CREG Energy Market Panel: The Evolution of Electricity Market Regulation in Colombia[1]

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1 Introduction

The Colombian Comisión de Regulación de Energía y Gas (CREG) has convened a panel of international experts to consider various proposals for electricity market reform on four topics: (1) the scarcity price, reliability charge and methods for the expansion of system capacity; (2) a forward market for energy contracts (MOR); (3) spot market reform and the creation of day-ahead and intra-day markets; and (4) mechanisms to elicit investment in nonconventional renewable energy (FNCERs) in Colombia.

This report contains my analysis and recommendations on these topics. In summary form, my observations and recommendations are:

1.0.1 Scarcity price, reliability charge and methods for the expansion of system capacity

The experience of the El Niño event of 2015-2016 revealed some weaknesses in the firm energy market design, but did not indicate a need for major reforms. My conclusions and recommendations are:

- the operation of the Firm Energy Market relies upon commitments from generators to deliver firm energy when it is required. The CREG should consider how these obligations could be strengthened by requiring performance guarantees and/or imposing more severe penalties on generators in breach of their obligations. If some existing generators prefer to drop out of the Firm Energy Market, new technology-neutral auctions open to all generators, irrespective of their variable costs of producing energy, should be held.

- the CREG *could* consider an adjustment to the Scarcity Price based on a new fuel index, or alternatively recalibrating and updating it by establishing a price exceeded by the spot market less than 5% of the time (perhaps as a rolling five-year average).

- if any resulting change in the Scarcity Price is significant, generators with 20 year contracts should either be held to their contracts at the original Scarcity Price, or be given the option of recontracting at the new Scarcity Price, but only once a new (lower) Reliability Charge level has been established.

- annual firm energy auctions should be held, primarily to establish a lower value of the Reliability Charge for existing generation plant during periods when capacity is in surplus.

- the Firm Energy auctions should adopt a sealed-bid format.

1.0.2 Forward market for energy contracts

- the CREG's proposal for quarterly auctions for longer-term contracts is the recommended approach, given that most commentators believe that an exchange would suffer from liquidity problems for the foreseeable future.

- it is unclear why a descending clock auction is preferable to a sealed-bid auction. Price discovery, the usual rationale for preferring a clock auction, does not appear to be a significant factor in this setting.

- the proposed auctions do not address the issue of vertically-integrated generators and price discrimination between the regulated and nonregulated markets. A participation requirement may need to be imposed on vertically-integrated generators.

- the proposed one-year contracts do not address the problem of inadequate supply of contracts from hydro generators. This may require the introduction of interruptible contracts, similar to the "conditional firm" contracts used in the Colombian gas market. Both firm and conditional firm contracts purchased in the auctions could be passed through in full to Regulated Demand at the auction clearing prices.

- if multiple, substitute contracts are to be sold in the auctions, an *ascending* clock auction format should be used to allow demand to arbitrage between the contract types. Alternatively, sealed-bid auctions of the "product mix" or "assignment" type could be implemented.

1.0.3 Spot market reform: day-ahead and intra-day markets

A change to a new market arrangement for short-term transactions should work well in Colombia, although evidence for serious problems or efficiency losses under the current trading arrangements seems to be lacking. It is unclear that the level of capacity redeclarations, or water spillages by hydro generators, are more than would be expected in any other hydro-based electricity market. Nor does any attempt appear to have been made to study these issues. Likewise, the putative efficiency losses from the limited participation by demand-side bidders under the current arrangements have not been quantified. I recommend that these issues be given more serious study prior to adopting the proposed reforms.

1.0.4 Mechanisms to elicit investment in nonconventional renewable energy in Colombia

All of the CREG's proposals seem to be in accord with recent international experience in the auctioning of renewables. An industry consultation process should probably be undertaken before a particular design is adopted. Details of the auction designs need to be adjusted in some of the proposals, and in all of them the reserve prices need careful consideration, especially if there is a risk that insufficient supply offers will be elicited.

FNCER generators in Colombia suffer a financial disadvantage due to their very low capacity factors, or ENFICCs. There are sound economic reasons for adopting a new methodology for calculating ENFICCs for these technologies, and this should be considered before a subsidy system is implemented.

The subsequent sections consider these issues in greater detail.

2 Scarcity Price, Reliability Charge and Expansion of System Capacity

In 2006 Colombia introduced a new regulatory scheme to ensure the reliability of the long-term supply of electric energy. The scheme allocates Firm Energy Obligations (OEFs) to new and existing generating plant in order to guarantee a sufficient long-run supply of firm energy at prices determined in competitive auctions. Firm Energy Obligations commit generating companies to supplying energy to the market at a fixed price during periods of scarcity. The OEFs needed to cover predicted long-run demand are auctioned: a generator which is allocated an OEF in an auction receives a fixed annual option fee (the "Reliability Charge") for each capacity unit covered by the OEF, and is committed to delivering energy up to a specified quantity when the energy spot price is higher than a pre-determined "Scarcity Price". Generators supplying energy under an OEF are paid the Scarcity Price for the amounts of energy supplied up to their committed quantities, and receive the spot price on any additional quantities. Generators receive 20 year OEF contracts for new projects while existing generators are voluntarily assigned annual OEFs.

The El Niño event of 2015-16 severely tested the firm energy market, and in particular its ability to function in the face historically low water levels in Colombia's hydro reservoirs when combined with a series of unanticipated events. These events were: (i) the declaration by thermal generator TermoCandelaria of its inability to honour its firm energy obligations; (ii) the forest fire which took the Guatapé hydro plant and other plants operating downstream of it out of operation for more than a month in March/April 2016; (iii) increased demand for domestic gasoline due to the closure of the Colombian-Venezuelan border in August/September 2016; and (iv) delays in the operation of the LNG port in Cartagena which was intended to open in December 2015. Despite these events, rationing of electricity was avoided and the firm energy market proved itself capable of operating under extreme stress. Nevertheless, certain problems or weaknesses in the system appear to have been revealed by the crisis, leading to calls for a variety of reforms. We discuss these proposals in this Section.

2.1 The Scarcity Price and Reliability Charge

The Scarcity Price is the price at which generators must deliver the energy they commit to voluntarily in acquiring firm energy obligations and in return for which they receive the Reliability Charge. Since the value of the Reliability Charge is determined in periodic competitive auctions in which the value of the Scarcity Price and the method for indexing it are known to all participants, the two prices are linked and inversely related. That is, the lower the Scarcity Price the greater the risk to generators in acquiring an OEF, and hence the higher the Reliability Charge required to compensate for this risk, and *vice versa*.[1]

The initial value of the Scarcity Price was defined in CREG Resolution 071 of 2006 as:

- a price level which was exceeded in the spot market less than 5% of the time in the preceding eight years; and

- the cost of generation of the least efficient or highest variable cost thermal generating plant using Fuel Oil No. 6.[2] The initial value of the Scarcity Price was estimated at COP 306/kWh and is updated monthly based on the average daily maximum price of the Platts US Gulf Coast Residual Fuel No. 6 1.0% sulfur fuel oil.

From 21 September 2015 to 26 October 2016 for the first time the spot market price in Colombia exceeded the Scarcity Price for every hour of the day for more than an entire month, as a result of a number of factors identified by the CREG:[3]

[1]Unlike in most other electricity capacity markets (e.g. UK, New England, PJM) the value of the Scarcity Price therefore determines *both* when generators will be called upon to deliver under their Firm Energy Obligations (i.e. the price signal which determines when the system is in "critical condition") *and* the amount of remuneration they receive for doing so per kWh supplied.

[2]The Scarcity Price defined in this way consists of threee components: (i) fuel costs; (ii) operating costs; (iii) variable costs of using the national transmission network.

[3]CREG Document 120, 27 October 2015

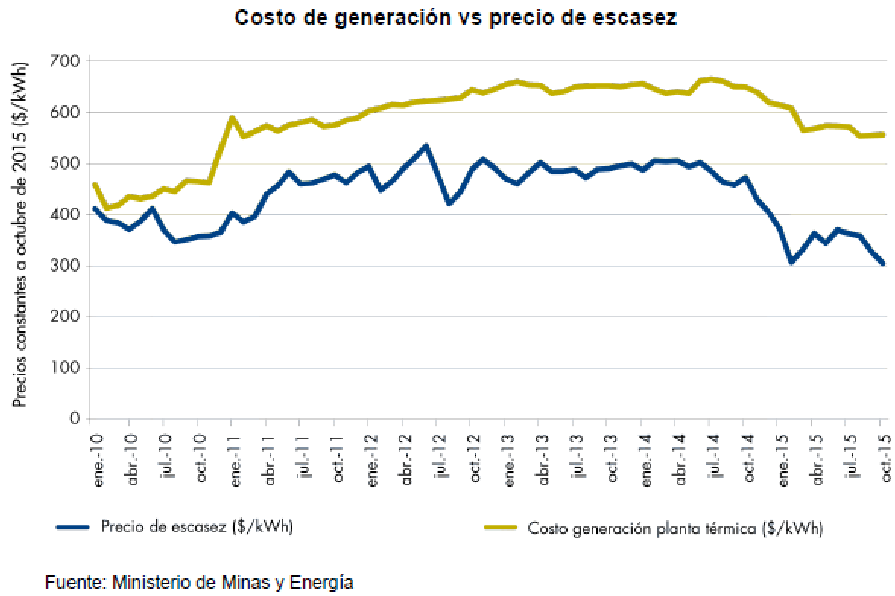

Figure 1: Scarcity Price versus Thermal Generation Costs, 2010-2015

- the intensity and long duration of the El Niño phenomenon beginning in 2015
- a reduction in the value of the Scarcity Price beginning in November 2014 resulting from a steady decrease in the value of Fuel Oil No. 6. From November 2011 until October 2014 the average value of the Scarcity Price was $451.5/kWh and from November 2014 to October 2015 it was $349.7/kWh., having reached a level of $302.43/kWh in October 2015 (see Figure 1).
- interruptions in supplies from fuel oil refineries in Cartagena and Barrancabermeja within Colombia, and the closure of the border with Venezuela, resulting in increased costs of fuel oil for the higher cost generators
- insufficient gas supply for thermal generators due to an unexpected shortfall of gas extracted from Colombia's Guajira fields
- an unexpected increase in electricity demand from May 2015.

As a result of these factors, in October 2015 the CREG introduced measures to ensure continuing supply of electricity given doubts about the financial ability of some thermal generators operating with liquid fuels to supply under their OEFs at the lower Scarcity

Price, complying with Presedential Decree No 2108 of 2015. These measures, contained in CREG Resolution 178 of 2015, were:

(i) establish the Scarcity Price of $302.43/kWh reached in October 2015 as a floor for the Scarcity Price in subsequent months (see Table 1).

Table 1 Scarcity Price

Month	**$/kWh**
oct-15	302,43
nov-15	303,47
dic-15	306,39
ene-16	302,43
feb-16	302,43
mar-16	302,43
abr-16	302,43
may-16	302,43
jun-16	302,43
jul-16	306,92
ago-16	320,88

(ii) establish a new Scarcity Price (P*) for thermal generators operating with liquid fuels of $470.66/kWh, which was the CREG's estimate of what the price would have been in the absence of the five factors described above. This price was the price paid to recompense these generators for providing firm energy under their obligations whenever spot market prices exceeded the Scarcity Prices shown in Table 1 above. These 12 plants account for approximately 10.73% of installed capacity in Colombia, and *13.38%* (INCORRECT) of firm energy commitments (Table 2).

Given these measures, which took effect in November 2015 and lasted until May 2016, all of the thermal generators except one were able to continue to supply energy under their OEFs, albeit at a financial loss in many cases.[4]

[4] "Las plantas térmicas tuvieran una pérdida del orden de $ 600 mil millones de pesos (200 millones de dólares) en 6 meses, y entre ellas Zona Franca Celsia asumió una pérdida de $300 mil millones de pesos (100 millones de dólares)."

Table 2: Plant Operating with Liquid Fuels in Colombia (June 2016)

Name	Fuel	OEF(kWh/día)	C[MW]	VCs($/kWh)	Bids ($/kWh)
Cartagena 1	Combustoleo	1,133,286	61	485.57	406.34
Cartagena 2	Combustoleo	1,240,291	60	464.24	407.01
Cartagena 3	Combustoleo	1,319,686	66	495.29	404.93
Barranquilla 4	Combustoleo	1,119,857	56	554.57	523.91
Barranquilla 4	Combustoleo	1,146,855	56	638.80	522.20
Termocandelaria 1	ACPM	*0*	157	681.23	729.68
Termocandelaria 2	ACPM	*0*	158	669.59	726.55
Termodoradda 1	JET-A1	896,992	51	544.00	507.58
TermocaliI 1	ACPM	4,837,524	213		443.75
Flores 1	ACPM	3,549,089	158	354.63	484.69
TermosierraB	ACPM	6,955,604	445		593.04
Termovalle 1	ACPM	3,770,461	205	*1173.35*	*113.74*
Totals		**25,296,644**	**1.686**		

2.2 Proposals for Reform

The situation caused by El Niño of 2015-16 has led to a variety of calls for changes in the Reliability Charge and Scarcity Price mechanism, including:

- proposals to increase the Scarcity Price to the price of the highest-cost generator operating with liquid fuels or other source of energy (Andeg)
- proposals to increase the Scarcity Price to the variable costs of thermal generators operating with LNG and eliminate the higher variable cost generators from the system, possibly by placing them in a "strategic reserve" for a temporary period of time (Acolgen)
- proposals to increase the Scarcity Price to a very high level (Oren/Garcia), or abolish it altogether and establish critical or scarcity events via technical criteria (Gecelca)

Andeg, which represents the thermal generators, proposes a revision of the Scarcity Price to the cost of the highest-cost plant operating in the system, on the grounds that this was the intention when the Scarcity Price was first defined (in CREG 043 and 085 of 2006), and is in accordance with recent international practice. Their initial proposal was to use the heat rate of the Termocandelaria plant 2 based on the price of diesel, and including associated costs regulated by the Energy Ministry. (Documento ANDEG—001—2014: Un Análisis del Precio de Escasez 2014). The current proposal seems to be to adjust the Scarcity Price to the highest-cost thermal plant with an OEF **for each duration**, over a twelve month period starting in December 2016, taking the maximum of diesel, Fuel No. 6, Jet Fuel or LNG. [5]

Acolgen, which represents largely hydro generators, along with their consultants Batlle and Barroso[6] propose: (i) revising the Scarcity Price to reflect the marginal cost of the group of generating plants that have backed their firm energy obligations with fuel from the LNG facility to come on stream at year-end 2016; and (ii) that firms receiving the Reliability Charge should be restricted to those which can produce energy at a variable cost lower than the revised Scarcity Price based on LNG. Generators which received the higher Scarcity Price of $470.66/kWh under CREG Resolution 178 during the last El Niño event would be placed temporarily in a "strategic reserve", and "substitution auctions" held to replace this plant with new generating capacity capable of delivering energy with variable costs lower than the newly established, LNG-based Scarcity Price.

Oren and Garcia (2016) argue that attempting to set a scarcity price based on the variable costs of thermal generator is a more complex and error-ridden exercise than it may appear, especially since the scarcity price must track fuel prices based on an index which may not reflect changes in marginal costs over time. They refer to the recent experience of New England which initially defined its scarcity price in this way but has now abandoned it, in May 2015, in favour of an arbitrarily high price of $1000/MWh. Oren and Garcia suggest that the CREG should specify a similarly high scarcity price in Colombia (which is about 10 times higher than the current Scarcity Price of approx $100/MWh) thereby avoiding the uncertainties surrounding estimation, but ensuring that the price is almost certainly higher than the marginal costs of any generator operating in the system. They also recommend demand-side participation in the Firm Energy Market which setting a higher Scarcity Price will encourage. Oren and Garcia suggest that such a reform should result in Reliability Charge payments significantly lower than they currently are, corresponding to the capacity costs of new thermal plant, and suggest that penalties for noncompliance should be made steep, e.g. loss of 20% of annual payment for each noncompliance incident. Finally, they propose "decoupling" the two objectives of ensuring adequate capacity during scarcity events, and providing insurance against high prices for consumers by (i) substituting firm energy obligations for an obligation to make capacity available at prices less than the scarcity price during scarcity events; and (ii) mandatory

[5] Andeg, "Balance de El Niño y futuro del sector eléctrico colombiano", Agosto 3 de 2016. Some of the thermal generators, such as Celsia-EPSA, made the same or similar proposals in separate submissions.

[6] "Proposal To Reform The Reliability Charge Mechanism To" Re-Balance and Reconfigure the Colombian Electricity System's Long-Term Energy Mix, July 2016.

long-term contracting (5-7 years) on behalf of demand by suppliers serving the Regulated Market.[7]

Finally, Gecelca took a different line from Andeg and suggests abolishing the Scarcity Price altogether, and substituting a technical test to determine when capacity is scarce, thus triggering the OEFs.[8]

2.3 CREG's Proposals

The CREG notes that the Reliability Charge is really equivalent to an option in which a value is paid for the right to have firm energy delivered at a fixed price and the seller is obligated to deliver when the spot market price exceeds the Scarcity Price. The value of the option depends upon, amongst other factors, of the difference between the spot market price and the scarcity price. The Reliability Charge is determined, as noted in the Introduction, in competitive auctions where the Scarcity Price and the method for indexing it is given and known to all participants. The value of the Scarcity Price and the Reliability Charge are therefore not independent and are inversely proportional. That is, the lower the Scarcity Price, the higher the level of risk assumed by the vendor, and therefore, the higher the value of the premium; or on the contrary, the higher the scarcity price, the lower the risk and therefore, the lower the reliability charge. As noted by Oren and Garcia in the limit, with the Scarcity Price set at infinity, the value of the Reliability Charge should fall to zero (no missing money).

Hence any revision to the Scarcity Price should imply a corresponding change in the Reliability Charge paid to generators. Increasing the Scarcity Price with no subsequent lowering of the Reliability Charge would result in a unwarranted transfer from consumers to generators, and possibly incentivise construction of inefficient, high cost generation plant. Instead, the CREG is proposing:

- to hold additional Firm Energy Auctions restricted to plant with variable production costs of 80% or less of the current value of the Scarcity Price

[7] They suggest that the latter will deal with market power concerns during scarcity events also. As an alternative, Owen and Garcia suggest an auction to determine the value of the Scarcity Price:

> De forma alternativa, puede utilizarse un mecanismo de subasta así:
> 1. Se establece una meta de capacidad (MW) y un valor a pagar por capacidad($/MW).
> 2. Se reciben ofertas de los generadores en la forma de precio "strike" o de referencia para el ejercicio de la obligación. Se ordenan las ofertas por este valor y se define el precio de escasez como el valor de precio "strike" de la planta marginal.

[8] According to Oren and Garcia this would imply moving to a "pure energy market" as in Texas, New Zealand and elsewhere, and in theory should result in the Reliability Charge going to zero (no "missing money").

- adjustments to the Reliability Charge allocation rule to send efficiency signals in the allocation of Firm Energy Obligations among existing resources, for which two alternatives have been presented

2.3.1 Additional Firm Energy Auctions

The CREG is proposing to hold special Firm Energy auctions to replace the higher variable cost plant of Res 178 of 2015. The additional auctions would be sealed-bid, first-price auctions open to generating plants with variable operating costs less than or equal to 80% of the current Scarcity Price and with a reserve (maximum bid) price equal to the value of the current Reliability Charge. The quantity of firm energy to be purchased will be determined by the CREG, and the generating plant selected in the auction allocated Firm Energy Obligations for up to 20 years. The Reliability Charge determined by the auction(s) will apply only to the plant selected in this auction.

2.3.2 Alternatives for Managed Allocations

Article 25 of CREG Resolution 071 / 2006 states that demand that is not covered by prior allocation of Firm Energy Obligations to new plants in the Firm Energy Auctions is allocated to existing generation plants in proportion to their firm energy (ENFICCs). The CREG is now proposing two alternative methods for allocating OEFs to existing generation plant as follows:

A. Allocation of Firm Energy Obligations to plant in order of their average bid prices in the electricity spot market in the year prior to the allocation. Specifically,

i) The remaining demand is allocated proportionately among the generation plants that have average bid prices less than or equal to the average scarcity price.

ii) The remaining demand to be allocated, after applying step i., will be assigned proportionately among the generation plants with average bid prices greater than the average scarcity price.

The average bid price is no more than the arithmetic average of the daily bid prices declared by the plant during the twelve calendar months prior to the allocation date. The average scarcity price is the arithmetic average of the monthly scarcity prices corresponding to the twelve calendar months prior to the allocation date.

B. Allocation of Firm Energy Obligations with Annual Auctions. Following a study by Cramton (2015), the proposal is for annual auctions with the participation of both new and existing plants. If no new plants participate when the auction is called, the Reliability Charge price would be established with the participation of only existing plant.

2.4 Conclusions and Recommendations

Any proposal to alter the value of the Scarcity Price faces the problem that it implicitly alters the terms of the 20-year contracts which have been allocated to new generation plant in the two previous Firm Energy Auctions which set the value of the Reliability Charge for all generation capacity. If it is concluded that an upward adjustment to the value of the Scarcity Price is desirable, either by redefining the marginal plant or by adopting a different fuel index, then this issue must be addressed. One option would be to have a system with multiple Scarcity Prices, i.e. by maintaining the current value of the Scarcity Price for plant already allocated 20-year contracts in past auctions, and to apply any new value of the Scarcity Price to new and existing generation plant once new Reliability Charge auctions had been held with that price as a parameter.

In our view the experience of the El Niño event of 2015-2016, while revealing some weaknesses in certain aspects of the firm energy market design, did not reveal any major flaws nor indicate a need for major reforms. Our conclusions and recommendations, in light of this and the above discussion, are the following:

- certain generators, i.e. those operating with liquid fuels, appear to have been unable or unwilling fulfill their OEF obligations at the historically low Scarcity Prices of 2015-16, leading to CREG Resolution 178 of 2015 as a stop gap measure. It is possible that the various unexpected events of 2015 led to a situation which these generators could not have reasonably foreseen when they acquired their OEFs, and so the measures adopted in CREG Resolution 178 of 2015 were a reasonable response. Nevertheless, the operation of the Firm Energy Market relies upon solid commitments from generators to deliver firm energy when it is required. Hence the CREG should consider how these obligations could be strengthened in future either by requiring larger financial guarantees of performance and/or imposing more severe penalties on generators which find themselves in breach of their obligations. Such financial guarantees should ensure that generators are financially capable of fulfilling their firm energy obligations, and/or paying the appropriate penalty when they do not.[9]
- if in view of strengthened guarantees and penalties some existing generators prefer

[9] Oren and Garcia (2016) and Cramton (2015) discuss the importance of having strong performance guarantees. Currently, to participate in reliability charge auctions, generators have to present a guarantee for 5% of their offer. The generators selected in the auction then have to change the guarantee for one that covers the construction period, equal to one year of their reliability charge income. If during scarcity periods a generator does not deliver on its OEF, they pay the difference between the spot price and the scarcity price on the amount of the deficit.

to drop out of the Firm Energy Market, new auctions such as those held in 2008 and 2011 could be called to elicit new capacity commitments. Such auctions should be technology neutral and open to all generators, irrespective of their variable costs of producing energy. Restricting the auctions to technologies with lower variable costs (such as in the CREG proposal to restrict participation to generators with variable costs less than or equal to 80% of the Scarcity Price) risks increasing the average cost of acquiring firm energy in Colombia, and introducing an inefficient mix of technologies. That is, restricting participation to certain types of plants will most likely result in excluding plant that can provide firm energy at the lowest average cost.

- the CREG could consider whether the indexing of the Scarcity Price to Fuel Oil No. 6 has served its intended purpose, and if not consider an adjustment to the Scarcity Price using a new index, perhaps based on a mix of various relevant fuel prices, or eliminating indexing altogether. Various proposals for adjusting the Scarcity Price to reflect the current marginal costs of "more expensive" technologies have been noted above (e.g. the proposals of Andeg and Alcogen). However, there is no necessity for the Scarcity Price to reflect the operating costs of any particular generating technology, so eliminating indexing may be a preferable option (as suggested by Oren and Garcia 2016).

- as an alternative the CREG could consider whether the Scarcity Price should be recalibrated and updated by redoing the exercise carried out in CREG Resolution 071 of 2006 and establishing a price exceeded by the spot market less than 5% of the time (perhaps as a rolling five-year average). This would avoid the problems of indexing described above and arguably ensure that the Scarcity Price is adjusted to more accurately reflect actual scarcity conditions over time.

- if any resulting change in the Scarcity Price is small, then no revisiting of the 20-year contracts may be necessary. If the change is significant, however, then generators with 20 year contracts should either be held to their original contracts at the original Scarcity Price, or be given the option of recontracting at the new Scarcity Price, but only once a new Reliability Charge level has been established in competitive auctions.

- annual Reliability Charge auctions, as proposed in Cramton (2015), would seem to be preferable to a managed allocation system based on generator bid prices. An auction should result in a more efficient allocation of firm energy obligations, and establish a different, and presumably lower, value for the Reliability Charge for existing generation plant during periods when capacity is in surplus. As pointed out in Harbord and Pagnozzi (2014), decoupling the prices paid to new versus existing capacity is a potentially important market power mitigation measure, especially when most of the new capacity offered in the auctions is likely to come from a relatively small number of energy companies which already own the lion's share of extant capacity.[10]

- Cramton (2015) has now accepted our recommendation (in Harbord and Pagnozzi 2012) that the Firm Energy auctions adopt a sealed-bid format. He has also proposed changes to the price determination rule to the maximization of net value by solving a combinatorial optimization problem. Our views on this issue can be found in Harbord and Pagnozzi (2012), Section 3.4.1, where we express some doubts about adopting such a pricing rule.

[10] Large bidders with significant amounts of existing capacity that will receive the auction-clearing price set by new capacity exacerbates market power problems in the auctions. They have strong incentives to reduce their supply of new capacity in order to set a higher price for their existing units. In the 2014 capacity auction in New England, an administrative price for existing capacity was set, presumably to avoid this problem. See Harbord and Pagnozzi (2014) for a discussion.

3 Forward Market for Energy Contracts

Organized forward markets can complement spot markets for wholesale electricity by reducing risk, mitigating market power in the spot market,[11] reducing transaction costs and improving liquidity and transparency. Risk is reduced by allowing generators and suppliers lock in energy prices and quantities for longer terms, reducing the quantity of energy traded at more volatile spot prices. Longer-term contracts can mitigate market power problems by reducing generators' incentives to manipulate spot market prices.

Most of Colombia's electricity (85% - Andeg) is already traded in contracts with durations of one or two years, and sometimes more. Unfortunately, the existing electricity contract market has high transaction costs, as a result of non-standard contracts, poor price formation, localized contracting, lack of transparency, and other factors. Evidence of a problem is seen in the frequent occurrence of higher contract prices for regulated customers compared with nonregulated customers, which is unexplained by load shapes, credit risks, and other factors. There is concern that vertically integrated generator-retailers sell contracts which favour their own non-regulated customers over regulated customers. For instance, the generator with the largest share of installed capacity in Colombia (22.18% - EMGESA?) also represented nearly 17% of demand on the National Grid (SIN in Spanish) in 2015. The generator with the second largest share (19.49% - EPM?) is part of a consortium of several retailers that represented 22% of the national demand in 2015. In total, 52% of generation has commercial interests in companies that represent nearly 40% of the national demand.

Figure 2 shows average prices of contracts in the regulated and nonregulated markets for 2014-2015. The average price difference between the two markets was $26,265 (COP/kWh) in 2014 and $26,751 (COP/kWh) in 2015. This implied average percentage price differences of 22.36% in 2014 and 20.70% in 2014, respectively. The corresponding figures for the first eight months of 2016 were $30,226 (COP/kWh) and 22.09% respectively.

In Colombia, an average of 5,962 GWh-month were purchased in longer-term contracts throughout the year 2015. Compared to actual monthly generation, the churn ratio is 1.07 on average, much lower than in Germany where this ratio was 7.1 in 2015, and 5 in the Nordic market. Thus the liquidity of the contract market in Colombia, at least according

[11] See for example Ausubel and Cramton (2010). However, a number of authors have now identified various strategic effects which can work in the opposite direction, so that the introduction of forward markets results in less, rather than more, competitive outcomes in the spot market. See von der Fehr and Harbord(1994), Herrera Dappe (2008), Holmberg and Willemsz (2012) and Holmberg and Willemsz (2011).

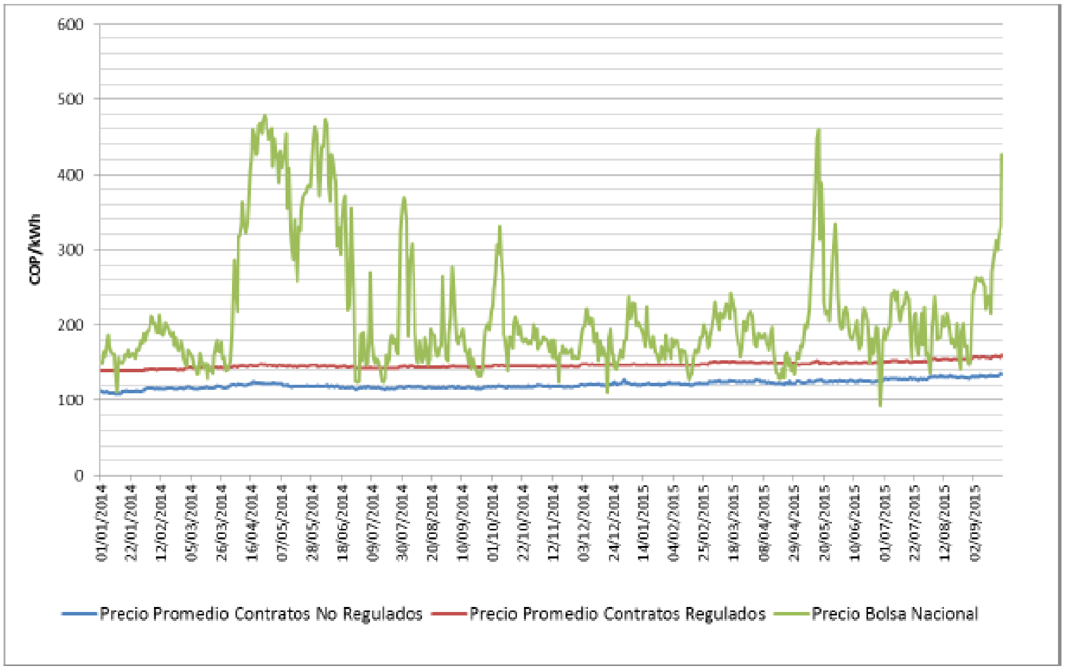

Figure 2: **Average contract prices (COP/kWh) in regulated & nonregulated markets, 2014 - 2015**

to this measure, is comparatively low by international standards.[12]

Concerns have also been raised in Colombia about the lack of longer-term contracts offered by generators at "competitive prices".[13] The source of this problem seems to be the unwillingness of hydro generators to offer contracts for energy levels in excess of their firm energy (ENFICCs), as doing so exposes them to the risk of nondelivery during dry periods, and in the extreme El Niño periods, when spot market prices are very high.

3.1 CREG Proposal for an Organized Market for Energy Supply Contracts

Given the issues mentioned above, the CREG is proposing to introduce an organized market for contracts in Colombia that will create "neutral and transparent sales mechanism

[12] "In the last few years in Germany and the Nordic markets the so-called churn rate, showing the ratio of all traded volume of power and the electricity consumed in a given period, was particularly high, implying that total volume of traded power exceeded the annual electricity consumption by a factor of 5 to 7. The amount of traded power also exceeded the annual electricity consumption in the UK. In the other EU markets the role of the OTC market was of lesser importance." Quarterly Report on European Electricity Markets Market Observatory for Energy DG Energy Volume 8 (issue 1; first quarter of 2015).

[13] "Proposals For The Entry Of New Generation Plants And The Allocation Of The Reliability Charge To Existing Plants" - Creg Document -000, September Xx, 2015.

that will ensure the participation and availability of information to all stakeholders."

3.1.1 Primary Auction Market

The key component of this proposal consists in the implementation of centralized, quarterly auctions for the purchase and sale of a standardized futures energy contracts in which the generators can sell, and agents representing regulated and non-regulated consumers, can buy forward contracts for electricity at fixed prices and volumes. The auction mechanism proposed by the CREG is a reverse, descending clock auction in which prior to the auction regulated and nonregulated demand submit their demand curves, and generators then compete to supply this demand offering one-year forward contracts for differences. The product that would be auctioned corresponds to a 1 MWh-day energy supply contract for one year, for delivery in a future period. The contract proposed is a flat product, in which the same quantity of energy is contracted each hour of the day.

These contracts will be purchased in auctions held two or three years before the start of the commitment. This is intended to allow for the resulting auction prices to reveal the expectations of market agents in the near future. The initial proposal is to hold four auctions per year. In the first two, contracts would be traded for delivery in t+2 and t+3 years, and in the other two, contracts would be traded for delivery in t+3 and t+4 years. This way, the demand can be covered gradually allowing a forward curve of energy prices to be constructed.

The advantage of having a single product for each year is to allow for greater competition, and reduce price discrimination, between the regulated and nonregulated markets. A yet-to-be determined proportion of regulated demand will be required to purchase its energy requirements in the auctions (e.g. 60%-80%), and agents serving regulated demand will be able to "pass through" the entire cost of these contracts to regulated consumers.

3.1.2 Secondary Market

In addition to the primary market the CREG proposes to organize a secondary OTC market for bilateral trading of contracts acquired in the auctions. It is proposed that in this market, agents can transfer entire fractions of the products acquired in monthly periods and agree on the price of the product bilaterally. It is important to remember that the duration of the supply contract traded in the auction is one year, and the quantity of energy is 1 MWh-day, so on the secondary market, the products acquired can be traded by dividing them into monthly portions, provided the minimum quantity is 1 MWh-day and the energy traded is a whole number. The purpose of the above is for the secondary market to be liquid and to allow all the agents to satisfy their needs as they wish.

3.2 Alternatives to the CREG Proposal

A number of alternatives to the CREG proposal have been put forward:

Cramton (2007) Peter Cramton proposed a mandatory market for suppliers of regulated demand with two load-following products to be purchased in quarterly, simultaneous descending clock auctions. For the regulated product, each supplier bids to serve its desired share of Colombia's regulated load. A supplier that wins a 10% share at auction has an obligation to serve 10% of the actual regulated load in every hour of the commitment period. The supplier is paid the auction clearing price for every MWh of energy supplied. Deviations between the supplier's hourly supply and obligation are settled at the spot energy price or the scarcity price, whichever is lower. The nonregulated product is essentially the same, except each supplier bids to serve its desired share of the nonregulated load. Cramton also proposed an organized secondary market in the form of a monthly sealed-bid auction.

Oren and Garcia (2016) The National Planning Department's consultants, Oren and Garcia, also propose a mandatory market or exchange for suppliers of regulated demand. The products proposed are either standard contracts for differences or standardized call option contracts (such as those used in the firm energy market), with a duration of five to seven years, so that each product will cover at least one El Niño event. To address possible liquidity issues they also propose that vertically integrated generator-suppliers be obliged to purchase a minimum fraction of their contracts to serve both regulated and nonregulated demand in the centralized market.

Wolak (2016) Addressing the issue that most wholesale electricity markets have a small number of vertically-integrated "gentailers" (own generation units and also sell retail electricity), including New Zealand, Australia, Colombia, Chile, Singapore, and virtually all US markets, Frank Wolak proposes an anonymous market for standardized energy forward contracts to allow entry of purely financial participants into electricity retailing, and face incumbent retailers with greater competition. Forward market purchases by financial participants can increase forward market obligations of incumbent generation owners which reduces incentives of incumbent generators to exercise unilateral market power, leading to lower retail and wholesale electricity prices. In April 2015, Singapore introduced an anonymous standardized futures market for electricity. Contracts are traded on Singapore

Exchange (SGX), and each incumbent generator is a market maker. Incumbent gentailers are required to serve as market makers and post bid-ask spreads for minimum volumes of energy, for each delivery horizon of the futures contracts. (Current spread is SGD 5/MWh). Currently there are six market makers in Singapore.

Three purely financial retailers entered market between April 2015 and the present time who purchase contracts in futures market and compete to sell energy in retail market to contestable customers Wolak analyzes the data and finds that incumbents' contracts were priced an average 7% lower, and new entrants' contracts priced an average 4% lower than they otherwise would have been. He also finds that total wholesale energy costs over the period SGX futures market was in place were 8% lower as a result of existence of this market.

Industry Proposals

- Chivor suggests that generators be permitted to offer monthly or seasonal contracts to better reflect their generation profiles, and not solely 1 MWh-Dia contracts.

- Gecelca proposes: (i) establishing an exchange for futures contracts and financial derivatives in which "los contratos bilaterales suscritos a la fecha coexistirán con el nuevo mecanismo propuesto, se ejecutarán de acuerdo a lo pactado mientras estén vigentes. Así mismo, se establecerá como techo de la componente G de la formula tarifaria del CU el precio promedio de transacciones del Exchange para el mes correspondiente"; (ii) Establishing "Markets Makers" obligatorios para garantizar la liquidez del mercado; (iii) a "submercado" semi-estandarizado donde los agentes integrados verticalmente celebrarán contratos de máximo el 30% de los compromisos de la demanda regulada representada por su comercializador, límite que se reducirá gradualmente hasta desaparecer. Estos contratos igualmente serán estandarizados como los del EXCHANGE, se firmaría fuera del sistema o plataforma del mercado financiero para mayor transparencia, pero luego se registraran ante el EXCHANGE y el SPOT."

- Isagen wasn't clear on the preferred mechanism but they propose standardized contracts for the very long term (10-20 years); medium term (5 years) and shorter term (one year). The latter could be traded in a futures exchange which would serve as secondary market for longer-term contracts.

3.3 Comments and Discussion of the Proposals

- no commentators have supported the Cramton approach of offering load-following contracts in auctions. Flat, fixed-quantity contracts would appear to be the preferred option (but see Chivor contract proposal).

- most commentators seem to believe that an exchange would suffer from liquidity problems for the foreseeable future, citing the Derivex experience as an example. Therefore the CREG's proposal for quarterly auctions may appear to be a better approach. However, liquidity in the exchange would presumably be increased by the requirement that regulated demand participate for at least 60-80% of its energy requirements, so this issue may not be as important as some have suggested.[14]

- assuming that auctions are adopted, it is unclear why a open, descending clock auction is preferable to a sealed-bid auction. Price discovery, the usual rationale for preferring a clock auction (Ausubel and Cramton 2010), does not appear to be a significant factor in this setting, and sealed-bid auctions are simpler to implement and mitigate market power problems.[15] A practical reason for preferring a clock auction might arise if there were a significant number of substitute products to be offered simultaneously in the auction. Although such substitutions can be handled in sealed-bid auctions,[16] auction participants apparently find them more difficult, or at least unfamiliar.

- the proposed auctions do not appear to deal effectively with the issue of vertically-integrated generators and price discrimination between the regulated and nonregulated markets. Vertically integrated generators could seek to avoid purchasing anonymous contracts to supply their regulated demand by declining to sell contracts in the auction, making the auctions infeasible. There may therefore need to be a participation requirement for vertically-integrated generators, as suggested by Oren and Garcia (2016), or alternatively, a requirement that these generators act as "market makers" (as described by Wolak 2016; also Gecelca). This would (at least partially) prevent vertically integrated generators from trading only with themselves, and setting different prices for regulated versus non-regulated demand.

[14] Likewise, if participation requirements on generators were also imposed, as discussed immediately below, liquidity problems would presumably cease to be of relevance.

[15] For discussions of these issues in a different, but related, context see Harbord and Pagnozzi (2014). Also Cramton (2015).

[16] In simultaneous sealed-bid auctions, also known as "assignment" or "product-mix" auctions. See Milgrom (2009) and Klemperer (2010). For a detailed discussion of these auctions in the context of Colombian gas contracts see Harbord, Pagnozzi and von der Fehr (2011).

- the proposed one-year contracts in the auction would not appear to deal with the problem of inadequate supply of contracts from hydro generators. It is not clear why hydro generators will be willing to offer energy in contracts in excess of their firm energy (ENFICCs) in these auctions, when they have been unwilling to do so in the past. Nor is it clear how longer-term contracts, such as those suggested by Oren and Garcia, would alleviate this problem. Five to seven year contracts which should be sufficient to ensure at least one El Niño event within the contract's duration will presumably make hydro generators even less willing to commit to selling energy above their guaranteed (ENFICC) levels.[17]

- eliciting greater supplies of energy in contracts from hydro generators (which account for approx. 80% of Colombia's produced energy in "normal" times, and "40% during El Niño periods) may require the introduction of interruptible contracts, similar to the "conditional firm" contracts utilized in the gas market, which are interrupted during scarcity periods. These contracts should allow hydro generators to sell more energy in contracts during "normal" times, without facing the risk of having to buy energy at high spot market prices to fulfill their obligations during El Niño events. During scarcity periods, the generators and consumers are fully hedged, as they will sell and buy all of their energy at the Scarcity Price. In effect, during scarcity events the private bilateral contract is replaced by a regulated contract at the Scarcity Price.

- both firm and conditional firm contracts purchased in the auctions should be passed through in full to Regulated Demand at the auction clearing prices; as noted, demand is already fully protected during scarcity events by the Scarcity Price.

- if multiple, substitute contracts are to be sold in the auctions - firm and "conditional firm", interruptible contracts - the auction should use an ascending clock format to allow demand to arbitrage between the contract types. Generators could offer the quantities of energy they wish to supply in each contract type prior the auctions, along with their reserve prices. Alternatively, sealed-bid auctions of the "product mix" or "assignment" type mentioned above could be implemented.

[17] To the degree that vertically-integrated generators are hydro generators, the participation requirements mentioned above might, indirectly at least, partially resolve this issue.

4 Spot Market Reform: Day-Ahead and Intra-Day Markets

The CREG is suggesting various reforms to the current short-term or spot-market design, in particular the introduction of a day-ahead and intra-day trading markets.

4.1 Current Market Design

Currently, transactions in the energy spot market are configured and settled in a three-stage process. On the day before operations (t-1), each generator i must submit an offer that consists of two elements. First, a single price P_{ij} must be offered for each of its generating units j for the 24 hours of the following day, and availability of each unit for each hour of the day which is denoted D_{ijh}. The market operator uses these offers, together with projections of demand and grid restrictions to calculate the scheduled dispatch. It orders the offers from lowest price highest price to determine which units must generate in each hour of the following day to meet expected demand. XM publishes the "precio de bolsa del predespacho ideal", which shows the price of the marginal plant for each hour the day before operation.[18]

On the day of operation (t), if a plant that entered the scheduled dispatch becomes unavailable, the market operator replaces it by calculating a new dispatch schedule based on the price offers made by generators the previous day. A generating company which declares a plant or unit unavailable does not incur any penalty, provided that advance notice is given.

The day after operation (t + 1), the market operator calculates an "ideal dispatch" using the price offers from day (t-1), the plants dispatched and actual demand on day t. This ideal dispatch does not take account of grid restrictions and is used to determine generators' remuneration by calculating the single, country-wide spot price for each hour P_h. These prices are used to settle transactions in long-term contracts and in the spot market for each generator. Generators who have plant that are either "constrained on" or "constrained off" due to transmission constraints are paid (or pay) "reconciliation" payments.[19]

[18] This is an estimate of the next day's spot price which takes into account the bids made by the generators, but it does not include network restrictions nor the technical dispatch charateristics of the plants. It serves to activate the imports or exports to Ecuador, the demand response program and the purchase options in the gas market.

[19] Generators whose actual quantity supplied exceeds their "ideal quantity" because of transmission constraints, receive positive reconciliation payments equal to the minimum of their variable production costs and their (t-1) price offer for the additional quantity supplied, and the spot price P_h for their "ideal

This design of the spot market that has been operating in Colombia since 2001, and a number of issues have been identified or raised by market particleboards and the CREG:

- the lack of any firm commitment of capacity offers, with no penalties for declaring plant unavailable, means that generators may have an incentive to manipulate capacity declarations in order to increase prices strategically. When changes in availability can be made without penalty, generators can change their availability near to real time operations whenever they identify situations in which decreasing generation can increase the market price and therefore the payments received. [20]

- real time dispatch is based on the price offers made the previous day. This may lead to some inefficiencies, such as the dumping of water by hydro electric plant not scheduled for dispatch but which reach the maximum water levels in their reservoirs, and hence must dispose of stored water[21]

- coordination with short term gas market contracting is made difficult as the scheduled dispatches in the electricity market occur before completion of the use it or sell it daily auctions in the secondary gas market. Thus a generator that is dispatched that does not find natural gas and pipeline capacity must be declared unavailable,[22] and the CND must redispatch, with cost overruns paid by demand. Similarly, if a thermal generator can find natural gas at a low price, it cannot place a new bid based on these less expensive resources.

- uncertainty concerning scheduled dispatch and market prices has implications for decisions of other agents. In particular, the fact that scheduled dispatch is only indicative has been identified by the CREG as one of the elements that limits participation of demand in the market and complicates the import-export market with Ecuador.

quantity". Constrained off generators make negative reconciliation payments so that they receive Ph or their actual quantity and $\frac{1}{2}$ x ($P_h - P_{Offer}$) for the difference between the ideal and the actual quantity. See Frank Wolak "Report on Market Performance and Market Monitoring in the Colombian Electricity Supply Industry", July 30, 2009 for a discussion.

[20] According to data provided by XM, on average 3.12% of the generation was redispatched in 2012. Although the average amount of redispatches may not seem very high, there are situations in which the redispatching amounts to as much as 10% of the total dispatch.

[21] According to information provided by XM, from 2010 to mid-2014, the average amount of usable water dumped was equivalent to 1.32% of total system generation.

[22] But this would not appear to be a declaration of unavailability for "technical" reasons as discussed above.

4.2 The Proposed Market Design

In the proposed market design, generators will make the same type of offers as in the current market design for each of their units at 1 pm on the day before operation. Unlike in the current market setup however, the market will be cleared immediately, i.e. before actual operation. Market clearing – or economic dispatch – is done in a similar way to what was above termed the indicative dispatch (i.e., the least-cost configuration of units that meets forecasted demand), but without taking network restrictions into account. A market price will be determined for each hour according to the same marginal-cost rule as in the current ex post price determination. The result of this optimization will be the day ahead energy market which will determine the financial obligations acquired by each generator dispatched for the day of operations. The only difference with the current scheme is that all offers accepted for dispatch become firm commercial commitments that will be settled at a price that matches supply and demand during each hour in this market.

All generators connected to the National Interconnected System (SIN) with capacities greater than or equal to 20 MW are required to participate in the day-ahead market. The same is true for traders that serve end users who are connected to the SIN. Nonregulated users can send their supply and demand curves and disconnection price through traders who represent them.

After the day-ahead market is cleared, CND calculates an indicative physical dispatch taking network restrictions into account. Results – including both economic and physical positions – are communicated to each of the market participants before 1.35 pm.

The initial market clearing will be followed by three auctions at, respectively, 9:00-9:15 pm on the day before operation and at 6:00-6:15 am and 2:00-2:15 pm on the day of operation. The first auction covers the entire day of operation (i.e. all 24 hours), the second auction covers the period 9 am to the end of operation (i.e. 15 hours), while the last auction covers the period from 5 pm to the end of operation (i.e. 7 hours). In each auction, generators make offers in the same format as in the day-ahead market.[23] A market-clearing process determines the market price as well as the [economic and physical] energy positions of the various market participants. Financial settlement is based on differences between these market positions and the positions resulting from the previous auctions, including the day-ahead market.

[23] According to the proposal "price offers from generators able to participate in the intraday market must be less than the last price offered the previous day".

4.3 Comments and Proposals by Others

Oren and Garcia (2016) broadly approve of the change to a day-ahead market but also propose:

- a "Sistema de Liquidación Doble" which they suggest is simpler than intra-day markets;
- nodal pricing to eliminate reconciliation payments;
- the introduction of more complex bids to more accurately reflect the cost structure of generation; and
- a market monitoring scheme to mitigate the exercise of market power in the spot market.

Celsia/Epsa suggest:

- allowing "las plantas térmicas también puedan ofertar en función del costo de oportunidad, con lo cual se reduciría la posibilidad de ejercer poder de mercado por parte de los recursos hídricos";
- que el esquema de despacho para cubrir generaciones de seguridad considere un periodo mayor a las 24 horas del día de operación, y que se evalúen otros periodos, por ejemplo semanal, de manera que se permita optimización de los recursos térmicos;
- un análisis profundo sobre lo impactos de implementar precios multinodales en Colombia;
- disponibilidad de información del mercado para los agentes;
- que el mercado debería iniciar alrededor de 4 o 6 subastas de intradiario, de manera que se pueda valorar los recursos inflexibles de mejor manera; and
- que la oferta hidráulica puede tener un esquema de oferta en bloques que permita una mejor gestión de los embalses y que podría aplicar exclusivamente en condiciones denominadas "Críticas".

AES Chivor, along with some others, argues that generators should have more timely information over the price offers made in the spot market. They also suggest including costos de arranque y parada in generator bids and that generators be allowed to bid two price/quantity offers in the day ahead market so that the most competitive offer is used to fulfill firm energy obligations.

Gecelca have suggested introducing a "sistema de Ofertas Semanales", "en el cual participen las Plantas Despachadas Centralmente, mediante el envío de ofertas de precios y disponibilidades semanales pero diferenciadas con posiciones de ofertas diarias. Estas ofertas se enviarían el último día hábil de la semana anterior a la semana de despacho, cuyo primer día será lunes. Podría evaluarse la posibilidad de otorgar beneficio de modificar disponibilidad a aquellos embalses multipropósitos y/o filos de agua" alongside a Mercado "Day-Ahead" and Mercado Intradiario de balance.

Isagen suggest:

- allowing for multiple price/quantity offers from each generating unit in the day ahead market;
- returning to unitary price offers without start up or shut down costs; and
- making bid/offer information publicly available.

4.4 Comments and Discussion

The CREG proposal substitutes *ex post* price formation, i.e. hourly market prices calculated from actual demand and supply conditions on the day of operation, for *ex ante* price formation, i.e. hourly prices calculated using day ahead estimates of these variables. If demand and supply conditions change very little on average between day t-1 and day t, then this is innocuous but arguably unnecessary. When the changes between the *ex ante* and *ex post* prices can be substantial, this implies that most spot market transactions will be settled at prices which may be very different from actual, real-time market-clearing prices. Only the changes in positions relative to the day-ahead market (e.g. additional, unexpected demand or capacity outages) will be priced at "real time" prices in the intra-day auctions.

To recapitulate, the arguments in favour of adopting this new model presented by the CREG were:

- capacity withdrawals without penalties to be replaced by day-ahead financial commitments
- improvement in despatch when, for example, hydro reservoirs have more water than predicted, or similarly for renewables such as wind and solar

- easier demand-side participation as a result of greater *ex ante* certainty about prices
- easier coordination of imports/exports as a result of *ex ante* certainty about prices

The first thing to observe is that these issues don't appear to have been the subject of any detailed study, as one might expect before a large-scale market reform is proposed. The CREG report that on average 3.12% of the generation was redispatched in 2012 without any indication of whether this is an unusually large percentage. Similarly, the CREG reports that from 2010 to mid-2014 the average amount of usable water dumped was equivalent to 1.32% of total system generation.

The second thing to note is that simply moving to a day-ahead market with prices determined *ex ante* would not necessarily improve matters. In particular, although a demand-side bidder may reduce demand based upon the day-ahead prices, if they are unable to change this position in light of changing conditions on the day of operation, the same inefficiency remains. The same is true for importers-exporters. Thus the day-ahead market is only an improvement when combined with the multiple settlement or retrading opportunities. Indeed, it is possible to take the view that the real improvement in the CREG proposal has little or nothing to do with day-ahead pricing, but rather in the way it deals with financial commitments to day-ahead bids and offers, and the flexibility it allows for adjusting positions closer to real time in the intra-day markets. This may or may or not entail a change to a system in which most energy market transactions are settled at day-ahead prices.

For example, the CREG proposal resolves the strategic capacity withdrawal issue by making offers on the day-ahead market binding financial commitments. Thus a generator which offers a quantity q_0 on the day-ahead market will receive the clearing price of P_0 if the quantity is accepted. If it reduces this quantity to q_1 on the day of operation, it will be obliged to purchase the deficit in the intra-day market, at whatever price clears that market, say P_1. The generator will then receive $P_0 q_0$ from the day-ahead transaction and pay $P_1(q_0 - q_1)$ in the intra-day market. In other words,

$$\text{Generator remuneration} = P_0{\cdot}q_0 - P_1(q_0 - q_1) = P_1{\cdot}q_1 - (P_1 - P_0)q_0 \tag{1}$$

The incentive for strategic capacity withdrawals is thus reduced or eliminated, as they do not change day-ahead prices, and a financial penalty of $P_1(q_0 - q_1)$ is paid (presuming that P_1 is greater that P_0 as a result of the capacity withdrawal). If, on the other hand, a generator wishes to sell additional energy into the intra-day market, to avoid spilling water say, the resulting payments are,

$$\text{Generator remuneration} = P_0 \cdot q_0 + P_1(q_1 - q_0) = P_1 \cdot q_1 + (P_0 - P_1)q_0 \tag{2}$$

In a real-time pricing system, an equivalent set of obligation can be introduced.[24] In the case of a capacity redeclaration, prices change in real time from P_0 to P_1, and the generator is paid

$$P_1 \cdot q_1 - (P_1 - P_0)q_0 \tag{3}$$

where $(P_1 - P_0)q_0$ is the additional cost or penalty imposed on the generator for the redeclaration. Since (4) is equivalent to (1) the same incentives are created.[25]

Note that this scheme works symmetrically for capacity additions. A hydro generator wishing to increase its offer on the day of operation to avoid spilling water can increase its offered quantity from q_0 to q_1 and be paid,

$$P_1 \cdot q_1 + (P_0 - P_1)q_0 \tag{4}$$

where $(P_0 - P_1)q_0$ now represents the saving to the system from increased, lower cost energy which substitutes for more costly energy. The same would apply to other nonconventional renewables such as wind or solar, as well as exports and imports.

Demand increases and reductions could also be accommodated in this setup in principle, although this may be more difficult in a single nodal system such as Colombia's where real-time prices are not continuously updated (so demand-side bidders would not have the relevant price information available to adjust their bids). Therefore a number of the issues identified by the CREG, such as capacity redeclarations, could be resolved simply by making day-ahead capacity bids firm financial commitments, without requiring a move to day-ahead pricing followed by intraday trading. As we have noted above (and repeat below), the extent of the efficiency losses associated with any one of the issues identified by the CREG have not been quantified, so we are not in a position to judge whether a relatively minor reform to make capacity bids financially binding, or a larger-scale reform such as that proposed by the CREG, is more desirable.

4.4.1 A Note on the Market Power Issue

It is often claimed that introducing day-ahead markets followed by intra-day markets will mitigate market power problems in the spot market, compared to a single settlement system (Oren and Garcia 2016, Section 4.1; also Ausubel and Cramton 2010). While a

[24] This may be what Oren and Garcia mean by a "Sistema de Liquidación Doble".

[25] So long as we apply (4) to the generator's entire capacity rather than to a single capacity unit.

potential for a procompetitive effect clearly exists, a number of authors have identified strategic effects which can work in the opposite direction. As a result, the introduction of forward markets may result in less, rather than more, competitive outcomes in spot markets.[26]

Herrera Dappe, for example, shows that when capacity-constrained firms compete in a multi-unit auction with a price cap, forward trading does not always enhance competition. On the contrary, firms can use forward trading to soften competition between them, leaving consumers worse off. The intuition for this result is that when a capacity constrained firm commits itself through forward trading to offering more output in the auction, its competitor faces a more inelastic residual demand in that market. Hence, the competitor prefers not to follow suit in the forward market and thus behaves less competitively than it otherwise would, by inflating its bids. A similar strategic effect of forward trading was found in von der Fehr and Harbord (1994).

4.5 Concluding Comments

A change to a new market arrangement for short-term transactions should work well in Colombia, although evidence for serious problems or efficiency losses under the current trading arrangements seems to be lacking. It is unclear that the level of capacity redeclarations, or water spillages by hydro generators, are more than would be expected in any other hydro-based electricity market. Nor does any attempt appear to have been made to study these issues. Likewise, the putative efficiency losses from the limited participation by demand-side bidders under the current arrangements have not been quantified. I recommend that these issues be given more serious study prior to adopting the proposed reforms.

Finally, I can see no argument for adding greater complexity to generators' bids by including additional cost information, as suggested by some industry participants. These costs are best internalized by generators, and increased bid complexity can lead to additional opportunities for market manipulation by generators with market power. I am more sympathetic to suggestions, made by some market participants, for a return to simple energy-only bids. Nor can I see any argument for making generators' bid/offer information publicly available earlier than it currently is.

[26] See von der Fehr and Harbord (1994), Herrera Dappe (2008) and Holmberg and Willemsz (2011) (2012).

5 Mechanisms to Elicit Investment in Nonconventional Renewable Energy in Colombia

The Colombian government is interested in encouraging investment in nonconventional renewable energy (FNCER), and the CREG has accordingly brought forward proposals to implement this policy. We consider the three alternatives put forward by the CREG in this section, followed by a brief annex which discusses the calculation of capacity factors, or firm energy, for wind powered generation in Colombia.

5.1 Proposal 1: Auctioning of Long-Term Mean Energy Agreements

The CREG proposal is for two (or more) consecutive auctions. The first elicits proposals for nonrenewables energy capacity, and purchases the mean annual energy from accepted projects in 20 year energy purchase agreements at a price determined in a sealed-bid, discriminatory price auction. The quantity of energy to be purchased in the auction (the demand) will be defined by CREG and will be expressed in megawatt hours per year (MWh-year).[27] Participating sellers in the auction will be generators with new, FNCER-based generation projects which have yet to start operations, and which have no firm energy obligations (OEFs) assigned to them. Each will submit a mean energy price bid for each project offered, and price offers must be lower than the reserve price set for the auction, which will be set by CREG.[28] Selected projects will receive their bid prices for their mean energy in 20 year contracts.

Following this auction. a second auction will then be held to determine the buyers of the mean annual energy of projects selected in the first auction. This auction will be an ascending clock auction, with a reserve price given by the quantity weighted average of the prices assigned in the energy purchase auction, plus the equivalent cost of energy CERE. 20 year purchase contracts will be awarded. If this auction fails to sell all of the mean energy purchased in the first auction, a subsequent clock auction for five year contracts will be held. Finally, if these two auctions fail to award all of the purchased mean energy to suppliers or distributors, the remaining amount will be allocated pro rata to regulated demand.

[27] The CREG's assumption is that the sum of the total amount of energy sold by generators through this mechanism will not exceed 5% of the demand forecast by the UPME's high-demand scenario for year t+4, at least in the first auction.

[28] The reserve price proposed by the CREG is the average spot market price for the year preceding the auction, using the scarcity price as the cap for spot market prices. It is unclear whether this reserve price is appropopiate, or if it will elicit sufficient bids.

The product offered in the first auction is an Energy Purchase Agreement (EPA-type contract) for annual mean energy. Under the terms of this contract, the seller commits to delivering a specific amount of energy during the year (MWh-year), at a fixed price.

The product offered in the second (and third) auction is a take-or-pay contract for a fixed hourly energy amount over a 20 or 5-year term, respectively.

Issues

- First, it is unclear that a reserve price set at the average spot market price will be sufficient to induce investment in new, presumably risky and higher-cost technologies. If it were, then it is unclear why these investments would not be made without any special inducements or subsidies. More consideration will need to be given to this issue.

- Second, it is unclear why the first auction to elicit investment in new technologies is sealed bid, while the second and third auctions to allocate the energy purchased to distributors are ascending clock auction. All auctions should use the sealed bid format, and consideration given to adopting a uniform pricing rule.

- Third, it is unclear why the first and second auctions cannot be combined into a single, first-price sealed-bid auction in which any deficit in demand offered by distributors is made up for by the CREG. Any mean energy purchased in this auction, but not purchased by distributors, could subsequently be allocated to demand.

- Finally, the "take-or-pay" contacts purchased, or allocated to demand, appear to require a rather complex weekly, monthly and annual balancing of accounts. A simpler solution might be to simply allocate purely financial "contracts for differences" to demand, doing away with the need to keep track of the generators' actual production.[29]

[29] Such as the renewables contracts recently auctioned in the UK. Auction winners were awarded contracts for differences (CfDs), a financial instrument which guarantees additional revenue over those received from selling power into the wholesale power market. Payments per MWh are calculated as the difference between the contract or 'strike price' and a measure of the wholesale market price known as the 'reference price'. The level of the contract strike price is determined in the auction. In instances where the wholesale power price is higher than the strike price, the contract requires that the generator makes payments to the contract counterparty. See Aures Report D4.1-UK, March 2016, "Auctions for Renewable Energy Support in the United Kingdom: Instruments and lessons learnt."

5.2 Proposal 2: Auctioning of "Pay as Generated" Long-Term Energy Agreements

This proposal is similar to the first except that selected generation projects will be allocated ten- year "pay as generated" contracts. Under these contracts, the generator receives a fixed price for all of the energy delivered during the contract's term. As a result, exposure to the spot market price is eliminated, and there is no commitment for an hourly, monthly, or annual delivery, which would appear to suit the intermittent generation profiles of these type of generators.

The proposed mechanism involves holding a sealed-bid, discriminatory auction in which a specified amount of capacity (MW) of FNCER-based generation will be elicited. Interested generators will submit their projects' installed capacity, as well as the price per kilowatt/hour in pesos (COP/kWh) at which they are willing to sell their energy (i.e. including the CERE) over ten years.

Rather than a second series of auctions, these pay-as-generated contracts will be allocated to demand via one of two possible methods: the first is an allocation to all suppliers serving the regulated demand, as a pro-rata amount of their own demand. The second option is to allocate it to all marketers that are exposed in the spot market, as a pro-rate amount of their own exposure.

Issues

- First, this type of contract is simpler and less risky for nonconventional renewable generators, and to this extent may be preferable.
- Second, as with the first option above, it is unclear that a reserve price set at the average spot market price will be sufficient to induce investment in new, presumably risky technologies. More consideration will need to be given to this issue.
- Third, sealed-bid auctions appear to have worked successfully in eliciting investment in renewables in other countries, however the issue of a first-price versus discriminatory auction should be given further consideration.
- An alternative would be to auction a pay as generated subsidy in which generators bid to receive a premium over whatever price they receive from selling their energy in the spot or contract markets (as adopted in many European countries, and in the third proposal below).

5.3 Proposal 3: Green Charge Auctions

Given that the capacity factors, or ENFICCS, for FNCERs are much lower than those for hydro or thermal generation, this proposal defines a "green charge" that will reduce this discrepancy for these types of technologies. In particular, the idea is to define a maximum green charge which, if paid for all of energy produced by the selected generation projects, would give them the average Reliability Charge on their mean energy produced. This subsidy will be paid on top of any revenues received from long-term contracts or spot market sales by these generators.

The allocation of the green charge will be made via a sealed-bid, uniform price auction in which the "reserve price" will be maximum green charge. This is defined as the difference between the average reliability charge paid to thermal and hydro generators per unit of national demand (i.e. (CxC) (Firm Energy Commitments (OEFs))/Demand) and the average reliability payments made to FNCER plant (i.e. (CxC)(FNCER ENFICCs)/(FNCER Average Energy). Generators' offers in the auction will be a percentage of the maximum green charge up to limit of 100% and these bids will be accepted, starting with the lowest, until the desired amount of FNCER capacity is acquired. The uniform green charge paid to all accepted projects will be the offer price (%) of the last plant accepted in the auction.

Green charges will be paid to finished plants on each kWh of energy produced and sold under contract or in the spot market, for a period of 10 years. FNCER plants will also receive Reliability Charge payments for their firm energy.

5.4 Discussion

All of the proposals seem to be in accord with recent international practice in the auctioning of renewables.[30] Proposal 1 may appear to be the least desirable, at least for reasons of greater complexity, but this could be eliminated by making the auction product straightforward "contracts for differences" as recently done in the UK. Both Proposals 2 and 3 appear to be good options, but an industry consultation process should probably be undertaken before a particular design is adopted.[31] In all of the proposals the reserve prices need careful consideration, especially if there is a risk that insufficient supply offers will be elicited.

The Green Charge approach makes clear that FNCER generators in Colombia suffer a financial disadvantage due to their very low capacity factors, or ENFICCs. As discussed

[30] See AURES (2016) for a recent survey of international experience.

[31] Proposal 2 places less risk on the FNCER plant, and consequently may result in lower subsidy costs.

in our reports on wind power in Colombia,[32] there appear to be sound economic reasons for adopting a new approach to calculating ENFICCs for these technologies, and perhaps these should be reconsidered before a subsidy system is implemented (see Annex).

5.5 Annex on Calculating Firm Energy Levels from Wind Power in Colombia

There is no universally accepted method for calculating the contribution of intermittent generating technologies (such a wind) to system reliability. However, there are some basic principles that guide the methodology to be used, as well as experience in the application of this methodology.

The main principle for calculating the contribution of wind power to system reliability is to reflect the amount of firm energy the system can rely on when there is a high risk of shortages. In most systems, this occurs during periods of peak demand. However, in Colombia, the probability of shortage is highest during El Niño periods – in other words when hydro generation is low. So the question is how much firm energy can be provided by wind power in those periods.

The most straightforward approach is to calculate the wind capacity factor during times of high system demand. Many US regulators and utilities use this method. Each system has different hours of shortage, and each wind power station within a system will have output that coincides more or less with those shortage hours. To the extent that wind generation is higher at times of shortage, the plant will have a higher capacity credit factor. If generation occurs mainly during off-peak hours and little during shortage hours, the capacity credit factor will be much lower.

There are different ways to use the time period-related data to approximate wind's firm energy factor. One method is that used in PJM (the Pennsylvania–New Jersey–Maryland Interconnection, a regional transmission organization in the USA). This approach averages the wind-related generation over the relevant shortage periods in recent years in order to estimate the level of firm energy that can be expected during a period of system stress.

The relevant shortage periods in Colombia are mainly El Niño periods, especially during peak hours. Following the logic of the PJM approach, we estimated the ENFICCs for wind power using hourly generation data from the experimental Jepírachi wind farm in Colombia's Guajira region, between April 2004 and April 2011.

The ENFICC estimate (shown in the table above) uses the PJM methodology, applied to wind output on a daily basis and during peak hours during the last three El Niño

[32] See Robinson, Riascos and Harbord (2012) and Harbord, Robinson and Giraldo (2016).

PJM methodology to determine ENFICC for wind power in Colombia		
ENFICCs base	**5–7 a.m.; 6–8 p.m.**	**All day**
Niño 1	24.13%	29.05%
Niño 2	27.32%	37.02%
Niño 3	30.34%	33.78%
Average	27.26%	33.29%
	5–7 a.m.; 6–8 p.m.	**All day**
All 3 Niños	27.52%	32.58%

periods. This yields average estimates of ENFICC between 27 per cent and 33 per cent, compared to the CREG's estimates of below 15 per cent.

This suggests that the CREG's original 2011 methodology, with ENFICC below 15 per cent is too conservative. By narrowing our focus to periods when the systems is under stress, our ENFICCs reflect wind's contribution to system reliability when hydro generation is low.

An additional point is that in a system such as Colombia's, with high levels of both storage and installed capacity, the intermittency of renewables may be less relevant. In such a system, energy may be stored (i.e. hydro resources may be saved) when output from renewable sources is high, in order to be used (i.e. hydro resources produce) when output from renewables are small. This feature could be particularly important in defining renewables' firm energy factors, since it relates to periods of scarcity when spare capacity in both hydro dams is high.

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