraints, and determined the redispatch of the units with respect to their schedules in the first pass. Units which were dispatched up were compensated for any above market bid costs based on their mitigated offers (using a formula based on the frequency of redispatch); units dispatched down were not compensated for the segment not scheduled. The out of market payments for units dispatched up were compensated through an uplift.[19]

On March 1, 2003, ISO-New England implemented a set of market design reforms which at the time it called the Standard Market Design (SMD), and which included LMP in both a day-ahead and real-time market and a real-time Regulation market (the ISO also operated a Forward Reserve market for operating reserves, with obligations to be available for reserves in the real-time market). In addition, the local market power mitigation method was changed to an automated bid mitigation method, and mitigated bids could now set the LMP. LMPs were calculated at nodes, one trading hub, and eight load zones.

The overall assessment of this market redesign by both internal and external market monitors was positive. In the ISO's internal market monitoring report (ISO-NE, 2004), the general conclusion was that "The ISO's smooth transition to SMD was the culmination of a significant effort to improve wholesale markets in New England. The SMD markets substantially advance the efficiency of congestion management and associated electric energy pricing in New England" (ISO-NE, 2004. pg. 6). The external market monitor concurred with the general assessment, observing that "these markets substantially improve the efficiency of congestion management and associated energy pricing in New England" (Potomac Economics, 2004, pg. 3).

[19] Both the Independent Energy System Operator (IESO) of Ontario, Canada and the Colombian market currently use similar methods.

With respect to congestion management, the implementation of LMP made congestion patterns more transparent, although the initial period of the transition did not experience high congestion due to several factors discussed below. In contrast to the single zone price, the nodal prices around the region now reflected whether the congestion component was negative or positive, consistent with the direction of power flow and the location of binding constraints (ISO-NE, 2004, pgs. 18-20). Most significant was that anticipation of the implementation of LMP resulted in major infrastructure upgrades in the greater Boston area (Boston/NEMA zone), which was previously a highly constrained area. These upgrades along with other operational actions resulted in the following:

> The NEMA zone experienced very low levels of congestion, contrary to historical experience. These low levels of congestion can be attributed to recent transmission improvements into the area, the installation of a considerable quantity of new generation in the NEMA zone, and supplemental commitment and out-of-merit dispatch that occurs in the NEMA zone to address second-contingency reliability requirements. (Potomac Economics 2004, pg. 26)

Of the three case studies, ISO-New England was the only one to experience more extreme system conditions shortly after the market redesign. A general concern preceding the design changes was whether system operations during periods of scarcity would be facilitated by the operational and pricing reforms. The external market monitor's review (Potomac Economics, 2004, pg. 31) concluded that:

> The overall implementation of the SMD markets in New England has been very smooth, with little evidence of any type of disruptions during the transition to the markets. This is particularly impressive given the market conditions when the SMD markets began operation. These conditions included tight natural gas markets and unusual weather patterns that led to uncommonly high electricity demand.

Nodal prices demonstrated a close correlation with natural gas prices in the New England region, which was "consistent with a well-performing market given that: a) fuel costs constitute the vast majority of most generators' marginal costs, and b) natural gas-fired units are frequently on the margin, setting the market price in New England" (Potomac Economics, 2004, pg. 4).

The internal market monitor also observed a reduction in uplift costs following the transition, such that "on an overall basis, [the market redesign] has significantly lowered the level of "out of market" compensation" (ISO-NE, 2003, pg. 16).

Another metric, the frequency of market price corrections, was also assessed to be low after the transition, an outcome which "can be attributed, in part, to the additional time and resources the ISO devoted to development and testing of the SMD markets to ensure they would perform as designed" (Potomac Economics, 2004, pg. 32-33).

On the other hand, the SMD implementation did not in itself address some operational actions which the external market monitor identified as potentially suppressing nodal prices, including additional operator commitments of units following the day-ahead market for local reliability and supplemental contingency reserves. In addition to these issues, since the initial implementation, ISO-New England has undertaken many further design modifications to the energy markets, including changes to day-ahead market timing to improve electric-gas coordination (2013), transitioning from fixed daily to variable hourly bidding in the day-ahead market (2014), and 5-minute financial settlements in the real-time energy market (2017).

California ISO

From April 1998 – March 2009, California ISO (CAISO) operated a real-time market and used zonal pricing for congestion management between two large zones internal to CAISO corresponding to the northern and southern California utilities, utilizing just two transmission lines connecting the regions, and on the CAISO interties. This approach distinguished between inter-zonal congestion, to be managed prior to real-time, and intra-zonal congestion, to be managed in real-time operations. From 1998 – 2001, a separate organization, the California Power Exchange (CalPX), operated day-ahead and hour-ahead self-commitment auction markets with one-part energy bids and zonal market clearing prices. Zonal schedules were first established by the CalPX without consideration of congestion, and were sent to the CAISO, which evaluated infeasibilities and iterated with CalPX, which used adjustment bids to clear inter-zonal congestion for finalization of day-ahead and hour-ahead prices; CAISO then used adjustment bids to address intra-zonal congestion in real-time operations. In 2001, the CalPX was terminated due to market manipulation, and the market participants subsequently provided day-ahead and hour-ahead schedules to the CAISO, along with adjustment bids for congestion management. As observed by the CAISO internal market monitor (CAISO DMM, 2009, pg 5.2):

> The congestion management algorithm minimized the cost of adjustment bids accepted to manage congestion. However, any adjustment bids accepted from scheduling coordinators' portfolios were required to keep the loads and supply in the portfolio in balance. In other words, if an adjustment bid to reduce an import was accepted, this had to be balanced by accepting an adjustment bid to reduce the scheduling coordinator's load or exports by an equal amount. This constraint represented a significant source of potential inefficiency in the prior congestion management process.

For intra-zonal dispatch, the CAISO grid operators (CAISO DMM, 2009, pg 5.2):

> …managed intra-zonal congestion within the ISO zones by manually dispatching resources to increase or decrease output. This was referred to as out-of-sequence dispatch. This form of congestion management was not priced in a transparent fashion, because intrazonal congestion was managed outside the market.

This arrangement continued to March 2009.[20]

On April 1, 2009, CAISO implemented a revised market design which included a day-ahead market with SCUC, co-optimization of energy and reserves, followed by a real-time market. Both markets calculated LMPs at over 2,000 nodes, one trading hub, and three load zones corresponding to the territory of the three large investor-owned utilities. CAISO did not introduce virtual transactions concurrently with this market re-design, but determined to evaluate them following a period of experience and any refinement of nodal pricing.

In the period of the transition, CAISO was not experiencing significant internal or import congestion, and hence the implementation of nodal pricing did not immediately have a major effect on actual congestion. The internal market monitor (CAISO DMM, 2009, pg 5.1) notes that:

> The relatively low level of congestion under the new market design may be attributable to a combination of factors. As discussed in previous chapters, internal load and supply conditions were generally favorable in 2009. Bidding of generation within transmission constrained load pockets was also highly competitive. Improved congestion management under the market design may have also contributed to the limited congestion. [Moreover] high day-ahead scheduling allows for more efficient unit commitment, scheduling and congestion management.

With respect to the other concurrent changes in the CAISO market design, some of the clearest immediate benefits were in the efficiency of the ancillary service markets, due to the implementation of a day-ahead market with SCUC and co-optimization of energy and reserves. Ancillary service prices dropped subsequent to the market implementation and also in comparison to the prior year. Specifically, "ancillary service costs decreased from $0.74/MWh of load in 2008 to $0.39 in 2009. Ancillary service costs also dropped from 1.4 percent of estimated wholesale costs in 2008 to 1 percent in 2009" (CAISO 2010, pg. 6.1). The DMM (CAISO 2010, pg. 6-12) finds that these improvements resulted from several factors, including the following:

> • Supply in the new market significantly increased because scheduling coordinators could bid in all certified capacity into both energy and ancillary service markets. Previously, total capacity bid into energy plus ancillary services could not exceed the certified capacity.
>
> • Bid prices tended to decrease in the new market because the co-optimization in the new market compensates a supplier for their lost opportunity cost of selling ancillary services in lieu of energy. Suppliers no longer have to forecast their lost opportunity cost and include that in their ancillary service bid.
>
> • Suppliers no longer needed to account for commitment cost (start up and minimum load) in their bid prices. The new market, through market revenue or bid cost recovery, will compensate suppliers for these costs.

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[20] Additional details on this process as it existed prior to nodal pricing can be found in CAISO DMM (2010), pg. 5.2.

The CAISO did experience some market issues in the first months of implementation, including more volatile real-time pricing, which resulted in some inefficient dispatch of quick-start units, subsequently resolved. Since the initial implementation, CAISO added scarcity pricing (2011) and virtual transactions (2011), along with many other design revisions utilizing the basic framework, including improvements to combined cycle optimization, a ramping reserve product, and dispatch of variable energy renewable resources.

While CAISO and its market monitor did not undertake a comprehensive assessment of the economic benefits of the market redesign (which included many elements), Wolak (2011) subsequently estimated a 2.1 percent cost reduction due to the transition to nodal pricing, which implies a roughly $105 million reduction in the total annual variable cost of producing fossil fuel energy in California associated with the introduction of nodal pricing.

ERCOT

From 2001 to November 30, 2010, ERCOT operated a real-time energy market with variant on zonal pricing, initially with four zones determined on the basis of what were considered Commercially Significant Constraints (CSCs). The congestion management scheme used two steps. First, the ISO resolved zonal congestion based on the CSCs and determined the resulting zonal shadow prices. In the second step, the ISO used real-time balancing energy offers to resolve local congestion with out of merit dispatch payments. Also, unlike ISO-New England and CAISO, the ERCOT market is "energy-only" meaning that it relies on high energy market prices to provide incentives for investment (with no capacity payments), and hence resolving design or operational issues which may suppress energy market prices is more relevant in this market.

On December 1, 2010, ERCOT implemented nodal pricing in both the day-ahead and real-time markets. As will be discussed, some of the immediate benefits could be measured in December 2010, while others were more evident over 2011 and in subsequent years. In its 2011 annual report (Potomac Economics, 2012), the external market monitor summarized the expected types of benefits from the transition to nodal pricing (pg. xxviii):

- Fundamental improvements in ERCOT's ability to efficiently manage transmission congestion, which is one of the most important functions in electricity markets.
- The nodal market will enable all transmission congestion to be managed through market-based mechanisms.
- The nodal market will provide better incentives to market participants, facilitate more efficient commitment and dispatch of generation, and improve ERCOT‟s operational control of the system.
- The use of unit-specific dispatch in the nodal market will allow ERCOT to more fully utilize generating resources than the zonal market, which frequently exhibited price spikes even when generating capacity was not fully utilized.
- The nodal market will allow ERCOT to increase the economic and reliable utilization of scarce transmission resources well beyond that attainable in the zonal market.

- The nodal market will significantly improve the ability to efficiently and reliably integrate the ever-growing quantities of intermittent resources, such as wind and solar generating facilities.
- The nodal market will produce price signals that better indicate where new generation is most needed (and where it is not) for managing congestion and maintaining reliability.

For December 2010, the external market monitor observes (Potomac Economics, 2011) that "Two of the expected benefits from the nodal market have been immediately observed:"

- Improved management of transmission congestion was evident from even prior to full nodal market implementation. Figure 43 demonstrates the improved utilization of the West to North interface observed during market trials; an increase from 64 percent to 83 percent.
- More frequent energy deployment instructions and reduced quantities of regulation capacity procured resulted in regulation capacity costs being reduced by $8.5 million during the first month of operation of the nodal market.

In 2011, ERCOT experienced higher prices than in 2010 due to weather events. However, the market monitor found that nodal pricing and other elements of the market redesign were conducive to more efficient market results than the prior zonal market. In the 2011 state of the market report (Potomac Economics, 2012), the external market monitor includes the following findings:

- "The nodal market has … enabled the higher utilization of transmission facilities ..." (pg. 45)
- "…implementation of the nodal market has resulted in less price volatility than experienced in the zonal market. Price volatility in the West zone has continued to be higher than in the other zones, which is expected given the very high penetration of variable output wind generation located in that area." (pg. 13)
- "In well-functioning markets we expect to observe a close correlation between price and load levels. This relationship was not observed under the zonal market design and was described repeatedly in prior annual reports… (pg. 14)
- "More reliable and efficient shortage pricing mechanisms than existed in the zonal market allowed energy prices to rise automatically up to the system-wide offer cap during periods of operating reserve shortages. Prices at the system-wide offer cap were experienced in dispatch intervals which totaled 28.5 hours in 2011, or 0.33 percent of the total hours." (pg. 2)
- "Overall pricing outcomes from the nodal real-time market have met expectations for improved efficiency." (pg. xxix)

Since the initial implementation, ERCOT has undertaken many further market enhancements. In particular, ERCOT increased its energy offer caps several times (to the current $9,000/MWh), introduced look-ahead optimization in the real-time market with indicative pricing for next hour (2012), revised its scarcity pricing method to include the current Operating Reserve Demand Curve (ORDC) (2014), and conducted a comprehensive review of ancillary service market design (2013-2015) which is resulting in several reforms, including a separate primary frequency response product (2019). Currently, ERCOT is improving its real-time co-optimization of energy and reserves, which is expected to result in significant economic benefits.

Conclusions

Each of the ISOs reviewed here operated variants on single or multiple zone pricing of energy for many years before making the transition to a nodal design. They had different designs for other prior design elements, such as ancillary services and scarcity pricing. Hence, each case offers slightly different lessons with respect to the benefits of this transition. However, there is a common finding that the immediate result in each case was improved congestion management, more competitive bidding, and more liquid markets. In some cases, average market prices were lowered due to the market design reforms. There appears to be no example of a region making this transition and then finding that it resulted in higher prices due to the market design reforms themselves.

Some ISOs show other particular results from this transition. For example, in ISO-New England, the expectation that locational marginal prices in the greater Boston area would reflect the actual marginal bid cost of energy lead to more rapid investment in transmission upgrades and new local generation to alleviate those potential costs.

Each of these ISOs undertook extensive market testing and other market readiness measures before making the transition, and in each case this was credited with facilitating a smooth transition, with few subsequent issues identified directly with design decisions (in some cases, market issues which did occur subsequently and needed correction were derived from the market design but were not an inherent flaw of the design).

We note that subsequently to the transition period, there have been continuous design enhancements in each region. Some of these were briefly referenced in the review above, and most take advantage of the opportunities for improvements in optimization and price formation offered by the market re-designs.

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Appendix 2 – Locational Market Power Mitigation in the Energy Markets

In all competitive wholesale electric power markets, transmission constraints can amplify the potential market power of owners of generation and possibly other resources, such as energy storage, in locations affected by those constraints. When they "bind," transmission constraints subdivide the wholesale market into subregions, and at those times, concentration of ownership of supply resources within the subregion can allow resource owners to increase the monetary offers for their resources (also called "economic withholding"). Such constraints could also increase incentives for "physical withholding" (such as declaring an unplanned derating or outage) to drive up prices.

Since the beginning of competition in these markets around the world, regulators and market monitors have had to impose rules to monitor and mitigate such "local" market power when it affects bidding behavior in the short-term energy, ancillary service and capacity markets. This appendix is focused on rules for economic withholding in the energy markets. While XM already conducts LMPM using variants on the methods discussed below, there may be a benefit to adjustments to the process when LMP is implemented. This appendix provides some review and comments on this process. In particular, the appendix explains at a basic level the methods for LMPM in several markets, focused on those which have implemented locational marginal pricing (LMP). Table 6 provides a summary survey of the U.S. markets, with more details provided next. This appendix does not consider many details of LMPM, which a more extended survey could consider. A useful general reference is FERC (2014).

Table 6 – ISO market power mitigation rules in the day-ahead energy markets

	Energy markets	**Start-up and minimum load bids; Reliability Unit Commitment (RUC)**
ISO-NE	The Internal Market Monitor has the authority and responsibility to mitigate electric energy offers under certain circumstances and to apply rules that identify Market Participant behavior that results in NCPC payments in excess of defined thresholds and virtual transactions that increase the hourly value of an FTR held by the Market Participant submitting the virtual transaction. Resources submitting Supply Offers that are significantly above their Reference Prices are	Resources committed for reliability purposes generally use Supply Offers that have already been reviewed against their Reference Prices and mitigated if necessary. NCPC calculations generally use offers that have been evaluated against their Reference Prices and mitigated if necessary.

	Energy markets	**Start-up and minimum load bids; Reliability Unit Commitment (RUC)**
	reviewed by the Internal Market Monitor for potential offer mitigation. Demand Bids may be reviewed if they appear calculated to manipulate the markets. Demand Reduction Offers are not subjected to mitigation under the current rules because they are ineligible to participate in the Energy Markets.	
NYISO	There are extensive automatic Market Power Mitigation rules (Market Services Tariff Att. H) which include trigger, conduct, and impact tests. There are both physical and economic withholding rules and different thresholds for detecting conduct and the impact on the market. There are rules for the NYCA and tighter rules for constrained areas (New York City).	There are separate impact thresholds for Bid Production Cost Guarantees. These are applied automatically in the billing system. There are tighter conduct and impact thresholds for reliability committed units.
PJM	Three Pivotal Supplier test for local constraints; mitigation to marginal cost.	Generation owners submit cost-based offers in addition to their market offers. Cost based offers are used if mitigation is needed and cost offer is lower than the market offer RUC - Three Pivotal Supplier test for local constraints.
MISO	Conduct and Impact tests, for both physical and economic withholding.	Start-up - Conduct and Impact tests, for both physical and economic withholding RUC - Conduct and Impact tests, for both physical and economic withholding
SPP	Conduct thresholds and Impact tests, for both physical and economic withholding.	RUC - Conduct thresholds and Impact tests, for both physical and economic withholding
ERCOT	In real-time, offers are mitigated for resources impacting non-competitive constraints. In general, the Independent Market Monitor monitors for market power abuse across all markets. Resources that own less than 5% of market share are not deemed to have any market power and not subject to mitigation.	Offers used by RUC are capped at the generic or verifiable costs for the generator
CAISO	There are three basic mechanisms: bid price cap of $1,000/MWh to prevent economic withholding, a must offer requirement for capacity totaling 115% of 1 in 2 peak load each month to prevent physical withholding, and a local market power mitigation mechanism that is triggered when transmission constraints are congested and create uncompetitive conditions.	Caps are placed on start-up, no-load, and configuration transition cost bids. Further, revenue shortages related to these costs are first covered by resource market revenues from other sources before being paid uplift. For more extreme reliability needs, the ISO has a contracting structure that provides cost recovery and mitigates local market power.

Sources: modified from EPRI 2016; FERC 2014; ISO documents.

General features of LMPM

The general features of LMPM include determination on the scope of the procedure, the design of screens or triggers of mitigation, whether a conduct-impact framework is applied and whether the process is automated or with active decisions by market monitors. This subsection briefly reviews these components.

Scope of LMPM

In its broadest application, some ISOs require all energy market offers to be cost-based, whether they affect transmission constraints or not. Mexico is a current example, and in the U.S., both PJM and MISO followed this method for a brief initial period of market operations. However, most ISOs apply LMPM to evaluate a narrower set of offers, those which are located in electrical proximity to a congested transmission element and which may thus obtain market power during congested market intervals, particularly in combination with other offers from the same supplier, or suppliers, which could also affect that congested element. For these types of LMPM, the next step is to define the locations within which the mitigation procedures will take place.

Fixed zones vs. dynamic screening

LMPM methods vary as to whether a geographical area created by transmission congestion is pre-defined as a fixed zone, or identified dynamically in actual operations. Both approaches and variants have been implemented (e.g., MISO uses fixed zones; PJM, NYISO, CAISO use dynamic methods). For the fixed zone methods, LMPM is applied to the offers within that zone. In the dynamic methods, LMPM may be triggered anywhere in the power system by specific congestion conditions on transmission elements. Fixed zones are clearly simpler to implement. Dynamic methods require calculating market solutions before applying LMPM, and only then calculating the final market solution. Hence, it is more difficult to implement, but can be automated (see discussion of CAISO methods below).

Conduct-impact test

Market power mitigation methods can be based (1) entirely on structural metrics (as discussed further below), or (2) they can first examine whether the offers being screened would have actually affected market prices before applying mitigation. The latter approach is generally called a “conduct-impact” test: the *conduct* refers to whether a supplier increases its offer above some competitive benchmark, and the *impact* refers to whether that offer increases the market price from where it would be otherwise. There are several variants on the conduct-impact procedure, some discussed below.

Pivotal supplier tests

Among the structural metrics, the most common are variants on the “pivotal supplier” tests. These were first introduced to address market concentration during peak hours and identified whether particular companies own all the generation needed to serve residual demand in those hours, and therefore have unlimited ability to set offer prices unless subjected to mitigation. When adapted to LMPM, the pivotal supplier test evaluates the concentration of particular companies which can relieve the congestion on the relevant transmission constraint.

In both types of applications of the pivotal supplier test, the scope of mitigation can be modified by adjusting the set of pivotal suppliers. For example, the pivotal supplier screen can be expanded to include also the “second” pivotal supplier – that is, the resources owned by the company which in combination with the first pivotal supplier can affect prices or congestion – or the third pivotal supplier, and so on. Economic theory suggests that coordination between these pivotal suppliers could require that the market offers of the full set of these suppliers are mitigated. Adding pivotal suppliers to the test thus expands the set of supply offers subject to mitigation.

Failure of the pivotal supplier test by a supplier leads to direct mitigation of its offers, or it can be further evaluated with an impact test before determining whether to mitigate the offers.

Mitigation methods

When market offers fail the LMPM screen, they are mitigated to a reference level considered to be competitive, which may be based on marginal cost-based calculations, averages of prior accepted offers, or other accepted offer levels. While similar in purpose, these have some variations by ISO market. The mitigated offers are then re-entered into the auction market for use in calculation of LMPs.

Automated processes

As noted, most US ISOs use automated procedures which mitigate offers which fail the relevant screens prior to submission of the offers into the final energy auction market. The advantage of an automated process is that it eliminates operator discretion; the degree of mitigation remains a regulatory decision. Most U.S. ISOs report very few adjustments when automated processes are deployed, because suppliers know how such processes work and avoid triggering them.

LMPM methods in selected zonal pricing markets

Whether LMPM is applied to markets with single-system/zonal pricing or nodal pricing will have similarities and differences with these procedures in markets with LMP. This review begins with markets which do not have LMP, and which may have similarities to the current LMPM methods in Colombia. In the case of ISO-New England, the prior method of calculating the system price is described in Appendix 1.

IESO (Ontario, Canada)

IESO operates a real-time energy market with a single system price, calculated with some similarities and differences to the other markets with such pricing methods, including Colombia and the prior ISO- England design.[21] Similarly to some other markets, IESO designates "constrained off watch zones where there are persistent and significant constrained off events" and LMPM procedures are focused on these zones. Figure 1 shows the seven-step process flow of the LMPM methodology, excerpted directly from the relevant IESO manual (IESO 2018, pg. 1-7).

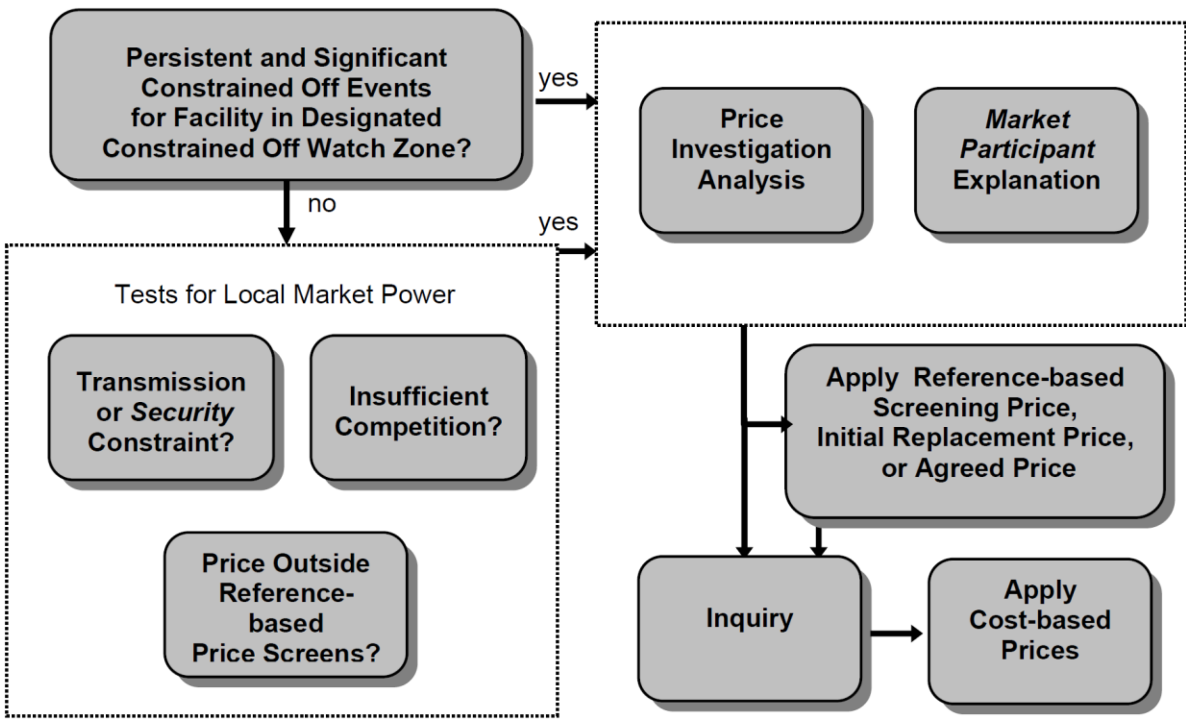

Figure 1 -- Overview of IESO LMPM Review Process

[21] The basic method is summarized as follows (IESO, 2019, pg. 3): "Currently, the pricing schedule ("unconstrained schedule") is used to set a single price across the province every five minutes. This uniform market clearing price (MCP) is then used to establish the province-wide hourly Ontario energy price (HOEP) for electricity. Because this price doesn't take into account actual system conditions or operational constraints, it doesn't reflect the real cost of generating or consuming electricity at different locations. However, in order to maintain reliability, the dispatch schedule ("constrained schedule"), which determines the physical dispatch instructions, has to take all system and operational limitations into account."

With the pending transition to an LMP market, IESO is in the process of modifying this procedure to adopt new methods. While this revised method is not summarized here, it is worth examining as part of any further review of this topic (see IESO, 2019a,b).

ISO-NE (1999-2002)

Prior to implementing LMP in 2002, ISO-NE conducted a two-pass process to determine a single market clearing price for energy, similar to IESO and Colombia (see Appendix 1). ISO-NE's methods for LMPM evolved from 1999-2002. Initially, the internal market monitor developed methods to review and possibly mitigate offers from resources that were "constrained on/up" due to the two-pass congestion management method. In 2000, a "conduct-impact" based method was adopted. Following the implementation of LMP, the conduct-impact approach was continued using reference levels to determine the triggers for mitigation.

LMPM methods in selected LMP markets

PJM

PJM has utilized versions of LMPM since the start of the energy markets with LMP in 1999. Of note, PJM operated its energy markets in 1998 for one year with cost-based offers only, due the lack of a determination that the market was structurally competitive. A useful reference on the current approach to LMPM is Monitoring Analytics (2011), and the annual PJM *State of the Market* reports provide details of LMPM performance over the prior years.

Three Pivotal Supplier (TPS) test

PJM was the first ISO to implement the TPS for LMPM in the U.S. wholesale energy markets; a regulatory record of this implementation can be found in Monitoring Analytics (2011).

As reviewed above, the objective of the TPS test is to evaluate the ownership of the supply available to relieve a transmission constraint, and mitigate offers from that supply in the event that potential market power is detected. Similarly to other ISOs, when a supplier fails the TPS test for a constraint, the relevant units "can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units."

California ISO

Similarly to ISO-New England, CAISO significantly modified its LMPM procedures with the implementation of the day-ahead and real-time markets with LMP in 2009.

CAISO's method has several unique elements (see Section 6.5, CAISO 2019). First, in both the day-ahead and real-time markets, there is a complete separate optimization run using the submitted market offers and utilizing the full network model. This run takes place immediately after the offers and schedules are submitted and validated. The purpose of this process, called Dynamic Competitive Path Assessment, is to identify which transmission paths are considered competitive, and which are considered non-competitive, and then adjust the offers of units which impact the non-competitive paths. The optimization calculates an LMP decomposition, which identifies the competitive and non-competitive congestion components in each LMP. Each resource which has a non-competitive congestion component at its bus is subject to mitigation. Similarly to PJM, the CAISO uses a Three Pivotal Supplier (TPS) test to identify the offers subject to mitigation. Mitigated offers are re-set to the higher of the resource's Default Energy Bid – a cost-based offer – or to the "competitive" LMP which is the sum of the other components of the LMP. This process is automated.

CAISO does not use a conduct-impact test; LMPM is applied regardless of whether the identified units would impact the market price with their offers, or not.

NYISO

New York ISO (NYISO) subdivides the power system into Constrained Areas and Unconstrained Areas, and applies more stringent market power mitigation methods in the Constrained Areas. Constrained Area mitigation procedures apply to all resources which have a positive shadow price (≥ $0.04/MWh) on transmission facilities which enter the area.

NYISO was the first ISO to apply conduct-impact tests to energy market offers. These proceed in sequence. First, the offer is evaluated to see if it exceeds a reference level by a threshold. Second, any offers which fail the conduct test are entered collectively into a dispatch simulation to determine if they would have an impact on the market clearing price.

For Constrained Areas, the Conduct test evaluates whether an offer exceeds its reference level by the following threshold – (2% × Average LMP × 8760) ÷ (number of constrained hours) – which is designed to loosen the threshold as the number of constrained hours declines. The Impact test for Constrained Areas then evaluates whether the set of resource offers which fail the Conduct test would increase LMPs by an amount greater than the Conduct threshold.

Mitigated offers are re-set to reference levels which the supplier can opt to be based on accepted offers during competitive conditions in the prior 90 days (as adjusted for fuel prices), or the mean of the lowest 50% of LMPs during that period, or a cost-based formula.

This process is called the Automated Mitigation Procedures (AMP).

For the Unconstrained Areas, there is a less stringent procedure, in which the conduct test evaluates whether offer exceed the reference level by the lower of $100/MWh or 300 percent.

For offers which fail the conduct test, the impact test then evaluates whether the set of failed offers would raise the LMP by the lower of $100/MWh or 200 percent. Offers that fail the impact test are mitigated to reference levels.

CENACE, Mexico

Mexico caps all offers into the day-ahead energy market to cost plus 10 percent. There are thus no specific tests related to the effect of transmission constraints.

Conclusions and recommendations

This appendix has provided a brief review of LMPM methods in different ISOs, focused on those compatible with LMP. As discussed, there are several methods being utilized, and to obtain a deeper understanding of their properties, we encourage a more detailed expansion of this appendix. In particular, given the range of methods, we recommend further review to develop options for a phased implementation methodology which could then be transitioned into any future LMP design.

We recommend that as a next step, an automated LMPM method is implemented to screen and mitigate offers into the day-ahead market (and subsequently the real-time market) before market prices are calculated. This could be compatible with both the current energy market pricing method and any future LMP implementation. As Colombia makes the transition to LMP, LMPM methods should be reviewed to ensure that they are compatible with any changes to energy pricing.

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Appendix 3 – Status of Energy Storage as T&D Assets in the United States and Lessons for Colombia

Energy storage – both stand-alone and within aggregations which include distributed energy resources (DER) – can provide an alternative to transmission and distribution (T&D) infrastructure upgrades and provide other T&D services, such as voltage control. These T&D applications also generally leave unused capability on the storage system. Such capability can then provide other services to the wholesale market, including energy time-shift, ancillary services and capacity. The ability to provide T&D applications along with other services is being investigated in numerous jurisdictions within the United States and other countries, including several ISOs. In the U.S., the terms used include *multiple uses* (FERC), *multiple-use applications* (California), *dual-market participation* (New York), and *dual-use capability* (Texas).

In regions with competitive energy markets and industry restructuring, these types of projects are complicated for several reasons. First, the regulatory determination has to be made on how to structure a regulated rate of return for the T&D asset, at the same time that it may also earn wholesale market revenues. Even if operated solely as a T&D asset, and not allowed to participate in the wholesale markets, the storage device may affect those market prices by charging and discharging. In addition, there are many other regulatory and market design issues, such as appropriate priority ranking of market and non-market services, and the role of the market operator in forecasting and optimizing device operations across both market and non-market applications. Finally, the complexity of analyzing the costs and benefits of such multiple uses can lead to uncertainty about the viability of such projects. Very few of these projects have moved to actual deployment to date around the world, although in some regions, there have been studies which find significant potential. In Colombia, there is the added complication that wholesale market design is expected to be revised substantially over the next 5-10 years, which will alter the value of energy storage.

We expect that there will be continued analysis and evolution in the rules for such projects, and recommend that Colombia review developments in other regions and consider the long-term changes in market design in project assessment. This appendix provides some of this review. The discussion is focused on the United States. References are at the end.

U.S. regulatory background

In the United States, the Federal Energy Regulatory Commission (FERC) has jurisdiction over cost recovery for high voltage transmission investment (via transmission access charges) in all U.S. regions except ERCOT (Texas). The states have jurisdiction over investor-owned utilities distribution planning processes and ratemaking, with variations by state.

Table 7 summarizes FERC's major rulings to date; in 2016, FERC held a technical conference on this topic and then issued a policy statement in 2017 titled *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*. In the policy statement, FERC was flexible with respect to the types of regulated rate and market-based contractual structures which might emerge to support these projects, and largely has left it to the ISO regions to establish specific rules. Since then, two U.S. ISOs under FERC jurisdiction, MISO and CAISO, have begun stakeholder processes to establish rules for these types of projects. In Texas, which is not under FERC jurisdiction, the Public Utilities Commission of Texas (PUCT) has been analyzing these types of projects for several years and has taken a different regulatory approach, which to date has been more restrictive. As this topic is evolving fairly rapidly, there may be updated results available fairly frequently over the next few years.

U.S. state regulators have also allowed projects with storage providing distribution upgrade deferral, and in some cases also wholesale market services, to date notably in New York and California. These projects are also providing information on asset valuation and operations. Many utilities around the United States are conducting scoping evaluations of such projects through distribution resource planning or grid modernization. Recent examples include the investor-owned utilities in California, New York, Hawaii and Nevada.

Table 7 summarizes some key regulatory milestones related to energy storage as a T&D asset. The citations and links to these documents or proceedings are listed below.

Table 7 – Selected U.S. milestones relevant to energy storage as a transmission and distribution asset

Date	Milestone	Summary Description
2008	FERC *Nevada Hydro* order	FERC agreed with CAISO in approving the eligibility of a large proposed pumped storage plant for cost-of-service regulated rates as a transmission asset but denied its request to have CAISO operate the plant in the wholesale markets on behalf of the owner. The project did not move forward.
2010	FERC *Western Grid* order	FERC approves rate recovery for storage as a transmission asset without wholesale market participation.
2014 onwards	Regulated utilities in key states begin distribution system planning to identify non-wires alternatives	These include Hawaii, California, New York and several other states since then; see references below.

Date	Milestone	Summary Description
November 9, 2016	FERC Technical Conference on Utilization in the Organized Markets of Electric Storage Resources as Transmission Assets Compensated Through Transmission Rates, for Grid Support Services Compensated in Other Ways, and for Multiple Services	Presentations, conference transcript, and post-conference comments are available on the FERC website. FERC Docket No. AD16-25-000.
January 19, 2017	FERC Policy Statement on Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery	See summary in this appendix.
2018–2019	PUCT Project No. 48023, Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service	Stakeholder review of multiple questions relating to storage as a distribution asset. Project paused in January 2019 pending further legislative direction, which is currently underway.
March 2018, ongoing	MISO Storage as a Reliability Transmission Asset initiative	Two-phase stakeholder process, with the first phase focused on storage dedicated to transmission services only and the next phase to address both transmission and market services.
March 2018; temporarily suspended January 2019	CAISO Storage as a Transmission Asset initiative	Examination of storage projects requesting regulated rate of return as transmission assets with and without market participation.

Ranking of multiple uses and ISO role

In most regions, a starting point for the development of market and regulatory rules for multiple uses is to establish a structure for ranking of these applications in system operations, to be codified in contracts and subsequently in market/utility scheduling. There is no standard practice yet in the U.S. markets, but preliminary rules have been presented in several regions, notably California.

General rules for multiple uses

The California Public Utilities Commission (CPUC) was the first state regulator to develop general rules for multiple use projects (CPUC 2018); these are shown in Table 8, which excerpts the full description of the CPUC's 11 adopted rules for evaluation of multiple use applications.

The first 3 rules recognize that "storage resources may only provide services within the domain in which they are interconnected, or a higher level grid domain but not in reverse. These rules are based on current law and practice…" However, the decision notes that community storage resources could in principle be distribution-located and provide retail customer services.

Rules 5 and 6 “are designed to ensure that reliability services always take precedent.”

Rules 7-10 focus on transparency and enforcement through penalties to ensure that the utility and the system operator have confidence in the prioritization of services procured under contract or offered into the market.

Rule 11 on “incrementality” is intended to protect against double compensation. This is because aggregated distributed resource projects may incorporate financing and revenues from different sources.

Table 8 – Interim adopted rules for multiple-use applications

Rule 1	Resources interconnected in the customer domain may provide services in any domain.
Rule 2	Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources, per Ordering Paragraph 11 of D.17-04-039.
Rule 3	Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.
Rule 4	Resources interconnected in any grid domain may provide resource adequacy, transmission and wholesale market services.
Rule 5	If one of the services provided by a storage resource is a reliability service, then that service must have priority.
Rule 6	Priority means that a single storage resource must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource from being unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include, but should not be limited to, financial penalties.
Rule 7	If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of the resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.
Rule 8	For each service, the program rules, contract or tariff relevant to the domain in which the service is provided, must specify enforcement of these rules, including any penalties for non-performance.
Rule 9	In response to a utility request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this Rule is to provide transparency in the energy storage market.

Rule 10	For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.
Rule 11	In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

Source: CPUC Decision (2018), Appendix A (directly excerpted)

Prioritization of reliability and non-reliability services

With respect to the prioritization of reliability and non-reliability services, the CPUC (2018) has further specified the distinctions by service, as shown in Table 9. This categorization is intended to facilitate contracts which establish which types of services are given reliability priority by the utility or the ISO, and which services are considered not reliability and hence subject to limitation at the direction of the utility or ISO.

Table 9 – CPUC determination about reliability and non-reliability services

Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased self-consumption of on-site generation; Back-up power; DR program participation
Distribution	Distribution capacity deferral; Reliability (back-tie) services; Voltage support; Resiliency/microgrid/islanding	None
Transmission	Transmission deferral; Inertia*; Primary frequency response*; Voltage support*; Black start*	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves; Flexible ramping product	Imbalance energy
Resource Adequacy	Local capacity; Flexible capacity; System capacity	None
*In California, Black start, voltage support, inertia, and primary frequency response have traditionally been obtained as inherent characteristics of conventional generators, and are not today procured as distinct services.		

Role of the ISO

FERC provides some general guidelines to preserve RTO/ISO independence from the operations of the storage resources. The RTO/ISO should support prioritization of storage dispatch to provide cost-based services over market-based ones. In addition, "the provision of market-based rate services should be under the control of the electric storage resource owner or operator, rather than the RTO/ISO, to ensure RTO/ISO independence." However, FERC remains open to other operational solutions that ensure RTO/ISO independence.

Contractual structures for multiple use projects

When both types of applications – T&D only and wholesale market – are intended for the project, there are several regulatory issues to address. These include whether such joint applications are allowed, and if so, what role the regulator has in structuring such contracts.

In the United States, FERC's (2017) policy statement has indicated approval in general for storage as transmission projects which allow for both rate-based and market-based revenues. In contrast, the PUCT has explicitly not allowed multiple uses, and has placed restrictions also on transmission-only storage projects to minimize impacts on the energy markets.

FERC's primary requirement is that any such contract must avoid "double counting" market revenues and rate recovery. FERC does not endorse a particular method but notes generally that "crediting any market revenues back to the cost-based ratepayers is one possible solution" and could take different forms (for example, whether as part of the calculation of the approved rate of return or on a continuing basis, and depending on how much cost recovery is sought through cost-based rates).

In its most recent stakeholder papers, and reflecting the FERC policy statement and other prior proposals, CAISO (2018) has identified four options for how rate recovery could be mixed with market revenues (directly excerpted):

1. Full cost-of-service based cost recovery with complete energy market crediting back to ratepayer;
2. Partial cost-of-service based cost recovery and the storage project retains energy market revenues;
3. Full cost-of-service recovery with partial market revenue sharing between owner and ratepayer; and
4. Partial cost-of-service recovery with partial market revenue sharing between owner and ratepayer.

Impact of storage projects on energy markets

In all regions, it is recognized that whether storage is being operated for T&D applications only, and or in projects with multiple uses, it will have impacts on the energy markets. These impacts will clearly become more significant as the scale of such storage projects increases. Different regulators and regions in the United States have taken different postures on this issue, in part reflecting the role of the energy markets in guiding investment in those regions.

FERC perspective

In its policy statement (FERC 2017), FERC took a very general view on this question, reflecting that it has jurisdiction both over states with restructured power markets, and those which remain largely vertically integrated. FERC notes that many power system assets participating in the wholesale markets may have similar combinations of regulated and market-based revenues. FERC finds that in principle, assets obtaining cost recovery should be allowed to participate in the markets. However, FERC will allow ISOs to evaluate these impacts individually.

Texas perspective

In contrast to FERC, the PUCT has shown much greater concern for the impact of such projects on the energy markets, particularly since the ERCOT market does not include capacity payments. In 2018, the PUCT began a Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service (Project No. 48023) which established the different views of stakeholders and requested legislative consideration. A major issue is that as these types of storage projects increase in scale, even if operated just for T&D services, their impact on energy market prices will distort incentives for generation entry. Current legislation thus strictly limits the quantity of such projects.

Project assessment and implementation to date

There are a number of research studies, pilot projects, utility T&D planning and grid modernization studies, and ISO transmission planning studies which can be used as references, although the conclusions are still varying in these studies and by region. This review is not comprehensive.

Chang et al., (2015) estimated that there could be up to 580 MW of storage capacity utilized for "high-value" distribution deferral in ERCOT. When added to wholesale market revenues, the joint value could result in several GW of potential projects. However, as noted above, the state regulator has presented barriers to such projects.

A growing number of utilities in the United States are providing quantitative review of these types of projects in their transmission and distribution system planning. These include the investor-owned utilities in the following states with the years indicating when they submitted distribution resource plans which included non-wires alternatives: Hawaii (2014), California (2015), New York (2016, 2018), and Nevada (2019).

In New York, the Consolidated Edison "Brooklyn/Queens Demand Management (BQDM) project" is one of the largest and most complicated non-wires alternatives projects implemented to date. Energy storage is just a small component of the distributed resources procured for distribution deferral. The New York utilities have also individually and jointly presented on methods and selection of non-wires alternatives (e.g., Joint Utilities, 2017). In California, Southern California Edison's Preferred Resources Pilot (PRP) is an extensive infrastructure deferral project with several rounds of RFOs, incorporating storage.

Not all utilities are identifying extensive deferral opportunities. In its 2019 Distribution Resource Plan, the NV Energy utilities (Nevada) found that from 2020-2025, only a small 400 kW BESS installation was a component of a cost-effective non-wires alternative for a distribution upgrade, and that there were no cost-effective opportunities for transmission upgrade deferral. Brattle Group (2018) identified a larger set of potential projects in Nevada.

The U.S. ISOs have also published some analysis on storage as a transmission asset. CAISO has more experience than most ISOs with storage as a transmission asset, having studied a pumped storage project and 27 battery storage proposals, to date, with 2 battery projects approved in the 2017–2018 transmission plan (these projects will be transmission assets only).

Conclusions and recommendations

Energy storage in multiple uses is a viable application, which is being evaluated and in some cases deployed across many regions. The initial results emphasize that these are highly complicated projects, which need to balance the objective of maximum economic value against the limitations of market rules and procedures, software, and contractual/regulatory requirements.

For Colombia, some lessons learned include the need to establish comprehensive regulatory rules for such projects, and build scenarios about future market design reforms into project valuation.

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